12

Automatic Generation Control: Conventional Scenario

12.1 INTRODUCTION

An electric energy system must be maintained at the desired operating level characterized by nominal frequency, voltage profile and load flow configuration. It is kept in this nominal state by close control of the real and reactive powers generated in the controllable sources of the system. The generation changes must be made to match the load variations at the nominal conditions, if the nominal state is to be maintained. The control of an electric energy system in order to achieve an exact matching of the generation to load at nominal state is a complex problem. The load changes continuously and the system generation, responding to control impulses, chases the load with the transient unbalance of load and generation reflected in speed (or frequency) variations.

The total real and reactive power demands P_D and Q_D changes slowly throughout the day, but during time periods measured in seconds or minutes; they may be considered as essentially constant with superimposed first-order perturbation ΔP_D and ΔQ_D respectively. For small perturbations, a mismatch in real power balance affects primarily the system frequency but leaves the bus voltage magnitudes essentially unaffected and similarly a mismatch in reactive power balance affects mainly the bus voltage magnitudes but leaves the system frequency essentially unaffected. In view of this, the real power-frequency (p–f) control and reactive power-voltage (Q–V) control problems are treated as two independent or "decoupted" control problems for all practical purposes.

The change in turbine output (mechanical power) results due to governor and speed changer actions. The generator response is, for all practical purposes instantaneous and hence changes in turbine power output causes instantaneous change in electrical power output.

In any power system, it is a desirable feature to achieve better frequency constancy than is obtained by the speed governing system alone. In an interconnected power system, it is also desirable to maintain the tie-line power flow at scheduled level irrespective of load changes in an area. To accomplish this, it becomes necessary to automatically manipulate the operation of main steam valves or hydro-gates in accordance with a suitable control strategy, which in turn controls the real power output of electric generators. The problem of controlling the real power output of electric generators in this way is termed as Automatic Generation Control (AGC).

12.2 BASIC GENERATOR CONTROL LOOPS

In an interconnected power system, Load Frequency control (LFC) and Automatic Voltage Regulator (AVR) equipment are installed for each generator. Figure 12.1 gives the schematic diagram of the LFC loop and AVR loop. The controllers take care of small changes in load demand to maintain the frequency deviation and tie-power deviation–within the specified limits. As mentioned in section 12.1, small changes in real power are mainly dependent on changes in rotor angle δ and thus, the frequency. The reactive power is mainly dependent on the voltage magnitude (*i.e.*, on the generator excitation). The excitation system time constant is much smaller than the prime mover time constant and its transient decay much faster and does not affect the LFC dynamic. Thus the coupling between the LFC loop and the AVR loop is negligible and the load frequency and excitation voltage control are analyzed independently.

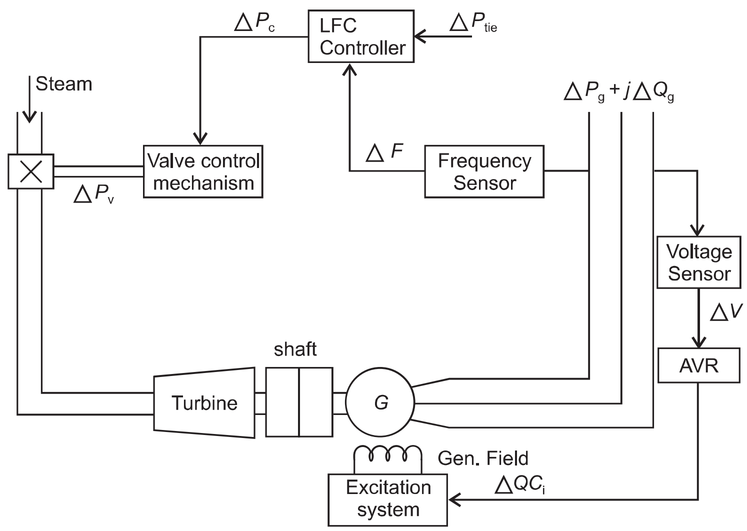
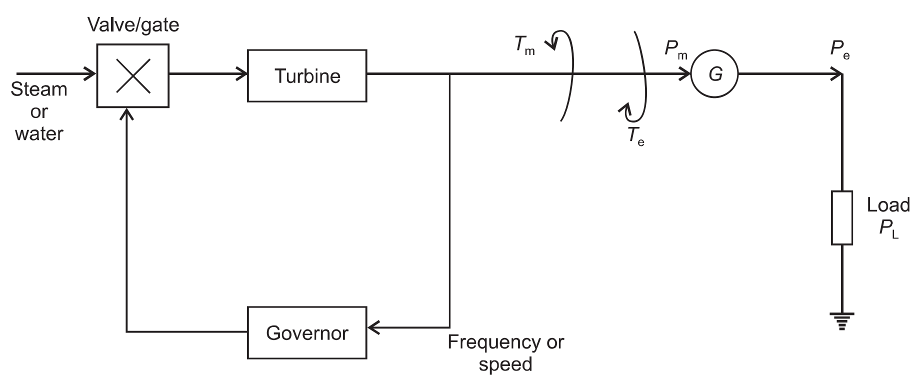


Fig. 12.1: Schematic diagram of LFC and AVR of a synchronous generator.

12.3 FUNDAMENTALS OF SPEED GOVERNING SYSTEM

The basic concepts of speed governing can be illustrated by considering an isolated generating unit supplying a local load as shown in Fig. 12.2



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

Fig. 12.2: Generator supplying a local load.

12.4 ISOCHRONOUS GOVERNOR

The "isochronous" means constant speed. An isochronous governor adjusts the turbine valve/gate to bring the frequency back to the nominal or scheduled value.

Figure 12.3 shows the schematic diagram of isochronous speed governing system. The measured frequency f (or speed w) is compared with reference frequency f_r (or reference speed w_r). The error signal (equal to frequency deviation or speed deviation) is amplified and integrated to produce a control signal ΔE which actuates the main steam supply valves in the case of a steam turbine, or gates in the case of a hydro turbine.

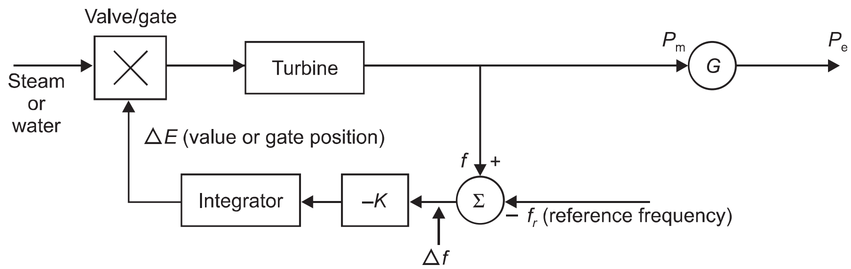


Fig. 12.3: Schematic diagram of an isochronous governor.

An isochronous governor works very well when a generator is supplying an isolated or when only one generator in a multigenerator system is requireed to respond to changes is load. However, for load sharing between generators connected to the system, droop characteristic or speed regulation must be provided as discussed in next section.

12.5 GOVERNORS WITH SPEED-DROOP CHARACTERISTICS

When two or more generating units are connected to the same system, isochronous governors can not be used since each generating unit would have to have precisely the same speed setting. Otherwise, they would fight each other, each will try 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 regulation or speed-droop characteristic can be obtained by adding a steady-state feedback loop around the integrator as shown in Fig. 12.4,

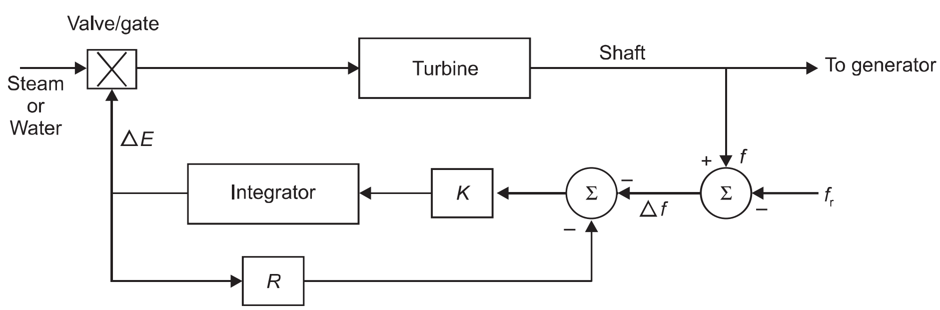
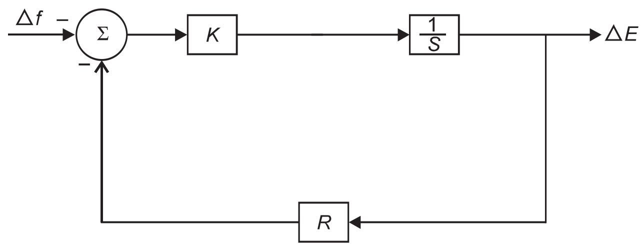
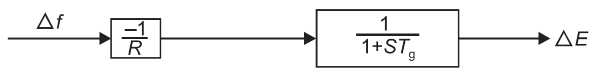


Fig. 12.4: Governor with steady-state feedback.

The transfer function of the governor of Fig. 12.4 reduces to the form as shown in Fig. 12.5. This type of governor may be characterized as proportional controller with a gain 1/R.



(*a*) Block diagram of Governor



(*b*) Reduced block diagram

Fig. 12.5: Block diagram of speed governor with droop
Where $T_g = 1/KR$ = governor time constant.

12.6 SPEED REGULATION (DROOP)

The value of speed regulation parameter R determines the steady-state frequency versus load characteristic of the generating unit as shown in Fig. 12.6. The ratio of frequency deviation (Δf) to change in valve/gate position(ΔE) or power output(ΔP_g) is equal to R. The parameter R is referred to as speed regulation or droop. It can be expressed as:

$$\text{Percent } R = \frac{\text{percent frequency change}}{\text{percent power output change}} \times 100 \qquad \text{...(12.1)}$$

For example, a 4% droop or regulation means that a 4% frequency deviation causes 100% change in valve position or power output.

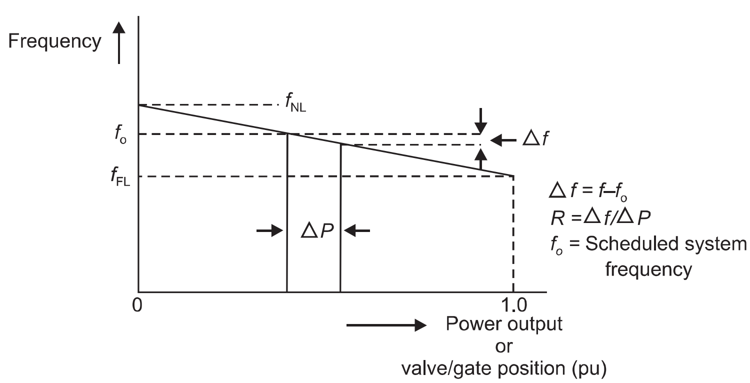


Fig.12.6: Steady-state characteristics of a governor with speed droop.

12.7 LOAD SHARING BY PARALLEL GENERATING UNITS

If two or more generating units with drooping governor characteristics are connected to a power system, there must be a unique frequency at which they will share a load-change. Fig. 12.7 shows the droop characteristics of two generating units. Initially they were operating at nominal frequency f_0, with outputs P_{g1} and P_{g2}. An increase of load ΔP_L causes the generating units to slow down and the governors increase the output until they reach a new common operating frequency f_c.

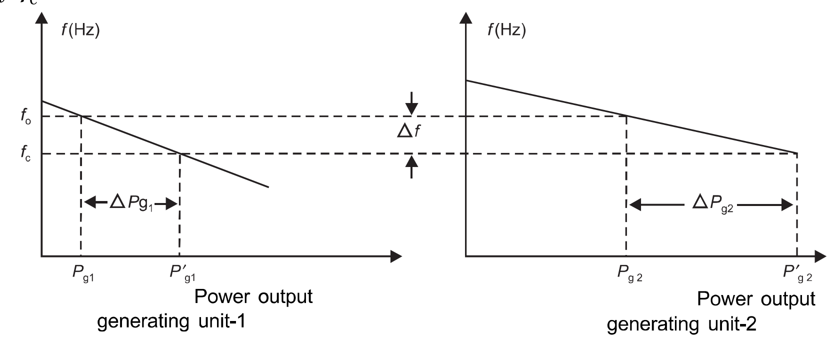


Fig. 12.6: Load sharing by two prallel generating units with drooping governor characteristics.

The amount of load picked up by each unit depends on the droop characteristic:

$$\Delta P_{g1} = P'_{g1} - P_{g1} = \frac{\Delta f}{R_1} \quad \text{...(12.2)}$$

$$\Delta P_{g2} = P'_{g2} - P_{g2} = \frac{\Delta f}{R_2} \quad \text{...(12.3)}$$

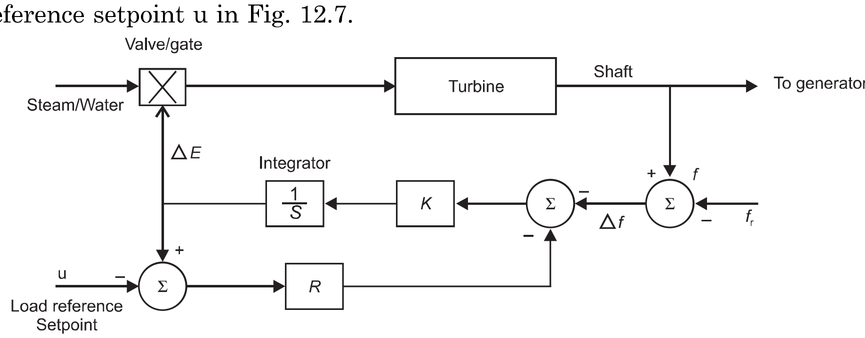
Hence,

$$\frac{\Delta P_{g1}}{\Delta P_{g2}} = \frac{R_2}{R_1} \quad \text{... (12.4)}$$

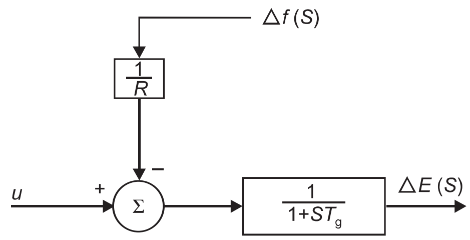
If the percentages of regulation of the units are nearly equal, the change in the outputs of each generating unit will be nearly in proportion to its rating.

12.8 CONTROL OF POWER OUTPUT OF GENERATING UNITS

The relationship between frequency and load can be adjusted by changing an input shown as "load reference setpoint u in Fig. 12.7.



(a) Schematic diagram of governor and turbine



(*b*) Reduced block diagram of governor

Fig. 12.7: Governor with load reference control for adjusting frequency-load relationship.

From the practical point of view, the adjustment of load reference set point is accomplished by operating the "speed-changer motor." Fig. 12.8 shows the effect of this adjstment. Family of parallel characteristics are shown in Fig. 12.8 for different speed-changer motor settings.

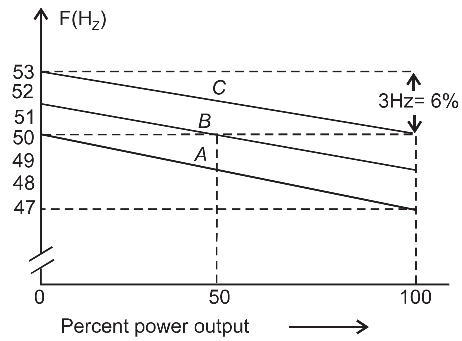


Fig. 12.8: Effect of speed-changer setting on governor characteristics.

The characteristics shown in Fig.12.8 associated with 50 Hz system. Three characteristics are shown representing three load reference settings. At 50 Hz, characteristic A results in zero output, characteristic B results in 50% output and characteristic C results in 100% output. Therefore, by adjusting the load reference setting (u) through actuation of the speed-changer motor, the power output of the generating unit at a given speed may be adjusted to any desired value. For each setting, the speed-load characteristic has a 6% droop; that is, a speed change of 6% (3Hz) causes a 100% change in power output.

12.9 TURBINE MODEL

All compound steam turbine systems utilize governor-controlled valves at the inlet to the high pressure (or very high pressure) turbine to control steam flow. The steam chest and inlet piping to the steam turbine cylinder and reheaters and crossover piping down stream all introduce delays between the valve movement and change in steam flow. The mathematical model of the steam turbine accounts for these delays.

Figure 12.9 (*a*) shows a schematic diagram of a tandem compound single reheat steam turbine and Fig. 12.9 (*b*) shows the linear transfer function model of the tandem compound single reheat steam turbine. The time constants T_t, T_r and T_c represent delays due to steam chest and inlet piping, retreates and crossover piping respectively. The fractions F_{HP}, F_{IP} and F_{LP} represent portions of the total turbine power developed in the high pressure, intermediate pressure and low pressure cylinders of the turbine. It may be noted that $F_{HP} + F_{IP} + F_{LP} = 1.0$. The time delay in the crossover piping T_c being small as compared to other time constants is neglected. The reduced order transfer function model is given in Fig. 12.9(*c*)

The portion of the total power generated in the intermediate pressure and low pressures cylinders

$$= (F_{IP} + F_{LP}) = (1 - F_{HP})$$

From Fig. 12.9 (*c*),

$$\Delta P_g(S) = \frac{1}{(1+ST_t)}\left[F_{HP} + \frac{1-F_{HP}}{1+ST_r}\right]\Delta E(S)$$

$$\therefore \quad \frac{\Delta P_g(S)}{\Delta E(S)} = \frac{(1+SK_rT_r)}{(1+ST_t)(1+ST_r)} \quad \text{...(12.5)}$$

K_r = reheat coefficient, i.e., the fraction of the power generated in the high pressure cylinders.

For non-reheat turbine, $F_{HP} = 1.0$, therefore transfer function model for non-reheat turbine is given as:

$$\frac{\Delta P_g(S)}{\Delta E(S)} = \frac{1}{(1+ST_t)} \quad \text{... (12.6)}$$

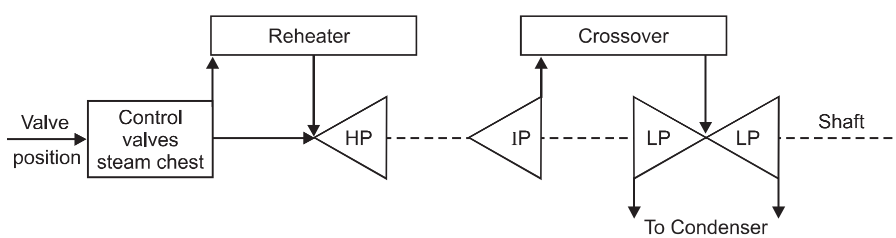


Fig. 12.9(*a*): Steam system configuration for tandem compound single reheat steam turbine.

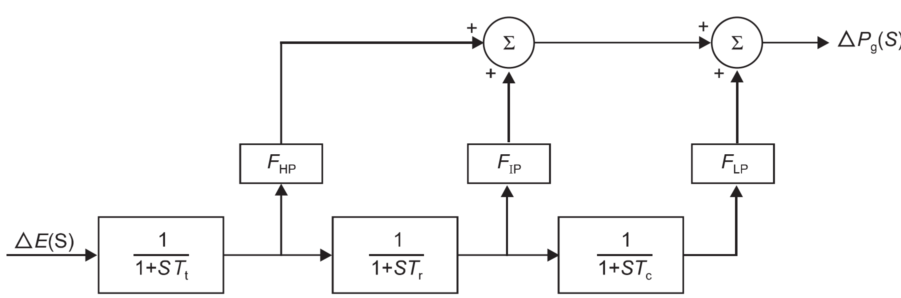


Fig. 12.9(*b*): Approximate linear model for tandem compound single reheat steam turbine.

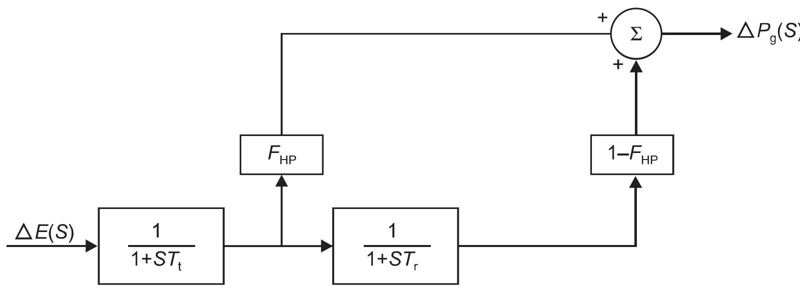


Fig. 12.9(*c*): Reduced order model for tandem compound single reheat steam turbine neglecting T_c.

12.10 GENERATOR-LOAD MODEL

Increment in power input to the generator-load system is $(\Delta P_g - \Delta P_L)$. Where $\Delta P_g = \Delta P_t$ = incremental turbine power out (assuming generator incremental loss is negligible) and ΔP_L is the load increment. $(\Delta P_g - \Delta P_L)$ is accounted for in two ways:

(1) Rate of increase of stored kinetic energy (*KE*) in the generator rotor.

At scheduled system frequency (f_0), the stored energy is

$$W^0_{ke} = H \times P_r \text{ MW} - \text{sec} \qquad \text{...(12.7)}$$

where

P_r = rated capacity of turbo-generator (MW)

H = inertia constant

The kinetic energy is proportional to square of the speed (hence frequency). The *KE* at a frequency $(f_0 + \Delta f)$ is given by

$$W_{ke} = W^0_{ke}\left(\frac{(f_0 + \Delta f)}{f_0}\right)^2$$

$$\therefore \qquad W_{ke} \approx HP_r\left(1 + \frac{2\Delta f}{f_0}\right)$$

$$\therefore \qquad \frac{d}{dt}(W_{ke}) = \frac{2HP_r}{f_0}\frac{d}{dt}(\Delta f) \qquad \text{...(12.8)}$$

(2) It is assumed that the change in motor load is sensitive to the speed (frequency) variation. However, for small changes in system frequency Δf, the rate of change of load with respect to frequency, that is $\left(\frac{\partial P_d}{\partial f}\right)$ can be regarded as constant. This load changes can be expressed as:

$$\left(\frac{\partial P_L}{\partial f}\right).\Delta f = D.\Delta f \qquad \text{...(12.9)}$$

Where $$D = \frac{\partial P_L}{\partial f} = \text{constant.}$$

Therefore, the power balance equation can be written as:

$$\Delta P_g - \Delta P_L = \frac{2HP_r}{f_0}\frac{d}{dt}(\Delta f) + D\Delta f$$

$$\therefore \quad \frac{\Delta P_g}{P_r} - \frac{\Delta P_L}{P_r} = \frac{2H}{f_0}\frac{d}{dt}(\Delta f) + \frac{D}{P_r}\Delta f$$

$$\therefore \quad \Delta P_g(\text{pu}) - \Delta P_L(\text{pu}) = \frac{2H}{f_0}\frac{d}{dt}(\Delta f) + D(\text{pu})\Delta f \qquad ...(12.10)$$

Taking the Laplace transform of eqn. (12.10), we get

$$\Delta f(S) = \frac{\Delta P_g(S) - \Delta P_L(S)}{D + \frac{2H}{f_0}S}$$

$$\therefore \quad \Delta f(S) = \left[\Delta P_g(S) - \Delta P_L(S)\right] \times \frac{K_p}{(1 + ST_p)} \qquad ...(12.11)$$

where $$T_p = \frac{2H}{Df_0} = \text{Power system time constant}$$

$$K_p = \frac{1}{D} = \text{Gain of power system.}$$

Block diagram representation of eqn. (12.11) is shown in Fig. 12.10.

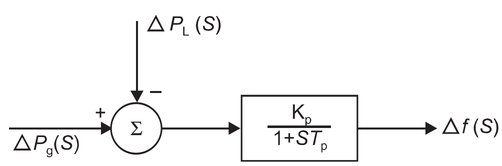


Fig. 12.10: Block diagram representation of generator-load model

12.11 BLOCK DIAGRAM REPRESENTATION OF AN ISOLATED POWER SYSTEM

Figure 12.11 shows the block diagram of a generating unit with a reheat turbine. The block diagram includes speed governor, turbine, rotating mass and load, appropriate for load frequency analysis.

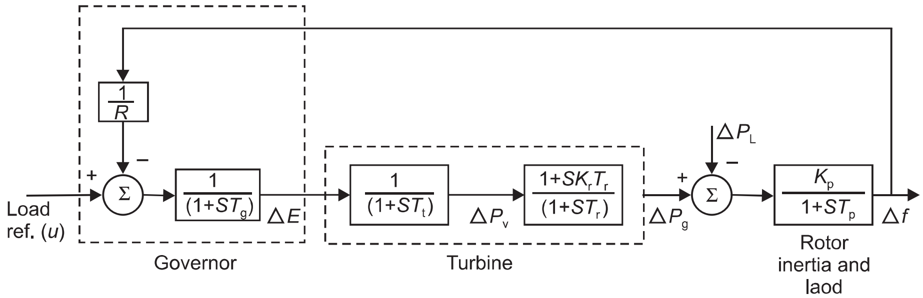


Fig. 12.11: Block diagram representation of a generating unit with a reheat turbine.

The block diagram of Fig. 12.11 is also applicable to a unit with non-reheat turbine. However, in this case $T_r = 0.0$.

12.12 STATE-SPACE REPRESENTATION

In Fig. 12.11, assume $\Delta f = x_1$, $\Delta P_g = x_2$, $\Delta P_v = x_3$ and $\Delta E = x_4$.

Differential equations are written by describing each individual block of Fig. 12.11 in terms of state variable. (Note that S is replaced by $\frac{d}{dt}$)

$$\dot{x}_1 = \frac{-1}{T_p} x_1 + \frac{K_p}{T_p} x_2 - \frac{K_p}{T_p} \Delta P_L \qquad \text{...(12.12)}$$

$$\dot{x}_2 = \frac{-1}{T_r} x_2 + \left(\frac{1}{T_r} - \frac{K_r}{T_t}\right) x_3 + \frac{K_r}{T_t} x_4 \qquad \text{...(12.13)}$$

$$\dot{x}_3 = \frac{-1}{T_t} x_3 + \frac{1}{T_t} x_4 \qquad \text{...(12.14)}$$

$$\dot{x}_4 = \frac{-1}{RT_g} x_1 - \frac{1}{T_g} x_4 + \frac{1}{T_g} u \qquad \text{...(12.15)}$$

Eqns. (12.12) – (12.15) can be written in matrix form:

$$\begin{bmatrix} \dot{x}_1 \\ \dot{x}_2 \\ \dot{x}_3 \\ \dot{x}_4 \end{bmatrix} = \begin{bmatrix} \frac{-1}{T_p} & \frac{K_p}{T_p} & 0 & 0 \\ 0 & \frac{-1}{T_r} & \left(\frac{1}{T_r} - \frac{K_r}{T_t}\right) & \frac{K_r}{T_t} \\ 0 & 0 & \frac{-1}{T_t} & \frac{1}{T_t} \\ \frac{-1}{RT_g} & 0 & 0 & \frac{-1}{T_g} \end{bmatrix} \begin{bmatrix} x_1 \\ x_2 \\ x_3 \\ x_4 \end{bmatrix} + \begin{bmatrix} 0 \\ 0 \\ 0 \\ \frac{1}{T_g} \end{bmatrix} u + \begin{bmatrix} \frac{-K_p}{T_p} \\ 0 \\ 0 \\ 0 \end{bmatrix} \Delta P_L \qquad \text{... (12.16)}$$

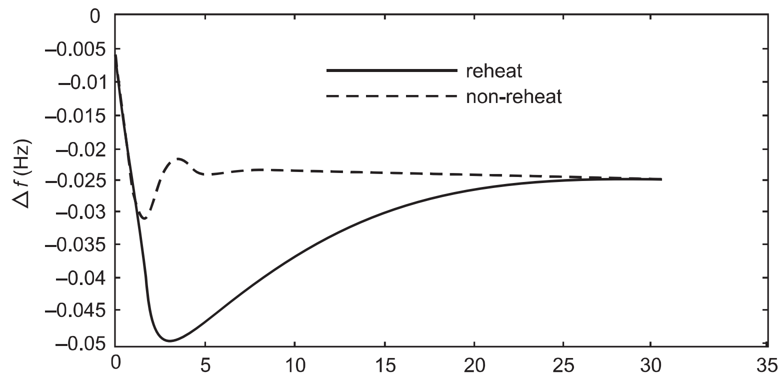


Fig. 12.12: Dynamic responses for single area reheat and non-reheat systems.

Eqn. (12.16) can be written as:

$$\dot{X} = AX + BU + \Gamma p \qquad \text{...(12.17)}$$

Where

$$X' = [x_1 \;\; x_2 \;\; x_3 \;\; x_4]$$

$$A = \begin{bmatrix} \dfrac{-1}{T_\mathrm{p}} & \dfrac{K_\mathrm{p}}{T_\mathrm{p}} & 0 & 0 \\ 0 & \dfrac{-1}{T_\mathrm{r}} & \left(\dfrac{1}{T_\mathrm{r}} - \dfrac{K_\mathrm{r}}{T_\mathrm{t}}\right) & \dfrac{K_\mathrm{r}}{T_\mathrm{t}} \\ 0 & 0 & \dfrac{-1}{T_\mathrm{t}} & \dfrac{1}{T_\mathrm{t}} \\ \dfrac{-1}{RT_\mathrm{g}} & 0 & 0 & \dfrac{-1}{T_\mathrm{g}} \end{bmatrix}$$

$$B' = \begin{bmatrix} 0 & 0 & 0 & \dfrac{1}{T_\mathrm{g}} \end{bmatrix}$$

$$\Gamma' = \begin{bmatrix} \dfrac{-K_\mathrm{p}}{T_\mathrm{p}} & 0 & 0 & 0 \end{bmatrix}$$

$p = \Delta P_\mathrm{L}$

′ Stands for transpose

Figure 12.12 Shows the dynamic responses for a step increase in load demand. The results presented in Fig. 12.12 demonstrate that, although the steady-state speed deviation is the same for two units considered, there are significant differences in their transient responses.

12.13 FUNDAMENTALS OF AUTOMATIC GENERATION CONTROL

With the primary speed control action, a change in system load will result in a steady-state frequency deviation, depending on the droop characteristic of governor and frequency sensitivity of the load. Restoration of system frequency to nominal value requires supplementary control action which adjusts the load reference setpoint through the speed-changer motor. Therefore, the problem can be subdivided into fast primary and slow secondary control modes. The fast primary control counteracts random load changes and has a time constant of the order of few seconds. The slow secondary control (Supplementary Control) with time constant of the order of minutes regulates the generation to satisfy economic generator loading requirements and contractual tie-line loading agreements.

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 defined as Load Frequency Control (LFC). A secondary objective is to distribute the required change in generation among various units to minimize operating costs.

Example 12.1: *A system consists of 4 identical 400 MVA generating units feeding a total load of 1016 MW. The inertia constant H of each unit is 5.0 on 400 MVA base. The load changes by 1.5% for a 1% change in frequency. When there is a sudden drop in load by 16 MW.*

(*a*) Obtain the system block diagram with constants H and D expressed on 1600 MVA base
(*b*) Determine the frequency deviation, assuming that there is no speed-governing action.

Solution

(*a*) For 4 units on 2000 MVA base,

$$H = 5.0 \times \left(\frac{400}{1600}\right) \times 4 = 5.0$$

Assuming $f_0 = 50$ Hz

$$\frac{\partial P_L}{\partial f} = \frac{1.5(1016-16)}{1 \times 50} = \frac{1.5 \times \overset{20}{\cancel{1000}}}{\cancel{50}} = 30 \text{ MW/Hz}$$

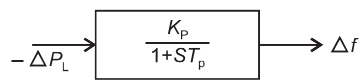
$$D = \left(\frac{\partial P_L}{\partial f}\right) \Big/ 1600 = \frac{3\cancel{0}}{160\cancel{0}} = \frac{3}{160} \text{ pu MW/Hz}$$

We know

$$T_p = \frac{2H}{Df_0} = \frac{2 \times 5}{\frac{3}{160} \times 50} = \frac{2 \times \cancel{5} \times 16\cancel{0}}{3 \times \cancel{50}} \text{ sec}$$

$\therefore \qquad T_p = \dfrac{32}{3}$ sec.

(b) With $\Delta P_g = 0$ (no speed governing), the block diagram of Fig. 12.10 with system parameters can be given as



where $\qquad K_p = \dfrac{1}{D} = \dfrac{160}{3}$ Hz/pu MW.

$$T_p = \frac{32}{3} \text{ sec.}$$

The load change is

$$\Delta P_L = 16 \text{ MW} = \frac{16}{1600} = 0.01 \text{ pu MW.}$$

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

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

From the block diagram

$$\Delta f(s) = \left(\frac{-0.01}{S}\right)\left(\frac{K_p}{1+ST_p}\right)$$

$$\therefore \qquad \Delta f(t) = -\,0.01\, K_p e^{-t/T_p} + 0.01\, K_p$$

$$\therefore \qquad \Delta f(t) = 0.01 \times \frac{160}{3} - 0.01 \times \frac{160}{3}\, e^{-t/(32/3)}$$

$$\therefore \qquad \Delta f(t) = \frac{1.6}{3}\left(1 - e^{-3t/32}\right)$$ **Ans.**

Fig. 12.13 shows the frequency response.

$\therefore \qquad \Delta f_{ss} = 0.533$ Hz **Ans.**

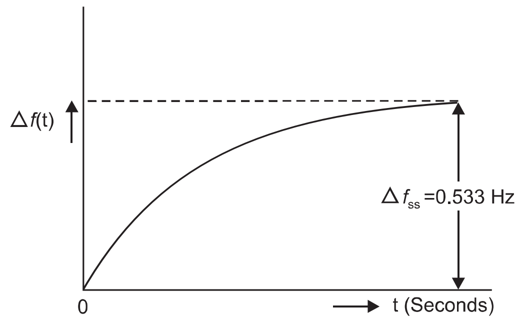


Fig. 12.13: Frequency response.

12.14 STEADY STATE ANALYSIS

From Fig.12.11, steady state error of frequency deviation can easily be obtained with $u = 0$. From Fig. 12.11, we can write (Assume $\Delta f = \Delta f$ss)

$$\left(\frac{-\Delta f_{ss}}{R} - \Delta P_L\right) \times K_p = \Delta f_{ss}$$

$$\therefore \qquad \left(\frac{-\Delta f_{ss}}{R} - \Delta P_L\right) = D.\Delta f_{ss}$$

$$\therefore \qquad D.\Delta f_{ss} + \frac{\Delta f_{ss}}{R} = -\Delta P_L$$

$$\therefore \qquad \Delta f_{ss} = \frac{-\Delta P_L}{\left(D + \frac{1}{R}\right)} \qquad \text{...(12.18)}$$

12.14.1 Composite Frequency Response Characteristic

Figure 12.14 shows a power system having n number of generating units. It may be assumed that all the generators swing in unison and the equivalent generator has an inertia constant equal to the sum of the inertia constants of all the generating units. From Fig. 12.14. steady state error of frequency deviation can be given as:

$$\Delta f_{ss} = \frac{-\Delta P_L}{\left(D + \frac{1}{R_1} + \frac{1}{R_2} + \ldots + \frac{1}{R_n}\right)}$$

$$\therefore \qquad \Delta f_{ss} = \frac{-\Delta P_L}{D + \frac{1}{R_{eq}}} \qquad \text{... (12.19)}$$

where $$R_{eq} = \frac{1}{\left(1/R_1 + 1/R_2 + \ldots 1/R_n\right)} \qquad \text{...(12.20)}$$

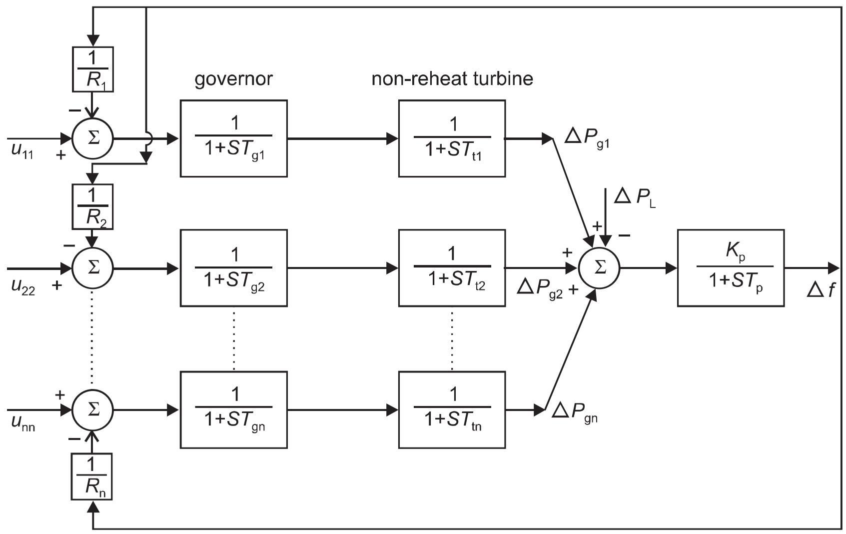


Fig. 12.14: Multi-unit isolated power system.

It has already mentioned in the previous section that the supplementary generation control action is much slower than the primary speed control action. As such it comes into action after the primary speed control has stabilized the system frequency. For isolated system, function of AGC is to restore system frequency to the specified nominal value and this is accomplished by adding a reset or integral control. This is shown in Fig. 12.15.

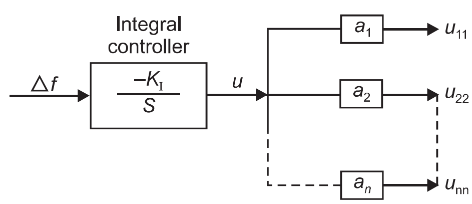


Fig. 12.15: Structure of integral controller.

Note that $a_1, a_2, ..., a_n$ are the participation factor and $a_1 + a_2 + ... + a_n = 1.0$. At steady state, output of each generating unit can be given as:

$$
\begin{aligned}
\Delta P_{g1ss} &= a_1 . \Delta P_L \\
\Delta P_{g2ss} &= a_2 \, . \, \Delta P_L \\
. \quad & \quad . \\
. \quad & \quad . \\
. \quad & \quad . \\
\Delta P_{gnss} &= a_n \Delta P_L
\end{aligned}
\qquad ...(12.21)
$$

Readers may easily verify that through computer simulation.

12.15 CONCEPT OF CONTROL AREA

Consider a practical system with number of generating stations and loads. AGC problem of a large interconnected power system has been studied by dividing the whole system into a number of control areas. A control area is defined as a power system, a part of a system or a combination of systems to which a common generation control scheme is applied. The electrical interconnections within each control area are very strong as compared to the ties with the neighbouring areas. All the generators in a control area swing in unison or coherently and it is characterized by a single frequency. In normal steady state operation each control area of a power system should strive to meet its load demand. Simultaneously each control area of a power system should participate in regulating the frequency of the system.

The two basic inter-area regulating responsibilities of each control area are:

1. When system frequency is on schedule, each area is expected automatically to adjust its generation to maintain its net transfers with other areas on schedule, thereby absorbing its own load variations. So long as all areas do so, scheduled system frequency as well as net interchange schedules for all areas are maintained.
2. When system frequency is off schedule, because one or more areas are not fulfilling this requlating responsibility, other areas are expected automatically to shift their respective net transfer schedule proportionally to the system frequency deviation and in direction to assist the deficient areas and help to restore system frequency. The extent of each area's shift of net interchange schedule is programmed by its frequency bias setting. Failure of an area to respond fully to frequency deviations caused by other areas creates extra regulating requirements for areas that do properly respond.

Cooperative assistance between areas is one of the planned benefits of interconnected operation. But when the assistance is unscheduled, it is obtained at the expense of departures of system frequency and area net interchange from their respective schedules. These integrate respectively into system time deviation and area unscheduled or inadvertent interchange, and cause additional regulation burden on the part of assisting areas.

Example 12.2: *A power system has a total load of 1260 MW at 50 Hz. The load varies 1.5% for every 1% change in frequency. 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 spining reserve evenly spread among 500 MW generation capacity with 5% regulation based on this capacity. Assume that the effect of governor dead bands is such that only 80% of the governors respond to the reduction in system load.

Solution

Total remaining load is (1260–60) = 1200 MW. The damping constant of remaining load is

$$D = \left(\frac{1.5 \times 1200}{100}\right) \times \left(\frac{100}{50 \times 1}\right) = 36 \text{ MW/Hz.}$$

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

$$\Delta f_{ss} = \frac{-\Delta P_L}{D} = \frac{-(-60)}{36} = \frac{5}{3} \text{ Hz}$$

$\therefore \qquad \Delta f_{ss} = 1.667$ Hz **Ans.**

(*b*) The total spinning generation capacity is equal to

Load + reserve = 1260 + 240 = 1500 MW

Generation contributing to regulation is

$0.8 \times 1500 = 1200$ MW

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

$$\frac{1}{R} = \frac{1200}{(0.05 \times 50)} = 480 \text{ MW/Hz}$$

The composite system frequency response characteristic is

$$\beta = D + \frac{1}{R} = 36 + 480 = 516 \text{ MW/Hz.}$$

Steady-state increase in frequency is

$$\Delta f_{ss} = \frac{-\Delta P_L}{\beta} = \frac{-(-60)}{516} \text{ Hz}$$

$\therefore$ $\Delta f_{ss} = 0.1162$ Hz. **Ans.**

Example 12.3: *Two generators rated 250 MW and 400 MW are operating in parallel. The droop characteristics of the governors are 4% and 6% respectively. How would a load of 650 MW be shared between them? What will be the system frequency? Assume nominal system frequency is 60 Hz and no governing action.*

Solution

Let load on generator 1 = x MW

load on generator 2 = $(650 - x)$ MW

Reduction in frequency = Δf

Now

$$\frac{\Delta f}{x} = \frac{0.04 \times 60}{250} \quad ...(i)$$

$$\frac{\Delta f}{(650 - x)} = \frac{0.06 \times 60}{400} \quad ...(ii)$$

From eqns (*i*) and (*ii*), we get

$$\frac{650 - x}{x} = \frac{0.04 \times 60}{250} \times \frac{400}{0.06 \times 60} = 1.066$$

$\therefore$ $x = 314.52$ MW. (load on generator 1)

$650 - x = 335.48$ MW (load on generator 2)

and $\Delta f = 3.019$ Hz

$\therefore$ System frequency = $(60 - 3.019) = 56.981$ Hz.

Example 12.4: *A 200 MVA generator operates on full load at a frequency of 60 Hz. The load is suddenly reduced to 20 MW. Due to time lag in governor system, the steam valve begins to close after 0.22 sec. Determine the change in frequency that occurs in this time. Given H = 10 KW – sec/ KVA of generator capacity.*

Solution

$$\text{Stored kinetic energy} = 10 \times 200 \times 1000 \text{ KW–sec}$$
$$= 2 \times 10^6 \text{ KW–sec}$$

Excess power input to generator before the steam valve begins to close = 20 MW.

Excess energy input to rotating parts in 0.22 sec = 20 × 1000 × 0.22 = 4400 KW–sec.

Stored kinetic energy is proportional to the square of frequency.

∴ Frequency at the end of 0.22 sec

$$= 60 \times \left(\frac{2\times10^6 + 4400}{2\times10^6}\right)^{1/2} = 60.066 \text{ Hz.}$$ **Ans.**

12.16 AGC OF TWO AREA INTERCONNECTED POWER SYSTEM

Fig. 12.16 shows a two area power system interconnected by tie-line. Assume tie-line resistance is negligible.

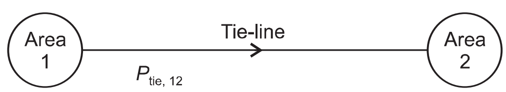


Fig. 12.16: Two area power system.

From Fig. 12.16, tie-line power flow can be written as:

$$P_{\text{tie},12} = \frac{V_1V_2}{x_{12}} \sin(\delta_1^o - \delta_2^o) \qquad \text{...(12.22)}$$

Where δ_1^o and δ_2^o are power angles.

For incremental changes in δ_1 and δ_2, the incremental tie-line power can be expressed as

$$\Delta P_{\text{tie},12}{}^{(\text{pu})} = T_{12}(\Delta\delta_1 - \Delta\delta_2) \qquad \text{...(12.23)}$$

Where

$$T_{12} = \frac{|V_1||V_2|}{P_{r1}x_{12}} \cos(\delta_1^o - \delta_2^o) = \text{synchronizing coefficient.}$$

Eqn. (12.23) can also be written as

$$\Delta P_{\text{tie},12} = 2\pi T_{12}\left(\int \Delta f_1 dt - \int \Delta f_2 dt\right) \qquad \text{...(12.24)}$$