LOAD FREQUENCY CONTROL

The following basic requirements are to be fulfilled for successful operation of the system:

1. The generation must be adequate to meet all the load demand
2. The system frequency must be maintained within narrow and rigid limits.
3. The system voltage profile must be maintained within reasonable limits and
4. In case of interconnected operation, the tie line power flows must be maintained at the specified values.

When real power balance between generation and demand is achieved the frequency specification is automatically satisfied. Similarly, with a balance between reactive power generation and demand, voltage profile is also maintained within the prescribed limits. Under steady state conditions, the total real power generation in the system equals the total MW demand plus real power losses. Any difference is immediately indicated by a change in speed or frequency. Generators are fitted with speed governors which will have varying characteristics: different sensitivities, dead bands response times and droops. They adjust the input to match the demand within their limits. Any change in local demand within permissible limits is absorbed by generators in the system in a random fashion.

An independent aim of the automatic generation control is to reschedule the generation changes to preselected machines in the system after the governors have accommodated the load change in a random manner. Thus, additional or supplementary regulation devices are needed along with governors for proper regulation.

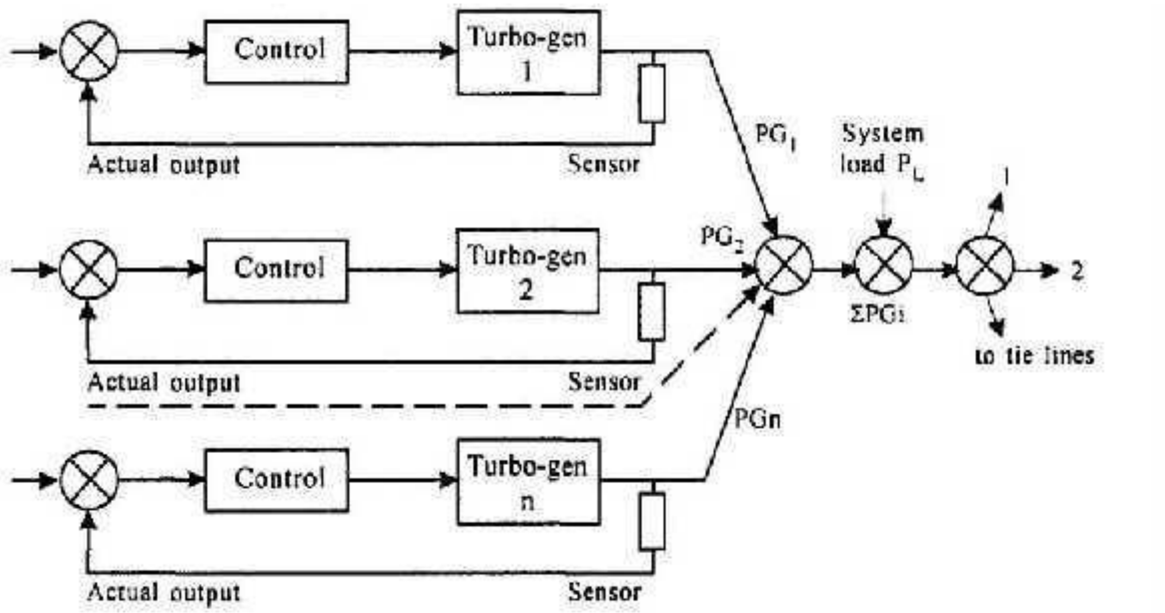
The control of generation in this manner is termed load-frequency control. For interconnected operation, the last of the four requirements mentioned earlier is fulfilled by deriving an error signal from the deviations in the specified tie-line power flows to the neighboring utilities and adding this signal to the control signal of the load-frequency control system. Should the generation be not adequate to balance the load demand, it is imperative that one of the following alternatives be considered for keeping the system in operating condition:

I. Starting fast peaking units.

2. Load shedding for unimportant loads, and

3. Generation rescheduling.

It is apparent from the above that since the voltage specifications are not stringent. Load frequency control is by far the most important in power system control.



The block schematic for Load frequency control

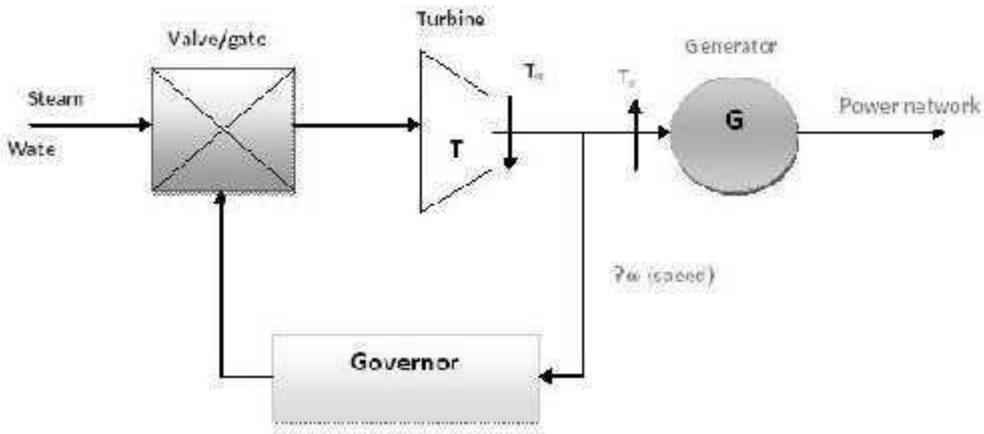
In order to understand the mechanism of frequency control, consider a small step increase in load. The initial distribution of the load increment is determined by the system impedance; and the instantaneous relative generator rotor positions. The energy required to supply the load increment is drawn from the kinetic energy of the rotating machines. As a result, the system frequency drops. The distribution of load during this period among the various machines is determined by the inertias of the rotors of the generators partaking in the process. This problem is studied in stability analysis of the system.

After the speed or frequency fall due to reduction in stored energy in the rotors has taken place, the drop is sensed by the governors and they divide the load increment between the machines as determined by the droops of the respective governor characteristics. Subsequently, secondary control restores the system frequency to its normal value by readjusting the governor characteristics.

AUTOMATIC LOAD FREQUENCY CONTROL

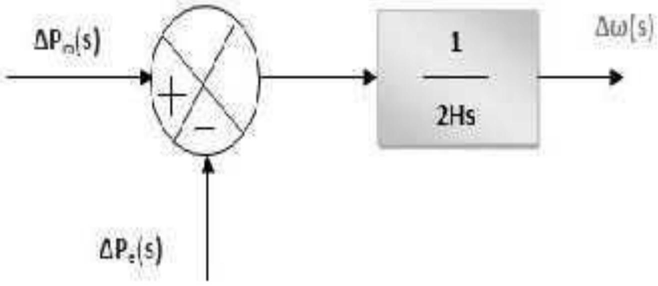
The ALFC is to control the frequency deviation by maintaining the real power balance in the system. The main functions of the ALFC are to i) to maintain the steady frequency; ii) control the tie-line flows; and iii) distribute the load among the participating generating units. The control (input) signals 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 Fig3.3



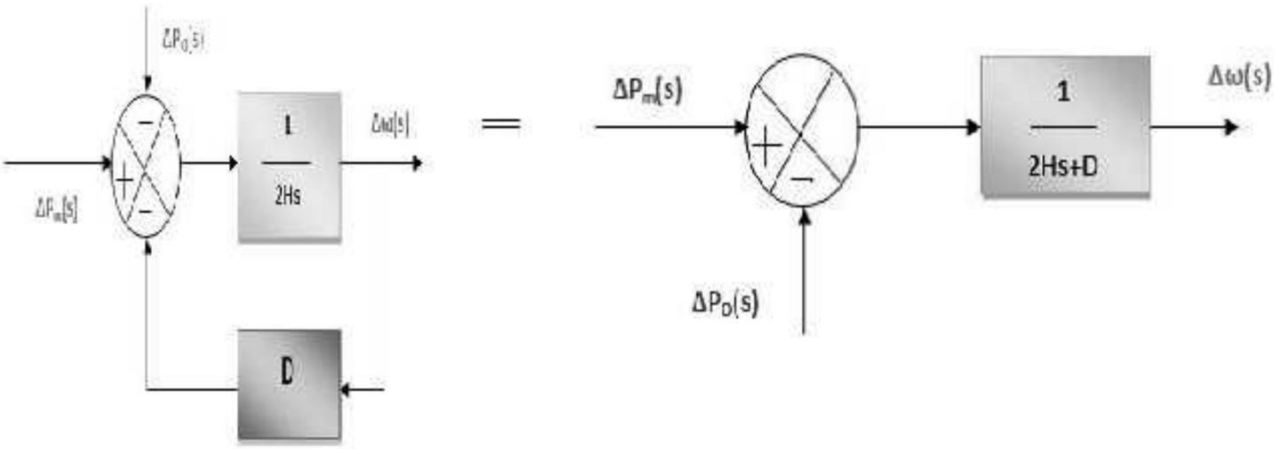
The Schematic representation of ALFC system

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, theegenerator can b Using the swing equation, the generator can be modeled by �



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 Pe = P0 + Pf

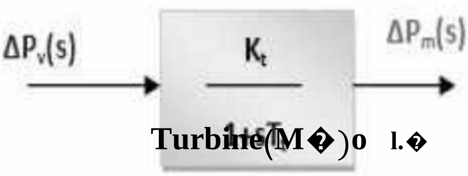


Block Diagram Representation Of The Generator And Load

where, Pe is the change in the load;
P0 is the frequency independent load component; Pf is the frequency dependent load component.

Pf = D 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 Fig3.5

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



Turbine Model.

$$G(s) = \frac{\Delta Pm(s)}{\Delta Pv(s)} = \frac{K_t}{1+sT_t}$$

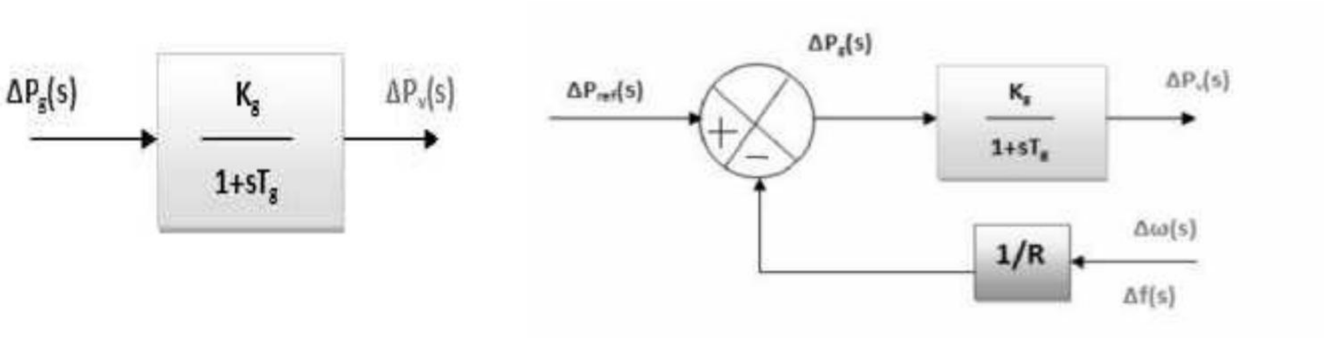
Gt(s) is the TF of the turbine; ΔPV(s) is the change in valve output (due to action). Pm(s) is the change in the turbine output

The governor can similarly modeled as shown inig2F.7. The output of the governor is by

Where ΔP_{ref} is the reference set power, and Δw/R is the power given by governor speed characteristic. The hydraulic amplifier transforms this signal Pg into valve/gate position corresponding to a power PV.

Thus

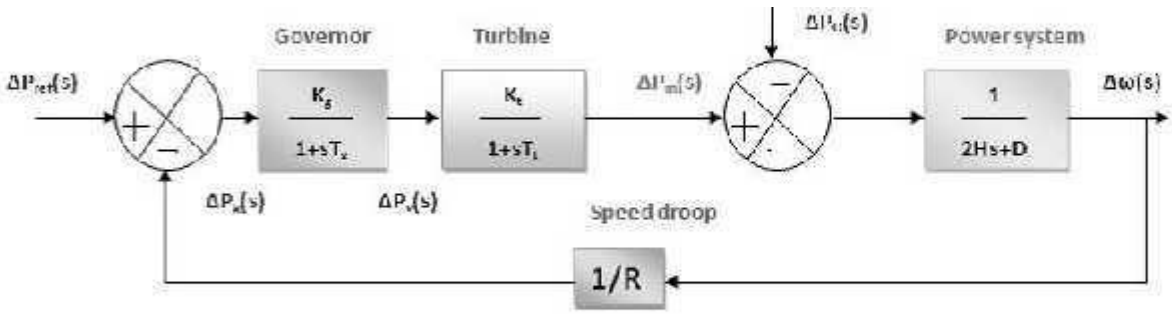
PV(s) = (Kg/ (1+sTg)) _Pg(s).



Block Diagram Representation Of The Governor

LFC control of single area and derive the steady state frequency error.

All the individual blocks can now be connected to represent the complete ALFC loop as



Block diagram representation of the ALFC Static

Power Generation

We have

$\Delta P_G(s) = k_G k_t / (1+sT_G)(1+sT_t)[\Delta P_c(s) - 1/R \Delta F(s)]$

The generator is synchronized to a network of very large size. So, the speed or frequency will be essentially independent of any changes in a power output of the generator

ie, $\Delta F(s) = 0$

Therefore $\Delta P_G(s) = k_G k_t / (1+sT_g)(1+sT_t) * \Delta P_c(s)$

Steady state response

(i)Controlled case:

To find the resulting steady change in the generator output:

Let us assume that we made a step change of the magnitude ΔP_C of the speed changer For step change, $\Delta P_C(s) = \Delta P_C/s$

$\Delta P_G(s) = k_G k_t / (1+sT_g)(1+sT_t)$.

$\Delta P_c(s)/s \; s\Delta P_G(s) = k_G k_t /$

$(1+sT_g)(1+sT_t). \; \Delta P_c(s)$

Applying final value theorem,

$\Delta P_{G\,(stat)} = \Delta$

(ii)Uncontrolled case

Let us assume that the load suddenly increases by small amount ΔP_D.Consider there is no external work and the generator is delivering a power to a single load.

Since $\Delta P_C=0$, kgkt=1

It has been shown that the load frequency control system posses inherently steady state error for a step input. Applying the usual procedure, the dynamic response of the control loop can be evaluated so that the initial response also can be seen for any overshoot.

For this purpose considering the relatively larger time constant of the power system the governor action can be neglected, treating it as instantaneous action. Further the turbine generator dynamics also may be neglected at the first instant to derive a simple expression for the time response.

$\Delta P_G(s) = 1/(1+sT_G)(1+sT_t)\,[-\Delta F(s)/R]$ For a step change $\Delta F(s) = \Delta f/s$ Therefore

$\Delta P_G(s) = 1/(1+sT_G)(1+sT_t)[-\Delta F/sR]$

$\Delta f/\Delta P_{G\,(stat)} = -R$ Hz/MW

Steady State Performance of the ALFC Loop

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

With $s \rightarrow 0$, Gg(s) and Gt(s) become unity, then,(note that $\Delta Pm = \Delta PT = PG = \Delta Pe = \Delta PD$; That is turbine output = generator/electrical output = load demand)

$\Delta Pm = \Delta Pref - (1/R)\,\Delta\omega$ or $\Delta Pm = \Delta Pref - (1/R)\Delta f$

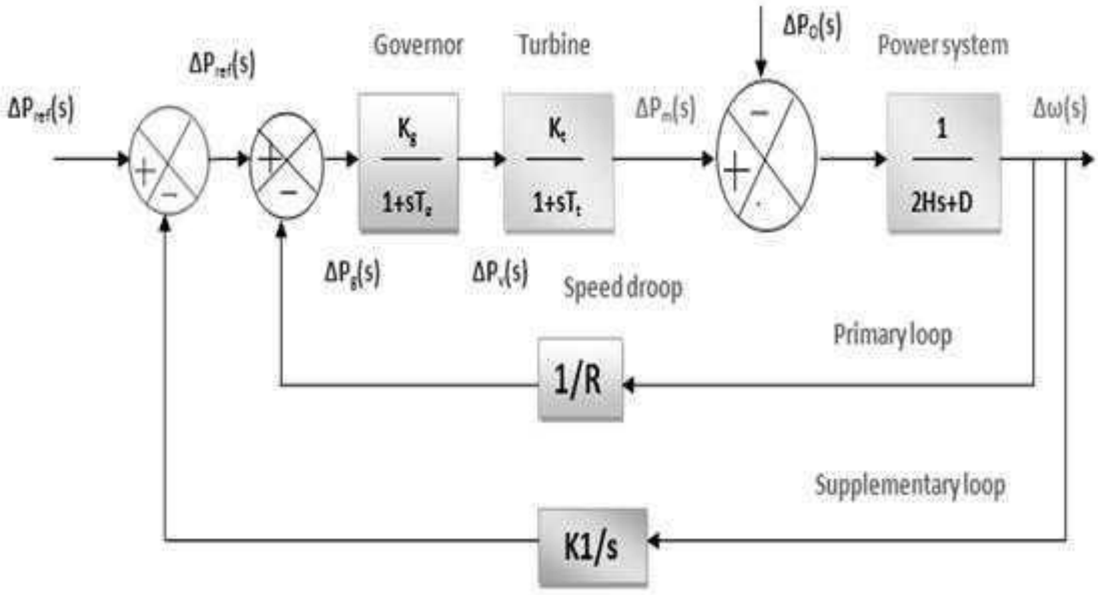
When the generator is connected to infinite bus ($\Delta f = 0$, and $\Delta V = 0$), then $\Delta Pm = \Delta Pref$.

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

$\Delta P_m = (1/R)\Delta f$ or $\Delta f = RP_m$.

Concept of AGC (Supplementary ALFC Loop)

The ALFC loop shown in 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 Fig3.9. 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).



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.3.9) which uses the integral controller to change the reference power setting so as to change the speed set point. The integral controller gain KI 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.

Dynamic Response of the One-Area System

`Now we are going to study the effect of a disturbance in the system derived above. Both loss of generation and loss of load can be simulated by imposing a positive or negative step input on the variable P_{load}. A change of the set value of the system frequency f_0 is not considered as this is not meaningful in real power systems. From the block diagram in Figure 3.9 it is straightforward to derive the transfer function between ΔP_{load} and Δf $(\Delta P_{m0}^{set} = 0)$:

$$\Delta f(s) = \frac{1 + sT_t}{\frac{1}{S} + \frac{1}{D_l}(1 + sT_t) + (\frac{2W_0}{f_0} + \frac{2HS_B}{f_0})s(1 + sT_t)} \Delta P_{load}(s)$$

The step response for

$$\Delta P_{load}(s) = \frac{\Delta P_{load}}{s}$$

$$\Delta f_\infty = \lim_{s \to 0}(s \cdot \Delta f(s)) = \frac{\Delta P_{load}}{\frac{1}{S} + \frac{1}{D_l}} = \frac{\Delta P_{load}}{\frac{1}{D_R}} = -\Delta P_{load} \cdot D_R$$

with

$$\frac{1}{D_R} = \frac{1}{S} + \frac{1}{D_l}$$

In order to calculate an equivalent time constant Teq, Tt is put to 0. This can be done since for realistic systems the turbine controller time constant Tt is much smaller than the time constant

AGC IN A MULTI AREA SYSTEM

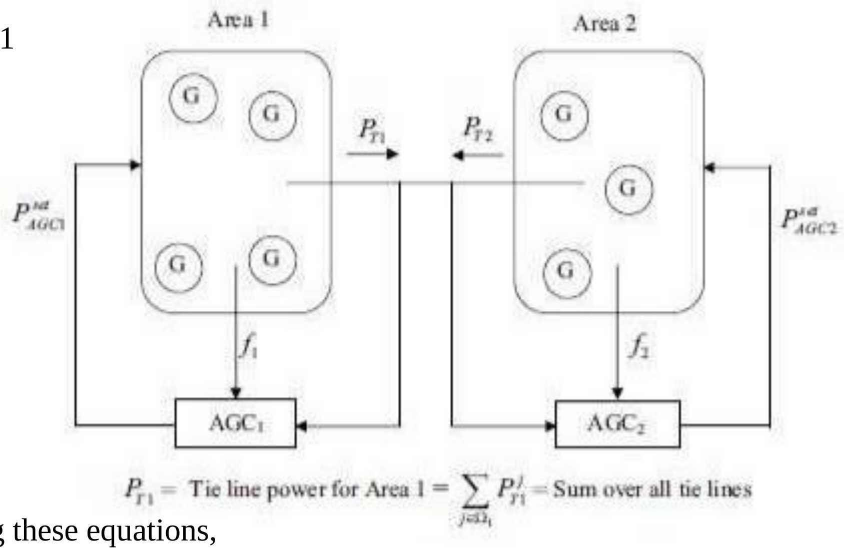
In an interconnected (multi area) system, there will be one ALFC loop for each control area (located at the ECC of that area). They are combined as shown in Fig2.10 for the interconnected system operation. For a total change in load of ΔPD, the steady state Consider a two area system as depicted in Figure 3.10. The two secondary frequency controllers, AGC1 and AGC2, will adjust the power reference values of the generators participating in the AGC. In an N-area system, there are N controllers AGCi, one for each area

A block diagram of such a controller is given in Figure 4.2. A common way is to implement this as a proportional-integral (PI) controller:

Deviation in frequency in the two areas is given by

$\Delta f = \Delta\omega_1 = \Delta\omega_2$

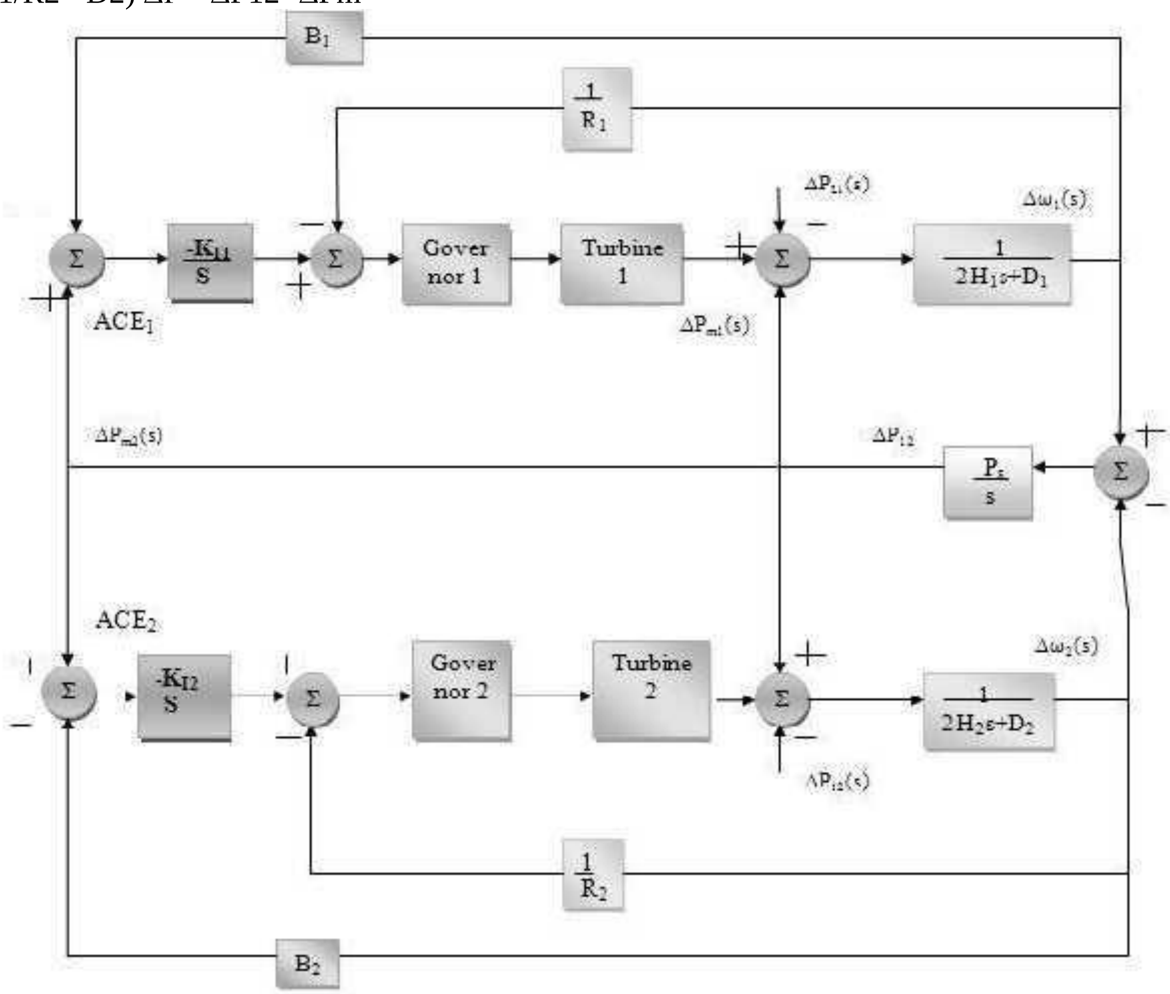
$\beta 1 = D1 + 1/R1$



Substituting these equations,

yields $(1/R1 + D1)\,\Delta f = -\Delta P12 - \Delta Pm$

$(1/R2 + D2)\,\Delta f = -\Delta P12 - \Delta Pm$



A G C for a multi-area operation

DYNAMIC RESPONSE OF LOAD FREQUENCY CONTROL LOOPS

It has been shown that the load frequency control system posses inherently steady state error for a step input. Applying the usual procedure, the dynamic response of the control loop can be evaluated so that the initial response also can be seen for any overshoot.

For this purpose considering the relatively larger time constant of the power system the governor action can be neglected, treating it as instantaneous action. Further the turbine generator dynamics also may be neglected at the first instant to derive a simple expression for the time response.

It has been proved that

$$\Delta F(S) = -\frac{G_p}{1+\frac{1}{R}G_S G_{tG} G_p}\Delta P_D(S)$$

For a step load change of magnitude k

$$\Delta P_D(S) = \frac{-k}{S}$$

Neglecting the governor action and turbine dynamics

$$\Delta F(S) = -\frac{G_p}{1+\frac{1}{R}G_p}\frac{k}{S}$$

$$= -\left(\frac{K_p}{1+ST_p}\right)\frac{1}{\left(1+\frac{1}{R}\frac{K_p}{1+ST_p}\right)}\frac{k}{S}$$

Applying partial fractions

$$\Delta F(S) = -\frac{K_p k}{T_p}\left(\frac{1}{S\left[S+\left(\frac{1}{T_p}+\frac{K_p}{RT_p}\right)\right]}\right) - \frac{K_p k}{T_s}\left[\frac{1}{S\left[S-\frac{1}{T_p}+\frac{K_p}{RT_p}\right]}\right]$$

INTERCONNECTED OPERATION

Power systems are interconnected for economy and continuity of power supply. For the interconnected operation incremental efficiencies, fuel costs. Water availability, generation limits, tie line capacities, spinning reserve allocation and area commitment's are important considerations in preparing load dispatch schedules.

Flat Frequency Control of lnter- connected Stations

Consider two generating stations connected by a tie line as in Fig3.12.For a load increment on station B, the kinetic energy of the generators reduces to absorb the same. Generation increases in both the stations A and B, and frequency will be less than normal at the end of the governor response period. The load increment will be supplied partly by A and partly by B. The tie line power flow will change thereby. If a frequency controller is placed at B, then it will shift the governor characteristic at B parallel to itself as shown in Fig and the frequency will be restored to its normal value fs' reducing the change in generation in A to zero.

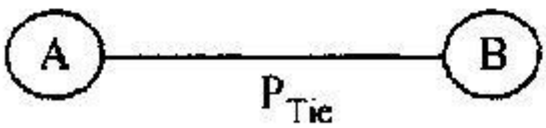


Figure 3.12.Two area with tie line power

Assumption in Analysis:

The following assumptions are made in the analysis of the two area system:

1. The overall governing characteristic of the operating units in any area can be represented by

   a linear curve of frequency versus generation.

2. The governors in both the areas start acting simultaneously to changes in their respective areas.

3. Supplementary control devices act after the initial governor response is over

The following time instants are defined to explain the control sequence:

To=is the instant when both the areas are operating at the scheduled frequency

and Tie=line interchange and load change takes place.

tl = the instant when governor action is initiated at both A and

B. t2 =the instant when governor action ceases.

t3 =the instant when regulator action begins.

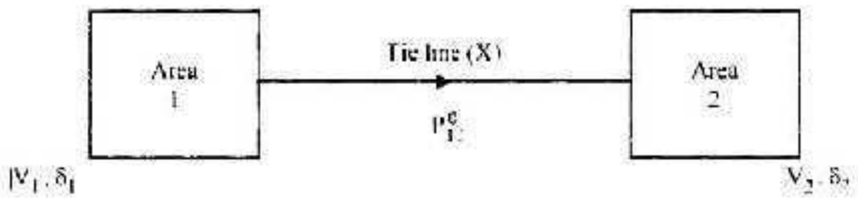
t4 = the instant when regulator action ceases.

`While the initial governor response is the same as for the previous case, the action of the controller in B will force the generation in area B to absorb the load increment in area A. When the controller begins to act at t3, the governor characteristic is shifted parallel to itself in B till the entire load increment in A is absorbed by B and the frequency is restored to normal.

Thus, in this case while the frequency is regulate on one hand, the tie-line schedule is not maintained on the other hand.

If area B, which is in charge of frequency regulation, is much larger than A, then load changes in A will not appreciably affect the frequency of the system. Consequently, it can be said that flat frequency control is useful only when a small system is' connected to a much larger system.

3.10.4. Two Area Systems - Tie-Line Power Model:



Two Area Systems - Tie-Line Power

Consider two inter connected areas as shown in figure operating at the same frequency fl

while a power Power flow from area I to area 2

let V1 and V 2 be the voltage magnitudes

δ **1, 2** voltage phase angles at the two ends of the tie-line

While P flows from area I to area 2 then,

$$P_{12}^0 = \frac{|V_1||V_2|}{X}\,\mathrm{Sin}\left(\delta_1^0 - \delta_2^0\right)$$

Where X is the reactance of the line. If the angles change by f1o1, and f102 due to load changes in areas I and 2 respectively. Then, the tie-line power changes by

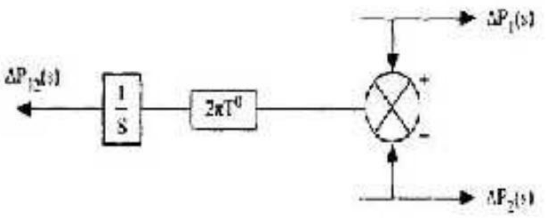
$$\Delta P_2 = \frac{|V_1^0||V_2^0|}{X}\,\mathrm{Cos}\left(\delta^0 - \delta_2^0\right)\left(\Delta P_1 \quad \Delta P_2\right)$$

$$\frac{\Delta P_{12}}{\Delta\delta - \Delta\delta_2} = \frac{\Delta P_{12}}{\Delta\delta} \ \mathrm{MW/radian}$$

$$\Delta P_{12} = T^0\left(\Delta\delta_1^0 - \Delta\delta_2^0\right)$$

$$\Delta\omega = \frac{d}{dt}\Delta\delta$$

Block diagram for tie-line power



$$\frac{P_{r1}}{P_{r2}} = a_{12}$$

$$\Delta P_{21}(S) = \frac{2\pi T^0_{21}}{S}\left[\Delta F_2(S) - \Delta F_1(S)\right]$$

$$= -\frac{2\pi T^0_{21} \cdot a_{12}}{S}\left[\Delta F_1(S) - \Delta F_2(S)\right]$$

Dynamic Response:

Let us now turn our attention during the transient period for the sake of simplicity. We shall assume the two areas to be identical .Further we shall be neglecting the time constants of generators and turbines as they are negligible as compared to the time constants of power systems. The equation may be derived for both controlled and uncontrolled cases. There are four equations with four variables, to be determined for given PDl and PD2. The dynamic response can be obtained; even though it is a little bit involved. For simplicity assume that the two areas are equal. Neglect the governor and turbine dynamics, which means that the dynamics of the system under study is much slower than the fast acting turbine-governor system in a relative sense. Also assume that the load does not change with frequency (D, = D2 = D = 0).

$$\left\{-\frac{1}{R_1}\Delta F_1(S)\left[\frac{K_S}{1+ST_{S1}}\right]\left[\frac{K_{TG1}}{1+ST_{TG2}}\right] - \Delta P_{D1}(S) - \Delta P_{12}(S)\right\}\frac{K_{P1}}{1+ST_{P1}} = \Delta F_1(S)$$

$$\left\{-\frac{1}{R_2}\Delta F_2(S)\left[\frac{K_{S2}}{1+ST_{S2}}\right]\left[\frac{K_{TG2}}{1+ST_{TG2}}\right] - \Delta P_{D2}(S) - \Delta P_{21}(S)\right\}\frac{K_{P2}}{1+ST_{P2}} = \Delta F_2(S)$$

$$\Delta P_{12}(S) = \frac{2\pi T^0}{S}\left[\Delta F_1(S) - \Delta F_2(S)\right]$$

$$\Delta P_{21}(S) = -\Delta P_{21}(S)$$

We obtain under these assumptions the following relations

$$\Delta P_{12}(S) = \frac{\left[\Delta P_{D2}(S) - \Delta P_{D1}(S)\right]\frac{f^0}{2SH}}{\frac{S}{2\pi T^0} + \frac{2f^0}{2\pi T^0} + \frac{Sf^0}{2\pi RT^0 2SH}}$$

$$= \frac{\left[\left[\Delta P_{D2}(S) - \Delta P_{D1}(S)\right]\frac{\pi f^0 T^0}{SH}\right]}{S + \frac{2f^0\pi T^0}{SH} + \frac{f^0}{2RH}}$$

$$= \frac{\pi f^0 T^0}{H}\frac{\left[\Delta P_{D2}(S) - \Delta P_{D1}(S)\right]}{S^2 + \left(\frac{f^0}{2RH}\right)S + \left(\frac{2f^0\pi T^0}{H}\right)}$$

The denominator is of the form

$$\left(S^2 + 2KS + \omega^2\right) = \left(S + K\right)^2 + (\omega^2 - K^2)$$

where $K = \frac{f^0}{4RH}$ and $\omega = \sqrt{\frac{2\pi f^0 T^0}{H}}$

setting $\sqrt{\omega^2 - K^2}$ as ω_0.

$$\omega_0 = \sqrt{\frac{2\pi T^0 f^0}{H} - \left(\frac{f^0}{4RH}\right)^n}$$

Note that both K and ro2 are positive. From the roots of the characteristic equation we notice that the system is stable and damped. The frequency of the damped oscillations is given by ω_0 Since Hand f_0 are constant, the frequency of oscillations depends upon the regulation parameter R. Low R gives high K and high damping and vice versa .We thus conclude from the preceding analysis that the two area system, just as in the case of a single area system in the uncontrolled mode, has a steady state error but to a lesser extent and the tie line power deviation and frequency deviation exhibit oscillations that are damped out later.