Control System Tuning Assessment Guidelines

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ABSTRACT

Power plant control systems must perform well if the whole plant is to perform well. One key to successful control system performance is proper tuning of the system. Tuning is the process of adjusting the magnitude and speed of control system actions to match the characteristics of the plant being controlled. The first step toward improving tuning on an operating unit is an assessment of the unit to identify performance problems and their causes. This report provides detailed guidelines on power plant control system tuning assessment. It begins with a review of process response concepts and control system fundamentals. Assessment techniques and tests are covered next, followed by loop specific recommendations. This report represents a technical update on a project that seeks to extend this tuning assessment guidance to develop an approach for automating boiler control system tuning.

CONTENTS

1 INTRODUCTION

Power plant control systems must perform well if the whole plant is to perform well. One key aspect of successful control system performance is proper tuning of the system. Tuning is the process of adjusting magnitude and speed of control system actions to match the characteristics of the plant being controlled. Many would say that this is the most difficult aspect of making a control system perform well. The first step toward improving tuning on an operating unit is an assessment of the unit to identify control system performance problems and their causes. This can be quite a challenge in itself, because it is often hard to determine whether a problem is caused by the process or by the control system. The two systems are very closely coupled, and the assessor must have an understanding of both systems to isolate the root cause of a problem.

There is a considerable amount of literature on control system tuning, particularly PID controller tuning. There is much less information available on tuning assessment. It is now common for technicians to use tuning as the first fix for most problems without adequately assessing the true cause of the problem. This is unfortunate, because with drift-free modern digital control systems the tuning will not vary over time. So, if the loop performed well at one time but doesn't anymore, it is probably not the fault of the control system tuning. There are several major components of the control system, including the sensors and signal conditioners, the computing section, and the output signals and actuators systems. Anyone of these systems can cause performance problems, as can changes in the process itself. Assessment is all about determining where the root cause of the problem is in a systematic way so time is not wasted trying to fix the wrong problem.

This report provides detailed guidelines on power plant control system tuning assessment. It is part of larger project within the *I&C and Automation for Improved Plant Operation Target* at EPRI to improve control system tuning in fossil power plants. The report begins with a review of process response concepts such as process gain and response time. Control system fundamentals are discussed next, including major components, PID control basics, and performance measures. The report then explains the actual assessment process, including the types of tests that provide the most insight. Finally, loop specific guidance is provided for assessing the major power plant control functions.

The intended audience for this report is plant personnel and supervisors charged with maintaining control system performance. In addition staff engineers at the plant and central office engineers with control system responsibilities can also improve their understanding of control system tuning issues from this report. This report represents a technical update on a project that seeks to extend this tuning assessment guidance to develop an approach for automating boiler control system tuning. This report does not cover actual tuning procedures but there is an earlier EPRI report [1] that goes into some detail on control system tuning techniques.

2
PROCESS RESPONSE CONCEPTS

When analyzing control system performance, it is important to understand the inherent dynamic characteristics of the process being controlled. This is necessary to determine whether an observed problem is originating in the control system or in the process. Figure 2-1 shows a simplified diagram of a typical process with a feedback control system. All processes have at least one input from the control system, and it is usually called the manipulated variable. The process also has at least one output that is being controlled by the control system, called the controlled or process variable. All processes also have disturbances that are generally thought of as external disturbance inputs, although they may originate entirely within the process. Understanding the concept of disturbances is very important because disturbances are a major contributor to control system response problems.

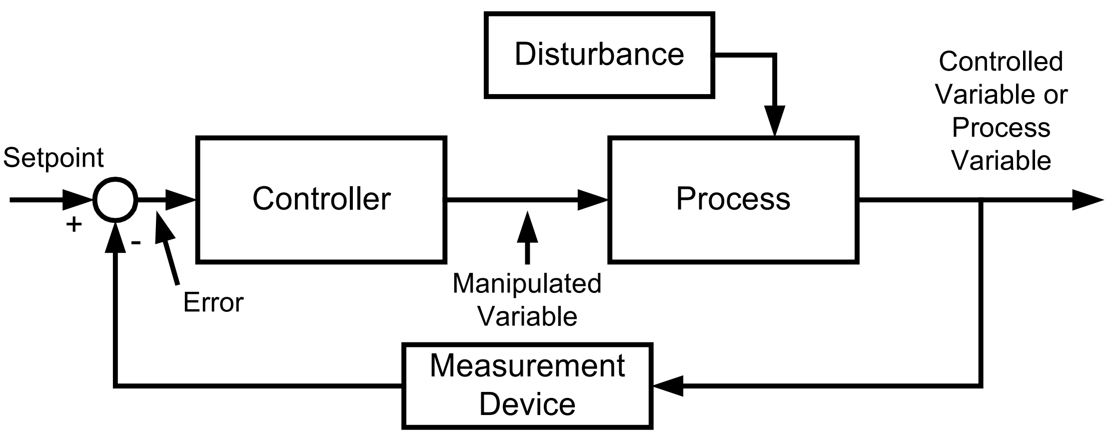


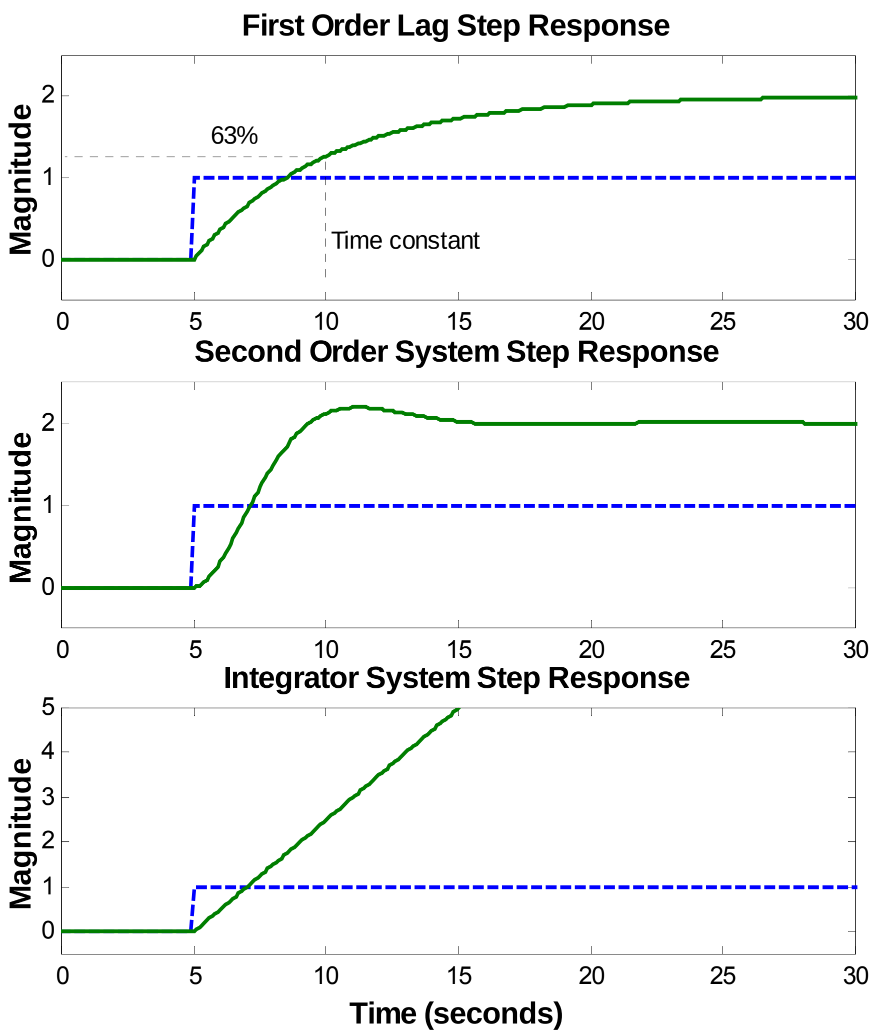
Figure 2-1
Simplified Process Diagram

2.1 Process Characterization

Although real processes have very complex non-linear responses, it is very useful to approximate the responses with simple mathematical representations (or models). It turns out that almost all power plant processes can be adequately modeled by a few simple transfer functions. The two main characteristics of interest are the speed of the response and the magnitude of the response. Figures 2-2a, 2-2b, and 2-2c show the three most common types of process responses to a step change in the manipulated variable.

The most common step response is a first order lag response as shown in Figure 2a. It is called first order because it is the response of a system modeled by a first order differential equation. In transfer function or Laplace transform notation, the 's' variable is first order or raised to the power of 1. There are only two parameters required to specify a first order response, the time constant and the gain. Figure 2a shows the time constant is determined by the time required for the response to reach 63% of its final value and it usually designated with the Greek letter tau ( ). A fast responding process has a small time constant. The time constants for power plant processes can range from a few seconds up to several hours. Flow control and liquid pressure control are usually the fastest processes, with time constants of a few seconds, while temperature control is usually the slowest, with time constants of a few minutes. Examples for specific power plant loops will be discussed in Section 6, Loop Specific Assessments.

The process gain (all gains are usually designated with the letter K) is simply the ratio of the steady state change in the output to the change in the input. Another term that is frequently used as a synonym of process gain is sensitivity. A process with high gain is more sensitive than a process with low gain. One thing to keep in mind about process gain is that it depends on the units of measure chosen for the inputs and outputs. If real engineering units are chosen, there can be a very wide range of values but if everything is presented as a percent of full-scale, the typical gain values range from about 0.1 to 20.



Figures 2-2a, 2-2b, 2-2c
Common process response curves

The process gain (all gains are usually designated with the letter K) is simply the ratio of the steady state change in the output to the change in the input. Another term that is frequently used as a synonym of process gain is sensitivity. A process with high gain is more sensitive than a process with low gain. One thing to keep in mind about process gain is that it depends on the units of measure chosen for the inputs and outputs. If real engineering units are chosen, there can be a very wide range of values but if everything is presented as a percent of full-scale, the typical gain values range from about 0.1 to 20.

Another common process response is called the second order response as shown in Figure 2b. This response is called second order because it is modeled with a second order differential equation, or a transfer function with the 's' variable raised to the second power. The most distinguishing characteristic of this response is the presence of overshoot. Overshoot means that the output exceeds its final value during the response. There are three parameters that define a second order response, the gain, the damped natural frequency and the damping ratio. The gain is similar to the gain in the first order response; it is the ratio of the steady state change in the output to the change in the input. The damped natural frequency is a measure of the speed of the response and is usually expressed in radians per second or sometimes in cycles per second. It is analogous to the time constant for a first order system. A first order system with a time constant of T seconds will have about the same response time as a second order system with a damped natural frequency of 1/T radians per second. Another term that is sometimes used to describe the speed of a system is bandwidth. Bandwidth is expressed as a frequency and in this context is the same thing as the damped natural frequency. The damping ratio determines how quickly the overshoot and undershoot die out and the system reaches a steady value. Damping ratios vary from 0 to 1, with 0 meaning no damping and 1 meaning no overshoot.

The third common type of process response is called an integrator as shown in Figure 2c. This process generally represents the liquid level in a tank. There is only one parameter associated with an integrator and that is a gain. The gain determines the slope of the output ramp in response to a step input.

There is one other common type of process response that is not shown in Figure 2 and that is deadtime, sometimes called pure delay time. The only deadtime parameter is the time duration of the delay of the deadtime. Deadtime is often confused with the first order lag response but it is important to understand the differences. A deadtime response is flat for the period of the deadtime. It also doesn't affect the magnitude of the input signal in any way; it only delays it. A first order lag, on the other hand, shows an immediate response to a step input and it can affect the magnitude of the incoming signal. Deadtime responses originate in one of two ways in power plants. The first is through transport delay in which the time a material takes to travel from one location to another delays a response. The second is a little trickier. Most real processes tend to exhibit an initial deadtime response followed by a first or second order response. This initial deadtime is the result of the process having many lags in series. When many first order lags occur in series in a process, the response has some deadtime. There are very few processes in a plant where transport delay leads to a significant deadtime response. The cause is almost always many first order lags combined together.

2.2 Process Disturbances

The simplified process models described above do an adequate job of representing most common plant processes. One aspect of process models that has not been discussed yet is disturbances. Disturbances are any outside influences on the response of a process. Many disturbances are a normal part of the process, such as things related to load changes on a system. For instance, the outlet temperature of a pulverizer is disturbed by a change in coal flow through the pulverizer, and this is certainly a normal occurrence during plant load changes. Other disturbances are caused by abnormal situations such as a boiler tube leak or a coal feeder stoppage.

Noise is another type of disturbance. There are two common types of noise in plants. The first is process noise, which is noise that shows up in measurement signals and is caused by turbulence in the process being measured. Drum level, airflow and furnace pressure are processes that frequently have significant process noise. The other type of noise is electrical noise induced in the process measurement system. Electrical noise usually occurs at 60 Hz since, most of the plant is filled with 60 Hz electrical equipment. Electrical noise is generally easy to filter out in the process measurement system, but sometimes this is not done adequately.

2.3 Actuators

Actuators are the devices that convert the output commands from the control system into the movement of the mechanical control element. Actuators can be considered part of the control system or part of the process. From a troubleshooting standpoint it makes more sense to consider them part of the process. At their core, actuators are amplifiers and transducers. They receive a low power electrical or pneumatic signal and output a high power mechanical motion. Actuators can be categorized in many different ways, but the most common is by their power source. The power can come from air pressure (pneumatic), electricity (motors), or hydraulic pressure. The ideal actuator would have instantaneous response and perfect position accuracy. Unfortunately no actuators match the ideal. Since real actuators are not ideal, they can and do impact the control system performance. Some of the common problems with actuators are response deadtime, position deadband and hysteresis.

2.3.1 Pneumatic Actuators

Pneumatic actuators are very common on all types of processes. The actuator generally operates by admitting compressed air into a cylinder and thereby moving a piston. The motion of the piston can then be used directly in a linear motion or can be connected to a crank arm to produce a rotary motion. Pneumatic actuator position response is often modeled as a first order lag, but in reality the response is much more complex. The static friction of the piston in the cylinder causes a short amount of deadtime in the response, as the pressure in the cylinder has to change enough to overcome the static friction. Once the piston starts to move the friction is reduced significantly, and the piston may overshoot its desired position. The friction can sometimes cause hysteresis in the actuator positioning. When the pneumatic actuator is performing well, these effects are minimal and often would not even be noticed. But when the actuator or the air supply is not well maintained, these effects can become much more noticeable and cause significant problems with control loop performance.

2.3.2 Electric Actuators

Electric actuators use an electric motor and gear reduction system to produce a linear or rotary actuator motion. The motor may be AC or DC. They are generally modeled as an integrator (a constant velocity device). Electric actuators include a small position control system that includes a position sensor and an on/off power switch. If there is a position error, the power switch energizes the motor to run in the correct direction to reduce the error. The switch is generally designed to turn the motor on and off in rapid succession to more precisely control the position. When the position error is less than a small amount (typically 0.25% to 1%), the power switch stops moving the motor. Since there has to be a small deadzone in the position controller, there will always be a small deadband in the position accuracy of an electric actuator. If the actuator and its power switch are properly setup, this deadband should be quite small but if improperly setup can be a couple of percent. One big advantage of electric actuators is high breakaway force. This helps to reduce deadtime in the response.

2.3.3 Hydraulic Actuators

Hydraulic actuators use high pressure oil as their motive force. By far the most common application for hydraulic actuators in power plants is to position the turbine control valves. In recent years a new type of self-contained hydraulic actuator has begun service on other applications. Before about 1965, the hydraulic actuators on turbine valves were powered by relatively low pressure turbine lube oil. As turbines and their valves got bigger, more powerful actuators were required. A new breed of high-pressure, electrically-controlled actuators was introduced. These new electro-hydraulic (E-H) actuators are the closest to ideal of any actuator. They have very precise position control, fast speeds and high power. However they are far more expensive than the other types and so their use is restricted to only the most demanding service.

3
CONTROL SYSTEM FUNDAMENTALS

Understanding control system fundamentals is obviously an important aspect of control system tuning assessment. This chapter of the report provides a brief review of control system basic concepts, but it is not intended to be a comprehensive tutorial on power plant control systems. Topics covered include feedback, PID controllers and control system performance measures.

3.1 Feedback

By far the most important concept in control systems is feedback of the process measurement to the control system. When feedback is used the control system is also referred to as closed loop control, because the signal flow through the control system forms a loop (see Figure 2-1). Feedback is not a requirement in all applications, and when it is not used, the control system is said to be open loop. All modern power plant control systems have the capability of putting a loop in automatic or manual mode. Automatic mode generally implies closed loop control while manual mode is open loop control.

While feedback greatly improves the accuracy of control systems it does so at the expense of stability. Adding feedback to a system makes instability possible. To avoid instability, the control system must be properly "tuned."

3.2 PID Controllers

PID controllers are the most prevalent type of industrial controller in use today. PID stands for proportional-integral-derivative, which are the three control modes of the controller. The controller operates on the control loop error signal and produces an output signal that either goes to an actuator or to another controller. When the output goes to an actuator it is called the manipulated variable. When the output of one controller is the input of another controller it is called a cascade control loop. Cascade controls are very common in power plants.

PID controllers are very widely used because they work well, are flexible and are easily understood. PID controllers have tuning parameters that determine the contribution that each of the three modes makes in the final controller output. As noted in Section 2, every process has certain characteristics such as gain and time constant. For a PID controller to work well, it must be tuned to match the process characteristics.

One thing that makes PID controllers seem more complicated than they really are is that, in practice, there are many different varieties of PID controllers used on different brands of control systems. There are also different names for the control modes and the tuning parameters. Integral mode is also called reset. Derivative mode is also called rate. The proportional tuning parameter can be called proportional gain or proportional band. The integral tuning parameter can be called integral gain, integral time, or reset rate. The derivative tuning parameter can be called derivative gain or rate.

The term PID controller can refer to any controller that uses any combination of the P, I, or D control modes. The most common implementation is the PI controller. Other common implementations include the P, PD, I, and PID. If the controller is implemented in hardware, such as with a pneumatic or analog electronic system, then each implementation may require a different set of hardware. In modern digital control systems where the controllers are implemented in software, one algorithm can be any type of controller merely by setting the gain of unused modes equal to zero.

3.2.1 Controller Modes

The output of the PID controller is simply the sum of the outputs of each of the individual modes of the controller. The proportional control mode output is the controller error signal multiplied by a constant. The constant can be expressed in two different ways. The first is shown in Equation 3-1 and the constant is the proportional gain. The second is shown in Equation 3-2 and the constant is 100 divided by the proportional band. Some vendors use the gain designation while others use the band designation. Proportional gain equals 100 divided by the proportional band as shown in Equation 3-3.

$$OP = E * KP \qquad \textbf{3-1}$$

where:
OP is output of proportional mode
E is controller error, setpoint minus measured variable
KP is proportional gain.

$$OP = E * 100 / PB \qquad \textbf{3-2}$$

where:

PB is the proportional band

$$KP = 100 / PB \qquad \textbf{3-3}$$

The proportional mode alone will not guarantee zero error at steady state but the integral mode will. This is the main reason for the popularity of the PI controller. The output of the integral mode is the integral (or summation) of the error signal over time. So as long as there is even a very small error signal, the output will continue to change to drive the error to zero. Equation 3-4 shows the integral mode formula. The equation shown uses continuous notation, but digital control systems will use an equivalent discrete version of the formula. Much like the proportional mode, the integral constant can be expressed in two ways as shown Equations 3-4 and 3-5. The integral function will only stop changing when its input is zero.

$$OI = KI * \bullet E \qquad \textbf{3-4}$$

where:
OI is the output of the integral mode
KI is the integral gain

$$OI = (1 / TI) * \bullet E \tag{3-5}$$

where:

TI is the integral time

The derivative mode is the least used controller mode. The output of the derivative mode is proportional to the rate of change of its input signal. It is common for the input signal to the derivative mode to not be the error signal. Often the input signal is the measured variable. This is done to prevent output spikes when the operator makes a sudden change in the setpoint. Derivative mode can be used to speed up the response of slow processes. Equation 3-6 shows the formula for an ideal derivative mode.

$$OD = KD * d/dt(MV) \tag{3-6}$$

where:
OD is the output of the derivative mode
KD is the derivative gain
MV is the measured variable

It is not possible to build an ideal derivative function in hardware or software, so real implementations are slightly different than as shown in 3-6. Real implementations approximate a true derivative, but limit the magnitude of the output for rapidly changing inputs. Sometimes a second tuning parameter is provided to allow the magnitude limit to be set by the user. At other times it is fixed by the implementation.

The total output of the PID controller is the sum of the outputs of each of the modes as shown in Equation 3-7. Figure 3-1 shows the step response of each of the three controller modes.

$$O = KP * E + KI * \bullet E + KD * d/dt(MV) \tag{3-7}$$

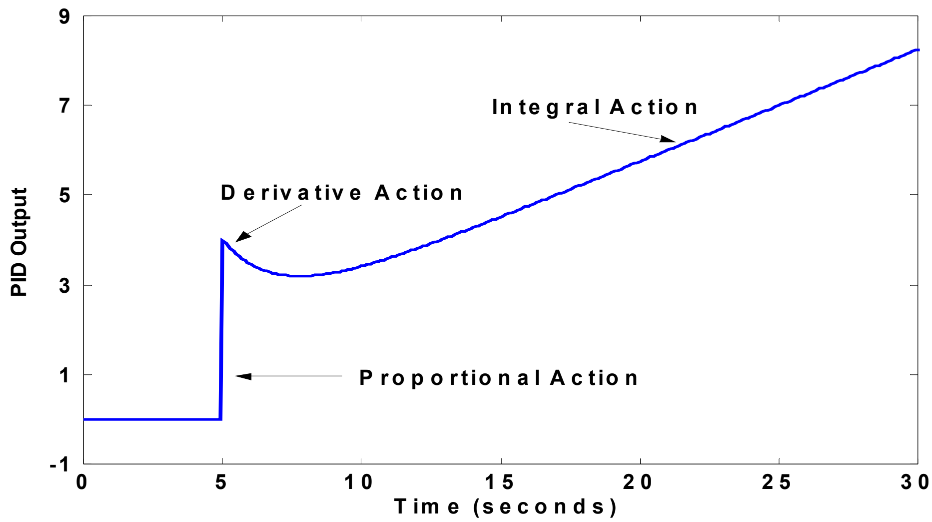


Figure 3-1
PID step response

3.3 Feedforwards

When simple PID controllers are not capable of satisfactory control, there are a couple of common enhancements that can be used to improve their performance. One of these enhancements is the use of a feedforward signal. A feedforward signal is generally added to the output of a PID controller and acts as a simple predictive controller. The idea behind using a feedforward scheme is that there is a signal in the plant that can provide additional useful information to the control system beyond that provided by the normal feedback variable. By bringing this signal into the control system, the control response can be improved. Most often a feedforward signal is used on a slow responding loop to speed up the loop's response to setpoint changes or reduce the impact of disturbances such as load changes. Figure 3-2 shows a typical arrangement of a feedforward signal in conjunction with a normal PID feedback control.

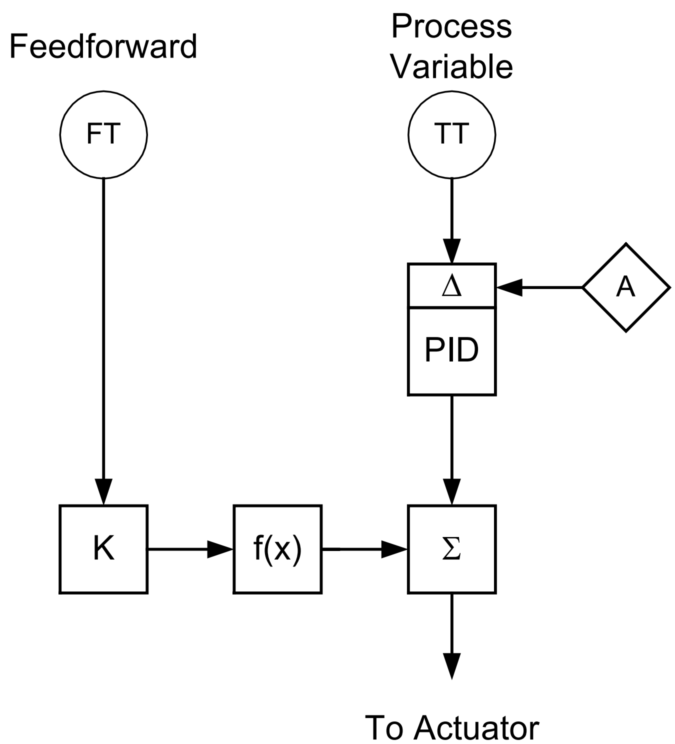


Figure 3-2
Typical static feedforward arrangement

Feedforward schemes are used extensively on power plant control systems. The feedforward controller can be static or dynamic. In a static feedforward controller, there are no dynamic elements such as lags or leads. In a static system the feedforward signal is only scaled or characterized. In a dynamic system, the feedforward signal is dynamically compensated in addition to scaling and characterization. Static compensation is much more common in power plant control systems. The most common feedforward signal is one that represents unit load, such as steam flow or megawatts. Often times a static load feedforward is called a load index. A most common type of dynamic feedforward provides a derivative action and it often called a "kicker."

3.4 Cascade Control

Another common way to improve on the simple PID controller's performance is to use a cascade control strategy. In a cascade control arrangement, two PID controllers are connected in series with the output of the first controller being the setpoint for the second controller. A cascade control scheme is shown in Figure 3-3. Cascade control can greatly improve a loop's ability to reject disturbances, but there has to be a secondary controlled variable that has a faster response than the primary controlled variable. Very often cascade control is used on temperature and level control loops where the secondary variable is a fast-responding flow signal.

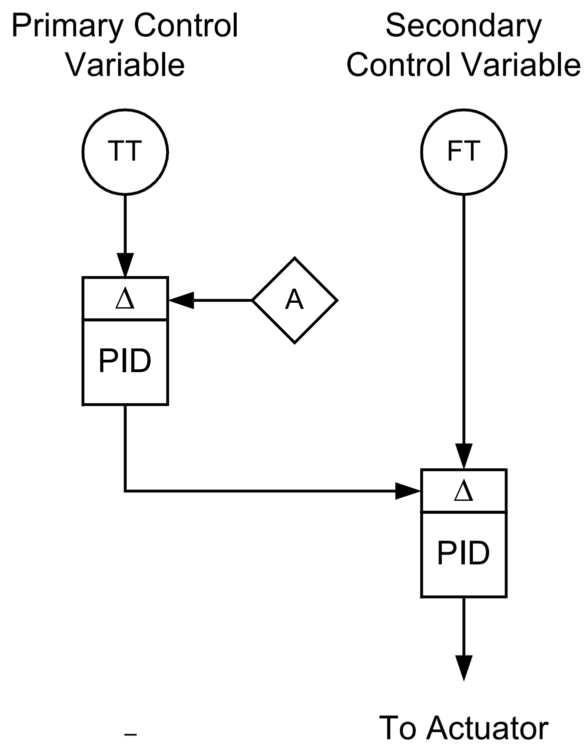


Figure 3-3
Cascade control scheme

3.5 Trim Controller

Trim controllers are very commonly used in boiler control systems and are just a special application of a PID controller. They are used to provide a slight adjustment, or trim, to a feedforward signal that is providing a loop's setpoint or demand signal. An example will help explain their function. In a three element drum level control strategy, steam flow is a feedforward setpoint of the feedwater flow loop. Under normal well tuned conditions, the steam flow signal will provide a very accurate setpoint for the feedwater flow. But no matter how accurate it is, the drum level will still drift away from setpoint. The drum level controller in a three element control strategy provides a slight trim to the steam flow signal to keep the drum level at setpoint. The main characteristic of a trim controller is that the output is normally zero and can be either positive or negative. Other trim controllers include the megawatt controller, the throttle pressure controller, and the excess oxygen controller. Since the oxygen controller is a ratio type controller its output is normally 1.0 and the trim can be from 0.8 to 1.2 or +/- 20%. One very easy way to tell if the system's feedforward signals are well calibrated is to check the output of the various trim controllers throughout the load range. If one varies from zero by more that a percent or two, then the feedforward signal needs recalibration.

3.6 Performance Measures

In order to judge the performance of a control system, there must be some measurements that quantify its performance. There are many good ways to measure control system performance, but this is still not very well understood in the power industry. Many engineers use very subjective measures to evaluate a control system. It is far better to be certain of the real performance by making actual measurements. From classical control system theory, there are several measures for control system performance. Terms such as maximum error, percent overshoot, damping ratio, rise time, response time, and bandwidth are some of the more common ones. In the world of power plant controls there are only two that are commonly used, maximum error and percent overshoot. Maximum error is generally used to specify the limits on control system performance in technical specifications. The requirement will typically be stated as follows: the drum level control system will maintain the drum level within +/- 1 inch (2.5 cm)of setpoint during steady state operation and within +/- 2 inches (5.1 cm) of setpoint during load ramping operation at 3% of full load per minute. This specifies the maximum loop error that is acceptable. Maximum error is really not the best way to specify control system performance, but it is the easiest to measure and understand.

Percent overshoot refers to the amount that the controlled variable exceeds the desired setpoint in response to a step change in setpoint. For example, if the superheat temperature setpoint is lowered from 1000 degF (538 degC) to 985 degF (529 degC) and the actual temperature goes from 1000 degF (538 degC) to 980 degF (527 degC) before it finally settles out at 985 degF (538 degC), then the overshoot was 5 degrees (2.8 degC). Since the change in setpoint was 15 degF (9.4 degC), the percent overshoot is 5/15 * 100 = 33.3%. Percent overshoot is mainly used as a performance measure when tuning individual control loops. Very often the desired response of the closed loop system is to have between 5-20% overshoot to a step change in setpoint.

4
ASSESSMENT FUNDAMENTALS

Sections 2 and 3 of this report have covered the fundamentals of process responses and control systems that are needed to begin the tuning assessment process. In this chapter, the fundamentals of tuning assessment are introduced. The following chapters provide specific guidance on assessment tests and loop specific assessment tips.

Many technicians and engineers who work on control systems probably don't think of tuning assessment as a separate process from tuning. It is certainly closely connected, but it can help bring order to the tuning process to think of the assessment as a separate task. Too often tuning adjustments are made before the real control system problem is identified. This ultimately compounds the problem, although at first it may appear to fix it. By following the procedures in this report, users should be able to identify the root cause of most control system performance problems.

4.1 Assessment Objectives and Scope

When beginning any new tuning assessment task, no matter how small, it is always a good idea to identify the objectives and scope of the assessment. The person that requested the assessment will usually dictate its objectives, but it may take some discussion to make sure everyone involved understands exactly what is expected. Putting the agreed objectives in writing will help minimize problems later and help keep the assessment on track. A typical objective is to identify the root cause of a control system performance problem, whether it is improper tuning, poor control strategy, or malfunctioning field devices.

The scope of the assessment just defines the boundaries of the study. It may be limited to a single control loop or it might be an entire plant control system. Sometimes the determination of a root cause will force the assessment outside its original boundaries. Interactions among control loops can make a problem appear in one loop, even though the real source is another loop.

4.2 Control System Objectives

In addition to defining the assessment objectives it is important to understand the plant's control system objectives. While it might seem that all control systems have the same objectives that is not really true. The control system objectives depend on the plant's operational objectives. Some plants are base loaded and only change load infrequently. Other plants are load following and are continually changing load. Plants with such different operating scenarios may need different control system objectives. The base loaded plant may want a control system that is more stable and less responsive, while the load following plant may want just the opposite. Plants may have specific constraints on their operation that dictate special control system needs.

The plant staff will usually have a general idea of what their control system objectives are, but they may not have quantified them. For example, they may say they want the unit to operate on automatic generation control, but they don't know how fast the load rate of change needs to be. They may want the system to handle the loss of a forced draft fan at full load without tripping the unit, but they don't know how fast the runback should be. If the plant staff is not sure about objectives, the assessor may have to help define them. If there are special situations and if the plant staff is not aware of them, they will generally surface during the assessment. An example of a special situation is a weak superheater that can not stand any high temperature excursions. This situation may dictate special setpoints or tuning to prevent such events, even though it may impact plant thermal performance.

Control system objectives are often described in terms of maximum deviations from setpoint for key parameters during a specified operating condition. For instance, the superheat outlet temperature shall not deviate from setpoint by more than 10 degrees during random load regulation at load rates of up to 2% of full load per minute.

4.3 Collecting documentation

It is very important to collect as much documentation about the control system being assessed as possible. This can be a daunting task at some plants. In particular, up-to-date configuration or logic drawings are vital. On digital control systems it is very easy to make a software change as a test and forget to document it after it becomes permanent. Here is a list of typical documents that will be needed to perform a thorough assessment.

1. Functional diagrams
2. Configuration or wiring drawings
3. Logic diagrams
4. Input/output list
5. Control block instructions
6. Input or output signal conditioning hardware
7. Electric drive unit or power switch instructions

One good thing about digital systems is that the actual control program can be checked fairly easily to confirm that the drawings are correct. On older analog systems, it can be almost impossible to verify the drawings are right. It is surprising how often there are undocumented changes in a control system that no one at the plant remembers, and yet the changes have an impact on the control system performance.

4.4 Understand the process being controlled

While this report is not intended to be a tutorial on power plant processes, there are several important details that need to be presented. Some of these are dynamic differences among similar processes, while others are unusual processes specific to power plants. Regardless, without a proper understanding of the actual process being controlled, the assessor will never be able to properly assess the control system. The following sections describe some of the more unusual or confusing processes encountered in power plants.

4.4.1 Ball Tube Mills

The dynamic response of the coal flow out of all types of coal pulverizers is similar, with the exception of ball tube mills. Ball tube mills are large rotating drums partially filled with small steel balls. The axis of rotation is horizontal, and coal and air are supplied to each end of the drum. As the drum rotates, the steel balls tumble and crush the coal. From a dynamic response standpoint what is different about this type of mill is the large inventory of crushed coal in the mill during normal operation. The coal flow out of the mill can be changed in a matter of seconds simply by adjusting the airflow through the mill. As the inventory of coal is reduced, the coal feeders are used to supply more coal to the mill. This is much different than the control philosophy of vertical spindle pulverizers, in which the outlet coal flow is directly controlled by the coal feeders. In dynamic terms, the outlet coal flow response characteristics of a ball tube mill are a few seconds of deadtime followed by a 20-30 second first order lag. A typical vertical spindle pulverizer has 30-60 seconds of deadtime followed by another 60-90 second first order lag. Units with ball tube mills respond much more like gas-fired units than like other coal fired units.

There is another type of vertical spindle pulverizer called a ball and race mill. This is sometimes shortened to ball mill, which is often confused with ball tube mill. Be sure to correctly identify the type of mills on the unit so that the proper type of response is expected.

4.4.2 Throttle pressure and megawatt control interaction

One of the most important and visible control loops is the throttle pressure control. Most operators are trained to keep a close eye on throttle pressure during load changes to ensure it does not deviate too far from setpoint. Megawatt control is not watched nearly as closely. The two loops are closely coupled in that making the megawatt loop respond faster causes larger throttle pressure deviations. Since it is often difficult to make throttle pressure response as good as desired, one way to help the situation is to slow down the megawatt control. The unit will still respond to load changes, but just not as quickly. This is not necessarily a bad thing to do, but the assessor should be aware that it could be done. If throttle pressure response seems better than expected, it may be time to check the megawatt response closely.

4.4.3 Drum level response

Many people think a boiler drum is just a big horizontal cylinder half full of water and half full of steam. Unfortunately it is a little more complicated than this. There are a variety of devices inside the drum to help the drum do its primary job of separating the steam from the water in the fluid leaving the waterwalls. Another device in the drum is a header to distribute the incoming feedwater more evenly along the length of the drum. The exact design of this header can have an effect on the dynamic response of the drum level to changes in feedwater flow. For certain drums, the introduction of new relatively cool feedwater will cause some of the steam in the drum and waterwalls to condense. This causes a temporary reduction in the volume in the drum and the drum level decreases. As more feedwater is added, the volume begins to increase again and the drum level begins to rise as would be expected. This type of response is called an inverse response and is difficult to control, because the initial feedback is in the wrong direction. A drum that exhibits this type of response will certainly have less precise level control than a drum that responds as expected.

4.4.4 Superheat and Reheat Temperature Control Mechanisms

There are two control mechanisms that apply to the boiler main steam and reheat temperature controls: (1) fire side control mechanisms which control the distribution of heat within the furnace; and (2) water side control mechanisms where pure water is sprayed into the superheated steam and is vaporized.

There are six methods for changing the heat distribution within the furnace that are commonly used in various combinations according to the design provided by the boiler manufacturer. Only the first three of these are automatically regulated by the control system.

1. Tilting nozzles – tilting nozzles change the direction of flame within the furnace. Raising the tilting nozzles increases superheat temperature and reheat temperature; conversely, lowering the tilting nozzles reduces superheat temperature and reheat temperature.
2. Superheat/reheat pass dampers – pass dampers control the amount of flue gas passing the superheater or reheater. Increasing the flue gas mass flow across the superheater or reheater will increase the steam temperature. Superheat and reheat pass dampers are normally controlled in a sequence where at one end of the controller's range the superheat pass damper is at its minimum and the reheat pass damper is wide open and at the other end of the controller's range the situation is reversed. In the middle of the range, both dampers are wide open.
3. Flue gas recirculation – flue gas recirculation increases the amount of flue gas mass flow in contact with the superheater and reheater, increasing the steam temperature.
4. Burners in service – putting burners at the upper elevations in service moves the flame to a higher level in the furnace and will increase superheat temperature and reheat temperature. Increasing the quantity of burners will increase both superheat and reheat temperatures.
5. Excess air – increasing excess air increases the amount of flue gas mass across the superheater/reheater for a given steam flow, hence it increases temperature.
6. Boiler cleanliness – As a boiler becomes fouled from continued operation, a higher gas temperature will occur across the superheater for a given steam flow, resulting in higher steam temperature. The advent of model-based controls as part of an intelligent sootblowing control package allows the management of boiler cleanliness to be part of the boiler heat distribution control strategy.

There is one mechanism for waterside temperature control. Spray attemperators inject pure water into the superheated steam that is then vaporized. The temperature of steam is reduced by the heat of vaporization of the water. Only for the drum-type boilers will desuperheating spray provide a sustained change in the steam temperature.

There are special temperature control considerations for variable pressure operation. During a pressure ramp, uncontrolled steam temperature will tend to increase about 20 degreesF (11 degrees C) during the first five minutes of the ramp followed by a drop in temperature of about 50 degrees F (28 degrees C.) This change is due to the change in fluid enthalpy as pressure in increased. Special feedforward compensation circuits are required to deal with this process non-linearity (usually using rate of change of throttle pressure set point and drum pressure).

Special temperature control considerations for once through boilers. With once-through boilers, the final steam temperatures are determined by the amount of firing rate in relation to the amount of feedwater being pumped to the boiler. Spray flow provides only a temporary change to final steam temperatures. Hence an integrated strategy to coordinate the spray attemperator controls with the firing rate/feedwater ratio controls is required.

4.5 Understanding the Control System Hierarchy

Boiler control systems are very hierarchical in their design, and it is important to understand the hierarchy to understand the control system tuning. At the top level of the hierarchy is the unit master control and at the bottom level are the base regulatory control loops and their actuators. A few loops are independent of the hierarchy and so they have no impact on the tuning of other loops. When tuning the control system it is important to start at the bottom of the hierarchy and work your way up. Achieving high control system performance is a highly structured process and if not done in the correct sequence will ultimately fail. Figure 4-1 shows the control system hierarchy for a typical boiler control system.

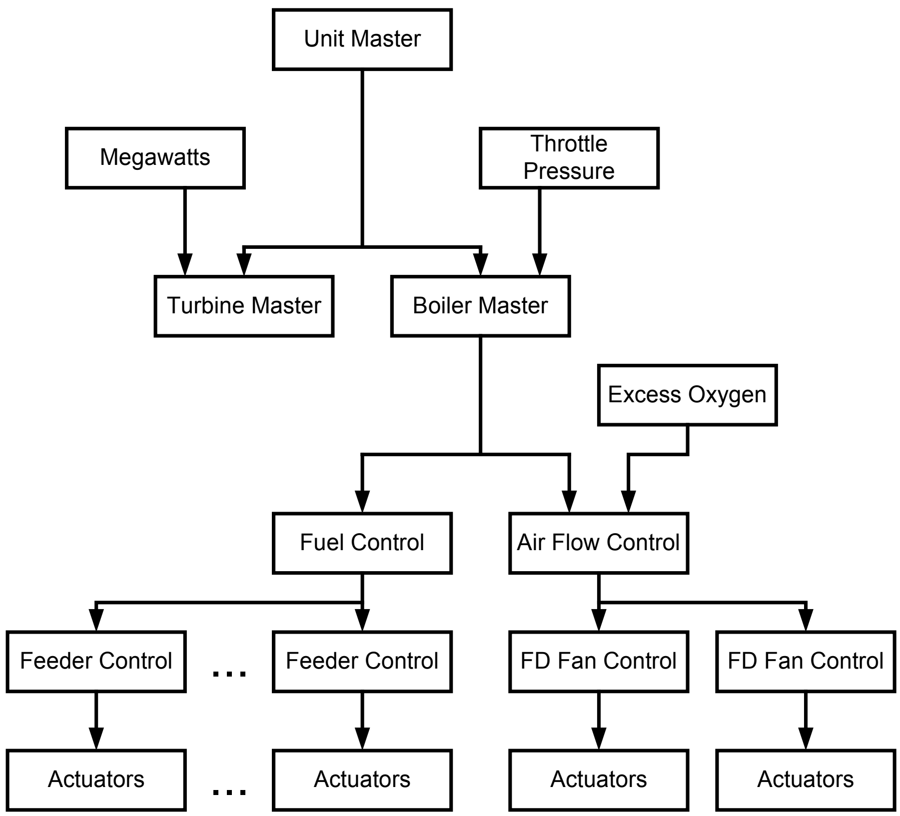


Figure 4-1
Typical boiler control system hierarchy

4.6 Manual mode as a diagnostic tool

One of the most useful ways of diagnosing control system problems is the selectively place control loops in manual mode. This disconnects the control system from the process and allows the process to respond without external excitation. Because of the coupled nature of boiler control systems, when one control loop is oscillating, it is probably causing several others to oscillate at the same time. It is almost impossible to identify the initiating loop when this happens. By placing various loops in manual mode and observing whether the oscillation increases or decreases, one can isolate the source of the problem. When placing loops in manual, it is best to start at the top of the control system hierarchy and work downward until the oscillations stop. As an example, suppose the throttle pressure, superheat temperature and drum level each have a sustained oscillation. Starting at the top of the hierarchy, place the throttle pressure in manual mode and see if the oscillations stop or decrease significantly. If not, leave the throttle pressure in manual and place the superheat sprays in manual mode. Again observe the response. If it is still oscillating, place the drum level in manual mode. Continue working down the hierarchy until you reach the bottom. If the system is still oscillating when everything above it is in manual mode, then there is an uncontrolled disturbance driving the oscillations. This can happen, but it is quite rare. Usually switching a loop to manual mode will provide quick insight into control system and process problems.

4.7 Recognizing saturation and hysteresis

When assessing control system tuning, it is common to see small oscillations in the controlled variable when the controls are not properly tuned. Normally these oscillations are smooth sine type waveforms. However, occasionally the oscillations will look more like square waves or trapezoidal waves. Whenever this type of waveform appears it is an indication of a non-linearity in the system somewhere. Remember that all real systems are non-linear but many are only slightly non-linear. When a square wave appears the system is highly non-linear. The two most likely types of non-linearity are saturation and hysteresis.

Saturation is another way of saying that part of the system has hit a limit such as a controller output reaching 100% or a valve actuator going closed. If saturation is present in the system, the sine wave will only be flattened on the top (as shown in Figure 4-2) or the bottom, but not on both. If the saturation is caused by a final drive actuator reaching a limit, it should be very easy to detect. But many times the limit that is being reached is in the control logic and it is not so obvious. Sometimes it is necessary to trace the signals step-by-step through the control system to find the culprit. Building a screen trend with the appropriate points is another good way to spot the problem.

The other common non-linearities are hysteresis and deadband. Technically these are not the same thing, but in practice they exhibit the same symptoms. Hysteresis is usually caused by actuators or field devices. Sticky valve actuators and worn or loose linkage are fairly common causes. Improper adjustment of the deadband for electric actuator power switches is also not unusual. The source can also be from inside the control logic from any function that has a built-in deadband. PID controllers with a gap function on the error signal, function generators with a flat spot, and exception reporting functions with too large a deadband are all possible sources. Hysteresis or deadband will generally cause the sine wave to be flattened on the top and the bottom, unlike the saturation shown in Figure 4-2. Just remember the key point is if you see a square wave type of response, there is a significant non-linearity in the system somewhere and it probably shouldn't be there.

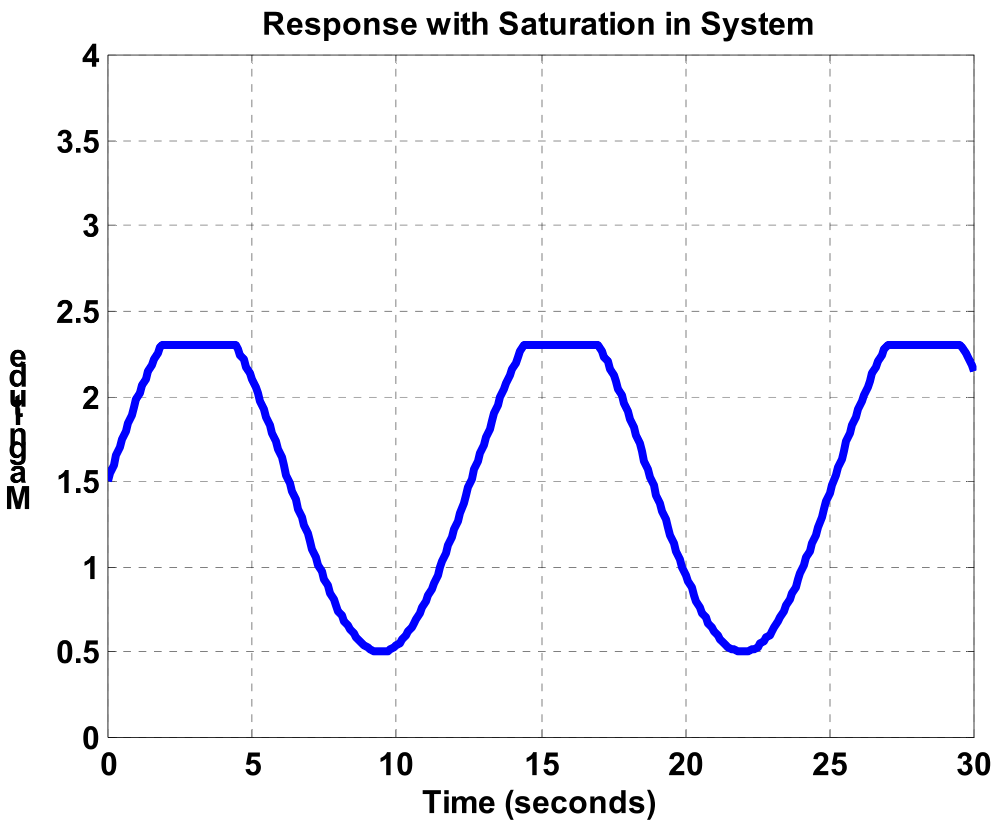


Figure 4-2
Response of a system with saturation present

4.8 Personnel interviews

It is always a good idea to talk with the people at the plant whom are closest to the control system being assessed. This would usually include the engineers or technicians who maintain the system and the operators who use the system. The Operations manager can often provide a better big picture view of the control system performance as it relates to overall plant performance. The interviewees may not be very good at diagnosing problems, but they are usually very good at knowing when there is a problem. Personnel interviews, preferably one-on-one, can point the assessor in the right direction to more quickly find important problems.

4.9 Effectively using the plant data archive system

All modern digital control systems have some type of data archive as a standard part of the system. Some plants have more sophisticated data archiving systems from third party vendors. Regardless of what type of system the plant being assessed has, it is the assessor's best friend. Only if you have been doing control system tuning work for more than twenty years can you appreciate how wonderful modern data archive systems are. But although they have tremendous capabilities, those capabilities are often not fully utilized. Most archive systems must be configured by the user and it can be a laborious job, so much so that it often is not done correctly. Most systems are set up by the vendor using some typical default settings that are fine for plant operation, but not adequate for engineering analysis.

4.9.1 Save the important points

The first step to effectively using the archive system is to make sure the proper points are being archived. On almost every system the key controlled variables are archived, so that is usually not a problem. However, there are several other important variables that are not usually archived by default. Tops on this list is the loop error signal. This is almost never archived, but it is the best signal to use for tuning assessment. Many people only look at the controlled variable, but when the loop is part of a cascade system where the setpoint is always changing, the controlled variable doesn't show the whole story. The error signal is much better. On some systems it takes a little effort to figure out how to archive the loop error signal but it generally can be done. Take the time at the start of the job to do it.

Other important signals to record include the loop output signal to the actuator and the position feedback signal from the actuator. Not all actuators have position feedback available, but if they do, make sure it is being archived. Another important point that is rarely saved is the PID controller output. If this signal is the same as the loop output to the actuator there is no need to save both. But often there is logic or a feedforward signal between the controller output and the loop output, so in those cases save the PID output also. If the controlled variable is not a direct analog input to the DCS, make sure it is archived. Sometimes only the actual inputs to the system are archived by default. This includes signals such as pressure compensated drum level, flow measurements made with differential pressure transducers and selected signals such as averages or medians. Any feedforward signals should also be recorded.

4.9.2 Configure the data compression

Besides selecting the proper points for archiving, you also need to define the archive parameters such as deadband, sample rate and duration. Most archive systems use some type of data compression before saving the data. One simple type of system only saves data if it has changed by more than a predefined deadband and only if it has not been saved during the previous defined sample time. Other systems are more sophisticated but still have parameters that define the compression rules. By default many archive systems are initially setup with a 1% of range deadband on most points. This is much too large a deadband for control tuning work. A deadband of 0.25% to 0.10% of range is much better for tuning work. It also can depend on how the range of the point is defined. Many steam temperatures have a range of 0-1200 degF (-18 to 649 degC), so 0.25% of that range is 3 degF (1.7 degC). Obviously this is still too much for serious tuning work. Also make sure that you know on what basis the deadband is computed. Some systems use engineering units and others use percent of range.

The scan rate for saving the data should also be checked. Often the default is once per minute which is clearly not fast enough. The proper scan rate depends and the speed of the loop being analyzed. The fastest loops such as feedwater flow and furnace pressure require a scan rate of a second or two. Slow loops like steam temperature control can use a slower scan rate such as 10-15 seconds. It is well worth the time at the beginning to investigate this thoroughly to be sure the data you need is being saved correctly.

4.9.3 Export the Data

One final point about the archive system is to determine how to export the data in a standard format for future analysis and plotting. On almost every system there is a utility function for exporting the data in a text based format, but finding the documentation may not be easy. Again persistence pays off. Many external PC applications such as Excel or MATLAB have better analysis and plotting capabilities than DCS trending software, so it is useful to be able to export the data.

5
ASSESSMENT TESTS

There are a variety of tests that can be performed on the control system to help assess its tuning. Many of these tests are not really tuning tests, but instead test the process to better understand the tuning. Some of the tests are performed on a single loop at a time, while others are performed on the control system as a whole. The particular tests that must be performed for an assessment depend on the scope and objectives of the assessment as described in Section 1. This section will provide a general description of the types and purposes of tests, and the next section will describe how to use the tests to evaluate specific loop performance.

5.1 Individual Loop Tests

The individual loop tests consist of open loop step response, closed loop step response and closed loop disturbance rejection. In some simple loops the closed loop step response and disturbance rejection tests will be redundant and only one must be performed. But in most loops there will be a difference between the two responses, so both will have to be checked.

5.1.1 Open Loop Step Response

The open loop step response test is designed to quantify the process response of a single loop. Open loop means that the controller is in manual mode during the test. The operator introduces a sudden small step (2-5%) into the actuator position, and the test continues until the process variable of interest reaches a new steady state value. It is always a good idea to step the system back to its original starting position to check for hysteresis effects. Placing the controller in manual for this test isolates the control system from the process and allows the response of the process itself to be examined.

There are several aspects of the process that can be learned from this test. First the basic characteristics of the process such as the gain and time constant are quantified as described in Section 2. Remember that for this test the process includes the final control actuator. The response data can be compared against a reference set of data to see if the process has changed its response. If no reference data is available, it can be compared against typical data for reasonableness. Section 6 will discuss typical open loop responses for various boiler control loops. If the loop response is abnormal, it means something is probably wrong with the process and not with the control system.

If the loop has considerable hysteresis in its response, the most likely cause is a problem with the actuator or its linkage. If the actuator is electric, the position controller may have too large a deadband configured. Another common problem is loose or worn linkage pieces. Often actuator problems can be identified simply be observing the actuator movement during the test.

By doing the test at minimum and maximum loads, the consistency of the loop's response over the load range can be checked. It is common for a loop's response to vary both its gain and speed over the load range. This is the root of many tuning problems, because normally only a single set of tuning parameters are used for the whole load range. If the gain and/or speed vary by 50% or more it can be difficult or impossible to get satisfactory control system performance over the load range with a single set of tuning parameters. These numbers can give an indication of how difficult the loop is to control.

5.1.2 Closed loop step response tests

Closed Loop Step Response testing consists of making small manual step changes to the control loop setpoint (in the range of 5% as approved by plant operations) with the associated control loop on automatic. The control response is observed. This test is used to assess control loop tuning. Loop tests should be performed at minimum, mid load range and maximum load to determine any requirements for variable tuning and or process linearization as a function of load. If variable tuning and/or linearization algorithms are not available, the slowest tuning adjustments will have to be accepted for all operating ranges.

5.1.3 Closed loop disturbance rejection tests

The closed loop disturbance rejection testing is generally the best test for assessing individual loop tuning. The only difficulty is trying to duplicate the same disturbance for repeated tests. The test is performed by making a small step change to the final actuator position (in the range of 5% as approved by plant operations) with the associated control loop on manual. After waiting about 10-30 seconds the control loop is returned to automatic and allowed to settle out. Since the loop setpoint has not changed, the process variable should return to its initial value. This procedure assumes that the setpoint is not configured to track the process variable while the loop is in manual. The speed of the response and the stability of the response can be easily assessed from this test. Step changes should be made in both directions at varying loads to determine if the loop tuning remains the same for all unit load levels.

5.2 Complete System Tests

The first element in performing assessment tests is the establishment of acceptable performance criteria for main steam pressure, superheat and reheat temperatures, drum level, deaerator storage tank level, furnace pressure, excess air, megawatts controls as well as any of the miscellaneous single loop controls that are to be considered in the performance assessment. There are five assessment criteria that need to be established before undertaking any assessment tests. They include:

1. The maximum allowable deviation of process variable from set point under steady load
2. The maximum allowable deviation of process variable from set point under load ramping conditions
3. The load ramping conditions to be tested including the load ramp rates to be tested and the load levels from which the load ramps are initiated
4. The maximum allowable time period to reach steady state condition after a load ramp or a process upset including the number of cycles for the process to stabilize – process stabilization is defined in terms of the number of overshoots (typically one overshoot of 10%) of the final control element(s) position
5. The maximum allowable deviation for the steady state condition of the control loop.

5.2.1 Load Ramp Tests

The next level for assessment testing is the operation of the control under load ramping conditions (load changes). This testing is required for all control loops that must perform under changing load conditions, including unit mw control, throttle pressure control, final main steam and reheat steam temperature controls, drum level, furnace pressure, deaerator level and related boiler input controls fuel, air and feedwater. This tests the dynamic performance of the control system under changing load conditions. It should be done (operating conditions permitting) to and from minimum load on which full automatic control can be sustained, to and from mid load range, and to and from maximum load under varying rates of change from 1% per minute to 5% per minute.

5.2.2 Disturbance rejection tests

Upon completion of the load ramp tests, disturbance rejection tests must be performed on the same loops as tested for load ramping. Specifically the unit mw control, throttle pressure control, final main steam and reheat steam temperature controls, drum level, furnace pressure, deaerator level and the related boiler inputs, fuel, air and feed water must be evaluated.

This testing may include a test for loss of an auxiliary while remaining auxiliaries have sufficient capacity to maintain the boiler at its current operating level such as: the start/stop (trip) fan; the start/stop (trip) pump; the start/stop (trip) pulverizer. Additional disturbance rejection testing might include a load rejection test, – cut back to house load, any soot blowing or other disturbances as defined by the scope of the assessment. The range of the point is defined. Many steam temperatures have a range of 0-1200 degF (-18 to 649 degC) so 0.25% of that range is 3 degF (1.7 degC).

A final stage of assessment testing includes the testing of runbacks and rundowns. This testing encompasses the same loops as previously tested for load ramping. The runback occurs when an auxiliary is lost and the remaining auxiliaries have insufficient capacity to maintain the current unit load. Unit runback controls reduce unit loading until the unit operates within the range of the limited auxiliaries. Runbacks are typically provided for loss of FD, ID, PA fans (central PA fans), boiler feed and condensate pumps. Independently adjustable rates are typically provided for each loss. The runback tests verify the setting of the proper limits and runback rates for the loss of any of the specified auxiliaries.

Rundowns occur when the unit is ramped up beyond the limit that can be carried by the current feedwater, fuel and air regulating equipment auxiliaries. The coordinated controls first block the unit from further increase, which would aggravate the limiting operating condition. If the limiting condition persists, the rundown controls will reduce the unit load until a sustained load can be maintained with the remaining auxiliaries in service. This testing is accomplished by ramping the unit beyond the load level that can be sustained by the auxiliaries in service. The rundown controls will then reduce the unit operation to the level that can be sustained by the auxiliaries in service.

6
LOOP SPECIFIC ASSESSMENTS

Now that the general approach to tuning assessment has been discussed (Section 4) and the various assessment tests have been described (Section 5), it is time to get down to specific control loops. This section will provide specific guidance for assessing many of the control loops in a typical boiler control system. Often there are simple tricks or shortcuts that can make the assessment process much easier. In addition, typical process characteristics will be discussed to help isolate process problems from control tuning problems.

6.1 Feedwater Flow/Drum Level Control

Drum level control is almost always done by what is called a three-element control strategy. Three-element control gets its name because it uses three measurements to achieve the control. It is a cascade control with feedforward strategy and uses drum level, feedwater flow and steam flow. When assessing the tuning of the drum level control there are several common areas where problems arise.

6.1.1 Steam Flow/Feedwater Flow Alignment

If the drum level tends to drift away from setpoint during load changes and then slowly returns to setpoint at steady load the problem may be inaccurate alignment of the steam flow and feedwater flow signals. The main concept behind the three element control strategy is to control the feedwater flow into the drum to be equal to the steam flow leaving the drum. If this is done well, it will take care of about 95% of the control needs of the loop. The remaining 5% of the control comes from the drum level controller which provides a trim action to the feedwater flow setpoint. Since matching the steam flow to feedwater flow handles most of the control action, it is very important that the two flow signals are scaled to be equal. Often times the steam flow and feedwater flow measurements do not agree exactly, due to measurement errors and unaccounted for flows. This doesn't matter as long as they are scaled equivalently within the drum level control system. Generally it is adequate to scale them to agree at the normal full load of the unit. Any difference between the signals will have to be corrected by the drum level controller, which responds more slowly than the flow controllers. This will often appear as a deviation during the load change followed by a relatively slow return to setpoint after the load change ends.

6.1.2 Shrink/Swell Effects

If the drum level response exhibits a sudden increase at the beginning of a load increase or a sudden decrease at the start of a load decrease, it may be caused by a shrink/swell effect. Normally during a load increase, the steam pressure will drop slightly. As the steam pressure in the drum drops, there is a swell effect on the drum level due to some of the saturated liquid in the waterwalls flashing into steam and increasing in volume tremendously. Also during a load increase the steam flow will increase immediately when the turbine valves start to open. If the feedwater flow increases along with the steam flow, while the drum level is already swelling, it can make the drum level deviation worse. To alleviate this problem, the steam flow signal should be lagged by about 30 seconds to delay the feedwater flow increase slightly. This allows the transient swell effect to die out before more feedwater flow is added to the drum. Not all drums will have this response due to differences in the way feedwater is introduced into the drum, as discussed in Section 2.

6.1.3 Instability at low loads

If the feedwater flow control is good at high loads but oscillatory at low loads, the problem may be the shape of the boiler feedpump head-flow curve. Centrifugal pump head-flow curves are generally flatter at low flow rates than at high flow rates. This effectively changes the gain of the feedwater flow process.

It is typical for control loops to be tuned at full load but not checked much at low loads. If the feedwater flow process has a higher gain at low loads, the flow controller will need a lower gain to achieve a similar response. With older analog control systems, it was not practical to change controller gains as a function of load, so the tuning had to be compromised between high load and low load. With digital control systems it is quite easy to schedule gain changes as a function of another variable in the system, such as feedwater flow or unit load. However it still requires additional work and often is not done. If the control tuning at high load does not provide adequate stability margins, then the response at low loads can be unsatisfactory. The fix is to either change the tuning at high load to have more stability margin or add a gain scheduling function to the PID tuning to reduce the gain at low loads.

6.1.4 Instability during pump addition

It is normal on feedwater pumping systems to have two or more pumps in parallel for reliability and efficiency reasons. At low loads only one pump is operated, while at full load two are in service. This means that the second pump must be started during a load change from minimum to maximum. Starting the second pump and bringing it into service often causes a large disturbance in feedwater flow. There are two common problems that can cause this disturbance. The first only occurs when variable speed feedpumps are used. A variable speed pump, whether motor driven or turbine driven, usually starts at a very low speed. At startup, the pump discharge pressure is very low, while the pressure in the feedwater header is typically near the normal boiler operating pressure. Under these conditions, there will be no flow from the second pump into the boiler. As the control system or the operator increases the speed on the second pump, its discharge pressure will increase until eventually the discharge pressure will be greater than the feedwater header pressure. At this point the pump will start contributing flow to the boiler. The problem with this is that it is very hard to predict the exact point where the flow will begin, and once it begins there is a lot of flow. If the feedwater flow loop is well-tuned, the upset can be minimized.

The other possible issue when starting a feedpump is interaction with the minimum flow recirculation controls. A centrifugal pump needs a certain amount of flow through it at all times to prevent overheating. When the pump is running but there is no flow to the feedwater header, a recirculation line is provided to allow flow through the pump. A control valve is used in the recirculation line to stop the recirculation flow when the flow to the header is sufficient. The control for the recirculation valve can be either on/off or modulating. When the recirculation valve closes, it affects the flow to the header. It is not uncommon for interactions to occur between the feedwater flow control and the recirculation control that cause significant flow swings. Sometimes these swings will persist until the flow through the second pump is well above the minimum flow requirement. By making the travel speed of the recirculation valve slower than the response time of the feedwater flow control loop, the interaction will be minimized.

6.2 Furnace Pressure Control

Furnace pressure control almost always uses induced draft fans to regulate the flue gas pressure in the combustion region of the furnace. The two most common problems with furnace pressure control are noisy measurement and improper feedforward action from the forced draft fans.

Furnace pressure is a very fast responding loop, with a response time of a couple of seconds. The fast response is somewhat of a double-edged sword in that it makes the control tuning fairly easy, but it also means that disturbances can upset the pressure very quickly. The pressure measurement is also very noisy due to the turbulence of the combustion process and the relatively narrow measurement range. The noise on the measurement signal will propagate through the control system to the ID fan actuators and cause excessive wear unless it is properly filtered. The pressure transmitter will generally have a simple adjustable filter built into it that can be used to reduce the noise somewhat. The problem with this type of filter is that if the time constant is set longer than a couple of seconds, it will slow down the response of the whole loop too much. To avoid this problem it is better to use a gap or deadzone function on the pressure error signal before it reaches the controller. On digital control systems this type of function is very easy to implement and is often a pre-programmed option. On older analog control systems a special hardware circuit was developed for this function. A deadzone filter is based on amplitude, not time, so it doesn't slow down the loop response. For a typical furnace pressure loop with a setpoint of -0.5" (1.3 cm) of water, the deadzone will usually be about +/- 0.2" (0.5 cm) but this will obviously depend on the noise magnitude.

Although the ID fans are generally used to control the furnace pressure, the FD fans have a similar influence on the furnace pressure. So during load changes, when the FD fans change their output, it tends to upset the furnace pressure. Since this upset is very predictable, it can be used as a feedforward to the ID fan controls very effectively. The only trick is to select the correct signal and then scale it appropriately. It is better to use the FD fan demand signal or the actuator position feedback signal as the feedforward rather than the air flow signal. Air flow should not be used, because ID fans can affect the air flow and this can lead to a positive feedback situation. If two FD fans are used, the individual demand signals should be summed to develop the feedforward signal. The signal should be scaled so that the feedforward moves the ID fan controls about 50-75% of the total amount required for a given FD fan change. Some people set the feedforward effect at 100%, but that generally leads to overshoot in the ID fan response.

6.3 Throttle Pressure and Megawatt Control on Drum-type Units

The throttle pressure and megawatt control is at the highest level in the control system hierarchy. It is also called the Unit Master or the Front End of the system. When a problem arises in this part of the control system the cause could be here or anywhere below it. Testing or diagnostic work should be done on the lower level loops before trying to assess this area of the control system. There are many different control strategies for the front end, so the suggestions offered here may not apply to all strategies. The throttle pressure and megawatt systems are controlled by manipulating the turbine valve position and the boiler firing rate. It is common to set up the strategy so that the turbine valve provides most of the control for megawatts and the firing rate provides most of the control for the throttle pressure. But most systems have additional modes that provide the opposite effects. And some systems split the control effort evenly between both systems. For the rest of this discussion, it will be assumed that the first scheme described above is being used.

Turbine valves can move very quickly and the megawatt response is quite fast, typically from 5 to 15 seconds time constant. This means that if turbine valve are assigned to control megawatts, the loop response will be very fast. Boiler pressure response is not nearly as fast. Coal fired boilers in particular (except those with ball tube mills) are very slow, due partly to the pulverizer response and partly to the boiler heat transfer response. Oil and gas fired boilers are quite a bit faster, because the fuel delivery system is very fast compared to a pulverizer, but the boiler response is about the same. A typical coal fired boiler pressure response time is about 60 seconds of deadtime followed by about a 90-300 second time constant. An oil or gas fired boiler will have about 10-20 seconds of deadtime followed by a 60-200 second time constant. If the firing rate is being used to control throttle pressure the response will be quite slow.

6.4 Superheat temperature control with sprays

Superheat steam temperature control using spray flow is almost always done with a cascade control scheme. The final superheat outlet temperature is the primary control variable and the desuperheater outlet temperature is the secondary control variable. The final outlet temperature response is very slow with a typical 30-60 second deadtime followed by another 60-120 second time constant. The desuperheater outlet temperature response is very fast, typically almost no deadtime and a 20-30 second time constant.

An important point to remember about all steam temperature controls is that they can be disturbed by almost every other system in the boiler including fuel, air and feedwater. So when there are problems with steam temperature response, try to isolate the effects of other loops before assuming the steam temperature tuning is incorrect. Often the effects of other loops can be eliminated by placing the suspected loop in manual mode and seeing if the disturbance disappears.

The tuning of the secondary loop is very easy and should provide about 20% overshoot in response to a step input. The primary loop can be very difficult to tune due to the usually long dead time. Typically the proportional control mode will do most of the work with the integral mode being very slow. Derivative mode can help in many cases. Steam temperature response is slower at low load than high load, so always check the response at low load, as that will be the worst case.

Evaluating whether the best feedforward signal is being used for the loop is fairly tricky. Many systems use steam flow as a default feedforward but that may not be the best choice. Each boiler is different, and the only way to properly select the feedforward signal is by doing open loop step response tests for all of the potential signals. These include steam flow, airflow, fuel flow, and drum pressure. If a step change in the feedforward signal doesn’t cause a noticeable response in the steam temperature, then it is not a good signal. It is beyond the scope of this report to go into more details of feedforward control design.

6.5 Reheat temperature control on tangentially fired boilers

Tilting burners are the standard method for reheat temperature control on tangentially fired boilers. In addition, reheat spray controls are also provided for situations where the tilting burners are not enough. Both of these loops are quite slow responding, with deadtimes of around 30 seconds and time constants of 60-120 seconds. These two control loops are fairly straight forward with two exceptions.

The first common problem arises from the fact the both loops have integral control and are trying to control the same temperature. If both had the same setpoint, the two integral modes would be fighting each other until one was driven to a limit. To avoid this, the setpoint for the spray controls is biased about 5 degrees above the setpoint for the tilt controls. The spray control setpoint is biased instead of the tilt control setpoint, because there is a sizable heat rate penalty for using reheat spray, so it is preferable to control the temperature with the tilts if possible. In this way the two controllers don't compete. Sometimes logic is employed to remove the bias gradually as the tilt controls reach their lower limit. This way if the tilt controls are out of range, the spray controls will still control to the real desired setpoint, instead of 5 degrees above it.

The second problem is interaction with the superheat spray controls. Moving the burner tilts up or down affects both superheat and reheat temperatures similarly. But the superheat sprays can counteract the effect of the tilts without any significant heat rate penalty. The superheat spray controls need a feedforward from the tilt position to minimize disturbances when the tilts are moving to control reheat temperature. If this feedforward is not used or is not scaled properly, the tilts will upset the superheat temperature unnecessarily.

6.6 Reheat temperature control with pass dampers

Pass dampers regulate flue gas flow over superheater and reheater convective surfaces in the boiler and thereby control steam temperatures. The dampers are designed so they never completely shut off the gas flow over either section. The response time for superheat and reheat are similar to the burner tilt response times listed above. There is generally one controller for both dampers, with each damper having a function generator to specify its position curve. When the controller output is 0%, one damper is at a minimum and the other is at a maximum position. When the controller output is 100% the situation is reversed. Even though the dampers are used primarily for reheat temperature control, they affect the superheat temperature as well, just like the burner tilts. Unlike the burner tilts, the effect on superheat temperature is in the opposite direction to the effect on reheat temperature. Because the dampers affect both steam temperatures, there is a need for a feedforward from the pass damper positions to the superheat spray controls. The effect of damper position on superheat temperature is quite nonlinear, so a function generator will be necessary on the feedforward signal.

6.7 Control tuning hierarchy

The following is a step-by-step procedure to be used either for boiler control loop performance assessment or for control tuning itself. Essential in initiating any performance assessment is the determination of the lowest level in the boiler control tuning hierarchy where a tuning problem exists. Once this determination is made, the sequence of assessment/tuning may proceed up the tuning hierarchy. The main elements of the assessment/tuning hierarchy are as follows:

First, verify that there are no problems with any of the field inputs or outputs. This includes the following activities: verification of field input/output wiring; verification/calibration of sensor input signals – zero and span; verification of software scaling (if system is digital); verification of grounding of shield for analog input according to manufacturers recommendations; verification of thermocouple wiring through junction boxes (if supplied) to assure continuity and polarity of extension lead wire; verification of mechanical seating of thermocouple in bottom of well; verification of routing of tubing for pressure and differential pressure transmitters. For water and steam applications the transmitter should be located physically below the process pressure taps. For air and gas applications the transmitter should be located physically above the process pressure taps. Finally, verify the system calibration for water leg compensation is correct and performed only once.

Second, verify that there are no problems/changes in actuator performance. This must be accomplished for all modulating drive unit/end element/actuators to establish remote manual control from control room. The procedure varies slightly depending on whether the actuators are electric or pneumatic.

For the electric actuator, the procedure is as follows

1. Disconnect linkage/coupling before energizing drive
2. Stroke actuator to verify power switch operation in both directions
3. Check limit switch settings for control drive travel limits
4. Reconnect linkage/coupling and jog drive in both directions to its travel limits
5. Set drive unit limit switches at the desired damper/end element travel limits
6. Tune drive unit position control loop so drive can be positioned within 0.25% of full travel. Position control should be able to move the drive unit in increments of 0.1% over the entire range of drive modulation and against all varying drive loading conditions.

For the pneumatic actuator, the procedure is as follows:

1. Disconnect linkage/coupling before energizing drive
2. Stroke actuator to verify I/P converter and positioner operation in both directions
3. Check limit switch settings for control drive travel limits
4. Reconnect linkage/coupling and jog drive in both directions to its travel limits
5. Set drive unit limit switches at the desired damper/end element travel limits; and (6) tune drive unit position control loop so drive can be positioned within 0.25% of full travel. Position control should be able to move the drive unit in increments of 0.1% over the entire range of drive modulation and against all varying drive loading conditions.

Third, verify the linkage arrangement (with drive crank, connecting link and driven crank if provided). This includes:

1. Checking the linkage alignment at full close and full open to provide full drive unit travel for the full effective control range of the driven damper/end element

2. Checking linkage pins for mechanical wear; there must be no play or lost motion in the linkage joints
3. Checking linearity between control system output signal and the parameter being regulated by the drive unit.

Once all field inputs and outputs are verified to be correct and all control drive unit/end element/actuator performance has been evaluated and corrected as necessary to meet minimum positioning resolution requirements, individual loop assessment/tuning can proceed. The simplest control loops are the single loop controls. Since the single loop controls are independent from one another, the order is not critical here. Verify that all single control loops are performing to specification.

The following is a partial listing of typical single loop controls to which assessment/tuning in accordance with the established performance criteria applies:

- Air heater temperature controls
- Lube oil temperature controls
- Hydrogen temperature controls
- Cooling water temperature controls
- Modulating boiler feed pump recirculation controls
- Modulating condensate pump recirculation controls
- Deaerator Level (if single element)

The control assessment/tuning hierarchy applies to all other control loops that make up the boiler control strategy. The reason for a control/tuning hierarchy is to minimize the interaction between control loops being assessed or tuned. The coordinated control of a boiler is a highly interactive multivariable control. Use of an assessment/tuning hierarchy effectively decouples the lower loops from the assessment/tuning strategy as the loop tuning is completed. The rational is that a well-tuned control loop will maintain a process error near to zero, effectively eliminating it from interaction with the higher-level control loops.

Additional single loop controllers that are part of the control assessment/tuning hierarchy to which assessment/tuning in accordance with established performance criteria follows:

- Throttle pressure control by governor (turbine follow mode)
- Mill primary air flow control
- Excess Oxygen Control

A listing of the applicable control loops in the order of the hierarchy is as follows:

1. Furnace pressure control
2. Preliminary system calibration of the coordinated control system
3. Drum level (feedwater) control
4. Throttle pressure control by the turbine governor valves
5. Air flow control
6. Pulverizer primary air flow and temperature controls
7. Primary air fan controls (if centralized primary air fans are provided)

8. Fuel flow control
9. Final system calibration of the coordinated control system
10. Throttle pressure control by boiler inputs
11. Excess oxygen control
12. Superheat temperature controls
13. Reheat temperature controls
14. Megawatt controls
15. Boiler limiting and runback functions.

The next step in the "bottom up" strategy is to identify in the control assessment/tuning hierarchy the lowest control loop where problem performance is observed. This identifies the point at which the assessment/tuning activity can begin. The assessment/tuning work can then proceed on a loop-by-loop basis up the hierarchy until all loops are assessed/tuned.

Many of the control loops in the tuning hierarchy involve multiple actuators, cascaded control strategies, feedforward signals and special signal calibrations. The function of and the assessment/tuning of these special features are described below.

Drive unit (actuator) equalizing control – For multiple drive applications, such as two FD fans in parallel, the relative bias applied to any single drive should be adjustable without upset to the primary control loop. Equalizing control adjustments are provided within the vendor's algorithm for multiple drive applications. Equalizing should be scalable on a per drive basis, so different sized auxiliaries may be handled by the same control function.

Feedforwards – Many multiple drive applications include feedforward signals as part of the control strategy. The feedforward function, when properly adjusted, will move the control drives to the new desired position independent of the integrating action of the loop controller.

Special Signal Calibrations – Many multiple drive applications include the calibration of special signals.

There is also an assessment/tuning order that applies to these multiple drive control loops as follows:

1. Drive unit equalizing control
2. Loop controller
3. Feedforward signals
4. Any special signal calibrations.

The following is a partial listing of typical multiple drive control loops to which the above described levels of assessment/tuning apply:

- Furnace Pressure controls with feedforward from air flow and from MFT
- Boiler (or compartment) secondary air flow (B&W compartmented windbox)
- Air flow control (FD Fans)
- Mill coal-air temperature control
- Primary air fans

- Fuel control – Coal firing with heat release, mill model and scaling of dissimilar fuel measurements for coal and oil.
- Reheat temperature control by heat distribution
- Reheat temperature control by spray

An expanded assessment/tuning order similar to the multiple drive control loop procedure applies to complex control loops that include a cascade control feature. The tuning order is as follows: (1) the drive unit equalizing control; (2) the secondary loop controller (if a cascade control arrangement is provided); (3) the primary loop controller; (4) feedforward signals; and finally (5) any special signal calibrations. The following are a partial listing of typical cascade multiple drive loop controls to which the above-described levels of assessment/tuning apply:

- Three Element Feedwater Control of Drum Level including calibration of process flow demand and lag on steam flow load index
- Superheat Temperature Control of Spray Valves
- Megawatt Control

7 CONCLUSIONS AND RECOMMENDATIONS

Power plant control systems are complex; they are also vital to the successful operation of any unit. Because of their complexity, they are difficult to tune properly. This report describes methods and techniques to assess control loop tuning, which is an important first step before attempting to tune an existing control system. Once a thorough assessment has been performed, the actual tuning can begin with some assurance that the root causes of the poor system response have been identified. Too often tuning is attempted when the real problem is in the process being controlled and not in the control system itself.

By following the techniques outlined in this report, plant engineers and technicians can gain a better understanding of their control system performance and what can be done to improve it. A proper assessment of system performance allows scarce resources to be directed where they are most needed to correct any problems.

This report describes procedures for tuning assessment, but not for the tuning itself. Additional work should be done to prepare a similar report for the tuning procedures themselves. Also, new work should begin on the development and use of automated tuning systems for power plant applications. By applying the rules and procedures of the manual methods, it may be possible to develop sophisticated automated tools for tuning. Future tuning work is planned in the *I&C and Automation for Improved Plant Operation* target in 2003 and 2004.

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