Load frequency Control

Automatic Load Frequency Control

The ALFC is to control the frequency deviation by maintaining the real power balance in the system. The main functions of the ALFC are to i) to maintain the steady frequency; ii) control the tie-line flows; and iii) distribute the load among the participating generating units. The control (input) signals are the tie-line deviation ΔP_{tie} (measured from the tie-line flows), and the frequency deviation Δf (obtained by measuring the angle deviation $\Delta\delta$). These error signals Δf and ΔP_{tie} are amplified, mixed and transformed to a real power signal, which then controls the valve position. Depending on the valve position, the turbine (prime mover) changes its output power to establish the real power balance. The complete control schematic is shown in Fig2.3

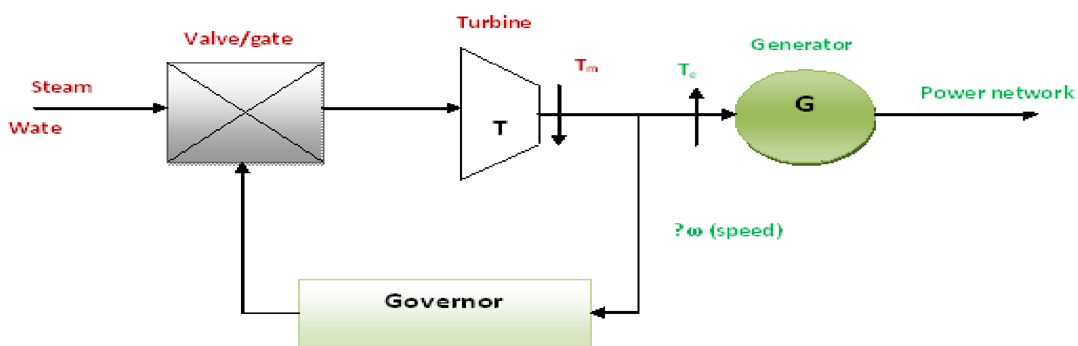


Fig2.3: The Schematic representation of ALFC system

For the analysis, the models for each of the blocks in Fig2 are required. The generator and the electrical load constitute the power system. The valve and the hydraulic amplifier represent the speed governing system. Using the swing equation, the generator can be modeled by $\frac{2Hd^2\Delta\delta}{\omega_s dt^2} = \Delta P_m - \Delta P_e$. Expressing the speed deviation in pu, $\frac{d\Delta\omega}{dt} = \frac{1}{2H}(\Delta P_m - \Delta P_e)$. This relation can be represented as shown in Fig2.4.

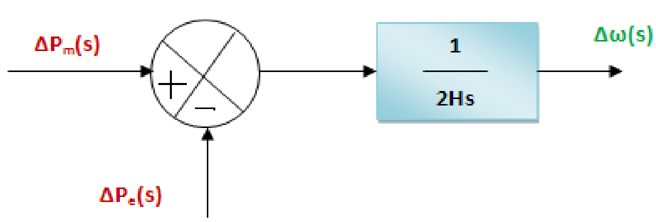


Fig2.4. The block diagram representation of the Generator

The load on the system is composite consisting of a frequency independent component and a frequency dependent component. The load can be written as $\Delta P_e = \Delta P_0 + \Delta P_f$ where, ΔP_e is the change in the load; ΔP_0 is the frequency independent load component; ΔP_f is the frequency dependent load component. $\Delta P_f = D\Delta\omega$ where, D is called frequency characteristic of the load (also called as damping constant) expressed in percent change in load for 1% change in frequency. If D=1.5%, then a 1% change in frequency causes 1.5% change in load. The combined generator and the load (constituting the power system) can then be represented as shown in Fig2.5

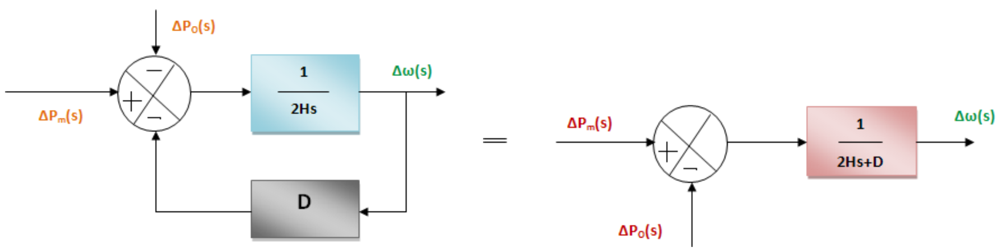
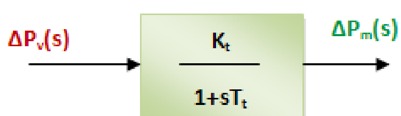


Fig2.5. The block diagram representation of the Generator and load

The turbine can be modeled as a first order lag as shown in the Fig2.6



$$G_t(s) = \frac{\Delta P_m(s)}{\Delta P_V(s)} = \frac{K_t}{1+sT_t}$$

$G_t(s)$ is the TF of the turbine; $\Delta P_V(s)$ is the change in valve output (due to action). $\Delta P_m(s)$ is the change in the turbine output

Fig2.6. The turbine model.

The governor can similarly modeled as shown in Fig2.7. The output of the governor is by $\Delta P_g = \Delta P_{ref} - \frac{\Delta\omega}{R}$ where ΔP_{ref} is the reference set power, and $\Delta\omega/R$ is the power given by governor speed characteristic. The hydraulic amplifier transforms this signal ΔP_g into valve/gate position corresponding to a power ΔP_V. Thus $\Delta P_V(s) = (K_g/(1+sT_g))\Delta P_g(s)$.

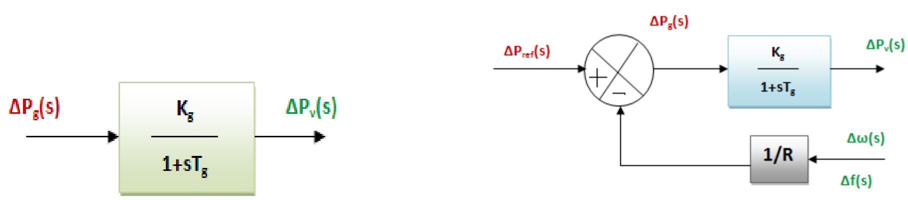


Fig2.7: The block diagram representation of the Governor

All the individual blocks can now be connected to represent the complete ALFC loop as shown in Fig2.8

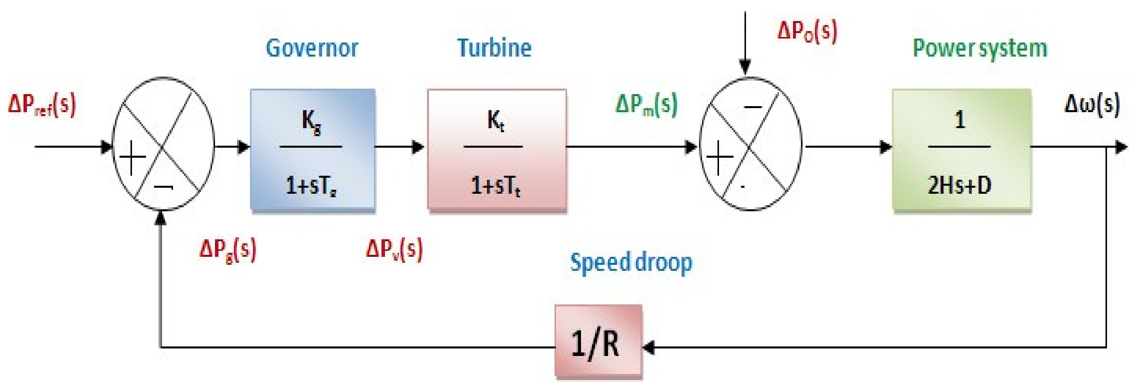


Fig2.8: The block diagram representation of the ALFC

Steady State Performance of the ALFC Loop

In the steady state, the ALFC is in 'open' state, and the output is obtained by substituting s→0 in the TF.

With s→0, Gg(s) and Gt(s) become unity, then, (note that $\Delta P_m = \Delta P_T = \Delta P_G = \Delta P_e = \Delta P_D$; That is turbine output = generator/electrical output = load demand)

$$\Delta P_m = \Delta P_{ref} - (1/R)\Delta\omega \quad \text{or} \quad \Delta P_m = \Delta P_{ref} - (1/R)\Delta f$$

When the generator is connected to infinite bus ($\Delta f = 0$, and $\Delta V = 0$), then $\Delta P_m = \Delta P_{ref}$.

If the network is finite, for a fixed speed changer setting ($\Delta Pref = 0$), then

$$\Delta P_m = -(1/R)\Delta f \quad \text{or} \quad \Delta f = -R\,\Delta P_m.$$

If the frequency dependent load is present, then

$$\Delta P_m = \Delta P_{ref} - (1/R + D)\Delta f \quad \text{or} \quad \Delta f = \frac{-\Delta Pm}{D + 1/R}$$

If there are more than one generator present in the system, then

$$\Delta P_{m.\ eq} = \Delta P_{ref.eq} - (D + 1/R_{eq})\Delta f$$

where, $\Delta P_{m.\ eq} = \Delta P_{m1} + \Delta P_{m2} + \Delta P_{m.3} + \ldots.$

$\Delta P_{ref.\ eq} = \Delta P_{ref1} + \Delta P_{ref2} + \Delta P_{ref3} + \ldots..$

$1/R_{eq} = (1/R_1 + 1/R_2 + 1/R_2 + \ldots.)$

The quantity $\beta = (D + 1/R_{eq})$ is called the area frequency (bias) characteristic (response) or simply the stiffness of the system.

Concept of AGC (Supplementary ALFC Loop)

The ALFC loop shown in Fig2.8, is called the primary ALFC loop. It achieves the primary goal of real power balance by adjusting the turbine output ΔP_m to match the change in load demand ΔP_D. All the participating generating units contribute to the change in generation. But a change in load results in a steady state frequency deviation Δf. The restoration of the frequency to the nominal value requires an additional control loop called the supplementary loop. This objective is met by using integral controller which makes the frequency deviation zero. The ALFC with the supplementary loop is generally called the AGC. The block diagram of an AGC is shown in Fig2.9. The main objectives of AGC are i) to regulate the frequency (using both primary and supplementary controls); ii) and to maintain the scheduled tie-line flows. A secondary objective of the AGC is to distribute the required change in generation among the connected generating units economically (to obtain least operating costs).

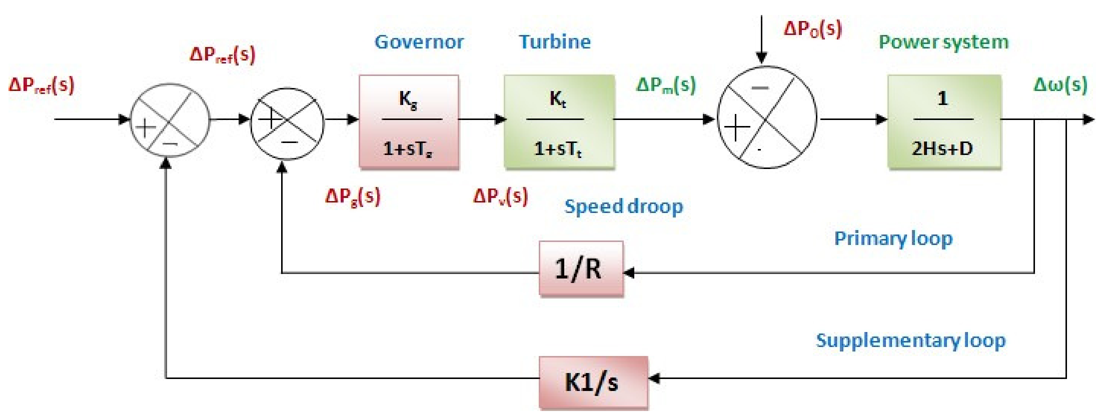


Fig2.9: The block diagram representation of the AGC

AGC in a Single Area System

In a single area system, there is no tie-line schedule to be maintained. Thus the function of the AGC is only to bring the frequency to the nominal value. This will be achieved using the supplementary loop (as shown in Fig.2.9) which uses the integral controller to change the reference power setting so as to change the speed set point. The integral controller gain K_I needs to be adjusted for satisfactory response (in terms of overshoot, settling time) of the system. Although each generator will be having a separate speed governor, all the generators in the control area are replaced by a single equivalent generator, and the ALFC for the area corresponds to this equivalent generator.

AGC in a Multi Area System

In an interconnected (multi area) system, there will be one ALFC loop for each control area (located at the ECC of that area). They are combined as shown in Fig2.10 for the interconnected system operation. For a total change in load of ΔP_D, the steady state deviation in frequency in the two areas is given by $\Delta f = \Delta\omega_1 = \Delta\omega_2 = \dfrac{-\Delta P_D}{\beta_1 + \beta_2}$ where, $\beta_1 = (D_1 + 1/R_1)$; and $\beta_2 = (D_2 + 1/R_2)$.

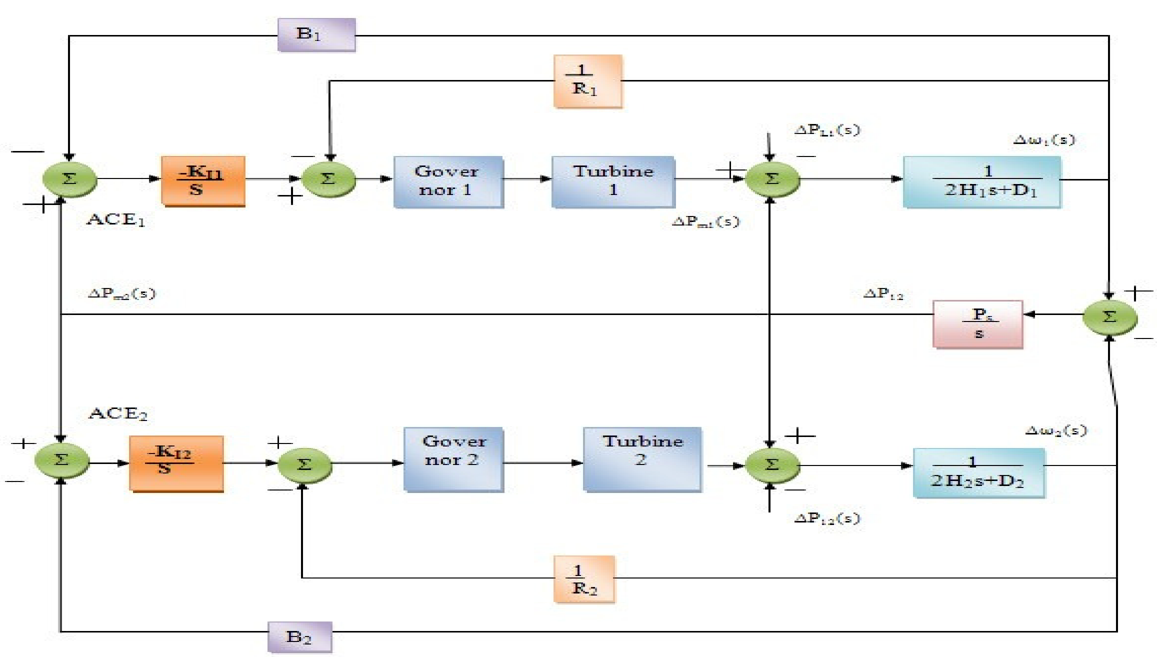


Fig.2.10. AGC for a multi-area operation.

Expression for tie-line flow in a two-area interconnected system

Consider a change in load ΔP_{D1} in area1. The steady state frequency deviation Δf is the same for both the areas. That is $\Delta f = \Delta f_1 = \Delta f_2$. Thus, for area1, we have

$$\Delta P_{m1} - \Delta P_{D1} - \Delta P_{12} = D_1 \Delta f$$

where, ΔP_{12} is the tie line power flow from Area1to Area 2; and for Area 2

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

The mechanical power depends on regulation. Hence

$$\Delta P_{m1} = -\frac{\Delta f}{R_1} \quad \text{and} \quad \Delta P_{m2} = -\frac{\Delta f}{R_2}$$

Substituting these equations, yields

$$\left(\frac{1}{R_1} + D_1\right)\Delta f = -\Delta P_{12} - \Delta P_{D1} \quad \text{and} \quad \left(\frac{1}{R_2} + D_2\right)\Delta f = \Delta P_{12}$$

Solving for Δf, we get

$$\Delta f = \frac{-\Delta P_{D1}}{(1/R_1 + D_1) + (1/R_2 + D_2)} = \frac{-\Delta P_{D1}}{\beta_1 + \beta_2}$$

and $$\Delta P_{12} = \frac{-\Delta P_{D1}\beta_2}{\beta_1 + \beta_2}$$

where, β_1 and β_2 are the composite frequency response characteristic of Area1 and Area 2 respectively. An increase of load in area1 by ΔP_{D1} results in a frequency reduction in both areas and a tie-line flow of ΔP_{12}. A positive ΔP_{12} is indicative of flow from Area1 to Area 2 while a negative ΔP_{12} means flow from Area 2 to Area1. Similarly, for a change in Area

2 load by ΔP_{D2}, we have $$\Delta f = \frac{-\Delta P_{D2}}{\beta_1 + \beta_2}$$

and $$\Delta P_{12} = -\Delta P_{21} = \frac{-\Delta P_{D2}\beta_1}{\beta_1 + \beta_2}$$

Frequency bias tie line control

The tie line deviation reflects the contribution of regulation characteristic of one area to another. The basic objective of supplementary control is to restore balance between each area load generation. This objective is met when the control action maintains

- Frequency at the scheduled value

- Net interchange power (tie line flow) with neighboring areas at the scheduled values

The supplementary control should ideally correct only for changes in that area. In other words, if there is a change in Area1 load, there should be supplementary control only in Area1 and not in Area 2. For this purpose the area control error (ACE) is used (Fig2.9). The ACE of the two areas are given by

For area 1: $ACE_1 = \Delta P_{12} + \beta_1 \Delta f$

For area 2: $ACE_2 = \Delta P_{21} + \beta_2 \Delta f$

Economic Allocation of Generation

An important secondary function of the AGC is to allocate generation so that each generating unit is loaded economically. That is, each generating unit is to generate that amount to meet the present demand in such a way that the operating cost is the minimum. This function is called Economic Load Dispatch (ELD).

Systems with more that two areas

The method described for the frequency bias control for two area system is applicable to multiarea system also.

Note:

The regulation constant R is negative of the slope of the Δf *verses* Δp_m *curve of the turbine-governor control. The unit of R is Hz/MW when* Δf *is in Hz and* Δp_m *is in MW. When* Δf *and* Δp_m *are in per-unit, R is also in per-unit.*

The area frequency characteristic is defined as $\beta = \{1/(D+1/R)\}$*, where D is the frequency damping factor of the load. The unit of* β *is MW/Hz when* Δf *is in Hz and* Δp_m *is in MW. If* Δf *and* Δp_m *are in per unit, then* β *is also in per unit.*

Examples:

Ex 1. A 500 MVA, 50 Hz, generating unit has a regulation constant R of 0.05 p.u. on its own rating. If the frequency of the system increases by 0.01 Hz in the steady state, what is the decrease in the turbine output? Assume fixed reference power setting.

Solution: In p.u. $\Delta f = 0.01/50 = 0.0002$ p.u.

With $\Delta p_{ref} = 0$, $\Delta p_m = -1/R(\Delta f) = -\ 0.004$ p.u.

Hence, $\Delta p_m = -0.004\ S_{base} = -\ 2$ MW.

Ex. 2. An interconnected 60 Hz power system consists of one area with three generating units rated 500, 750, and 1000 MVA respectively. The regulation constant of each unit is R= 0.05 per unit on its own rating. Each unit is initially operating at one half of its rating, when the system load suddenly increases by 200MW. Determine (i) the area frequency response characteristic on a 1000 MVA system base, (ii) the steady state frequency deviation of the area, and (iii) the increase in turbine power output.

Regulation constants on common system base are ($R_{pu\ new} = R_{pu\ old}\ (S_{base\ new}/S_{base\ old})$:

R1 = 0.1; R2 = 0.0667; and R3 = 0.05.

Hence $\beta = (1/R1 + 1/R2 + 1/R3) = 45$ per unit.

Neglecting losses and frequency dependence of the load, the steady state frequency deviation is $\Delta f = (-1/\beta)\Delta p_m = -4.444 \times 10^{-3}$ per unit $= (-4.444 \times 10^{-3})60 = -\ 0.2667$ Hz.

$\Delta p_{m1} = (-1/R1)(\Delta f) = 0.04444$ per unit = 44.44 MW

$\Delta p_{m2} = (-1/R2)(\Delta f) = 0.06666$ per unit = 66.66 MW

$\Delta p_{m3} = (-1/R3)(\Delta f) = 0.08888$ per unit = 88.88 MW

Ex.3. A 60 Hz, interconnected power system has two areas. Area1 has 2000 MW generation and area frequency response of 700 MW/Hz. Area 2 has 4000 MW generation and area frequency response of 1400 MW/Hz. Each area is initially generating half of its rated generation, and the tie-line deviation is zero at 60 Hz when load in Area1 is suddenly increases by 100 MW. Find the steady state frequency error and tie line error of the two areas. What is the effect of using AGC in this system?

In the steady state, $\Delta f = (-1/\beta)\ \Delta p_m = \{\Delta p_m / -(\beta 1 + \beta 2)\} = (-100/2100) = -0.0476$ Hz.

Assuming $\Delta p_{ref} = 0$,

$$\Delta p_{m1} = -\beta 1\ \Delta f = 33.33 \text{ MW; and } \Delta p_{m2} = -\beta 2\ \Delta f = 66.67 \text{ MW.}$$

Thus in response to 100 MW change in Area1, both areas will change their generation. The increase in Area 2 generation will now flow through tie line to Area1.

Hence $\Delta p_{tie1} = -66.67$ MW; and $\Delta p_{tie2} = +66.67$ MW.

With AGC, the Area control error is determined as follows.

ACE 1 = $\Delta p_{tie1} + B_1\ \Delta f$ where B_1 is the frequency bias constant.
ACE 2 = $\Delta p_{tie2}\ (= -\Delta p_{tie1}) + B_2\ \Delta f$ where B_2 is the frequency bias constant.
The control will actuate such that in the steady state the frequency and tie line deviations are zero. Thus till ACE1= ACE2 = 0, the control signal will be present.