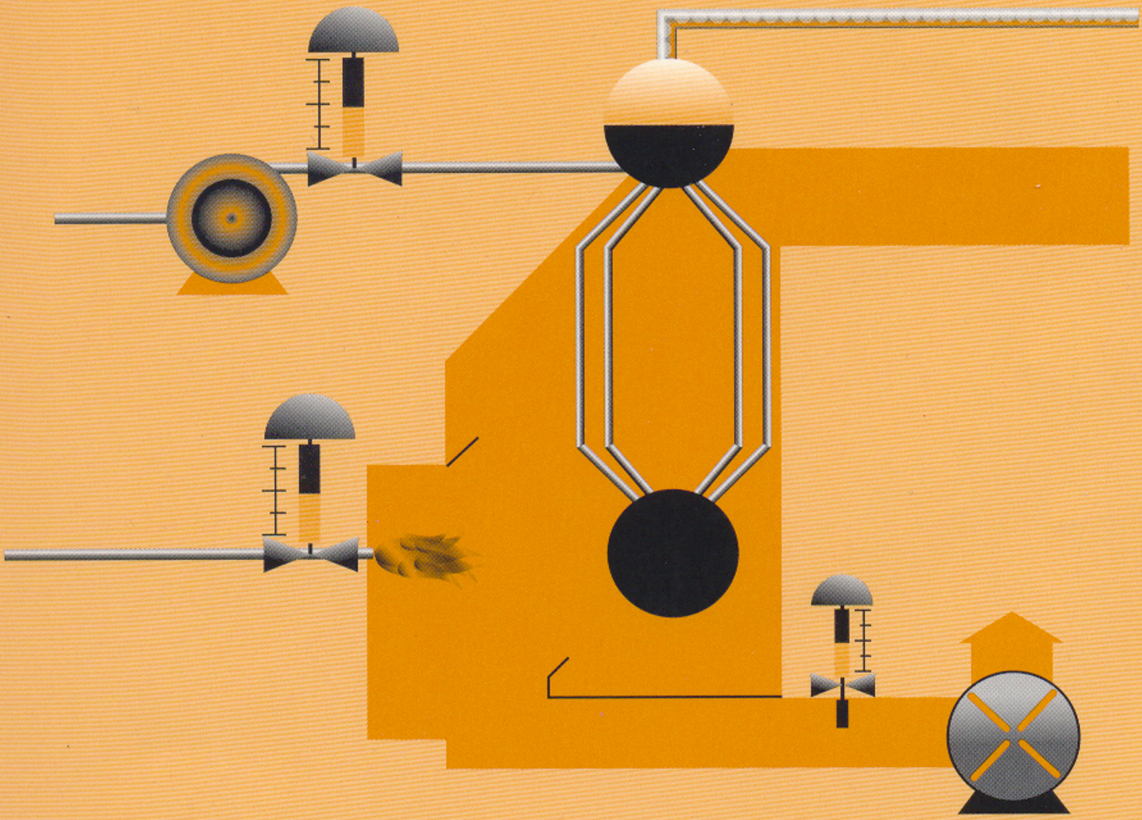
BOILER CONTROL SYSTEMS ENGINEERING



G.F. (Jerry) Gilman

ISA Connecting People and Ideas in Automation + Control

Printed in the United States of America
10 9 8 7 6 5 4 3 2

ISBN 1-55617-907-3

Library of Congress Cataloging-in-Publication Data

Gilman, G. F. (Jerry).
Boiler control systems engineering / G.F. (Jerry) Gilman.
p. cm.
ISBN 1-55617-907-3 (pbk.)
1. Steam-boilers--Automatic control. I. Title.
TJ288.G527 2005
621.1'94--dc22
2005010930

About the Author

Jerry Gilman's career has spanned over 35 years with Procter & Gamble (P&G), and its subsidiaries. As a process control systems engineer for P&G, Gilman was dedicated to improving control systems and implementing new technology in numerous product areas at P&G in the US and foreign countries. One of his areas of expertise has been with boiler control systems engineering: improving efficiency, conserving energy, and working as a primary troubleshooter on boilers and other combustion systems.

A licensed professional engineer, Jerry Gilman currently provides training and consulting to numerous utility and industrial plants. This includes performing startups, tuning, and troubleshooting more than a hundred boilers and combustion systems such as dryers, roasters, and ovens. Gilman's expertise in fuels and combustion control ranges from finding solutions for new unit applications to retrofitting existing installations in order to save fuel, change fuels, or improve overall control. He has applied his experience in combustion testing and energy utilization to help simplify boiler performance monitoring techniques and methods. His approaches are easy to understand and use effectively.

Jerry Gilman is also an instructor and course reviewer for ISA (The Instrumentation, Systems, and Automation Society) and developed the "ISA Boiler Control Systems Engineering" and "ISA Burner Management Systems Engineering" training courses. He has been a guest speaker on boiler control, burner management, and boiler safety issues at various ISA section meetings and other user groups and seminars. Additionally, he was a technical advisor for "Win Boiler Sim," a PC based boiler training program sold through ISA.

Jerry Gilman is an active member on the following ISA Standards Committees: ISA SP84 Programmable Electronic Systems (PES) for Use in Safety Applications; ISA SP84 Burner Management System Working Group; and ISA SP77 Fossil Fuel Power Plant Standards.

About the Cover Illustration

The cover graphic is a representation of the fuel gas, water tube, forced draft boiler simulated in the program Win Boiler Sim developed by Len Klochek and sold through ISA. The Windows-based simulation program was developed as a training tool, allowing personnel whose interests include boiler operations, as well as instrumentation and control maintenance and design, to obtain an understanding of the various control strategies and tuning procedures used on water tube boilers including: three element/single element drum level control, air flow/fuel flow cross limiting, and steam pressure control. In addition, a burner management system that follows the requirements of the NFPA 85 Boiler and Combustion Systems Hazard Code, 2004 Edition, Chapter 5: Single Burner Boilers, is part of the simulation allowing personnel to simulate a full boiler startup from filling boiler drum, light-off to full load. The program is used by the author as part of the ISA training seminars on boiler control.

Table of Contents

Figures and Tables

CHAPTER 1

Boiler Fundamentals

Basic Boilers

A boiler is comprised of two basic systems. (See Figure 1-1.) One system is the steam water system also called the waterside of the boiler. In the waterside, water is introduced and heated by transference through the water tubes, converted to steam, and leaves the system as steam.

Boilers must maintain a chemical balance. The manner in which this is done can interact with the feedwater control system. The amount of blowdown must be considered in the feedwater control scheme, especially if the blowdown is continuous. Often, the blowdown flow is divided by the concentration ratio times the feedwater flow. Continuous blowdown is the common method for controlling the chemical concentration. On large boilers this may be done automatically by measuring the boiler water conductivity to control the blowdown rate. The blowdown rate may also be achieved by combining the conductivity with ratio control of blowdown, ratioing blowdown to feedwater flow. In utility plants, conductivity is usually measured and blowdown is achieved manually. This is required on a periodic basis or when the conductivity gets too high.

Conductivity is measured in micro mhos which is equal to the reciprocal of 1 mechanical ohm (resistance). The other boiler system is the fuel air-flue gas system, also referred to as the fireside of the boiler. This system provides the heat that is transferred to the water. The inputs to this system are the fuel and air required to burn the fuel. The fuel and air chamber is also referred to as the windbox. The outputs are the flue gas and ash.

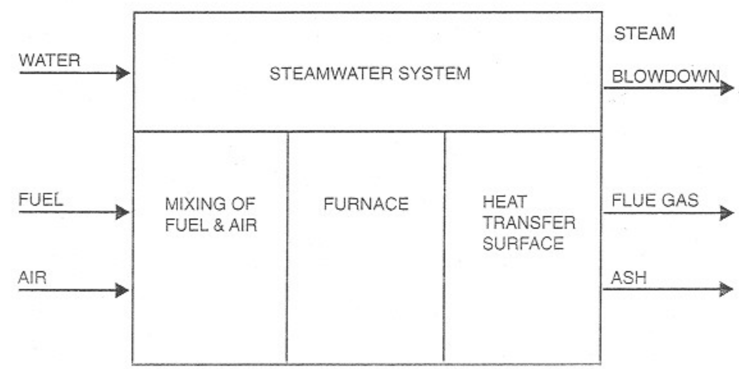


Figure 1-1 Basic diagram of a boiler.

Boiler Components

Note that in the boiler diagram, the steam goes to a header. This is common in industrial power plants; however, in utility plants the boiler is directly connected to the turbine. The firing demand in industrial plants is based on header pressure or drum pressure. Utility plants control the firing rate on megawatt demand, or throttle pressure. The firing rate demand depends on the particular system.

Furnace

The combustion chamber/furnace releases the heat and becomes the heat transfer system. There are three T's required for combustion to take place in the furnace: time, temperature, and turbulence. The control of the furnace draft is required to maintain a negative pressure in the furnace in a balanced draft boiler. This pressure is defined by the boiler manufacturer. Negative 0.5 inches is a common control point. The control set point may be raised during inspection rounds from 0.5 inches to 1.0 inches to minimize the possibility of flame coming out of inspection doors. Draft pressure control setting is defined by the boiler manufacturer and environmental equipment. Under certain conditions, the furnace pressure may be controlled positive.

Fans

Figure 1-2 illustrates the basic components of a coal-fired boiler. The boiler consists of an ID (Induced Draft) fan and an FD (Forced Draft) fan. Large utility boilers may have two ID fans and two FD fans. The ID fan pulls air through the boiler producing a negative pressure in the furnace, thus creating draft control. The FD fan pushes air for combustion through the boiler. On utility boilers, FD fans normally supply secondary and overfire (tertiary air) with primary air (P.A.) flow being supplied by the P.A. fans. Industrial boilers often have separate fans for the tertiary air as well.

Due to the 1990 Clean Air Act amendments, there is often emission control equipment such as precipitators, bag houses, and sulfur dioxide scrubbers on the discharge of boilers. (See Figure 1-3.) If environmental equipment is added, booster ID fans may be required. The draft pressure control is defined by both the boiler manufacturer and environmental equipment.

Windbox

The windbox distributes secondary air to the burners. The windbox may have damper adjustments to create turbulence to improve combustion.

Flue Gas Heat Exchangers

To reduce heat loss in the boiler flue gases and to improve boiler efficiency, heat exchangers are added to the boiler to recover heat and to cool the flue gases.

Source: Fisher Controls

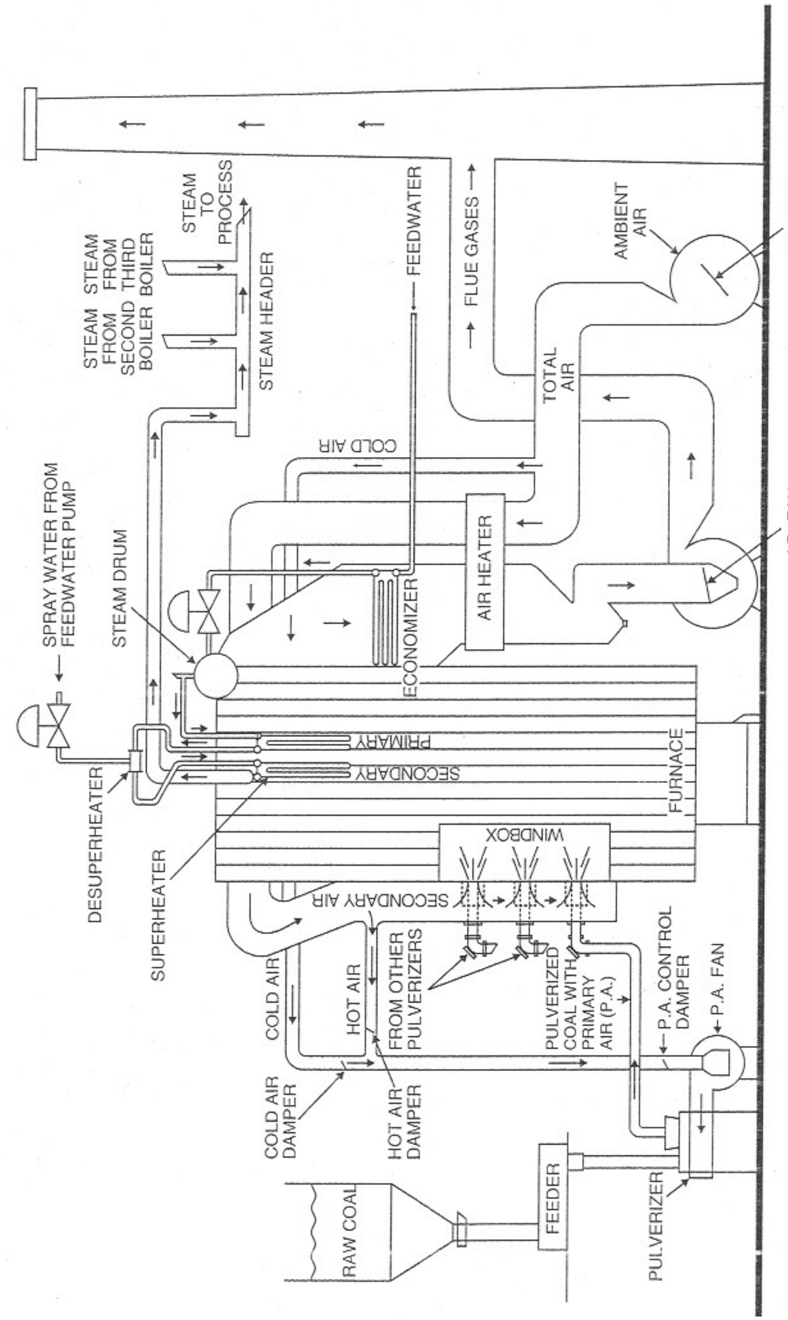


Figure 1-2 Boiler components.

B&W Steam its generation and Use 40th Edition.

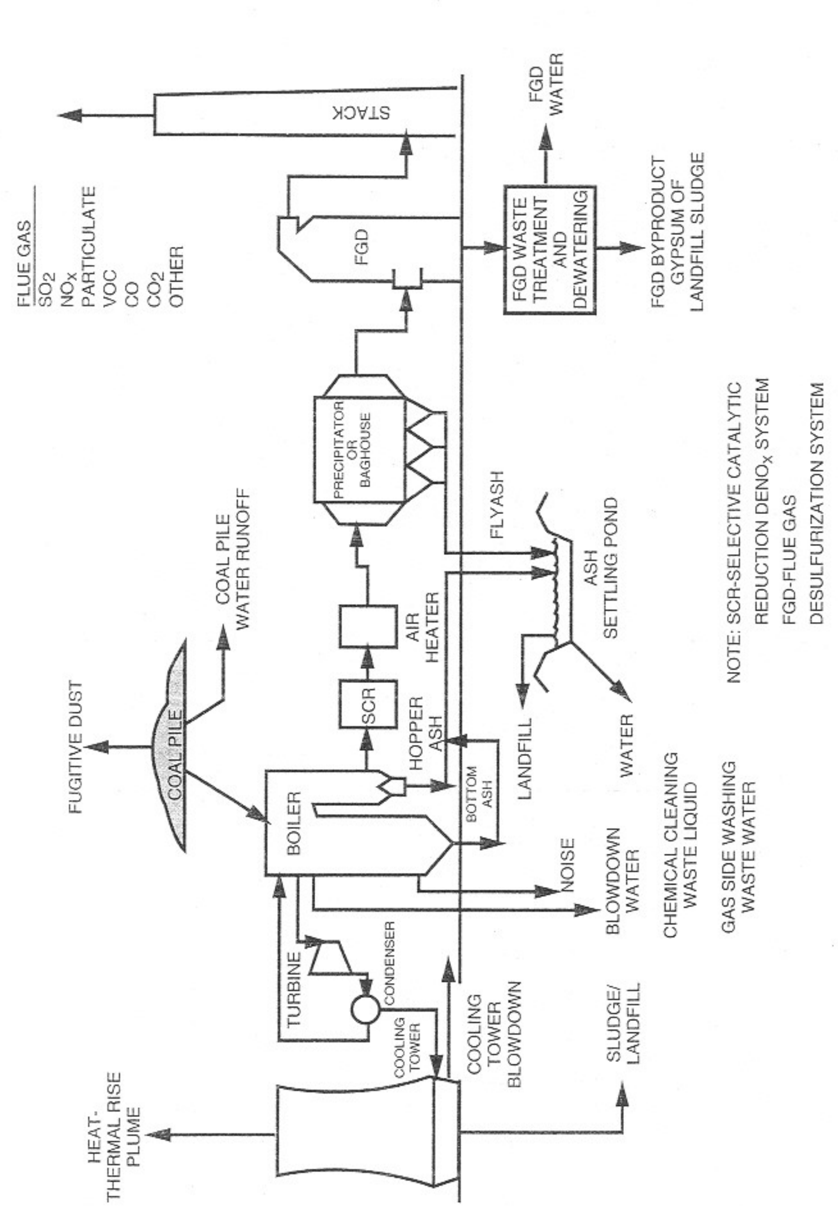


Figure 1-3 Typical power plant effluents and emissions.

Combustion Air Preheater

The combustion air preheater is one type of heat exchanger. (See Figure 1-4.) As the flue gas leaves the boiler, it passes through the combustion air preheater. The combustion air passes through the air preheater heat exchanger before being mixed with the fuel.

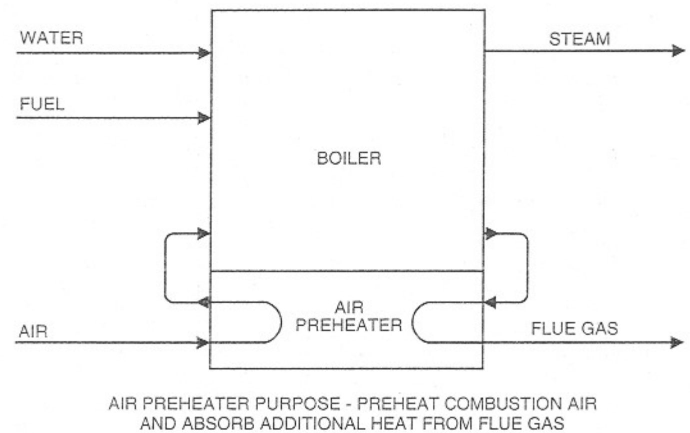


Figure 1-4 Simple boiler plus combustion air heater.

Since the flue gas temperature is higher than the air temperature, heat is transferred from the flue gas to the combustion air via the convection heat transfer surface of the combustion air preheater. This transfer of heat cools the flue gas and thus reduces its heat loss and reduces the temperature of the air to the stack. The added heat in the combustion air entering the furnace enhances the combustion process. This reduces the fuel requirement in an amount equal in heat value to the amount of heat that has been transferred in the combustion air preheater, thus improving efficiency.

By the use of an air preheater, approximately one percent of fuel is saved for each 40°F rise in the combustion air temperature.

Economizer

Another flue gas heat recovery method is through the use of an economizer. The economizer heats the feedwater to improve boiler efficiency and reduce heat loss to the stack. The increased heat in the feedwater reduces the boiler's requirement for fuel and combustion air. In the economizer arrangement shown in Figure 1-5, the flue gas leaves the boiler and enters the economizer where it makes contact with the heat transfer surface, in the form of water tubes, through which the boiler feedwater flows. Since the flue gas is at a higher temperature than the water, the flue gas is cooled and the water temperature is increased. Cooling the flue gas reduces its heat loss in an amount equal to the increased heat in the feedwater to the boiler. Both types of heat exchangers are often used in large boilers.

When both an air preheater and an economizer are used, the normal practice consists of passing the flue gases first through the economizer and then through the combustion air preheater. (See Figure 1-5.) Utility boilers normally have economizers and air heaters.

While economizers are used to recover heat from the flue gas, the use of Selective Catalytic Reduction (SCR) requires flue gas temperatures above a specified minimum temperature to operate. To extend the range of operation of the SCR, the economizer surface may be bypassed to raise flue gas temperatures at lower loads.

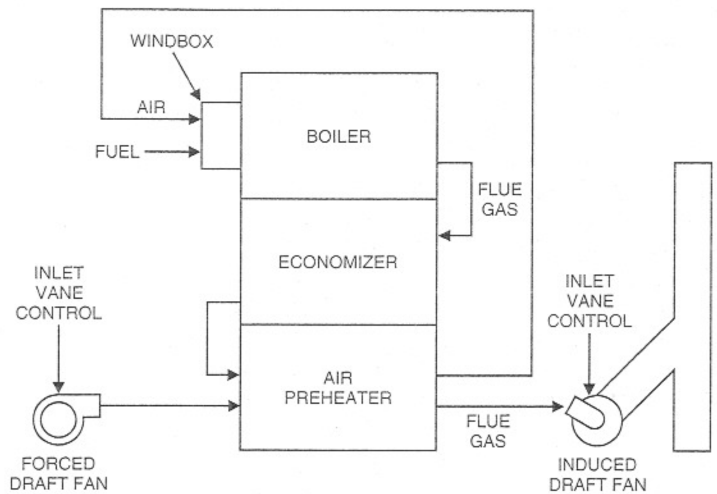


Figure 1-5 Economizer.

Superheater

The superheater provides additional heat to the steam to remove any moisture from the steam, thereby improving the quality of the steam. The dryness of the steam (in percent) is the determining factor of its quality. When there is no moisture in the steam, the quality is 100 percent.

Boiler Drums

The boiler in Figure 1-2 does not have a lower drum. High pressure utility boilers used for power generation have only an upper drum.

Boilers may consist of an upper drum, or steam or water drum, and a lower drum, or mud drum. The mud drum terminology comes from the function of the lower drum. Although the water is treated to eliminate dissolved solids, some solids always remain in the water. These solids collect in the lower drum, and a drum blowdown is required to remove the solids that collect in the lower drum. The blowdown may be manual or automatic.

Figure 1-6 has an upper and lower drum. Industrial plants commonly have both upper and lower drums. The heating of the tubes initiates a natural circulation of the water. In some large utility boilers, this circulation is not sufficient and a pump is installed to produce the required circulation. The circulation of the water creates a cooling effect to keep the tubes from overheating.

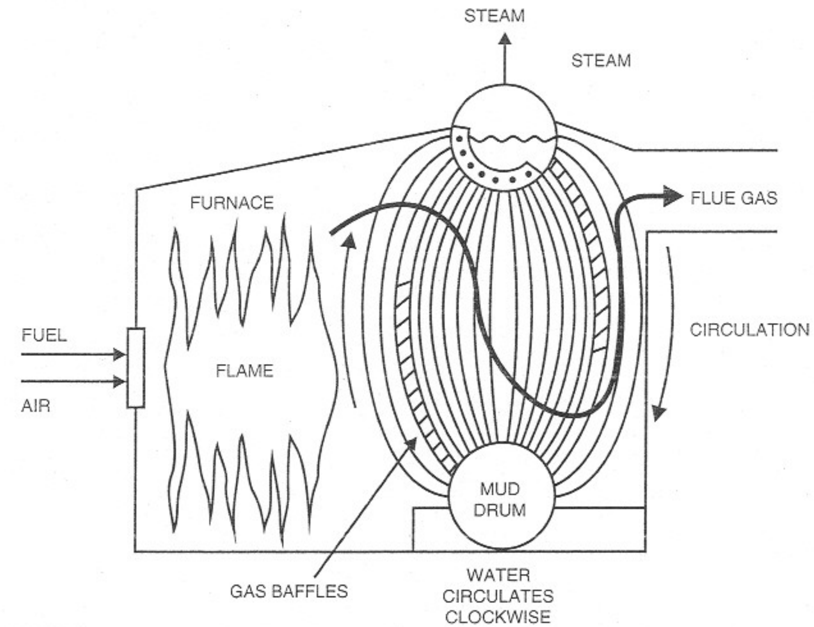


Figure 1-6 Boiler drums.

Piping and Instrument Diagrams (P&IDs)

The purpose of P&IDs is to provide an initial design basis for the boiler. The P&ID provides the engineering requirements to identify the measurements and functions that are to be controlled. It may be used to define the number of inputs and outputs and may also consist of a design basis check list (DBCL). The DBCL lists all the instruments and functions. Utility plants generally define the control systems on Scientific Apparatus Makers Association (SAMA) drawings and do not have a P&ID.

By identifying the required measurements and control functions, an I/O count can be defined. By defining the control functions, the memory requirements can be established. Memory and I/O capabilities can be important in selecting a basic process control system and/or logic system. Utility plants commonly use the term process control system (PCS).

The controls system may consist of panel mounted instruments, a distributive control system (DCS), logic system, or a combination. This also includes the amount of redundancy of both measurement and final control elements.

The numbering system will be based on the standard for the plant. The ISA and SAMA letter identification is used by most companies. ISA and SAMA identification letters are the same. (See ISA and SAMA identification tables in the Reference section for more information.) The letter configuration identifies the letter definition. For example, when T is the first letter, it represents temperature. T as a succeeding letter is a transmitter. The numbering will consist of the identification letters, such as a PT, and the tag number. The tag number can consist of a system or loop number. An example would be: PT 115 1001. The PT represents the pressure transmitter, the 115 the system number, and 1001 the instrument number.

In the examples on the design basis check list, the PT is a pressure transmitter. Note P is used for both pressure and vacuum. PV is the pressure valve. V is used for valves, vanes, or dampers. PIC is the abbreviation used for a pressure indicating controller.

Design Basis Check List

The purpose of the design basis check list (DBCL) is to track the instrumentation.

Example of a design basis check list							
Type	**Tag #**	**Service**	**Model**	**Calibration**	**P&ID**	**Delivery**	**Spec Status**
PT	1001	Draft Control	A 1234	-4 to +4 "wc"			
PV	1001	Draft Vane					
PIC	1001	Draft Control	BPCS	-4 to +4 "wc"			

The DBCL may have numerous columns including items such as SAMA drawings, logic drawings, serial numbers, or any other items determined by the engineering and plant team.

The DBCL may be used as a relational data base providing the ability to sort by categories such as delivery status, hardware to determine missing items, hardware to determine spare requirements, or any sort categories required.

CHAPTER 2

Control of Boilers

Control Strategies

There are basically five fundamental control strategies that are used in process control. They are: simple feedback control, feedforward plus feedback control, cascade control, ratio control, and feedforward control. In the control of boilers, all five of the fundamental control strategies are used. Many companies show all controllers on drawings as PID controllers. This is because vendor algorithms/function blocks for control are defined as PID controllers. Most control loops are PI only, therefore that format is used in this book.

Bumpless Transfer

The NFPA 85 Code requires bumpless transfer from manual to automatic. Before the development of the DCS (distributive control systems) and electronic systems, it was the responsibility of the operator to line up the set point and the process variable before transferring to automatic control. These systems have the capability of the set point tracking the process variable so they are aligned when control is transferred to automatic control.

Simple Feedback Control

With simple feedback control, changes in the primary variable feed back to a control function, as shown in Figure 2-1. The process variable is compared to the set point of the controller. The differential between the set point and process variable generates an output signal to the manipulated variable and adjusts the variable to bring it back to set point. The function can be proportional-plus-integral (as shown), proportion-only, proportional-plus-derivative, integral-only, or proportional-plus-integral-plus-derivative.

In all these cases, the controller includes an error detector function, which measures the error between the primary variable and the set point. Other terms are used such as process variable or measured variable. The controller output is determined by a combination or summation of the effects of the different control action capabilities that are built into the controller. This can be gain, reset, derivative, or any combination of the three. These are the proportional or gain multiplication of the error magnitude, the difference between the measured amount and the set point, the integral action based on incremental time away from set point multiplied by error magnitude, and the derivative or rate of change of the measured variable. Derivative action is not represented in the SAMA drawing examples, although it may be used.

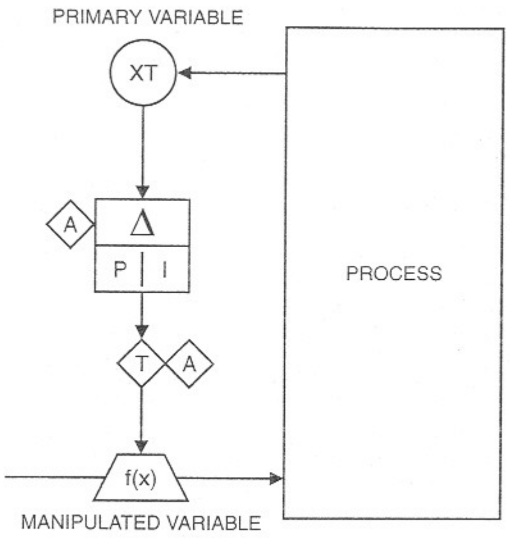


Figure 2-1 Simple feedback control.
Note: See Reference section for explanation of SAMA symbols.

Derivative action should only be used when there is dead time or a slow responding process such as temperature control. A change in the controller output changes the manipulated variable, which through action of the process, changes the process output selected as the primary variable. The manipulated variable may also be referred to as the process variable. For drum level control, the manipulated variable is the water flow. On draft control, the manipulated variable is typically the ID fan vane or damper and may be ID fan speed control or a combination of vane or damper and speed.

More detail on how proportional, integral, and derivative action function is covered in controller tuning.

Feedforward plus Feedback Control

In feedforward-plus-feedback control, a secondary variable that has a predictable relationship with the manipulated variable is connected. (See Figure 2-2.) In this case, a change in the secondary variable causes the manipulated variable to change in anticipation of a change in the primary variable. This reduces the magnitude of the primary variable change due to the more timely control action that originates from the secondary variable. The feedback portion of the loop contains the set point and can contain any of the controller functions of the basic feedback loop. The feedforward gain is adjustable.

Basically, the feedforward portion of the control loop minimizes upsets and keeps the process at the desired set point.

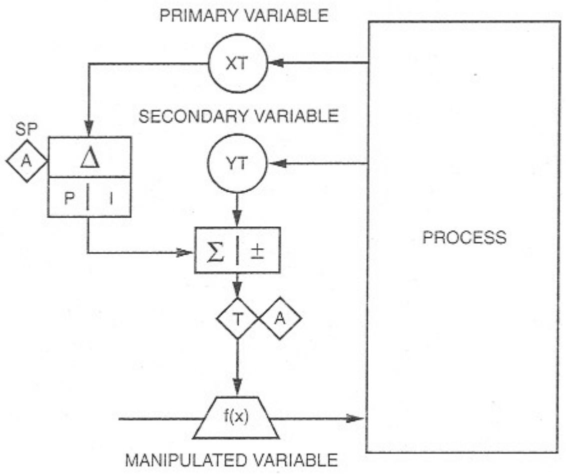


Figure 2-2 Feedforward plus feedback control.

Cascade Control

Cascade control consists essentially of two feedback control loops connected together with the output of the primary loop acting as set point for the secondary loop. (See Figure 2-3.) Cascade control is applied to stabilize the manipulated variable so that a predictable relationship between the manipulated variable and the primary variable can be maintained.

To avoid control instability due to interaction between the two feedback control loops, it is necessary that the response time constants be substantially different. Process response of the sec-

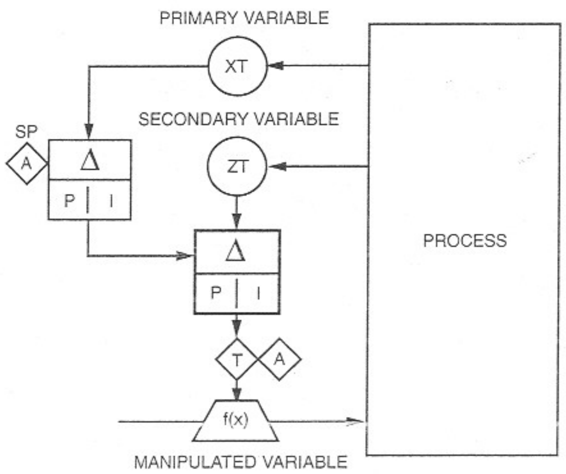


Figure 2-3 Cascade control.

ondary control loop should be the faster of the two. A general rule is that the time constant of the primary loop process response should be a minimum of 5 to 10 times that of the secondary loop. The longer time constant of the primary loop indicates a much slower response. Because of this, a normal application would be temperature control (a normally slow loop) cascading onto flow control (a normally fast loop). Other suitable candidates for cascade control are temperature cascading onto pressure control and level control cascading onto flow control.

Ratio Control

Ratio control consists of a feedback controller whose set point is in direct proportion to an uncontrolled variable. (See Figure 2-4.) The operator of the process can set the proportional relationship, or another controller, or a feedforward signal can automatically adjust it. When boilers burn multiple fuels, air requirements for the different fuels may vary. Ratio control is used to ratio the quantity of air required for different fuels.

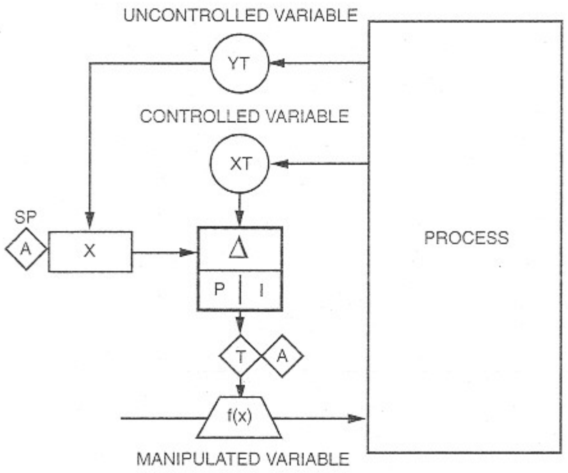


Figure 2-4 Ratio control.

As shown, the mathematical function is a multiplier. If the ratio is set, the set point of the controlled variable changes in direct proportion to changes in the uncontrolled variable. If the multiplication is changed, the direct proportional relationship, or ratio between the controlled and the uncontrolled variable, is changed.

Most boiler control applications will consist of an overall control system in an interconnected matrix of the five types of control.

Feedforward Control

Feedforward control is used in a number of configurations to improve process control. In feedforward control, a measured variable is used to detect a process change in the system. The

measured variable sends this information to a feedforward controller. The feedforward controller determines the required change in the manipulated variable, so that when the effect of the change is combined with the change in the manipulated variable, no change occurs in the controlled variable. This perfect correction is difficult to accomplish. Feedforward control has some significant problems. The configuration of feedforward control assumes that the changes are known in advance, that the changes will have transmitters associated with them, and that no important undetected changes will occur. Steam flow is used as a feedforward signal for the set point of an O_2 analyzer, or the signal from a fuel flow can be used to set a fuel air ratio. (See Figure 5-3 in Chapter 5.) Feedforword can be used to add derivative to increase pulverizer coal feed.

Controller Tuning

There are a number of procedures for tuning controllers. There is Default Tuning, S.W.A.G. tuning, Ziegler Nichols, Lambda, and self tuning. Some startup engineers still use the trial and error or S.W.A.G. method.

Self tuning controller algorithms are now available for insertion into control systems. Such controllers automatically compensate the controller tuning as process or boiler conditions change. Adaptive tuning can also be implemented from load or some other variable of the process.

"Lambda tuning was originated in the synthesis design method whereby the controller must cancel out the process dynamics. In more technical words, given the transfer functions of the components of a feedback loop, synthesize the controller required to produce a specific closed-loop response (loop in automatic). The simplest achievable closed-loop response is a first-order lag. This response was originally proposed by Dahlin (1968), who defined the tuning parameter with Greek letter LAMBDA, to signify the time constant of the control loop in automatic, hence the name Lambda Tuning. Lambda Tuning produces a first order, non-oscillatory response to a set point change. This is done by selecting the desired time constant on automatic. Loops tuned using Lambda Tuning will minimize (or eliminate) over-shoot, have great flexibility, and present repeatable results. This method is becoming more popular as more uniform products are required, minimum variability is demanded, and stable processes are needed."[1]

To demonstrate the various tuning modes the Ziegler Nichols method is used. In 1942, Ziegler and Nichols were the first to propose a standard method for tuning feedback controllers. After studying numerous processes, they arrived at a series of equations that can be used for calculating the gain, reset, and derivative values for feedback control loops. They developed two methods. One is referred to as the ultimate method because it requires the determination of the ultimate gain (sensitivity) and the ultimate period for the control loop. The ultimate gain is the maximum allowable value of gain for a controller with only a proportional mode in operation for which the closed loop system shows a stable sine wave response to a disturbance.

The second method developed by Ziegler and Nichols for tuning control loops was based on data from the process reaction curve for the system under control. The process reaction curve is simply the reaction of the process to a step change in the input signal. This process curve is the reaction of all components in the control system (excluding the controller) to a step change to the process.

[1] Tom Dorsch, "Lambda Tuning: An Alternative to Ziegler Nichols," December 1997: Fisher Controls.

The ultimate method is also referred to as the quarter decay tuning. (See Figure 2-5 and Table 2-1 for the equations.) This method requires defining the Su and the Pu. (See Figure 2-6.) Su is ultimate sensitivity and is the gain or proportional band that creates a continuous sine wave, steady state output as indicated on the center graph in Figure 2-6. This is determined with the reset/integral turned off. Pu is the ultimate period or time between the peaks of the steady state sine wave in Figure 2-6.

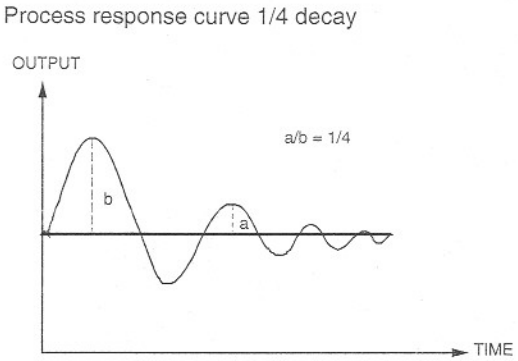


Figure 2-5 Ziegler Nichols tuning.

The ultimate method is used in the examples because it is easy to understand and demonstrates the difference between proportional/gain, reset/integral, and derivative control by using PC-ControLAB 3, a software training program developed by Harold Wade Associates and sold by ISA. The top diagram in Figure 2-6 demonstrates an unstable response. In this diagram the output variations become larger and larger. The bottom diagram demonstrates dampened response. In this diagram the outputs become smaller and smaller. With this method there is overshoot. In some cases, it is important to tune the system so that there is no overshoot.

The center diagram demonstrates a stable response. From this diagram we can determine the Su and the Pu. In these equations, gain is used and the integral is in minutes/repeat. Some vendors use repeats/minute instead of minutes/repeat, or proportional band, instead of gain.

For any feedback control system, if the loop is closed (and the controller is on automatic), one can increase the controller gain, during which time the loop will tend to oscillate more and more. If the gain is further increased, continuous cycling, or oscillation in the controller variable, will be observable. This is the maximum gain at which the system can be operated before it becomes unstable; therefore, this is the ultimate gain. The period of these sustained oscillations is called the ultimate period. If the gain is increased further still, the system will become unstable. These three situations are illustrated in Figure 2-6.

Table 2-1 Tuning terms/equations

Terms are:		
Kc = gain	Pu = ultimate period	
Ti = integral, reset (Time integral)	Su = ultimate sensitivity	
Td = derivative (Time)		
Equations are:		
Proportional only	Proportional only Figure 2-6 a	
Kc = 0.5 Su	Kc = 0.5 Su	0.5 x 9 = 4.5 gain
Proportional-Plus-Reset	Proportional-plus-reset Figure 2-6 b	
Kc = 0.45 Su	Kc = 0.45 Su	0.45 x 9 = 4.05 gain
Ti = Pu/1.2 min/rpt	Ti = Pu/1.2 min/rpt	7.5 / 1.2 = 6.25 reset
Proportional-Plus-Derivative	Proportional-Plus-Reset-Plus-Derivative Figure 2-6 c	
Kc = 0.6 Su	Kc = 0.6 Su	0.6 x 9 = 5.4 gain
Td = Pu/8	Ti = 0.5 Pu min/rpt	0.5 x 7.5 = 3.75 reset
	Td = Pu/8	7.5 / 8 = 0.94 derivative
Proportional-Plus-Reset-Plus-Derivative		
Kc = 0.6 Su		
Ti = 0.5 Pu min/rpt		
Td = Pu/8		
Using the equations Su = 9 and Pu = 7.5 minutes from Figure 2-6.		

Determining Gain, Reset, and Derivative

To determine the ultimate gain and the ultimate period, remove the reset and derivative action from the controller by setting the derivative time to zero and the reset time to infinity, or turn the reset off. PC ControLAB 3 provides the ability to turn off the reset by going to tune options and turning off reset.

With the controller in the automatic mode, the loop closed, and the gain set at 12, an upset is imposed on the control loop and the response observed. The easiest way to impose an upset is to change the set point by a small amount. If the response curve produced does not dampen out and is unstable (top of Figure 2-6 - unstable response), the gain is too high.

With the gain set to 3, an upset is created. If the response curve dampens out (bottom of Figure 2-6 - dampened response), the gain is too low. The gain was increased and upsets repeated until a stable response was obtained.

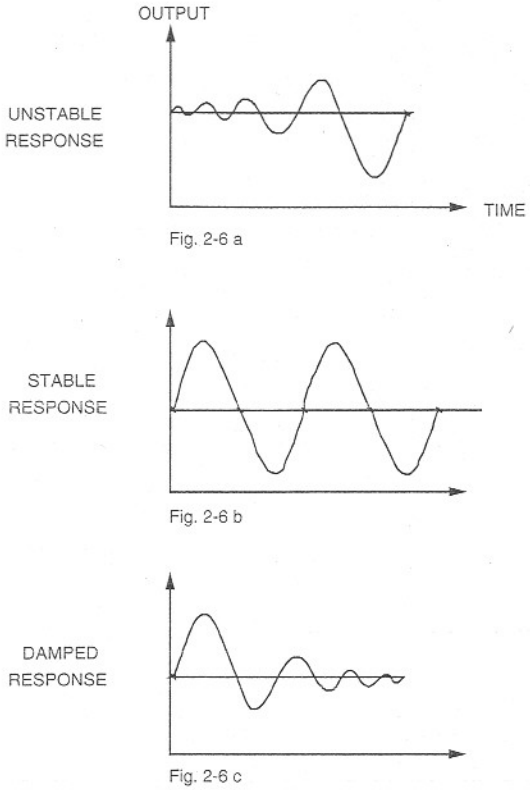


Figure 2-6 Typical control system responses.

When a stable response is obtained, the values of the ultimate gain (Su) and the ultimate period (Pu) of the associated response curve should be noted. The ultimate period is determined by the time period between successive peaks on the stable response curve. The ultimate gain (also called the ultimate sensitivity or Su) is the gain setting of the controller when a stable response is reached (center of Figure 2-6 - stable response).

Using PC-ControLAB 3, the stable response is achieved with a gain of 9, and the time from peak to peak is approximately 7.5 minutes. The 7.5 minutes is the peak to peak time on Figure 2-7. The cycle is generated with a gain of 9 and no reset (reset turned off).

Gain vs. Proportional Band (PB)

Gain and proportional band are used as tuning terms. Gain is the reciprocal of proportional band. Proportional band (PB) is in percent.

Prop Band = 100 / Gain
Gain = 100 / Prop Band

Examples: If Gain is 2, PB = ½ = 0.5 X 100 = 50% PB or 100% / 2 = 50%
If Gain is 0.5, PB = 1 = 2 X 100/0.5 = 200% PB or 100% / 0.5 = 200%

Repeats per minute vs. minutes per repeat:

Integral Action is minutes per repeat or repeats per minute. Repeats per minute is the reciprocal of minutes per repeat.

Example: 0.5 Min/Repeat = 1/0.5 = 2 Repeats/Min

Figure 2-7 demonstrates a typical output variable.

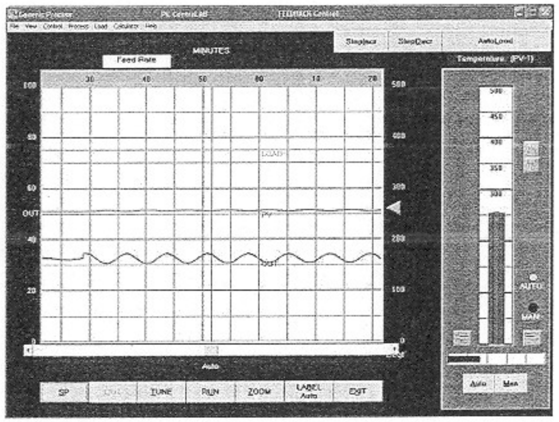


Figure 2-7 Typical output variable.
Note: Only a small output cycle is required to determine the Su and Pu values.

Controller Actions

Gain/Proportional Action

When gain/proportional control only is used, there is a one-time step change based on deviation from set point. A feedback controller with gain/proportional control only, may not stabilize the set point. (See Figure 2-8.) Note the difference between the process variable (PV) and set point (SP). For gain/proportional only control, the gain is 4.5 (see Table 2-1).

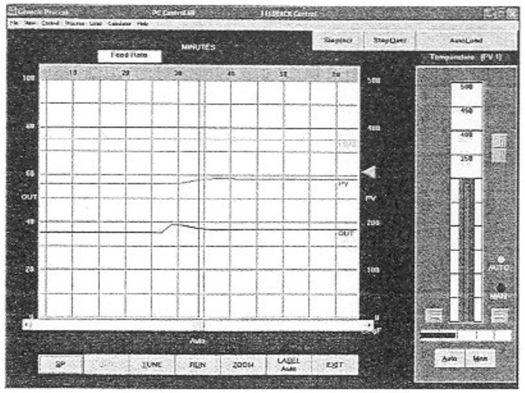


Figure 2-8 Deviation between setpoint and process variable.

Integral/Reset Action

Integral action is time-based change in minutes and repeats the gain change until the loop stabilizes at set point. The tuning setting is in repeats per minute or minutes per repeat. Note in Figure 2-9 with gain/proportional and integral/reset action, the measurement lines out at set point in approximately 30 minutes. Also note the recovery on the second cycle is one quarter of the first cycle. For gain/proportional plus reset control, the gain is 4.05 and reset is 6.25 (see Table 2-1).

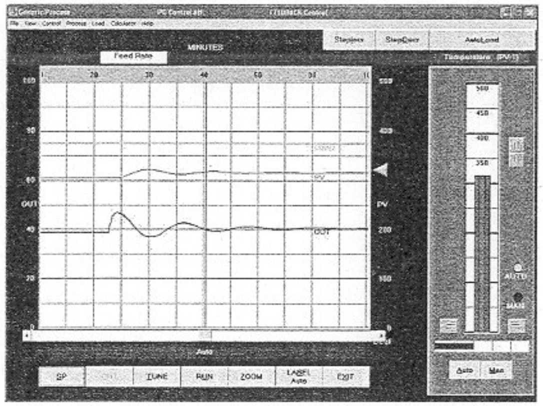


Figure 2-9 Upset in return to recovery with reset.

Derivative Action

When there is dead time or a slow reacting process, derivative can be added to improve control. Derivative time action contributes an immediate valve/output change proportional to the rate of change of the error. As the error increases, the proportional action contributes additional control valve movement. Later, the contribution of the proportional action will have equaled the initial contribution of the rate action. The time it takes for this to happen is called the derivative time. Derivative action is applied to a process that is slow or has dead time. Note in Figure 2-10, with the addition of derivative, the measurement lines out at set point in approximately 10 minutes for gain. As was noted in Figure 2-7, only a small output cycle was required to determine the Su and Pu values.

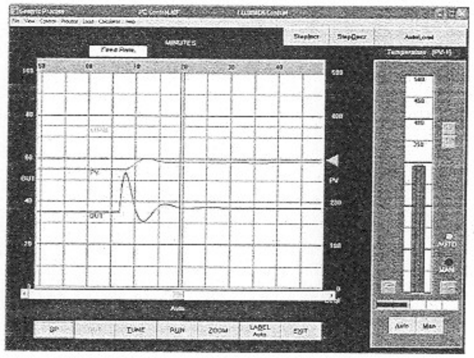


Figure 2-10 Upset in return to recovery with derivative action and reset.

The Ziegler Nichols method can be used on most process control loops; however, no one method can be used on all control loops.

Figure 2-11 is an example of control of a process with randomly varying load and with PID control and the tuning determined by using Ziegler Nichols tuning parameters.

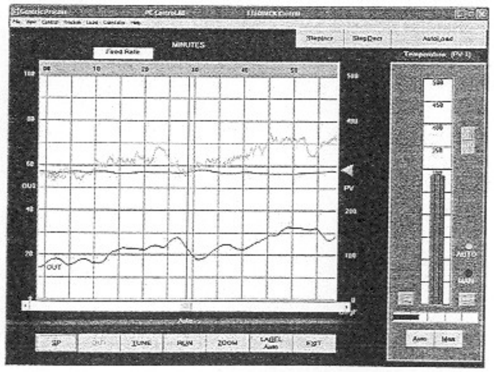


Figure 2-11 Steady process variable with randomly varying load.

Controller Actions Setup

There are many different functions required in design and configuration and/or programming a control system. Controller functions need to be determined. Controller functions can be direct or reverse acting. A direct acting controller output increases as the PV (Process Variable) increases, and a reverse acting controller output decreases as the PV increases. If the control system is programmable, the systems engineer must make the selection. The failure mode of the control valve or damper determines whether the controller is a direct or reverse acting controller. Units of measurement are in percent or engineering units. When we think of the various control signals such as the process variable or set points, we can define them as a percentage or assign engineering units.

The Effects on Tuning

There are numerous things that affect the tuning of control loops. Some examples are: reaction time of process, process noise (furnace pressure, air flow), calibration of transmitter (span of the transmitter), linearity of process (pH loop), linearity of final element, speed of response of final element (valves, dampers), valve sizing and valve hysteresis. The addition of a valve positioner can improve control by providing valve position repeatability for a specific input.

Temperature control would be an example of a slow responding process. Flow control would be an example of a fast responding process.

Calibration Effect on Gain

Example: Span of transmitter

0-2000 psi 4-20 ma = 125 psi/ma
1000 to 2000 psi 4-20 ma = 62.5 psi/ma

Note, the span is one number and calibration range is two numbers.

Using engineering units in this example, the span of 0-2000 is two times that of the span 1000-2000. Therefore, the gain would be two times greater than when calibrated with a span of 0-2000 psi. This is a common problem particularly on high pressure boilers. With a wide span, a control output may cycle and yet the process appears to be steady.

There is no one method of control tuning that is best for all process loops. Different types of processes, control valves or dampers, vendor control algorithms or function blocks can make this impractical.

Transmitters

Each control loop should be reviewed by a risk analysis to determine if a redundant transmitter or switch is required. Field transmitter or switch device redundancy should be provided to the extent necessary to achieve desired system reliability. When two transmitters or switches are employed, excessive deviation between the devices must be alarmed and the associated control loop transferred to manual. When three transmitters are employed, excessive deviation between the transmitters must be alarmed. A median select signal is required by the NFPA 85 Code for furnace pressure measurement and is commonly used when there are multiple transmitters.

When writing specifications for transmitters or switches, it is important to include calibration range and span. Also include materials of construction, especially the wetted parts. For transmitters consider the effect on tuning control loops. If the span is significant, the gain on the controller may be difficult to set.

Redundancy

When two transmitters or switches are employed, it may be configured as 1-o-o-2 – one out of two. This is called redundancy. Two protective circuits are operating essentially in parallel. A single point failure will disable one of the two circuits while the redundant circuit continues to provide the needed protection. A failure detection mode such as no output must be defined.

When two transmitters or switches are employed, it may be a 2-o-o-2 – two out of two. This is not redundancy, because a single point failure in either circuit will cause an output tripping action. This allows no fault tolerance, yet has two circuits required to hold. Where 1-o-o-2 might be a parallel circuit (normal operation energized with de-energize to trip), 2-o-o-2 would be a series circuit. If two flame detectors are required to see flame, or the boiler will trip, this is 2-o-o-2. This demonstrates that it is possible to have a 1-o-o-1 circuit with a 2-o-o-2 portion, a 1-o-o-2 circuit with a 2-o-o-2 portion, or a 2-o-o-3 circuit in which a critical portion is 2-o-o-2.

When three transmitters or switches are employed, it could be configured as 2-o-o-3 voting. This could be called triple redundancy. In this type of interlock system, the output of two out of three individual interlock circuits must agree to hold in a circuit in monitoring normal operation. If two out of three agree to trip, tripping action will trip the process equipment device. Any single point failure involving the interlock devices will not trip the operating equipment. A maximum of two such failures will trip, just as a minimum of two good circuits will allow continued operation.

Three transmitters or switches 2-o-o-3 could be configured voting with fault tolerance. While this type of system requires two out of three voting to keep process equipment operating, more than two single point failures in separate circuits can be tolerated. For example, if the total circuit is made triple redundant and each circuit broken into three sequential parts, 27 separate potential pathways in 9 circuit segments exist.

Interlock Circuitry

One, two, or three transmitters may be required. When only one transmitter is employed, it is referred to as 1-o-o-1 – one out of one. In this configuration, a single circuit with a single point failure in the system will cause an output action. The circuit itself should be designed so that any output action is always safe (e.g., shutdown the equipment). ASME recommends median select. The NFPA 85 Code requires median select for furnace pressure measurement.

Final Control Elements

All final control elements are to be designed to fail safe on loss of demand signal or motive power, i.e., open, close, or lock in place. The fail safe position must be determined by the user and based upon the specific application.

Furnace Draft

Pressure Fired Boilers

A pressure fired boiler does not have an induced draft fan and may operate under a positive pressure over some portion or all of the load range. In this type of boiler, the furnace pressure varies as the load is changed due to the variation in draft losses with respect to boiler load. As the firing rate increases, more air is supplied by the forced draft (FD) fan increasing the pressure in the boiler furnace.

Figure 3-1 represents the physical arrangement of a pressure fired boiler system. A key point with these boilers is that the furnace must be airtight and the flue gastight. This is necessary so that the very hot flue gas of the furnace cannot leak to the atmosphere. A small leak under such circumstances will deteriorate the material around it, eventually destroying the furnace walls and creating an operational hazard. Furnaces for pressure fired boilers are made pressure-tight with a welded inner casing or seal between the furnace wall steam-generating tubes and have a sealed window to observe the flame and furnace conditions.

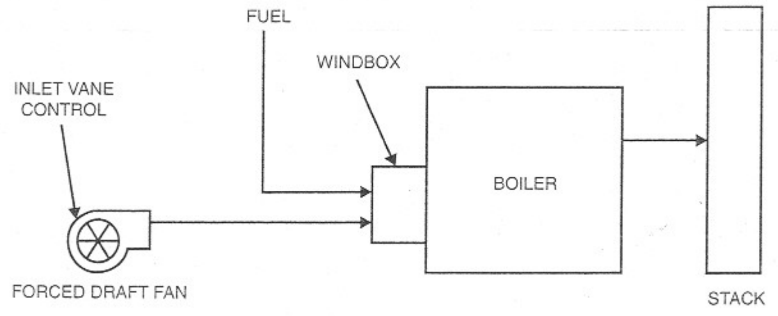


Figure 3-1 Pressure fired boiler.

Balanced Draft Boiler Fans

The fireplace in our homes is an example of a natural draft system. As heat rises, the draft is created by the natural heat rise to the outside air. There is no fan forcing air into or out of the fireplace. Utility and industrial boilers require some form of mechanical draft, which is produced by the combustion air fans. Balanced draft boilers consist of an FD and an induced draft (ID) fan(s). An FD fan, or air blower, takes suction from the atmosphere and forces combustion air through the system. The ID fan is located at the end of the boiler flow system path and takes its suction from the boiler flue gas stream, discharging the flue gas to the stack. Large utility boilers may have two FD fans and two ID fans. For an additional definition of fans, see the section on boiler components.

Furnace Pressure Control

Control systems are divided into furnace, drum level feedwater, fuel air, and temperature control (see Figure 3-2). The first system is furnace control.

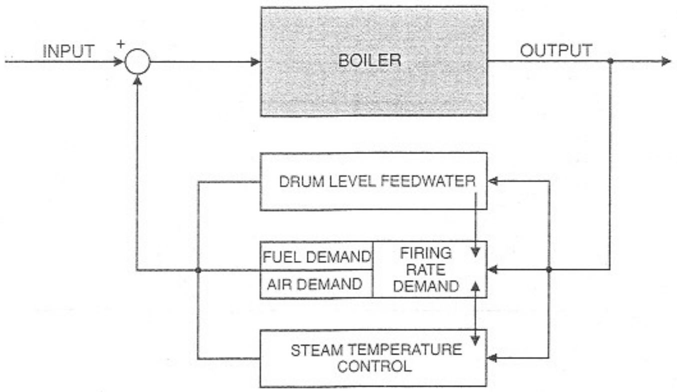


Figure 3-2 Block diagram of boiler control – furnace control.

The purpose of pressure control is to maintain a constant pressure in the boiler furnace. In most boilers, negative furnace pressure prevents flame excursions and helps avoid an external fire to the boiler or injury to personnel. The span of the transmitter may have an effect on the tuning, as well as maintaining good draft control. If the calibration range is –10 to +10 inches wc, the span is 20 inches wc. Referring to a 4-20 ma signal 4-20 equals 1.25 inches wc per ma. If the calibration range is minus 2 to plus 2 inches wc the span is 4 inches. Referring to a 4-20 ma signal, 4-20 equals 0.25 inches wc per ma. The narrow span will provide better control; however, span varies with the type and size of the boiler. The control set point may range from minus 0.5 inches in industrial plants to several inches negative in a utility plant. **Note:** Some utility plants may have a set point for positive pressure.

The furnace pressure control can be achieved by simple feedforward control. (See Figure 3-3.) The ID fan(s) pulls air through the boiler, maintaining a negative pressure from the furnace to the outlet of the ID fan. The typical boiler with draft control has inspection doors to observe the boiler flame. Monitoring boiler functions may improve operation or detect a problem. Personnel must wear proper face protection when opening inspection doors.

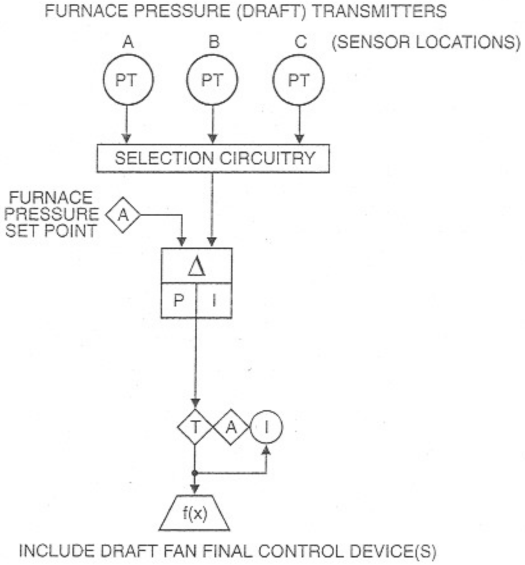


Figure 3-3 Furnace pressure transmitter.

The fan combinations available to the boiler system designer are FD plus stack; FD and ID plus stack; and ID plus stack. Tall stacks can produce furnace draft conditions that adversely affect flame stability and could require special draft control provisions on some small industrial boilers. The static pressure and flow characteristics of a centrifugal versus axial fan result from the specific design of the particular fan. One way to reduce auxiliary power requirements is to install variable pitch axial flow fans in fossil power generating systems. At 100% unit load, auxiliary power savings using a variable pitch axial flow fan will be 4000 kW, or about 7% of the total auxiliary power consumption. (Babcock & Wilcox. *Steam.* 40th Edition. The Babcock & Wilcox Company, 1992. Ch. 23-22)

Furnace pressure control is required on balanced draft boilers. While either the FD fan(s) or the ID fan(s) may be used to control the furnace pressure, the NFPA 85 Code requires that the ID fan(s) be used. The FD fan(s) controls the air for combustion control. The NFPA 85 Code requires the furnace and flue gas removal system to be designed so that the maximum head capability of the induced draft fan system with ambient air does not exceed the design pressure of furnace, ducts, and associated equipment. If the upper and lower limit of the furnace pressure is minus 20 to plus 20 inches or greater, a separate transmitter may be required to measure the range limits of the boiler furnace for high and low trip. The design pressure must be defined the same as the wind and seismic stresses of SEI/ASCE 7-02, *Minimum Design Loads for Buildings and Other Structures.*

A transmitter auctioneered median select scheme is to be used for control purposes. Furnace pressure is to be measured with three furnace pressure transmitters, each on a separate measurement tap.

Three furnace pressure transmitters in an auctioneered median select system with separate pressure sensing taps and suitable monitoring are required to minimize the possibility of operating with a faulty furnace pressure measurement. (See Figure 3-4.) It utilizes a feed-forward signal characterized to represent the position of the forced draft control device(s). In a properly designed and calibrated system, the output of the furnace pressure controller will remain near its midrange for all air flows.

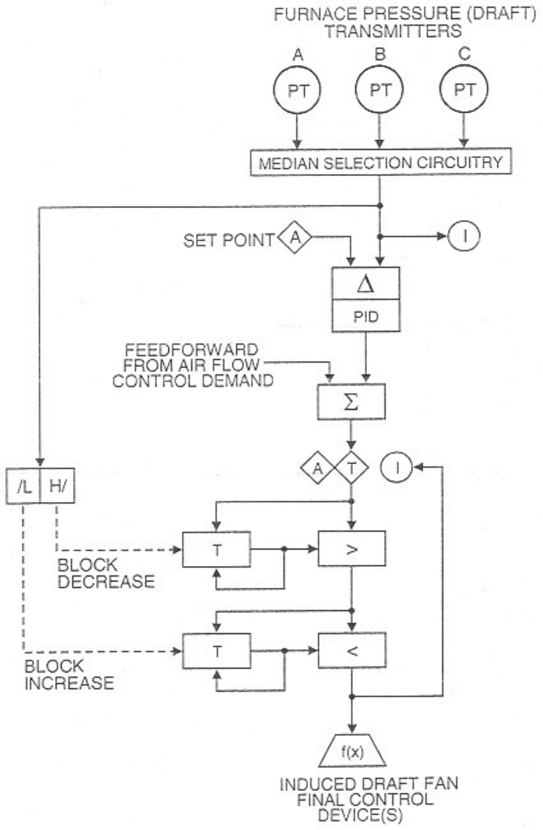


Figure 3-4 Furnace pressure transmitters.

Figure 3-5 is a representation of an approach to the entire furnace draft control logic, including implosion protection. The delta takes the difference between the set point and PV, and hi/lo selectors limit the difference set by the K values.

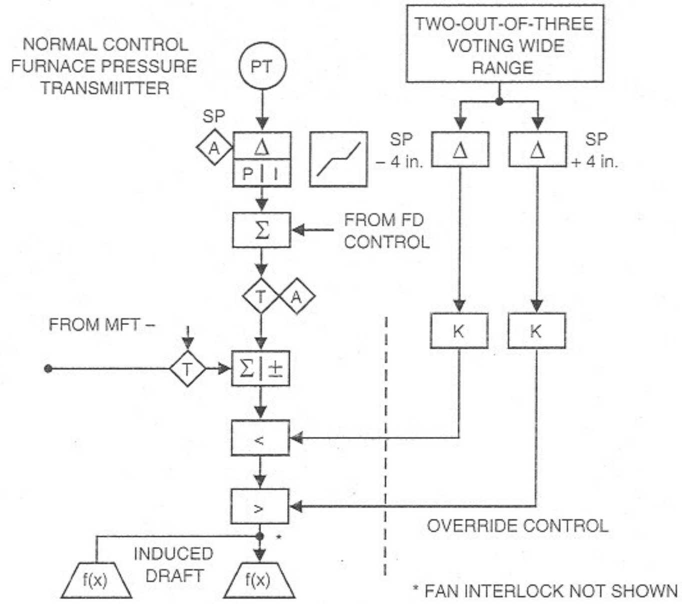


Figure 3-5 SAMA logic for furnace draft.

The furnace draft is controlled by modulating a vane(s) or damper(s) on the induced draft (ID) fan or by adjusting the speed of the ID fan. There may also be a combination of both speed and damper or vane control. Large utility boilers often have multiple ID and FD fans with variable speed drives on the ID fan. Although the ID fan and FD fan are two separate loops, they must be set up and tuned as a system.

In the draft control drawing (see Figure 3-3), the draft is controlled by single element feedback control. As the firing rate demand is changed, the furnace pressure increases or decreases as the FD fan(s) changes air flow to the furnace for fuel air control. In Figure 3-6 the furnace pressure changes as the demand changes. If feedforward is added from the FD control output the control can be improved as seen in Figure 3-7.

By controlling both damper and speed, the operating range of the damper is optimized. In Figure 3-8, speed control is required for the damper to remain near its midrange.

A satisfactory non-interacting method of combining damper and speed control is depicted in Figure 3-9. This is called split range or gap control. The positioners on the actuators are adjusted to split the control signal range with overlap in the center of the range. The damper control drive is adjusted to open the damper completely as the control signal changes from 0 percent to approximately 60 percent. The damper provides the best control in the overlap area between 40 and 60 percent. The damper becomes less responsive as it nears the 100 percent open position. By combining the two in this portion of the range there is a somewhat uniform flow response over the entire range.

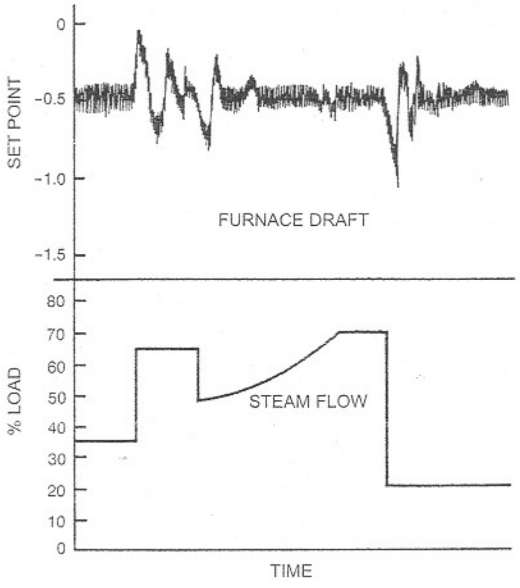


Figure 3-6 Furnace draft control.
(Single-element feedback control of induced draft fan.)

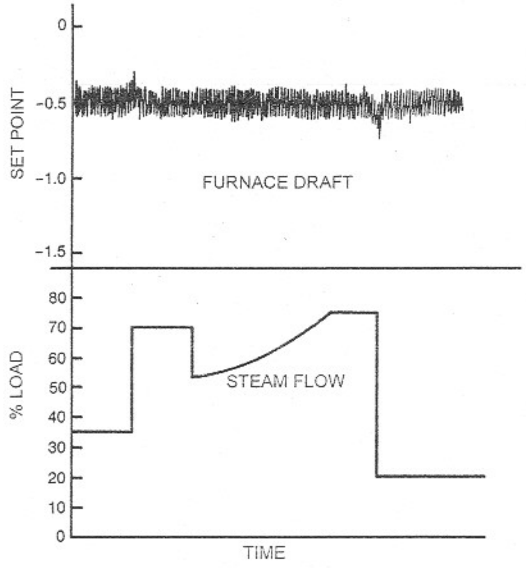


Figure 3-7 Furnace draft control.
(Feedforward-plus-feedback control of an induced draft fan.)

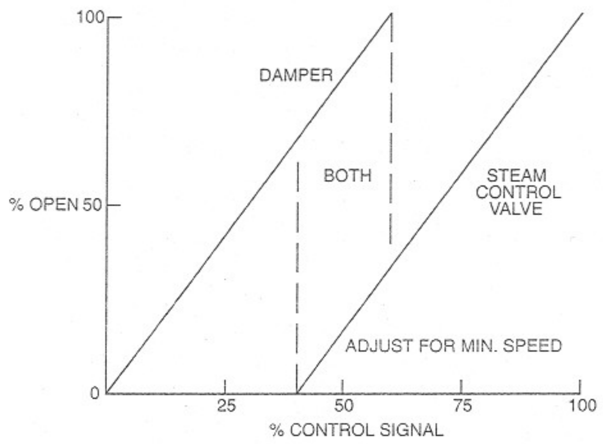


Figure 3-8 Damper and fan speed control.

If both speed and damper are controlled, Figure 3-9 depicts a method of controlling speed and damper control.

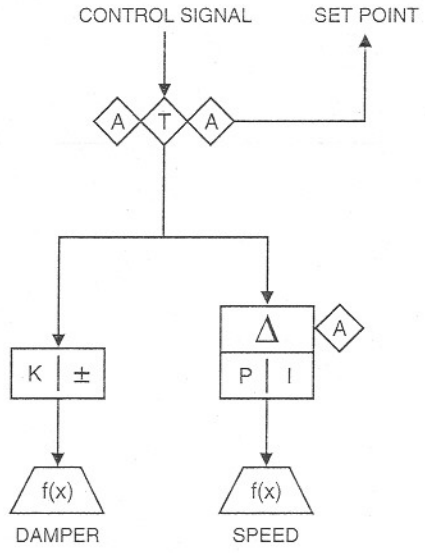


Figure 3-9 Damper and fan speed control-non-interacting method.

Another significant advantage is the reduction in horsepower as indicated in Figure 3-10.

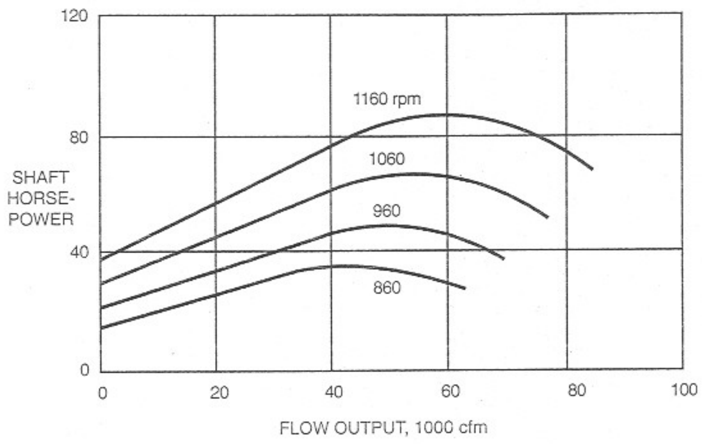


Figure 3-10 Variable speed fan characteristics – reduction in horsepower.

CHAPTER 4

Feedwater

Feedwater is the next section of a control system that will be discussed. (See Figure 4-1.)

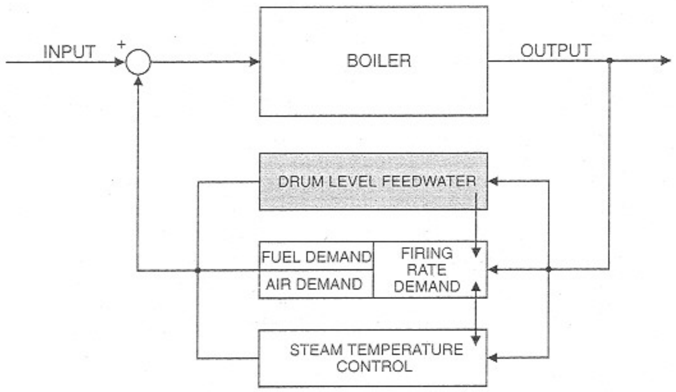


Figure 4-1 Block diagram of boiler control – drum level feedwater.

Once-Through Boilers

A once-through boiler can be thought of in terms of a long tube. Feedwater is pumped into one end of the tube, heated along its length, and superheated steam emerges out of the other end. Most once-through boilers operate at super critical pressures with a throttle pressure ranging from 3500 psig to as high as 5500 psig.

In drum-type boilers, the saturated steam leaves the drum and all superheat is added in the superheaters, which have fixed heat transfer areas. Drum-type boilers have separate systems for controlling combustion, feedwater, and steam temperature.

Once-through boilers have only one coupled, water-saturated, steam-superheated steam circuit. The total boiler heat transfer surface is divided into variable area boiler and superheater heat transfer surfaces. During operation, there is a constant shifting in heating surface area. Consequently, the steam temperature control and other boiler control functions must be coordinated together.

All such units have some form of flash tank for startup and low load operation. Bypass valving systems isolate the turbine from the boiler during the initial part of the startup process; otherwise cold water instead of steam could flow to the turbine. Boiler manufacturers have proprietary arrangements for such flash tank and bypass systems.

In once-through boilers, the feedwater flow control is an integral part of turbine throttle steam pressure and superheat temperature control. The pumping and firing rate system is a carefully calibrated parallel firing rate and feedwater flow control system that has both flow controls operating in the cascade mode.

This type of boiler can function in a very stable manner, with the firing rate demand on manual and the turbine maintaining the steam pressure with operation in the turbine following mode. If the electrical load is correct, pumping is held constant and the firing rate is adjusted to the point of stable set point steam temperature.

Due to the extreme interactions of once-through boilers while on automatic operation, the system performance can be improved by using a control coordinator approach. In this system configuration, combinations of inputs trim the firing rate and also trim the feedwater flow pumping rate.

Drum Level Feedwater Control

Drum Level

The drum level must be controlled to the limits specified by the boiler manufacturer. If the drum level does not stay within these limits, there may be water carryover. If the level exceeds the limits, boiler water carryover into the superheater or the turbine may cause damage resulting in extensive maintenance costs or outages of either the turbine or the boiler. If the level is low, overheating of the water wall tubes may cause tube ruptures and serious accidents, resulting in expensive repairs, down time, and injury or death to personnel. A rupture or crack most commonly occurs where the tubes connect to the drum. When the drum level gets too low, the boiler will trip to prevent damage to the tubes and cracks in the tubes where they connect to the boiler drum.

Because of the critical nature of this measurement, a variety of devices are usually applied to monitor the drum water level. A drum may have sight glasses, electrode columns, and differential pressure-based indicators and transmitters. (See Figure 4-2.)

Recommendations for the location of instrument and control equipment connections can be found in the American Boiler Manufacturer Association's (ABMA) *Recommendations for Location of Instrument and Control Connections for the Operation and Control of Watertube Boilers.*

The differential pressure-based level devices (and even most sight glasses) experience inaccuracies in measurement when boiler steam drum pressure is not at its design value. These changes in pressure can be overlooked on boilers operating at lower pressures but, for most boilers, corrections must be made for the changes in accuracy. Figure 4-3 is a graph showing reading deviations.

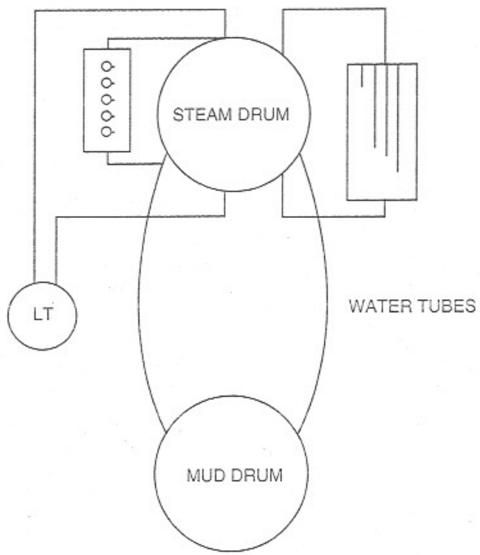


Figure 4-2 Boiler drums/level measurement.

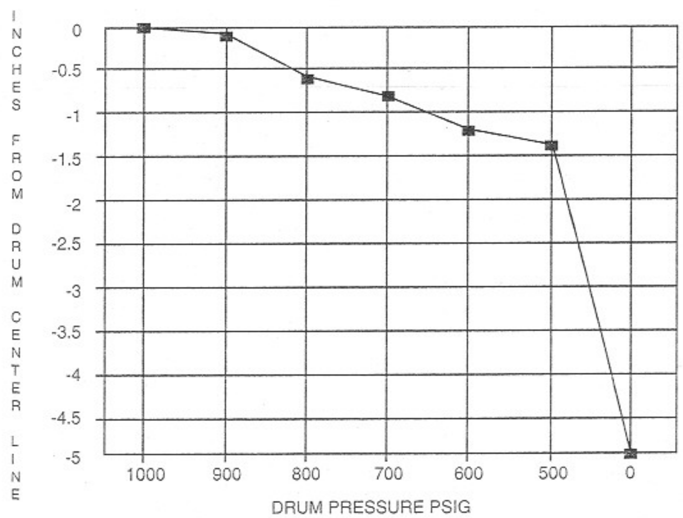
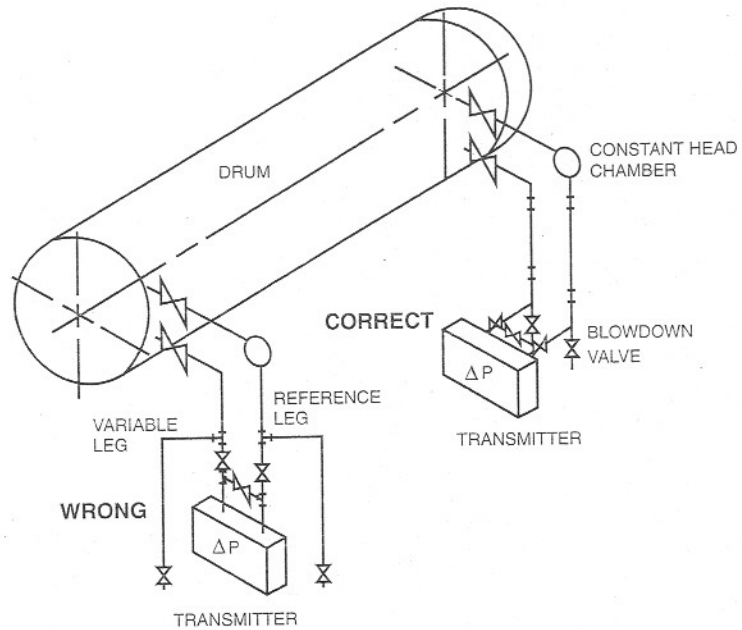


Figure 4-3 Indicated levels vs. drum pressure.



NOTE: Other drum level monitoring instrumentation may be applicable.

Figure 4-4 Typical drum level differential pressure transmitter connections.

On high pressure boilers, a condensate pot is necessary for the top connected water leg to stay full of condensate. If the condensate level varies in the top connected leg, the drum level measurement will not be accurate. On low pressure boilers, a condensate pot may not be required. Figure 4-4 is an example of the correct method of installing a differential pressure transmitter. The correct installation allows the sediment to remain in the blowdown line without getting into the transmitter.

The basic indication of the drum water level is that shown in a sight gage glass connected to the boiler drum. The American Society of Mechanical Engineers (ASME) requires a direct reading of the drum level. Due to the configuration of the boiler, and the distance the boiler drum is from the operator, a line-of-sight indication may not be practicable. The gage glass image can be projected with a periscope arrangement of mirrors. (See Figure 4-5.)

If the detection of the water level image is mechanically complex, or practically impossible, other methods of sighting may be necessary. One method is to use closed circuit television; other methods include using a remote level indicator based on a fiber optics signal. another method incorporates the use of a remote level indicator based on a fiber optics signal. The indication it provides is usually in error to some degree and is not as correct as a properly calibrated level measuring instrument. Condensate from cooling boiler steam circulates through the gage glass. This cooling of the steam and its condensate results in cooler water in the gage glass than in the boiler drum. The greater density of the cooler water in the gage glass indicates a lower level than is in the boiler drum.

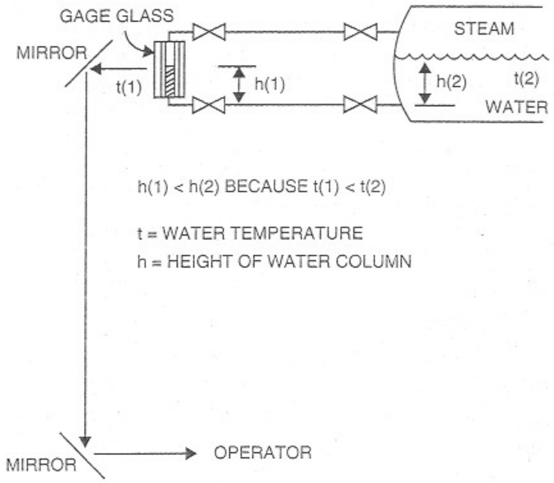


Figure 4-5 Gage glass drum level indication.

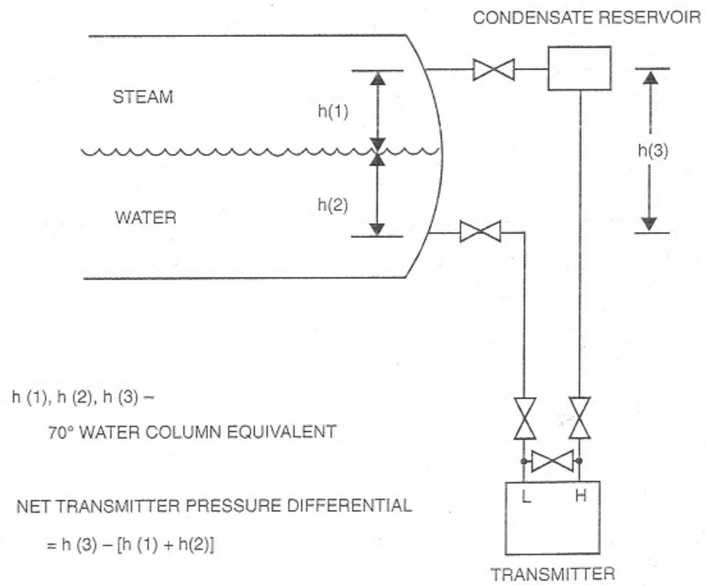


Figure 4-6 Drum level transmitter.

Figure 4-6 is a typical arrangement of a differential drum level measuring transmitter. The differential transmitter output signal increases as the differential pressure decreases. (Note the differential pressure connections.) The differential pressure range will vary between 15 and 30 inches, depending on the size of the boiler drum, with a zero suppression of several inches. On the high pressure side of the measuring device, the effective pressure equals boiler drum pressure plus the weight of a water column at ambient temperature having a length equal to the distance between the two drum pressure connections. On the low pressure side, the effective pressure equals boiler drum pressure, plus the weight of a column of saturated steam having a length from the upper drum pressure connection to the water level, and the weight of a column of water at saturation temperature having a length from the water level to the lower drum pressure connection.

Typically, for redundancy, there are three different methods used to measure drum level. (See Figure 4-2.) In this example, the bull's eye technology is a direct reading level measurement. The differential pressure transmitter represents the level control measurement, and the probe type sensor is a common method for level alarms and low and high level shutdown.

Feedwater Control

Some boilers utilize reasonably steady loads so that only drum level control from single element drum level measurement is possible. Single element control is used on boilers during startup or low load regardless of capacity or rapid load swings. Single element control has often been unsatisfactory because some of the newer boiler designs have minimum water storage compared to the steaming rate of the boiler. A majority of the larger sized units and those subject to rapidly fluctuating loads require different methods of control. A two element system controlling the feedwater control valve from the steam flow signal and resetting the drum level signal is able to handle some of the less difficult systems. Larger units with small storage capacity related to throughput, and units experiencing severe, rapid load swings, usually require three element control, whereby water flow is matched with steam flow and reset from the drum level signal.

Single element drum level control measures drum level only. This is a simple feedback control loop. (See Figure 4-7.)

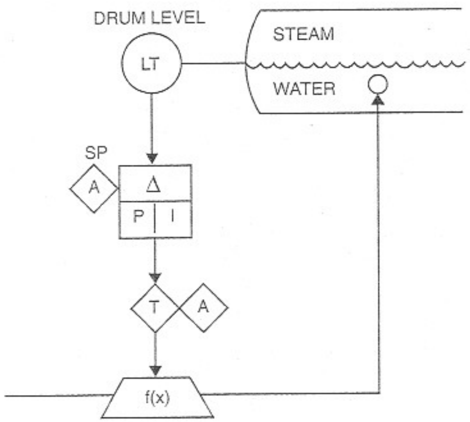


Figure 4-7 Simple feedback control loop.

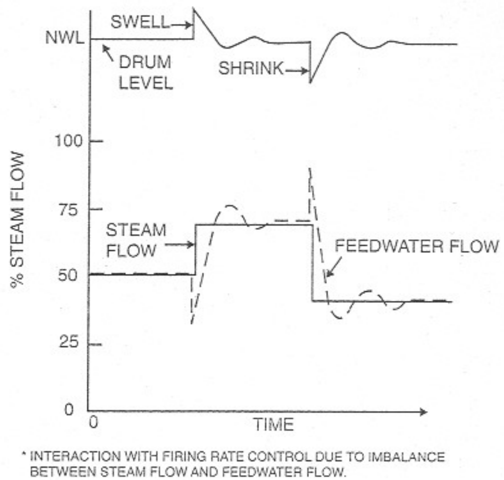


Figure 4-8 Single element control action.

Mechanical single element control is proportional control only. While this may work satisfactorily in a toilet, it may not be satisfactory for a boiler. Adding a control system will provide more efficient control but a single element control may not be sufficient. In Figure 4-8, the increase in steam demand results in a boiler drum swell, causing a decrease in water flow when an increase in flow is required. To reduce the upset, the reset action must be slow.

Transmitters

A differential pressure transmitter is used to measure drum level. If the instruments used are sensitive to density variation, then density compensation techniques must be employed. A mass steam flow and water flow signal is required for both two and three element control systems. (For more information refer to ANSI/ISA-77.42.01-1999 (R2005) - *Fossil Fuel Power Plant Feedwater Control System – Drum-Type*.) Observe the error due to density. (See Figure 4-3.)

The drum level control indicator scale for a 30 inch span would be -15 to +15 inches wc with zero as the controller set point. On higher pressure boilers typically above 1000 psi, a considerable error in level measurement at other than the operating pressures exist when a differential pressure is used due to water density changes in the boiler drum.

The top boiler connection to the transmitter will be filled with condensate. As the drum level increases, the two signals become equal, thus reading zero level when the drum level is at 100 percent. (See Figure 4-6.) By reversing the connections at the transmitter, the signal to the drum level controller may be reversed. The reading may also be corrected by calibrating the transmitter. It is also critical that the sensing line to the transmitter be sloped typically a half inch per foot. This is to eliminate air pockets in the sensing lines which would cause improper level readings.

The mass of the water flow and the steam flow must be regulated so that mass water flow equals the mass steam flow to maintain drum level. The feedwater control regulates the mass water flow to the boiler. The effects of the input control actions interact, since firing rate also affects steam temperature and feedwater flow affects the steam pressure, which is the final arbiter of firing rate demand. The overall system must be applied and coordinated in a manner to minimize the effects of these interactions. The interactions can be greatly affected by the control system design. If the boiler operates under varying steam pressure, the calibration of the liquid level transmitter will also vary with steam density.

SKUPLJANJE BUBRENJE,

Shrink and Swell

Shrink and swell must be considered in determining the control strategy of a boiler. During a rapid increase in load, a severe increase in level may occur. Shrink and swell is a result of pressure changes in the drum changing water density. The water in the drum contains steam bubbles similar to when water is boiled. During a rapid increase in load, a severe rise in level may occur because of an increase in volume of the bubbles. This increased volume is the result of both a drop in steam pressure from the load increase and the increase in steam generation from the greater firing rate to match the load increase (i.e., bubbles expand). (See Figure 4-9.)

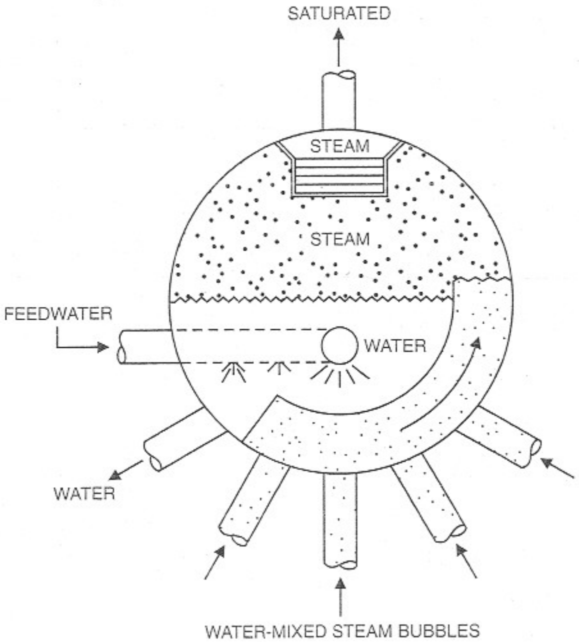


Figure 4-9 Shrink and swell.

When there is a decrease in demand, the drum pressure increases and the firing rate changes, thus reducing the volume of the bubbles (i.e., bubbles get smaller). A sudden loss in load could result in drum shrinkage severe enough to trip the boiler on low level.

The firing rate change has an effect on drum level, but the most significant cause of shrink and swell is rapid changes in drum pressure expanding or shrinking the steam bubbles due to load changes. The three element control scheme utilizes the steam flow and water flow to effectively maintain feedwater equal to steam flow. As load increases and decreases, the water flow will increase or decrease. The drum level control is a slow responding loop.

When a single element control system is implemented, the level transmitter (LT) sends a signal to the level controller. (See Figures 4-10 and 4-11.) The process variable (input signal) to the controller is compared to the set point (SP).

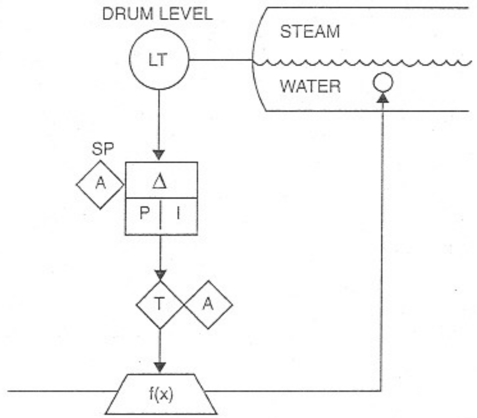


Figure 4-10 Single element control – drum level.

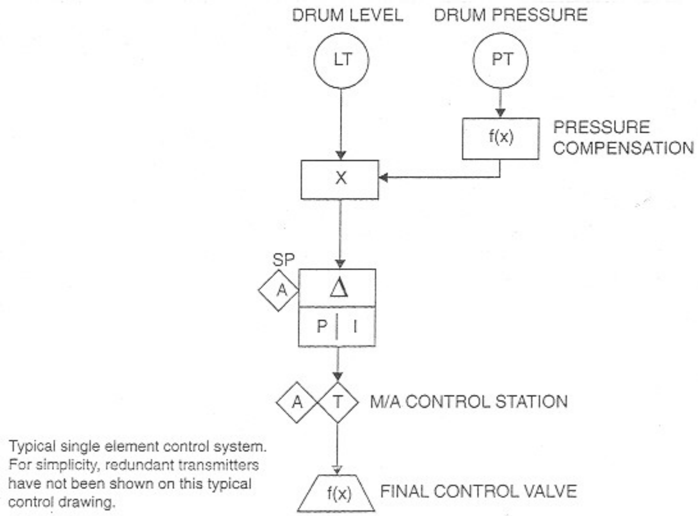


Figure 4-11 Single element feedwater control (SAMA Symbols).

Single Element Level Control

The output signal is modified and adjusts the final control device. The diagram for a P&ID would typically be in ISA symbols. (See Figure 4-12.)

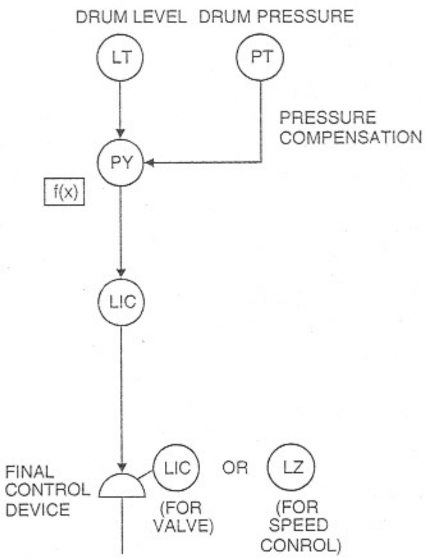
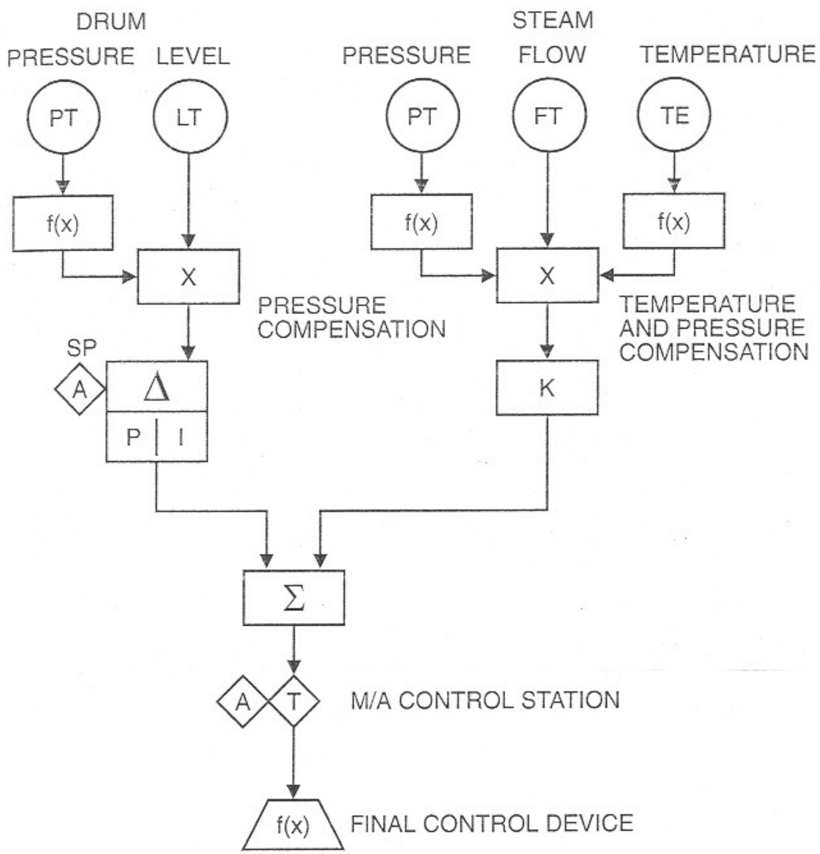


Figure 4-12 Single element feedwater control (ISA Symbols).

Two Element Level Control

The two element control scheme utilizes steam flow in addition to drum level. This is a simple feedback plus feedforward control system (see Figure 4-13) with a secondary variable that has a predictable relationship with the manipulated variable. The secondary variable causes the manipulated variable to change to the primary variable. The steam flow adjusts the feedwater control valve based on steam flow signal and the drum level controller signal. As the steam flow increases or decreases, the steam flow adjusts the output of the summer and directly sets the feedwater final element. (See summer section for further discussion.)

If the conditions are ideal, as in Figure 4-14, the feedwater flow would be equal to steam flow, and the level in the drum would be maintained. If feedwater is not constant, as seen in Figure 4-15, the changes in pressure would affect water control.



Typical single element control system. For simplicity, redundant transmitters have not been shown on this typical control drawing.

Figure 4-13 Two element feedwater control.

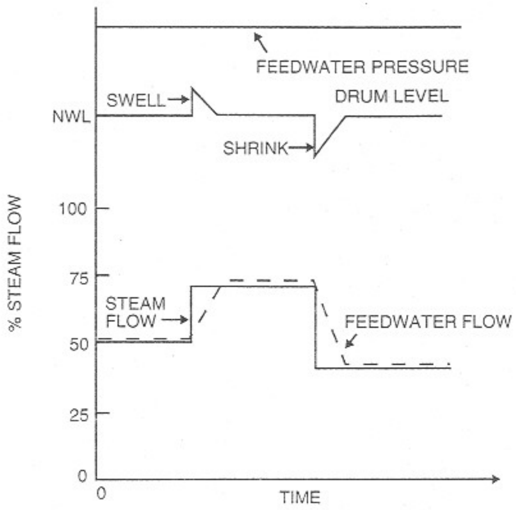


Figure 4-14 Performance two element (ideal conditions).

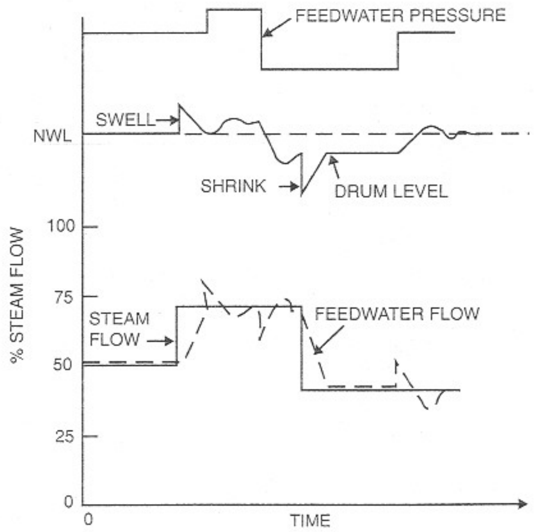


Figure 4-15 Performance two element (effect of feedwater variation).

The presentation of the diagram for a P&ID for two element control using ISA symbols is depicted in Figure 4-16.

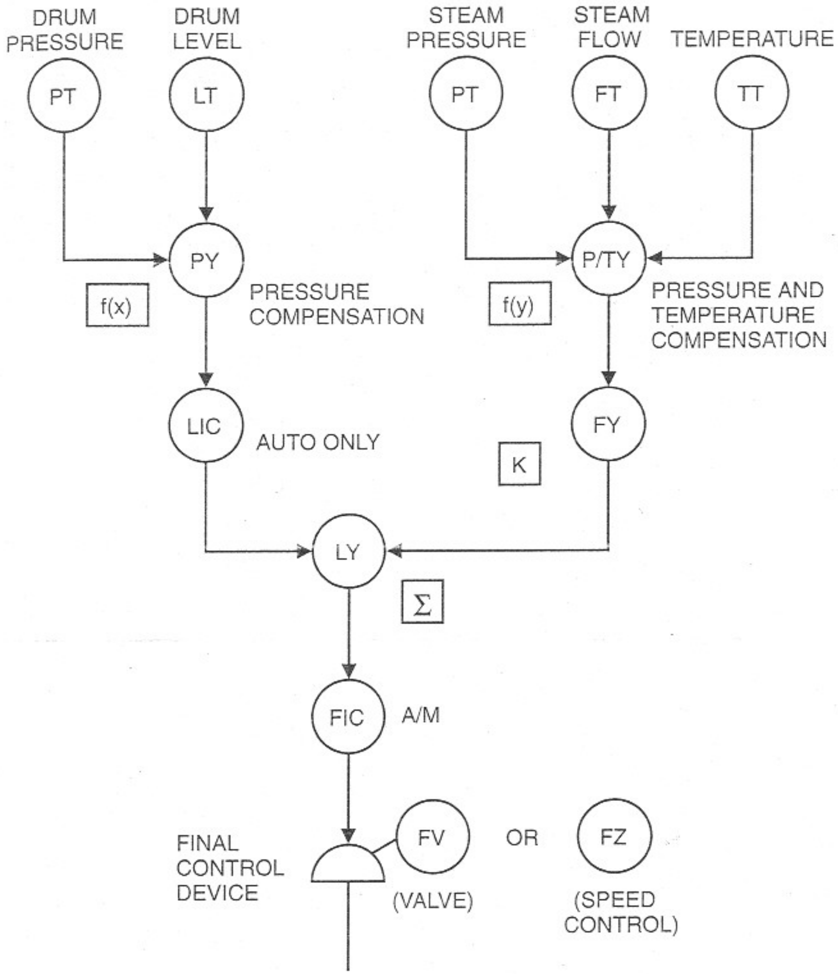


Figure 4-16 Two element feedwater control.

Three Element Level Control

Three element control utilizes steam and water flow in addition to drum level. (See Figure 4-17.) This is a simple feedback, feedforward, and cascade control loop. The steam flow adjusts the feedwater control valve based on the steam flow signal and the drum level controller signal. As the steam flow increases or decreases, the steam flow adjusts the output of the summer and directly sets the feedwater controller set point. By adding feedwater flow, the measured variable is the feedback to the controller, therefore measuring what is being controlled. Control is improved by adding mass flow compensation to drum level, steam flow, and water flow.

The presentation of the diagram for a P&ID for three element control using ISA symbols is depicted in Figure 4-18.

Three element feedwater adds the feedwater flow measurement to the control loop. The significant advantage is measuring what is being controlled. By measuring the feedwater flow and controlling it to a flow set point, the feedwater equals steam flow to maintain drum level over the boiler control range. The controlled variable water flow is measured. The desired feedwater is maintained and overrides shrink and swell and variations in feedwater header pressure.

Control System Configuration

The drum level controller is configured to be either a reverse or direct acting controller. This depends on the configuration of the final control device and the fail safe mode of the control valve. If the control valve fails closed, the controller is configured to be a reverse acting controller. If the control valve fails open, the controller is configured to be a direct acting controller. The final control element may be a control valve, speed control, or a combination of both.

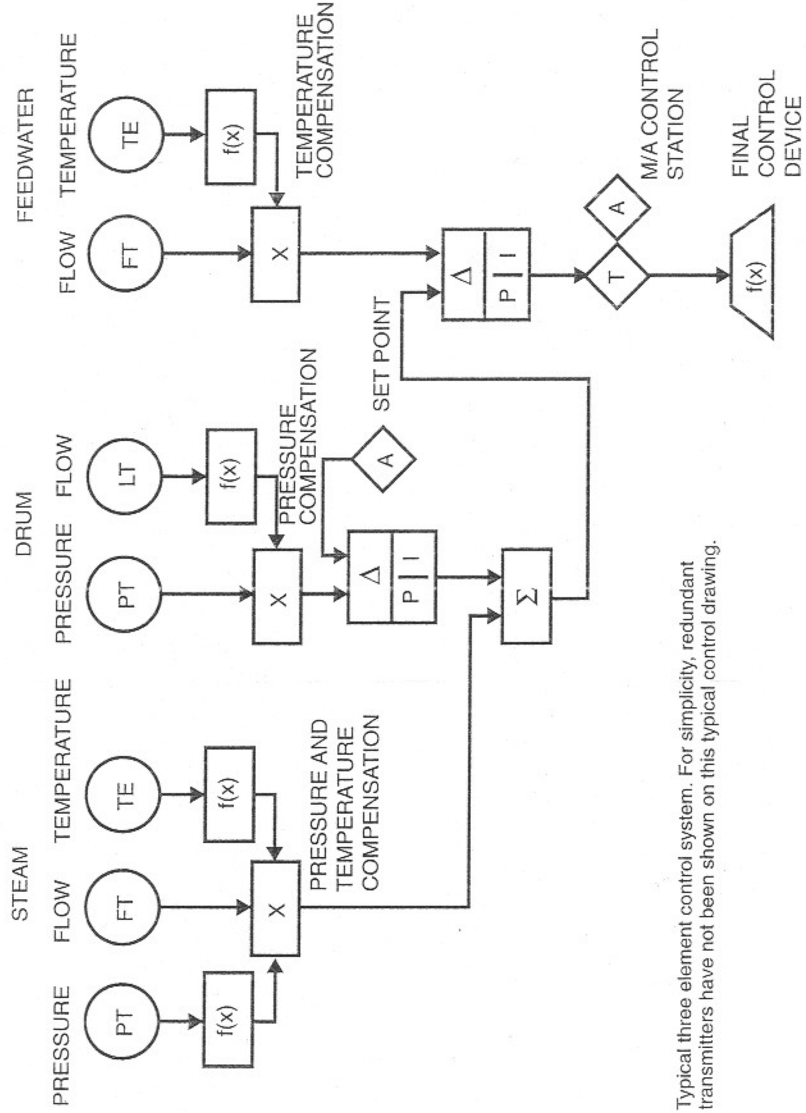
Summer

A summer occurs when two or more values come into an equation and the output equals the sum of the inputs in percent based on the K values. The functions are referred to as function blocks or algorithms. In Figures 4-17 and 4-18 the summer equation is used. Some companies use multiplication or division equations. The summer can be configured using a basic summer equation. The equations used will vary with the control systems specified, including the number of inputs. In the equation below, a, b, and c represent inputs. Only two inputs are used in Figure 4-18. This is a common type of equation that may have two or more inputs depending on the vendor algorithm/function block.

$$K\ (a) + K\ (b) + K\ (c) \pm \text{Bias} = \text{output}$$

A basic equation performing the same function should be available with most control systems.

Considering two inputs to the summer, set both K values to 1. Set the bias to -50 percent. With the drum level controller in manual mode and the drum level at the desired set point, set the controller output to 50 percent.



Typical three element control system. For simplicity, redundant transmitters have not been shown on this typical control drawing.

Figure 4-17 Three element feedwater control.

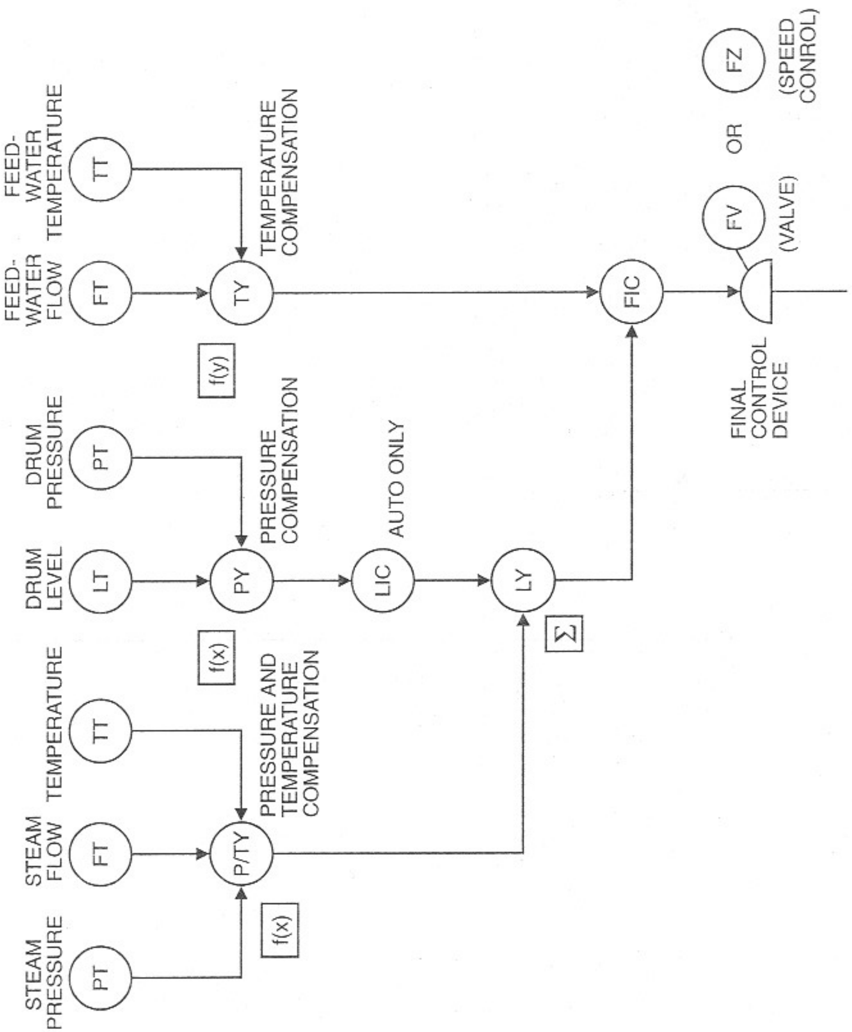


Figure 4-18 P&ID for three element control using ISA symbols.

The 50 percent output is offset by the -50 percent bias in the summer equation. Therefore, the steam flow signal input to the summer will equal the summer output. Considering a pound of steam equals a pound of water, the drum level would be maintained during all load changes. Even though swell and shrink may occur on load swing, the steam flow modifies the feedwater rate. The drum level controller becomes a trim controller adjusting the summer to bring the level back to set point.

Coal Fired Boilers

Coal fired boilers are the most common boilers in power generating plants primarily because of the overall cost of operation and the location of power plants relative to sources of energy. Coal can be transported to sites where gas supplies are not available. However, new environmental requirements are making the overall cost of burning coal higher due to the cost and maintenance of monitoring and pollution control equipment. (For a brief tutorial on fossil fuel power plant combustion controls, see Appendix A, Boiler Combustion Controls, based on information taken from ANSI/ISA-77.41.01-2005, *Fossil Fuel Power Plant Boiler Combustion Controls.*)

Coal fired boilers have specific problems that gas and oil fired boilers do not have. In addition to the common hazards involved in the combustion of solid, liquid, and gaseous fuels, other hazards related to the physical characteristics of pulverized coal, including Btu values, must be addressed in the design of the firing systems. Coal bunkers and other enclosed spaces must be designed to prevent accumulation of methane gas, a common cause of explosions and the possibility of spontaneous combustion resulting in fires in the coal pile.

Table 5-1 Fuel Btu Values per Pound by State

Variations of Btu values for coal are significant depending on the state where the coal comes from. The variations in Btu values have a significant effect on combustion control. Refer to Table 5-1 and Figure 6-14.

Table 5-1

Coal	Btu/lb
Alabama	13,500
Illinois	11,200
Indiana	11,300
Kansas	10,950
Kentucky	12,100
Ohio	12,550
Pennsylvania	13,850
Colorado	9,650
North Dakota	6,940

Pulverized Coal Fired Boilers

Pulverized coal fired boilers are one of the most common boilers used in utility plants; and are considered a vast improvement over stoker fired boilers. The firing rate response due to demand change is faster than stoker fired or fluid bed boilers. More mechanical equipment is required to pulverize the coal that is not required in stoker fired boilers. Figure 5-1 is an example of a direct fired pulverized coal system. Because explosions and fires are most likely to occur during start up, shut down, or after an emergency trip, a pulverized system and its components should be designed for continuous operation. The configuration of the boiler does not have coal shut off valves. The NFPA 85 Code now requires coal shut off valves; therefore, modifications to existing boilers require that they be installed. Examples of modifications can include installing a burner management system (BMS) or a basic process control system (BPCS), even if the logic has not changed. (See Figure 5-2.)

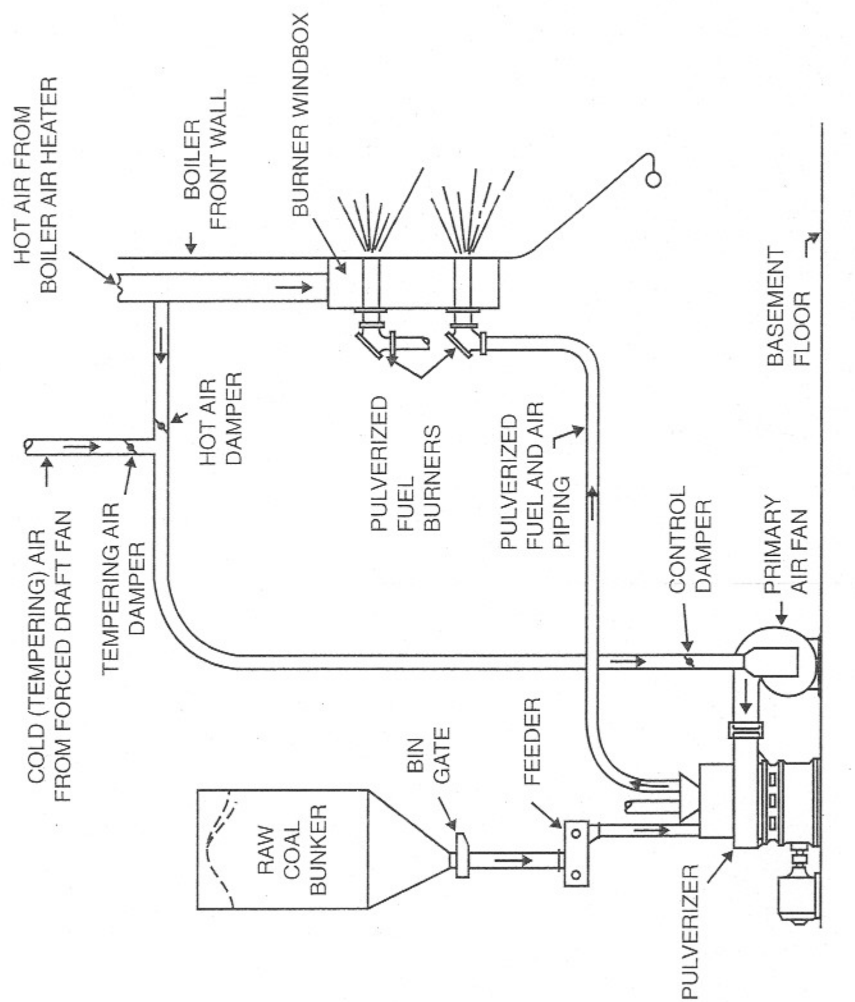


Figure 5-1 Direct firing system for pulverized coal.

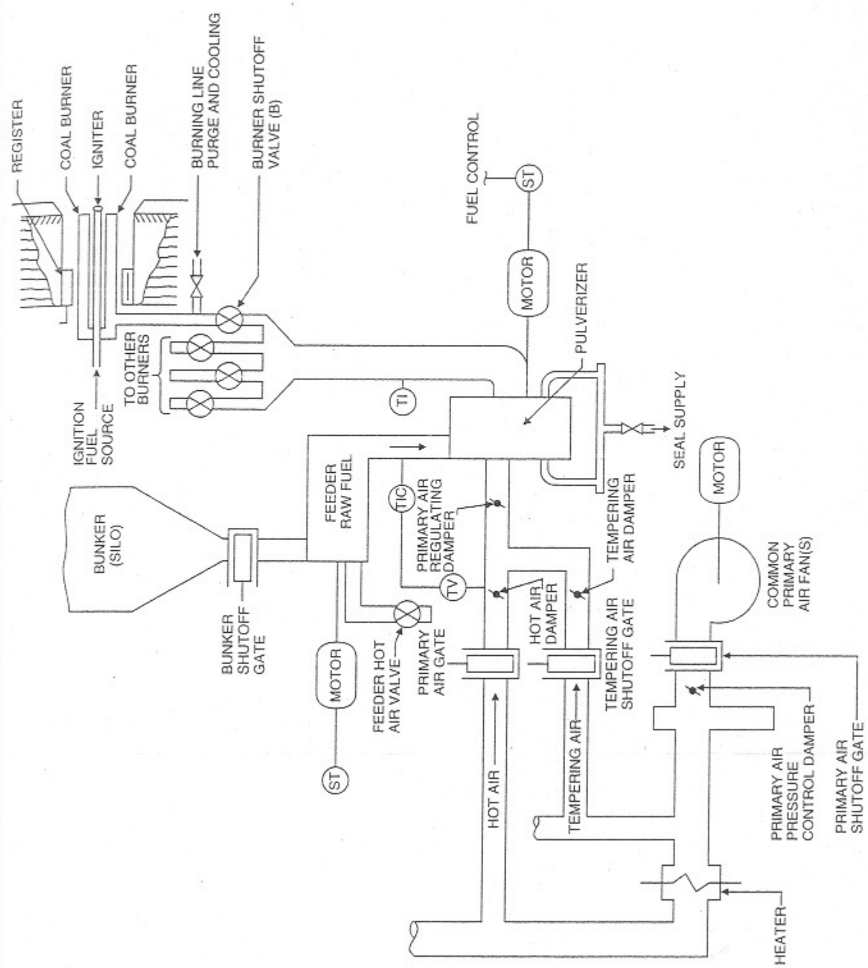


Figure 5-2 Modified direct fired pulverized coal system

When a loss of flame is detected on a predetermined number or arrangement of burners served by a pulverizer, that feeder, or pulverizer and feeder, is to be automatically tripped. When a loss of flame is detected, an audible alarm is required on each burner involved, and an operator is required to visually inspect flame conditions to determine whether burner or pulverizer operation should be continued.

The number and arrangement of burners for each pulverizer trip, showing the necessary loss of flame to automatically initiate a feeder, or pulverizer and feeder, is to be determined by the boiler manufacturer, as a function of the spacial arrangement of burners and the unit load. Under circumstances of operation where support between the operating burners does not exist, either from proven igniters or adjacent burners, loss of flame on an individual burner must automatically initiate a trip of the feeder, or the pulverizer and feeder.

To prevent settling of pulverized coal in burner pipes, and ignition of the coal, the transport air velocity in all burner pipes must be maintained at or above a minimum value during operation, and while purging the pipes during shutdown. This predetermined value is established by the manufacturer and verified by tests. The exception is during an emergency trip condition when transport air must not be maintained and a control system is required to control temperature. (See Figure 5-2.) The coal-air mixture temperature leaving the pulverizer must be maintained within the limits specified by the pulverizer and burner manufacturer(s) for the type of coal being burned. The heating of the coal removes the moisture from the coal and improves boiler efficiency.

Figure 5-3 is an example of a control system for a pulverized coal boiler. The system has the cross limiting/lead lag control to maintain the proper fuel air ratio. Pulverized coal utility boilers are more complex than this diagram indicates due to the number of burners and capacity, but the control strategy is often similar. There is derivative control on the output of the boiler drum pressure. This feedforward control signal will improve the response time for the coal feed, which is a result of the dead time between a load demand change and a change in coal feed rate response. Steam flow is also a feedforward signal to the output of drum pressure that will improve control. There is speed control and damper control on the FD fan. By controlling the speed and damper position, the damper can operate in the most efficient opening range for better control. The O_2 analyzer output is a feedforward control signal to air flow. Some control systems include combustibles as feedforward control. There are risks in combustible control due to the narrow band of potential control and the slow response time of combustible analyzers. (See Figure 5-4.)

Raw Coal and Feeder

The raw storage bin supplies the coal to the feeder. The coal feeder provides the coal supply to the pulverizer which grinds the coal into a fine powder. The changes in the rate of the feeder and the pulverizer control the coal feed to the boiler, in turn, controlling the boiler firing rate. The coal primary air fan blows the coal into the boiler. Hot primary air is used to remove some of the moisture from the coal and transport the coal to the burner. It also contributes to the combustion air being provided to the furnace.

To minimize explosions in the pulverizer or burner pipes, provisions must be made for cooling down and emptying the pulverizers as part of the process of shutting down the associated burners. Pulverized coal dust must be prevented from accumulating in pulverizer air ducts. Methods must be provided to prevent the reverse flow of furnace gases into idle burners or pulverizers. Pulverizers and pulverized fuel storage systems are required to be equipped with an inerting system that is capable of maintaining an inert atmosphere. If a pulverizer is tripped

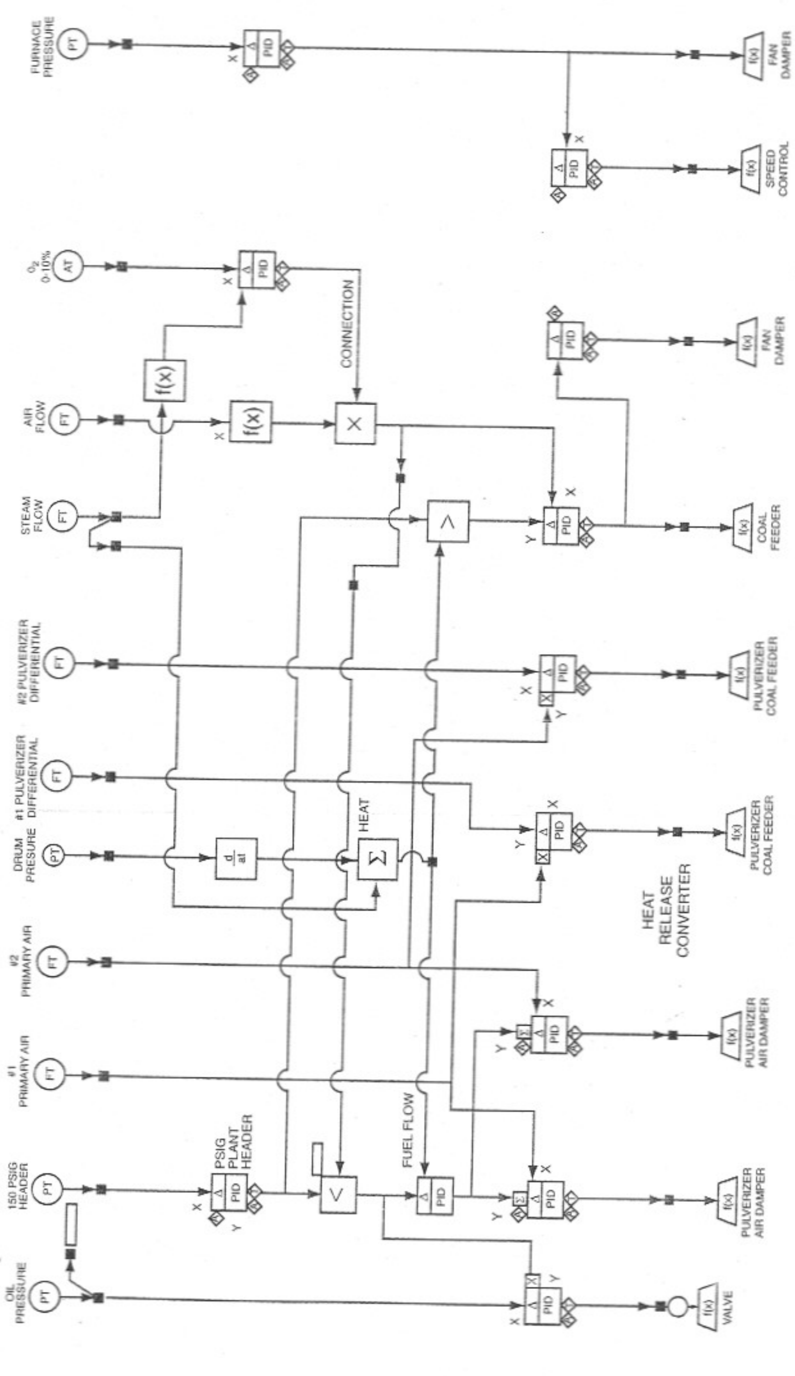
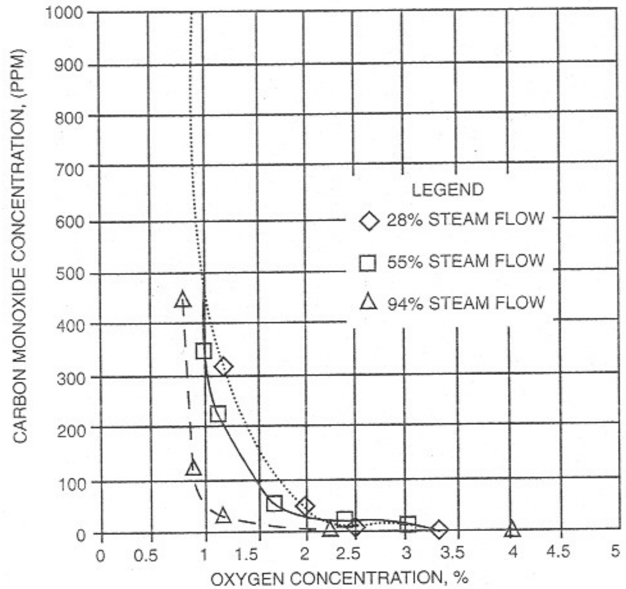


Figure 5-3 Control system for a pulverized coal boiler.



Source: The Control of Boilers, ISA Press 1991

Figure 5-4 Excess oxygen and carbon monoxide relationship at various loads for a gas-fired boiler.

Note: The curve for coal firing is similar to the one for gas.

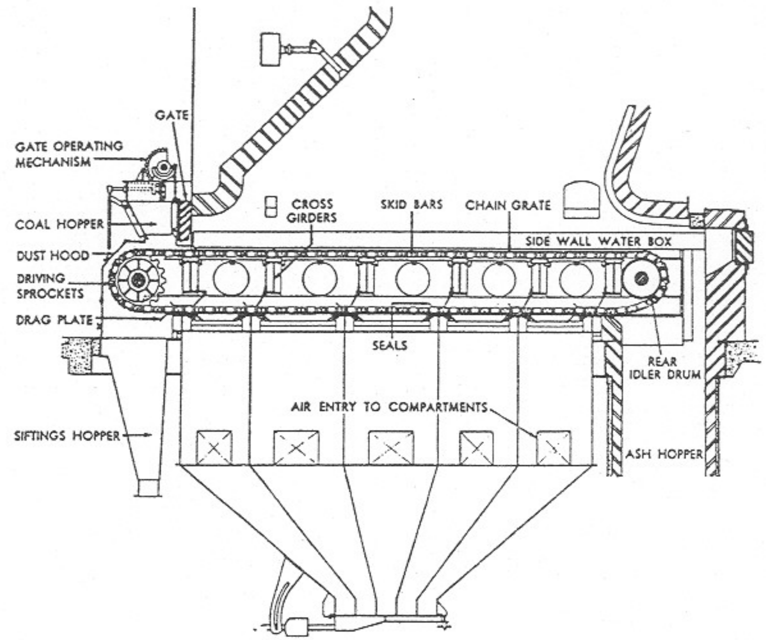
under load, the system must be inerted and maintained under an inert atmosphere until confirmation that no burning or smoldering fuel exists in the pulverizer, or until the fuel is removed. When an inerting system is activated, proof of flow of the inert media is required.

Stoker Boilers

Stoker fired boilers were the first coal fired boilers and their control firing demand rate was adjusted manually. Figure 5-5 is a chain grate stoker. The firing rate is controlled by adding and decreasing fuel to the grate and also by adjusting the air entry under the grate. Figure 5-6 is a control scheme for a stoker boiler. The control in this diagram is a fuel flow air flow control system and the boiler firing rate demand is a gain and derivative control that will improve the changes in firing rate demand.

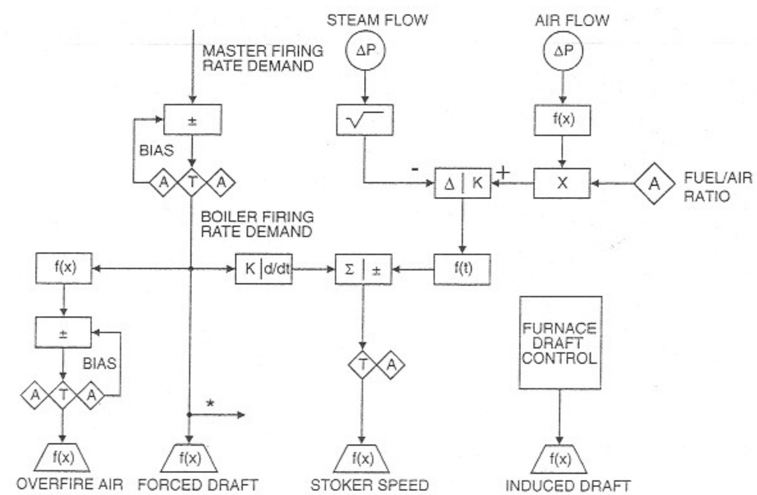
Cyclone Boiler

The cyclone boiler was developed to burn a large variety of fuels including wood, bark, coal char, refuse, and petroleum coke. As a means of disposing of old tires, for example, cyclone boilers have some of the same advantages as pulverized coal fired boilers, as well as some additional advantages. With cyclone boilers, there is a reduction in fly ash content in the flue gases. Coal does not need to be pulverized but is crushed to approximately one-quarter inch. The



Source: The Control of Boilers, ISA Press 1991

Figure 5-5 Chain grate stoker.



*Feedforward to furnace draft control (if required).

Figure 5-6 Control scheme for a stoker boiler.

Source: The Control of Boilers, ISA Press 1991

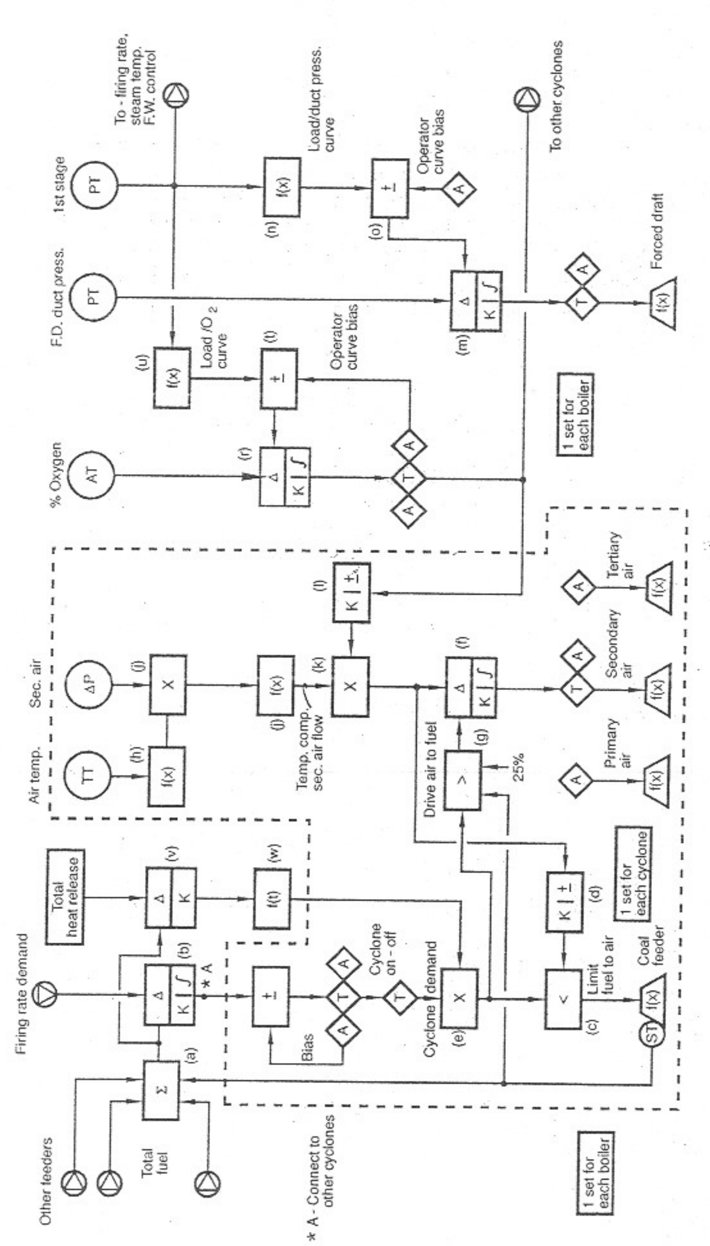


Figure 5-7 Combustion control for cyclone-fired boiler.

cyclone furnace is a smaller ancillary furnace that typically attaches horizontally near the bottom of the main boiler furnace. Diameters of the main barrel range from five to ten feet. Gravimetric feeders are used to control coal feed based on weight providing mass coal flow. See Figure 5-7. Although gravimetric feeders are more common today, volumetric feeders are also used for coal feed flow measurement. Air is controlled to each cyclone by a venture throat. Centrifugal force throws the coal against the cyclone wall. The temperature in the cyclone exceeds 3000°F, which melts the coal that forms a fluid slag on the cyclone walls. Heat is released at extremely high rates and combustion is completed within the combustion space of the cyclone, with approximately 15% excess air. The heat from the cyclone burners, in turn, supplies heat to the main boiler furnace. Sometimes, depending on the total boiler capacity, two or more cyclone furnaces are used.

Fuel and Air Control

The third system of a control system is fuel air control.

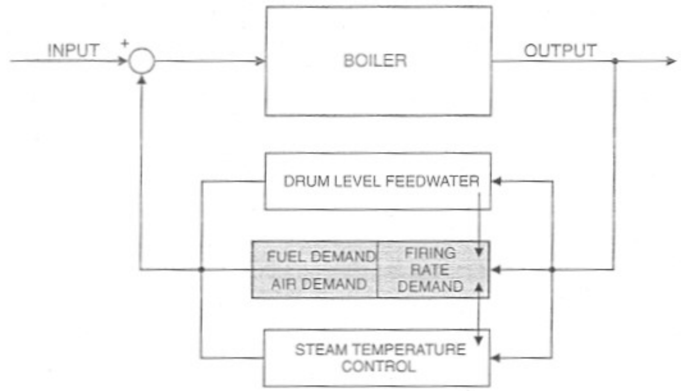


Figure 6-1 Block diagram of boiler control – fuel air control.

One of the key components of the control is the ability of the fuel air control system to maintain sufficient air proportional to fuel to eliminate the possibility of a fuel-rich condition and the possibility of an explosion. Consideration should be given to the effects of fuel, air density, and temperature fluctuations as related to the air flow and the performance of the fuel flowmeter in regulating the fuel air ratio.

Many installations, particularly smaller units or units firing an unmeasurable fuel, utilize what is called a jackshaft positioning control system in which fuel and air are not measured. (See Figure 6-2.) Figure 6-3 is a SAMA representative of a jackshaft positioning control system. The controller firing rate demand signal positions both the fuel and air. Their relationship is maintained by holding the positions of the final operators in correspondence with each other. Figure 6-3 is a parallel positioning system with no fuel or air measurement.

Every position of the fuel valve is assumed to represent a repeatable value of fuel flow, and a corresponding position of the air flow to represent a repeatable value of air flow. The air characterization must be provided in the air damper drive, and sometimes on the fuel valve, so the two final operators can track in proper sequence. A limited trim adjustment is provided in the fuel air ratio station to allow some modification of the initially calibrated fuel air ratio. This may be accomplished automatically, but a manual station is the most common method.

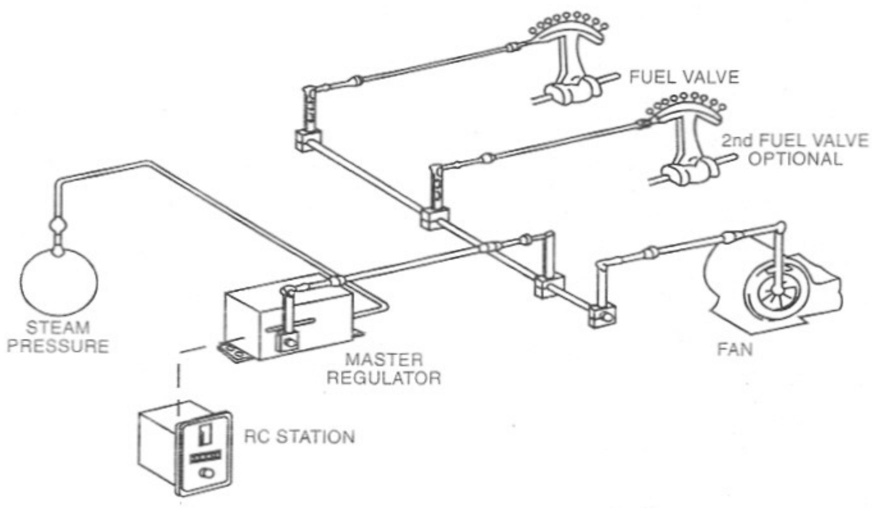


Figure 6-2 Mechanical positioning system.

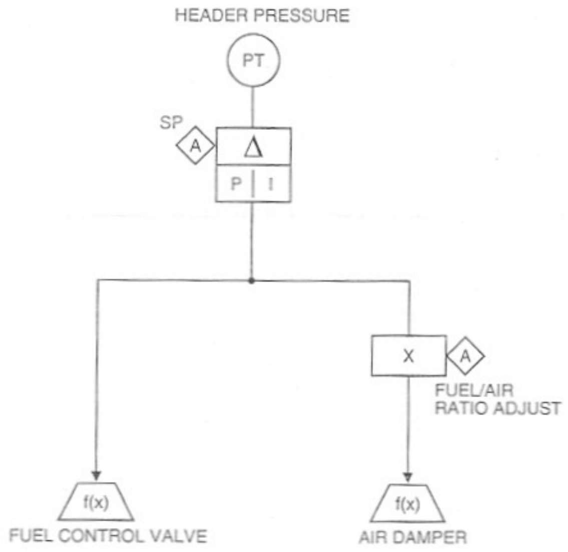


Figure 6-3 Parallel positioning with no fuel air measurement.

There are advantages and disadvantages to a parallel/jackshaft positioning system. Advantages include its simplicity, reliability, responsiveness, and cost effectiveness. On a pneumatic system with long transmission distances, for instance, parallel jackshaft positioning systems have been successfully applied in some cases where metered flow loops are undesirably slow. In addition, the rangeability of the system is high, limited only by the final operators.

Since it is not based on a measurement, fuel air ratio control is not precise. It depends on other parameters and is affected by varying fuel characteristics, fuel temperature, and/or pressure variations, atmospheric conditions, etc. If these conditions are not held constant, the fuel air ratio will be significantly affected. Also, this system cannot be applied to multiple burner installations. On out of service burners, air register position, system flow resistance, and consequently, fuel flow rate, are all a function of the number of burners in service.

To overcome the inherent disadvantages, so-called metering systems are generally applied to furnace control. Fuel and air are measured, and flow control loops are closed on these variables.

Mass air flow measurement must be a repeatable signal that is representative of the air entering the furnace. When volumetric measurement techniques are employed and the air temperature at the flow-measuring element varies 50° F (28° C) or more, the measured (indicated) flow must be compensated for flowing air density to determine the true mass air flow rate. Control systems must have the air characterized to fuel to prevent the addition of excess fuel.

Automatic tracking must be provided for bumpless control mode transfer. The combustion control, which responds to the boiler energy demand, must be accomplished by controlling furnace pressure (balanced draft systems), air demand, and fuel.

It is a prerequisite for air control to be in automatic whenever fuel control is in automatic. Provisions must be made to ensure that the automatic regulation of fuel will result in a fuel-to-air ratio that provides safe boiler operation. This includes limiting fuel flow or air flow under all conditions to ensure fuel flow never exceeds the safe combustion limit the air flow will support.

Excess air is required at all loads to ensure proper combustion of the fuel entering the furnace. The furnace should not operate at an oxygen level in the flue gas below the boiler or burner manufacturer's requirements. The exception is on low NO_x control. Sub-stoichiometric firing for NO_x control has no excess air in the burners.

Two basic approaches to metering systems are series metering and parallel metering. Figure 6-4 illustrates a series metering system referred to as fuel follow air. All differential pressure transmitter signals must be converted to a linear signal as depicted in Figure 6-4. The diagrams with a differential pressure transmitter depicting flow in the following control schemes will require square root extraction, which can be achieved in the transmitter or in the BPCS.

In this system, the firing rate demand establishes the set point for the air flow controller, and the air flow measurement establishes the set point of the fuel flow controller. Therefore, the maintenance of fuel air ratio is provided on a measured metered basis. With this configuration the fuel demand is never greater than the actual measured air flow. This is an important safety consideration. Fuel follows air on load increase. There is no possibility of unburned fuel accumulation. Since the air flow loop is usually somewhat slower responding than the fuel flow loop, parallel tracking of the two occurs on load decrease.

Figure 6-5 illustrates another series metering system referred to as an air follow fuel scheme. Structured identically to the fuel follow air system — except the fuel and air loops are reversed — this series metering system has one advantage. Its response is optimum because of the faster response of the fuel loop.

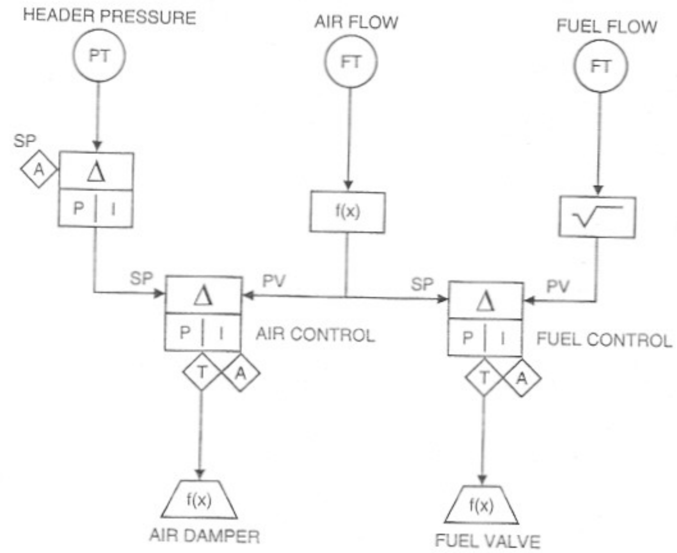


Figure 6-4 Fuel follow air series metering system.

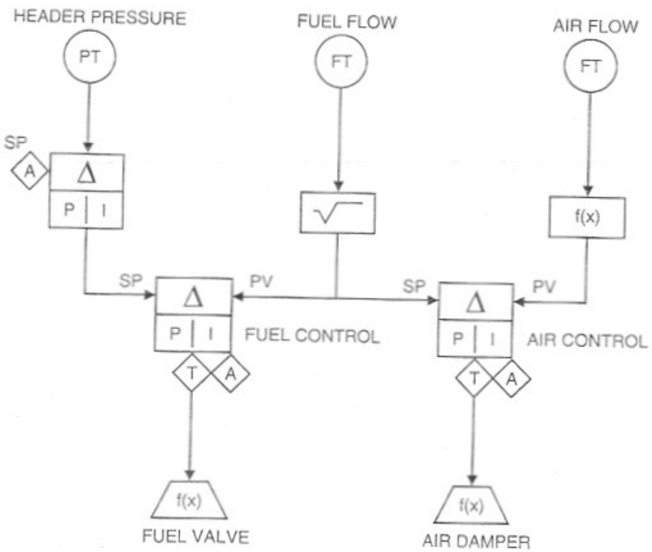


Figure 6-5 Air follow fuel series metering system.

From a safety standpoint, this configuration is undesirable. As the load increases, fuel will lead air. Also, fuel demand still has more fuel than air.

The better configuration for combustion control is developed in Figure 6-6. In this parallel metering system, the firing-rate demand signal is applied in parallel as the set point to two slave flow control loops. One flow control loop monitors fuel and the other monitors air.

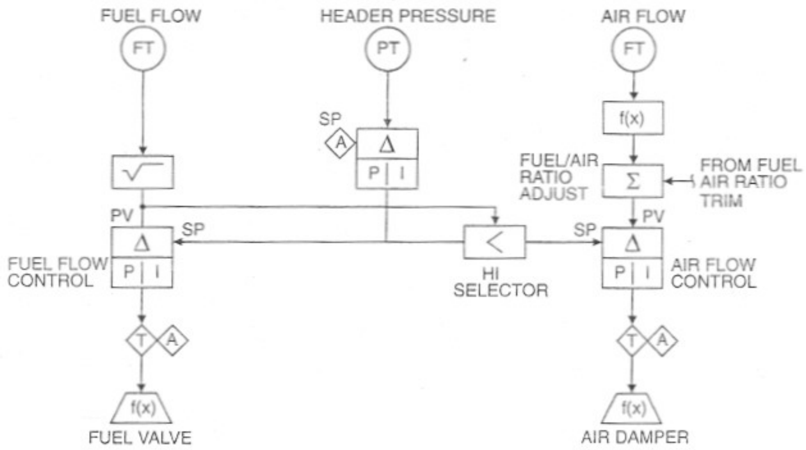


Figure 6-6 Basic parallel metering.

This system provides for stable, accurate control of energy input and fuel air ratio during normal steady-state operation, but does not guarantee combustion safety during transient conditions or during certain predictable operating irregularities.

A parallel system incorporating a fuel flow interlock is illustrated in Figure 6-7. The interlock is accomplished by inserting a low signal selector in the set point signal to the fuel flow controller. The second input to the selector is controlled air flow. Thus, the demand signal for fuel is either the firing-rate demand signal or the measured air flow, whichever is lower. With this system, fuel demand can never exceed measured air flow and, on a load increase, fuel demand must follow air demand. Fuel cannot be increased until air flow increase is proven through the air flow measurement loop.

Figure 6-8 is a parallel metering system with air flow interlock. This is accomplished by inserting a high signal selector in the set point signal to the air flow controller. The second input to the selector is measured fuel flow. Therefore, the demand signal for air is either the firing-rate demand signal or the measured fuel flow, whichever is higher.

With this system, air demand can never be less than measured fuel flow. On a load decrease, air demand must follow fuel. Air cannot be decreased until fuel flow decrease is proven through the fuel flow measurement loop.

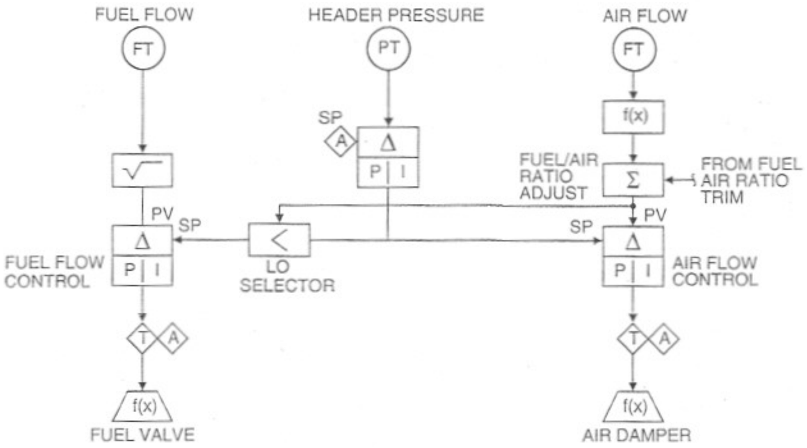


Figure 6-7 Parallel meter fuel flow interlock.

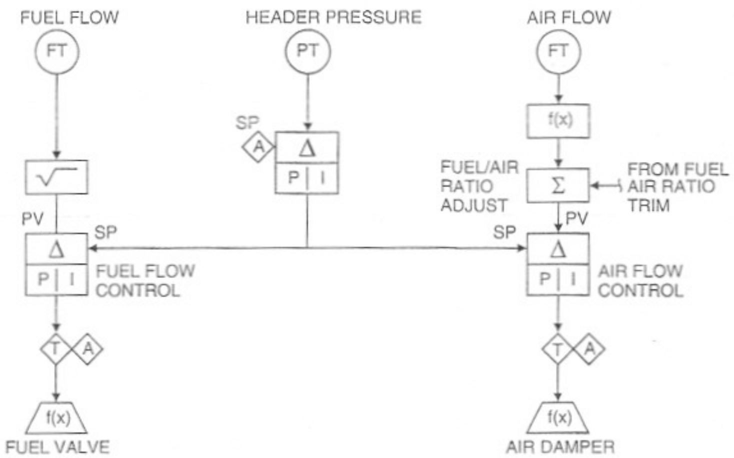


Figure 6-8 Parallel meter air flow interlock.

Fuel and Air Control Gas Oil

Figure 6-9 is a parallel metering system incorporating both the fuel flow and air flow interlocks previously described. This scheme is referred to as a cross limiting or lead-lag parallel-series metering system or flow interlocked system. Gas and oil control is depicted in this control scheme; however, the cross limiting control concept is commonly used for all fuels and has been the standard for utility boilers since the 1960's.

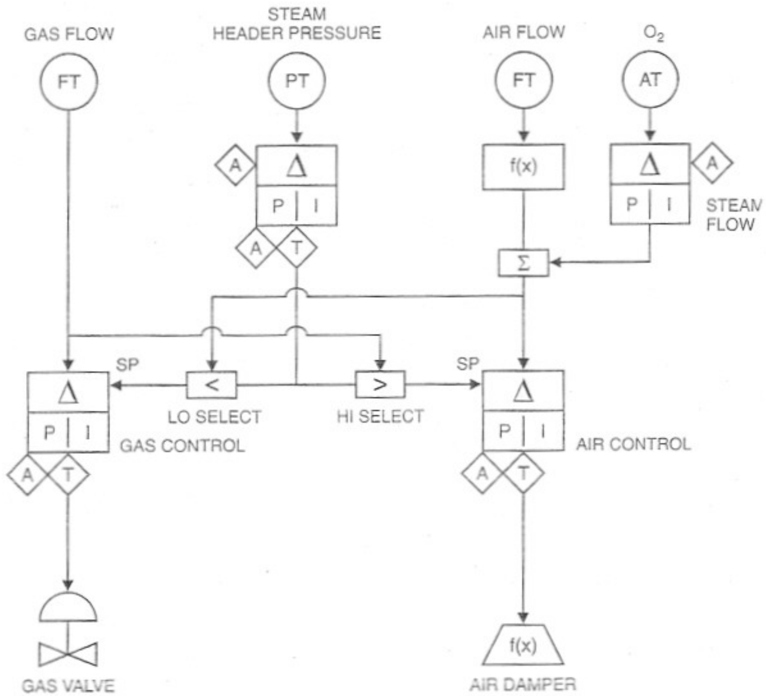


Figure 6-9 Firing single fuel/cross limiting.

First, the steady-state condition of this system is considered with all values in percent. The fuel and air controllers, which provide proportional-plus-integral action, act to continuously hold measurement equal to set point. Therefore, load demand, air flow set point, air flow measurement, fuel flow set point, and fuel flow measurement are all equal. The two flow loops are set in parallel.

On a load increase, the low selector rejects the load demand signal and accepts the air flow measurement signal. Fuel flow demand (set point) becomes equal to air flow measurement.

At the same time, the high selector rejects fuel flow measurement and accepts the increasing load demand signal. Air flow demand (set point) becomes equal to load demand. The system acts as a series metering system with fuel following air.

On a load decrease, the low selector accepts the load demand signal, and fuel demand (set point) becomes equal to load demand. Air demand becomes equal to fuel flow. Again the system is acting as a series metering system, this time with air following fuel.

The advantage of this system is on a load increase. Fuel demand cannot be increased until an actual increase in air flow measurement is sensed. On a load decrease, air demand cannot be decreased until an actual decrease in fuel flow measurement is sensed. On an inadvertent decrease in measured air flow, the fuel demand is immediately reduced an equal amount.

Fuel and Air Control Characterization

On all control systems, the air must be characterized to the fuel. Figure 6-10 is an example of what the output from the flow transmitters may look like. The air curve and the fuel curve must match for cross limiting control to control the fuel air ratio. On an increase in demand, the air increases first, modifying the set point for the fuel through the low select relay. On a decrease in demand, the fuel decreases and the air set point is modified through the low select relay. Note the air flow curve. When a vane or damper opens, the initial change in air flow is greater than it is as the opening increases. The drive is characterized to linearize the flow.

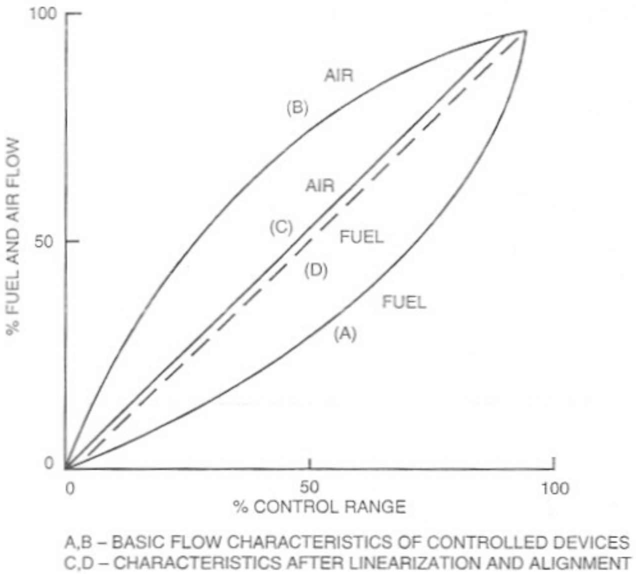


Figure 6-10 Output from flow transmitters.

Figure 6-11 is an example of the characterization curve. This curve is developed during boiler startup or at any time the fuel air ratio must be verified. The characterization of the air flow is a very important function in a boiler control scheme. It can be very time consuming, but it is important for safe and efficient operation of a boiler. This characterization is achieved by manually firing the boiler and increasing the air at various firing rates. After the air is increased, the fuel is slowly increased until a good flame is established. A good flame is achieved when the O_2 is at the desired level with no combustibles. Change the air flow output to match the fuel flow. The chart shows that with the fuel flow at 50 percent, the air flow is 37.5 percent. The output from the characterizer must be changed to 50 percent. At 60 percent fuel flow, the characterizer output must be changed from 45 percent to 60 percent.

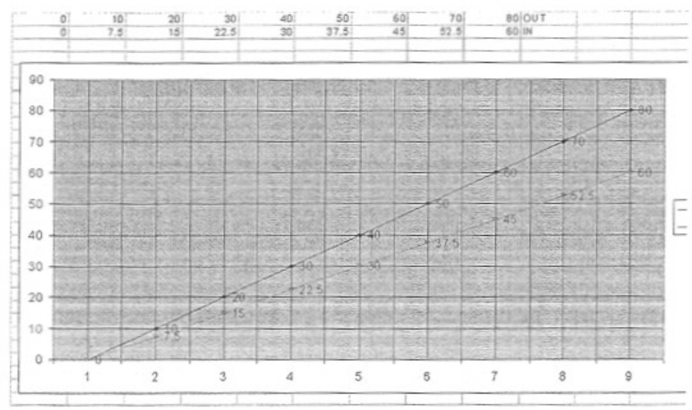


Figure 6-11 Characterization curve.

This procedure is continued until the firing rate of the boiler is complete. If the procedure is carried out accurately, the fuel air ratio will be at the desired oxygen level over the full firing rate of the boiler. Figure 6-12 shows that the first 50 percent of the boiler load typically will have high excess air. This is because the minimum air flow is typically 25 percent and, in general, all boilers require more excess air for complete combustion at lower loads. See Table 6-1 for a comparison of excess air to oxygen.

Excess air is controlled by measuring oxygen which is in direct correlation to it. When reducing excess air, the optimum point is reached when an increment of excess air reduction (e.g., 0.1 percent oxygen) is equal to the loss from the increase in ppm of carbon monixide. Since the flue gas temperature is higher at higher loads, the gain for 0.1 percent reduction in percent oxygen is greater than at lower loads.

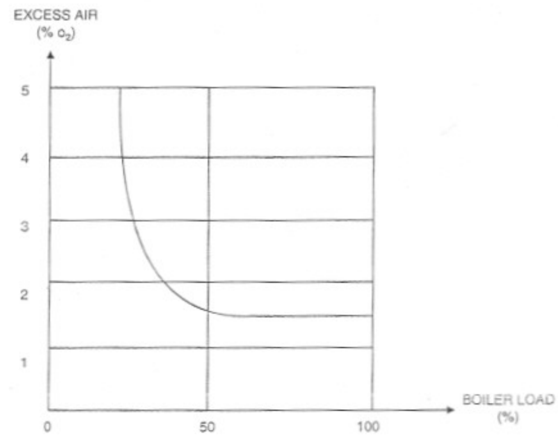


Figure 6-12 Excess air vs. boiler load.

Excess Air to Oxygen

When flue gas or other inert gases are introduced to the secondary air or combustion air being supplied to burners, a testing method must be used to demonstrate that the methods and devices used provide uniform distribution and mixing. The oxygen content of the mixture being supplied to the burners is not permitted to go below the limit specified by the burner manufacturer, or as proven by tests to provide stable combustion. Means must be provided to monitor either the ratio of flue gas to air or the oxygen content of the mixture.

Table 6-1 below gives the relationship of excess air to oxygen.

Table 6-1 Relationship of excess air to oxygen.

Gas										
Excess Air	0	4.5	9.5	15.1	21.3	28.3	36.2	45.0	55.6	67.8
Oxygen O_2	0	1	2	3	4	5	6	7	8	9

No. 6 Oil										
Excess Air	0	4.7	9.9	15.7	22.2	29.5	37.7	47.1	58.0	70.7
Oxygen	0	1	2	3	4	5	6	7	8	9

Coal										
Excess Air	0	4.9	10.2	16.2	22.9	30.4	38.8	48.5	59.5	72.9
Oxygen	0	1	2	3	4	5	6	7	8	9

A simple method for calculating excess air is:

$$\text{Excess air \%} = K\left(\frac{21}{21 - \%\ \text{oxygen}} - 1\right) \times 100$$

The K values are K= 0.9 gas; 0.94 oil; and 0.97 coal.

Multiple Fuel Control

The dual fuel cross limiting control in Figure 6-13 is used when the fuels are not fired simultaneously. The boiler must be shut down and started up on the alternative fuel. NFPA 85 requires a Btu of fuels being fired. This configuration does not sum the two fuels. This control scheme is burning gas or oil, not both. A selector switch is required.

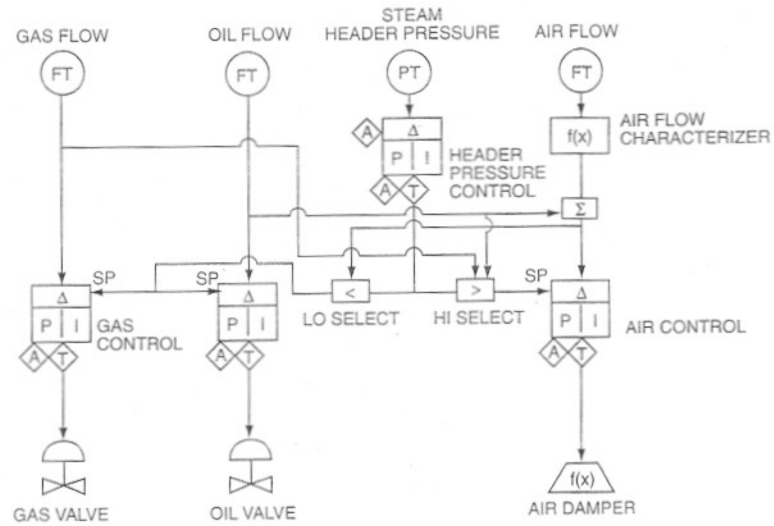


Figure 6-13 Dual fuel cross limiting control.

Figure 6-13 is also a multiple fuel control system. This control configuration is used when fuels are burned simultaneously, or for running fuel changes.

Some companies have gas curtailment contracts. When a company has a gas curtailment contract, the utility company can limit the gas supply if the demand for gas is high. This normally occurs in very cold weather. In the event of gas curtailment, the company must switch to an alternate fuel and not shut down the boiler. Typically, the alternate fuel is oil.

To change fuels, the oil recirculation system is started to establish flow. If the oil is heavy, such as #6 oil, it must be heated. Figure 6-14 is an example of a control system designed for multiple fuel burning and running fuel changes.

When multiple fuels are burned simultaneously, a Btu summer is required to control the air based on total Btu values of the fuel. In Figure 6-14, the Btu summer output is the total Btu value of the fuels burned in the boiler.

The Btu values of the gas and oil flows are not the same (see Figure 6-14); therefore, the scaling of the fuels will be required in the Btu summer for the two fuels. If the Btu for gas is 1,100 scfh, for 90,000 scf the Btu for gas is 99,000 K. If the Btu for #6 oil is 19,000 Btu/lb, the Btu for oil is 95,000 K Btu's. The K value for gas is 1 and the K value for oil is 0.96 (95/99 = 0.959 or 0.96).

The different air flow required for oil can be adjusted by the operator setting a ratio on the air controller. In addition, the ratio may be adjusted with a feedforward forward signal from the oil flow to the summer on the output from the air characterizer. The summer has three inputs. The input from the characterizer will have a K value of one, and the input from the oil will have a K value based on the air ratio difference of the oil versus gas (approximately 0.9).

A fuel controller controls the firing of the fuel. Typically, the primary fuel controls the boiler demand and the alternate fuel is base-loaded. A feedforward signal is also sent to the air flow demand from the secondary fuel in order to bias air flow for the secondary fuel. Boiler efficiency is improved by measuring oxygen and using the output from the oxygen controller as a feedforward signal to the air flow controller. To prevent a hazardous condition if the oxygen analyzer fails, a limit on the output is required. Combustible analyzers are often installed as a reference of percent combustibles with a high combustibles alarm.

The O_2 trim controller output is another input to the air flow summer. This can have a value of 1, if the output of the controller is limited. If the output of the controller is not limited, the limit of the trim can be set by the K value of the summer. If the K value is 0.1, the limit is 10 percent. A low O_2 condition must be alarmed.

One method for transferring fuels is to place the secondary fuel in manual and bias the air to prevent a fuel rich mixture from developing. The secondary fuel is slowly increased a few percent at a time. The header pressure increases and the header pressure controller decreases the primary fuel. This procedure is continued until the fuel transfer is complete, then the secondary fuel controller is placed in automatic/cascade control and the primary fuel is placed in manual control. The NFPA 85 Code describes the transferring of fuels in more detail.

On utility boilers, the boiler demand from the front end sets a demand for fuel Btu/hr. The firing rate master looks at the Btu/hr flows of the different fuels and adjusts the swing fuel to meet the total heat input demand as the base-loaded fuel changes. Because air requirements are different for different fuels, the air may also need to be adjusted.

Oxygen (O_2) Trim Control

O_2 trim control is demonstrated in Figure 6-14 and Figure 6-8. The O_2 trim control is used to trim the fuel air ratio due to a change in conditions such air density or fuel variations. The various fuel Btu values are shown in Table 6-2.

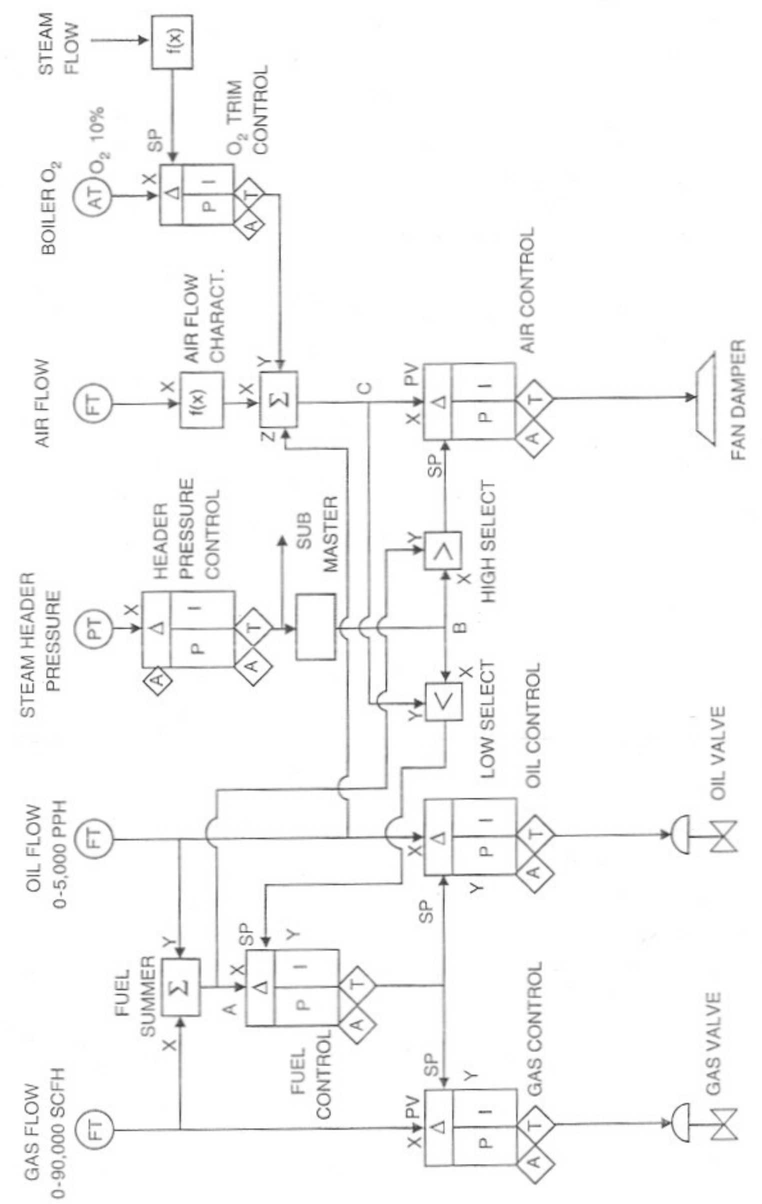


Figure 6-14 Running fuel change, dual fuel O_2 trim.

Table 6-2 Fuel Btu values per pound by state.

Gas	Btu/lb	Coal	Btu/lb	Oil	Btu/lb
Pennsylvania	23,170	Alabama	13,350	No. 2 Oil	19,170
South Carolina	22,904	Illinois	11,200		19,750
Ohio	22,077	Indiana	11,300	No. 6 Oil	17,410
Louisiana	21,824	Kansas	10,950		18,990
Oklahoma	20,160	Kentucky	12,100		
		Ohio	12,550		
		Pennsylvania	13,850		
		Colorado	9,650		
		North Dakota	6,940		

Multiple Boilers

Some plants have multiple boilers supplying steam to a common header. The NFPA 85 Code requires that each boiler with the same fuel supply have a manual isolation valve to isolate the fuel supply. The Code also requires that each boiler has dedicated safety shutoff valving with related alarm interlocks and control instrumentation. Figure 6-14 depicts a control system for a single boiler with a sub-master to provide a means of adjusting the firing rate demand for the boiler.

The ratio of the steam to a common header may be designed so that the waste fuel firing rate is steady and not an off and on supply. Some boilers burn waste fuels to dispose of fuels derived from plant production. Other boilers bring in waste fuels to reduce fuel costs. Plants have been able to obtain fuels such as scrap wood that has been ground into chips, at little or no cost, reducing the overall cost of steam generation. Each boiler should have drum pressure, steam flow, and header pressure transmitters for monitoring operation of the boiler.

It is also important to track boiler efficiency, especially if a plant has more than one boiler. If one of the boilers is less efficient than another, boiler load may be transferred to improve overall efficiency. A computerized system that calculates boiler efficiency enables the operator to monitor the efficiencies of each boiler and make manual adjustments, or have the computer make load corrections, for the most efficient operation.

CHAPTER 7

Steam Temperature

The fourth element of a control system is steam temperature control. (For a brief tutorial on steam temperature control, see Appendix B, Steam Temperature Control, taken from ANSI/ISA-77.44.02-2001, *Fossil Fuel Power Plant Steam Temperature Control System — Once-Through Type*.)

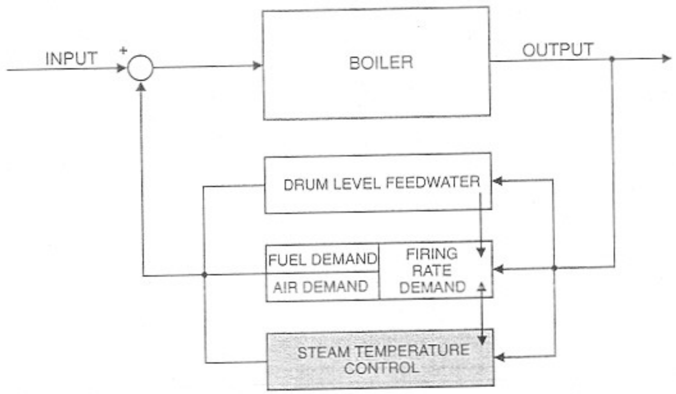


Figure 7-1 Block diagram of boiler control – steam temperature control.

The function of the superheat temperature control system is to maintain superheat steam temperature within the boiler manufacturer's specified limits. Generally, the goal is to obtain a specified final superheat steam temperature over the specified boiler-load range. The control strategy must be based on the particular control mechanisms used and the boiler manufacturer's philosophy for controlling steam temperature. The strategies consist of spray water attemperation, gas bypass, gas recirculation, burner tilt, or a combination of these processes. Although the control strategies described here use conventional PID control techniques, the use of advanced control strategies is not excluded. The primary benefit of constant steam temperature is improving the economy of conversions to mechanical energy and reducing the amount of moisture in the steam. Excessive steam moisture will result in damage to the turbines. Constant temperature control allows for smaller tolerances of the mechanical equipment.

Superheat tubes heat the steam and remove moisture from the steam. The steam is controlled to the desired temperature by cooling the steam with spray water. This process is referred to as de-superheating. De-superheating controls the temperature of the steam by spraying water into the steam line to reduce the superheated steam to the desired temperature. De-superheating can be accomplished by one, two, or three element control.

Single element steam temperature control is the minimum control strategy required to regulate the steam temperature leaving the boiler. Single element control should only be used in applications with slow load changes such as building heating systems, where constant steam temperature is not critical, or when the steam demand has very little variation.

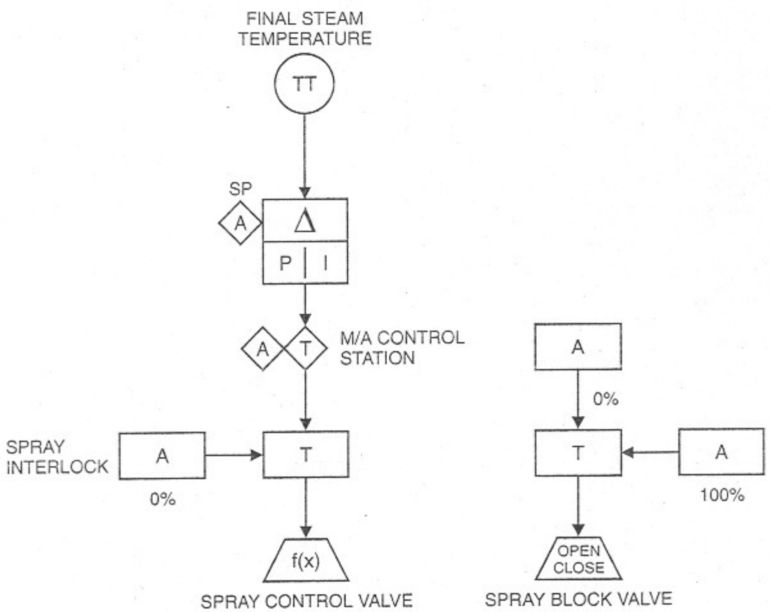


Figure 7-2 Typical single element superheat control.

Figure 7-2 is a typical simple feedback control, single element control system. The final steam temperature is measured and compared to a set point; the result is used to regulate the spray water flow. The spray interlock prevents the water injection if the steam temperature is not adequate.

Two element steam temperature control adds a feedforward signal and a transient correction signal to the single element control. As a minimum, the feedforward signal is derived from variations in steam load demand. This feedforward signal should recognize all major influences on steam temperature, including adjustments to heat distribution within the boiler.

A two element steam temperature control strategy should only be used in applications with slow to moderate load changes or with a steady spray water pressure supply and fixed steam pressure applications.

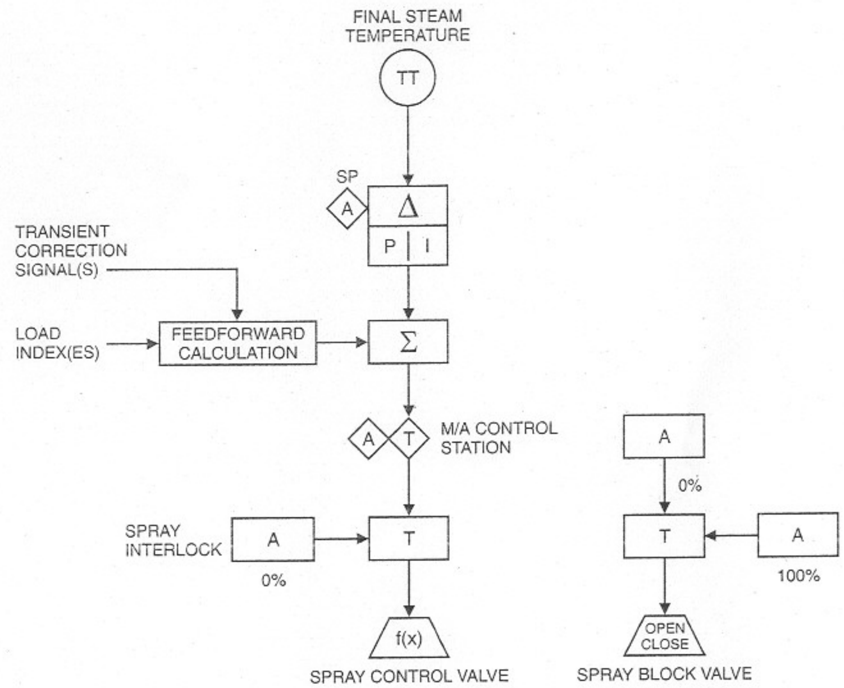


Figure 7-3 Typical two element superheat control.

Figure 7-3 is a typical feedforward plus feedback control system with a secondary variable and a load index that has a predictable relationship with the manipulated variable spray water. The final steam temperature is measured and compared to a set point, modified by the feedforward calculation, and the result is used to regulate the spray water flow.

Three Element Level Control

A three element steam temperature control strategy should be used in applications when there are rapidly changing loads, variable steam pressures or variations in spray water pressure. Three element steam temperature control adds a cascade control arrangement to the two element control strategy for control of the spray valve. The two element control strategy acts as the set point development for the inner control loop of the cascade control arrangement.

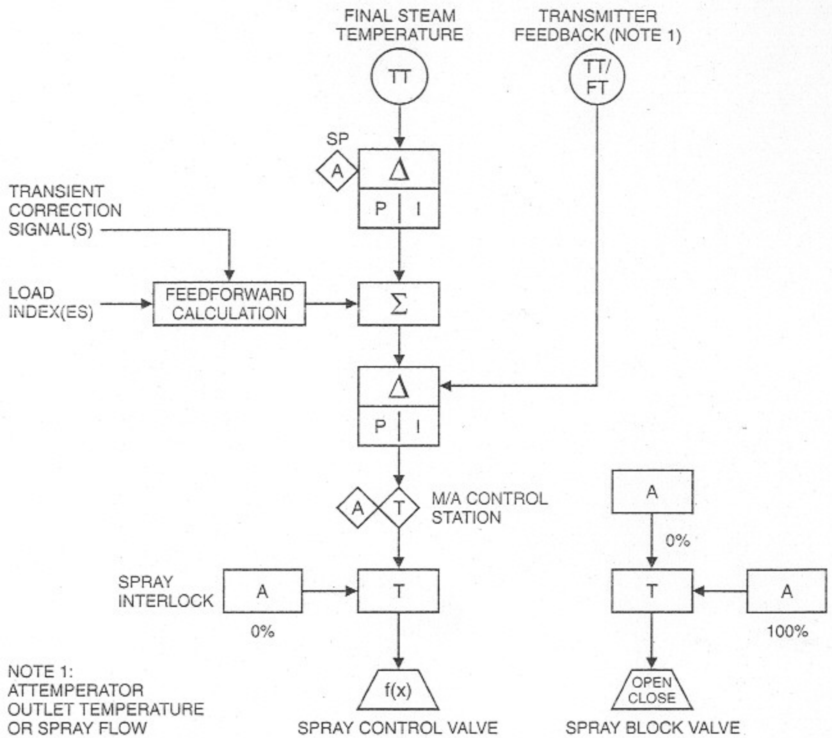


Figure 7-4 Typical three element superheat control.

Figure 7-4 is a feedforward controller with cascade control. The process variable for the inner control loop is a monitor of the spray action. Although steam temperature immediately after the attemperation (de-superheating) is the preferred process variable, spray water flow also may be used. At a minimum, the feedforward signal is derived from load variations. This feedforward signal should recognize all major influences on steam temperature, including adjustments to heat distribution within the boiler. For variable pressures, a suitable feedforward signal must be provided to reflect the influence of changes in the thermodynamic properties of steam on the final steam temperature.

Figure 7-5 outlines the control scheme for superheat steam temperature control. The spray water is measured and based on the steam temperature. The water is adjusted to control steam temperature to the turbine.

Single-stage attemperation refers to the boiler design that provides a single location for introducing spray water to regulate steam temperature. This application is typical of boilers with only a single superheat section or two superheater sections in series, commonly called the primary and secondary superheaters. It is normal to have the spray attemperation take place in the

headers between the two superheater sections or occasionally at the superheater outlet. Note that a single attemperation location does not necessarily refer to a single set of spray equipment.

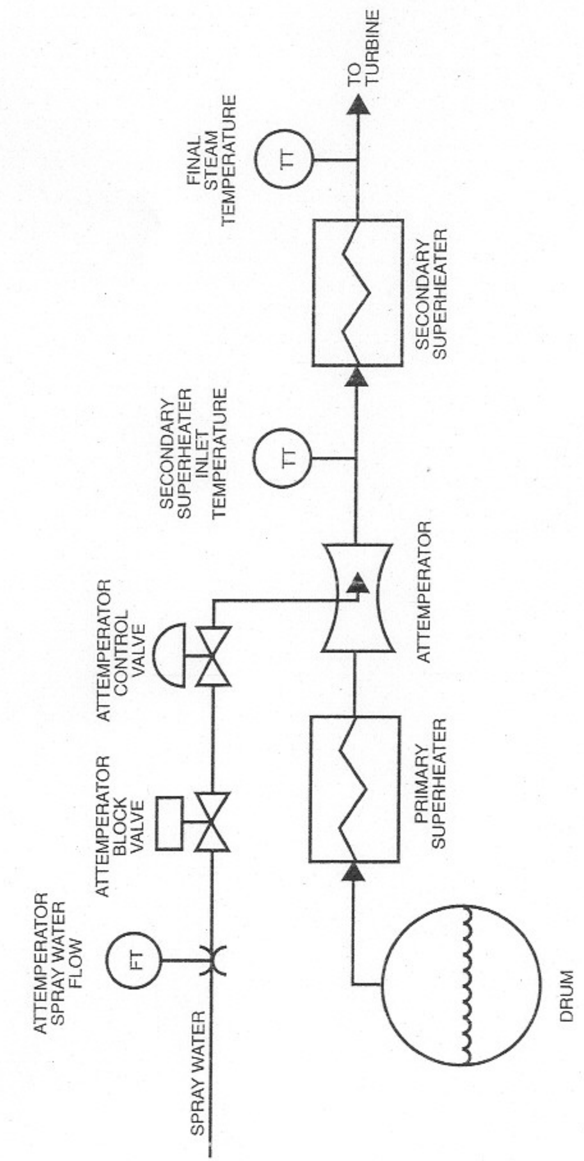


Figure 7-5 Typical superheater single-stage attemperator arrangement.

In Figure 7-6, the temperature measurement is taken at the outlet of the intermediate superheater section before the second state attemperator. This is required in a two-stage attemperator control strategy. A pressure measurement is required in a two-stage attemperator control strategy to prevent saturation following first-stage spray attemperation. Typically, this pressure is measured at the inlet of the intermediate superheater; however, drum pressure may be used also.

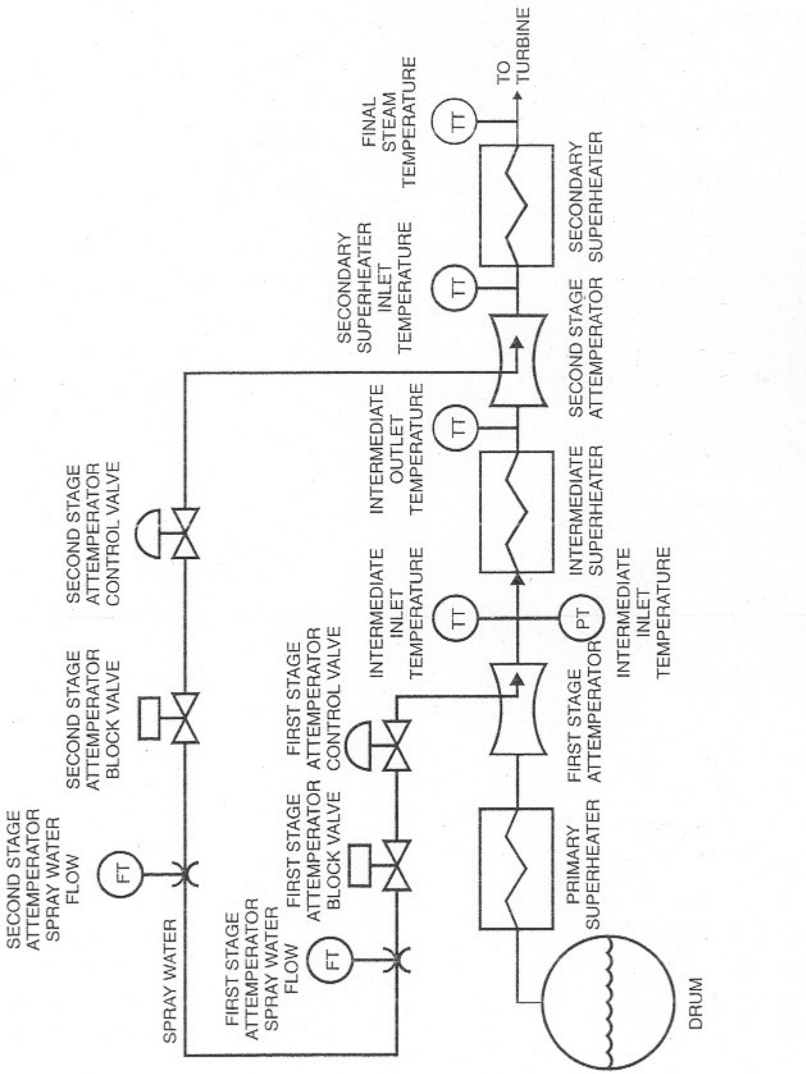


Figure 7-6 Temperature measurement taken at outlet of intermediate superheater section.

An attemperator spray water mass flow signal provides an alternative to the use of the attemperator outlet steam temperature as the secondary variable in a three element control strategy.

Superheating steam improves the quality of the steam by increasing its energy content. Moisture content in steam can reduce the efficiency and may cause severe damage to a turbine, resulting in power generation loss as well as turbine rebuilding and repairing expenses.

How far to go in providing instruments for indicating and recording temperature and for alarms depends on the steam generating equipment furnished and on the judgment of the designer engineer. In a small installation with moderate steam temperature, a simple instrument for indicating final steam temperature may be all that is necessary. For a large unit with high steam temperature, where deviation from design conditions may cause serious loss in efficiency or failure of equipment, instrumentation for all necessary functions should be provided.

The arrangement shown in Figure 7-7 serves as a basis for illustrating the need for, and the functions of, a typical set of instruments. The most important consideration is the final steam temperature, since satisfactory operation and safety of equipment beyond the boiler, as well as protection of the superheater, depend on steam temperature. This measurement is also needed for actuating the automatic control system.

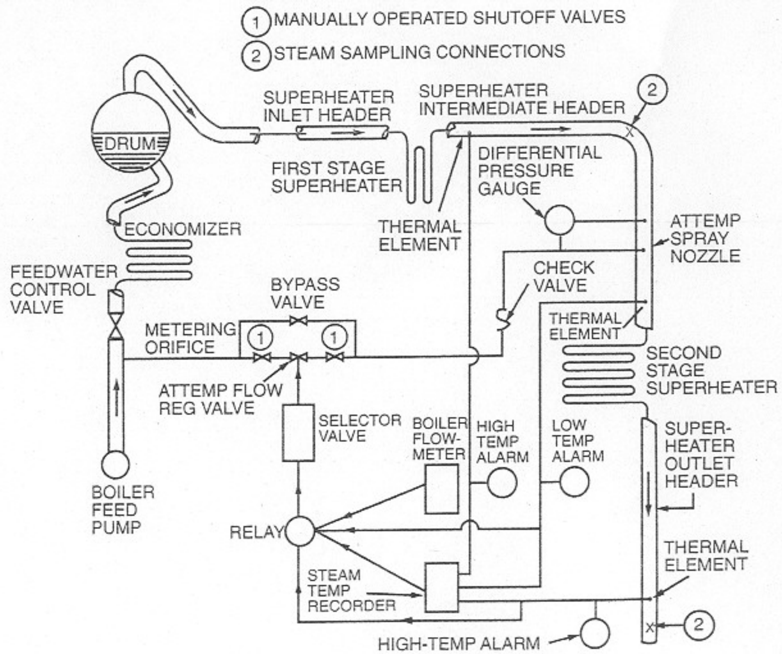


Figure 7-7 Three-element control for spray attemperator.

A high temperature alarm is recommended as an additional safety feature, even though the careful attention given to final steam temperature by both boiler and turbine operators is usually considered sufficient protection.

Measurement of steam temperature with a low temperature alarm at the spray attemperator outlet protects the second-stage superheater from the thermal shock of quenching by preventing over-attemperation and the consequent discharge of saturated steam and water into the hot superheater elements. Alternately, measurement of steam temperature with a high temperature alarm at the first-stage superheater outlet protects this stage from overheating should slagging or other upset conditions alter the distribution of heat absorption between first and second-stage superheaters to such an extent that the primary steam temperature becomes excessive.

A steam-sampling connection should be installed in the steam line between the steam drum and the attemperator to check the purity of steam leaving the drum. It is also desirable to install a steam sampling connection in the steam line, after the attemperator. This connection checks for leakage of boiler water into the line in the case of a submerged attemperator or for excessive solids carried over in the spray water of a spray-type attemperator.

Burner tilt is also used to control superheat. Combustion engineering uses the burner tilt control strategy. Powerful control drives are used to tilt the burners at angles approximately plus or minus 30 degrees. Potentially, this is a total angle of 60 degrees, though it is often restricted when the boiler is initially tested. It is important to have the tilt angle the same at all four corners to avoid distorting the fireball and compromising the controllability.

The burner flame is aimed at a tangent to an imaginary circle in the center of the furnace and the burners in the four corners of the furnace are tilted at the same angle. This results in a fireball in the center of the furnace which rotates and can be raised or lowered in the furnace by changing the tilt of the burners. Lowering the fireball increases furnace heat absorption, which lowers the flue gas temperature as it enters the superheater. Raising the fireball decreases the furnace heat absorption and thus raises the temperature of the flue gases entering the superheater.

For a boiler that includes a reheater, the burner tilt control is used to control reheat temperature. If this can be done successfully, there is, in normal operation, no water spray to the reheat section, and the unit thermal performance is not affected. This also means that water spray is needed for superheat temperature control, and a water spray system is needed as a reheat temperature override. The abnormal operating condition of low feedwater temperature from loss of the high pressure heater is one case in which reheat spray may be required.

A position transmitter sends a tilt position signal to the superheat temperature control system. If the superheat temperature is controlled with spray water, this signal is used as a feedforward to automatically change the superheat spray as the burner tilt position is changed. This prevents the burner tilt change, necessitated by the reheat temperature control, from causing a change in the superheat temperature.

Combustion engineering boilers with multiple use level burners use flue gas recirculation to control superheat. By varying the ratio of the fuel fired in the upper row of burners to that in the lower row of burners, the furnace heat absorption can be modified, thereby changing the temperature of the flue gases entering the superheater. The flow stream of the flue gas passing the superheater can be split. This allows the mass of flue gas in contact with the superheater to be varied by a mechanism called a superheater bypass damper. A flue gas recirculating fan is also used to add a variable amount of flue gas mass flow to the stream in contact with the superheater. An additional fireside method is that of increasing or decreasing the percentage of excess air in order to control steam temperature. This method tends to improve the overall heat rate of power generation equipment, although the thermal efficiency of the boiler itself may be lowered.

CHAPTER **8**

Burner Management Systems

Burner Management System (BMS) Control

The general term used for a safety system is burner management system (BMS). However, it may also be referred to as a combustion safeguard, burner/boiler safety system, burner control system, flame safeguard system, safety shutdown system, furnace safeguard supervisory system, emergency shutdown system or a safety instrumented system (SIS).

The BMS is the system that monitors the fuel burning equipment during startup, shutdown, operation and transient conditions. It is designed to present the status of all fuel burning equipment to the operator in a concise format. The BMS initiates a safe operating condition or shutdown procedure to prevent an explosion if an unsafe condition exists, thus protecting equipment from damage and people from injury or death. The basic process control system (BPCS) modulates fuel and air input to the boiler in response to load variations. The burner management system essentially is an on/off control system that permits firing of a boiler at any load when safe conditions exist. If an unsafe condition occurs, the BMS automatically shuts off fuel or causes the boiler to go to a safe state.

NFPA 85 Code

The comments and information in this section are based on the NFPA 85 Boiler and Combustion Systems Hazards Code 2004 Edition. This section does not cover the entire Code, but provides information on some of the most frequent questions that have arisen in my experiences in the field.

The NFPA 85 Code applies to single burner boilers; multiple burner boilers; stokers; atmospheric fluidized-bed boilers with a fuel input rating of 3.7 MW (12.5 million Btu/hr) or greater; pulverized fuel systems; and fired or unfired steam generators used to recover heat from combustion turbines (heat recovery steam generators, HRSG).

The purpose of the Code is to ensure safe operation and to prevent uncontrolled fires, explosions, and implosions in equipment. The Code establishes minimum requirements for the design, installation, operation, training, and maintenance of boilers, pulverized fuel systems, HRSGs, and their systems for fuel burning, air supply, and combustion products removal. The Code requires the coordination of operating procedures, control systems, interlocks, and structural design. The most common contributor to boiler explosions is human error.

It is important that the Code is not used as a design handbook. A designer capable of applying more complete and rigorous analysis to special or unusual problems has the latitude in the development of such designs. In such cases, the designer is responsible for demonstrating and documenting the validity of the proposed design.

Purge Control

Purging is required before ignition of the first burner to clear any combustibles that may have accumulated in the boiler and components. This is a critical time before the lighting of the first burner. Purge requirements vary with each boiler.

The multiple burner boiler purge rate must not be less than 25 percent and not greater than 40 percent of design full load mass air flow for coal-fired units. The requirements for a cold start are as follows. Multiple burner boiler unit purge must be completed by maintaining this purge rate, from the forced draft (FD) fan through the stack, for a period of not less than five minutes or not less than five volume changes of the boiler enclosure, whichever is longer. Prior to being placed in operation, components (e.g., precipitators, fired reheaters) containing sources of ignition energy must be purged for either a period of not less than five minutes or five volume changes of that component, whichever is longer. Completion of the purge must be indicated.

Single burner boiler purge air flow must reach no less than 70 percent of the air flow required at maximum continuous capacity of the unit. The purge must be for at least eight air changes. Air flow during the period of opening the damper and returning it to the light off position is permitted to be included in computing the time for eight air changes.

Fire tube boiler purge air flow must reach no less than 70 percent of the air flow required at maximum continuous capacity of the unit. The purge of the furnace and boiler gas passes must be for at least four air changes. During the purge, the air damper must be driven to the full open position. Air flow during the time to open the damper and return it to light-off position is permitted to be included in computing the time for four air changes.

Fluidized bed and boiler enclosure must be purged with no less than five volumetric air changes but, in any event, for a continuous period of no less than five minutes under the following conditions. A freeport purge without air passing through the bed material must be deemed as not meeting purge criteria. The purge must include the air and flue gas ducts, air heater(s), warm up burner(s), windbox(es), and bed(s). The purge is not to be less than 25 percent of design full load mass air flow. Total air flow must not be reduced below the purge rate.

HRSG purge rate must provide the required velocity in the connecting duct and the HRSG enclosure to ensure dilution and removal of combustible gases prior to turbine light off.

Requirement for Independence of Control (Hardware/Software)

The burner management system must be provided with independent logic, independent input and output systems, and independent power supplies. It must also be a functionally and physically separate device from other logic systems, such as the boiler or HRSG control system.

For single burner boilers, boiler control systems are permitted to be combined with the burner management system only if the fuel air ratio is controlled externally from the boiler control system (e.g., locked fuel air ratio with mechanical positioning-type system). Burner management safety functions must include, but not be limited to, purge interlocks and timing, mandatory safety shutdowns, trial timing for ignition, and flame monitoring. A logic system is to be limited to one steam generator.

The same hardware type used for burner management systems is permitted to be used for other logic systems. Data highway communications between the burner management system and other systems is permitted. Signals that initiate mandatory master fuel trips must be direct wired.

Alarms are to be generated to indicate equipment malfunction, hazardous conditions, and misoperation. The logic system designer must evaluate the failure modes of components, also referred to as a risk analysis, and at a minimum, the following failures are to be evaluated and addressed:

1. Interruptions, excursions, dips, recoveries, transients, and partial losses of power
2. Memory corruption and losses
3. Information transfer corruption and losses
4. Inputs and outputs (fail-on, fail-off)
5. Signals that are unreadable or not being read
6. Failure to address errors
7. Processor faults
8. Relay coil failure
9. Relay contact failure (fail-on, fail-off)
10. Timer failure

Note: *Some items do not apply to all types of systems, e.g. relay systems.*

The design of the logic system for burner management must include and accommodate the following requirements:

1. Diagnostics must be included in the design to monitor processor logic functions.
2. A logic system failure must not preclude proper operator intervention. A method must be provided to shut down the boiler or go to a safe state in the event of a logic system failure.
3. The logic must be protected from unauthorized changes. Logic is not to be changed while the associated equipment is in operation.
4. The system response time (throughput) must be short to prevent negative effects on the application.
5. Protection from the effects of noise must prevent false operation.
6. No single component failure within the logic system is to prevent a mandatory master fuel trip.

7. The operator must be provided with a dedicated manual switch(es) that will actuate the master fuel trip relay independently and directly.
8. At least one manual switch must be identified and located remotely where it can be reached in case of emergency.

Note: *Some items do not apply to all types of systems, e.g., relay systems*

Flame Detection

The NFPA 85 Code requires flame detection on all flames. The flame sensing detectors must be self checking, either mechanically or electronically, if the detector can fail in the flame proven mode. The failure of any single component cannot result in a false indication of flame. The scanner configuration depends on the class of igniters.

Visible light, infrared (IR), and ultraviolet (UV) are the primary technologies used to detect flame. In some applications, flame flicker is used in combination with IR and UV. UV flame detection is primarily for gas service. IR flame detection may be used on fuels such as oil, coal, and black liquor, as well as gas. In Figure 8-1 in the flame configuration, infrared and visible light is 90 percent of the flame and ultraviolet is between 1 to 10 percent of the flame. When sighting the flame, the flame detector must point down, or horizontal, at the flame.

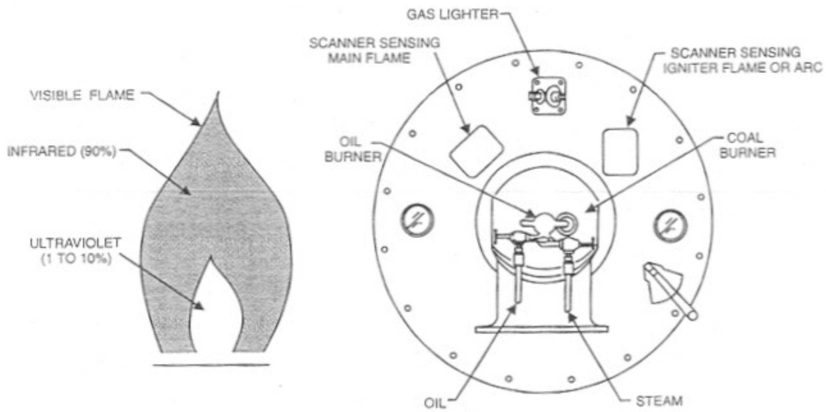


Figure 8-1 Flame detectors.

Flame Monitoring and Tripping System (Multiple Burner Boilers)

During initial startup, if flame on the first igniter(s) is not established within 10 seconds after the initiation of the spark or other source of ignition, the individual igniter safety shut off valve(s) must be closed, and the cause of failure to ignite is to be determined and corrected. With air flow maintained at purge rate, repurge is not required but at least one minute must lapse before a retrial of this or any other igniter is attempted. Repeated retrials of igniters without investigating and correcting the cause of the malfunction is prohibited. Each burner must be supervised individually, and upon detection of loss of a burner flame, that individual burner safety shut off valve must be automatically closed.

Class 1 Igniter

Where Class 1 igniters are provided, the main burner flame must be proven either by the flame detector or by the igniter being proven. At least one flame detector must be provided for each burner to detect the burner flame or igniter flame.

Class 2 Igniter

Burners with Class 2 igniters must have at least two flame detectors. One detector must be positioned to detect the main burner flame and must not detect the igniter flame. The second detector must be positioned to detect the igniter flame during prescribed light-off conditions.

Class 3 Igniter

Burners with Class 3 igniters must have at least one flame detector. The detector must be positioned to detect the igniter flame and detect the main burner flame after the igniter is removed from service at the completion of the main burner trial for ignition.

Upon detection of loss of all flame in the furnace or partial loss of flame to the extent that hazardous conditions develop, a master fuel trip must be automatically initiated. Regardless of the number or pattern of flame loss indications used for tripping, loss of flame indication on an operating burner or "flame envelope" must initiate an alarm that warns the operator of a potential hazard.

Flame Tripping Validation

The flame tripping concept used on the unit must have been validated by the boiler manufacturer for the specific furnace configuration being used. This validation must not be used to replace unit acceptance tests relating to proof of design, function, and components.

On loss of an individual burner flame, the burner's safety shut off valve must be automatically closed. The burner register is to be closed if it interferes with the air/fuel ratio supplied to any other individual burner flame.

On loss of an individual burner flame on coal fired boilers, the flow of fuel must be stopped unless furnace configuration and tests have determined that one of three automatic tripping philosophies is applicable. They are:

1. Detectors are located and adjusted to monitor specific zones in the furnace.
2. Under all reasonable operating conditions, main fuel combustion in one zone provides sustaining energy to adjacent zones if each zone is not self-sustaining.
3. Under circumstances of operation where support between zones receiving fuel does not exist, ignition support is provided, or, upon loss of flame in a zone or in the entire furnace, the master fuel trip is automatically initiated.

Figure 8-2 is a multiple burner boiler interlock system diagram.

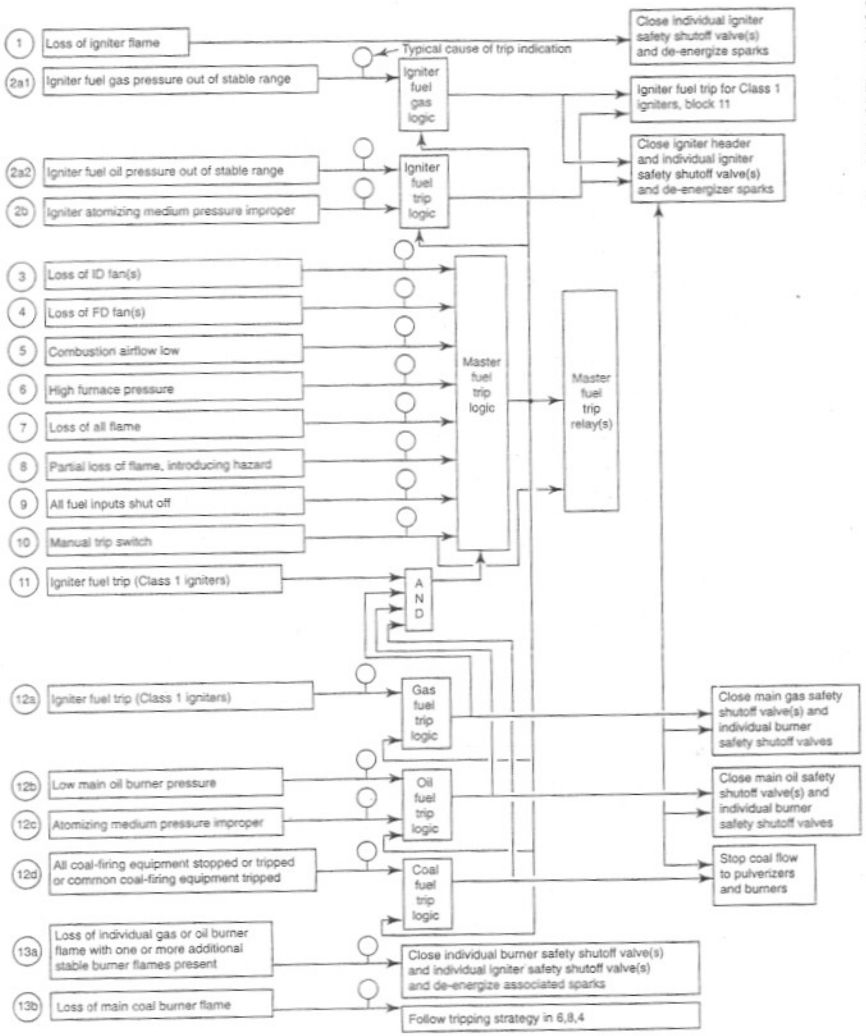


Figure 8-2 Interlock system for multiple burner boiler.

From NFPA 85 Figure 6.4.2.3.1

Table 8-1 defines the blocks in Figure 8-2.

Table 8-1 NFPA Table of shutdown requirements.

Block Number	Action
Block 1	Loss of an individual igniter flame must cause the following actions: 1. Close the individual igniter safety shut off valve(s) and de-energize the spark(s) 2. Open the vent valve (gas ignition only) 3. Signal the main flame protection system that the igniter flame has been lost
Block 2a1	The high or low igniter fuel gas header pressure must be interlocked to initiate the tripping of the igniter header and individual igniter safety shut off valves, de-energize sparks, and open vent valves.
Block 2a2	The low igniter fuel oil header pressure must be interlocked to initiate the tripping of the igniter header and individual igniter safety shut off valves and de-energize sparks.
Block 2b	Where oil is used for ignition fuel with air or steam atomization, atomizing air, or steam pressure out of range must trip the igniter and individual igniter safety shut off valves and de-energize sparks. Where direct electric igniters are used, blocks 1 and 2 must not apply. However, the master fuel trip system must de-energize sparks and prevent re-energizing until all conditions for light-off have been re-established.
Blocks 3-12	These blocks represent conditions that initiate the tripping of all main and ignition fuel supplies through a master fuel trip relay(s). The master fuel trip relay(s) must be of the type that stays tripped until the unit purge system interlock permits it to be reset. Whenever the master fuel trip relay(s) is operated, it must trip all fuel safety shut off valves and de-energize sparks and all ignition devices within the unit and flue gas path. The master fuel trip relay(s) must also trip the oil system circulating and recirculating valves. If the design of the oil supply system is such that backflow of oil through the recirculating valve is inherently impossible or positively prevented, this valve must be permitted to be manually operated and must not be required to be interlocked to close automatically on a master fuel trip. The master fuel trip relay(s) must also trip the coal burner line shut off valves or take equivalent functional action to stop coal delivery to burners, primary air fans or exhausters, and coal feeders.
Block 3	The loss of all induced draft fans must activate the master fuel trip relay.
Block 4	The loss of all forced draft fans must activate the master fuel trip relay.
Block 5	Low combustion air flow below the permitted limits must activate the master fuel trip relay.
Block 6	High fan pressure, such as that resulting from a tube rupture or damper failure, must activate the master fuel trip relay.
Block 7	Loss of all flame in the furnace must activate the master fuel trip relay.
Block 8	A partial loss of flame that results in a hazardous condition must activate the master fuel trip relay.
Block 9	When all fuel inputs to the furnace are shut off following a shutdown of the boiler for any reason, the master fuel trip relay must be activated.
Block 10	A manual switch that actuates the master fuel trip relay directly must be provided for use by the operator in an emergency.
Block 11	The igniter fuel trip must activate the master fuel trip relay in accordance to NFPA code requirements, if igniter fuel is the only fuel in service, or if it is being used to stabilize a main fuel.
Block 12a	When the gas burner header fuel pressure is above the maximum or below the minimum for a stable flame, that fuel must be tripped. If gas is the only fuel in service, the master fuel trip relay must be actuated.

Table 8-1 NFPA Table of Shutdown Requirements (cont.d)	
Block Number	**Action**
Block 12b	When the oil burner header fuel pressure is below the minimum for a stable flame, that fuel must be tripped. If oil is the only fuel in service, the master fuel trip relay must be actuated.
Block 12c	This block represents operation of the oil fuel trip to prevent operation when atomizing air or steam pressure is out of range. If oil is the only fuel in service, the master fuel trip relay must be actuated.
Block 12d	This block represents the tripping/shutdown of coal-firing equipment that will cause a coal fuel trip. If coal is the only fuel in service, the master fuel trip relay must be actuated.
Block 13a	Loss of flame at an individual gas or oil burner with one or more additional burners operating with stable flames that does not introduce a serious enough condition to warrant a master fuel trip as called for in Block 8, must close the individual burner safety shut off valve(s) and associated igniter safety shut off valve(s) and de-energize the associated igniter spark.
Block 13b	On loss of main coal burner flame, the tripping strategies must be followed.

Tables 8-2 and 8-3 are examples of documentation for communicating start up permissives, shutdown, alarms and status for operators. Table 8-2 is based on the requirements of NFPA 85 Code for alarms and shutdowns of single burner boilers. This is not an all-inclusive list but it is a possible format for design definition. The tag names are identification letters from ISA and SAMA identification tables which can be found in the Reference section. Also, see Figures 8-3 through 8-7 at the end of this chapter for information on interlock.

Table 8-3 is based on the requirements of NFPA 85 Code for alarms and shutdowns of multiple burner boilers. This is not an all-inclusive list but it is a possible format for design definition. The tag names are identification letters from ISA and SAMA identification tables which can be found in the Reference section. Also, see Figures 8-3 through 8-7 at the end of this chapter for information on interlock.

The fuel trip charts include some functions of the BMS.

Table 8-2 Communicating startup permissives, shutdown, alarms, and status for single burners

Tag Name	Single Burner Boiler Description/Common	Master Fuel Trip	Permissive	Alarm
BE	Loss or failure to establish flame	Yes	Yes	Yes
SS	Loss of combustion air	Yes	Yes	Yes
FSL	Combustion air flow	Yes	Yes	Yes
ZS	All fuel valves closed		Yes	Yes
HS	Master fuel trip	Yes	Yes	Yes
	Power failure	Yes	Yes	Yes
LSL	Low water level	Yes	Yes	Yes
TSL or PSH	Excessive water temperature either/or Excessive steam pressure	Yes	Yes	Yes
	Gas	**Gas Trip**	**Permissive**	**Alarm**
ZS	All fuel valves closed		Yes	Yes
PSH	High igniter gas pressure	Yes	Yes	Yes
PSL	Low igniter gas pressure	Yes	Yes	Yes
PSH	Burner header fuel pressure high		Yes	Yes
PSL	Burner header fuel pressure low		Yes	Yes
ZS	Flow control valve minimum fire		Yes	Yes
HS	Master fuel trip gas	Yes	Yes	Yes
	Oil	**Oil Trip**	**Permissive**	**Alarm**
ZS	All fuel valves closed		Yes	
PSH	Igniter fuel pressure high	Yes	Yes	Yes
PSL	Igniter fuel pressure low	Yes	Yes	Yes
PSH	High oil pressure	Yes	Yes	Yes
PSL	Low oil pressure	Yes	Yes	Yes
BE	Flame detection (loss of burner)		Yes	Yes
ZS	Flow control valve minimum fire		Yes	Yes
PSL / DPS	Loss of atomizing medium	Yes	Yes	Yes
PSL / DPS	Igniter atomizing pressure low	Yes	Yes	Yes
ZS	Oil gun in position*		Yes	Yes
HS	Master fuel trip oil	Yes	Yes	Yes
TSL	Low oil temperature	Yes	Yes	Yes

***Note:** *Not a requirement in the NFPA 85 Code 2004.*

Table 8-3 Communicating startup permissives, shutdown, alarms, and status for multiple burners

Tag Name	Multiple Burner Description/Common	Master Fuel Trip	Permissive	Alarm	Status	Not Req'd
BE	Loss of igniter flame (startup)		Yes	Yes	Yes	
SS	ID fan running	Yes	Yes	Yes	Yes	
SS	FD fan running	Yes	Yes	Yes	Yes	
FSL	Combustion air flow (< 25%)	Yes	Yes	Yes	Yes	
PSH	High furnace pressure	Yes	Yes	Yes	Yes	
PSL	Low furnace pressure	Yes	Yes	Yes	Yes	
BE	Flame detector (loss of all flame)	Yes	Yes	Yes	Yes	
BE	Partial loss of flame	Yes	Yes	Yes	Yes	
ZS	All fuel valves closed		Yes	Yes	Yes	
HS	Master fuel trip	Yes	Yes	Yes	Yes	
	Power failure	Yes	Yes	Yes	Yes	
LSL	Low water level		Yes	Yes	Yes	NR*
	Gas	**Gas Trip**	**Permissive**	**Alarm**	**Status**	
ZS	All fuel valves closed		Yes	Yes	Yes	
PSH	Igniter fuel pressure high	Yes	Yes	Yes	Yes	
PSL	Igniter fuel pressure low	Yes	Yes	Yes	Yes	
PSH	Burner header fuel pressure high	Yes	Yes	Yes	Yes	
PSL	Burner header fuel pressure low	Yes	Yes	Yes	Yes	
BE	Flame detection (loss of burner)		Yes	Yes	Yes	
ZS	Flow control valve minimum fire		Yes		Yes	
HS	Master fuel trip gas	Yes	Yes	Yes	Yes	
	Oil	**Oil Trip**	**Permissive**	**Alarm**	**Status**	
ZS	All fuel valves closed		Yes		Yes	
PSH	Igniter fuel pressure high	Yes	Yes	Yes	Yes	
PSL	Igniter fuel pressure low	Yes	Yes	Yes	Yes	
PSH	Burner header fuel pressure high	Yes	Yes	Yes	Yes	
PSL	Burner header fuel pressure low	Yes	Yes	Yes	Yes	
BE	Flame detection (loss of burner)		Yes	Yes	Yes	
ZS	Flow control valve minimum fire		Yes	Yes	Yes	
PSL / DPS	Atomizing pressure low	Yes	Yes	Yes	Yes	
PSL / DPS	Igniter atomizing pressure low	Yes	Yes	Yes	Yes	
ZS	Oil gun in position		Yes	Yes	Yes	NR*
HS	Master fuel trip oil	Yes	Yes	Yes	Yes	
TSL	Low oil temperature	Yes	Yes	Yes	Yes	
PS / SS	Coal firing equipment stopped		Yes	Yes	Yes	
BE	Flame detection (loss of igniter)		Yes	Yes	Yes	
ZS	All fuel valves closed		Yes	Yes	Yes	
BE	Flame detection (loss of burner)		Yes	Yes	Yes	
TSH	Coal duct temperature		Yes	Yes	Yes	
HS	Master fuel trip	Yes	Yes	Yes	Yes	

**Note:* *NR means "not required" by NFPA Code 2004.*

The following figures are PID representations of Figure 8-2 and Table 8-1 through 8-3.

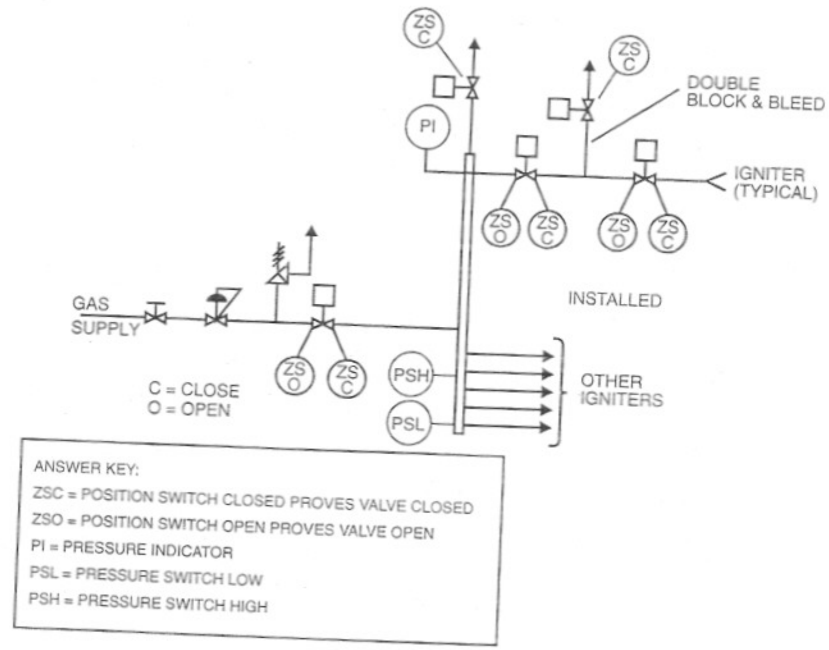
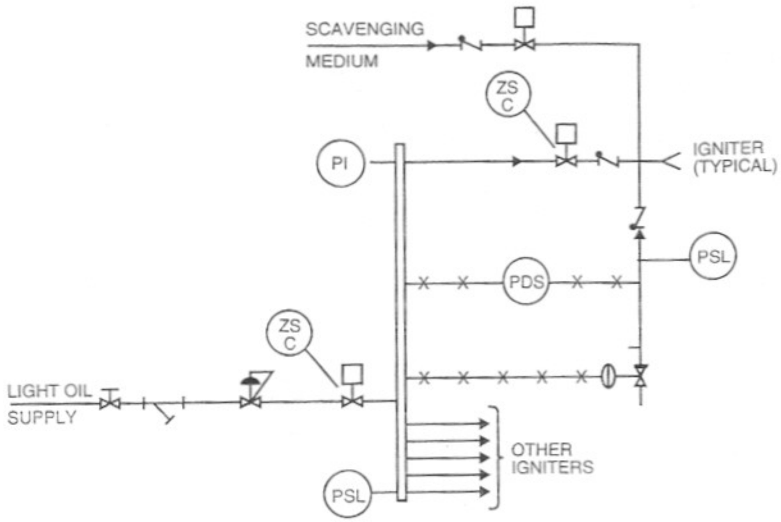


Figure 8-3 Example gas igniter.
Note: *Some companies also prefer to show when valves are open.*



ZSC = POSITION SWITCH CLOSED PROVES VALVE CLOSED

ZSO = POSITION SWITCH OPEN PROVES VALVE OPEN

PI = PRESSURE INDICATOR

PDS = PRESSURE DIFFERENTIAL SWITCH

PSL = PRESSURE SWITCH LOW

Figure 8-4 Example steam or air atomizing system light oil.

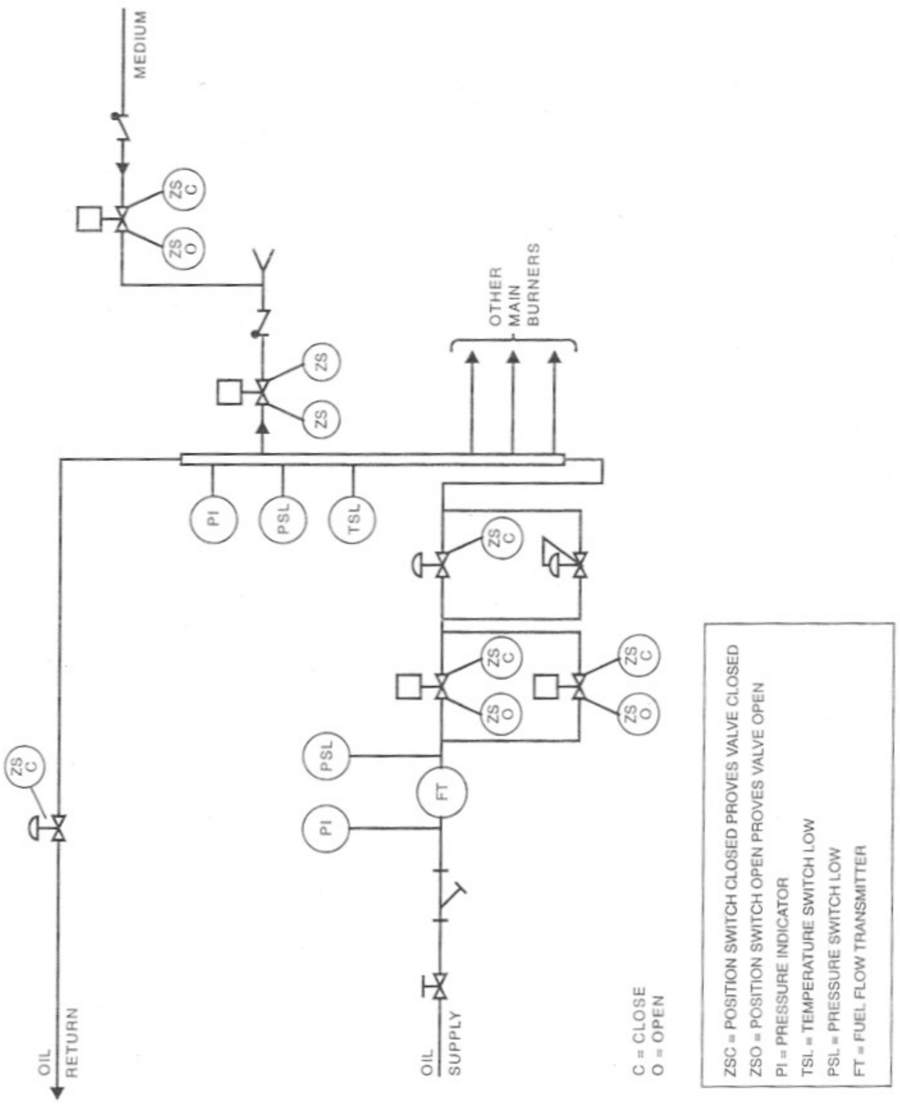
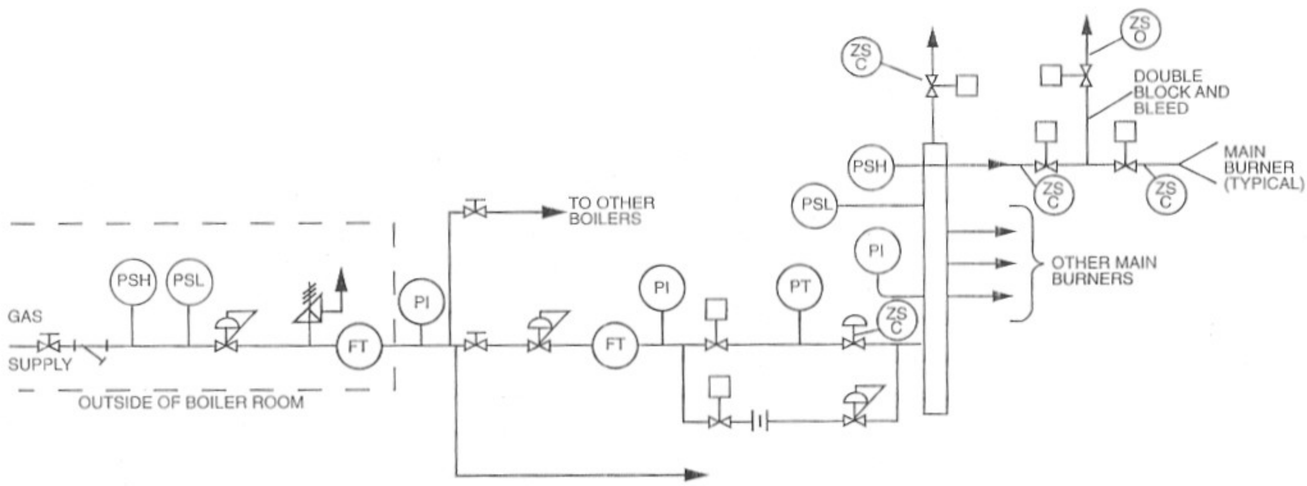
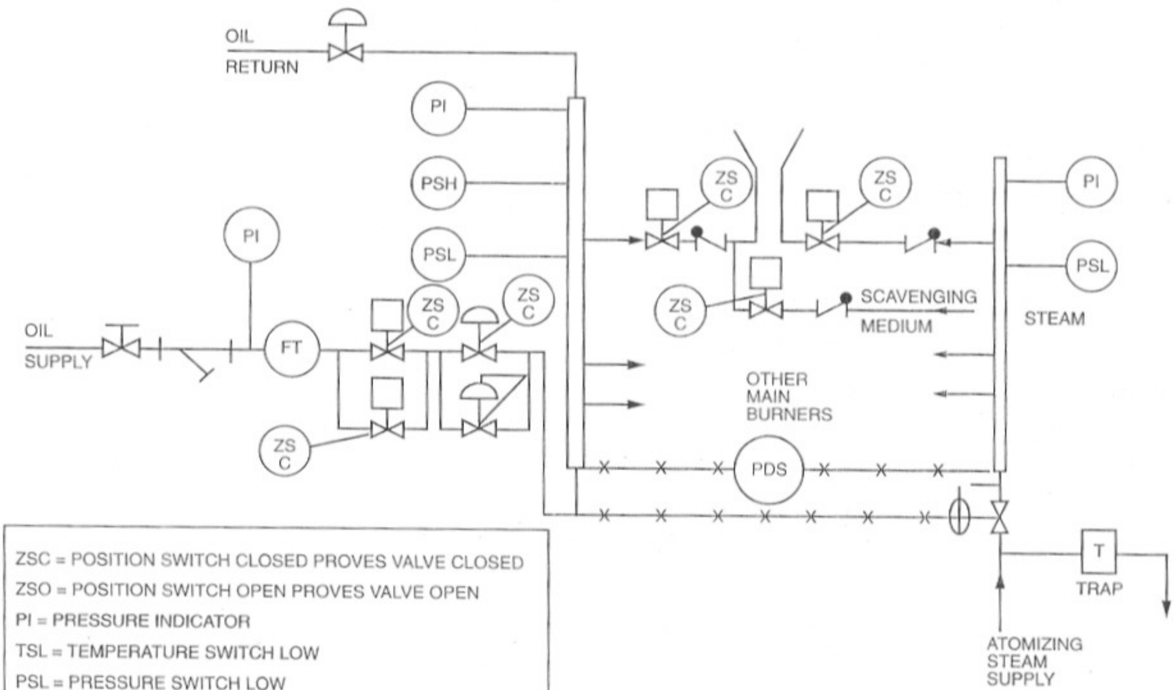


Figure 8-5 Example main oil burner system mechanical atomizing.



ZSC = POSITION SWITCH CLOSED PROVES VALVE CLOSED
ZSO = POSITION SWITCH OPEN PROVES VALVE OPEN
PI = PRESSURE INDICATOR
PSH = PRESSURE SWITCH HIGH
PSL = PRESSURE SWITCH LOW
FT = FUEL FLOW TRANSMITTER

Figure 8-6 Example main gas burner system.
Note: *All shutoff valves must have switches to prove closure.*



ZSC = POSITION SWITCH CLOSED PROVES VALVE CLOSED
ZSO = POSITION SWITCH OPEN PROVES VALVE OPEN
PI = PRESSURE INDICATOR
TSL = TEMPERATURE SWITCH LOW
PSL = PRESSURE SWITCH LOW
FT = FUEL FLOW TRANSMITTER

Figure 8-7 Example of an oil burner steam atomizing system.
Note: *All shutoff valves must have switches to prove closure.*

Environment

NO_x and NO_x Control

Nitrogen oxides (NO_x) create special problems in the operation of boilers. Air pollution control regulations require that new installations meet NO_x emission limits. These limits are lower than the emissions from many of the presently installed firing systems and furnace designs, which are using older operating procedures. In addition, air quality regulations in some local areas require existing boilers to reduce their NO_x emissions.

High temperature is the primary cause of NO_x formation, with the critical temperature at about 3000° F. To achieve emission reductions, there are a number of methods being used. Low excess air firing (i.e., less than the "normal" 10 percent to 25 percent excess air) is one method for reducing NO_x. Another method is multi-stage air admission, involving the introduction of combustion air in two or more stages partly at the fuel nozzle - which could be less than stoichiometric air - and partly by independent admission through special furnace ports and a second stage of air admission within the same burner housing. Flue gas recirculation into all or a portion of the secondary air, reduced secondary air temperature, and fuel staging are also methods used. Equipment manufacturers are introducing new burner and furnace designs. Generally, the effect of all these methods produces lower flame temperatures and longer, less turbulent flames, which results in lower NO_x.

Low NO_x firing methods create hazards including those related to furnace safety, particularly for existing units, and could introduce unacceptable risks if proper precautions are not taken.

NO_x emissions can also be reduced by removing them from the exhaust gases that are released from burners. In one process, ammonia is added to the flue gas prior to the gas passing over a catalyst. The catalyst enables the ammonia to react chemically with the NO_x, converting it to molecular nitrogen and water. This system promises as high as 90 percent removal of nitrogen oxides from the flue gases.

The control diagram in Figure 9-1 is a method for controlling ammonia injection. The steam flow feedforward adjusts the ammonia addition making a flow correction as the steam rate changes. The problem is that NO_x is not a part of this control scheme. There is technology available to measure NO_x continuously; however, the time delay of the NO_x measurement is an issue in closing the loop with the NO_x measurement.

In a second process, both NO_x and sulfur oxide (SO_x) are removed. The combustion gases are moved across a bed of copper oxide that reacts with the SO_x to form copper sulfate. The copper sulfate acts as a catalyst for reducing NO_x to ammonia. Approximately 90 percent of the NO_x and SO_x can be removed from the flue gases through this process.

One of the methods of reducing NO_x emissions from oil-fired combustion systems is to mix water with the oil before it is sprayed into the burner. Water decreases the combustion temperature and can reduce NO_x emissions from burning light weight oils by as much as 15 percent. A significant advantage in using these emulsions is that they reduce the emission of particulate matter. When water is mixed in the oil, each oil droplet sprayed into the firebox has several tiny water droplets inside. The heat existing in the firebox makes these water droplets flash into steam and explode the oil droplet. Increasing the surface area of the oil enables it to burn faster and more completely. A reduction in particulate emissions can be achieved regardless of whether light or heavy oils are being burned.

Fuel-firing systems designed to reduce NO_x emissions tend to reduce the margins created to prevent or minimize accumulations of unburned fuel in the furnace during combustion upsets or flameouts. Thus, it is important to trip fuel on loss of flame. These methods can narrow the limits of stable flames that are produced by the burner system. When flue gas recirculation is used, equipment should be provided to ensure proper mixing and uniform distribution of recirculated gas and the combustion air. Equipment should be provided to monitor either the ratio of flue gas to air or the oxygen content of the mixture when flue gas recirculation is introduced into the total combustion air stream. When flue gas recirculation is introduced so that only air and not the mixture is introduced at the burner, proper provisions should be made to ensure the prescribed distribution of air and the recirculating flue gas-air mixture.

All of these methods tend to increase the possibility of an unstable flame and unburned combustibles throughout the unit and ducts. Therefore, boiler, burner, and instrument manufacturer recommendations should be followed, or tests conducted, to verify operating margins. Any change in flame characteristics to reduce NO_x emissions can also require changing either, or both, the type and location of flame detectors on existing units.

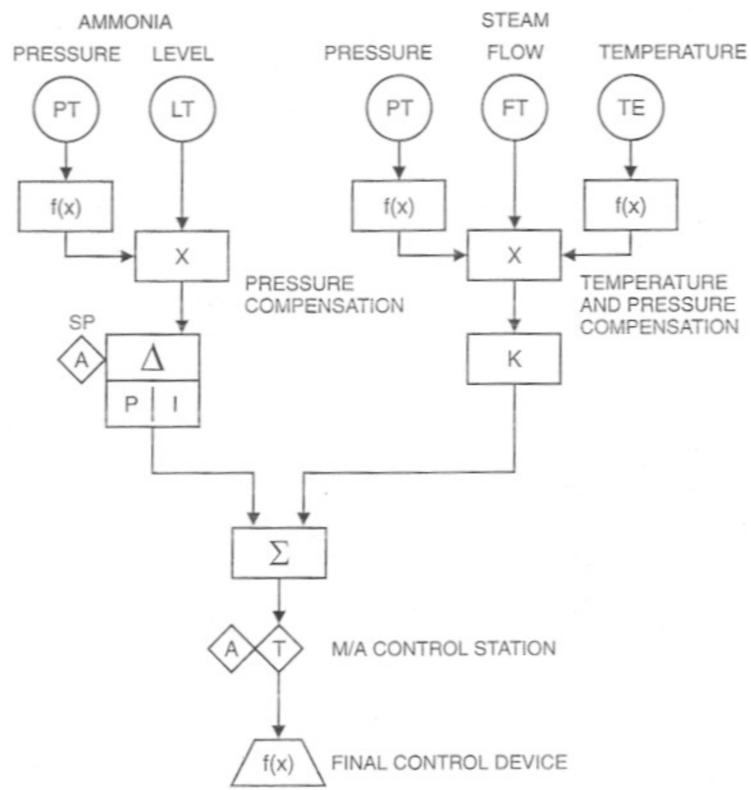


Figure 9-1 Controlling ammonia injection.

Excess Air to Oxygen

The control of excess air is critical to NO_x and to maintaining the correct fuel air ratio. The excess fuel, and the resulting improper fuel air ratio, is the primary cause of boiler explosions.

When flue gas or other inert gases are introduced to the secondary or combustion air being supplied to burners, the methods and devices being used must be tested to confirm uniform distribution and mixing. The oxygen content of the mixture supplied to the burners is not permitted to go below the limit specified by the burner manufacturer or as proven by tests to provide stable combustion. Either the ratio of flue gas to air or the oxygen content of the mixture should be monitored.

The following table gives the relationship of excess air to O_2.

Gas										
Excess Air	0	4.5	9.5	15.1	21.3	28.3	36.2	45.0	55.6	67.8
Oxygen O_2	0	1	2	3	4	5	6	7	8	9

No. 6 Oil										
Excess Air	0	4.7	9.9	15.7	22.2	29.5	37.7	47.1	58.0	70.7
Oxygen	0	1	2	3	4	5	6	7	8	9

Coal										
Excess Air	0	4.9	10.2	16.2	22.9	30.4	38.8	48.5	59.5	72.9
Oxygen	0	1	2	3	4	5	6	7	8	9

A simple method for calculating excess air is:

$$\text{Excess air \%} = K\left(\frac{21}{21 - \%\ \text{oxygen}} - 1\right) \times 100$$

The K values are K= 0.9 Gas, 0.94 Oil and 0.97 Coal

CHAPTER **10**

Control Valve Sizing

Valve Characteristics

The characteristics of the control valve or damper are an important consideration. It is important to select the flow characteristics for the process. The diagram in Figure 10-1 illustrates typical characteristics.

The flow characteristic of a control valve is the relationship between the flow rate through the valve and the valve travel, as the travel is varied from 0 to 100 percent. The inherent flow characteristic refers to the characteristic observed with a constant pressure drop across the valve. The installed flow characteristic refers to the characteristic obtained in service when the pressure drop varies with flow, and other changes, in the system.

The purpose of characterizing control valves is to provide relatively uniform control loop stability over the expected range of system operating conditions. To establish the flow characteristic needed to "match" a given system requires a dynamic analysis of the control loop. Analyses of the more common processes have been performed; however, some useful guidelines can be established for the selection of the proper flow characteristic. The chart below provides some of the flow characteristics in use today.

Guidelines for Choosing Valve Characteristics		
Process	**Application**	**Best Inherent Characteristics**
Pressure	Liquid Pressure	Equal Percent
	Gas Pressure, Small Volume	Equal Percent
	Gas Pressure, Large Volume Max ΔP Less than 5X Min ΔP	Linear
	Gas Pressure Large Volume Max ΔP Greater than 5X Min ΔP	Equal Percent
Temperature	Most Applications	Equal Percent
Flow	Load Changes	Equal Percent
	Set Point Changes	Linear
Liquid Level	Max ΔP Less than 5X Min ΔP	Linear
	Max ΔP Greater than 5X Min ΔP	Equal Percent
Back Pressure	Constant ΔP	Linear

Valve Characteristic Graph

Figure 10-1 shows the different valve flow characteristics.

Fisher Controls Company.

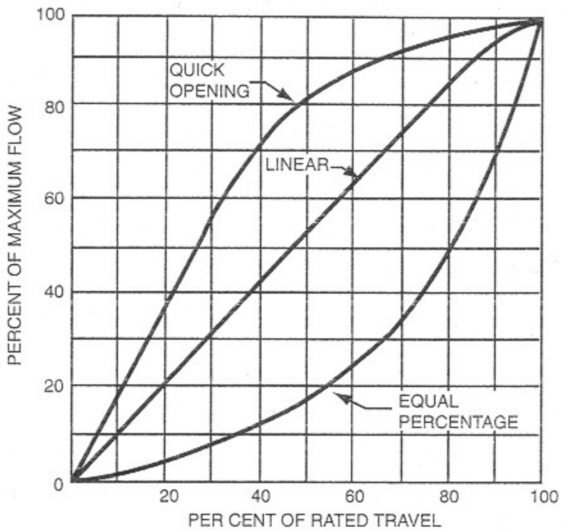


Figure 10-1 Typical flow characteristic curves.

Recommended Velocities

Clean fluids – Maximum operating condition values:

Liquids:

< 10 m/s < 33 ft/s

Air:

< 1/3 MA (Mach)
= 1/3 x (330 m/s)
< 110 m/s < 360 ft/s

Gases and Steam (dry):

<110 m/s < 360 ft/s

Flashing Liquids:

< 60 m/s < 196 ft/s

Valve Sizing for Different Control Media

For good control, it is very important to select the correct size valve as well as the valve characteristic. Each valve manufacturer supplies sizing information and programs for sizing a control valve. There are some basic equations that can be used to size control valves. The examples are based on the basic equations.

The term C_v is generally used in industry for calculating the relative flow capacity in valves. The C_v is numerically equal to the number of US gallons of water at 60° F that flows through a valve in one minute when the pressure differential across the valve is one pound per square inch. In the equation examples, sizing is for 100 percent flow rate and 25 percent flow rate because a typical turn down for control valves is four or five to one.

Control Valve Sizing Calculations

Water Valve Sizing

This is an example of valve sizing for 600,000 pounds per hour water flow with no density consideration. A rule of thumb for pressure drop is one third of the pressure drop across the system for the pressure drop across the valve.

Q = gpm
SG = specific gravity
ΔP = pressure drop across valve

C_v = GPM ($\sqrt{}$ SG ÷ ΔP)

The conversion of pounds per hour is 600,000 ÷ (8.34 x 60) = 1200 GPM

If the pump discharge pressure is 2000 psig and the drum pressure is 1400 psig, the differential pressure is 600 ÷ 3 = 200 psig.

$C_v = \text{GPM} \sqrt{(SG \div \Delta P)}$

$C_v = 1200 \times \sqrt{(1 \div 200)} = 84.84$

$C_v = 300 \times \sqrt{(1 \div 200)} = 14.14$

Assume a lower pressure drop of 150 psi for a lower flow rate.

$C_v = 300 \times \sqrt{(1 \div 150)} = 24.5$

If the water temperature is 450°F, then the change in specific gravity must be considered. The specific gravity of water at 450°F is 0.827.

$C_v = 1200 \times \sqrt{(0.827 \div 200)} = 77.16$

$C_v = 300 \times \sqrt{(0.827 \div 200)} = 12.86$

Assume a lower pressure drop of 150 psi for a lower flow rate.

One fourth $C_v = 300 \times \sqrt{(0.827 \div 150)} = 9.65$

If you look at the C_v sizing chart, a three or four inch valve can be used. If a three inch valve is selected, it is almost 100 percent open. A four inch valve should be selected and would have less line pressure drop. For best control, the C_v should be at 20 percent at the lowest flow and 80 percent at the highest flow rate.

At 60°F water temperature, the C_v is 84.84 and at 450°F, the C_v is 77.16.

Steam Valve

The calculations for 300,000 pounds per hour steam flow at 1000 psi and 800°F would be:

The equation is $C_v = \text{pph} / 63 \times \sqrt{(\Delta P \div V)}$

pph = pounds per hour
V = specific volume
ΔP = differential pressure across the valve

If we assume a 400 psi system pressure drop and one third across the valve, the valve pressure drop would be 133 psi.

The specific volume for steam at 800°F superheated steam at 1000 psi is 0.6875.

$C_v = 300{,}000 / 63 \times \sqrt{(133 \div 0.6875)}$

$\sqrt{133 \div 0.6875} = 13.9$

$C_v = 300000 \div (63 \times 13.9) = 300000 \div 876 = 684$

One fourth $C_v = 342$

Looking at the chart below, either an eight inch valve can be used or a ten inch valve with reduced trim.

Gas Valve Sizing

This example for gas valve sizing is based on 100,000 SCFH. The 460 is degrees Rankine.

$C_v = \text{SCFH} \times \sqrt{(460 + F°)}\ SG \div 1360 \times \sqrt{(P1 \times \Delta P)}$

$C_v = 100{,}000\ (0.6)\ \sqrt{(460 + 70°\ F)} \div 1360 \times \sqrt{(30 \times 10)}$

$C_v = 100{,}000\ (0.6)\ \sqrt{530} \div 1360 \times \sqrt{300}$

$C_v = 100{,}000 \times 0.6 \times 23.02 \div 1360 \times 17.32$

$C_v = 100{,}000 \times 13.8 \div 23555.2 = 58.59$

A three inch valve can be used.

Equal Percentage

		Percent									
Valve Size	Rated C_v	10	20	30	40	50	60	70	80	90	100
3 inch	95	4.45	6.25	8.78	12.3	17.3	24.4	34.2	48.1	67.6	95
4 inch	190	8.9	12.5	17.6	24.7	34.7	48.7	68.5	96.2	135	190
8 inch	420	19.7	27.6	38.8	54.6	76.7	108	151	213	299	420
10 inch *	420	19.7	27.6	38.8	54.6	76.7	108	151	213	299	420
10 inch	735	34.4	48.4	68	95.5	134	189	265	372	546	735

Printed by permission Samson Controls

*10 inch valve with reduced trim note the C_v is the same as the eight inch valve.

For more information, refer to ANSI/ISA-75.01.01-2002 (IEC 60534-2-1 Mod).

Acronyms

3Ts	time, temperature, and turbulence
ABMA	American Boiler Makers Association
ANSI	American National Standards Institute
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
BMS	burner management system
BPCS	basic process control system
Btu	British thermal units
CAD	computer-aided design
CADD	computer-aided design and drafting
CFR	Code of Federal Regulations
CS	The Canadian Standards Association
DCL	design check list
DCN	drawing change notices
DCS	distributed control system
DOE	Department of Energy
FD	forced draft
HRSG	heat recovery steam generator
I	the integral or reset
ID	induced draft
IEEE	Institute of Electrical and Electronic Engineers
I/O	in/out
IR	infrared
ISA	The Instrumentation, Systems, and Automation Society
I&C	instrumentation and control
Kc	gain, proportional band
NFPA	National Fire Protection Association
PPM	parts per million
PB	proportional band
PCS	process control system
P&ID	piping and instrument diagram
PID	proportional or gain-plus-integral (reset)-plus-derivative (rate)

PI	proportional or gain-plus-integral (reset)
PSI	pounds per square inch
PSIG	pounds per square inch gage
Pu	ultimate period
PV	process variable or pressure valve
SAMA	Scientific Apparatus Makers Association
SP	set point
Su	ultimate sensitivity or ultimate gain
Td	time derivative
Ti	time integral, reset integral
UV	ultraviolet

APPENDIX A

General Tutorial

Purpose

The purpose of this appendix is to provide tutorial information on the philosophy underlying ANSI/ISA-77.41.01-2005 and to assist in specifying and applying combustion control strategies that will best serve the requirements of the user.

Introduction

The purpose of any combustion control system is to safely and efficiently maintain the desired boiler output without the need for constant operator attention. Therefore, the combustion process inside the furnace must be controlled while the boiler output changes in response to load demands. The basic principle of combustion control is to meet the boiler load requirements by regulating the quantities of fuel and air while achieving optimum combustion and maintaining safe conditions for operators and equipment.

Combustion Process

As the combustion process takes place in the furnace, oxygen in the combustion air combines chemically with the carbon and hydrogen in the fuel to produce heat. The amount of air that contains enough oxygen to combine with all the combustible matter in the fuel is called the "stoichiometric" value or theoretical air.

It is improbable for every molecule of fuel that enters the furnace to combine chemically with oxygen. For this reason, it is necessary to provide more air than the stoichiometric requirement. For most boilers it is customary to provide 5 to 20 percent more air than the stoichiometric requirement to ensure complete combustion. This additional air is called "excess air." A boiler firing at 1.2 times the stoichiometric air requirement would be said to be firing at 20 percent excess air.

If insufficient oxygen is introduced into the furnace, incomplete combustion of the fuel will occur. This wastes fuel, causes air pollution, and results in hazardous conditions in the boiler. The unburned fuel may ignite in the boiler or breeching and result in secondary combustion, causing a dangerous explosion.

Providing too much combustion air reduces the explosion danger but also reduces efficiency. The largest energy loss in the boiler is the heat that escapes as hot flue gas. Increasing the excess air increases this energy loss. High excess air can also result in unstable burner conditions due to the lean fuel/air mixture.

In practice, a large number of items that affect boiler efficiency are related to excess air. The proper value of excess air is a function of boiler load, fuel quantity, air leakage through idle burners, steam temperature, flame stability, and energy losses.

Basic Combustion Control Strategies

Various combustion control strategies that are based on requirements for safe, efficient, and responsive control of boilers have evolved. More sophisticated controls were developed as instrumentation became more reliable and accurate. The control strategies can be divided into two major categories: positioning systems and metering systems.

In positioning systems the fuel and air control devices are simultaneously positioned, based on energy demand. Each position of the fuel control device assumes a corresponding position for the airflow control device. A control station is normally available for the operator to trim the fuel/air ratio.

The positioning system is simple and fast responding, but it cannot compensate for varying fuel characteristics, atmospheric conditions, dynamic characteristics of the fuel delivery equipment, or the imbalance of the fuel-to-air ratio during rapid load changes.

Metering systems measure the actual fuel and air delivered to the boiler. The measured flows are used in feedback control schemes to precisely regulate the fuel-to-air ratio. Air flows can be measured without too much difficulty. The fuel flow in a gas or oil boiler can also be readily measured. Fuel flow in a coal-fired boiler cannot be directly measured, and various schemes have been developed to infer the fuel delivery rate based on other variables. In addition, the heavy equipment necessary to transport the coal and prepare it for burning present dynamic operational and control problems.

A typical combustion control function diagram is shown in Figure A-1.

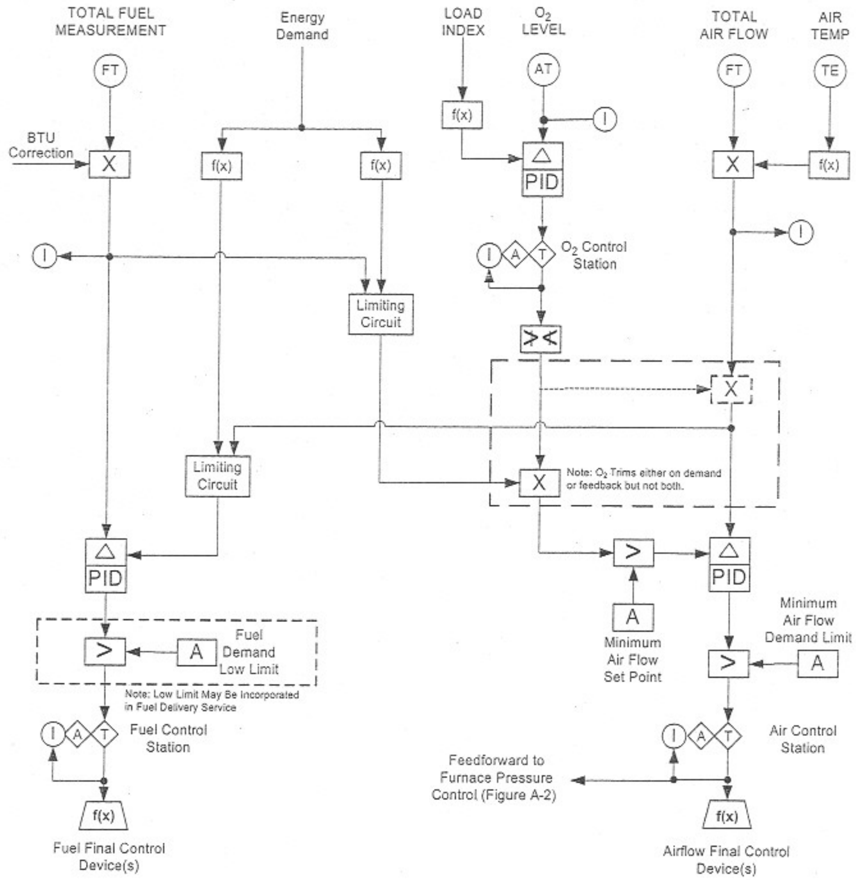


Figure A-1 Typical combustion control functional diagram.

Air Flow Requirements Concepts

Air flow measurements can be established by primary elements located on either the air side or the flue-gas side of the unit.

A suitable place to measure air flow is the entry of the forced draft fan. When there is potential leakage between the forced draft fan and the furnace, a preferred location may be the air duct between the forced draft fan and the burners downstream of the air heater.

An alternate, but less preferred, location for air flow measurement is on the flue-gas side of the boiler. Connections for a differential pressure transmitter are located across a section of the boiler, and the pressure drop of the flue gas is measured. The connections should be located to avoid the pressure drop across the air heater. Potential problems with this method are the corrosive effects of the flue gas and leakage.

Excess Air Requirements Concepts

The combustion air needed in an actual boiler will be in excess of the theoretical air. This excess air is needed because some of the combustion air supplied to the boiler will not react with the fuel. The amount of excess air required for good combustion is dependent upon the boiler's burner and furnace design. To minimize the requirement for excess air, the fuel must be thoroughly atomized and mixed with the combustion air. The combustion air must impart turbulence and momentum to the flame and the furnace must be sized to allow adequate residence time to insure completion of combustion.

Typically, a zirconium oxide based oxygen analyzer is a direct measurement of oxygen and, based on a given fuel, a direct measurement of the excess air in the combustion process. The measurement is taken before the air preheater to receive a representative sample of the combustion air. The excess air requirement is non-linear as a function of load. Thus, a load index signal is used to program the excess air setpoint. A controller acts on the resulting error and adjusts the fuel/air ratio. Suitable provisions should be included to prevent controller windup under minimum airflow limit conditions.

Adjustment of the fuel/air ratio can be accomplished by either adjusting the airflow demand or airflow feedback. Placing the trim on the demand inherently makes more sense and is easier for users to understand and commission. If more air is required then, increase the airflow setpoint to increase airflow. By adjusting the demand, the calibration of airflow demand curve, minimum airflow setpoint, airflow trips and purge rate are easily established because airflow represents the correct mass airflow rate into the furnace. However, drawbacks include more complicated fuel cross limit design, and trend pens do not overlay each other in term of percent MCR. When designed and calibrated properly either method (e.g., trim demand or trim feedback) can provide safe and reliable excess air trim control. The trim on demand is preferred.

Furnace Pressure (Draft)

Furnace pressure (draft) control is required on balanced draft boilers. While either the forced draft fan(s) or the induced draft fan(s) could be used to control the furnace pressure, NFPA 85

requires the induced draft fan(s) to be used. A typical furnace pressure control functional diagram is shown in Figure A-2. It utilizes a feedforward signal characterized to represent the position of the forced draft control device(s). In a properly designed and calibrated system, the output of the furnace pressure controller will remain near its midrange for all air flows.

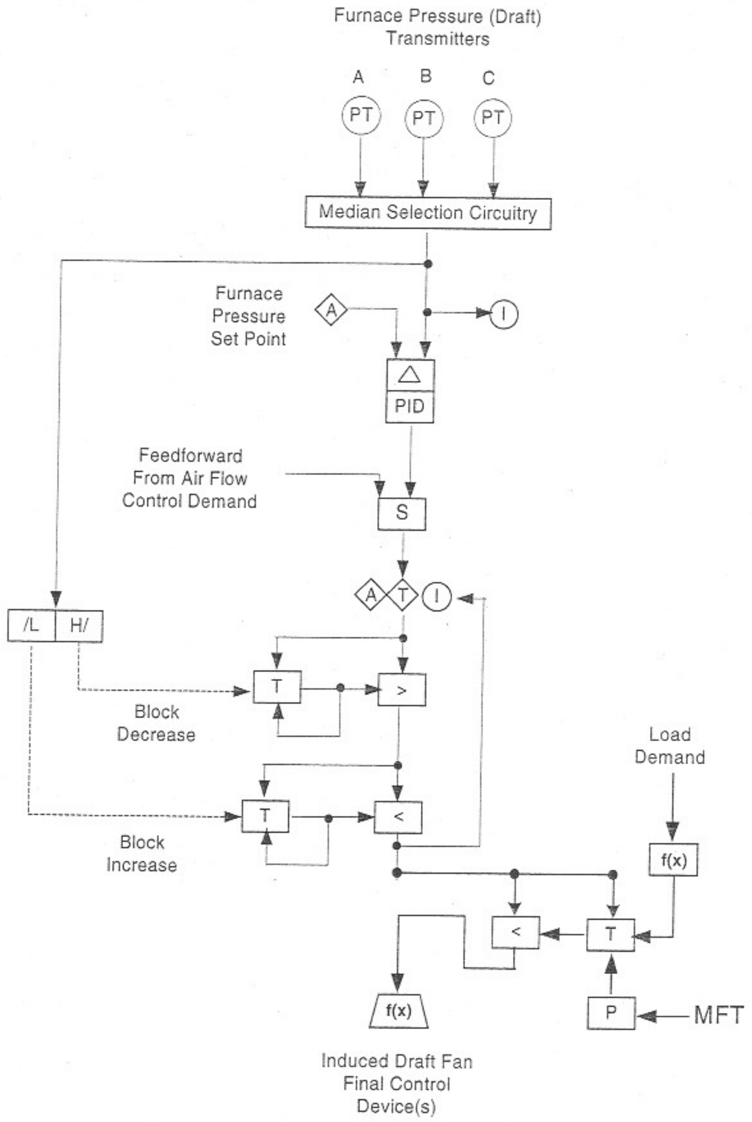


Figure A-2 Typical furnace pressure control functional diagram.

Control of Gas- and Oil-fired Boilers

Gas- and oil-fired boilers often allow burning gas and oil separately or together. Provisions must be made to assure that the fuel-to-air ratio is maintained as multiple fuels are introduced into the boiler. This can be accomplished by summing the individual fuel flows on a Btu (kJ) value basis. The output of the summer becomes the "total fuel" in the calculation of the fuel-to-air ratio. Limiting circuitry should be provided to ensure a safe fuel-to-air ratio.

When the fuel control is in automatic, there shall be a minimum fuel demand limit to prevent fuel from being reduced below the level required to support stable flame conditions in the furnace.

Control of Pulverized Coal-Fired Boilers

Two major considerations in the development of a metering-type control strategy for a pulverized coal-fired boiler are compensation for pulverizer dynamics and the selection of an inferred coal flow signal. In addition, the fuel demand signal must be corrected for the number of pulverizers in service.

When the fuel control is in automatic, there shall be a minimum fuel demand limit to prevent fuel from being reduced below the level required to support stable flame conditions in the furnace.

Pulverizer Dynamics

Pulverizers induce time lags into the control process. There is a finite time between the introduction of coal into the pulverizer and the delivery of fuel to the furnace. The grinding and drying of the coal in the pulverizer and the time required to transport the coal/air mixture to the burners both contribute to time lags. In addition, the volume of coal in the pulverizer increases as the load on the pulverizer increases.

Ball Tube Pulverizers

The ball tube or Harding e-type pulverizers utilize small diameter (two inch) steel balls in a rotating drum to grind coal. These pulverizers exhibit large coal storage characteristics. It is common for this type of pulverizer to produce controlled coal flow for 10 to 15 minutes after the coal feeder is stopped. The coal feeder signal is, therefore, useless in the control scheme as a fuel flow signal. An implied fuel flow signal can be derived from boiler heat release, primary air flow, linearized classifier differential, characterized primary air damper position, or exhauster inlet damper position. Since these signals, with the exception of heat release, can produce an apparent coal flow in an empty mill, the signals must be verified by logic signals monitoring the mill level and feeder status.

In a ball tube pulverizer, the coal feeder normally operates independently of the boiler energy demand or fuel demand signals. The coal feeder control for ball tube pulverizers may be based on the following:

- Pulverizer level (differential measurement)
- Pulverizer dB (sound measurement)
- Pulverizer kW (power measurement)
- Pulverizer kW and dB

The usual control of the feeder is based on pulverizer coal level with a slight feedforward or derivative from boiler energy demand or fuel demand.

Non-Ball Tube Mills

Pulverized coal-fired boilers normally use a sophisticated combustion control system having several pulverizers, each supplying multiple burners. It is not only important to maintain the correct fuel-to-air ratio at all times, but the fuel from each pulverizer to its associated burner should be properly proportioned and distributed for stable and efficient boiler operation.

The fuel demand is compared to the total measured fuel flow (summation of all feeders in service delivering coal) to develop the demand to the fuel controller. The fuel demand signal is then applied in parallel to all operating pulverizers.

Should an upset in available air occur so that air is limited, an error signal from air flow control should reduce the firing rate demand to the fuel controller to maintain a minimum acceptable fuel/air ratio. Limiting circuitry shall be provided to ensure that air flow is always above demanded fuel flow; hence, a safe combustion mixture is always present. This demand is compared with total feeder speeds or the heat absorbed signal. Should there be a difference between the fuel demand and total fuel flow, the fuel controller will readjust the speed of the feeders in service to the extent necessary to eliminate the error.

Since there may be some delay between a change in feeder speed and the actual change in coal to a furnace, a lag (mill model) is incorporated into the speed feedback, so that the air flow and fuel flow control are kept in step with the actual coal to the furnace. During conditions of a mill overload, the feeder speed demand signal should be reduced until the overload condition is resolved.

Pulverizer Coal-Air Control System

The primary control for a pulverizer is the coal flow demand to the primary air fans. The secondary control is the coal-air mixture temperature. The coal-air temperature control is important for it regulates the amount of surface moisture remaining in the fines going to the burner. The surface moisture adversely affects both pulverizer performance and the combustion process by up to 50 percent. In-mill drying is the accepted method for preparing coal for burning. By measuring the temperature in the pulverizer outlet pipes, the controls are able to regulate the amounts of hot and tempering air to provide adequate drying. The outlet temperature controller setpoint is usually ranged between 140-170°F depending on what type of fuel is burned. A single setpoint controls both the hot and tempering air damper actuators. Selecting too high a setpoint could create a hazardous condition, because the coal is too dry and very volatile. Selecting too low a setpoint, the coal will not flow as cleanly in the coal pipes, therefore causing coal pipe plugging. Therefore, a pulverizer's output is limited by its drying capacity and not its grinding ability.

Reference for Pulverizer Control

The pulverizer manufacturer is the prime source for information concerning recommended control strategies.

Dual Fuel Firing

A metering-type control strategy for a boiler capable of dual fuel firing simultaneously has to account for the total furnace heat input and different fuel/air ratios. The basic strategy of the boiler energy demand establishing the total fuel demand to the boiler and fuel to air ratio on a boiler basis is to be satisfied. Duel firing may include one or more of the following operating modes:

- One fuel in manual with second fuel automatically following boiler energy demand.
- One fuel in automatic with operator flow setpoint with second fuel automatically following boiler energy demand.
- Both fuels automatically following boiler energy demand.

If both fuels are following a boiler energy demand then, an operator adjustable fuel ratio setter determines the ratio of fuel being fired. Unless both fuels are automated to follow the boiler energy demand, the fuel ratio setter will track the actual fuel flow ratio.

Airflow is to be cross-limited by the total fuel flow inputted into the furnace. When firing duel fuels simultaneously, the airflow demand is to be characterized based on the ratio of fuels being fired to establish the correct fuel-to-air ratio.

When firing duel fuels simultaneously, the oxygen setpoint is computed based on the ratio of both fuels. Figure A-3 represents a typical duel firing diagram.

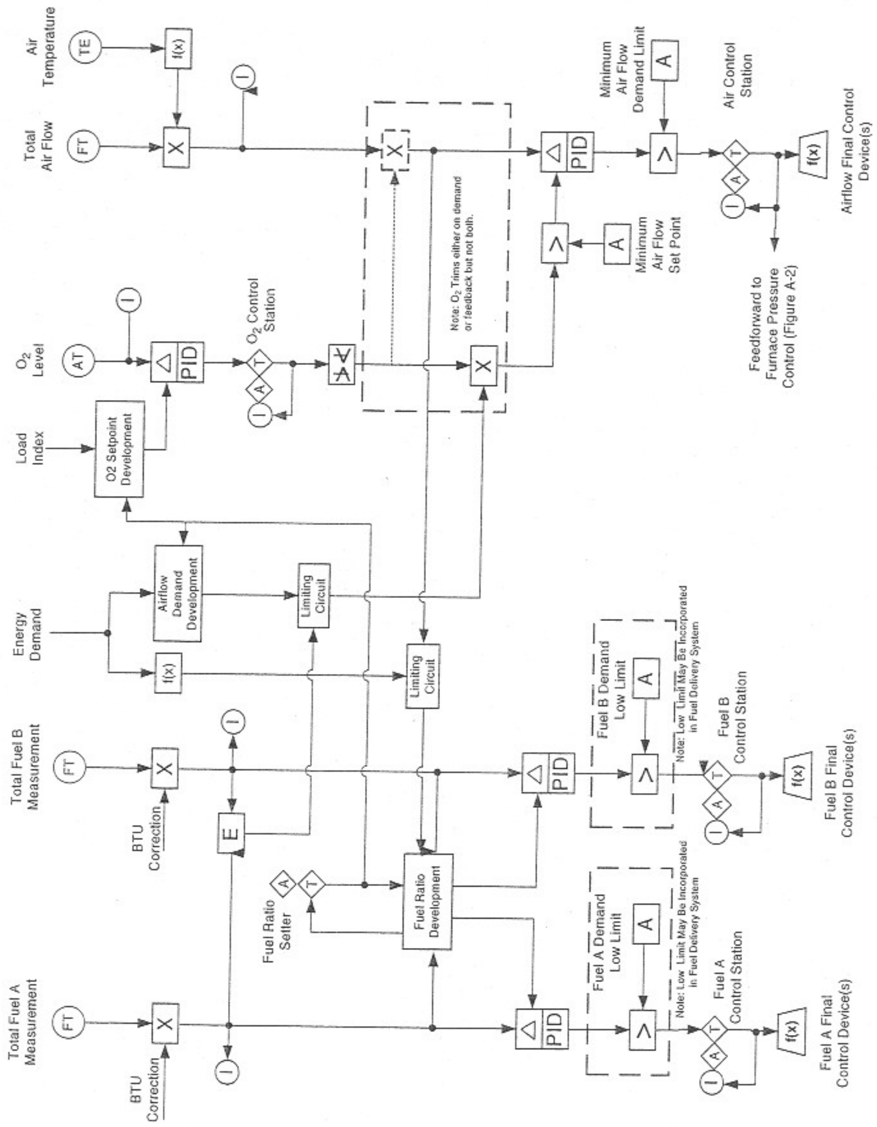


Figure A-3 Typical duel fuel firing strategy.

Steam Temperature Control

Purpose

This appendix is an excerpt from ANSI/ISA-77.44.02-2001 and provides tutorial information to assist the user in specifying and applying steam temperature control schemes.

Introduction

Subcritical vs. Supercritical in Once Through Boiler Design

A boiler is either subcritical or supercritical depending on whether it is designed to be operated below or above the critical pressure, respectively (critical pressure is 3206.2 psia). At critical pressure and above, boiling, as it is known within the saturation region, does not take place. The transition from water to steam is abrupt, and the temperature steadily increases rather than flattening completely. At critical pressure, the density differential between water and steam becomes zero, thus making natural circulation impossible.

Operation at subcritical pressures creates certain problems for the boiler designer. Probably the most important problem is the handling of water-steam mixtures. At subcritical pressures, the water-steam mixtures can separate into all water in one tube and all steam in an adjacent tube. Thus, the boiler design must achieve good mixing of the water-steam mixture and limit the amount of heat absorbed by a furnace panel to a value that will not cause damaging thermal stresses in the membrane walls. As examples, variable orifices are installed in each furnace panel to balance the flows, and furnace-mixing headers are used at particular locations to limit the heat absorption.

Operation at supercritical pressures eliminates concern over the separation of water-steam mixtures because this phenomenon does not occur. However, furnace-mixing headers redistribute the fluid where adjacent tubes are in different fluid passes. In supercritical operation, it is important to avoid subcritical pressures because of the possibility of steam to water separation where the boiler design does not consider this.

There are many similarities between subcritical and supercritical boilers. The gas side arrangement is practically identical, although some furnace panel surfaces may be located differently. The fluid side is also quite similar, particularly in the furnace circuitry. The boiler responses are quite similar, with supercritical boilers being slightly faster.

Steam Temperature Control by Ratio Adjustment

In a once-through boiler, final steam temperature is affected by the ratio of firing rate to feedwater flow. Therefore, changing firing rate, feedwater flow, or both, can affect control of steam temperature. The boiler master demand signal is typically sent in parallel to the firing rate demand and the feedwater demand. The temperature controller output is then configured as a ratio setting and applied to the firing rate, feedwater flow, or both.

The boiler master is tuned for pressure and load response, that is, orders of magnitude faster than the temperature loop. Therefore, changes to ratio setting have been applied with success in either or both subsystems. Generally, though, it is simplified to modify the firing rate demand.

Recognizing that megawatts output is proportional, the input firing rate and feedwater flow must equal the flow leaving the boiler to maintain constant storage of fluid; it is logical to send boiler demand to the firing rate and feedwater together. Adjusting firing rate for final steam temperature results in a compromise between controlling temperature and controlling load. Adjusting feedwater flow for final steam temperature results in a compromise between controlling temperature and controlling pressure. Furthermore, firing rate and feedwater flow are conditioned upon the specific boiler design, boiler/process constraints, and process variable responses.

Once-through boiler designs require a minimum feedwater rate to protect the furnace tubes from overheating. This boiler constraint requires that the firing rate be adjusted to control steam temperature until load exceeds the minimum feedwater flow. At which time, feedwater flow can participate in controlling final steam temperature.

When feedwater flow or firing rate changes, a temperature delay exists before final steam temperature changes. The temperature delay time for firing rate is shorter than feedwater flow due to shorter transport delay and provides better transient correction for steam temperature. Boilers with spray attemperation have means to shorten feedwater flow transport delays by introducing spray water before the superheater(s). While spray attemperation may initially control temperature excursions, steady state temperature is achieved when total feedwater flow (boiler inlet water flow and spray attemperation flow) is in correct ratio with firing rate.

The controls will overfire or underfire the firing rate to respond to load changes. This transient condition creates an incorrect steady state fuel demand that causes temperature and pressure errors. Using temperature controls to modify firing rate demand and feedwater demand in opposite direction helps the overall system stability because one process effect counteracts the other.

Principles and Methods of Transient Superheat Steam Temperature Control

Steam Temperature Feedback Control

A typical boiler arrangement is one where the spray attemperation takes place between the primary and secondary superheaters. With this arrangement, a large process time lag exists between the introduction of spray water and the detection and stabilization of exit steam temperature. A final steam temperature is used as the feedback measurement for control.

Load Index Development

The load index feedforward may be steam flow, airflow, or other measures of boiler load. Airflow offers the advantage of including excess combustion air requirements as a part of the load index signal. The load index feedforward signal is summed with the output signal from the steam temperature controller.

Transient Correction Signal Development

A steam temperature transient correction is a signal that is applied to the normal steam temperature control strategy to counter the impact of a transient process change. An example of a transient process change, and the most typical, would be overfiring or underfiring. Overfiring and underfiring are considered transients because they are not required to maintain a steady-state condition. A steam temperature transient correction recognizes the impact of a transient on the final steam temperature and attempts to minimize this impact.

Probably the best way to describe this action is to consider an example. Assuming that a load increase is occurring, the firing rate will increase to meet the new load setting and will increase even more to assist in achieving the new energy storage level in the unit. This additional firing is referred to as overfiring, and once the unit's energy level is satisfied, it will be removed. Since the overfiring is only temporary, it is considered a transient condition. Assuming that no transient correction is made, the new load setting will require an adjustment to the steam temperature control, which normally is satisfied through feedforward action. The overfiring would cause the steam temperature to increase, and the steam temperature controller would react to counter the temperature excursion by increasing the spray.

When the overfiring is removed, the steam temperature would drop because excess spray exists. The excess spray would then cause the steam temperature controller to reduce the spray flow. The end results are a longer time period to reach steady-state conditions and a greater deviation versus time. A transient correction would recognize when overfiring is occurring and bias the controls to increase the spray to help minimize the temperature excursion and to prevent the temperature controller from integrating a temperature error over time. Ideally, no temperature transient would occur; thus steady state is achieved more quickly, and the temperature deviation versus time will be reduced.

The actual transient correction for overfiring or underfiring is a function of the overall control strategy. One approach is to use the throttle pressure error as the source for the transient correction. Throttle pressure error is scaled and summed with other feedforward signals.

Use of Cascade Spray Valve Control

In a cascade control strategy, when the output of one controller is used to manipulate the setpoint of another, the two controllers are said to be cascaded. Although each controller will have its own measurement input, only the primary controller (outer loop) can have an independent setpoint, and only the secondary controller (inner loop) has an output to the process.

Steam temperature control strategies assume a predictable relationship between the spray water control valve position and the spray water flow. If this is not the case, a cascade spray water flow control strategy should be considered. With the cascade control strategy, the output of the temperature controller establishes the required spray flow setpoint for the spray water flow controller. In the cascade control arrangement, the temperature controller is the primary controller, and the spray flow controller is the secondary controller.

NO_x Control

The nitrogen and oxygen in the combustion air and fuel form oxides of nitrogen (NO_x) during the combustion process. The rate of NO_x formation is dependent on high temperature, stoichiometric conditions, resident combustion time, and the amount of nitrogen in the fuel. To suppress the formation of NO_x, the combustion conditions and control strategy must be altered to decrease O_2 level at the flame zone, stage combustion, or both and to decrease combustion gas temperature in the furnace and, hence, the time of exposure of the products of combustion to high temperature.

Air that bypasses the burner combustion can suppress the formation of NO_x by reducing the O_2 level and temperature at the primary combustion zone. This option is possible if the boiler design allows the use of burner out-of-service, or overfire air ports, or both to achieve the second stage of combustion. The out-of-service burners and overfire air ports provide means of introducing staged combustion air downstream of the furnace combustion zone. Excess air used for steam temperature control also must bypass the burner combustion zone.

Flue gas recirculation can suppress the formation of NO_x by reducing the combustion temperature if the boiler design allows introduction of flue gas recirculation into the secondary air stream.

Flue gas recirculation can be used for suppressing the formation of NO_x and controlling reheat steam temperatures if the boiler design allows the introduction of flue gas recirculation into both the secondary air stream and the furnace hopper. These boilers have a gas recirculation distribution damper for regulating the gas recirculation flow path.

Redundancy

Redundancy is employed when system reliability will be seriously affected by a component failure. Redundancy also permits on-line maintenance of components. For maximum availability, redundancy should always be considered. Deviation alarms and automatic failure detection/transfer should be considered in order to maximize the usefulness of the application of redundancy.

Reset Windup Prevention

Any control loop in which the controller has integral action and the final control element is likely to be fully open or fully closed during routine plant operation should have a provision to prevent reset windup. Steam temperature controls frequently fall into this category because boiler designers usually try to minimize the amount of spray flow required throughout the load range. This frequently leads to times when the spray valve is fully closed during normal operation and, therefore, to the need to reset windup prevention.

For conventional single-element control loops, reset windup prevention is relatively simple to implement. As soon as the final control element reaches one of its endpoints of travel (0% closed or 100% open), the integral (reset) action or the entire controller is disabled. For a simple control loop, the integral limits on the final control element correspond to the high and low limits on the controller output. Most controllers have automatic reset windup prevention when the controller output reaches a limit. Provided everything is calibrated correctly, the reset windup prevention will begin when the final control element reaches a travel limit.

For a three-element or cascade control loop, reset windup prevention becomes slightly more complicated. Now two controllers must both stop integrating to prevent reset windup. The inner or secondary controller operates the same as a single-element controller described previously. The primary controller must also have its integral or reset action disabled when the final control elements reach a limit. The output of the primary controller is not always at the same value when the final control elements reach a limit, so a different mechanism must be used to implement the windup prevention. On pneumatic and analog electronic controllers, it may not be practical to implement a reset windup prevention scheme such as is required in this situation. On a digital system, however, there are several ways to do this. The integral gain of the controller may be adaptively tuned to zero when the limit is reached, or the high or low limit of the controller may be adjusted to the controller output value when the limit is reached. This prevents the primary controller from winding up the setpoint for the secondary controller when the final control element is at a limit.

Advanced Steam Temperature Control

Steam temperature control is one of the most difficult control loops in the boiler control system. There are several factors that make the control difficult.

- The time response of the final steam temperatures is generally very slow and has a considerable deadtime response. This is due to the large mass of metal in the superheater sections of the boiler, which is slow to change temperature. Slow response and deadtime responses are both tough to handle well with conventional control strategies.

- Steam temperature can be upset by almost any disturbance in the boiler. These upsets continually challenge the control system and when combined with the slow temperature response make good control tough. Some of the more common upsets are load changes, fuel variations, boiler slag, pressure changes, pulverizer upsets, and sootblowing.

- Spray valves that are usually the primary control means for final steam temperature control sometimes go closed during certain load ranges or transients. Any time a final control element goes into saturation such as fully closed or fully open, it introduces a large nonlinearity into the control loop. Conventional control strategies do not cope with such nonlinear responses well.

- There are usually two methods of controlling reheat temperature. One is a spray valve and the other is some method of controlling heat distribution such as burner tilts, pass dampers, or gas recirculation. The action of these two control variables must be coordinated, and this adds some complexity to the control strategy.

With all of these factors making steam temperature control difficult, it is easy to understand why it is a frequent target of advanced control techniques. There are a variety of advanced control techniques which can be used. They range from relatively simple modifications such as better feedforward signals or deadtime compensation to full-blown multivariable optimal control systems. Many of the advanced control techniques can improve steam temperature control, but they generally involve added complexity in the control system. The added complexity in the control system can require a higher level of support by the plant staff.

Although ANSI/ISA-77.44.02-2001 describes the minimum requirements for steam temperature control, be aware that more advanced control techniques are available and can frequently provide better control performance.

Bibliography

ABMA-Boiler 307. *Combustion Control for Single Burner Firetube and Watertube Industrial/ Commercial Institutional Boilers.* American Boiler Manufacturers Association, 2003.

ANSI/ISA-77.41.01-2005 - *Fossil Fuel Power Plant Boiler Combustion Controls.* ISA, 2005.

ANSI/ISA-77.42.01-1999 (R2005) - *Fossil Fuel Power Plant Feedwater Control System – Drum-Type.* ISA, 2005.

ANSI/ISA-77.44.01-2000 (R2005) - *Fossil Fuel Plant Steam Temperature Control System (Drum-Type).* ISA, 2005.

ANSI/ISA-77.44.02-2001 - *Fossil Fuel Power Plant Steam Temperature Control System - Once-Through Type.* ISA, 2001.

Babcock & Wilcox. *Steam.* 40th edition. The Babcock & Wilcox Company, 1992.

Dukelow, Sam G. *The Control of Boilers.* Second edition. ISA, 1991.

Fisher Controls. *Control Valve Handbook.* Second edition. Fisher Controls International, Inc., 1977.

Hughes, Thomas A. *Measurement and Control Basics.* Third edition. ISA, 2002.

ISA-5.1-1984 (R1992) - *Instrumentation Symbols and Identification.* ISA, 1992.

Klochek, Len. *Win Boiler Sim.* (CD-ROM) CALA Engineering Services, 2002. (Sold through ISA.)

NFPA 85 — *Boiler and Combustion Systems Hazards Code.* National Fire Protection Association, 2004.

PC-ControLAB Release 3 – *Process Control Loop Simulation Program.* Wade Associates. (CD-ROM) Wade Associates, Inc., 2002. (sold through ISA.)

SAMA Standard PMC 22.1 – *Functional Diagramming of Instrument and Control Systems.* Scientific Apparatus Manufacturers Association, 1981.

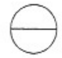
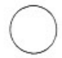
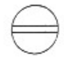
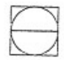
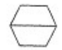
SEI/ASCE 7-02 – *Minimum Design Loads for Buildings and Other Structures.* American Society of Civil Engineers, 2003.

Reference

Identification Letters				
	First-Letter (4)		Succeeding-Letters (3)	
	Measured or Initiating Variable	**Modifier**	**Readout or Passive Function**	**Output Function/ Modifier**
A	Analysis		Alarm	
B	Burner, Combustion		User's Choice	User's Choice User's Choice
C	User's Choice			Control
D	User's Choice	Differential		
E	Voltage		Sensor (Primary Element)	
F	Flow Rate	Ratio (Fraction)		
G	User's Choice		Glass, Viewing Device	
H	Hand			High
I	Current (Electrical)		Indicate	
J	Power	Sean		
K	Time, Time Schedule	Time Rate Change		Control Station
L	Level		Light	Low
M	User's Choice	Momentary		Middle, Intermediate
N	User's Choice		User's Choice User's Choice	User's Choice
O	User's Choice		Orifice Restriction	
P	Pressure, Vacuum		Point (Test) Connection	
Q	Quantity	Integrate Totalize		
R	Radiation		Record	
S	Speed, Frequency	Safety		Switch

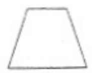
Identification Letters (cont'd.)				
	First-Letter (4)		Succeeding-Letters (3)	
	Measured or Initiating Variable	**Modifier**	**Readout or Passive Function**	**Output Function/ Modifier**
T	Temperature			Transmit
U	Multivariable		Multifunction	Multifunction/ Multifunction
V	Vibration, Mechanical			Valve, Damper, Louver
W	Weight, Force		Well	
X	Unclassified	X Axis	Unclassified	Unclassified/ Unclassified
Y	Event, State or Presence	Y Axis		Relay, Compute, Convert
Z	Position Dimension	Z Axis		Driver, Actuator, Unclassified Final Control Element

ISA General Instrument or Functional Symbols

	PRIMARY LOCATION NORMALLY ACCESSIBLE TO OPERATION	FIELD MOUNTED	AUXILIARY LOCATION NORMALLY ACCESSIBLE TO OPERATOR
DISCRETE INSTRUMENTS	1 	2 	3 
SHARED DISPLAY, SHARED CONTROL	4 	5 	6 
COMPUTER FUNCTION	7 	8 	9 
PROGRAMMABLE LOGIC CONTROL	10 	11 	12 

SAMA Symbols (Scientific Apparatus Makers Association)

ENCLOSURE SYMBOLS

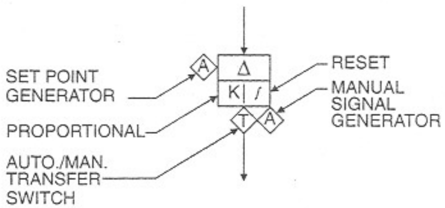
FUNCTION	SYMBOL
MEASURING OR READOUT	
MANUAL SIGNAL PROCESSING	
AUTOMATIC SIGNAL PROCESSING	
FINAL CONTROLLING	

SAMA Symbols

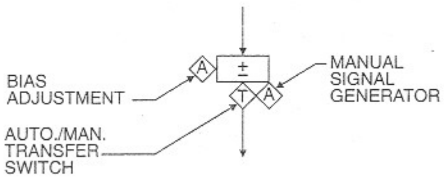
FUNCTION	SIGNAL PROCESSING SYMBOL	FUNCTION	SIGNAL PROCESSING SYMBOL
SUMMING	Σ or +	INTEGRATE OR TOTALIZE	Q
AVERAGING	Σ/n	HIGH SELECTING	>
DIFFERENCE	Δ or -	LOW SELECTING	<
PROPORTIONAL	K or P	HIGH LIMITING	$\not>$
INTEGRAL	$\int$ or I	LOW LIMITING	$\not<$
DERIVATIVE	d/dt or D	REVERSE PROPORTIONAL	-K or -P
MULTIPLYING	X	VELOCITY LIMITING	V $\not>$
DIVIDING	+	BIAS	$\pm$
ROOT EXTRACTION	$\sqrt{}$	TIME FUNCTION	f(t)
EXPONENTIAL	X^n	VARIABLE SIGNAL GENERATION	A
NON-LINEAR FUNCTION	f(x)	TRANSFER	T
TRI-STATE SIGNAL (RAISE, HOLD, LOWER)	$\updownarrow$	SIGNAL MONITOR	H/, H/L, /L

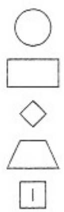
Note: SAMA and ISA Symbols are the same.

1. CONTROLLER



2. AUTO MANUAL + BIAS STATION





MEASURING OR READOUT

AUTOMATIC SIGNAL PROCESSING

MANUAL SIGNAL PROCESSING

FINAL CONTROLLING

SIGNAL REPEATER

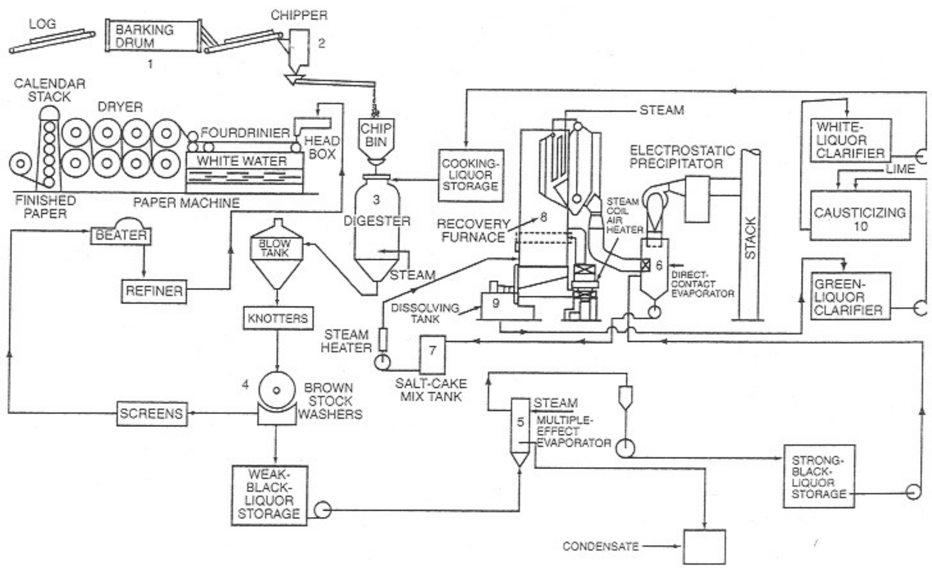
Σ	SUMMING Σ/h AVERAGING d/dt DERIVATIVE
Δ	DIFFERENCE ∫ INTEGRAL
K, −K	PROPORTIONAL, REVERSE PROPORTIONAL
X	MULTIPLYING ÷ DIVIDING √ ROOT EXTRACTING
f(x)	NON LINEAR OR UNSPECIFIED FUNCTION
f(t)	TIME FUNCTION
>	HIGH SELECTING < LOW SELECTING
≯	HIGH LIMITING ≮ LOW LIMITING
V ≯	VELOCITY OR RATE LIMITER
+,−,±	BIAS
T	TRANSFER
A	ANALOG SIGNAL GENERATOR

This diagram is of a Kraft pulping process. It is critical to the cost of operation of the Kraft process to recover the chemicals used. If the chemicals are not recovered, the process is cost prohibitive. The chemical is referred to as white liquor.

The logs are fed into a barking drum that removes the bark (1) and then into a chipper (2). The chips are fed into the digester where the chips are cooked at a high temperature and pressure. The cooking process breaks down the chips into wood fibers. The fibers go to a brown stock washer (4), are separated, and go to the paper machine process. The weak black liquor has 15 to 18% dissolved solids. The weak black liquor goes to the recovery process (6), (7), and (8). The multiple effect evaporator removes moisture producing strong black liquor. It then goes to a direct contact evaporator before it is sprayed into the recovery boiler forming a liquid bed in the boiler and forming a coating on the water tubes. The dissolved solids are about 80%. The dissolved solids are burned and the chemical is recovered. The liquor flows out of the furnace into a dissolving tank (9). This is referred to as green liquor. The green liquor then goes to causticizing where lime is melted in a lime kiln, and the lime is added to the green liquor to produce reusable white liquor (10).

The recovery process can be a hazardous process. If a water tube develops a leak the water mixing with the liquor bed may cause an explosion. The recovery boiler has a rapid drain system that can be energized if a leak is detected to drain the water from the boiler.

B&W Steam its generation and Use 40th Edition.



Glossary of Common Boiler Terms

Air - the mixture of oxygen, nitrogen, and other gases, which, with varying amounts of water vapor, forms the atmosphere of the earth.

Air pre-heater - a heat exchanger for transferring some of the waste heat in flue gases from a boiler or furnace to incoming air, thus increasing the efficiency of combustion.

Air purge - a flow of air through the furnace, boiler gas passages, and associated flues and ducts that will effectively remove any gaseous combustibles and replace them with air. Purging may also be accomplished by an inert medium.

Alarm - an indication used to alert an operator about an abnormal condition.

Attemperator - a mechanical device used for maintaining and controlling the temperature of superheated steam.

Attemperator (direct contact type) - a mechanical device in which the steam and the cooling medium (water) are mixed.

Automatic tracking - the action of a control system to automatically track a setpoint or the process variable without any other corrective mechanisms.

Balanced draft - a system of furnace pressure control in which the inlet air flow or the outlet flue gas flow is controlled to maintain the furnace pressure at a fixed value (typically slightly below atmospheric).

Blowdown - in a steam boiler, the practice of periodically opening valves attached to the bottom of steam drums and water drums, during boiler operation, to drain off accumulations of sediment.

Boiler - the entire vessel in which steam or other vapor is generated for use external to itself, including the furnace, consisting of the following: water wall tubes; the firebox area, including burners and dampers; and the convection area, consisting of any superheater, reheater, and/or economizer sections, as well as drums and headers.

Boiler follow mode - a mode of boiler control where the boiler responds to an energy demand requirement and controls boiler pressure by regulating boiler inputs.

Boiler follow system - a type of boiler control system in which the boiler inputs are adjusted to control the steam pressure out of the boiler.

Cascade control system - a control system in which the output of one controller (the outer loop) is the setpoint for another controller (the inner loop). The outer loop is normally a slow responding process as compared to the inner loop.

Combustion - the rapid chemical combination of oxygen with the combustible elements of a fuel, resulting in the production of heat.

Combustible - the heat producing constituent of a fuel, flue gas, or fly ash.

Condenser backpressure elements - a multiple breakdown diffuser, normally installed in the steam condenser neck, used to generate a positive back pressure upstream of the condenser vacuum and to reduce the kinetic energy of steam from an external source other than the turbine exhaust.

Control damper - a single or multiple bladed device that opens and closes to control air flow. A system with multiple blades tends to be more linear.

Control loop - a combination of field devices and control functions arranged so that a control variable is compared to a setpoint and returns to the process in the form of a manipulated variable.

Controller - any manual or automatic device or system of devices for the regulation of boiler systems to keep the boiler at normal operation. If automatic, the device or system is motivated by variations in temperature, pressure, water level, time, flow, or other influences.

Convection - the transmission of heat by the circulation of a liquid or a gas such as air. Convection may be natural or forced.

Coordinated control mode - a mode of boiler/turbine control that provides for the parallel operation of the boiler and the turbine as a unit to match generation to demand while maintaining boiler/turbine balance.

Coordinated control system - a type of boiler and turbine control system in which both the turbine inlet valves and the boiler inputs are adjusted together to simultaneously regulate the turbine load and the boiler output pressure.

Cyclone-fired boiler - a smaller ancillary furnace that typically attaches horizontally near the bottom of the main furnace. The number of cyclone furnaces depends on the total capacity.

Damper - a device for introducing a variable resistance for the purpose of regulating the volumetric flow of gas or air.

Desuperheater - see **attemperator (direct contact type)**.

Deviation - the difference between the loop setpoint and the process variable.

Differential pressure flow element - a measuring element that is inserted in a process flow path and used to create a pressure drop that is proportional to the square of the rate of flow.

Differential pressure transmitter - any of several transducers designed to measure the pressure difference between two points in a process and to transmit a signal proportional to this difference, without regard to the absolute pressure at either point.

Differential producer - a measuring element that is inserted in a process flow path and used to create a pressure drop that is proportional to the square of the volumetric flow rate.

Draft - the difference between atmospheric pressure and some lower pressure existing in the furnace or gas passages of a steam-generating unit.

Drum (steam) - a closed vessel designed to withstand internal pressure. A device for collecting and separating the steam/water mixture circulated through the boiler.

Economizers - heat exchangers that are used to recover excess thermal energy from process streams. Economizers are used for preheating feed and as column reboilers. In some systems, the reboiler for one column is the condenser for another.

Efficiency - the ratio of energy output to the energy input. The efficiency of a boiler is the ratio of heat absorbed by water and steam to the heat equivalent of the fuel fired.

Error - see **deviation**.

Excess air - air supplied for combustion in excess of theoretical combustion air.

Fail safe - the capability to go to a predetermined safe state in the event of a specific malfunction.

Fault tolerant - built-in capability of a system to provide continued, correct execution of its assigned function in the presence of a hardware and/or software fault.

Feedback - a signal produced by a measuring device that is proportional to the magnitude of a controlled variable or position of a control element.

Feedback control - an error-driven control system in which the control system to the actuators is proportional to the difference between a command signal and a feedback signal and a feedback signal from the process variable being controlled.

Feeder - a device such as a gravimetric weighing system or a volumetric device such as a screwdriver that is used to measure the quantity of a solid fuel to a boiler.

Feedforward - a control action that is taken to compensate for the effect of a sensed input disturbance.

Feedwater flow control system - a control system that uses input signals derived from the process for the purpose of regulating feedwater flow to the boiler to maintain adequate drum level according to the manufacturer's recommendations.

Final control element - a component of a control system (such as a control valve) that directly regulates the flow of energy or material to or from the process.

Final control device - a device that exerts a direct influence on the process.

Fireside of the boiler - see **fuel-air-flue gas system.**

Firing rate - the rate of fuel combustion in a boiler.

First-stage pressure - the pressure within a steam turbine at the point where the steam exits the first row of turbine blades. The pressure at this point is closely proportional to the flow rate of steam through the turbine. First-stage pressure is also referred to as impulse pressure.

Flame tripping validation - the flame tripping concept used on the unit must have been validated by the boiler manufacturer for the specific furnace configuration being used.

Flue gas - the gaseous products of combustion in the flue to the stack.

Forced draft (FD) fan - a fan supplying air under pressure to the fuel-burning equipment.

Frequency - an electrical measurement of the number of cycles in a given period of time that an electrical current oscillates. In the United States, the electrical system operates at a frequency of sixty Hertz (cycles/sec).

Fuel - a substance containing combustible material used for generating heat.

Fuel-air-flue gas system - the fuel air is the air from the atmosphere that supplies combustion air to the burners. On most boilers the air is mechanically supplied by an FD fan or fans. The flue gases are the gases leaving the boiler furnace combustion chamber that go to the stack. Some boilers have a mechanical source ID fan that pulls the gases from the furnace. The flue gas system may have equipment such as precipitators and scrubbers to minimize pollution.

Fuel trip - the automatic shutoff of a specific fuel as the result of an interlock or operator action.

Furnace - an enclosed space provided for the combustion of fuel.

Furnace pressure - the pressure of gases in the furnace (see also draft).

Gas pass - an arrangement in which the convection banks of a boiler are separated by gas-tight baffles into two or more parallel gas paths isolating portions of the superheater and reheater surfaces. The proportion of total gas flow through each gas pass may be varied by regulating dampers.

Gas recirculation - a method by which gas from the boiler, economizer, or air heater outlet is reintroduced to the furnace by means of a fan(s), duct(s), or both.

Igniter - a device for initiating an explosion or combustion in a fuel-air-mixture.

Induced draft (ID) fan - a fan exhausting flue gases from the furnace.

Integral control action - an action in which the controller's output is proportional to the time integral of the error input. When used in combination with proportional action, it previously was called reset action.

Integral windup - the saturation of the integral controller output in the presence of a continuous error, which may cause unacceptable response in returning the process to its setpoint within acceptable limits of time and overshoot.

Interlock - a device or group of devices (hardware or software) arranged to sense a limit or off-limit condition, or improper sequence of events, and to shut down the offending or related piece of equipment, or to prevent proceeding in an improper sequence in order to avoid an undesirable condition.

Intermediate (platen) superheater - a heating surface receiving steam from the primary superheater located between the primary and secondary superheater.

Lambda tuning - a controller tuning method originated in the synthesis design method whereby the controller must "cancel out" the process dynamics.

Linearity - the nearness with which the plot of a signal or other variable plotted against a prescribed linear scale approximates a straight line.

Load - a device that receives power or that power which is delivered to such a device, as in the rate of output, lb/hr (kg/s) of steam or megawatts (kilowatts) of electrical generations.

Load dispatch - a remotely developed signal transmitted to an electric generating unit's control system for the development of that unit's net generation requirement.

Load index - signal representative of desired output energy flow rate.

Logic system - decision-making logic equipment with its associated power supplies, I/O hardware, and sensing devices.

Mass feedwater flow rate - the mass flow rate of all water delivered to the boiler; it is derived either from direct process measurements and/or calculations from other parameters. When volumetric feedwater flow rate measurement techniques are employed and the feedwater temperature at the flow-measuring element varies 100°F (37.8°C), the measured (indicated) flow shall be compensated for flowing feedwater density to determine the true mass feedwater flow rate.

Mass steam flow rate - the mass flow rate of steam from the boiler, derived either from direct process measurements and/or calculations from other parameters. If volumetric steam flow-rate measuring techniques are employed, the measured (indicated) flow shall be compensated for flowing steam density to determine the true mass steam flow rate.

Master fuel trip (MFT) - an event resulting in the rapid shutoff of all fuel. (See also **fuel trip.**)

megawatt - A unit of power measurement equal to one million watts. Turbine/generator capability is usually expressed in megawatts.

Mho - a unit of electrical conductance. Equal to the reciprocal of ohm.

Mode (submode) - a particular operating condition of a control system, such as manual, automatic, remote, or coordinated.

Mud drum - a lower drum in a boiler where chemical sludge collects. A blow down valve on the bottom of the mud drum is open periodically to remove the chemical sludge.

Overfire air - a second source of combustion air to the furnace. The air is injected in the furnace to enhance combustion and reduce NO_x by reducing the furnace temperature.

Piping and Instrument Diagrams (P&IDs) - **(1.)** Drawings that show the interconnection of process equipment and the instrumentation used to control the process. The process industry, a standard set of symbols is used to prepare the drawings of processes, generally based on ISA 5.1. **(2.)** The primary schematic drawing that is used for laying out a process control installation.

Primary air (transport air, pulverizer air) - the air or flue gas introduced into the pulverizer to dry the fuel and convey the pulverized fuel to the burners.

Primary (convection or initial) superheater - a heating surface receiving steam from the drum.

Primary/secondary control loop controller - the controller that adjusts the setpoint for the secondary control loop controller in the cascade control action scheme.

Protective logic circuits - logic circuits designed to prevent damage to equipment by related system equipment malfunctions, failure, or operator errors.

Pump drive control - a control component of the final device that translates a control system demand signal into an electronic, hydraulic, pneumatic, or mechanical signal that affects pump speed.

Ratio controller - a controller that maintains a predetermined ratio between two or more variables or that maintains the magnitude of a controlled variable at a fixed ratio to another variable.

Redundant (redundancy) - duplication or repetition of elements in electronic or mechanical equipment to provide alternative functional channels in case of failure of the primary device.

Regenerative - a quality of signal that feeds back on itself, causing control system instability.

Reheater - a heating surface receiving steam returning to the boiler from the high-pressure turbine exit.

Runback - an action by the boiler control system initiated by the loss of any auxiliary equipment that limits the capabilities of the unit to sustain the existing load. Upon runback initiation, the boiler demand signal is reduced at a preset rate to the capability of the remaining auxiliaries.

Rundown (runup) - an action by the boiler control system initiated by an unsafe operating condition i.e., fuel air limit (crosslimiting), temperature limits, etc. Upon rundown (runup) initiation, the boiler demand signal is reduced in a controlled manner to the load point where the unsafe operating condition is eliminated.

Secondary air - the air supplied by the forced draft fan to the burners for combustion.

Secondary combustion - combustion that occurs as a result of ignition at a point beyond the furnace.

Secondary (radiant or final) superheater - a heating surface receiving steam from either the primary or intermediate superheater.

Self-tuning - the technique of automatically modifying control algorithm constants based upon process conditions.

Severe duty valve - a mission-critical valve, typically seeing high-pressure drop service, which may see cavitating or flashing fluids, or if not properly designed, may see early trim erosion, vibration, or excess noise.

Shall, should, and may - the word "SHALL" is to be understood as a REQUIREMENT; the word "SHOULD" as a RECOMMENDATION; and the word "MAY" as a PERMISSIVE, neither mandatory nor recommended.

Shrinkage - a decrease (shrinkage) in drum level due to a decrease in steam-bubble volume. This condition is due to a decrease in load (steam flow), with a resulting increase in drum pressure and a decrease in heat input.

Single-element feedwater control - a control system whereby one process variable, drum level, is used as the input to the control loop that regulates feedwater flow to the drum to maintain the drum level at setpoint.

Steady-state - a characteristic of a condition, such as value, rate, periodicity, or amplitude, exhibiting only negligible change over a long (arbitrarily chosen) period of time. **Note** - It may describe a condition in which some characteristics are static, others dynamic.

Steam header - a pipe in which steam output from multiple boilers is collected and then distributed to various steam loads.

Steam quality - the ratio of the vapor's mass to the mixture's mass.

Stoker - a mechanized means for feeding coal or other solid combustibles into a furnace, burning them under controlled conditions, and carrying away the solid combustion products.

Summer - a summer occurs when two or more values come into an equation and the output equals the sum of the inputs in percent based on the K values.

Superheater - a bank of heating surface tubes contained within a boiler, and to which heat is applied to elevate the steam temperature to a desired value above saturation.

Swell - an increase (swell) in drum level due to an increase in steam bubble volume. This condition is due to an increase in load (steam flow), with a resulting decrease in drum pressure and an increase in heat input. Swelling also occurs during a cold start-up as the specific volume of the water increases.

Tertiary air - the air supplied to certain types of burners for cooling the burner metal or to improve the combustion process.

Theoretical (stoichiometric) combustion air - the chemically correct amount of air required for complete combustion of a given quantity of a specific fuel.

Three-element feedwater control - a control system whereby three process variables (steam flow, feedwater flow, and drum level) are used as inputs to the control loop that regulates feedwater flow to the drum to maintain the drum level at setpoint. This is a cascaded feedforward loop with drum level as the primary variable, steam flow as the feedforward input, and feedwater flow (feedback) as the secondary variable.

Tracking - forcing an inactive control function to follow the active control function so that upon a mode transfer, no process upset occurs.

Transient - the behavior variable during the transition between two steady states.

Transient correction - a control action specifically applied to minimize any process error resulting from a temporary process change; e.g., temperature control action applied to counter the effects of over- or under-firing during load changes.

Trip - the automatic removal from operation of specific equipment or the automatic discontinuance of a process action or condition as the result of an interlock or operator action.

Turbine - a machine that converts energy from a moving fluid into rotating mechanical energy that drives a load. In a power plant, a turbine converts energy in the steam into mechanical energy to drive an electric generator (the mechanical load).

Turbine governor valves - the primary control valves used to regulate the flow of steam through the turbine during normal operation.

Turn-down ratio - the ratio from maximum operating to minimum operating conditions, providing a controllable or measurable span. The device must perform over this range.

Two-element feedwater control - a control system whereby two process variables (steam flow and drum level) are used as inputs to the control loop that regulates feedwater flow to the drum to maintain the drum level at setpoint. The feedforward input is steam flow, with the output of the drum level controller as the primary control signal.

Two-out-of-three logic circuit (2/3 logic circuit) - a logic circuit that employs three independent inputs. The output of the logic circuit is the same state as any two matching input states.

Vane control - a set of movable vanes in the inlet of a fan for the purpose of regulating air flow.

Waterside of the boiler - see **steam-water system.**

Windbox - a chamber below the grate or surrounding a burner, through which air under pressure is supplied for combustion of the fuel.

Ziegler-Nichols method - a method for determining optimum controller settings when tuning a process control loop (also called the "ultimate cycle method"). It is based on finding the proportional gain that causes instability in a closed loop. This method is sometimes called the "Ziegler-Nichols closed-loop method" to distinguish it from another tuning approach devised by Ziegler and Nichols in which settings are derived from open-loop parameters.