DYNAMIC RESPONSE OF STEAM GENERATORS

by

TERRENCE WAYNE RYAN

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Major Professor

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NOMENCLATURE

S_G	complex electrical power/phase	MVA/phase
P_G	real power/phase for generator	MW/phase
Q_G	reactive power/phase for generator	MVar/phase
$E=E^\circ$	generator exitation voltage	volts
V	terminal voltage	volts
δ	power angle	radians
ϕ	phase angle	radians
X_d	transient reactance, direct axis	p.u.
X_q	transient reactance, qudrature axis	p.u.
V^f	terminal voltage after fault	volts
E'	generator exitation voltage after fault	volts
X_d'	subtransient reactance, direct axis	p.u.
δ°	power angle before fault	radians
H	generator inertia constant	seconds
f°	initial frequency	radians/second
D	rotor damping constant	p.u. MW/hz
P_T	turbine power	MW
ΔP_c	power setting	p.u.
ΔX_E	movement of steam valve	p.u.
R	speed regulation due to governor action	Hz/p.u. MW
ΔF	change in output frequency	hertz
s	complex variable	-

C1	electrical system gain constant	seconds
C2	governor integral gain constant	seconds
C3	governor gain constant	seconds
C4	reheat fraction	dimensionless
C6	combustion control gain constant	seconds
C7	fuel system time delay	seconds
C8	boiler storage gain constant	seconds
C9	combustion control integral gain constant	seconds
C0	combustion control derivative gain constant	seconds
T1	electrical system time constant	seconds
T3	governor time constant	seconds
T4	turbine time constant	seconds
T5	reheat time constant	seconds
T6	combustion control time constant	seconds
T7	combustion control time constant	seconds
T8	fuel system time constant	seconds
T9	thermal inertia time constant	seconds
T0	boiler storage time constant	seconds
Ri	electrical power demand	seconds
Mo	maximum overshoot	p.u.
To	time of maximum overshoot	seconds
Mu	maximum undershoot	p.u.
Tu	time of maximum undershoot	seconds
Ts	time when signal is within 0.05% tolerance level of steady state value	
Ss	steady state value	

CHAPTER I

INTRODUCTION

A modern electric power system is characterized by continual power fluctuations. These fluctuations may either be routine due to normal changes in demand, or large and unexpected, caused by major disturbances such as loss of a generating plant or faulting of a large power line. With the ever increasing complexity of modern power systems, the need for control becomes more important. Use of automatic control enables the power system to reliably meet the public's demand for electric power.

Since electrical systems are becoming more tightly interconnected, all the power plants in a given network aid in returning disturbed systems back to steady state conditions. Conversely, these large networks are subject to the possibility of disturbances pulling them down and out of service, as in the New England blackout of 1965. For this reason the electric power industry has been improving its understanding of system responses due to major disturbances and the ways of decreasing or controlling their effects. These efforts have resulted in better design procedures for station control systems.

To date, most dynamic studies of power systems have been involved with only the electrical network system. These studies are commonly known as load-frequency studies. These studies relate changes in frequency with changes in electrical demand and do not include boiler responses, (see page 18 for a simple example). Therefore, load-frequency studies are accurate only for small electrical load changes and short test times. It is the purpose of this thesis to investigate the dynamic response of an electrical power generating station subject to an electrical demand. Variations in the electrical system and the boiler will be considered. The fact that boiler changes are considered will result in a better control model and more information on power plant responses.

CHAPTER II

DESCRIPTION OF SYSTEM

Electrical System

The objective of a power system is to generate electricity at constant frequency and voltage. The generation rate of electric power will have to change in order to meet variations in electrical demand. These variations in electrical demand must be sensed quickly for the generating station to match these fluctuations. The variable that is sensed or controlled is line frequency which is proportional to the shaft speed of the electrical generator. There are three main reasons for this choice:

1. Most types of a.c. motors run at speeds that are directly related to the frequency.
2. A large number of electrically operated clocks are used. The accuracy of these clocks is a function not only of the frequency error but, also, of the time integral of the frequency error.
3. It has been found through experience that the overall operation of a power system can be controlled reliably if the frequency error is maintained within strict limits.

The following example demonstrates the use of line frequency as the controlled variable:

The power system consisting of one steam generator, turbine, electrical generator, and several motors is operating at 60.00 hertz* at steady state conditions. A small electrical load drop is experienced. Assume that the prime mover turbine power setting is unchanged, meaning in effect, that the generator driving torque is unchanged. The decrease in load results in a current decrease. This current decrease produces a slight decrease in the electromechanical torque requirement in the machine. The generator will experience a small surplus accelerating torque, resulting in a speed and frequency increase. The rate at which the speed and frequency increases depends on the total moment of inertia of the turbine and generator and upon the magnitude of the accelerating torque. All the motors that are being supplied by the steam power station will experience the frequency increase. After steady state conditions are reached, the power generator and motors will be operating at a higher frequency. Therefore, frequency constitutes a sensitive indicator of the energy demand in the system and may be used as the control variable of the control system of the power station.

Sequence of Events in Power Plant Control

The purpose of this section is to describe the physical processes occurring in a power station subject to electrical disturbances. Consider a single isolated steam generating plant operating at steady state conditions when a step increase in electrical demand is experienced. The sequence of events will be as follows:

1. The mechanical power output from the turbine will remain essentially constant until the energy input to

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* Normal line frequency under routine operating conditions is 60.00 ± 0.20 hertz.

the turbine is changed by means of the turbine inlet steam valve. At steady state the electrical energy output is essentially equal to the mechanical energy output.

2. The increase in demand will be met by the decreasing of the rotational kinetic energy of the rotating mass in the turbine-generator and a subsequent decrease in shaft speed.
3. This decrease in speed is sensed by the speed control sensor as a shift in generator output frequency. The difference between this signal and the frequency signal representing the desired speed is the input to the turbine inlet steam valve control mechanism. This error signal will cause the turbine inlet steam valve to open. Therefore, there will be an increase in steam flow through the turbine to meet the increase in electrical demand.
4. The increase of steam flow produces a corresponding decrease in steam pressure. This decrease in steam is sensed. An error signal representing the difference between the steam pressure signal and a reference steam pressure signal and a reference steam pressure signal is the input to the boiler control system or combustion control system. The combustion control system, described in more detail in Chapter III, varies in complexity. Its object is to adjust the firing rate of the boiler in order to maintain constant steam pressure.

THIS BOOK CONTAINS NUMEROUS PAGES WITH DIAGRAMS THAT ARE CROOKED COMPARED TO THE REST OF THE INFORMATION ON THE PAGE.

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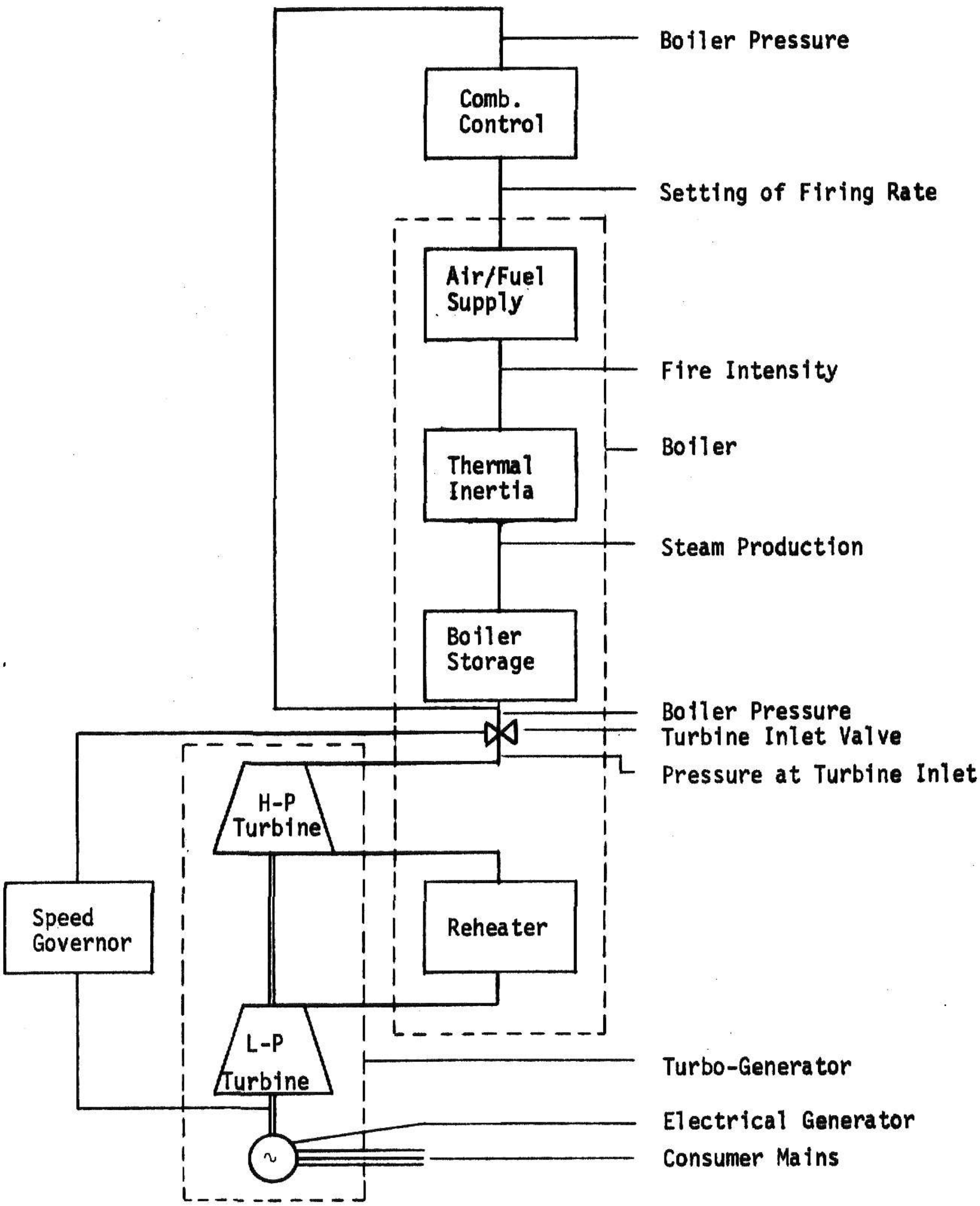


Figure 1. Power Plant Schematic Diagram

5. The action of the combustion control system will result in a return of boiler pressure at the higher steam flow rate through the turbine. Figure 1 illustrates a power plant schematic diagram.

The generator output frequency (or speed of the generator shaft) and steam pressure are the two variables that are used to control the dynamic behavior of the steam generating plant. The response of the different processes may be varied with different combustion control systems. Figures 2 and 3 show the response of the steam power plant to a step increase in load. Figure 4 shows the sequence of events experienced due to a decrease in electrical demand.

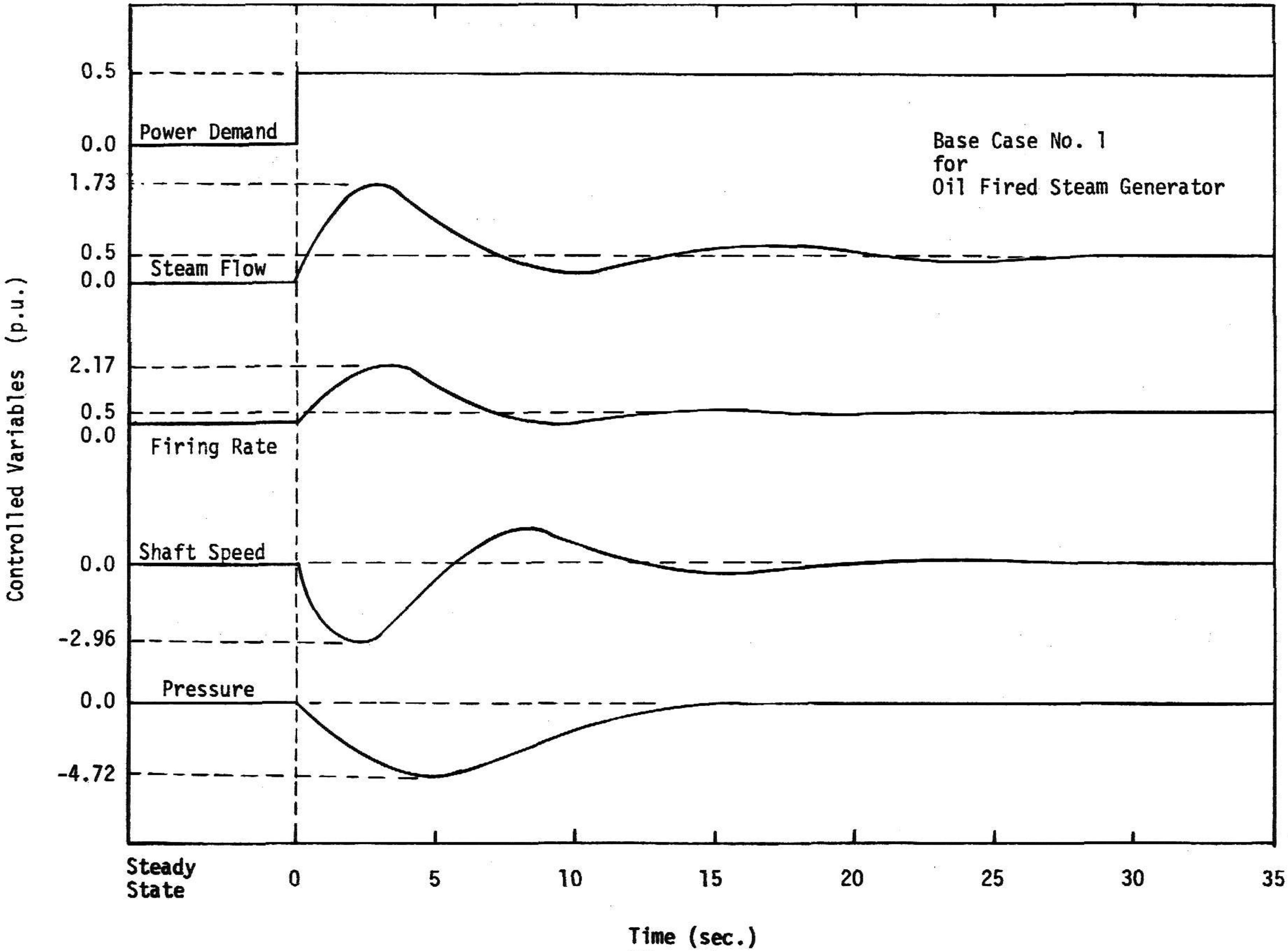
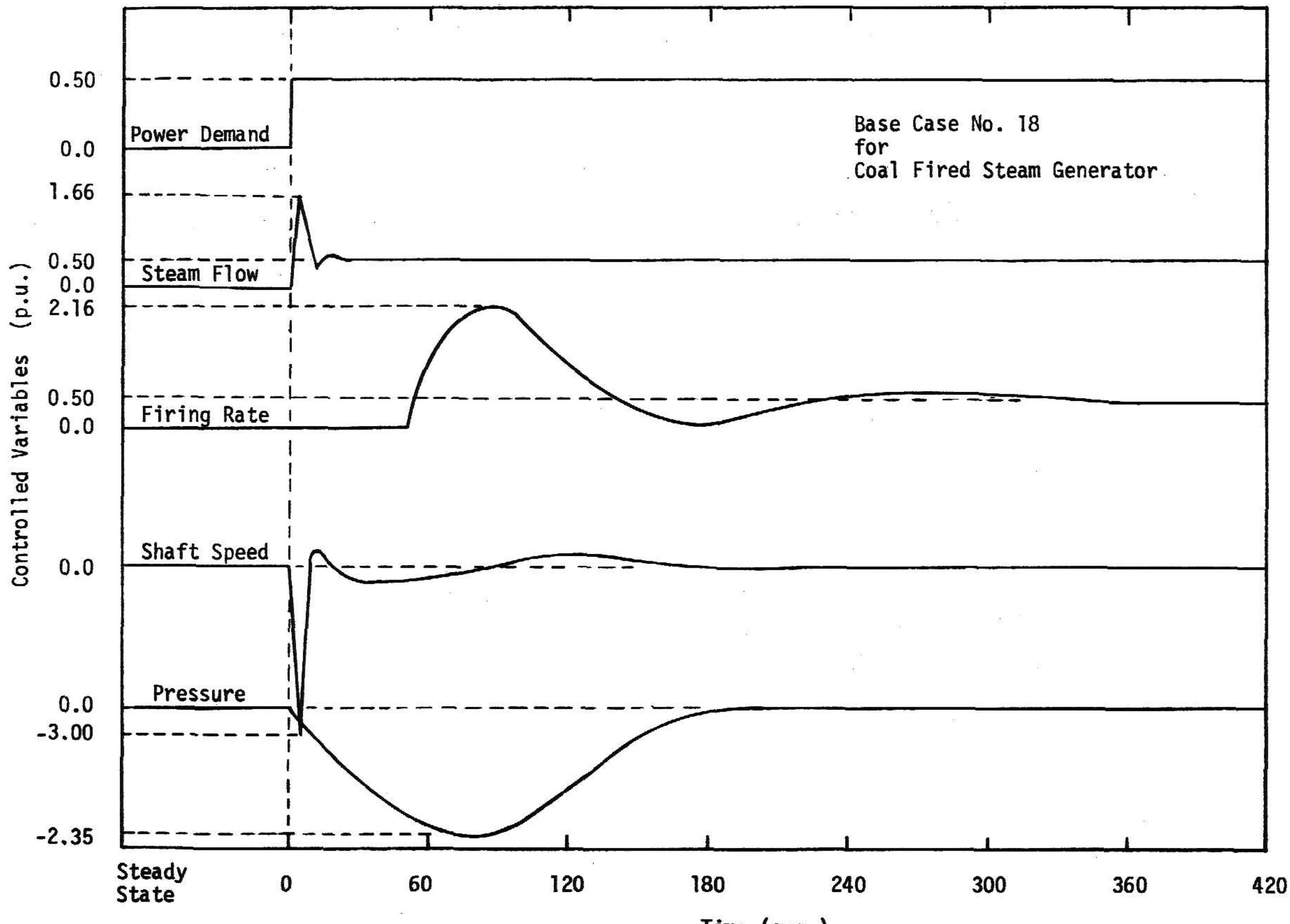

0.5
0.0
1.73
0.5
0.0
2.17
0.5
0.0
0.0
-2.96
0.0
-4.72
Controlled Variables (p.u.)
Power Demand
Steam Flow
Firing Rate
Shaft Speed
Pressure
Base Case No. 1
for
Oil Fired Steam Generator
Steady State
0
5
10
15
20
25
30
35
Time (sec.)

Figure 2.



Base Case No. 18
for
Coal Fired Steam Generator
Power Demand
Steam Flow
Firing Rate
Shaft Speed
Pressure
0.50
0.0
1.66
0.50
0.0
2.16
0.50
0.0
0.0
0.0
-3.00
-2.35
Controlled Variables (p.u.)
Steady State
0
60
120
180
240
300
360
420
Time (sec.)

Figure 3.

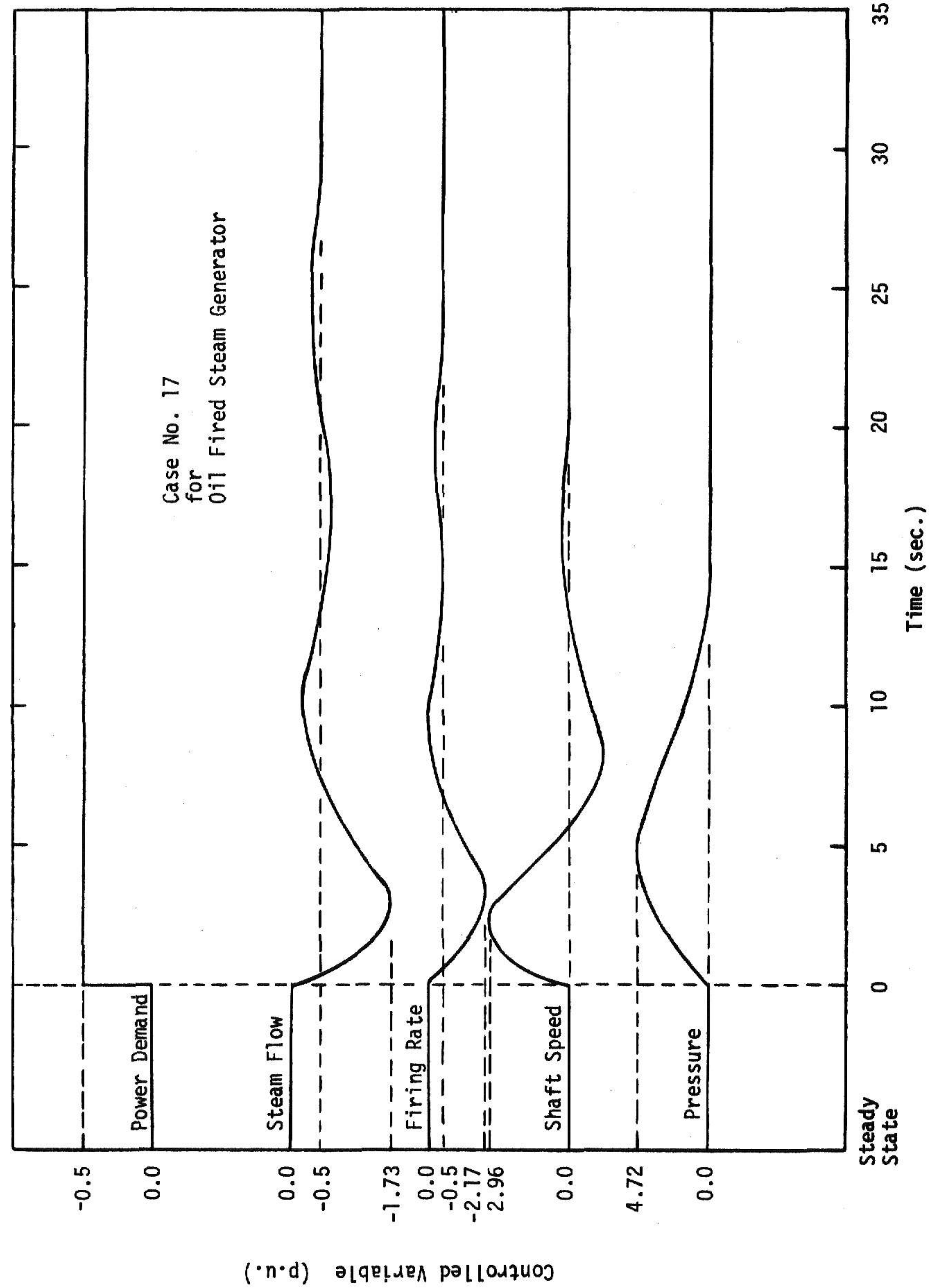

Case No. 17
for
Oil Fired Steam Generator
Power Demand
Steam Flow
Firing Rate
Shaft Speed
Pressure
Steady State
0
5
10
15
20
25
30
35
Time (sec.)
-0.5
0.0
0.0
-0.5
-1.73
0.0
-0.5
-2.17
2.96
0.0
4.72
0.0
Controlled Variable (p.u.)

Figure 4.

CHAPTER III

REVIEW OF CONTROL SYSTEMS

Closed-Loop Control

A closed-loop control system is one in which the output signal is measured and used to determine the control action to be applied to the system. Closed-loop control systems are feedback control systems. The actuating error signal which is the difference between the input signal and the feedback signal (which may be the output signal or a function of the output signal and its derivatives) is fed to the controller. This action will reduce the error and vary the output of the system to a desired value. In other words, the term "closed-loop" implies the use of feedback action in order to reduce system error.

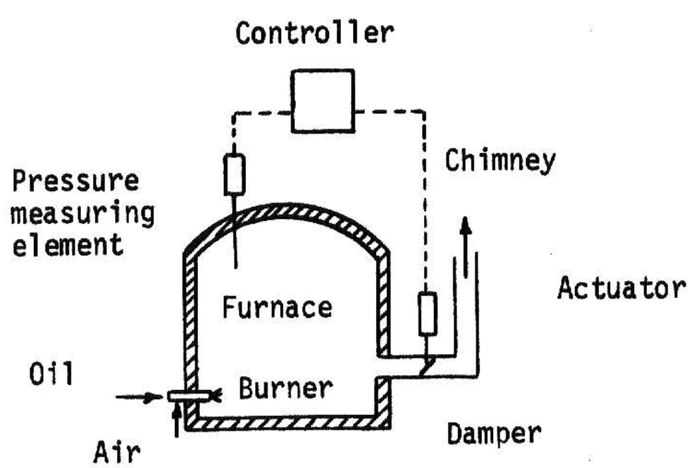


Figure 5. Pressure control system.

Two Examples of Closed-Loop Control Systems

1. Pressure Control Systems. Figure 5 shows a pressure control system. The pressure in the furnace is controlled by the position of the damper. This pressure is measured by a pressure-measuring element. The signal obtained is fed to the controller for comparison with the desired value. If there is any difference, the controller output is sent to the actuator which positions the damper in order to reduce the error.

2. Speed Control Systems. The basic principle of Watt's governor for steam turbines is illustrated in the schematic diagram of Figure 6. The amount of steam admitted to the steam turbine is adjusted according to the difference between the desired and actual turbine speeds.

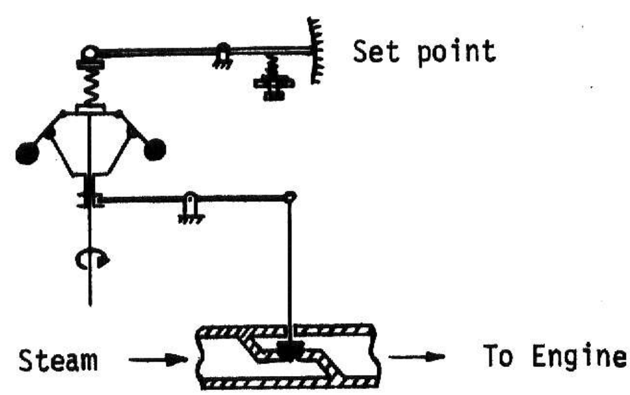


Figure 6. Speed control system.

The sequence of action may be as follows:

The reference input (set point) is set according to the desired speed. If the actual speed drops below the desired value, the decrease in the centrifugal force of the speed governor causes the control valve to move upward.

This action causes an increase in steam flow. The speed of the turbine increases until the desired value is reached. On the contrary, if the turbine speed increases above the desired value, the increase in centrifugal force by the governor will cause the control valve to move downward. This decreases the supply of steam. Turbine speed will decrease until the desired value is reached.

General Requirements of a Control System

Any control system must be stable; this is a primary requirement. In addition to absolute stability, a control system must have a reasonable relative stability. Therefore, the speed of response must be reasonably fast and the response must show reasonable damping. A control system must also be capable of reducing errors to zero or to some small tolerance value. Any useful control system must satisfy these requirements.

The requirement of reasonable relative stability and that of steady state accuracy tend to be incompatible. In designing control systems, it is necessary to make the most effective compromise between these two requirements.

Laplace Transformation

The Laplace Transform method is an operational method which can be used advantageously for solving linear differential equations. By using Laplace Transforms, many common functions such as sinusoidal functions, damped sinusoidal functions, and exponential functions can be converted into algebraic functions of a complex variable. Operations such as differentiation and integration can be replaced by algebraic operations in the complex variable.

Thus, a linear differential equation can be transformed into an algebraic equation in the complex variable. The solution of the differential equation may be found by use of a Laplace Transform Table. These tables are found in most texts on control theory or Mathematical Tables.

Mathematical Models of Physical Systems

1. Introduction. Many dynamic systems, whether they are mechanical, electrical, thermal, etc., may be characterized by differential equations. The equations can be obtained by utilizing physical laws governing the system, for example, Newton's laws for mechanical systems, Kirchoff's laws for electrical systems, etc. Such a mathematical description is called a mathematical model. The first step in the analysis of a dynamic system is to derive its mathematical model.

2. Transfer Function. The mathematical model can either be in the form of a differential equation or a transfer function. The transfer function is defined as the ratio of the Laplace Transform of the output (response function) to the Laplace Transform of the input (driving function) under the assumption that all initial conditions are zero.

3. Block Diagram. A block diagram is a symbolic representation of the interconnection of elements in a system. Each block in the diagram represents the mathematical operation on its input signal to produce its output. The transfer functions of the components are entered in the corresponding blocks, which are connected by signal flow lines to indicate the interacting between the components. Several "blocks" connected by signal flow lines can be used to represent an entire operation. Figures 7 and 8 are examples of block diagrams used in this thesis.

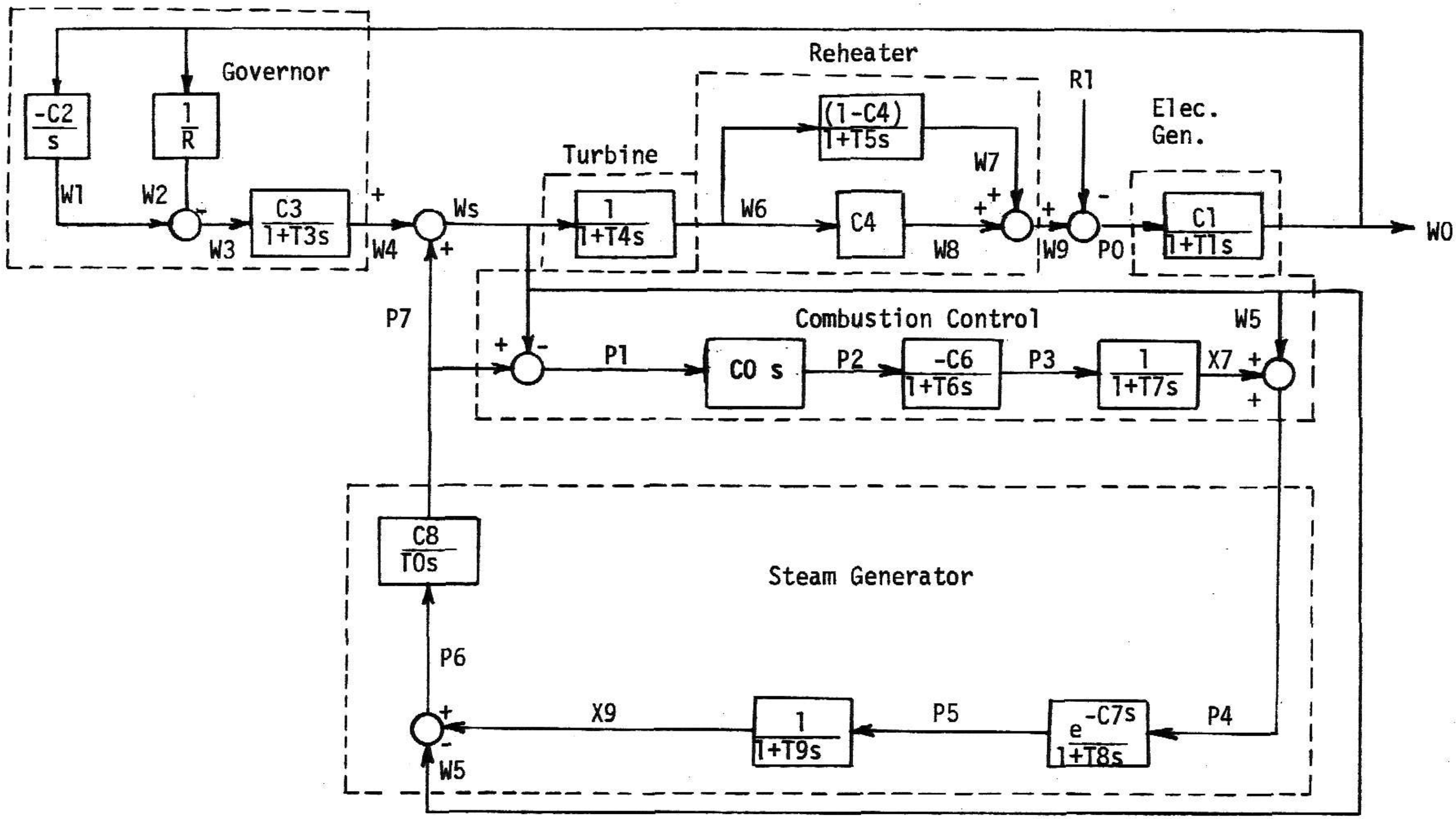


Figure 7. Control Block Diagram
Steam Generator with Derivative Combustion Control

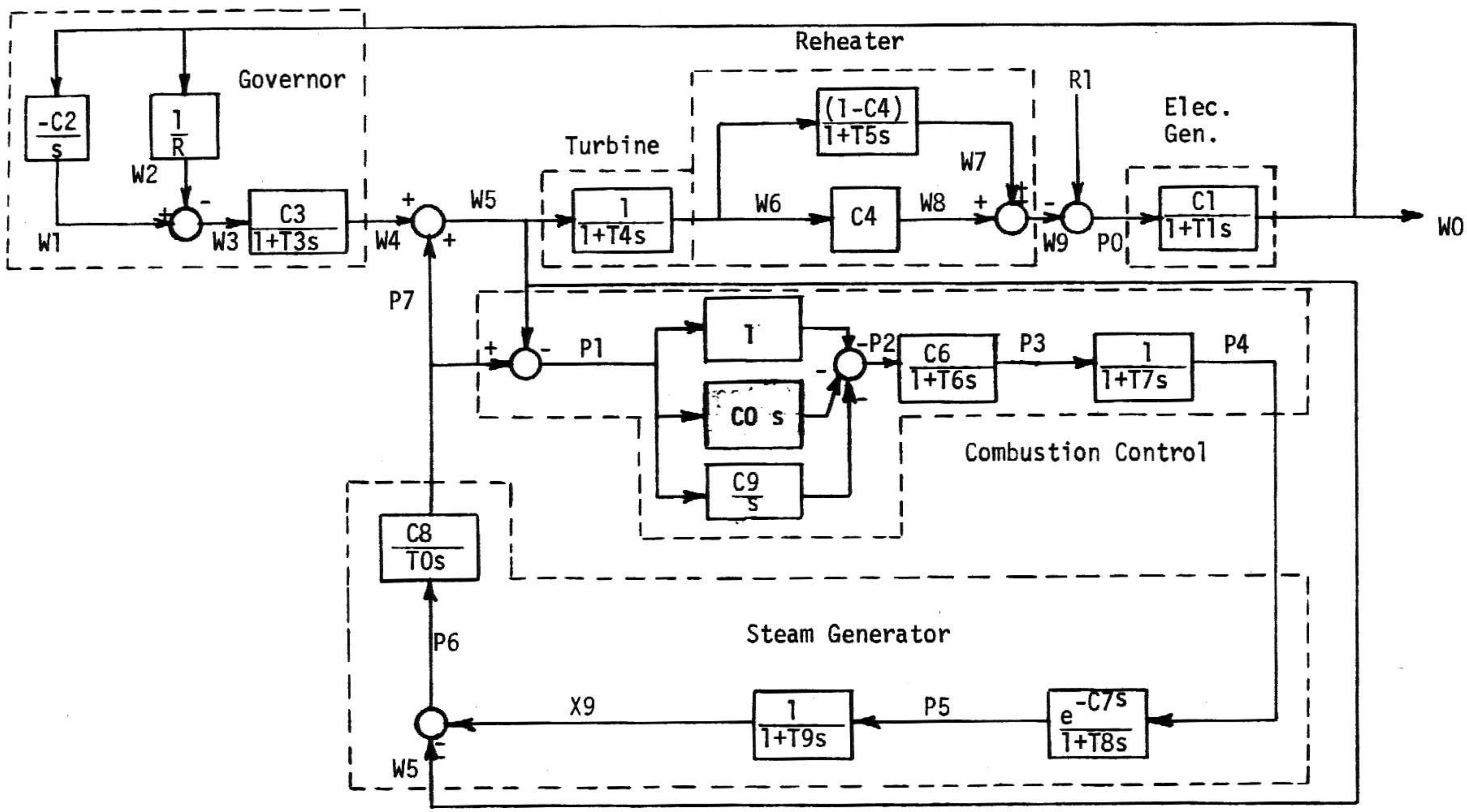


Figure 8. Control Block Diagram
Steam Generator with Proportional + Integral
+ Derivative Control

Mode of Control

In automatic control systems it is frequently necessary to modify the error signal. A controller is normally used to perform the necessary signal modification. The most simple mode of control is proportional control in which the control signal is proportional to the error signal. Other commonly used modes in combustion control systems include derivation, proportional plus derivative, and proportional plus derivative plus integral.

Proportional combustion control must sense a change in deviation (in this case steam pressure error) in order to produce a new air and/or fuel valve position. It can provide exact correction for only one load change. All other loads will have some remaining deviation. This error is called offset or droop and is an inescapable characteristic of proportional control mode. The example of a Load-Frequency Control System, Chapter III, uses proportional control mode.

Proportional plus integral control mode modifies the error signal two ways. First, proportional mode changes the error signal proportionally. Second, integral control integrates the error signal. As the steam pressure changes from a desired reference point, the controller moves the valve according to the proportional and integral of the error signal. The pressure would remain low for proportional control only. With the addition of integral control, the valve opens in relation to the integral of the error signal. This action automatically resets the control point to its desired value. Integral control is sometimes referred to as reset control.

Proportional plus derivation control mode positions the valve proportionally and to the rate of change of the error signal. This type of controller is sensitive to direction. If the pressure is rising, the controller will tend to close the valve and so has a stabilizing effect. A derivation controller can produce a satisfactory control signal in a transient situation, but is insensitive to steady state errors. As a result derivative control is used in conjunction with proportional or integral control. This is because derivative control alone cannot sense a datum. The control mode can by either proportional or integral or both.

Example of Load-Frequency Control System

Consider a simplified model for load-frequency control system shown in Figure 9.

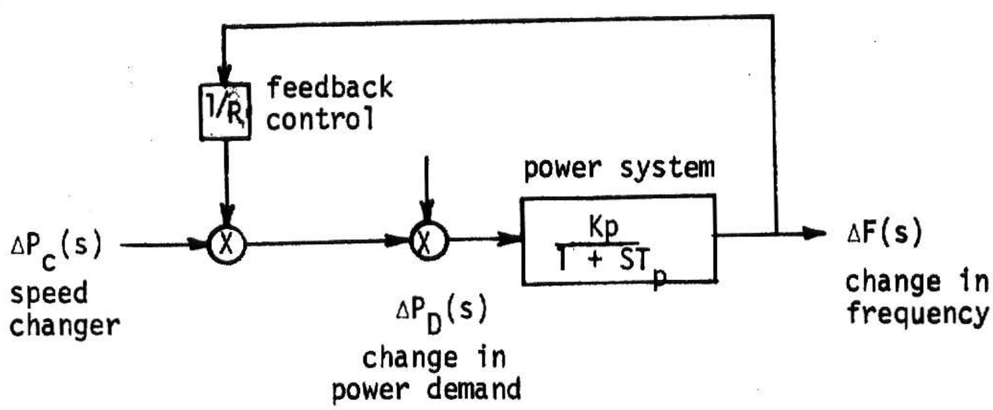


Figure 9

Assume a change in power demand, $\Delta P_D(s)$, is experienced. Without any increase in the speed changer position, $\Delta P_c(s)=0$, a decrease in frequency is expected. Therefore, the output is decreased with respect to an increase in power demand, $\Delta P_D(s)$.

Now assuming that $\Delta P_D(s)$ is a step increase,

$$\Delta P_D(s) = \frac{0.01}{s}$$

$$\Delta F(s) = -\Delta P_D \frac{RKp}{R+Kp} \left(\frac{1}{s} - \frac{1}{s + \frac{R+Kp}{RTp}} \right)$$

After assigning the appropriate values:

$$\Delta F(s) \approx -0.02\left(\frac{1}{s} - \frac{1}{s+2.5}\right)$$

$$\Delta f(t) \approx -0.02\left(1 - e^{-2.5t}\right)$$

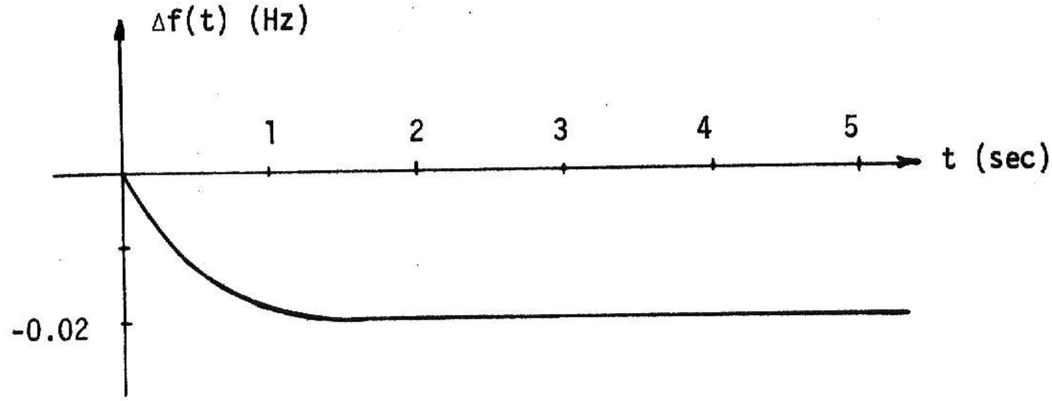


Figure 10

The results are shown in Figure 10. The frequency levels out to a new value which is lower than the original frequency.

CHAPTER IV

MATHEMATICAL MODELS

Electrical Generator

1. Physical Description. The rotor of a three phase synchronous machine when functioning as a generator is driven by a prime mover. The prime mover will be a steam turbine in this thesis. The armature or stator windings are arranged in three symmetrical phase groupings in the stator surface. The magnetic field intensity is controlled by a d.c. current in the rotor or field windings. The generator supplies a complex power to the system.

The control of the synchronous machine as a generator is dependent upon two control inputs. These inputs are rotor or field current and mechanical shaft torque. There are also four control outputs; real power, reactive power, voltage, and frequency. In general, there is cross coupling between the inputs and outputs. Changing one input could result in changes in all outputs. Real power and reactive power are functions of mechanical shaft torque and rotor (field) current, respectively, when considering the special case of the generator connected to an infinite bus. It is necessary for the mathematical model to represent realistically and accurately the interdependence of the input and output parameters of the electrical generator. This is usually shown by an electrical phasor diagram from which the power equations are derived for the generator.

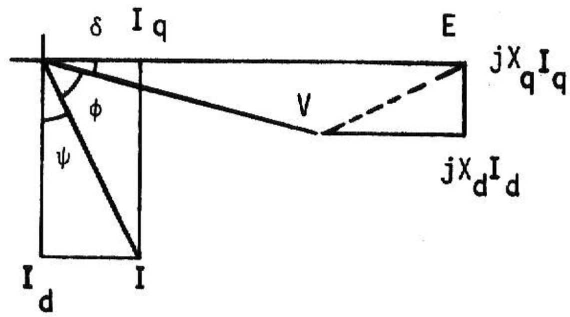


Figure 11. Phasor Diagram of Synchronous Generator

2. Steady State Equations. The assumptions, according to Elgerd [10], used in this phasor diagram, Figure 11, are:

a. complete symmetry exists between the three phases

b. the power angle δ is defined as positive when E leads V.

c. the phase angle ϕ is positive when voltage leads current.

$$S_G = P_G + j\,Q_G = |V|\ |I| \cos\phi + j\ |V|\ |I| \sin\phi \tag{1}$$

It can be shown that:

$$P_G = \frac{|V|\ |E|}{X_d} \sin\delta + \frac{|V^2|}{2}\left(\frac{1}{X_q} - \frac{1}{X_d}\right) \sin 2\delta = \frac{|V|\ |E|}{X_d} \sin\delta \tag{2}$$

This last equation is for a nonsalient machine.

If $|V|$ and $|E|$ are held constant, then for all practical purposes P_G is a function only of power angle δ. Also, the reactive power can be expressed for a nonsalient machine.

$$Q_G = \frac{|E|\ |V|}{X_d} \cos\delta - \frac{|V|^2}{X_d} \tag{3}$$

Assume that the generator is connected to an infinite bus. $|V|$ and $|E|$ are constant and P_G can be expressed as:

$$P_G = P_{max} \sin \delta \tag{4}$$

where

$$P_{max} = \frac{|V|\ |E|}{X_d} \tag{4a}$$

Now plotting P_G versus δ,

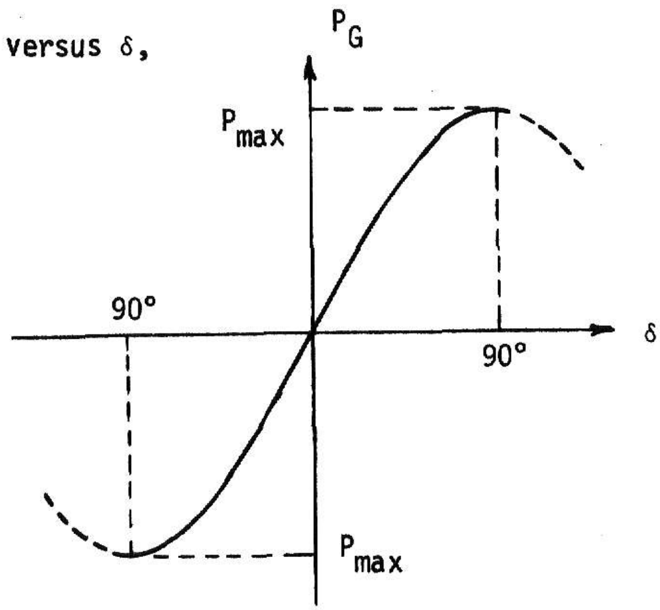


Figure 12

The pullout power, P_{Po}, is defined as the power at which the machine steps out of synchtonization. That is:

$$P_{Po} = \pm P_{max} = \pm \frac{|V|\ |E|}{X_d} \tag{5}$$

Also, the machine acts as a generator when $\delta > 0$ and as a motor when $\delta < 0$.

3. <u>Load versus Frequency, Vars versus Voltage</u>. Consider the reactive power equation (3). The reactive power can be controlled by changing field current and thus $|E|$ if $|V|$ is constant. This change will also change the magnitude of P_{max} and δ if P_G is constant. For example, a reduction in the field

current will increase the magnitude of δ, and even possibly to the point of pullout.

A change in shaft torque will immediately change the power P_G. At the same time the power angle δ will also change. There will also be a change in Q_G because Q_G depends on cos δ. The fluctuations of Q_G are not large when the power angle is 30° or less. Therefore, this term is a weak interconnection or coupling with the rest of the system.

This discription so far has been based on approximate steady state conditions. Two possible functions that have to be controlled have been introduced. These functions are real power versus voltage. For reasons stated above, reactive power will vary appreciably for small changes in δ and possible infinite system connection. According to Elgerd [10], a voltage regulator control system reacts much faster than a real power frequency control system. Therefore, the control of an electrical system is based upon the relationship of real power versus frequency.

4. Transient Equations. According to Elgerd [10] and Neuenswander [14], the equations for transient conditions are similar to those for steady state conditions and are as follows:

$$P_G = \frac{|V^f|\ |E'|}{X_{d'}} \sin \delta + \frac{|V^f|^2}{2} \left(\frac{1}{X_q} - \frac{1}{X_{d'}}\right) \sin 2\delta \tag{6}$$

where

$$|E'| = \frac{X_{d'}|E^\circ| + (X_d - X_{d'})\ |V_q^\circ|}{X_d} \tag{6a}$$

$$|V_q^\circ| = |V^\circ| \cos \delta^\circ \tag{6b}$$

In this thesis, the generator has been assumed to be connected to an infinite system. Therefore, $|V^\circ|$ is equal to $|V^f|$. This assumption eliminated the need of using a static load flow program to supply the instantaneous voltage at the generator.

5. The Swing Equation. The variation of P_G as a function of δ has been discussed above. At steady state, the prime mover torque must equal the electromagnetic torque plus some losses. Elgerd [10] and Neuenswander [14] showed a direct proportionability between torque and power. Therefore, prime mover torque is also a function of δ. The rotor angle will advance if the prime mover torque to the generator is increased. This change in δ will cause the phasor E to pull away from the phasor V resulting in an increase in δ and thus an increase in P_G (see Figure 11). The new δ value will correspond to exactly the power needed to balance out the added torque. If the torque is increased beyond the value P_{max}/ W mech, then a further increase in troque will not result in a corresponding increase in P_G. At this point, the machine will go out of synchronism and "skip poles". The relationship between all these variables is given by the swing equation:

$$P_T - P_G = \frac{H}{\pi f^{\circ}} \frac{d^2\delta}{dt^2} + D \frac{d\delta}{dt} \tag{7}$$

According to Elgerd [10] and Neuenswander [14], most electrical transients die out in a few seconds. The electrical generator can be modeled by a first order transfer function (see Example of Load-Frequency Control System, section III).

$$\frac{\text{Shaft Speed}}{\text{Power Input}} = \frac{WO}{PO} = \frac{C1}{1+T1\ s} \tag{8}$$

where

$$C1 = 1/D \tag{8a}$$

$$T1 = 2H/f^{\circ}D \tag{8b}$$

Speed Governing System

1. Description. It had been shown that the real power in a electrical power system is controlled by controlling the driving torque of the turbine. The driving torque is controlled by sensing changes in frequency. This latter process is the function of the speed-governing system shown schematically in Figure 13.

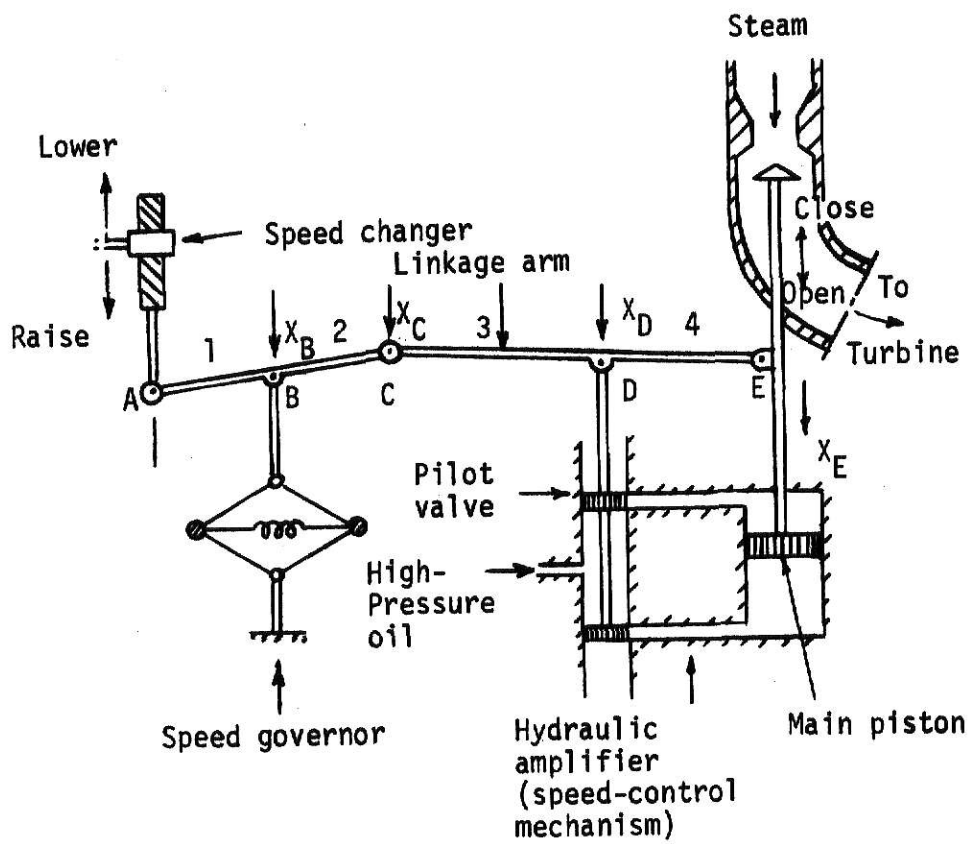


Figure 13. Speed Governor Schematic Diagram

The high-pressure steam flow to the turbine is controlled by controlling the turbine inlet valve position measured by X_E. Since large mechanical forces are needed to control the high-pressure steam flow, a hydraulic amplifier is needed. The position of the pilot valve can be effected by the linkage system in three ways:

a. Directly, by moving the linkage point A by "raise" or "lower" commands of the speed changer.

b. Indirectly, by feedback, due to position changes of the main piston.

c. Indirectly, by feedback, due to piston change of the linkage point B resulting from speed changes.

2. Mathematical Model. Assume the electrical system is operating at steady state. Assuming all changes are small, a power increase, ΔP_c, is commanded by means of the speed changer.

$$\Delta X_C = k_1 \ \Delta f - k_2 \ \Delta P_c \tag{9a}$$

$$\Delta X_D = k_3 \ \Delta X_C + k_4 \ \Delta X_E \tag{9b}$$

The constants k_1, k_2, k_3, and k_4 depend upon the lengths of linkage of 1, 2, 3, and 4 respectively. If the oil flow into the hydraulic motor is proportional to position ΔX_D of the pilot valve, then:

$$\Delta V_E = k_5 \int (-\Delta X_D) \ dt \tag{10}$$

where k_5 is a function of the orifice, cylinder geometries, and fluid pressure. By simplifying and taking the Laplace Transform.

$$\Delta X_E(s) = \frac{k_2 k_3 \ \Delta P_c(s) - k_1 k_3 \ \Delta F(s)}{k_4 + s/k_5} \tag{11}$$

By rewriting:

$$\Delta X_E(s) = \frac{C3}{1+T3s} \ [\Delta P_c(s) - \frac{1}{R} \ \Delta F(s)] \tag{12}$$

Typical value for T3 is 100 milliseconds. The steady state speed regulation, R, is defined as the change in speed that is necessary to move the valves from no load to full load. It is usually expressed in per unit or percent of rated speed. For example, the steady state speed versus power outlet for a typical steam driven turbine generator adjusted for rated speed at fifty percent power output is five percent. Thus

$$R = \frac{0.05 \times 60}{0.5} = 0.6 \frac{\text{Hz}}{\text{pu MW}} \tag{13}$$

Therefore, a static load increase of 0.05 p.u. MW would give a static frequency drop of:

$$0.6 \times 0.5 = 0.3 \text{ Hertz} \tag{14}$$

This example indicates desired speed regulation be as small as possible.

Combustion Control

As stated earlier, the boiler is controlled by controlling turbine inlet pressure. This process is called combustion control. The function of the automatic control is to act upon the firing system and modify the steam production in order to maintain steam pressure within specified limits over the range of steam flow rates.

There are three basic types of combustion control systems.

1. Two-Position or On-Off. This type of control is found only on small packaged boilers. The master control is a bellows-operated switch that responds to steam pressure changes. The stoker or fuel oil pump and fan motors will start up when the pressure drops below a preset value. This equipment will run a constant speed until pressure has risen to its predetermined upper limit. The header pressure varies appreciably. The boiler operation is inefficient throughout most of its steaming range.

2. Positioning Control. Positioning control enables the firing rate to follow load changes more closely. The steam pressure is the measured variable. The

operating conditions of the pumps, motors, and dampers respond to the steam pressure. Therefore, the steam pressure is maintained within much closer limits than is possible with a two-position system.

The air/fuel ratio still varies. It will be correct at one load setting but not at any other. The efficiency will still depend largely on the stability of the steam demand and continued cleanliness of the boiler surface.

3. Metering Control. Metering Control is constantly metering the air/fuel ratio. Therefore, it is basis for all automatic combustion control systems. Control signals are generated in response to steam pressure fluctuations. These signals are modulated in accordance with the actual fuel and air flows. The effects of boiler slagging, barometric conditions and similar variables can be eleminated. Therefore, combustion efficiency is maintained throughout the entire steaming range.

4. Mathematical Model. The metering combustion control system will be used in this thesis. There is a time delay between the measurement of actual fuel and air flows and adjustment of the fuel and air control mechanism. There will also be a time delay due to the action of the regulators and control motors of the metering control system. The transfer function of these two time delays is:

$$\frac{\text{combustion rate}}{\text{steam pressure}} = \frac{P4}{P2} = \frac{C6}{(1+T6s)(1+T7s)} \tag{15}$$

Typical values of T6 and T7 are 0.8 seconds.

Boiler Responses

1. Introduction. The process of developing accurate mathematical models for all the coupled interactions in the boiler has been most difficult in

establishing a satisfactory boiler control system. The approximate ratio of the time constant of storage to the time constant of thermal inertia is decreasing with newer boilers. Typical ratios are:

fire-tube boilers	1:1
drum-type natural circulation boilers	1:6
once-through forced circulation boilers	1:60

Therefore, the modeling of the boiler is becoming more important.

There are several methods used in developing adequate mathematical models of the boiler. One source, Thompson [17], solved 235 equations, describing the various boiler operations, simultaneously. Another source, Profos [16], developed transfer functions of the boiler operations from actual test data. Dr. Profos' method will be used in this thesis.

2. Transfer Functions. Figures 1, 7, and 8 illustrate the physical significance and sequence of these boiler operations or processes. A signal from the combustion control system causes a change in the firing rate. A time delay will occur before the fire intensity is changed. The steam production will change after a time delay in thermal inertia. The steam pressure will change after a corresponding delay in storage in the boiler. The effect of steam storage in the piping will be neglected in this thesis. The change in steam pressure will cause a change in mechanical power output to the generator after a delay due to the turbine and reheat. The transfer functions with typical time constants are:

a. Firing System

$$\frac{\text{Firing Intensity}}{\text{Comb. control signal}} = \frac{P4}{P5} = \frac{e^{-C7s}}{1+T8s} \qquad (16)$$

b. Thermal Inertia

$$\frac{\text{Steam Production}}{\text{Fire Intensity}} = \frac{X9}{P5} = \frac{1}{1+T9s} \qquad (17)$$

c. Boiler Storage

$$\frac{\text{Actual Steam Production}}{\text{Steam Production}} = \frac{P7}{P6} = \frac{C8}{T0s} \tag{18}$$

d. Turbine

$$\frac{\text{Total Turbine Work}}{\text{Total Steam Input}} = \frac{W6}{W5} = \frac{1}{1+T4s} \tag{19}$$

e. Reheat

$$\frac{\text{Total Mechanical Work}}{\text{Total Turbine Work}} = \frac{W9}{W6} = \frac{(1-C4)}{1+T5s} + C4 \tag{20}$$

f. Typical values of time constants in seconds are:

	oil fired			coal fired		
	low	average	high	low	average	high
C7		0		25	50	75
T8	10	15	20	10	25	40
T9	4	7	15	40	60	80
T0	25	100	200	25	100	200
T4		0.3			0.3	
T5		11			11	
C8		0.25 (reheat)			0.25 (reheat)	
		1.0 (no reheat)			1.0 (no reheat)	

Presentation of Entire Control Model

The entire control model for a stream power plant can be constructed by combining the transfer functions presented in this thesis. Figures 7 and 8 show the control model with two types of combustion control systems. The different physical systems are represented by the following equations.

a.	Electric Generator	Equation 8
b.	Speed Governor	12
c.	Combustion Control	15
d.	Steam Generator	16
e.	Turbine	19
f.	Reheater	20

The assumptions and limitations to which the control model is subject:

1. The energy content versus heat transfer characteristics of the boiler are non-linear. Thus, the thermal inertia time constant T9 varies with unit loading.
2. More information is needed by the designer to properly simulate the effects of combustion control on the fire intensity or heat release.
3. The rotor velocity deviations of the electrical generator are very small compared with the synchronous velocity of 377 radians per second. Therefore, the static portion (lines and transformers) of the network is considered to be at steady state.
4. The disturbances are electrically balanced disturbances.

CHAPTER V

DYNAMIC ANALYSIS OF CONTROL MODEL

Introduction

The digital computer program used in solving this dynamic analysis will be presented in this chapter. The time constants and the combination of time constants and different types of controls can vary greatly. Therefore, two base cases will be considered. The first case is for oil or gas fired and the second is for coal fired steam generator. Once these two base cases are presented, the dynamic response will be studied while changing different variables.

The Computer Program

The program developed for this thesis incorporates the principle of simultaneous solution of several first order differenial equations by a numberical integration technique. The numerical technique used is Euler's method.

The first step in developing the program is to express the transfer functions as first order differential equations. The method presented below works for all cases in which the order of the polynomial in terms of complex variable s in the numerator is equal to or less than the order of the polynomial in the denominator. To illustrate this method, assume a transfer function as such:

$$\frac{C(s)}{R(s)} = \frac{a_2 s^2 + a_1 s + a_o}{b_2 s^2 + b_1 s + b_o}$$

Now introduce three dummy variables: N, D, and X:

$$\frac{C(s)}{R(s)} = \frac{a_2 s^2 + a_1 s + a_o}{b_2 s^2 + b_1 s + b_o} = \frac{N(s)}{D(s)} \quad , \quad X(s) = \frac{R(s)}{D(s)}$$

Now rearrange the variables as such

1. $C(s) = N(s)\ X(s) = (a_2 s^2 + a_1 s + a_o)\ X(s) = a_2 s^2\ X(s)$
   $+ a_1 s\ X(s) + a_o\ X(s)$
2. $D(s)\ X(s) = R(s)$ or $(b_2 s^2 + b_1 s + b_o)\ X(s) = R(s)$
   or $s^2 X(s) = (R(s) - b_1 s\ X(s) - b_o X(s))/b_2$

Now taking the inverse Laplace Transform of these two equations:

1. $$C(t) = a_2 \frac{d^2X}{dt^2} + a_1 \frac{dX}{dt} + a_o X$$

2. $$\frac{d^2X}{dt^2} = (R(t) - b_1 \frac{dX}{dt} - b_o X)/b_2$$

These are second order differential equations. Therefore, another dummy variable is introduced.

1. $$\frac{dX(1)}{dt} = X(2)$$

2. $$\frac{dX(2)}{dt} = (R(t) - b_1 X(2) - b_o X(1))/b_2$$

3. $$C(t) = a_2 \frac{dX(2)}{dt} + a_1 X(2) + a_o X(1)$$

The transfer function is now expressed in terms of first order differential equations and this method can be used for all transfer functions in the control model. The computer programs for the two base cases are listed in Figures 14a, 14b, 15a and 15b.

COMPUTER PROGRAM FOR OIL FIRED STEAM GENERATOR

Figure 14a.

```
7  PRINT  TAB 36;"PRESSURE"; TAB 48;"BOILER";
8  PRINT
10  PRINT "TIME"; TAB 12;"SPEED"; TAB 24;"STEAM";
11  PRINT  TAB 36;"SIGNAL"; TAB 48;"PRESSURE";
12  PRINT  TAB 60;"FIRE RATE";
15  PRINT
20  LET J= 0
25  LET H=.02
30  LET C1=100
35  LET C2=.1
40  LET C3=1
45  LET C4=.25
50  LET C5=1
55  LET C6=1
60  LET C7= 0
65  LET C8=1
75  LET C0=25
80  LET T1=20
85  LET T3=.08
90  LET T4=.3
95  LET T5=10
100  LET T6=.08
102  LET T7=.08
105  LET T8=20
110  LET T9=7
115  LET T0=100
120  LET R=2.4
122  LET R4=250
125  LET R1=.5
130  FOR I= 0 TO 600 STEP H
135    LET D1=(P0-X1)/T1
140    LET W0=C1*X1
145    LET D2=W0
150    LET W1=-C2*X2
155    LET W2=(1/R)*W0
160    LET W3=W1-W2
165    LET D3=(W3-X3)/T3
170    LET W4=C3*X3
175    LET W5=W4+P7
180    LET D4=(W5-X4)/T4
185    LET W6=X4
190    LET D5=(W6-X5)/T5
195    LET W7=(1-C4)*X5
200    LET W8=C4*W6
205    LET W9=W7+W8
210    LET P0=W9-R1
215    LET P1=-W5+P7
220    LET P2=-(C0*((P1-P9)/H))
```

Figure 14b.

```
225  LET D6=(P2-X6)/T6
230  LET P3=C6*X6
235  LET D7=(P3-X7)/T7
240  LET P4=X7+W5
245  LET D8=(P4-X8)/T8
250  IF  ABS (I-C7)<H GOTO  260
255  LET P5=X8
260  LET D9=(P5-X9)/T9
265  LET P6=X9-W5
267  LET P8=P6-W4
270  LET D0=P6
275  LET P7=(C8/T0)*X0
294  IF  ABS (I- 0)<.01 GOTO  299
295  LET J=J+1
296  IF I>10 GOTO  305
298  IF  ABS (J-50)>H GOTO  320
299  LET J= 0
300  PRINT ( INT (I*50+.2)/50); TAB 12;W0; TAB 24;W5;
301  PRINT  TAB 36;P1; TAB 48;P7; TAB 60;P5;
302  PRINT
303  GOTO  320
305  IF  ABS (J-R4)>H GOTO  320
310  LET J= 0
315  PRINT ( INT ((I*R4+250)/R4)); TAB 12;W0; TAB 24;W5;
316  PRINT  TAB 36;P1; TAB 48;P7; TAB 60;P5;
317  PRINT
320  LET X1=X1+H*D1
325  LET X2=X2+H*D2
330  LET X3=X3+H*D3
335  LET X4=X4+H*D4
340  LET X5=X5+H*D5
345  LET X6=X6+H*D6
350  LET X7=X7+H*D7
355  LET X8=X8+H*D8
360  LET X9=X9+H*D9
365  LET X0=X0+H*D0
370  LET P9=P1
380  NEXT I
```

COMPUTER PROGRAM FOR COAL FURED STEAM GENERATOR

Figure 15a.

```
7  PRINT  TAB 24;"VALVE"; TAB 36;"BOILER"; TAB 48;"BOILER";
8  PRINT
10  PRINT "TIME"; TAB 12;"SPEED"; TAB 24;"STEAM";
11  PRINT  TAB 36;"PRESSURE"; TAB 48;"STEAM";
12  PRINT  TAB 60;"FIRE RATE";
15  PRINT
20  LET J= 0
25  LET H=.02
30  LET C1=100
35  LET C2=.1
40  LET C3=1
45  LET C4=.25
50  LET C5=1
55  LET C6=1
60  LET C7=50
65  LET C8=5
70  LET C9=.002
75  LET C0=50
80  LET T1=20
85  LET T3=.08
90  LET T4=.3
95  LET T5=10
100  LET T6=.08
102  LET T7=.08
105  LET T8=25
110  LET T9=60
115  LET T0=100
120  LET R=2.4
122  LET R4=250
125  LET R1=.5
130  FOR I= 0 TO 600 STEP H
135    LET D1=(P0-X1)/T1
140    LET W0=C1*X1
145    LET D2=W0
150    LET W1=-C2*X2
155    LET W2=(1/R)*W0
160    LET W3=W1-W2
165    LET D3=(W3-X3)/T3
170    LET W4=C3*X3
175    LET W5=W4+P7
180    LET D4=(W5-X4)/T4
185    LET W6=X4
190    LET D5=(W6-X5)/T5
195    LET W7=(1-C4)*X5
200    LET W8=C4*W6
205    LET W9=W7+W8
210    LET P0=W9-R1
215    LET P1=-W5+P7
```

Figure 15b.

```
217  LET Z2=P1
218  LET Z0=-C9*Z1
220  LET P2=-(C0*((P1-P9)/H))+Z0-(1*P1)
225  LET D6=(P2-X6)/T6
230  LET P3=C6*X6
235  LET D7=(P3-X7)/T7
240  LET P4=X7
245  IF (I-C7)<H GOTO  260
250  LET D8=(P4-X8)/T8
255  LET P5=X8
260  LET D9=(P5-X9)/T9
265  LET P6=X9-W5
270  LET D0=P6
275  LET P7=(C8/T0)*X0
294  IF  ABS (I- 0)<.01 GOTO  299
295  LET J=J+1
296  IF I>10 GOTO  305
298  IF  ABS (J-50)>H GOTO  320
299  LET J= 0
300  PRINT ( INT (I*50+.2)/50); TAB 12;W0; TAB 24;W5;
301  PRINT  TAB 36;P1; TAB 48;P7; TAB 60;P5;
302  PRINT
303  GOTO  320
305  IF  ABS (J-R4)>H GOTO  320
310  LET J= 0
315  PRINT ( INT ((I*R4+250)/R4)); TAB 12;W0; TAB 24;W5;
316  PRINT  TAB 36;P1; TAB 48;P7; TAB 60;P5;
317  PRINT
320  LET X1=X1+H*D1
325  LET X2=X2+H*D2
330  LET X3=X3+H*D3
335  LET X4=X4+H*D4
340  LET X5=X5+H*D5
345  LET X6=X6+H*D6
350  LET X7=X7+H*D7
355  LET X8=X8+H*D8
360  LET X9=X9+H*D9
365  LET X0=X0+H*D0
370  LET P9=P1
375  LET Z1=Z1+H*Z2
380  NEXT I
```

Presentation of Results

The two base cases considered are that of oil or gas fired and coal fired steam generators. Two different types of control modes are used in the combustion control system. They are derivative control mode for oil or gas fired and proportional plus derivation plus integral control mode for the coal fired steam generator. The results for the oil fired steam generator are given in case 1. The variables shown in cases 2 to 17 are those that are changed from the base case for oil fired. The base case for coal fired steam generators is case 18. Similarly, the variables shown in cases 19 to 21 are changes from the base case for coal fired. The results of the dynamic analysis are presented according to the notation described in Figure 16.

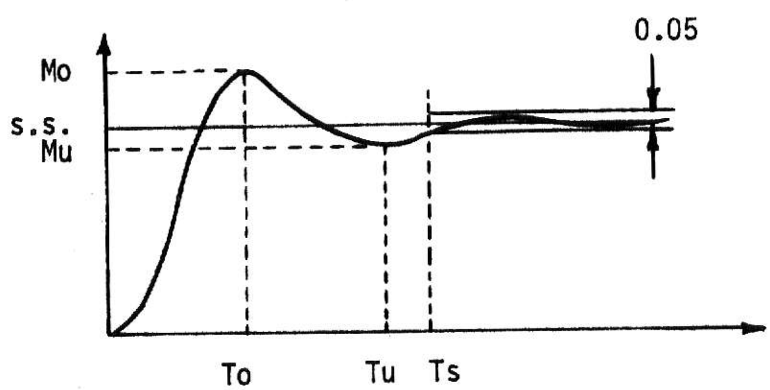


Figure 16. Dynamic Response Notation

The values for the variables in seconds that are changed are:

				Oil			Coal	
			low	avg.	high	low	avg.	high
1.	Governor Integral Gain Constant	C2	0.05	0.1	0.25	0.05	0.1	0.25
2.	Reheat Fraction	C4		0.25			0.25	
	without reheat	C4		1.0			1.0	
3.	Derivative Gain Constant	C0	20	25	50	20	25	50
4.	Delay for Air and Fuel Input	Cf		0		25	50	75
5.	Air and Fuel Time Constant	T8	10	20	30	10	25	40
6.	Thermal Inertia Time Constant	T9	4	7	15	40	60	80
7.	Boiler Storage Time Constant	T0	25	100	200	25	100	200
8.	Change in Electrical Power Demand	R1	0.25	0.5	0.75	0.25	0.5	0.75

The results are presented in tabular form in Tables 1 and 2. The graphs representing these results are Figures 2, 3, 4, 17 and 18. Steam flow rate and shaft speed do not vary appreciably with changes in the different variables, Therefore, two graphs, Figures 19 and 20, show the effects of changing variables to the overshoot for boiler pressure and firing rate, respectively. The variables range from low to high values along the abscissas. The overshoot along the ordinate is given in percent of the overshoot of the base case. An overshoot greater than 100 percent indicates larger overshoot and possibly longer transient response.

TABLE 1

OIL FIRED STEAM GENERATOR

CHANGE	CASE	RESPONSE	POWER DEMAND	STEAM FLOW RATE	FIRING RATE	SHAFT SPEED	PRESSURE
Base Case (Figure 2)	1	Mo	0.5	2.17	2.96	2.96	0.047
		To	0.0	3	3	2	6
		Mu	-	0.22	0.23	1.17	-
		Tu	-	9	10	8	-
		Ts	0.0	20	35	20	14
		Ss	0.5	0.5	0.5	0.0	0.0
To=200	2	Mo	0.5	1.17	1.76	2.95	0.026
		To	0.0	3	3	2	6
		Mu	-	0.22	0.24	1.19	-
		Tu	-	9	9	8	-
		Ts	0.0	20	20	20	15
		Ss	0.5	0.5	0.5	0.0	0.0
To=25	3	Mo	0.5	1.69	2.21	2.98	0.18
		To	0.0	3	3	2	6
		Mu	-	0.28	0.33	1.01	-
		Tu	-	10	10	9	-
		Ts	0.0	35	35	15	60
		Ss	0.5	0.5	0.0	0.0	0.0
Co=50	4	Mo	0.5	1.74	4.19	2.96	0.028
		To	0.0	3	3	2	5
		Mu	-	0.22	0.006	1.23	-
		Tu	-	9	10	8	-
		Ts	0.0	20	25	20	15
		Ss	0.5	0.5	0.5	0.0	0.0
Co=20	5	Mo	0.5	1.74	1.77	2.96	0.052
		To	0.0	3	3	2	6
		Mu	-	0.23	0.26	1.16	-
		Tu	-	9	9	8	-
		Ts	0.0	20	20	20	15
		Ss	0.5	0.5	0.5	0.0	0.0
C2=0.05	6	Mo	0.5	1.55	1.95	3.05	0.044
		To	0.0	3	3	2	6
		Mu	-	0.37	0.41	0.45	-
		Tu	-	10	10	10	-
		Ts	0.0	30	40	40	40
		Ss	0.5	0.5	0.5	0.0	0.0

CHANGE	CASE	RESPONSE	POWER DEMAND	STEAM FLOW RATE	FIRING RATE	SHAFT SPEED	PRESSURE
C2=0.25	7	Mo	0.5	2.18	2.75	2.68	0.053
		To	0.0	3	3	2	5
		Mu	-	0.27	0.43	2.15	-
		Tu	-	8	8	6	-
		Ts	0.0	45	45	40	40
		Ss	0.5	0.5	0.5	0.0	0.0
T8=10	8	Mo	0.5	1.74	4.00	2.96	0.03
		To	0.0	3	3	2	4
		Mu	-	0.22	2.72	1.22	0.033
		Tu	-	9	9	8	25
		Ts	0.0	30	55	40	120
		Ss	0.5	0.5	0.5	0.0	0.0
T8=30	9	Mo	0.5	1.76	1.49	2.96	0.056
		To	0.0	3	3	2	7
		Mu	-	0.22	0.27	1.15	-
		Tu	-	9	9	8	-
		Ts	0.0	30	75	35	180
		Ss	0.5	0.5	0.5	0.0	0.0
T9=4	10	Mo	0.5	1.74	2.17	2.96	0.036
		To	0.0	3	3	2	5
		Mu	-	0.22	0.20	1.2	-
		Tu	-	9	10	8	-
		Ts	0.0	35	60	30	120
		Ss	0.5	0.5	0.5	0.0	0.0
T9-15	11	Mo	0.5	1.73	2.17	2.96	0.061
		To	0.0	3	3	2	7
		Mu	-	0.22	0.25	1.14	-
		Tu	-	9	10	8	-
		Ts	0.0	35	50	25	180
		Ss	0.5	0.5	0.5	0.0	0.0
R1-0.25	12	Mo	0.25	2.18	2.75	2.68	0.053
		To	0.0	3	3	2	5
		Mu	-	0.27	0.43	2.15	-
		Tu	-	8	8	6	-
		Ts	0.0	45	45	40	40
		Ss	0.25	0.25	0.25	0.0	0.0

CHANGE	CASE	RESPONSE	POWER DEMAND	STEAM FLOW RATE	FIRING RATE	SHAFT SPEED	PRESSURE
R1=0.75	13	Mo	0.75	2.60	3.26	4.44	0.071
		To	0.0	3	3	2	6
		Mu	-	0.34	0.34	1.76	-
		Tu	-	9	10	8	-
		Ts	0.0	25	40	30	30
		Ss	0.75	0.75	0.75	0.0	0.0
C4=10 (No reheat)	14	Mo	0.5	0.67	0.76	0.80	0.022
		To	0.0	1	1	2	10
		Mu	-	-	-	-	-
		Tu	-	-	-	-	-
		Ts	0.0	7	50	25	40
		Ss	0.5	0.5	0.5	0.0	0.0
C2-0 (Figure 18)	15	Mo	0.5	1.35	1.75	3.29	0.039
		To	0.0	3	3	3	6
		Mu	-	-	-	-	-
		Tu	-	-	-	-	-
		Ts	0.0	20	25	50	40
		Ss	0.5	0.5	0.5	1.19	0.0
No Comb. Control (Figure 17)	16	Mo	0.5	1.73	0.0	2.96	0.018
		To	0.0	3	0.0	2	3
		Mu	-	-	-	0.34	-
		Tu	-	-	-	6	-
		Ts	0.0	-	0.0	-	-
		Ss	0.5	-	0.0	-	-
R1=0.5	17	Mo	0.5	1.74	2.17	2.96	0.047
		To	0.0	3	3	2	6
		Mu	-	0.22	0.23	1.17	-
		Tu	-	9	10	8	-
		Ts	0.0	20	35	20	15
		Ss	0.5	0.5	0.5	0.0	0.0

TABLE 2

COAL FIRED STEAM GENERATOR

CHANGE	CASE	RESPONSE	POWER DEMAND	STEAM FLOW RATE	FIRING RATE	SHAFT SPEED	PRESSURE
Base Case (Figure 3)	18	Mo	0.5	1.66	2.15	2.99	2.35
		To	0.0	3	85	2	80
		Mu	-	0.29	1.40	0.32	-
		Tu	-	9	175	125	-
		Ts	0.0	60	3.5	2.5	185
		Ss	0.5	0.5	0.5	0.0	0.0
Prop=0.5*P1	19	Mo	0.5	1.66	1.52	2.99	2.46
		To	0.0	3	85	2	85
		Mu	-	0.29	-	0.18	-
		Tu	-	9	-	134	-
		Ts	0.0	65	360	270	315
		Ss	0.5	0.5	0.5	0.0	0.0
C4=1.0 Prop=1.5*P1	20	Mo	0.5	1.66	2.75	2.99	2.30
		To	0.0	3	85	2	75
		Mu	-	0.29	0.50	0.44	0.40
		Tu	-	9	165	120	170
		Ts	0.0	140	475	340	345
		Ss	0.5	0.5	0.5	0.0	0.0
T8=10 T9=40 CF=25	21	Mo	0.5	1.66	1.82	2.99	1.57
		To	0.0	3	40	2	45
		Mu	-	0.29	-	0.63	-
		Tu	-	9	-	8	-
		Ts	0.0	60	290	275	360
		Ss	0.5	0.5	0.5	0.0	0.0

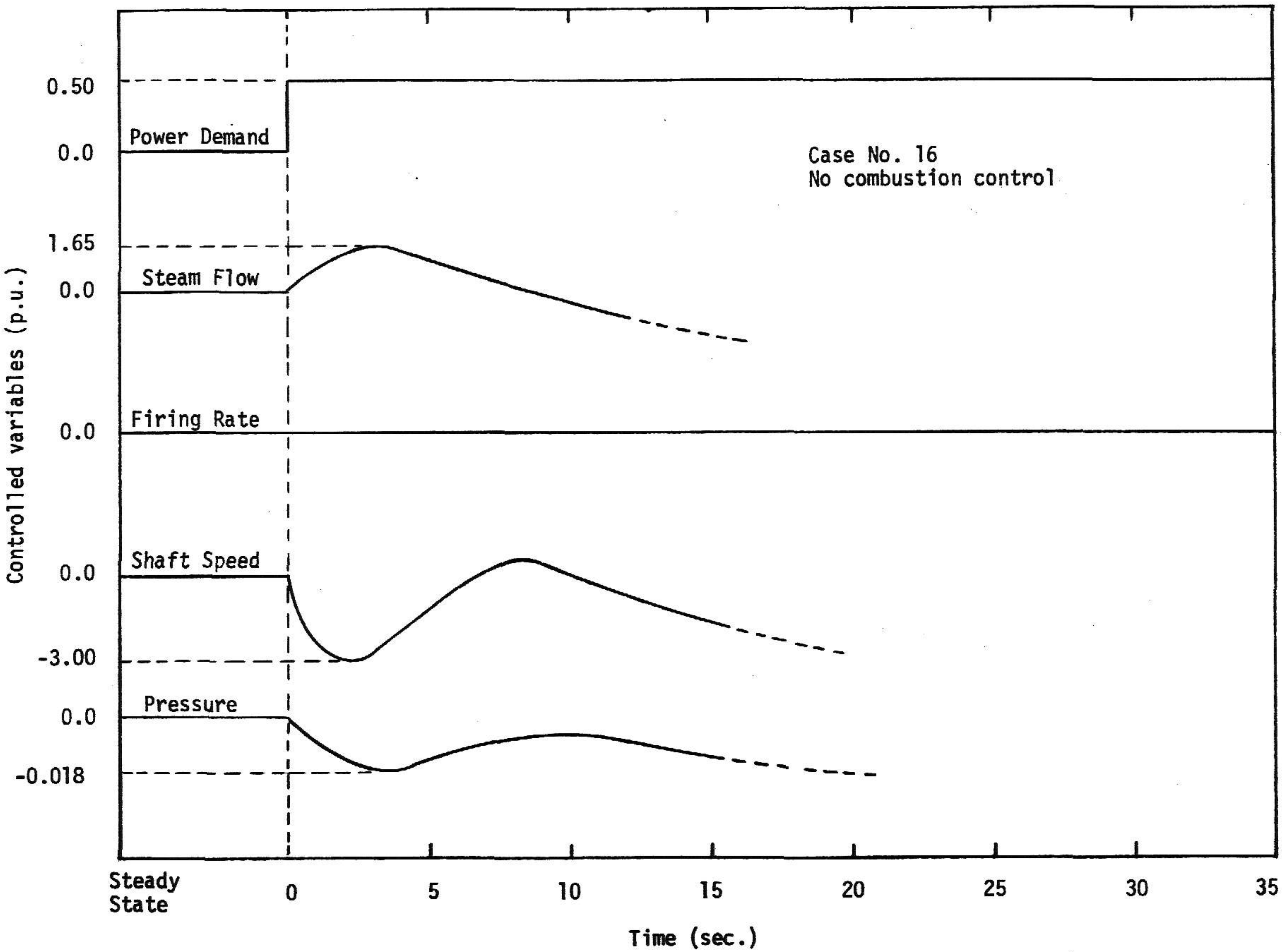

Case No. 16
No combustion control
Controlled variables (p.u.)
0.50
0.0
Power Demand
1.65
0.0
Steam Flow
0.0
Firing Rate
0.0
Shaft Speed
-3.00
0.0
Pressure
-0.018
Steady State
0
5
10
15
20
25
30
35
Time (sec.)

Figure 17

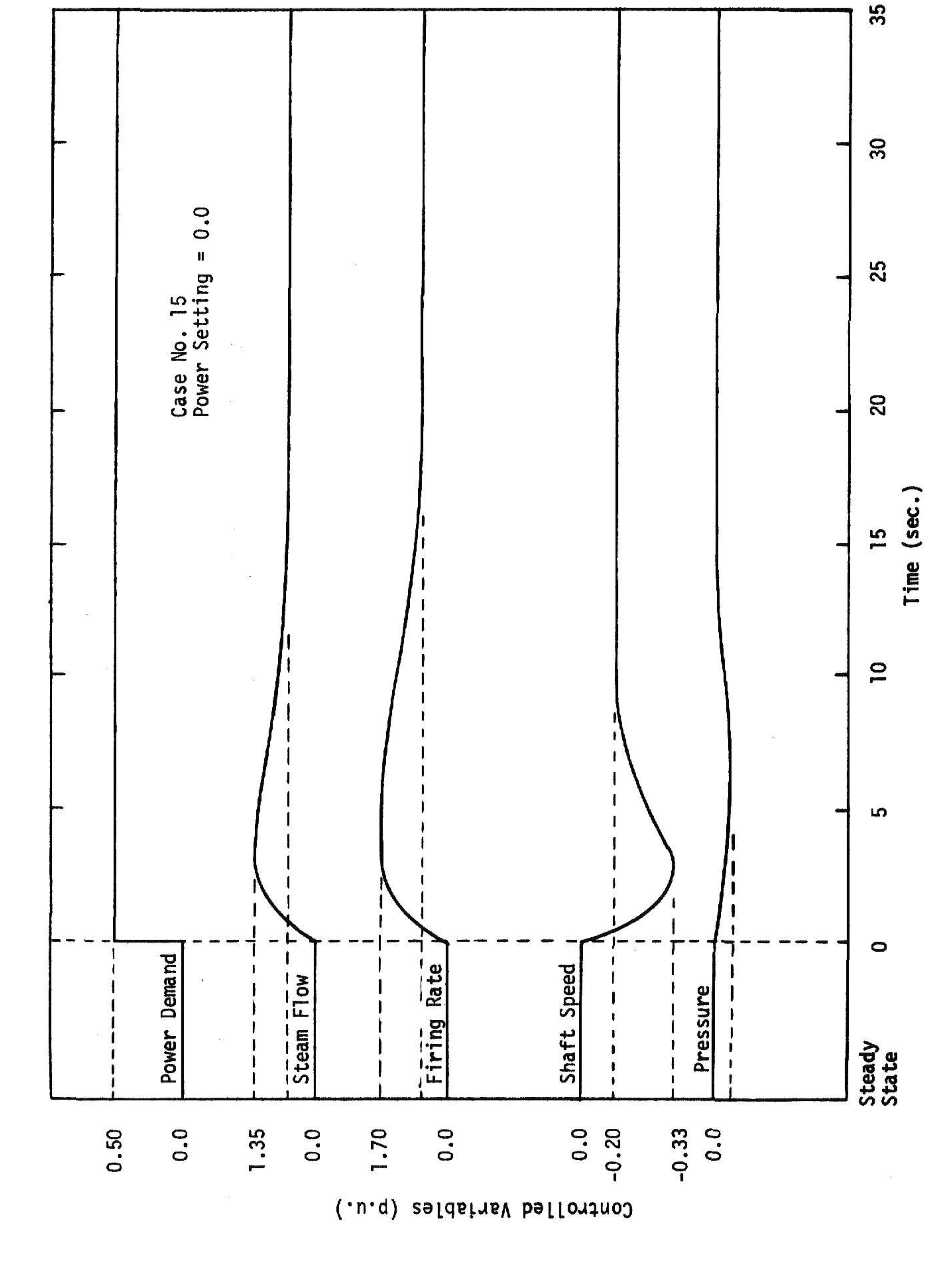

Case No. 15
Power Setting = 0.0
Power Demand
Steam Flow
Firing Rate
Shaft Speed
Pressure
Steady State
0
5
10
15
20
25
30
35
Time (sec.)
0.50
0.0
1.35
0.0
1.70
0.0
0.0
-0.20
-0.33
0.0
Controlled Variables (p.u.)

Figure 18.

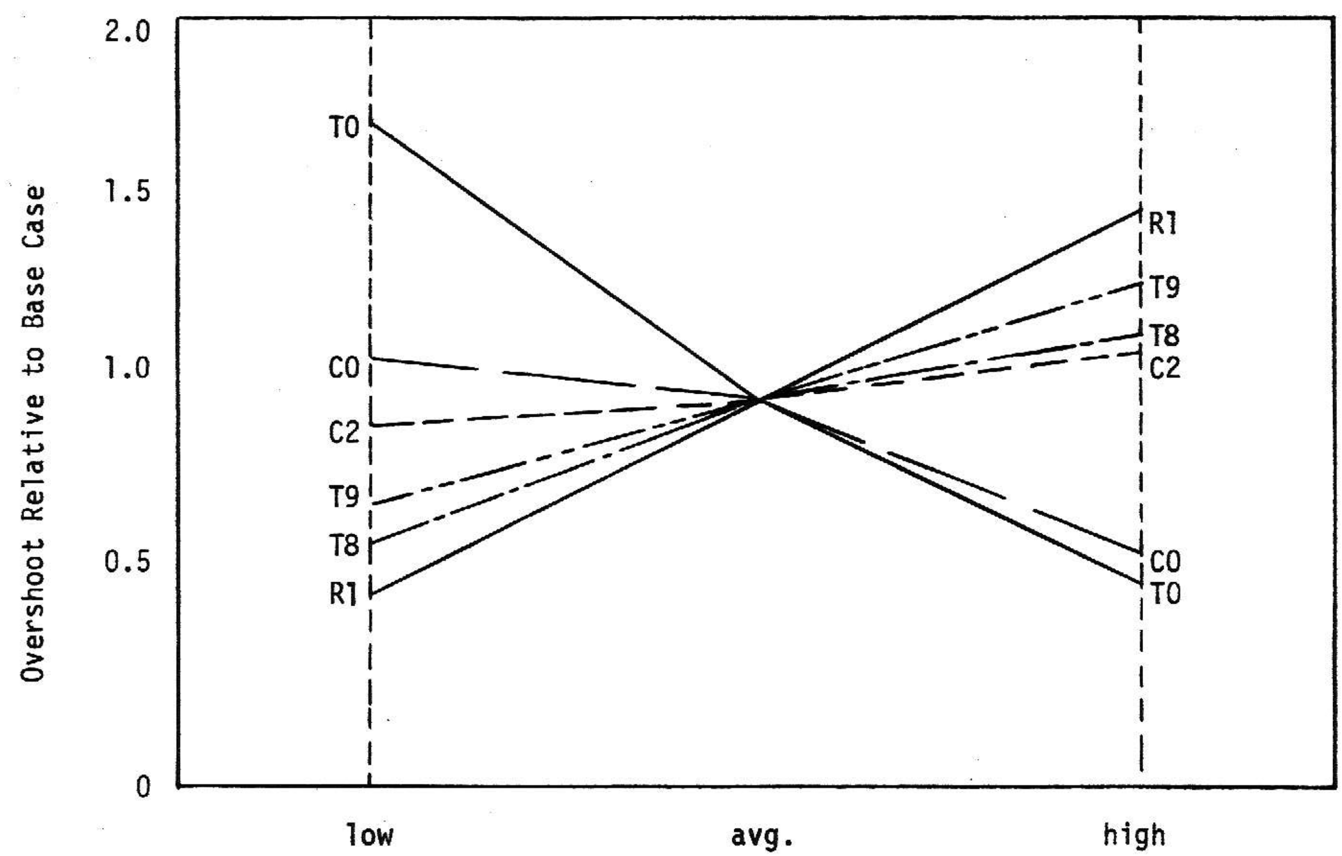


Figure 19. Overshoot vs. Variables for Boiler Pressure

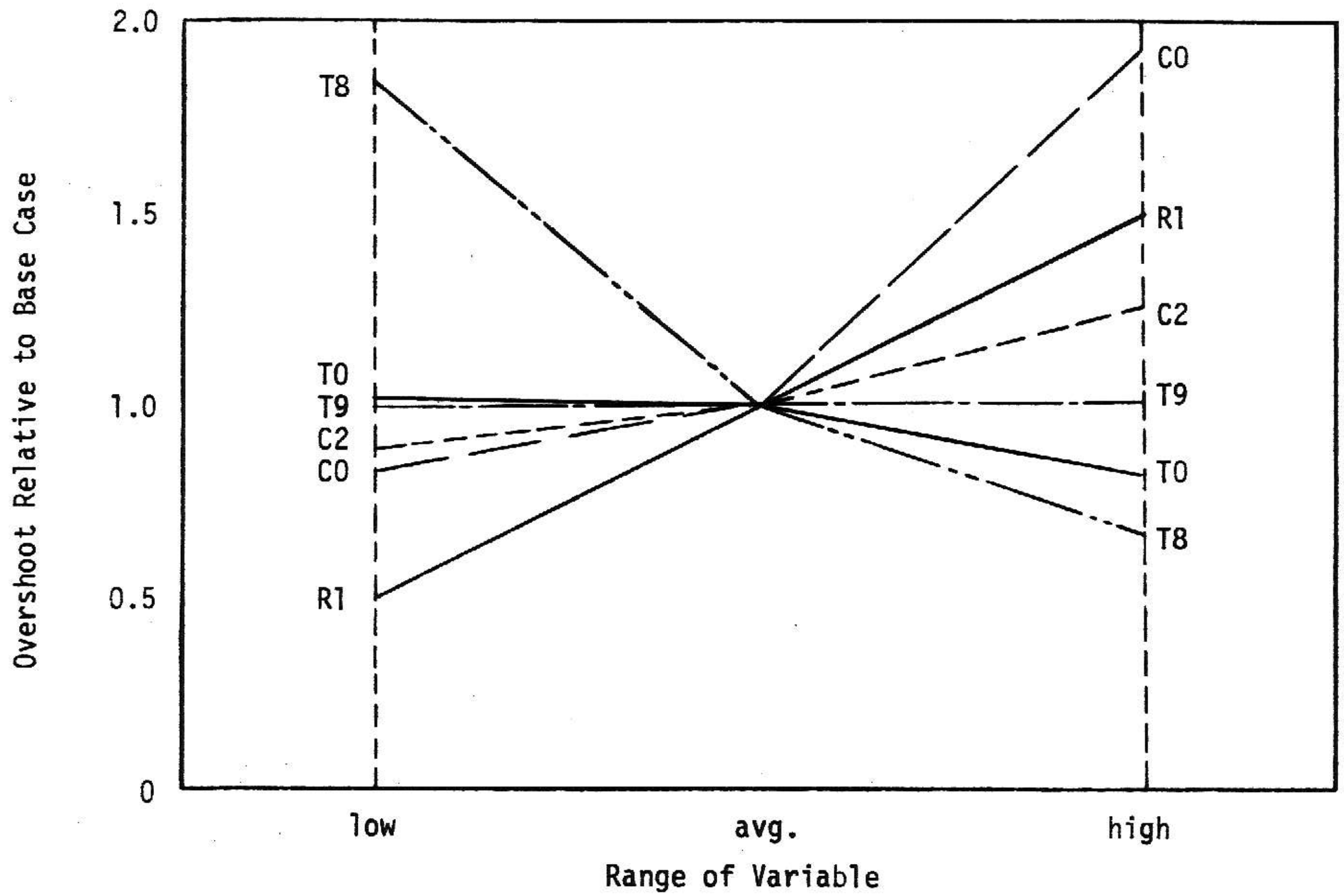


Figure 20. Overshoot vs. Variables for Firing Rate

CHAPTER VI

CONCLUSIONS AND RESULTS

The computer program used Euler's numerical integration technique. The results obtained by using this program for sample problems compared very closely to results obtained by using IBM's Continuous Systems Modeling Program and the exact solution by use of control theory. This accuracy is due to extremely small incremental steps. The computer language is BASIC. The computer used was a Nova computer made by Data General Corporation.

The results obtained by using these control models show much similarity to actual test data found in the literature, De Mello [5]. The power plant with a coal fired steam generator is subjected to a step increase in electrical demand. The pressure deviation (see Figure 21) follows the same trend as pressure deviation obtained in this thesis (see Figure 3). The time at which the actual data over shoot occurs is approximately 30 seconds compared to about 60 seconds for the overshoot for the calculated pressure response. This difference may be due to different time constants, gain constants, and combustion control systems. De Mello [6] also developed a computer program to predict the dynamic response of boiler pressure. The results in this thesis compared very closely to those obtained by De Mello.

Figures 19 and 20 show the sensitivity of the pressure and firing rate overshoot to changes in the time constants, gain constants, and power demand. Overshoot was used to represent the general trend of the dynamic response. The dynamic response of firing rate is sensitive to values of T8, air and fuel time constant, and CO, derivative gain constant. Less firing rate overshoot can be obtained by increasing TO and T8 and decreasing C2, CO, and R1.

The dynamic response of boiler pressure is sensitive to TO, boiler storage constant. Pressure overshoot can be decreased if C2, CO, R1 are decreased while increasing TO and T8. Decreasing the overshoot for both cases by changing different variables is due to interaction of these variables. Therefore, a sensitivity study like this should provide a means for evaluating the effect of dynamic response to changes in time constants, gain constants, and control systems. Suggested changes to enable better steam generator dynamic response it to decrease C2 and R1 while increasing TO and T8.

There is a great difference in the dynamic response of oil or gas fired or coal fired steam generators. For the oil fired base case, all transients died out within 35 seconds. In the coal fired base case, this settling time increased to 315 seconds. The main cause for this difference is the fuel system delay time which is about 50 seconds. This reacts as being no change in the firing rate for at least 50 seconds. Also the time constant for the coal firing system is nearly twice as long as that for oil fired. The other reason is the increase in the thermal inertia time constant.

The dynamic response is also a strong function of the type of control system used. The first control system that is encountered is the speed governor. This control system has been in use and analized for many years. Therefore, the time constants and gain constants are well established. The second control system is combustion control which adjusts the air-fuel inputs in order to maintain constant pressure. Derivative control worked satisfactorily for the oil fired case but was slow in bringing the transients back to steady state for the coal fired case. The dynamic response of the coal fired case was fairly sensitive to the gain constants used in the proportional plus derivative plus integral control mode. It was found that the major portion of the transients died out quickly with this type of control mode, but the settling time was more sensitive to the gain constant of the proportional part of the control.

The dynamic response for about 30 seconds for a power plant is valid when pressure changes are neglected. This approximation is valid because in the oil fired case the pressure changes are very small and the fuel system delay time constant for the coal fired case is usually longer than the total time valid for the approximation. This approximation has been used in load-frequency studies for several years. This approximation is limited to about 20 percent power demand change and a total time of about 30 seconds.

More work is needed in obtaining accurate models of the steam generator. The dynamic analysis obtained by using the control model in this thesis is reasonably accurate to power plant characteristics. More knowledge is needed for better control in the power plant. More data is also needed for power plants subjected to large scale faults. Some tests are being planned for the future as a joint electric utility effort. These tests should provide more data with which predicted dynamic analysies can be compared.

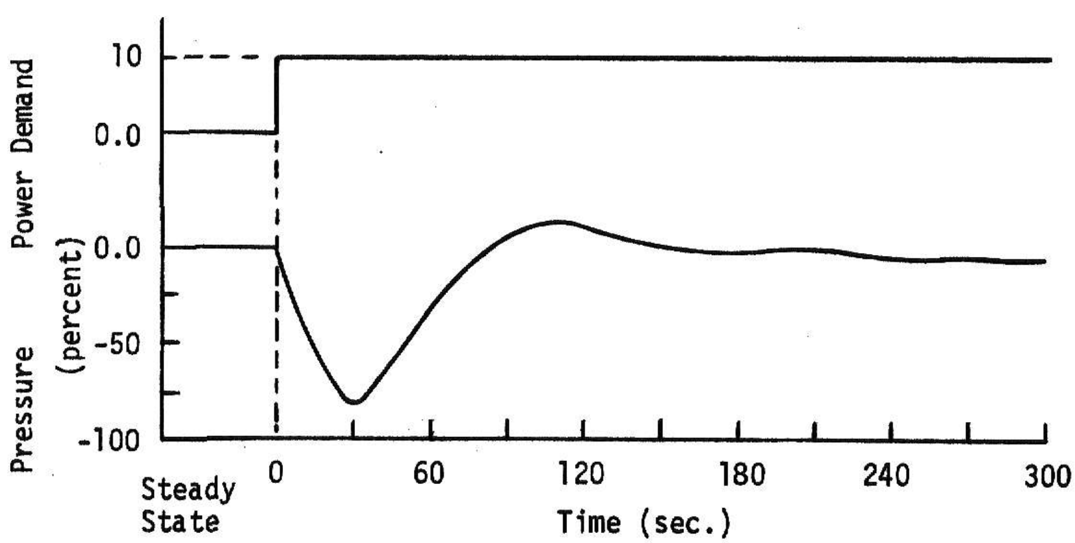


Figure 21. Graph of Actual Data

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DYNAMIC RESPONSE OF STEAM GENERATORS

by

TERRENCE WAYNE RYAN

B.S. Kansas State University, 1972

AN ABSTRACT OF A MASTER'S THESIS

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MASTER OF SCIENCE

Department of Mechanical Engineering

Kansas State University

Manhattan, Kansas

1973

ABSTRACT

This thesis presents a mathematical analysis of the dynamic behavior of a steam power generating station in response to changes in the electrical demand. The results presented in this thesis are for a single generating station, i.e. boiler, turbine, and electrical generator, subjected to changes in electrical demand. The power plant was assumed operating into an infinite electrical system.

A mathematical model was derived for the dynamic response of all basic operations and controls of the power plant. A digital computer program was written to solve the set of first order differential equations of the mathematical model.

The dynamic response of the plant parameters was obtained for several representative time constants and gain constants. The plant parameters considered were: steam flow rate, firing rate, shaft speed, and boiler pressure. Two types of combustion control systems were considered. These control systems incorporated either derivative control mode or proportional plus derivative plus integral control mode. The different responses of oil fired or coal fired steam generators were also considered.

The results of this analysis were presented in tabular and graphical form so that the changes in power station responses as a function of station variables and control were shown.