Control of Active Power and Reactive Power

So far this book has concentrated on the characteristics and modelling of individual elements of the power systems. This chapter will examine control of active power and reactive power by considering the system as an entity. In addition, the characteristics and modelling of equipment used for control will be described.

The flows of active power and reactive power in a transmission network are fairly independent of each other and are influenced by different control actions (see Section 6.3). Hence, they may be studied separately for a large class of problems. Active power control is closely related to frequency control, and reactive power control is closely related to voltage control. As constancy of frequency and voltage are important factors in determining the quality of power supply, the control of active power and reactive power is vital to the satisfactory performance of power systems.

11.1 ACTIVE POWER AND FREQUENCY CONTROL

For satisfactory operation of a power system, the frequency should remain nearly constant. Relatively close control of frequency ensures constancy of speed of induction and synchronous motors. Constancy of speed of motor drives is particularly important for satisfactory performance of generating units as they are highly dependent on the performance of all the auxiliary drives associated with the fuel, the feed-water and the combustion air supply systems. In a network, considerable drop in frequency could result in high magnetizing currents in induction motors and transformers. The extensive use of electric clocks and the use of frequency for other timing purposes require accurate maintenance of synchronous time which is proportional to integral of frequency. As a consequence, it is necessary to regulate not only the frequency itself but also its integral.

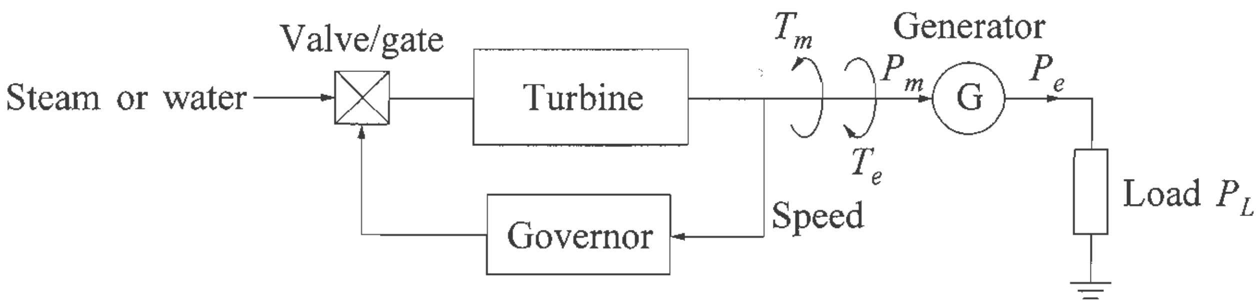
The frequency of a system is dependent on active power balance. As frequency is a common factor throughout the system, a change in active power demand at one point is reflected throughout the system by a change in frequency. Because there are many generators supplying power into the system, some means must be provided to allocate change in demand to the generators. A speed governor on each generating unit provides the primary speed control function, while supplementary control originating at a central control centre allocates generation.

In an interconnected system with two or more independently controlled areas, in addition to control of frequency, the generation within each area has to be controlled so as to maintain scheduled power interchange. The control of generation and frequency is commonly referred to as *load-frequency control* (LFC).

We will first review the requirements for primary speed governing and then discuss supplementary control.

11.1.1 Fundamentals of Speed Governing

The basic concepts of speed governing are best illustrated by considering an isolated generating unit supplying a local load as shown in Figure 11.1.

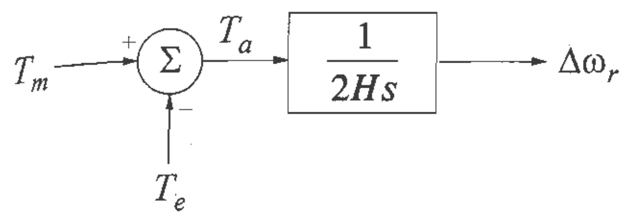


T_m = mechanical torque $\quad$ T_e = electrical torque
P_m = mechanical power $\quad$ P_e = electrical power $\quad$ P_L = load power

Figure 11.1 Generator supplying isolated load

Generator response to load change

When there is a load change, it is reflected instantaneously as a change in the electrical torque output T_e of the generator. This causes a mismatch between the mechanical torque T_m and the electrical torque T_e which in turn results in speed variations as determined by the equation of motion. As shown in Chapter 3 (Section 3.9), the following transfer function represents the relationship between rotor speed as a function of the electrical and mechanical torques.



s = Laplace operator
T_m = Mechanical torque (pu)
T_e = Electrical torque (pu)
T_a = Accelerating torque (pu)
H = Inertia constant (MW-Sec/MVA)
$\Delta\omega_r$ = Rotor speed deviation (pu)

Figure 11.2 Transfer function relating speed and torques

For load-frequency studies, it is preferable to express the above relationship in terms of mechanical and electrical power rather than torque. The relationship between power P and torque T is given by

$$P = \omega_r T \tag{11.1}$$

By considering a small deviation (denoted by prefix Δ) from initial values (denoted by subscript 0), we may write

$$\begin{aligned} P &= P_0 + \Delta P \\ T &= T_0 + \Delta T \\ \omega_r &= \omega_0 + \Delta\omega_r \end{aligned} \tag{11.2}$$

From Equation 11.1,

$$P_0 + \Delta P = (\omega_0 + \Delta\omega_r)(T_0 + \Delta T)$$

The relationship between the perturbed values, with higher-order terms neglected, is given by

$$\Delta P = \omega_0 \Delta T + T_0 \Delta\omega_r \tag{11.3}$$

Therefore,

$$\Delta P_m - \Delta P_e = \omega_0(\Delta T_m - \Delta T_e) + (T_{m0} - T_{e0})\Delta\omega_r \tag{11.4}$$

Since, in the steady state, electrical and mechanical torques are equal, $T_{m0} = T_{e0}$. With speed expressed in pu, $\omega_0 = 1$. Hence,

$$\Delta P_m - \Delta P_e = \Delta T_m - \Delta T_e \tag{11.5}$$

Figure 11.2 can now be expressed in terms of ΔP_m and ΔP_e as follows:

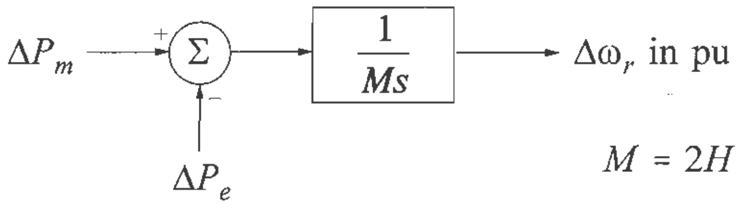


Figure 11.3 Transfer function relating speed and power

Within the range of speed variations with which we are concerned, the turbine mechanical power is essentially a function of valve or gate position and independent of frequency.

Load response to frequency deviation

In general, power system loads are a composite of a variety of electrical devices. For resistive loads, such as lighting and heating loads, the electrical power is independent of frequency. In the case of motor loads, such as fans and pumps, the electrical power changes with frequency due to changes in motor speed. The overall frequency-dependent characteristic of a composite load may be expressed as

$$\Delta P_e = \Delta P_L + D\Delta\omega_r \tag{11.6}$$

where

ΔP_L = non-frequency-sensitive load change
$D\Delta\omega_r$ = frequency-sensitive load change
D = load-damping constant

The damping constant is expressed as a percent change in load for one percent change in frequency. Typical values of D are 1 to 2 percent. A value of D=2 means that a 1% change in frequency would cause a 2% change in load.

The system block diagram including the effect of the load damping is shown in Figure 11.4.

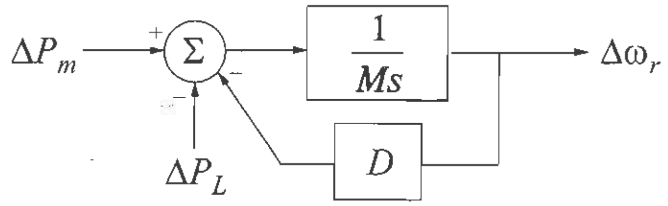


Figure 11.4

This may be reduced to the form shown in Figure 11.5.

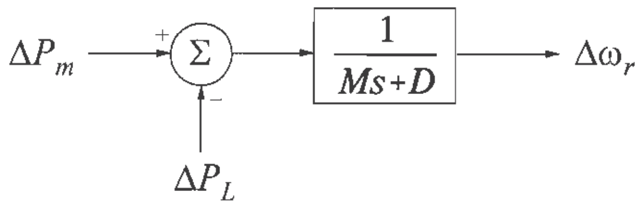


Figure 11.5

In the absence of a speed governor, the system response to a load change is determined by the inertia constant and the damping constant. The steady-state speed deviation is such that the change in load is exactly compensated by the variation in load due to frequency sensitivity. This is illustrated in the following example.

Example 11.1

A small system consists of 4 identical 500 MVA generating units feeding a total load of 1,020 MW. The inertia constant H of each unit is 5.0 on 500 MVA base. The load varies by 1.5% for a 1% change in frequency. When there is a sudden drop in load by 20 MW,

(a) Determine the system block diagram with constants H and D expressed on 2,000 MVA base.

(b) Find the frequency deviation, assuming that there is no speed-governing action.

Solution

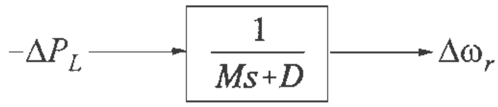
(a) For 4 units on 2,000 MVA base, $H = 5.0\times(500/2000)\times4 = 5.0$. Hence,

$$M = 2H = 10.0 \text{ s}$$

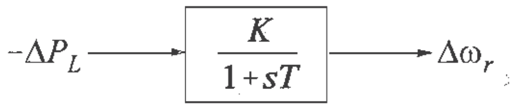
Expressing D for the remaining load (1020−20=1000 MW) on 2,000 MVA base,

$$D = 1.5\times1000/\ 2000 = 0.75\%$$

(b) With $\Delta P_m = 0$ (no speed governing), the system block diagram with parameters expressed in pu on 2,000 MVA is



This may be expressed in the standard form in terms of a gain and a time constant:



where

$$K = \frac{1}{D} = \frac{1}{0.75} = 1.33$$

$$T = \frac{M}{D} = \frac{10}{0.75} = 13.33 \text{ s}$$

The load change is

$$\Delta P_L = -20 \text{ MW}$$

$$= \frac{-20}{2000} = -0.01 \text{ pu}$$

For a step reduction in load by 0.01 pu, Laplace transform of the change in load is

$$\Delta P_L(s) = \frac{-0.01}{s}$$

Hence, from the block diagram

$$\Delta\omega_r(s) = -\left(\frac{-0.01}{s}\right)\left(\frac{K}{1+sT}\right)$$

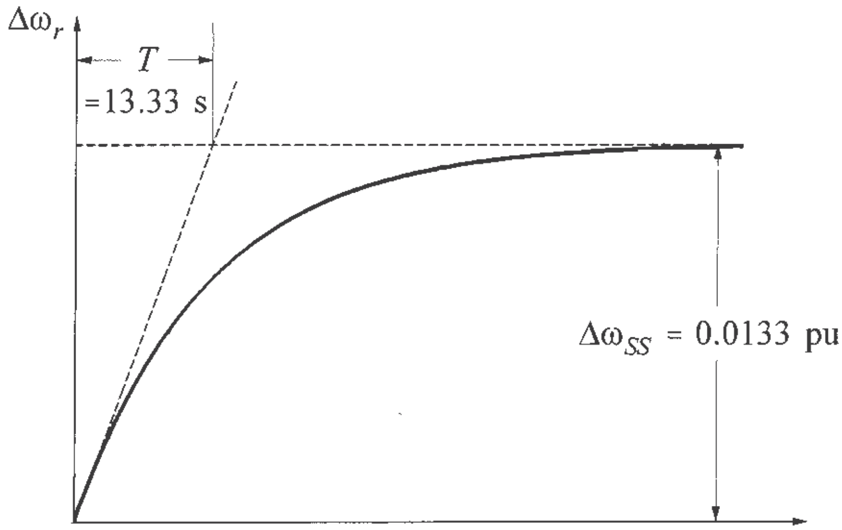
Taking the inverse transform,

$$\Delta\omega_r(t) = -0.01K e^{-\frac{t}{T}} + 0.01K$$

$$= -0.01 \times 1.33\, e^{-\frac{t}{13.33}} + 0.01 \times 1.33$$

$$= -0.0133\, e^{-0.075t} + 0.0133$$

The pu speed deviation as function of time is shown in the following figure.



The time constant T is 13.33 s and the steady-state speed deviation is

$$\Delta\omega_{ss} = -\frac{\Delta P_L}{D} = 0.0133 \text{ pu}$$

$$= 0.0133 \times 60 = 0.8 \text{ Hz}$$

■

Isochronous governor [1,2]

The adjective isochronous means constant speed. An isochronous governor adjusts the turbine valve/gate to bring the frequency back to the nominal or scheduled value. Figure 11.6 shows the schematic of such a speed-governing system. The measured rotor speed ω_r is compared with reference speed ω_0. The error signal (equal to speed deviation) is amplified and integrated to produce a control signal ΔY which actuates the main steam supply valves in the case of a steam turbine, or gates in the case of a hydraulic turbine. Because of the reset action of this integral controller, ΔY will reach a new steady state only when the speed error $\Delta\omega_r$ is zero.

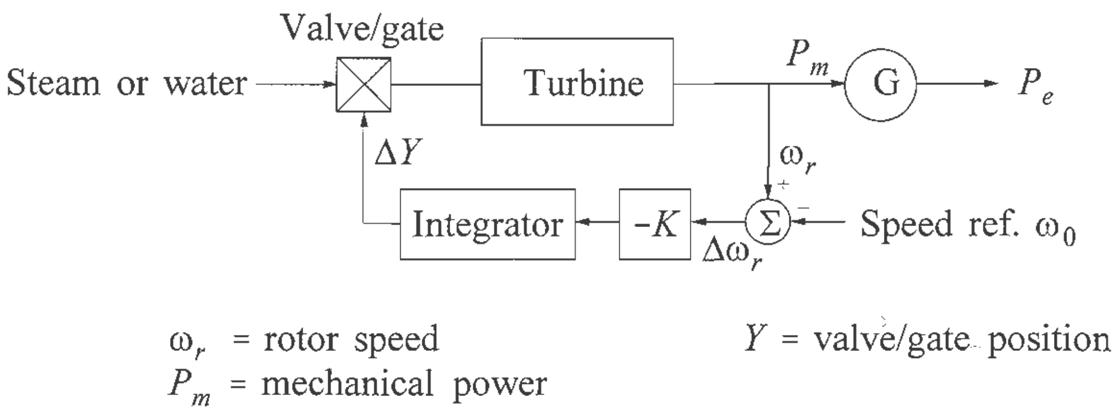


Figure 11.6 Schematic of an isochronous governor

Figure 11.7 shows the time response of a generating unit, with an isochronous governor, when subjected to an increase in load. The increase in P_e causes the frequency to decay at a rate determined by the inertia of rotor. As the speed drops, the turbine mechanical power begins to increase. This in turn causes a reduction in the rate of decrease of speed, and then an increase in speed when the turbine power is in excess of the load power. The speed will ultimately return to its reference value and the steady-state turbine power increases by an amount equal to the additional load.

An isochronous governor works satisfactorily when a generator is supplying an isolated load or when only one generator in a multigenerator system is required to respond to changes in load. For power load sharing between generators connected to the system, speed regulation or droop characteristic must be provided as discussed next.

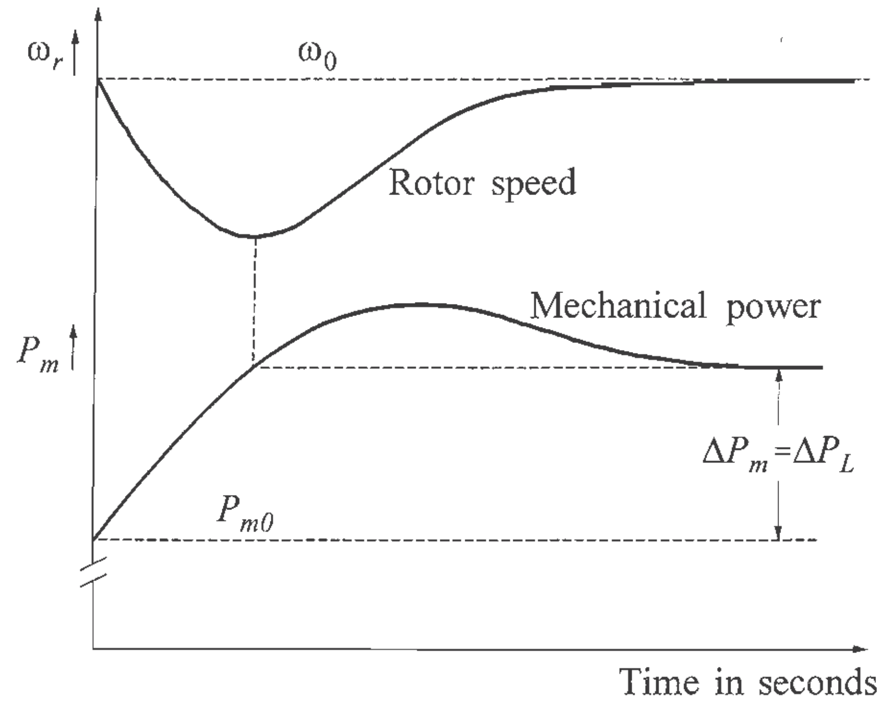


Figure 11.7 Response of generating unit with isochronous governor

Governors with speed-droop characteristic [1,2]

The isochronous governors cannot be used when there are two or more units connected to the same system since each generator would have to have precisely the same speed setting. Otherwise, they would fight each other, each trying to control system frequency to its own setting. For stable load division between two or more units operating in parallel, the governors are provided with a characteristic so that the speed drops as the load is increased.

The speed-droop or regulation characteristic may be obtained by adding a steady-state feedback loop around the integrator as shown in Figure 11.8.

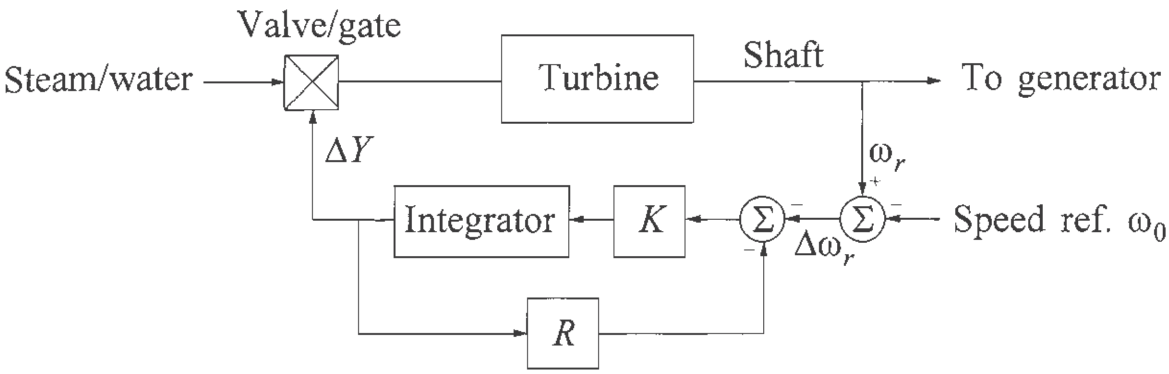
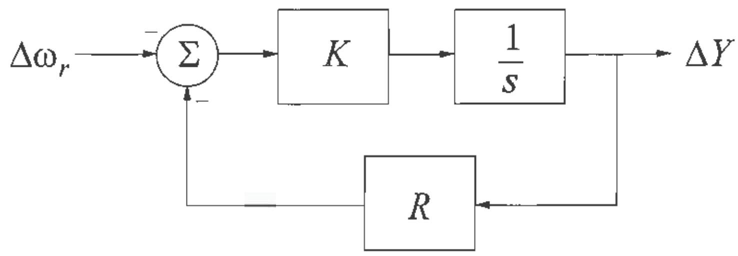
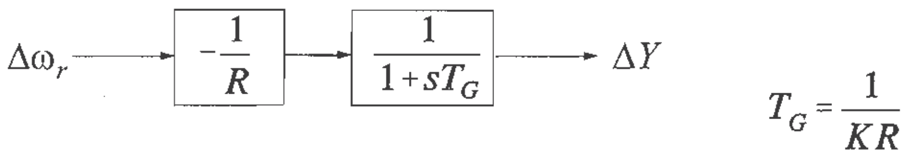


Figure 11.8 Governor with steady-state feedback

The transfer function of the governor of Figure 11.8 reduces to the form shown in Figure 11.9. This type of governor is characterized as a *proportional controller* with a gain of $1/R$.



(a) Block diagram with steady-state feedback



(b) Reduced block diagram

Figure 11.9 Block diagram of a speed governor with droop

Percent speed regulation or droop:

The value of R determines the steady-state speed versus load characteristic of the generating unit as shown in Figure 11.10. The ratio of speed deviation ($\Delta\omega_r$) or frequency deviation (Δf) to change in valve/gate position (ΔY) or power output (ΔP) is equal to R. The parameter R is referred to as speed regulation or droop. It can be expressed in percent as

$$\text{Percent } R = \frac{\text{percent speed or frequency change}}{\text{percent power output change}} \times 100$$

$$= \left(\frac{\omega_{NL} - \omega_{FL}}{\omega_0}\right) \times 100$$

where

ω_{NL} = steady-state speed at no load
ω_{FL} = steady-state speed at full load
ω_0 = nominal or rated speed

For example, a 5% droop or regulation means that a 5% frequency deviation causes 100% change in valve position or power output.

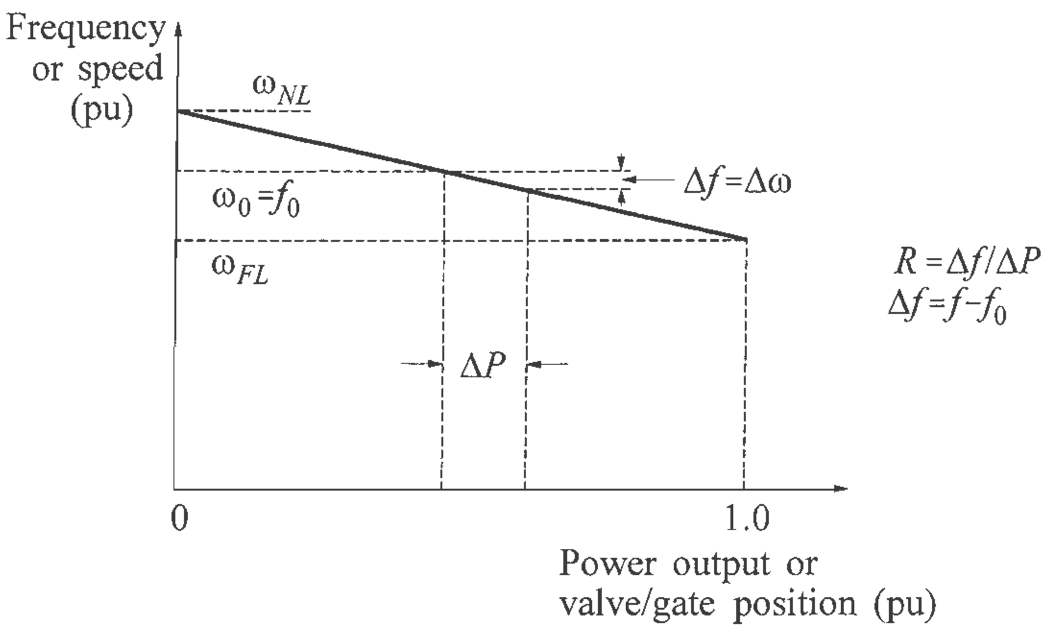


Figure 11.10 Ideal steady-state characteristics of a governor with speed droop

Load sharing by parallel units:

If two or more generators with drooping governor characteristics are connected to a power system, there will be a unique frequency at which they will share a load change. Consider two units with droop characteristics as shown in Figure 11.11. They are initially at nominal frequency f_0, with outputs P_1 and P_2. When a load increase ΔP_L causes the units to slow down, the governors increase output until they reach a new common operating frequency f'. The amount of load picked up by each unit depends on the droop characteristic:

$$\Delta P_1 = P_1' - P_1 = \frac{\Delta f}{R_1}$$

$$\Delta P_2 = P_2' - P_2 = \frac{\Delta f}{R_2}$$

Hence,

$$\frac{\Delta P_1}{\Delta P_2} = \frac{R_2}{R_1}$$

If the percentages of regulation of the units are nearly equal, the change in the outputs of each unit will be nearly in proportion to its rating.

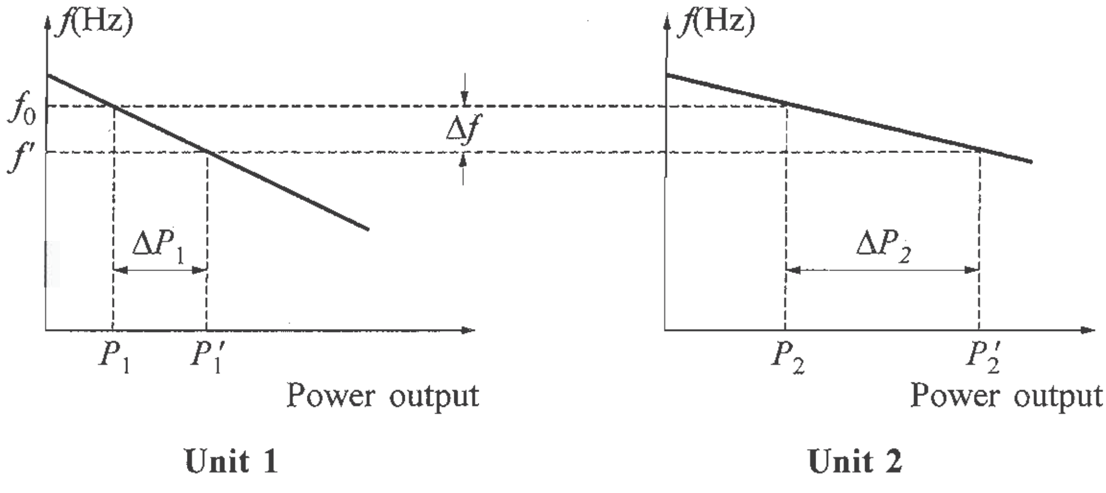


Figure 11.11 Load sharing by parallel units with drooping governor characteristics

Time response

Figure 11.12 shows the time response of a generating unit, with a speed-droop governor, when subjected to an increase in load. Because of the droop characteristic, the increase in power output is accompanied by a steady-state speed or frequency deviation ($\Delta\omega_{SS}$).

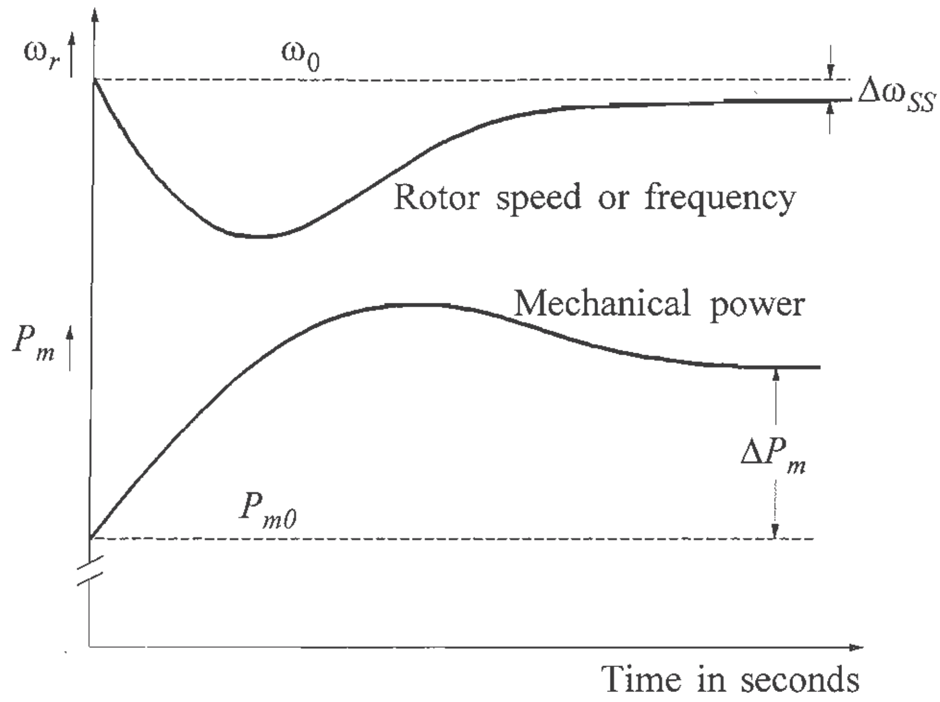


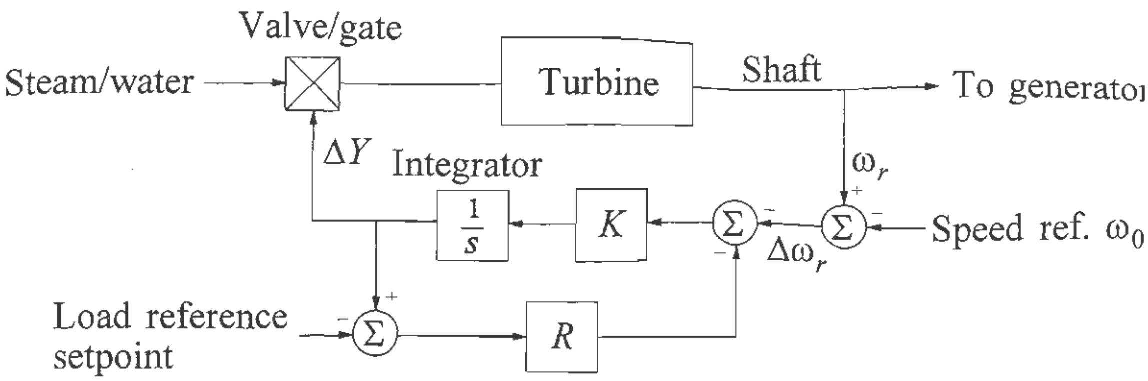
Figure 11.12 Response of a generating unit with a governor having speed-droop characteristic

11.1.2 Control of Generating Unit Power Output

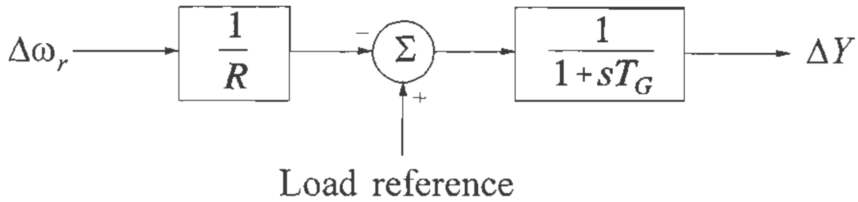
The relationship between speed and load can be adjusted by changing an input shown as "load reference setpoint" in Figure 11.13.

In practice, the adjustment of load reference setpoint is accomplished by operating the "speed-changer motor." The effect of this adjustment is depicted in Figure 11.14, which shows a family of parallel characteristics for different speed-changer motor settings. The characteristics shown are for a governor associated with a 60 Hz system. Three characteristics are shown representing three load reference settings. At 60 Hz, characteristic A results in zero output, characteristic B results in 50% output, and characteristic C results in 100% output. Thus, the power output of the generating unit at a given speed may be adjusted to any desired value by adjusting the load reference setting through actuation of the speed-changer motor. For each setting, the speed-load characteristic has a 5% droop; that is, a speed change of 5% (3 Hz) causes a 100% change in power output.

When two or more generators are operating in parallel, the speed-droop characteristic (corresponding to a load reference setting) of each generating unit merely establishes the proportion of the load picked up by the unit when a sudden change in system load occurs. The output of each unit at any given system frequency can be varied only by changing its load reference, which in effect moves the speed-droop characteristic up and down.



(a) Schematic diagram of governor and turbine



(b) Reduced block diagram of governor

Figure 11.13 Governor with load reference control for adjusting speed-load relationship

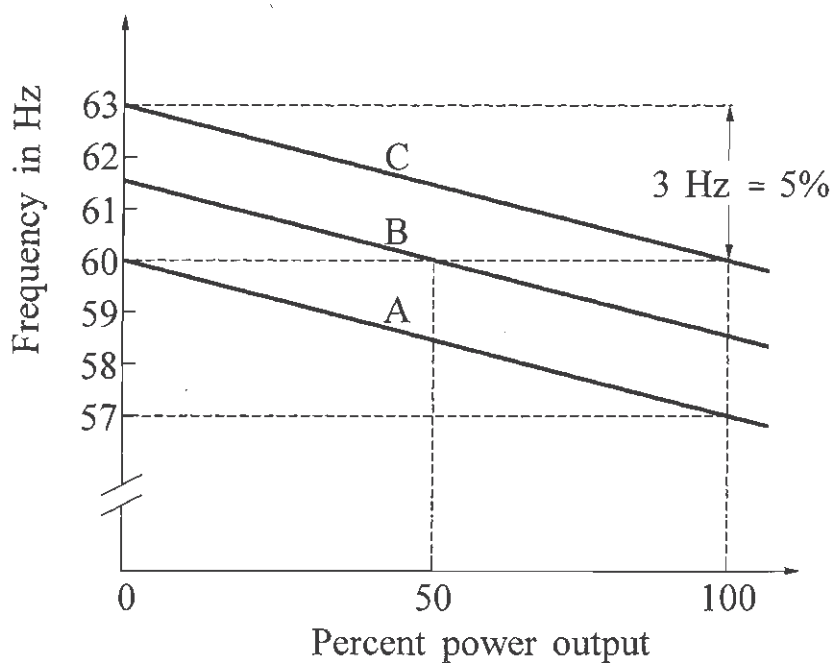


Figure 11.14 Effect of speed-changer setting on governor characteristic

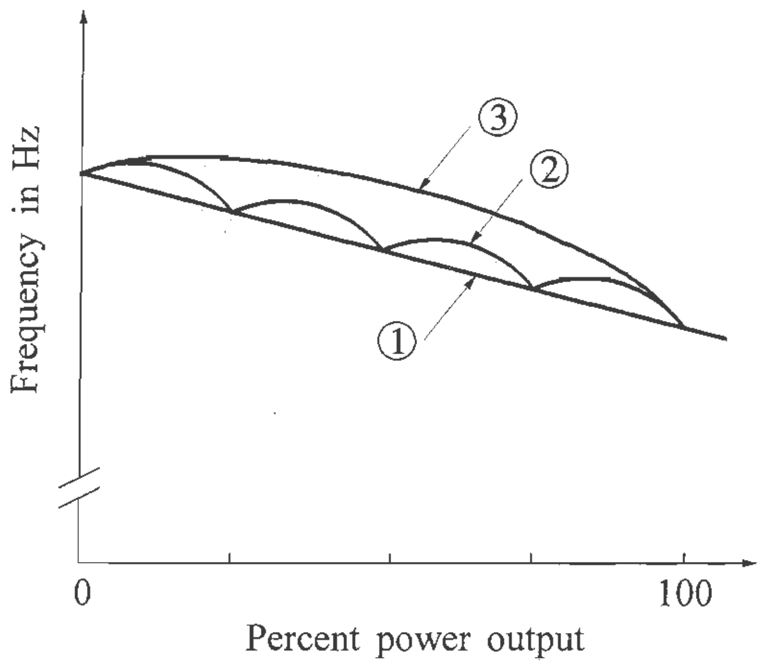
When a generating unit is feeding an isolated load, the adjustment of the speed changer changes the unit speed. However, when the unit is synchronized to a power system, the speed-changer adjustment changes the unit power output; it has only a minor effect on system frequency, depending on the size of the unit relative to that of the total system generation.

Actual speed-droop characteristic [1]

The governor speed-droop characteristic we have considered so far (Figures 11.10 and 11.14) represents the ideal relationship. In actual practice the characteristic departs from the straight-line relationship as depicted in Figure 11.15.

As discussed in Chapter 9, steam turbines have a number of control valves, each having nonlinear flow area versus position characteristic. Hence, they have the speed-droop characteristics of the general nature of curve 2 in Figure 11.15. Each section of curve 2 represents the effect of one control valve. Hydraulic turbines, which have a single gate, tend to have the characteristic similar to curve 3.

The actual speed-droop characteristic may thus exhibit *incremental regulation* ranging from 2% to 12%, depending on the unit output. Modern electrohydraulic governing systems minimize these variations in incremental regulation by using linearizing circuits or first-stage pressure feedback.



Curve 1: Ideal linear characteristic
Curve 2: Actual characteristic for steam units
Curve 3: Actual characteristic for hydraulic units

Figure 11.15 Actual and ideal governor speed-droop characteristics

11.1.3 Composite Regulating Characteristic of Power Systems

In the analysis of load-frequency controls (LFCs), we are interested in the collective performance of all generators in the system. The intermachine oscillations and transmission system performance are therefore not considered. We tacitly assume the coherent response of all generators to changes in system load and represent them by an equivalent generator. The equivalent generator has an inertia constant M_{eq} equal to the sum of the inertia constants of all the generating units and is driven by the combined mechanical outputs of the individual turbines as illustrated in Figure 11.16. Similarly, the effects of the system loads are lumped into a single damping constant D. The speed of the equivalent generator represents the system frequency, and in per unit the two are equal. We will therefore use rotor speed and frequency interchangeably in our discussion of load-frequency control.

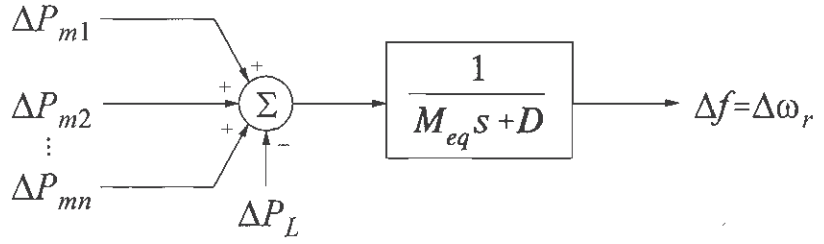


Figure 11.16 System equivalent for LFC analysis

The composite power/frequency characteristic of a power system thus depends on the combined effect of the droops of all generator speed governors. It also depends on the frequency characteristics of all the loads in the system. For a system with n generators and a composite load-damping constant of D, the steady-state frequency deviation following a load change ΔP_L is given by

$$\Delta f_{ss} = \frac{-\Delta P_L}{(1/R_1 + 1/R_2 + \cdots + 1/R_n) + D} = \frac{-\Delta P_L}{1/R_{eq} + D} \tag{11.7}$$

where

$$R_{eq} = \frac{1}{1/R_1 + 1/R_2 + \cdots + 1/R_n} \tag{11.8}$$

Thus, the composite frequency response characteristic of the system is

$$\beta = \frac{-\Delta P_L}{\Delta f_{SS}} = \frac{1}{R_{eq}} + D \tag{11.9}$$

The composite frequency response characteristic β is normally expressed in MW/Hz. It is also sometimes referred to as the *stiffness* of the system. The composite regulating characteristic of the system is equal to 1/β.

The effects of governor speed droop and the frequency sensitivity of load on the net frequency change are illustrated in Figure 11.17, which considers the composite effects of all the generating units and load in the system. An increase of system load by ΔP_L (at nominal frequency) results in a total generation increase of ΔP_G due to governor action and a total system load reduction of ΔP_D due to its frequency-sensitive characteristic.

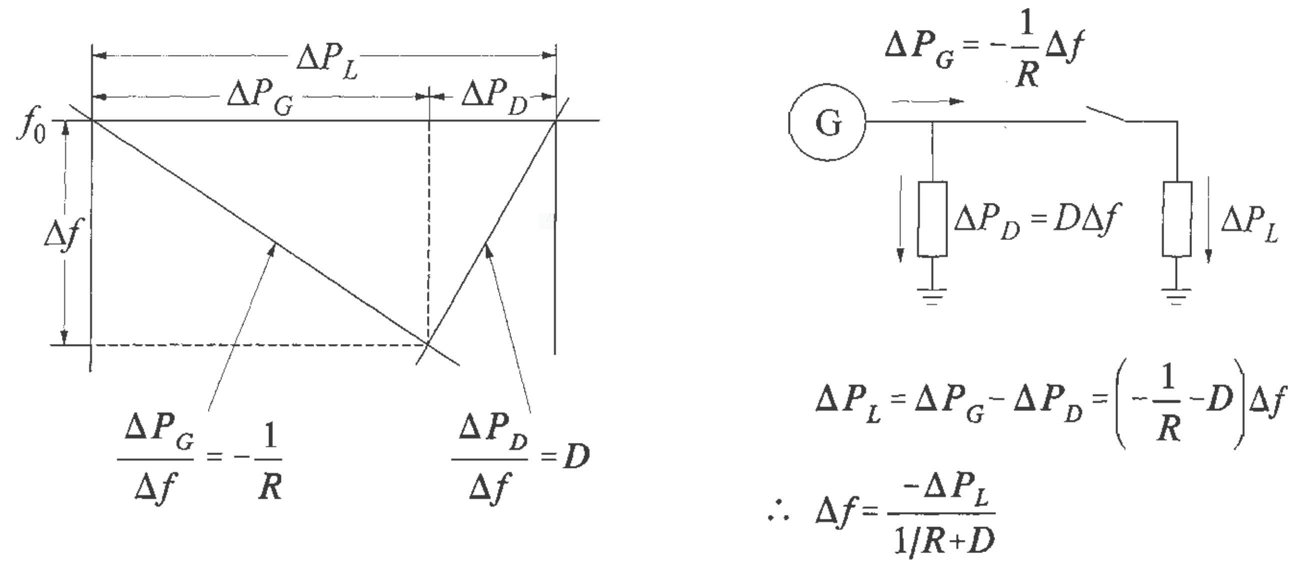


Figure 11.17 Composite governor and load characteristic

Example 11.2

A power system has a total load of 1,260 MW at 60 Hz. The load varies 1.5% for every 1% change in frequency (D=1.5). Find the steady-state frequency deviation when a 60 MW load is suddenly tripped, if

(a) There is no speed control.

(b) The system has 240 MW of spinning reserve evenly spread among 500 MW of generation capacity with 5% regulation based on this capacity. All other generators are operating with valves wide open. Assume that the effect of governor dead bands is such that only 80% of the governors respond to the reduction in system load.

Neglect the effects of transmission losses.

Solution

Total remaining load is 1260−60 = 1200 MW. The damping constant of remaining load is

$$D = \left(\frac{1.5}{100}\times 1200\right)\times\left(\frac{100}{60\times 1}\right) = 30 \quad \text{MW/Hz}$$

(a) With no speed control, the resulting increase in steady-state frequency is

$$\Delta f = \frac{-\Delta P_L}{D} = \frac{-(-60)\ \text{MW}}{30\ \text{MW/Hz}}$$

$$= 2.0 \quad \text{Hz}$$

(b) Since there is a reduction in system load and an increase in frequency, all generating units (not just those on spinning reserve) respond. However, due to the effects of dead band, only 80% of the total generation contributes to speed regulation.

The total spinning generation capacity is equal to

$$\text{Load}+\text{reserve} = 1260+240 = 1500 \text{ MW}$$

Generation contributing to regulation is

$$0.8\times 1500 = 1200 \text{ MW}$$

A regulation of 5% means that a 5% change in frequency causes a 100% change in power generation. Therefore,

$$\frac{1}{R} = \frac{1200}{(5/100)\times 60} = 400 \quad \text{MW/Hz}$$

The composite system frequency response characteristic is

$$\beta = \frac{1}{R}+D = 400+30$$

$$= 430 \quad \text{MW/Hz}$$

Steady-state increase in frequency is

$$\Delta f = \frac{-\Delta P_L}{\beta} = \frac{-(-60)\ \text{MW}}{430\ \text{MW/Hz}}$$

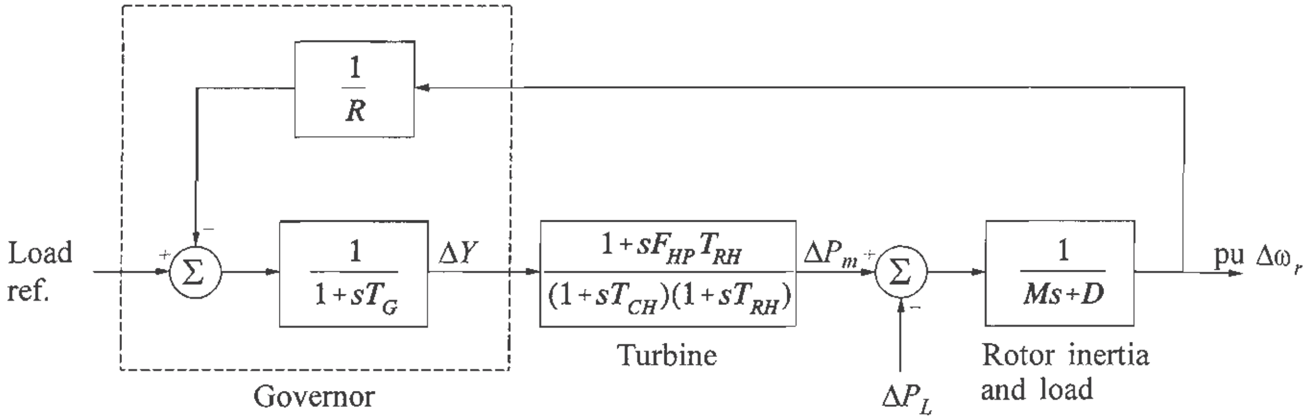
$$= 0.1395 \quad \text{Hz}$$

■

11.1.4 Response Rates of Turbine-Governing Systems

So far, we have analyzed steady-state performance of speed-governing systems. We will now examine the relative response rates of steam and hydraulic turbines and their governing systems.

As discussed in Chapter 9, steam turbines may be of either reheat type or non-reheat type. Figure 11.18 shows the block diagram of a generating unit with a reheat turbine. The block diagram includes representation of the speed governor, turbine, rotating mass and load, appropriate for load-frequency analysis. The turbine representation is based on the simplified transfer function developed in Chapter 9 (Section 9.2.1), and assumes constant boiler pressure.

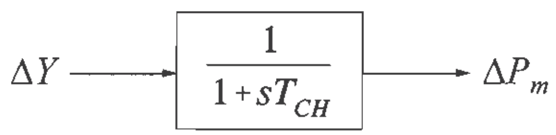


Typical values:

$R = 0.05$ $T_G = 0.2$ s $F_{HP} = 0.3$ $T_{RH} = 7.0$ s
$T_{CH} = 0.3$ s $F_{LP} = 0.7$ $M = 10.0$ s $D = 1.0$

Figure 11.18 Block diagram of a generating unit with a reheat steam turbine

The block diagram of Figure 11.18 is also applicable to a unit with non-reheat turbine. However, in this case T_{RH}=0, and the turbine transfer function simplifies to that shown in Figure 11.19.



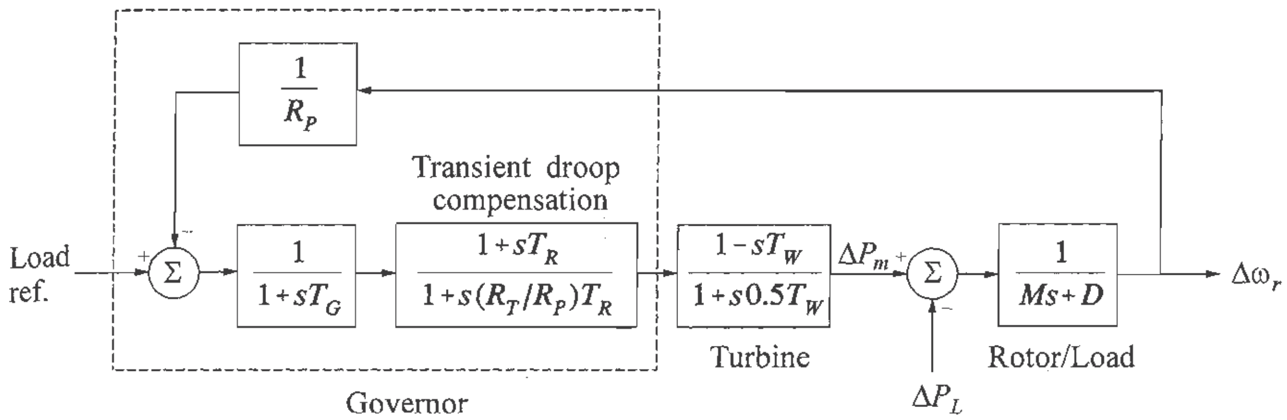
Typical value:

$T_{CH} = 0.3$ s

Figure 11.19 Non-reheat turbine transfer function

In Chapter 9 (Section 9.1.3), we showed that the governors of hydraulic units require *transient droop compensation* for stable speed control performance. Because a change in the position of the gate at the foot of the penstock produces an initial short-term turbine power change which is opposite to that sought, hydro turbine governors are designed to have relatively large transient droop, with long resetting times. This ensures stable frequency regulation under isolated operating conditions (islanding). Consequently, the response of a hydraulic unit to speed change or to changes in speed-changer setting is relatively slow.

The block diagram of a generating unit with a hydraulic turbine is shown in Figure 11.20. The governor includes transient droop. The transfer functions for the turbine and the speed governor used in the block diagram were developed in Chapter 9. For fast-frequency deviations, the governor exhibits a high regulation (or low gain); for slow changes and in the steady state it has a lower regulation (or high gain).



Typical values:

$R_P = 0.05$	$T_G = 0.2$ s	$M = 6.0$ s	$D = 1.0$
$T_W = 1.0$ s	$R_T = 0.38$	$T_R = 5.0$ s	

Figure 11.20 Block diagram of hydraulic unit

The nature of the responses of generating units with reheat and non-reheat steam turbines, and hydraulic turbines when subjected to a step change in load (ΔP_L), is illustrated in Figure 11.21. These responses have been computed by using the linearized models and typical parameters shown in Figures 11.18 and 11.19. Constant boiler pressure has been assumed for the steam turbines. Depending on the type of boiler and its controls, and on the size of the load change, the response of the steam turbines may be significantly slower than that shown. On the other hand, a low-head hydraulic unit may have a significantly faster response than the one considered here.

The results presented here demonstrate that, although the steady-state speed deviation is the same for all three units considered, there are significant differences in their transient responses. Unit response characteristics, in fact, vary widely

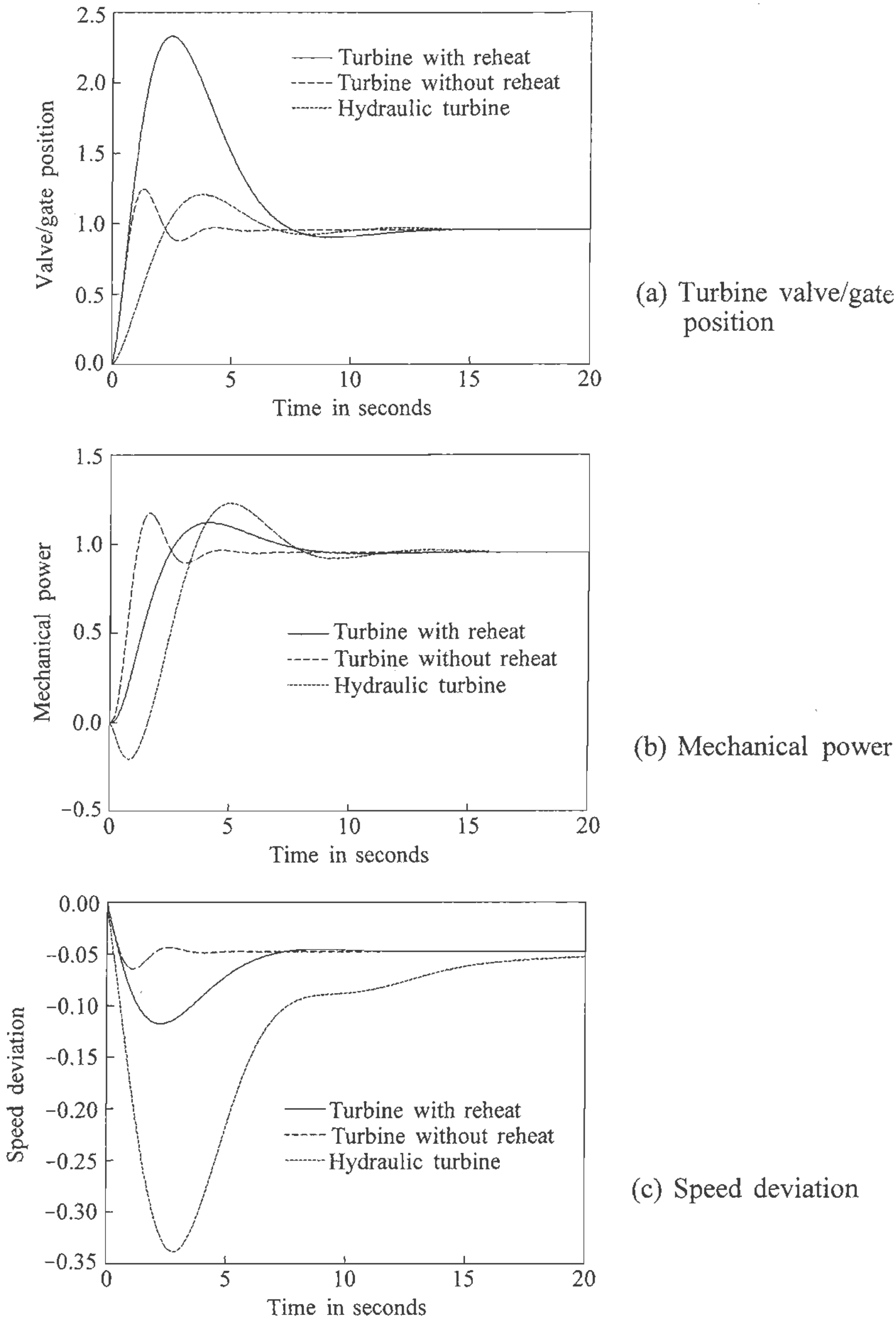


Figure 11.21 Responses of steam and hydraulic generating units to a small step increase in load demand; values shown are in per unit of the step change.

depending on many factors. These include, in addition to the type of plant, plant controls and mode of operation (e.g., boiler-follow, turbine-follow), and operating point (e.g., nearness to valve point, load limit).

11.1.5 Fundamentals of Automatic Generation Control [3-6]

With primary speed control action, a change in system load will result in a steady-state frequency deviation, depending on the governor droop characteristic and frequency sensitivity of the load. All generating units on speed governing will contribute to the overall change in generation, irrespective of the location of the load change. Restoration of system frequency to nominal value requires supplementary control action which adjusts the load reference setpoint (through the speed-changer motor). Therefore, the basic means of controlling prime-mover power to match variations in system load in a desired manner is through control of the load reference setpoints of selected generating units. As system load is continually changing, it is necessary to change the output of generators automatically.

The primary objectives of *automatic generation control* (AGC) are to regulate frequency to the specified nominal value and to maintain the interchange power between control areas at the scheduled values by adjusting the output of selected generators. This function is commonly referred to as *load-frequency control* (LFC). A secondary objective is to distribute the required change in generation among units to minimize operating costs.

AGC in isolated power systems

In an isolated power system, maintenance of interchange power is not an issue. Therefore, the function of AGC is to restore frequency to the specified nominal value. This is accomplished by adding a reset or integral control which acts on the load reference settings of the governors of units on AGC, as shown in Figure 11.22. The integral control action ensures zero frequency error in the steady state.

The supplementary generation control action is much slower than the primary speed control action. As such it takes effect after the primary speed control (which acts on all units on regulation) has stabilized the system frequency. Thus, AGC adjusts load reference settings of selected units, and hence their output power, to override the effects of the composite frequency regulation characteristics of the power system. In so doing, it restores the generation of all other units not on AGC to scheduled values.

AGC in interconnected power systems

To form the basis for supplementary control of interconnected power systems, let us first look at the performance with primary speed control only.

Consider the interconnected system shown in Figure 11.23(a). It consists of two areas connected by a tie line of reactance X_{tie}. For load-frequency studies, each area may be represented by an equivalent generating unit exhibiting its overall

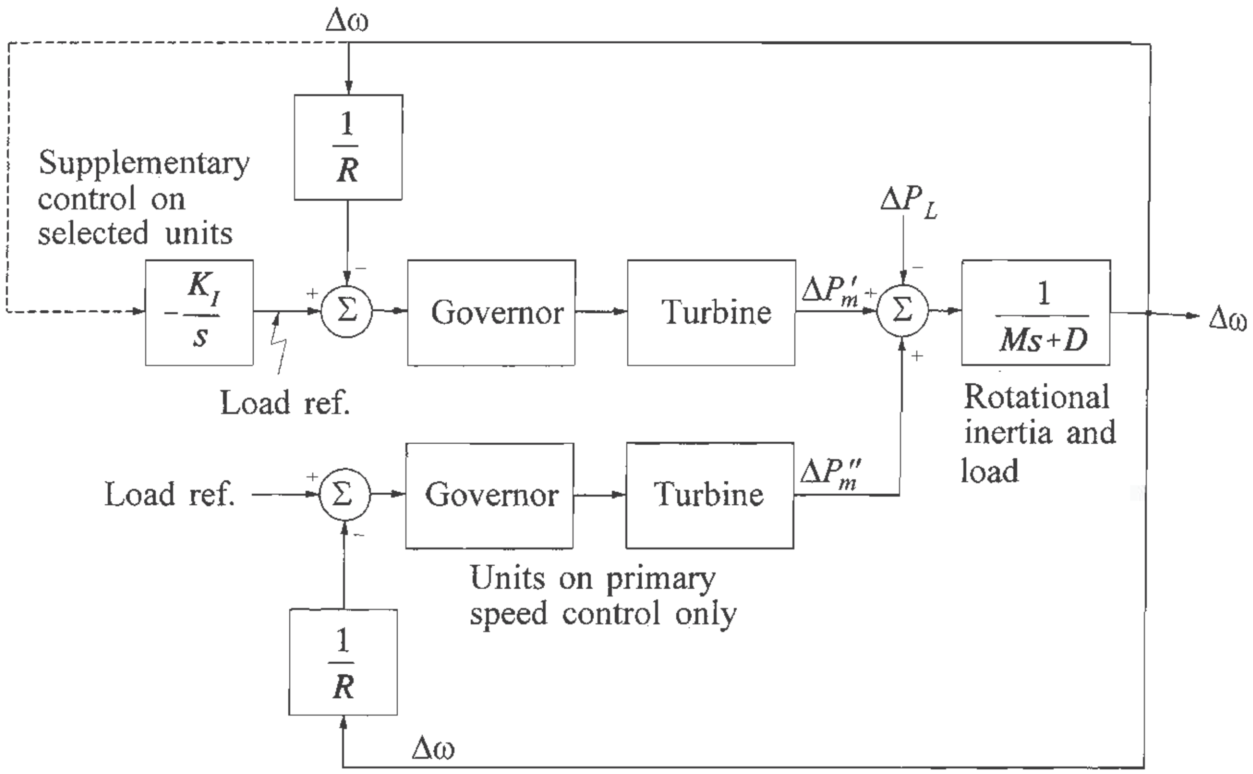


Figure 11.22 Addition of integral control on generating units selected for AGC

performance. Such composite models are acceptable since we are not concerned about intermachine oscillations within each area.

Figure 11.23(b) shows the electrical equivalent of the system, with each area represented by a voltage source behind an equivalent reactance as viewed from the tie bus. The power flow on the tie line from area 1 to area 2 is

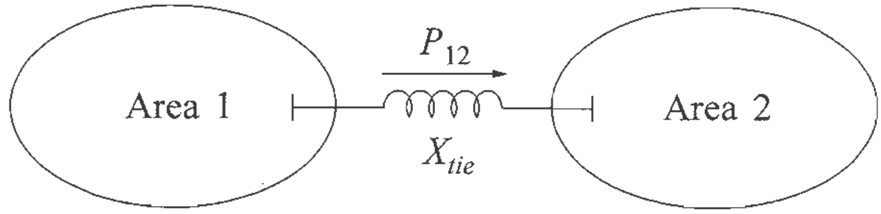
$$P_{12} = \frac{E_1 E_2}{X_T} \sin(\delta_1 - \delta_2)$$

Linearizing about an initial operating point represented by $\delta_1 = \delta_{10}$ and $\delta_2 = \delta_{20}$, we have

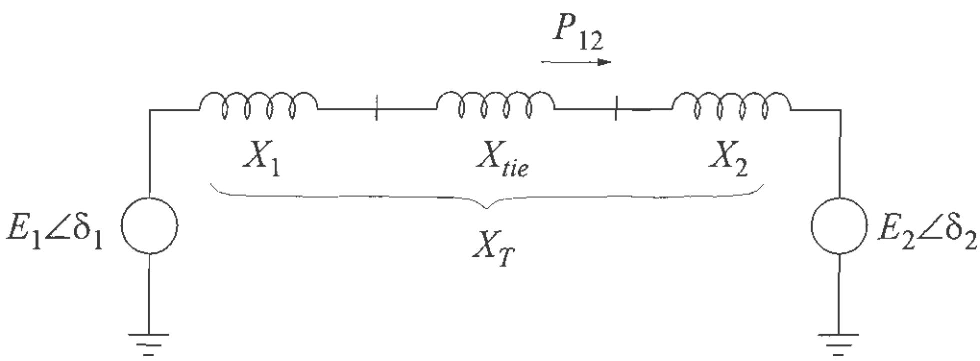
$$\Delta P_{12} = T \Delta\delta_{12}$$

where $\Delta\delta_{12} = \Delta\delta_1 - \Delta\delta_2$, and T is the synchronizing torque coefficient given by

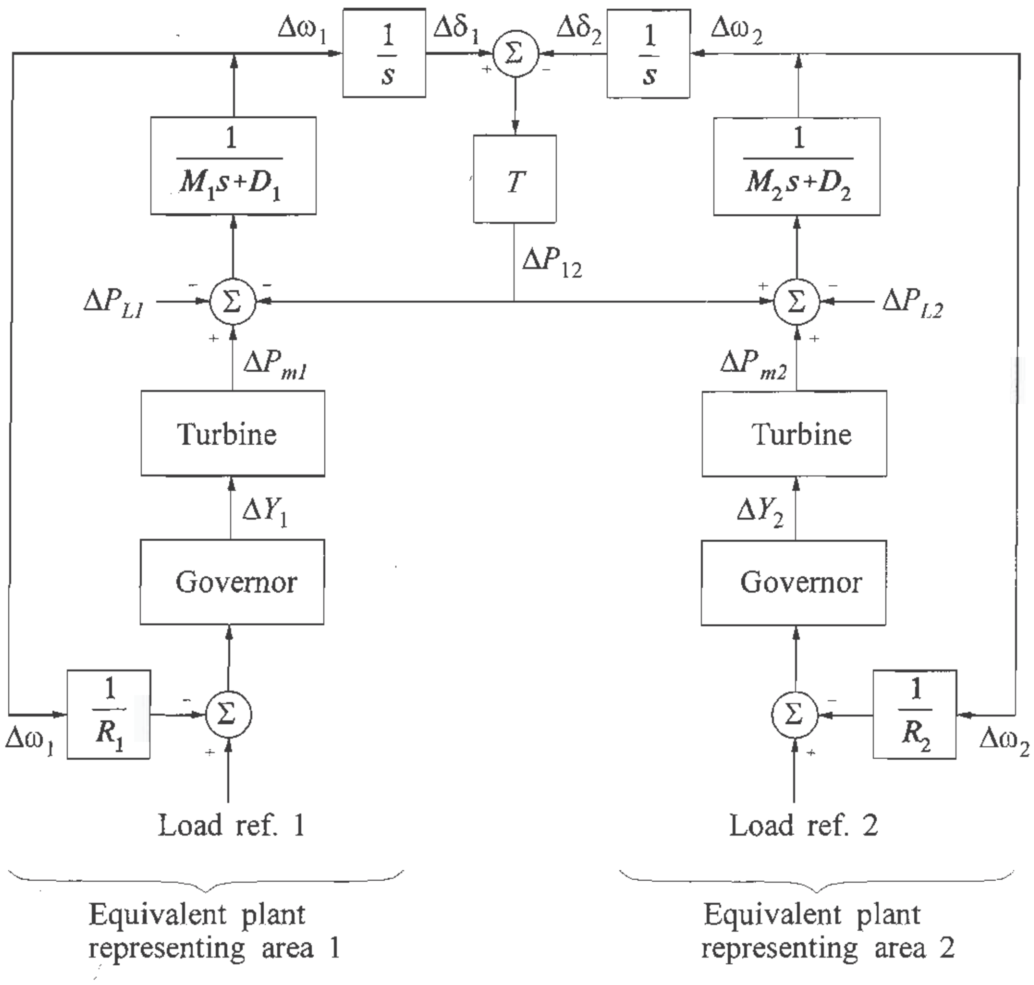
$$T = \frac{E_1 E_2}{X_T} \cos(\delta_{10} - \delta_{20}) \tag{11.10}$$



(a) Two-area system



(b) Electrical equivalent



(c) Block diagram

Figure 11.23 Two-area system with only primary speed control

The block diagram representation of the system is shown in Figure 11.23(c) with each area represented by an equivalent inertia M, load-damping constant D, turbine, and governing system with an effective speed droop R. The tie line is represented by the synchronizing torque coefficient T. A positive ΔP_{12} represents an increase in power transfer from area 1 to area 2. This in effect is equivalent to increasing the load of area 1 and decreasing the load of area 2; therefore, feedback of ΔP_{12} has a negative sign for area 1 and a positive sign for area 2.

The steady-state frequency deviation $(f-f_0)$ is the same for the two areas. For a total load change of ΔP_L,

$$\Delta f = \Delta\omega_1 = \Delta\omega_2 = \frac{-\Delta P_L}{(1/R_1+1/R_2)+(D_1+D_2)} \tag{11.11}$$

Consider the steady-state values following an increase in area 1 load by ΔP_{L1}. For area 1, we have

$$\Delta P_{m1}-\Delta P_{12}-\Delta P_{L1} = \Delta f D_1 \tag{11.12}$$

and for area 2,

$$\Delta P_{m2}+\Delta P_{12} = \Delta f D_2 \tag{11.13}$$

The change in mechanical power depends on regulation. Hence,

$$\Delta P_{m1} = -\frac{\Delta f}{R_1} \tag{11.14}$$

$$\Delta P_{m2} = -\frac{\Delta f}{R_2} \tag{11.15}$$

Substitution of Equation 11.14 in Equation 11.12 and Equation 11.15 in Equation 11.13 yields

$$\Delta f\left(\frac{1}{R_1}+D_1\right) = -\Delta P_{12}-\Delta P_{L1} \tag{11.16}$$

and

$$\Delta f\left(\frac{1}{R_2}+D_2\right) = \Delta P_{12} \tag{11.17}$$

Solving Equations 11.16 and 11.17, we get

$$\Delta f = \frac{-\Delta P_{L1}}{(1/R_1+D_1)+(1/R_2+D_2)} = \frac{-\Delta P_{L1}}{\beta_1+\beta_2} \tag{11.18}$$

and

$$\Delta P_{12} = \frac{-\Delta P_{L1}(1/R_2+D_2)}{(1/R_1+D_1)+(1/R_2+D_2)} = \frac{-\Delta P_{L1}\beta_2}{\beta_1+\beta_2} \tag{11.19}$$

where β_1 and β_2 are the composite frequency response characteristics of areas 1 and 2, respectively. The above relationships are depicted in Figure 11.24.

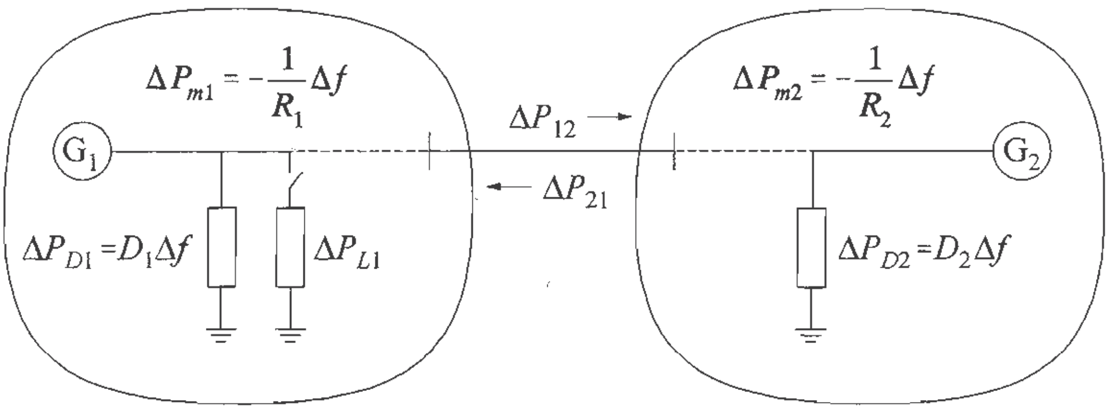


Figure 11.24 Effect of change in area 1 load

An increase in area 1 load by ΔP_{L1} results in a frequency reduction in both areas and a tie line flow of ΔP_{12}. A negative ΔP_{12} is indicative of flow from area 2 to area 1. The tie line flow deviation reflects the contribution of the regulation characteristics $(1/R+D)$ of one area to another.

Similarly, for a change in area 2 load by ΔP_{L2}, we have

$$\Delta f = \frac{-\Delta P_{L2}}{\beta_1+\beta_2} \tag{11.20}$$

and

$$\Delta P_{12} = -\Delta P_{21} = \frac{\Delta P_{L2}\beta_1}{\beta_1+\beta_2} \tag{11.21}$$

The above relationships form the basis for the load-frequency control of interconnected systems.

Frequency bias tie line control

The basic objective of supplementary control is to restore balance between each area load and generation. This is met when the control action maintains

- Frequency at the scheduled value
- Net interchange power with neighbouring areas at scheduled values

The supplementary control in a given area should ideally correct only for changes in that area. In other words, if there is a change in area 1 load, there should be supplementary control action only in area 1 and not in area 2.

Examination of Equations 11.18 to 11.21 indicates that a control signal made up of tie line flow deviation added to frequency deviation weighted by a *bias factor* would accomplish the desired objectives. This control signal is known as *area control error* (ACE).

From Equations 11.16 and 11.17, it is apparent that a suitable bias factor for an area is its frequency-response characteristic β. Thus, the area control error for area 2 is

$$\mathrm{ACE}_2 = \Delta P_{21} + B_2 \Delta f \qquad (11.22)$$

where

$$B_2 = \beta_2 = \frac{1}{R_2} + D_2 \qquad (11.23)$$

Similarly, for area 1

$$\mathrm{ACE}_1 = \Delta P_{12} + B_1 \Delta f \qquad (11.24)$$

where

$$B_1 = \beta_1 = \frac{1}{R_1} + D_1 \qquad (11.25)$$

The ACE represents the required change in area generation, and its unit is

MW.[1] The unit normally used for expressing the frequency bias factor B is MW/0.1 Hz.

The block diagram shown in Figure 11.25 illustrates how supplementary control is implemented. It is applied to selected units in each area and acts on the load reference setpoints.

The area frequency-response characteristic $(1/R+D)$ required for establishing the bias factors can be estimated by examination of chart records following a significant disturbance such as a sudden loss of a large unit.

Basis for selection of bias factor [3-8]

Actually, from steady-state performance considerations, the choice of bias factor is not important. Any combination of area control errors containing components of tie line power deviation and frequency deviation will result in steady-state restoration of the tie flow and frequency since the integral control action ensures that ACE is reduced to zero. In order to illustrate this, consider the following area control error signals applicable to a two-area system:

$$\mathrm{ACE}_1 = A_1 \Delta P_{12} + B_1 \Delta f = 0 \tag{11.26}$$

$$\mathrm{ACE}_2 = A_2 \Delta P_{21} + B_2 \Delta f = 0 \tag{11.27}$$

The above equations result in $\Delta P_{12}=0$ and $\Delta f=0$ for all non-zero values of A_1, A_2, B_1 and B_2.

However, the composition of area control error signals is more important from *dynamic performance* considerations. This can be illustrated by considering the transient response of the AGC system to a sudden increase in area 1 load. The sudden increase in load will result in a decrease in system frequency, followed by governor response (primary speed control of units in both areas) which limits the maximum frequency excursion and subsequently (typically on the order of 10 seconds) brings the frequency deviation back to a value Δf_R determined by the regulation characteristics of both systems:

$$\Delta f_R = \frac{-\Delta P_{L1}}{\beta_1 + \beta_2} \tag{11.28}$$

---

[1] In the literature, several alternative equations have been used to express ACE. A commonly used alternative form is

$$\mathrm{ACE} = \Delta P_{tie} - B\Delta f$$

where $B=-\beta$, a negative number.

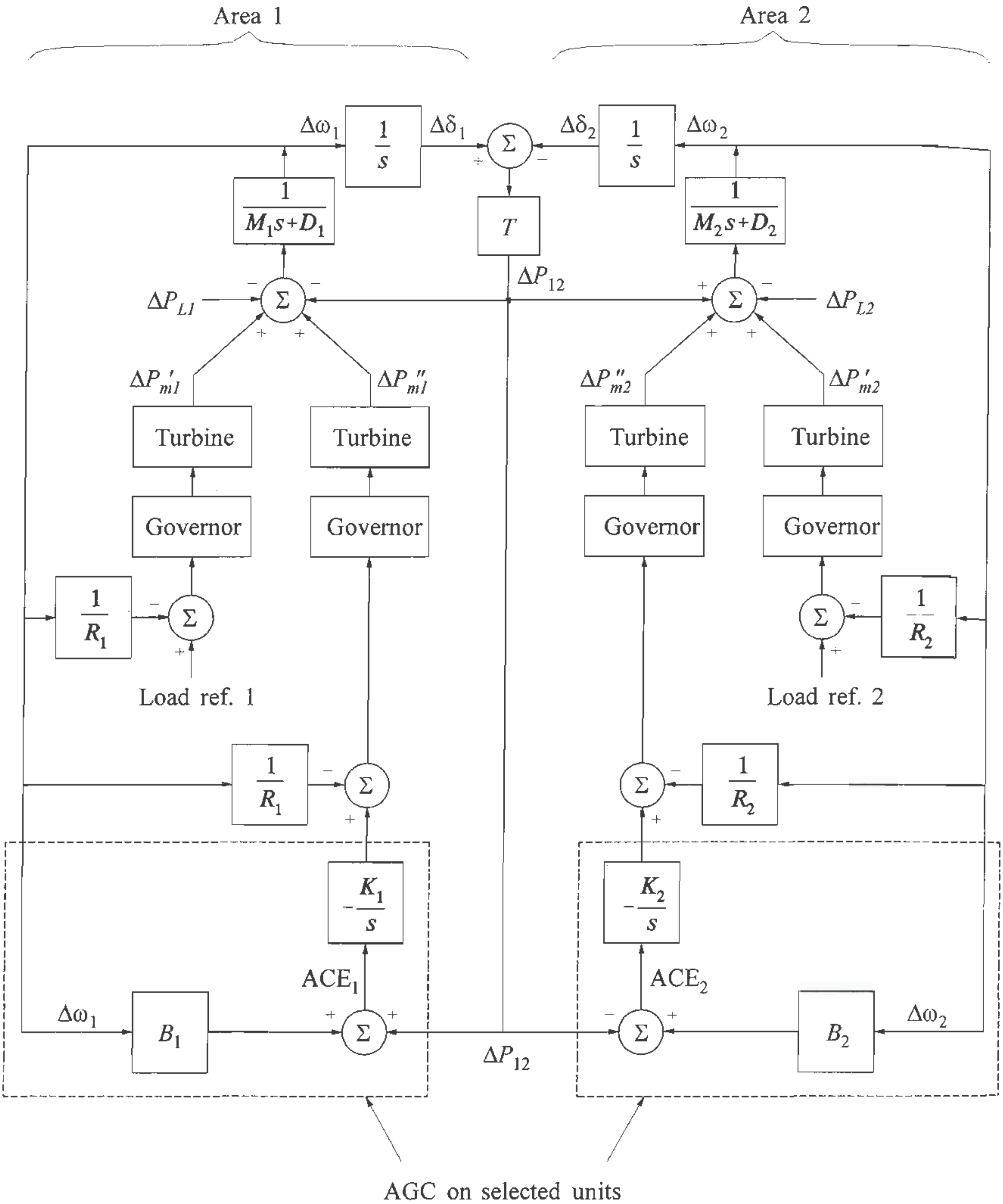


Figure 11.25 Block diagram of two-area system with supplementary control

At this point, there is a deviation of tie line power flow from the scheduled value. The supplementary control, which is much slower than the primary speed control, will now commence responding. Let us examine the performance of the supplementary control for different settings of the area frequency bias factors at the instant when the frequency deviation is Δf_R.

(a) With B_1 equal to β_1, and B_2 equal to β_2, we have

$$\begin{aligned} ACE_1 &= \Delta P_{12} + B_1 \Delta f_R \\ &= \frac{-\Delta P_{L1}}{\beta_1 + \beta_2}(\beta_2 + \beta_1) \\ &= -\Delta P_{L1} \end{aligned}$$

and

$$\begin{aligned} ACE_2 &= -\Delta P_{12} + B_2 \Delta f_R \\ &= \frac{-\Delta P_{L1}}{\beta_1 + \beta_2}(-\beta_2 + \beta_2) \\ &= 0 \end{aligned}$$

Only the supplementary control in area 1 will respond to ΔP_{L1} and change generation so as to bring ACE_1 to zero. The load change in area 1 is thus unobservable to the supplementary control in area 2.

(b) If, on the other hand, B_1 and B_2 were set to double their respective area frequency-response characteristics,

$$\begin{aligned} ACE_1 &= \Delta P_{12} + B_1 \Delta f_R \\ &= \frac{-\Delta P_{L1}}{\beta_1 + \beta_2}(\beta_2 + 2\beta_1) \\ &= -\Delta P_{L1}\left(1 - \frac{1}{\beta_2}\right) \end{aligned}$$

Similarly,

$$\begin{aligned} ACE_2 &= -\Delta P_{12} + 2\beta_2 \Delta f_R \\ &= \frac{-\Delta P_{L1}}{\beta_2} \end{aligned}$$

Thus, both area 1 and area 2 supplementary controls would respond and correct the frequency deviation twice as fast. However, the generation picked up by area 2 will subsequently reflect itself as a component of ACE_2, and will be backed off again in the steady state.

(c) If we set the bias factors significantly lower than the respective area βs, a situation opposite to the above would exist. In this case, the supplementary control in area 2 would tend to back off the generation picked up by its generators as a result of primary speed control or governor action. This would result in a degradation of system frequency control.

In addition to the above considerations, a very high value of bias factor is not desirable from the control stability viewpoint. At values significantly higher than the area β, the control action may become unstable.

The appropriateness of setting the frequency bias factor B nearly equal to the area β from dynamic considerations has been examined by a number of investigators [3-8]. A recommendation made in reference 7 to use significantly lower bias settings (B equal to nearly 0.5β) has not gained acceptance. A subsequent optimization study reported in reference 8 showed that $B=\beta$ is indeed a logical choice.

Systems with more than two areas

The description of the frequency bias tie line control described above applies equally well to systems with more than two areas. The interchange schedule applicable to each area is the algebraic sum of power flows on all the tie lines from that area to the other areas.

When an area is interconnected with more than one additional area, scheduled interchange transfers between them do not necessarily flow directly through the tie lines connecting the respective areas. Actual flows could split over parallel paths through other areas, depending on the relative impedances of the parallel paths. This is illustrated in Figure 11.26 which considers a three-area system.

Performance of AGC under normal and abnormal conditions

Under *normal conditions*, with each area able to carry out its control obligations, steady-state corrective action of AGC is confined to the area where the deficit or excess of generation occurs. Interarea power transfers are maintained at scheduled levels and system frequency is held constant.

Under *abnormal conditions*, one or more areas may be unable to correct for the generation-load mismatch due to insufficient generation reserve on AGC. In such an event, other areas assist by permitting the interarea power transfers to deviate from scheduled values and by allowing system frequency to depart from its pre-disturbance value. Each area participates in frequency regulation in proportion to its available regulating capacity relative to that of the overall system.

The following example illustrates the above aspects of AGC performance.

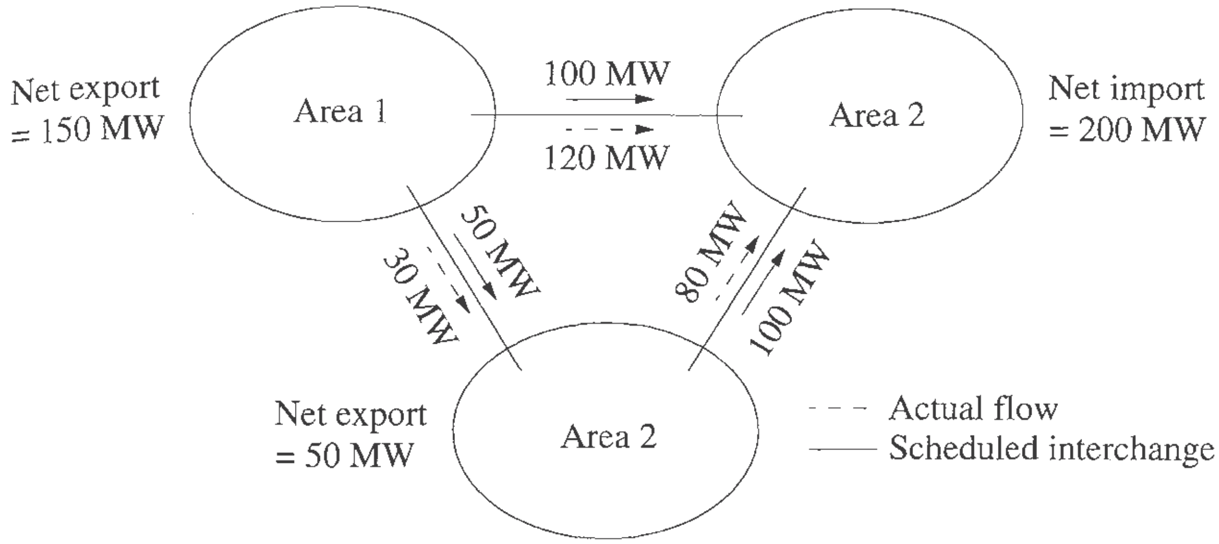
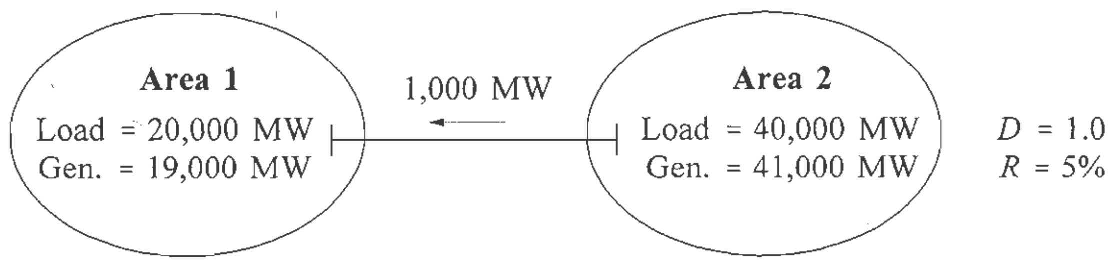


Figure 11.26 Three areas connected by tie lines

Example 11.3

Consider two interconnected areas as follows:



The connected load at 60 Hz is 20,000 MW in area 1 and 40,000 MW in area 2. The load in each area varies 1% for every 1% change in frequency. Area 1 is importing 1,000 MW from area 2. The speed regulation, R, is 5% for all units.

Area 1 is operating with a spinning reserve of 1,000 MW spread uniformly over a generation of 4,000 MW capacity, and area 2 is operating with a spinning reserve of 1,000 MW spread uniformly over a generation of 10,000 MW.

Determine the steady-state frequency, generation and load of each area, and tie line power for the following cases.

(a) Loss of 1,000 MW load in area 1, assuming that there are no supplementary controls.

(b) Each of the following contingencies, when the generation carrying spinning reserve in each area is on supplementary control with frequency bias factor settings of 250 MW/0.1 Hz for area 1 and 500 MW/0.1 Hz for area 2.

(i) Loss of 1,000 MW load in area 1

(ii) Loss of 500 MW generation, carrying part of the spinning reserve, in area 1

(iii) Loss of 2,000 MW generation, not carrying spinning reserve, in area 1

(iv) Tripping of the tie line, assuming that there is no change to the interchange schedule of the supplementary control

(v) Tripping of the tie line, assuming that the interchange schedule is switched to zero when the ties are lost

Solution

(a) *With no supplementary control.*

Assuming that none of the governors are blocked, all generating units in the two areas respond to the loss of load.

A 5% regulation on 20,000 MW generating capacity (including spinning reserve of 1,000 MW) in area 1 corresponds to

$$\frac{1}{R_1} = \frac{1}{0.05} \times \frac{20{,}000}{60} = 6{,}666.67 \quad \text{MW/Hz}$$

Similarly, a 5% regulation on 42,000 MW generating capacity in area 2 corresponds to

$$\frac{1}{R_2} = \frac{1}{0.05} \times \frac{42{,}000}{60} = 14{,}000.00 \quad \text{MW/Hz}$$

Total regulation due to 62,000 MW generating capacity in the two areas is

$$\frac{1}{R} = \frac{1}{R_1} + \frac{1}{R_2} = 20{,}666.67 \quad \text{MW/Hz}$$

Load damping due to 19,000 MW load (remaining after loss of 1,000 MW load) in area 1 is

$$D_1 = 1 \times \frac{19{,}000}{100} \times \frac{100}{60} = 316.67 \quad \text{MW/Hz}$$

Load damping due to 40,000 MW load in area 2 is

$$D_2 = 1 \times \frac{40{,}000}{100} \times \frac{100}{60} = 666.67 \quad \text{MW/Hz}$$

Total effective load damping of the two areas is

$$D = D_1 + D_2 = 983.33 \quad \text{MW/Hz}$$

Change in system frequency due to loss of 1,000 MW load in area 1 is

$$\Delta f = \frac{-\Delta P_L}{1/R + D} = \frac{-(-1000)}{20{,}666.67 + 983.33} = 0.04619 \quad \text{Hz}$$

Load changes in the two areas due to increase in frequency are

$$\Delta P_{D1} = D_1 \Delta f = 316.67 \times 0.04619 = 14.63 \quad \text{MW}$$

$$\Delta P_{D2} = D_2 \Delta f = 666.67 \times 0.04619 = 30.79 \quad \text{MW}$$

Generation changes in the two areas due to speed regulation are

$$\Delta P_{G1} = -\frac{1}{R_1} \Delta f = 6{,}666.67 \times 0.04619 = -307.93 \quad \text{MW}$$

$$\Delta P_{G2} = -\frac{1}{R_2} \Delta f = 14{,}000.00 \times 0.04619 = -646.65 \quad \text{MW}$$

The new load, generation and tie line power flows are as follows.

Area 1		Area 2	
Load	= 20,000.00 − 1,000.00 + 14.63 = 19,014.63 MW	Load	= 40,000.00 + 30.79 = 40,030.79 MW
Generation	= 19,000.00 − 307.93 = 18,692.07 MW	Generation	= 41,000.00 − 646.65 = 40,353.35 MW

Tie line power flow from area 2 to area 1 is 322.56 MW. Steady-state frequency is 60.04619 Hz.

(b) *With supplementary control.*

(i) Loss of 1,000 MW load in area 1:

Area 1 has a generating capacity of 4,000 MW on supplementary control, and this will reduce generation so as to bring ACE_1 to zero. Similarly, area 2 generation on supplementary control will keep ACE_2 at zero:

$$\text{ACE}_1 = B_1 \Delta f + \Delta P_{12} = 0$$

$$\text{ACE}_2 = B_2 \Delta f - \Delta P_{12} = 0$$

Hence,

$$\Delta f = 0 \qquad \Delta P_{12} = 0$$

Area 1 generation and load are reduced by 1,000 MW. There is no steady-state change in area 2 generation and load, or the tie flow.

(ii) Loss of 500 MW generation carrying part of spinning reserve in area 1:

Prior to loss of generation, area 1 had a spinning reserve of 1,000 MW spread uniformly over a generation of 4,000 MW capacity (3,000 MW generation plus 1,000 MW reserve). Spinning reserve lost with generation loss is

$$\frac{500}{3,000}\times 1,000 = 166.67 \quad \text{MW}$$

Spinning reserve remaining is 1,000.00−166.67=833.33 MW. This is sufficient to make up for 500 MW generation loss. Hence, the generation and load in the two areas are restored to their pre-disturbance values. There are no changes in tie line flow or system frequency. However, area 1 spinning reserve is reduced from 1,000 MW to 833.33 MW.

(iii) Loss of 2,000 MW generation in area 1, not carrying spinning reserve:

Half of the generation loss will be made up by the 1,000 MW spinning reserve on supplementary control in area 1. When this limit is reached, area 1 is no longer able to control ACE. Supplementary control in area 2, however, is able to control its ACE. Hence,

$$\text{ACE}_2 = B_2 \Delta f - \Delta P_{12} = 0$$

or

$$\Delta P_{12} = B_2 \Delta f = 5,000 \Delta f$$

There is thus a net reduction in system frequency. This causes a reduction in loads due to frequency sensitivity.

Area 1 load damping is

$$D_1 = 1 \times \frac{20,000}{100} \times \frac{100}{60} = 333.33 \quad \text{MW/Hz}$$

The balance of generation loss in area 1 is made up by a reduction in load and tie flow from area 2. Hence,

$$-1{,}000 = D_1\Delta f + \Delta P_{12}$$
$$= 333.33\Delta f + 5{,}000\Delta f$$

Solving for Δf, we have

$$\Delta f = \frac{-1{,}000}{5{,}000+333.33} = -0.1875 \quad \text{Hz}$$

Change in area 1 load is

$$\Delta P_{D1} = D_1\Delta f = 333.33\times(-0.1875)$$
$$= -62.5 \quad \text{MW}$$

The tie flow change is

$$\Delta P_{12} = 5{,}000\times(-0.1875) = -937.5 \quad \text{MW}$$

Change in area 2 load is

$$\Delta P_{D2} = D_2\Delta f = 666.67\times(-0.1875)$$
$$= -125.00 \quad \text{MW}$$

The area load and generation are as follows.

Area 1		Area 2	
Load	= 20,000.0 − 62.5 = 19,937.5 MW	Load	= 40,000.0 − 125.0 = 39,875.0 MW
Generation	= 19,000.0 − 1,000.0 = 18,000.0 MW	Generation	= 41,000.0 − 125.0 + 937.5 = 41,812.5 MW

The steady-state tie line power flow from area 2 to area 1 is 1,937.50 MW, and the system frequency is 60.0 − 0.1875 = 59.8125 Hz.

(iv) Tripping of the tie line, assuming no change in interchange schedule:

The supplementary control of area 1 attempts to maintain interchange schedule at 1,000 MW. Hence,

$$\text{ACE}_1 = \Delta P_{12} + B_1\Delta f_1 = 1{,}000 + 2{,}500\Delta f = 0$$

Solving, we find

$$\Delta f_1 = -\frac{1000}{2500} = -0.4 \quad \text{Hz}$$

Change in area 1 load is

$$\Delta P_{D1} = D_1 \Delta f_1 = 333.33 \times (-0.4) = -133.33 \quad \text{MW}$$

Similarly for area 2, we have

$$\Delta f_2 = \frac{1{,}000}{5{,}000} = 0.2 \quad \text{Hz}$$

and

$$\Delta P_{D2} = 666.67 \times 0.2 = 133.33 \quad \text{MW}$$

The area load, generation, and frequencies are as follows:

Area 1		Area 2	
Load	= 20,000.00 − 133.33 = 19,866.67 MW	Load	= 40,000.00 + 133.33 = 40,133.33 MW
Generation	= 19,866.67 MW	Generation	= 40,133.33 MW
f_1	= 59.6 Hz	f_2	= 60.2 Hz

(v) Tripping of the tie line, with interchange schedule switched to zero:

With interchange schedule switched to zero, area 1 supplementary control will pick up 1,000 MW generation to make up for loss of import power. Similarly, area 2 supplementary control reduces generation by 1,000 MW to compensate for loss of export. The generation in each area is equal to the respective loads and the area frequencies are equal to 60 Hz. ■

Economic allocation of generation

As noted earlier, an important secondary function of automatic generation control is to allocate generation so that each power source is loaded most economically. This function is referred to as *economic dispatch control* (EDC). The theory of economic dispatch is based on the principle of equal incremental costs.

For control of tie line power and frequency, it is necessary to send signals to generating plants to control generation. It is possible to use these signals to control generation to satisfy economic dispatch criteria. Thus, the requirements for EDC can be handled as part of the AGC function.

Since system load is continually changing, economic dispatch calculations have to be made at frequent intervals. The allocation of individual generation output is accomplished by using *base points* and *participation factors* (PFs). The base point represents the most economic output for each generating unit, and the participation factor is the rate of change of the unit output with respect to a change in total generation. The new desired output for each generator is calculated as follows [2]:

$$P_{desired} = P_{base\ point} + \mathrm{PF}(\Delta P_{total}) \tag{11.29}$$

where

$$\Delta P_{total} = \text{total new generation} - \text{sum of } P_{base\ point} \text{ for all generation}$$

Sum of participation factors of all units is equal to unity.

11.1.6 Implementation of AGC

In modern AGC schemes, the control actions are usually determined for each control area at a central location called the dispatch centre. Information pertaining to tie line flows, system frequency, and unit MW loadings is telemetered to the central location where the control actions are determined by a digital computer. The control signals are transmitted via the same telemetering channels to the generating units on AGC as shown in Figure 11.27. The normal practice is to transmit raise or lower pulses of varying lengths to the units. The control equipment at the plants then changes the reference setpoints of the units up or down in proportion to the pulse length.

Figure 11.27 illustrates the implementation of AGC for one control area (normally the service area of an individual utility). Each control area of an interconnected system is controlled in a similar manner, but independently of the other control areas. That is, the control of generation in the interconnected system is "area-wise decentralized."

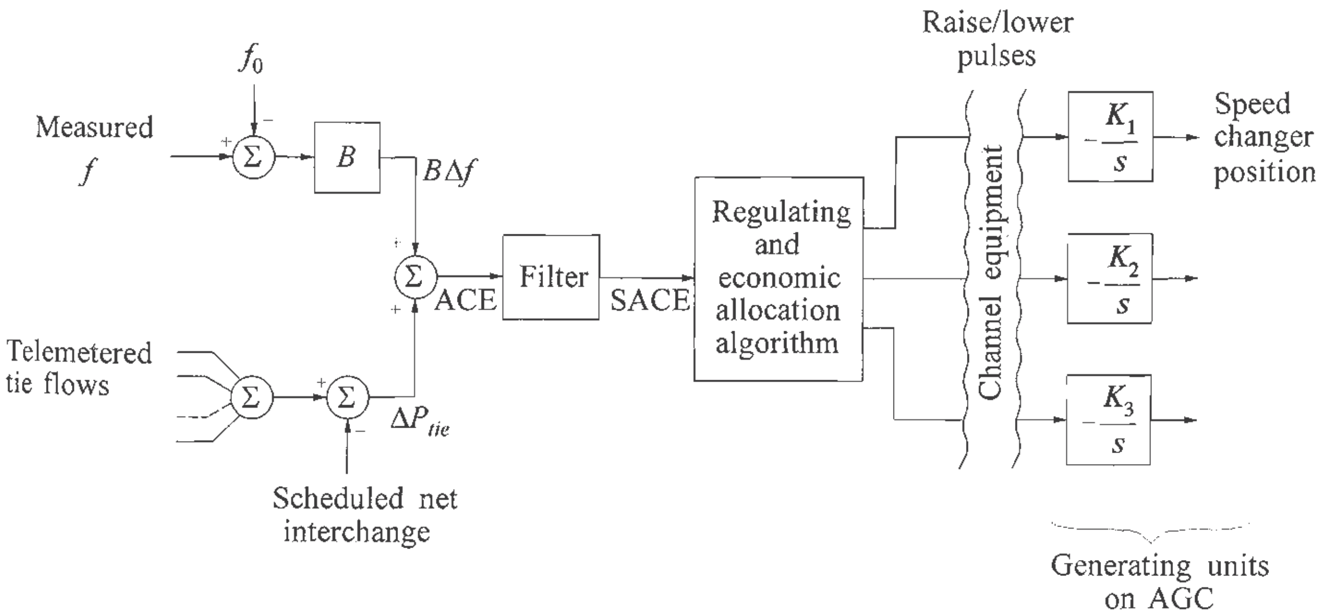


Figure 11.27 AGC control logic for each area

Early AGC systems, developed in the 1950s, were based on analog control equipment. These were gradually superseded by digital systems beginning in the late 1960s. Now, all-digital systems are the universal choice for AGC applications.

Filtering of ACE

Much of the change in ACE is usually due to fast random variations in load to which generating units need not respond. In fact, control action in response to these random components does not reduce ACE but merely causes unnecessary wear and tear on governor motors and turbine valves. Therefore, AGC programs normally use filtering schemes to filter out random variations, and *smoothed ACE* (SACE) is used to control generation.

The conventional approach is to use a low-order filter which reduces noise at the expense of speed of response.

Reference 9 suggests a method of distinguishing random variations and sustained load-change requirements by evaluating whether or not the error is in the direction of correct inadvertent interchange.

Rate limits

In establishing AGC signals, it should be recognized that there is a limit to the rate at which generating unit outputs can be changed. This is particularly true of thermal units where mechanical and thermal stresses are the limiting factors. The maximum loading rate for thermal units is on the order of 2% MCR (*maximum continuous rating*) per minute. For hydro units, the rate is on the order of 100% MCR per minute.

Control performance criteria

The guidelines followed by North American utilities for load-frequency control are developed by the Operating Committee of the North American Electric Reliability Council (NERC). The following criteria specify the minimum control performance standards set by NERC [10].

Under *normal conditions* the following criteria apply:

1. A1 criterion – The ACE must return to zero within 10 minutes of previously reaching zero. Violations of this criterion count for each subsequent 10-minute period that the ACE fails to return to zero.

2. A2 criterion – The average ACE for each of the six 10-minute periods during the hour (i.e., for the 10-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_d, that are determined from the control area's rate of change of demand characteristics:

$$L_d = 5 + 0.025\,\Delta L \quad \text{MW}$$

where ΔL is the greatest hourly change in the net system load of a control area on the day of its maximum summer or winter peak load.

Under *disturbance conditions* (sudden loss of generation or increase of load) the following criteria apply:

1. B1 criterion – The ACE must return to zero within 10 minutes following the start of the disturbance.

2. B2 criterion – The ACE must start to return to zero within 1 minute following the start of the disturbance.

A disturbance is said to have occurred when a sampled value of ACE exceeds $3L_d$.

Time deviation correction

It is the practice of U.S. and Canadian interconnected systems to assign to one area the maintenance of a system time standard. For example, the standard for the eastern systems is maintained by the American Electric Power (AEP) company at Canton, Ohio. Through designated communication channels, information on the status of the system time deviation is relayed to all control areas, and certain periods are designated as time-correction periods. During such periods, all areas are expected to simultaneously offset their frequency schedules by an amount related to accumulated system time deviation.

Frequency of AGC execution

The stability of an AGC system and its ability to react to changing inputs are influenced by phase lags in the input system quantities and in the transmission of its control signals.

With digitally based systems, experience has shown that the execution of AGC once every 2 to 4 seconds results in good performance. This means the ACE is computed and the raise/lower control signals are transmitted to the generating plant once every 2 to 4 seconds.

Figure 11.28 shows the overall function diagram of a typical AGC system.

Frequency bias setting

The general practice in North America is to establish frequency bias in each control area once a year based on the area's natural regulation characteristic ($1/R+D$) corresponding to the forecasted peak load of the coming year. The average frequency bias setting employed is about 2% per 0.1 Hz based on the estimated peak load and spinning reserve. The bias factor remains fixed through the year for all load levels.

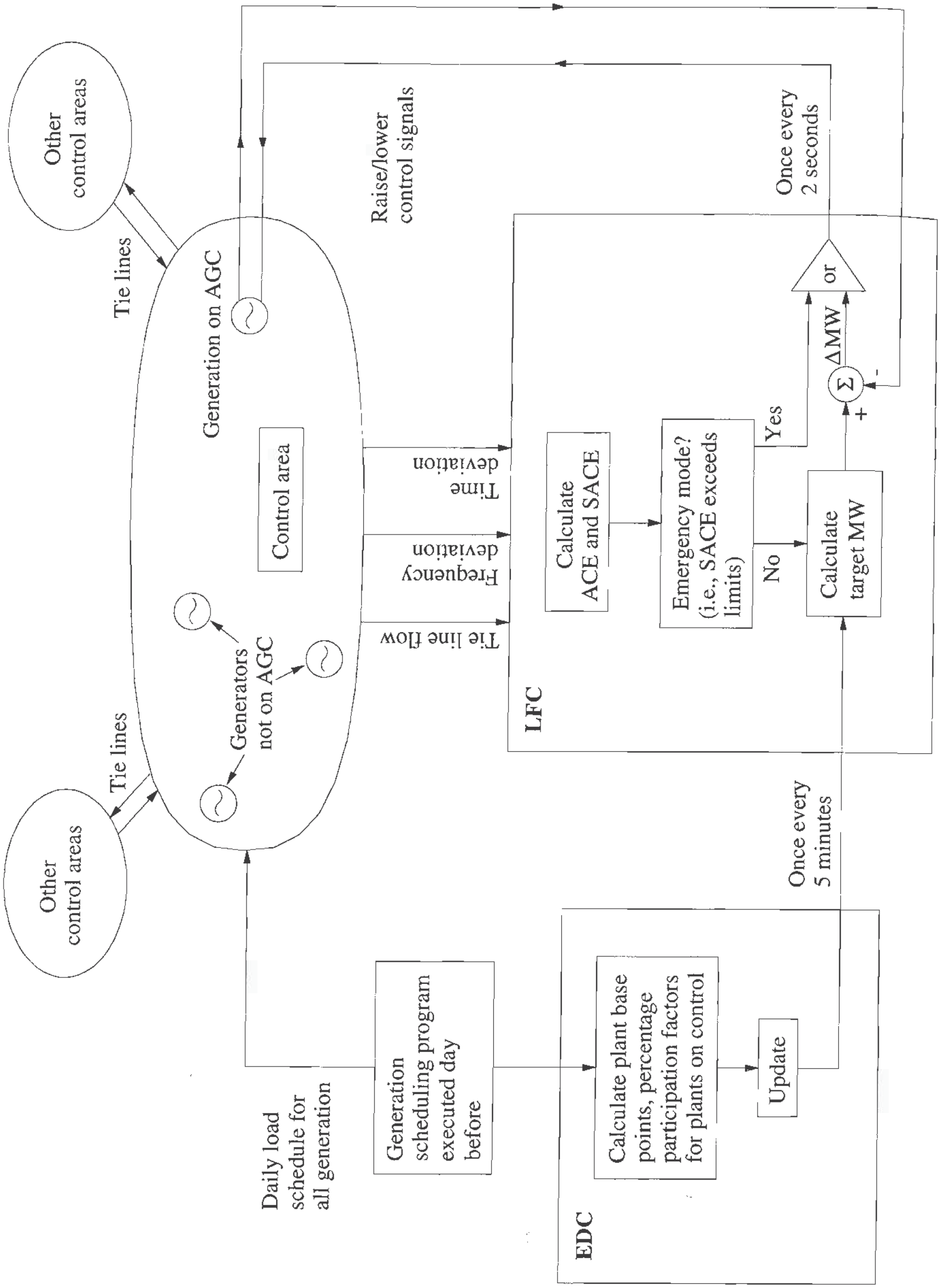


Figure 11.28 *Functional diagram of a typical AGC system*

A result of the above practice appears to be that, at times of low loads, the bias factor is much higher than the actual frequency regulation characteristic of the area. This is suspected of sometimes causing unstable control action resulting in limit cycle oscillations, large inadvertent interchange power accumulation and time deviation [3].

Reference 11 describes a scheme using a variable, nonlinear frequency bias, which results in improved control performance.

AGC tuning and performance [18,19]

The overriding consideration in the design and tuning of the AGC system is the impact on the power plants that are controlled. The characteristics of power plants vary widely and a number of physical constraints exist with regard to their manoeuvrability. A simple system that results in smooth control and a fairly well-damped system is preferable to a rapid control that attempts to bring ACE to zero rapidly. The plant characteristics in relation to variations in ACE are such that it is impossible to perfectly match generation and load continuously. The realization of the control function is limited by the amount of stored energy in the generating units and the rapidity with which generation can be changed. Therefore, the control attempts to match the average of generation and load over a time.

The control strategy should include the following objectives:

- To minimize fuel cost
- To avoid sustained operation of the generating units in the undesirable ranges (e.g., valve points for steam units)
- To minimize equipment wear and tear by avoiding unnecessary manoeuvring of generating units

Practical AGC systems achieve the above objectives by keeping the control strategies simple, robust, and reliable.

The stability of the control system and its ability to respond to the ACE signals are influenced by the phase lags associated with the measurement and transmission of control signals.

The ideal way to determine the AGC system parameters is by means of simulations. An important parameter that has an influence on the stability of AGC system is the overall loop gain; its value should be finalized based on field tests.

Emergency mode operation

For major system upsets causing splitting of the interconnected system into separate islands or opening of tie lines, AGC is suspended. This may be based on detection of very large changes in frequency or ACE. In some cases, AGC may be suspended for intentional tripping of load/generation so that AGC may not defeat the purpose of such tripping.

Effect of speed-governor dead band

The dead band associated with a speed governor is defined as "the total magnitude of the change in steady-state speed within which there is no resulting measurable change in the position of the governor-controlled valves or gates" [12]. Dead band is expressed in percent of the rated speed.

The effect of the dead band on the governor speed-droop characteristic is depicted in Figure 11.29. The speed-droop characteristic appears as a band rather than a line.

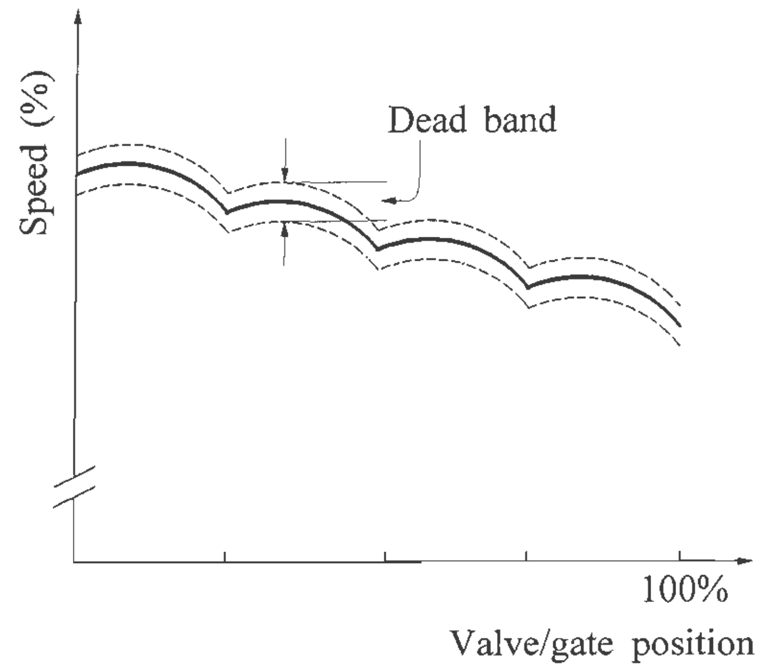


Figure 11.29

Dead band is caused by coulomb friction and backlash effects in various governor linkages, and by valve overlap in the hydraulic relays [1].

The current IEEE standards specify a maximum dead band of 0.06% (0.036 Hz) for governors of large steam turbines [12]. For governors of hydraulic turbines, the standards specify a maximum speed dead band of 0.02% and a maximum blade control dead band of 1.0% [13]. Dead bands of modern electrohydraulic governors are in fact much smaller. In some cases, special measures have been taken to practically eliminate the dead band [14]. However, there are many older units in operation with significant governor dead band.

The effect of the dead band on the speed governor response depends on the magnitude of the frequency deviation. If the deviation is small, it may remain entirely within the dead band; consequently, the speed control will be inactive. In any given situation, however, the entire dead band width will not have to be overcome. The position of each governor would be randomly distributed within its dead band; hence, for small changes in input signal the response of the individual generating units will tend to be random [15]. Speed governor dead bands result in random frequency fluctuations. In large power systems, these random fluctuations have a magnitude on the order of 0.01 Hz.

Results of investigations of the effects of governor dead bands on the performance of AGC systems are reported in references 5, 16 and 17. One effect of the dead band is to reduce the area frequency response characteristic β (i.e., to increase the effective frequency regulation). This requires a reduction in the frequency bias setting to ensure satisfactory AGC performance [16]. Reference 3 provides an in-depth analysis of AGC system dynamic performance and hypothesizes that governor dead bands may cause AGC system limit cycling with periods ranging from 30 seconds to 90 seconds.

Further reading on AGC

The state-of-the-art AGC systems have evolved from the early analog systems to the present digital systems. The result is a simple, yet robust, decentralized system that controls a complex, highly nonlinear, and continuously changing power system. There is a large amount of literature on the subject, some of which has attempted to use modern control theory in an effort to achieve optimal performance. However, these techniques have not been applied to practical AGC systems.

Reference 20 provides a good review of the properties of the conventional AGC systems and of some of the systems proposed in the literature that are based on modern control theory. It identifies potential areas in which the conventional approach may be improved by using concepts based on modern control theory.

Reference 21 presents a general approach to the analysis and synthesis of AGC systems based on multivariable control theory. It proposes two criteria for the design of the load-frequency controllers: (a) non-interaction between controls of frequency and tie line powers; (b) autonomy of controls of each area in taking care of its load variations during steady-state as well as transient conditions.

References 20 and 21 provide additional insight into the requirements and performance of AGC systems. They are both recommended for further reading.

11.1.7 Underfrequency Load Shedding

Severe system disturbances can result in cascading outages and isolation of areas, causing formation of electrical islands. If such an islanded area is undergenerated, it will experience a frequency decline. Unless sufficient generation with ability to rapidly increase output is available, the decline in frequency will be largely determined by frequency sensitive characteristics of loads. In many situations, the frequency decline may reach levels that could lead to tripping of steam turbine generating units by underfrequency protective relays, thus aggravating the situation further. To prevent extended operation of separated areas at lower than normal frequency, load-shedding schemes are employed to reduce the connected load to a level that can be safely supplied by available generation.

Hazards of underfrequency operation

There are two main problems associated with the operation of a power system at low frequency, both related to thermal generating units.

The first problem is concerned with the vibratory stress on the long low-pressure turbine blades. As discussed in Chapter 9 (Section 9.2.3), operation of steam turbines below 58.5 Hz is severely restricted. Since the effects of vibratory stress are cumulative with time, restoration of normal frequency operation as soon as possible is essential.

The second problem is concerned with the performance of plant auxiliaries driven by induction motors. At frequencies below 57 Hz, the plant capability may be severely reduced because of the reduced output of boiler feed pumps or fans supplying combustion air [22]. In the case of nuclear power plants, the reactors may overheat due to reduced flow of coolant as the frequency declines. Low-flow protections or underfrequency relays are normally used to guard against this condition. If the frequency decline is excessive, the generating units may be tripped off the power system.

In addition to avoiding the above consequences, it is necessary to restore normal frequency as soon as possible so that the affected area may be reconnected to the main power system.

Limitations of prime mover systems

The prime movers have several limitations which affect their ability to control frequency decay:

1. The generation can be increased only to the limits of available spinning reserve within each affected area.

2. The load that can be picked up by a thermal unit is limited due to thermal stress in the turbine. Initially, about 10% of turbine rated output can be picked up quickly without causing damage by too rapid heating. This is followed by a slow increase of about 2% per minute.

3. The ability of a boiler to pick up a significant amount of load is limited. An increase in steam flow when the turbine valves open results in a pressure drop. An increase in fuel input to the boiler is required to restore pressure. This takes several minutes and is of little use in limiting frequency drop.

4. The speed governors have a time delay of 3 to 5 seconds.

As a consequence of the above, generation reserve available for control of frequency is limited to a fraction of the remaining generation.

Factors influencing frequency decay

Assuming that the separated area has negligible spinning reserve with speed governing, the extent to which the frequency of the separated area will decrease and the rate of decay depend mainly on three factors: the magnitude of the overload ΔL (i.e., generation deficiency), load-damping constant D applicable to the area load, and the inertia constant M representing the total rotational inertia of the generators in the area.

Based on the results of Example 11.1, we may write the following expression for the frequency decay:

$$\Delta f = -\Delta L(1-e^{-\frac{t}{T}})K \tag{11.30}$$

where $K=1/D$ and $T=M/D$.

For example, with $D=1.0$ and $M=10$ s, the frequency reduction as a function of time t is

$$\Delta f = -\Delta L(1-e^{-\frac{t}{10}}) \text{ pu}$$

$$= -\Delta L(1-e^{-\frac{t}{10}})60 \text{ Hz}$$

Figure 11.30 shows the frequency decay for four values of ΔL.

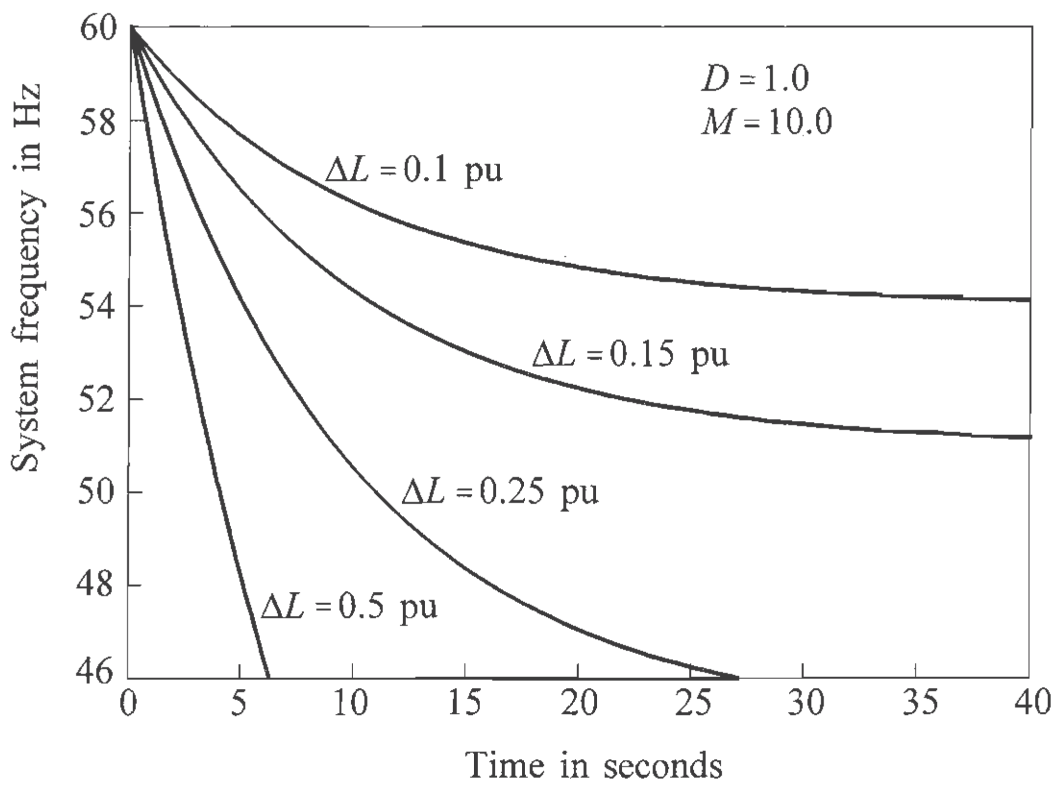


Figure 11.30 Frequency decay due to generation deficiency

Basis for selection of load-shedding schemes

Results such as those presented in Figure 11.30 are helpful as a first step in establishing the basis for load-shedding schemes. Considerations in the selection of the scheme include the maximum generation deficiency for which protection is required, the minimum permissible frequency, likely areas of system separation, and the range of inertia constant M and load-damping constant D.

Reference 23 describes a procedure for developing a load-shedding scheme. A typical scheme shedding load in three steps is as follows:

- 10% load is shed when frequency drops to 59.2 Hz
- 15% additional load is shed when frequency drops to 58.8 Hz
- 20% additional load is shed when frequency reaches 58.0 Hz

Typical operating time with solid-state relays is in the range of 0.1 to 0.2 second.

A scheme based on frequency drop alone is generally acceptable for generation deficiencies up to 25%. For greater generation deficiencies, a scheme which takes into account both frequency drop and rate of change of frequency provides increased selectivity by preventing unnecessary tripping of load [24]. Ontario Hydro uses such a relay to trip appropriate amounts of load in an area. The relay is referred to as a *frequency trend relay* (FTR), and its tripping logic is shown in Figure 11.31. The relay sheds up to 50% of area load. The system within Ontario is divided into 22 areas, and the load shedding is applied to several stations in each area to maintain the integrity of the area under disturbance conditions.

The procedure described above provides a simple means of determining the settings for underfrequency load shedding. After selection of possible areas of separation and specific load blocks for shedding, *detailed dynamic simulation should be carried out to ensure satisfactory system performance, with due regard to power plant and network protections/controls and to system voltages* (see Chapter 16, Section 16.5.2).

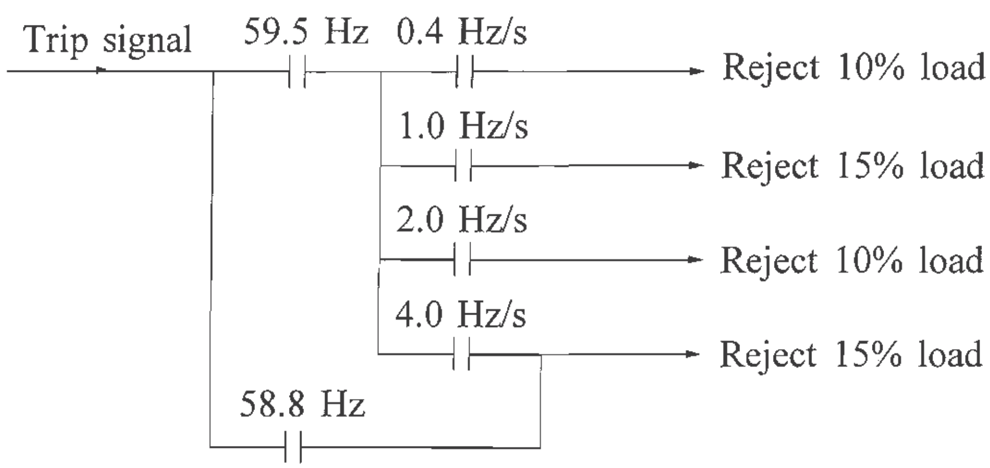


Figure 11.31 Tripping logic for frequency trend relay