Chapter 2

AUTOMATIC LOAD FREQUENCY CONTROL

1. INTRODUCTION

This chapter deals with the control mechanism needed to maintain the system frequency. The topic of maintaining the system frequency constant is commonly known as AUTOMATIC LOAD FREQUENCY CONTROL (ALFC). It has got other nomenclatures such as Load Frequency Control, Power Frequency Control, Real Power Frequency Control and Automatic Generation Control.

The basic role of ALFC is:

1. **To maintain the desired megawatt output power of a generator matching with the changing load.**

2. **To assist in controlling the frequency of larger interconnection.**

3. **To keep the net interchange power between pool members, at the predetermined values.**

The ALFC loop will maintain control only during small and slow changes in load and frequency. It will not provide adequate control during emergency situation when large megawatt imbalances occur. We shall first study ALFC as it applies to a single generator supplying power to a local service area.

2. REAL POWER CONTROL MECHANISM OF A GENERATOR

The real power control mechanism of a generator is shown in Fig. 1. The main parts are:

1) Speed changer 2) Speed governor 3) Hydraulic amplifier 4) Control valve. They are connected by linkage mechanism. Their incremental movements are in vertical direction. In reality these movements are measured in millimeters; but in our analysis we shall rather express them as power increments expressed in MW or p.u. MW as the case may be. The movements are assumed positive in the directions of arrows.

Corresponding to "raise" command, linkage movements will be:

"A" moves downwards; "C" moves upwards; "D" moves upwards; "E" moves downwards. This allows more steam or water flow into the turbine resulting incremental increase in generator output power.

When the speed drops, linkage point "B" moves upwards and again generator output power will increase.

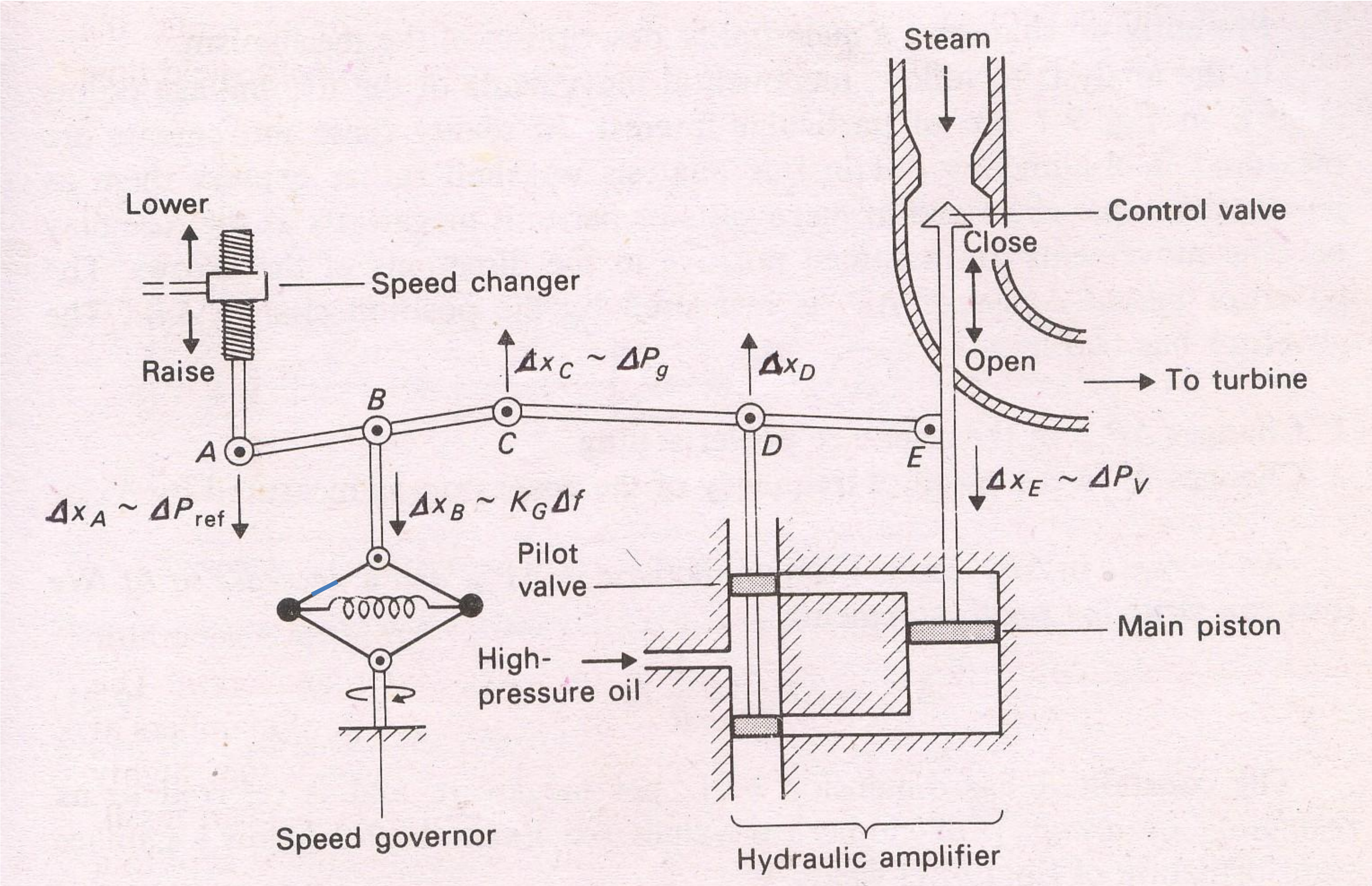

Fig. 1 Functional diagram of real power control mechanism of a generator

2.1 SPEED GOVERNOR

The output commend of speed governor is ΔP_g which corresponds to movement Δx_C. The speed governor has two inputs:

1) Change in the reference power setting, ΔP_{ref}

2) Change in the speed of the generator, Δf, as measured by Δx_B.

It is to be noted that a positive ΔP_{ref} will result in positive ΔP_g A positive Δf will result in linkage points B and C to come down causing negative ΔP_g. Thus

$$\Delta P_g = \Delta P_{ref} - \frac{1}{R}\Delta f \qquad (1)$$

Here the constant R has dimension hertz per MW and is referred as speed regulation of the governor.

Taking Laplace transform of eq. 1 yields

$$\Delta P_g(s) = \Delta P_{ref}(s) - \frac{1}{R}\Delta f(s) \qquad (2)$$

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Taking Laplace transform of eq. 1 yields

$$\Delta P_g\,(s) = \Delta P_{ref}\,(s) - \frac{1}{R}\,\Delta f\,(s) \qquad (2)$$

The block diagram corresponding to the above equation is shown in Fig. 2.

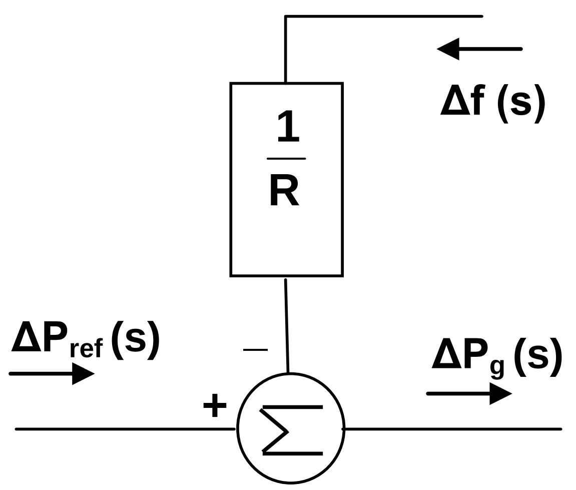


Fig. 2 Block diagram of speed governor

2.2 HYDRAULIC VALVE ACTUATOR

The output of the hydraulic actuator is ΔP_v. This depends on the position of main piston, which in turn depends on the quantity of oil flow in the piston. For a small change Δx_D in the pilot valve position, we have

$$\Delta P_v = k_H \int \Delta x_D \, dt \tag{3}$$

The constant "k_H" depends on the orifice, cylinder geometries and fluid pressure.

The input to Δx_D are ΔP_g and ΔP_v. It is to be noted that for a positive ΔP_g, the change Δx_D is positive. Further, for a positive ΔP_v, more fuel is admitted, speed increases, linkage point B moves downwards causing linkage points C and D to move downwards resulting the change Δx_D as negative. Thus

$$\Delta x_D = \Delta P_g - \Delta P_v \tag{4}$$

Laplace transformation of the last two equations are:

$$\Delta P_v(s) = \frac{k_H}{s}\ \Delta x_D\,(s)$$

$$\Delta x_D(s) = \Delta P_g(s) - \Delta P_v(s)$$

Eliminating Δx_D and writing ΔP_v (s) in terms of ΔP_g (s), we get

$$\Delta P_v\,(s) = \frac{1}{1 + s\,T_H}\ \Delta P_g\,(s) \tag{5}$$

where T_H is the hydraulic time constant given by

$$T_H = \frac{1}{k_H} \tag{6}$$

In terms of the hydraulic valve actuator's transfer function G_H (s), eq. 5 can be written as

$$G_H(s) = \frac{\Delta P_v(s)}{\Delta P_g(s)} = \frac{1}{1 + s\,T_H} \qquad (7)$$

Hydraulic time constant T_H typically assumes values around 0.1 sec. The block diagram of the speed governor together with the hydraulic valve actuator is shown in Fig. 3.

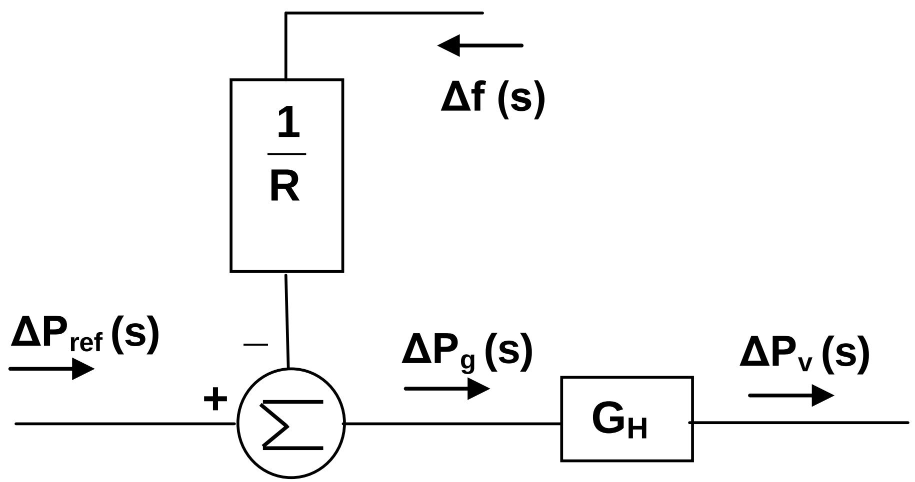


Fig. 3 Block diagram of speed governor together with hydraulic valve actuator

2.3 TURBINE – GENERATOR

In normal steady state, the turbine power P_T keeps balance with the electromechanical air-gap power P_G resulting in zero acceleration and a constant speed and frequency.

During transient state, let the change in turbine power be ΔP_T and the corresponding change in generator power be ΔP_G .

The accelerating power in turbine generator unit = $\Delta P_T - \Delta P_G$

Thus accelerating power = $\Delta P_T(s) - \Delta P_G(s)$ (8)

If $\Delta P_T - \Delta P_G$ is negative, it will decelerate.

The turbine power increment ΔP_T depends entirely upon the valve power increment ΔP_V and the characteristic of the turbine. Different type of turbines will have different characteristics. Taking transfer function with single time constant for the turbine, we can write

$$\Delta P_T(s) = G_T\ \Delta P_V(s) = \frac{1}{1 + s\,T_T}\ \Delta P_V(s) \qquad (9)$$

The generator power increment ΔP_G depends entirely upon the change ΔP_D in the load P_D being fed from the generator. The generator always adjusts its output so as to meet the demand changes ΔP_D. These adjustments are essentially <u>instantaneous,</u> certainly in comparison with the slow changes in P_T. We can therefore set

$$\Delta P_G = \Delta P_D \quad \text{i.e.} \quad \Delta P_G(s) = \Delta P_D(s) \qquad (10)$$

In view of equations 8,9 and 10,

$$\text{Accelerating power} = \Delta P_T(s) - \Delta P_G(s) \qquad (8)$$

$$\Delta P_T(s) = G_T\ \Delta P_V(s) = \frac{1}{1+s\,T_T}\ \Delta P_V(s) \qquad (9)$$

$$\Delta P_G(s) = \Delta P_D(s) \qquad (10)$$

the block diagram developed is updated as shown in Fig. 4. This corresponds to the linear model of primary ALFC loop excluding the power system response.

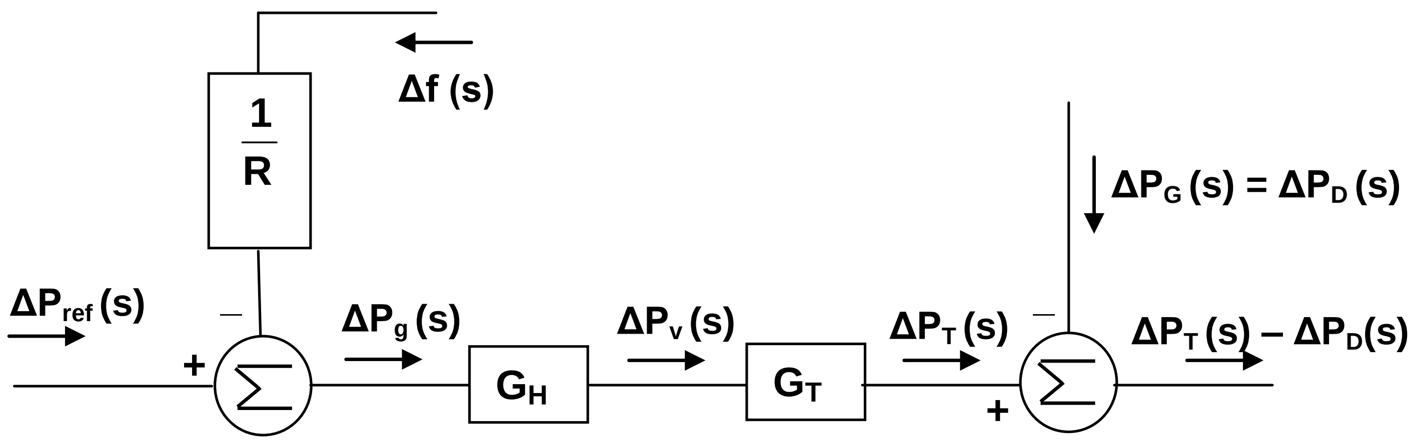
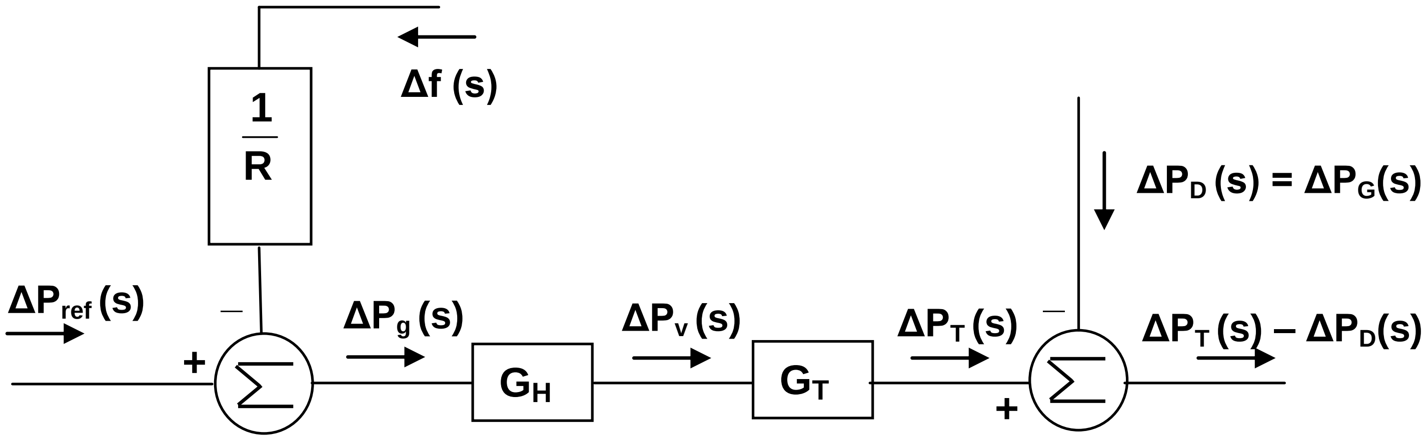


Fig. 4 Block diagram corresponding to primary loop of ALFC excluding power system response



3. STATIC PERFORMANCE OF SPEED GOVERNOR

The present control loop shown in Fig. 4 is *open*. We can nevertheless obtain some interesting information about the static performance of the speed governor. The relationship between the static signals (subscript "0") is obtained by letting $s \longrightarrow 0$. As $G_H(0) = G_T(0) = 1$ we obtain directly from Fig. 4

$$\Delta P_{T\,0} = \Delta P_{ref\,0} - \frac{1}{R}\,\Delta f_{\,0} \qquad (11)$$

Note that at steady state, ΔP_T is equal to ΔP_G. i.e. $\Delta P_{T\,0} = \Delta P_{G\,0}$

We consider the following three cases.

$$\Delta P_{T\,0} = \Delta P_{ref\,0} - \frac{1}{R}\Delta f_{0} \qquad (11)$$

<u>Case A</u>

The generator is synchronized to a network of very large size, so large in fact, that its frequency will be essentially independent of any changes in the power output of this individual generator ("infinite" network). Since $\Delta f_0 = 0$, the above eq. becomes

$$\Delta P_{T\,0} = \Delta P_{ref\,0} \qquad (12)$$

Thus for a generator operating at constant speed,(or frequency) there exists a direct proportionality between turbine power and reference power setting.

Thus for a generator operating at constant speed, (or frequency) there exists a direct proportionality between turbine power and reference power setting.

$\Delta P_{T\,0} = \Delta P_{ref\,0}$ **i.e. when the generator is operating at constant frequency, if the speed changer setting is INCREASED,(DECREASED) turbine output power will increase (decrease) to that extent.**

Example 1

A 100-MW, 50-Hz generator is connected to "infinite" network. How would you increase its turbine power by 5 MW?

Solution

Its turbine power can be increased by 5 MW by simply giving a "raise" signal of 5 MW to the speed changer motor.

Case B

Now we consider the network as "finite". i.e. its frequency is variable. We do, however, keep the speed changer at constant setting. i.e. $\Delta P_{ref} = 0$. From eq. (11)

$$\Delta P_{T\,0} = \Delta P_{ref\,0} - \frac{1}{R}\Delta f_{0} \qquad (11)$$

we obtain

$$\Delta P_{T\,0} = -\frac{1}{R}\Delta f_{0} \qquad (13)$$

1. The above eq. shows that for a constant speed changer setting, <u>the static increase in turbine power output</u> is directly proportional to the <u>static frequency drop.</u>

2. The above eq. (13) can be rewritten as $\Delta f_{0} = -R\,\Delta P_{T\,0}$. This means that the plot of f_{0} with respect to $P_{T\,0}$ (or $P_{G\,0}$) will be a straight line with slope of – R.

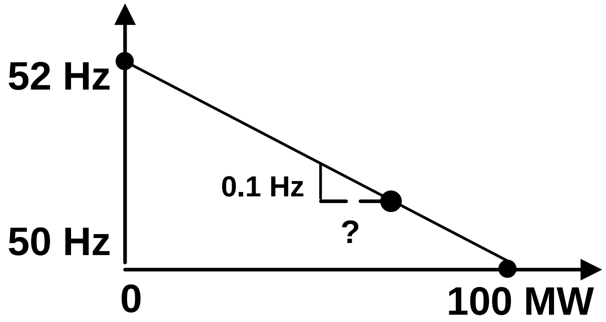
We remember that the unit for R is hertz per MW. In practice, both the frequency and the power can be expressed in per unit.

Example 2

Consider 100-MW 50-Hz generator in the previous example. It has a regulation parameter R of 4 %. By how much will the turbine power increase if the frequency drops by 0.1 Hz with the speed changer setting unchanged.

Solution

Regulation is 4%. 4% of 50 = 2 Hz. This means that for frequency drop of 2 Hz the turbine power will increase by 100 MW.



Thus $R = \dfrac{2}{100} = 0.02$ **Hz per MW**

It is given $\Delta f_0 = -\,0.1$ **Hz**

In eq. (11), $\Delta P_{T\,0} = \Delta P_{ref\,0} - \dfrac{1}{R}\Delta f_0$

setting ΔP_{ref} **as zero,** $\Delta P_{T\,0} = -\dfrac{1}{R}\Delta f_0$ **i.e.** $\Delta P_{T\,0} = -\dfrac{1}{0.02}(-\,0.1) = 5$ **MW**

Thus the turbine power will increase by 5 MW.

We can also get the result using symmetrical triangles.

Example 3

Consider again 100-MW, 50-Hz generator in the previous example. If the frequency drops by 0.1 Hz, but the turbine power remains unchanged, by how much should the speed changer setting be changed?

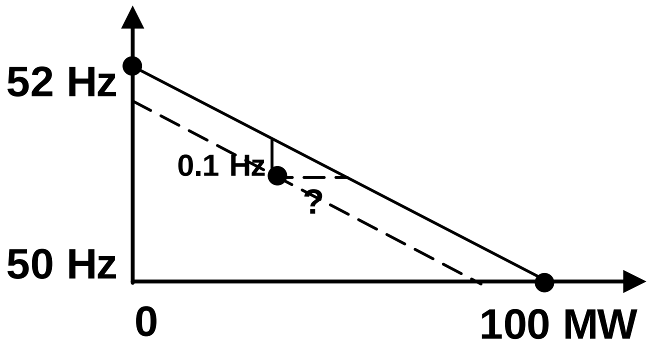
Solution

As $\Delta P_{T\,0} = 0$, **from eq.(11),** $\Delta P_{T\,0} = \Delta P_{ref\,0} - \dfrac{1}{R}\Delta f\ 0$ **we have** $\Delta P_{ref\,0} = \dfrac{1}{R}\Delta f_0$

Given that

$R = 0.02$ **Hz per MW and** $\Delta f_0 = -0.1$ **Hz**

$$\Delta P_{ref\,0} = \frac{1}{0.02} \times (-0.1) = -5 \text{ MW}$$



Therefore, speed changer setting must be lowered by 5 MW

Case C

In general case, changes may occur in both the speed changer setting and frequency in which case the relationship $\Delta P_{T\,0} = \Delta P_{ref\,0} - \frac{1}{R}\Delta f_0$ applies.

For a given speed changer setting, $\Delta P_{ref\,0} = 0$ and hence $\Delta f_0 = -R\,\Delta P_{T\,0}$. In a frequency-generation power graph, this represents a straight line with a slope = - R.

For a given frequency, $\Delta f_0 = 0$ and hence $\Delta P_{T\,0} = \Delta P_{ref\,0}$. This means that for a given frequency, generation power can be increased or decreased by suitable raise or lower command.

Thus the relationship $\Delta P_{T\,0} = \Delta P_{ref\,0} - \frac{1}{R}\Delta f_0$ represents a family of sloping lines as depicted in Fig. 5, each line corresponding to a specific speed changer setting.

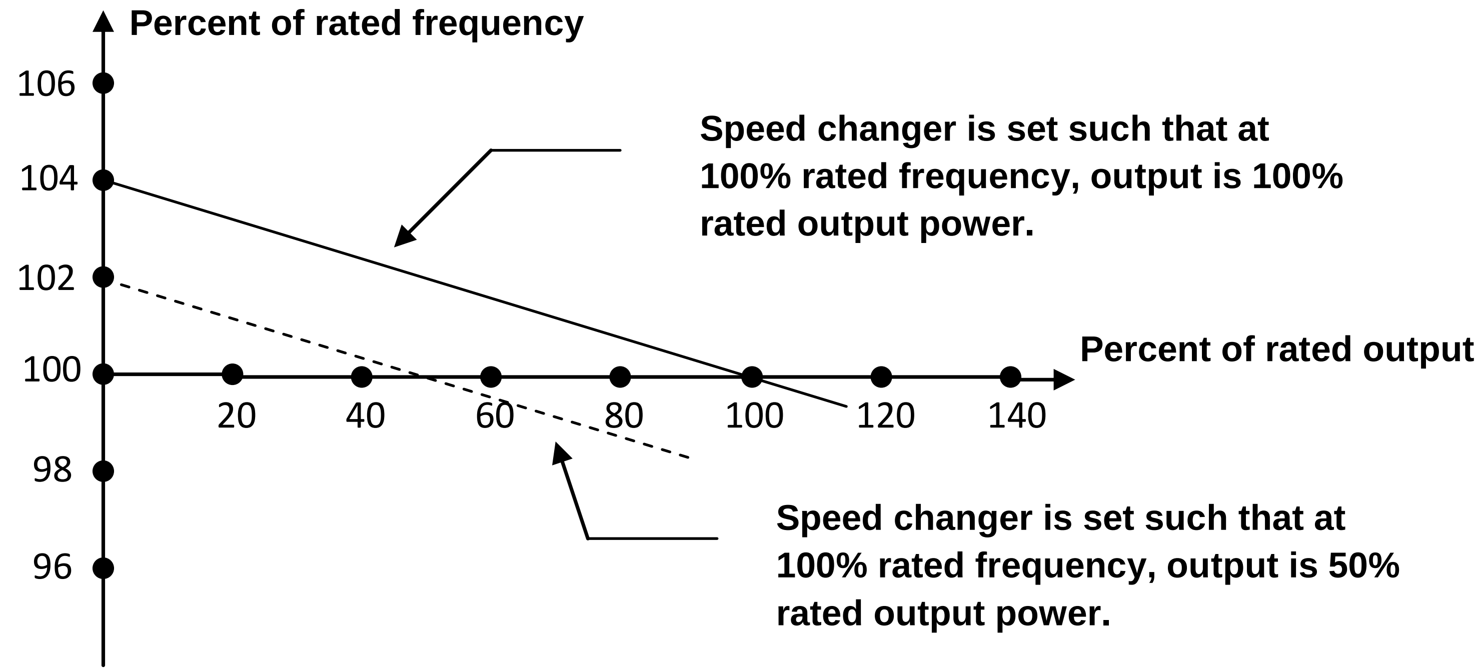
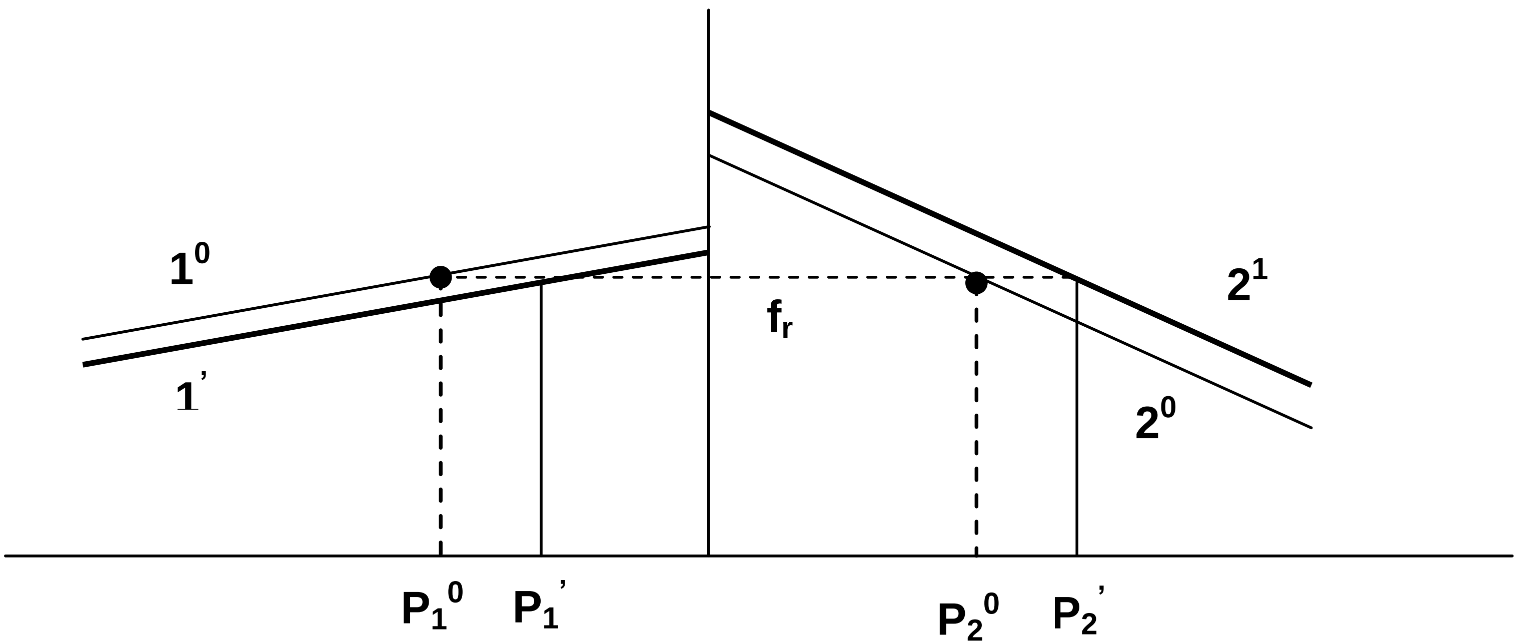


Fig. 5 Static frequency-power response of speed governor (R = 0.04 p.u.)

The thick line shows that corresponding to 100% rated frequency, the output power is 100 % of rated output. But for the new speed changer setting as shown by the dotted line, for the same 100% rated frequency, output power is 50 % of rated output. Hence the power output of the generator at a given frequency can be adjusted at will, by suitable speed changer setting. <u>Such adjustment will be extreme importance for implementing the load division as decided by the optimal policy.</u>

Let the governor characteristic of two units be 1^0 and 2^0. Let the operating frequency be f_r. Then load shared by unit 1 and 2 are P_1^0 and P_2^0. If the economic division of load dictates the load sharing as $P_1^{'}$ and $P_2^{'}$, the governor characteristics should be shifted to $1^{'}$ and $2^{'}$ as shown in Fig. below.

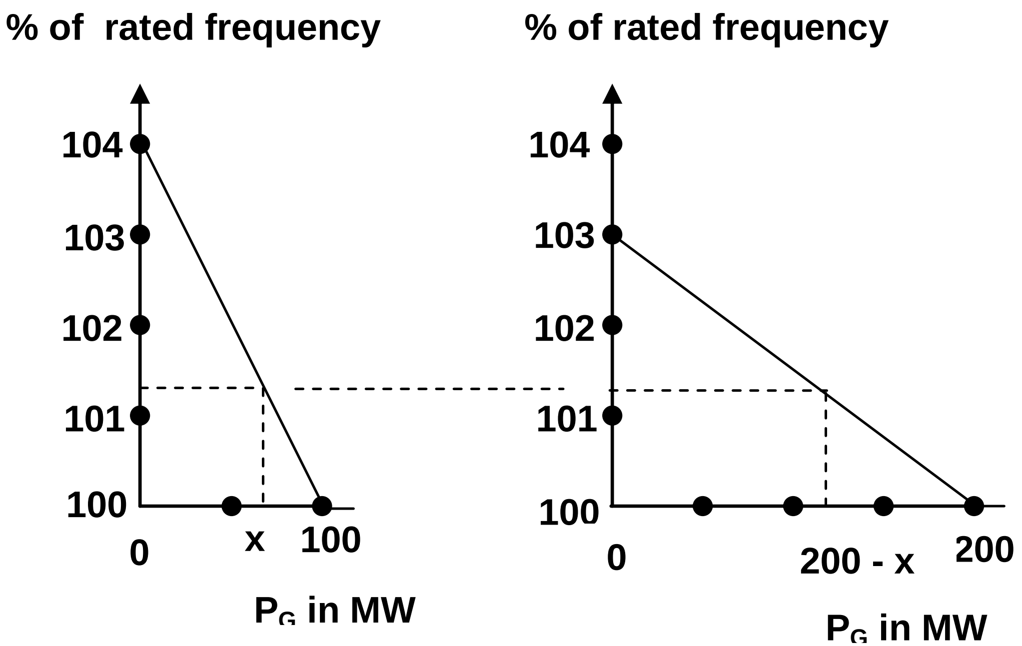


Shifting of governor characteristic

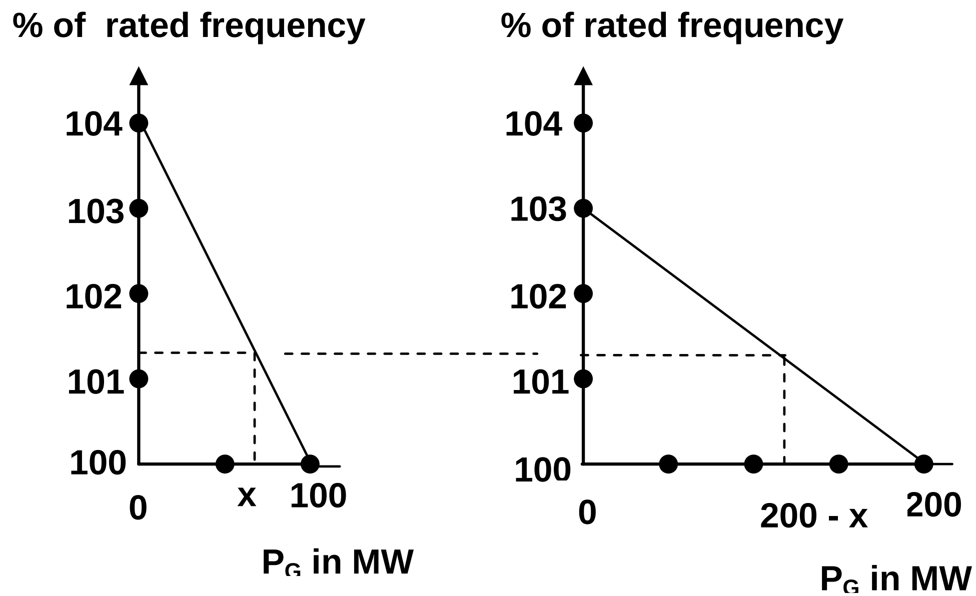
Example

Two synchronous generators operating in parallel supply a total load of 200 MW.The ratings of the machines 1 and 2 are 100 MW and 200 MW. Machines 1 and 2 have governor droop characteristic of 4% and 3% respectively, from no load to full load. Assume that at full load, machines run at rated speed and the system frequency is 50 Hz. Calculate the load taken by each machine and the operating frequency.

Solution



The figures show the characteristics of the machines.



Let x MW be the load taken by the machine 1. Then the load taken by the machine 2 is 200-x MW. Both should operate at same speed and frequency.

Equating the common frequency: $$104 - \frac{4}{100}x = 103 - \frac{3}{200}(200 - x)$$

On solving the above, x = 72.73 MW and 200 - x = 127.27 MW. Thus

Load on machine 1 = 72.73 MW; Load on machine 2 =127.27 MW

Operating frequency $= 104 - \frac{4}{100}(72.73) = 101.09\%$

$$= \frac{50}{100}(101.09) = 50.545 \text{ Hz.}$$

Example 4

Two generators are supplying power to a system. Their ratings are 50 and 500 MW respectively. The frequency is 50 Hz and each generator is half-loaded. The system load increases by 110 MW and as a result the frequency drops to 49.5 Hz. What must the individual p.u. regulation be if the two generators should increase their turbine powers in proportional to their ratings?

Solution

Generator ratings: 50 MW 500 MW ; Initial loadings: 25 MW 250 MW

Change in load = 110 MW; Change in frequency = - 0.5 Hz

Required changes in turbine power: 10 MW 100 MW (Proportional to ratings)

Since $\Delta f_0 = -R\,\Delta P_{T\,0}$, Regulation = - (change in frequency) / (change in power)

Smaller unit: $R = -\dfrac{-0.5}{10} = 0.05$ **Hz per MW;** $R = -\dfrac{-0.5/50}{10/50} = 0.05$ **p.u. Hz / p.u.MW**

Larger unit: $R = -\dfrac{-0.5}{100} = 0.005$ **Hz per MW;** $R = -\dfrac{-0.5/50}{100/500} = 0.05$ **p.u. Hz / p.u.MW**

The above result teaches us that generators working in parallel should have same regulation (expressed in p.u. based on their own rating) in order to share the load changes in proportional to their ratings.

3. CLOSING THE ALFC LOOP

We observed earlier that the loop in Fig. 4 is "open". We now proceed now to "close" it by finding a mathematical link between ΔP_T and Δf. As our generator is supplying power to a conglomeration of loads in its service area, it is necessary in our following analysis to make reasonable assumptions about the "lumped" area behavior. We make these assumptions:

1. **The system is originally running in its normal state with complete power balance, that is, $P_G^0 = P_D^0$ + losses. The frequency is at normal value f^0. All rotating equipment represents a total kinetic energy of W^0_{kin} MW sec.**

2. **By connecting additional load, load demand increases by ΔP_D which we shall refer to as "new" load. (If load demand is decreased new load is negative). The generation immediately increases by ΔP_G to match the new load, that is $\Delta P_G = \Delta P_D$.**

3. It will take some time for the control valve in the speed governing system to act and increase the turbine power. Until the next steady state is reached, the increase in turbine power will not be equal to ΔP_G. Thus there will be power imbalance in the area that equals ΔP_T - ΔP_G i.e. ΔP_T – ΔP_D. As a result, the speed and frequency change. This change will be assumed uniform throughout the area. The above said power imbalance gets absorbed in two ways. 1) By the change in the total kinetic K.E. 2) By the change in the load, due to change in frequency.

Since the K.E. is proportional to the square of the speed, the area K.E. is

$$W_{kin} = W^0_{kin} \left(\frac{f}{f^0}\right)^2 \text{ MW sec.} \tag{14}$$

The "old" load is a function of voltage magnitude and frequency. Frequency dependency of load can be written as

$$D = \frac{\partial P_D}{\partial f} \text{ MW / Hz} \tag{15}$$

Thus $\Delta P_T - \Delta P_D = \dfrac{d}{dt}(W_{kin}) + D \; \Delta f$ (16)

Noting that $f = f^0 + \Delta f$

$$W_{kin} = W^0_{kin}\left(\frac{f^0 + \Delta f}{f^0}\right)^2 = W^0_{kin}\left[1 + \frac{2\,\Delta f}{f^0} + \left(\frac{\Delta f}{f^0}\right)^2\right] \approx W^0_{kin}\left(1 + 2\frac{\Delta f}{f^0}\right) \qquad (17)$$

$$\frac{d}{dt}(W_{kin}) = \frac{2\,W^0_{kin}}{f^0}\frac{d}{dt}(\Delta f)$$

Substituting the above in eq. (16)

$$\Delta P_T - \Delta P_D = \frac{2\,W^0_{kin}}{f^0}\frac{d}{dt}(\Delta f) + D\;\Delta f \quad \text{MW} \qquad (18)$$

By dividing this equation by the generator rating P_r and by introducing per-unit inertia constant

$$H = \frac{W^0_{kin}}{P_r} \quad \text{MW sec / MW (or sec)} \qquad (19)$$

it takes on the form

$$\Delta P_T - \Delta P_D = \frac{2\,H}{f^0}\frac{d}{dt}(\Delta f) + D\;\Delta f \quad \text{pu MW} \qquad (20)$$

$$\Delta P_T - \Delta P_D = \frac{2H}{f^0} \frac{d}{dt}(\Delta f) + D \Delta f \quad \text{pu MW} \tag{20}$$

The ΔP's are now measured in per unit (on base P_r) and D in pu MW per Hz. Typical H values lie in the range 2 – 8 sec. Laplace transformation of the above equation yields

$$\Delta P_T(s) - \Delta P_D(s) = \frac{2H}{f^0} s \ \Delta f(s) + D \ \Delta f(s) \tag{21}$$

$$= \left[\frac{2H}{f^0} s + D \right] \Delta f(s) \quad \text{i.e.}$$

$$\Delta f(s) = \frac{1}{\frac{2H}{f^0} s + D} \left[\Delta P_T(s) - \Delta P_D(s) \right]$$

$$\Delta f(s) = G_p(s) \left[\Delta P_T(s) - \Delta P_D(s) \right] \tag{22}$$

$$\Delta f(s) = G_p(s)\ [\Delta P_T(s) - \Delta P_D(s)] \tag{22}$$

where

$$G_p(s) = \frac{1}{\frac{2H}{f^0}s + D} = \frac{1/D}{1 + s\frac{2H}{f^0 D}} = \frac{K_p}{1 + sT_p} \tag{23}$$

$$K_p = \frac{1}{D} \tag{24}$$

$$T_p = \frac{2H}{f^0 D} \tag{25}$$

Equation (22) represents the missing link in the control loop of Fig. 4. By adding this, block diagram of the primary ALFC loop is obtained as shown in Fig. 6.

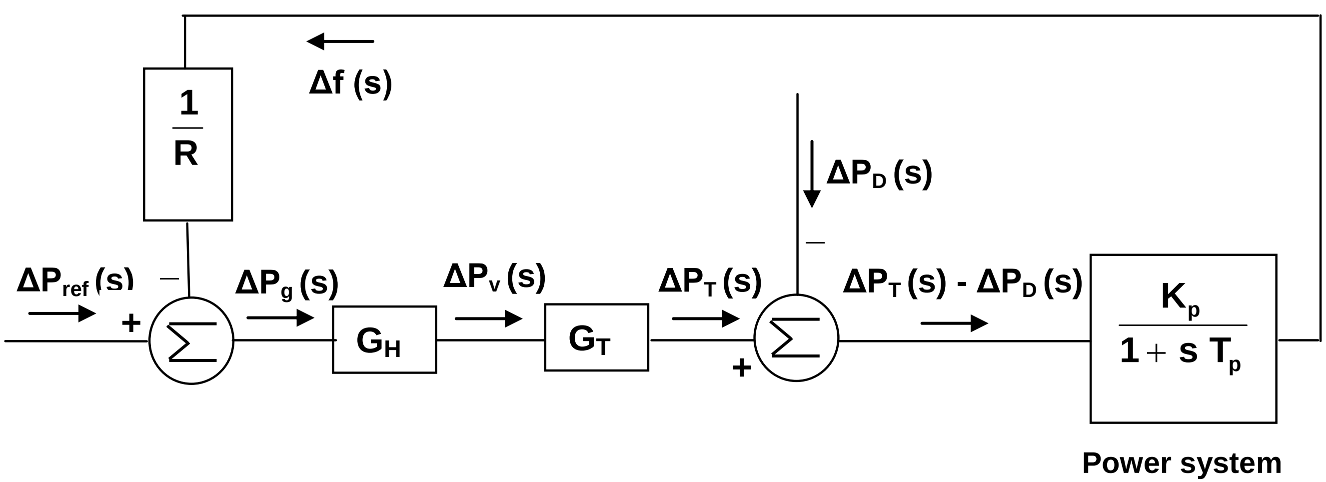


Fig. 6 Block diagram corresponding to primary loop of ALFC

Example 5

Primary ALFC loop parameters for a control area are:

Total rated capacity P_r = 2000 MW

Normal operating load P^0_D = 1000 MW

Inertia constant H = 5.0 sec.

Regulation = 2.0 Hz / p.u. MW

Assume that the load-frequency dependency is linear, meaning that the load would increase one percent for one percent frequency increase.

Obtain the power system transfer function.

Solution

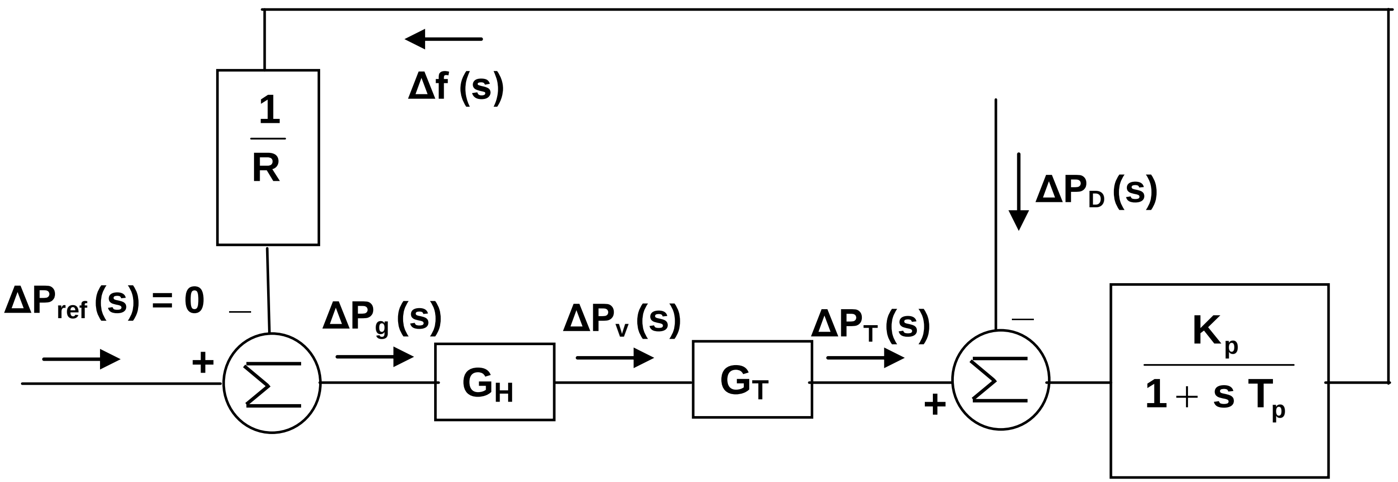
$$D = \frac{\partial P^0{}_D}{\partial f} = \frac{1\%\text{ of }1000}{1\%\text{ of }50} = \frac{10}{0.5} = 20\text{ MW / Hz} = \frac{20}{2000} = 0.01\ \text{p.u. MW / Hz}$$

$$K_P = \frac{1}{D} = 100\text{ Hz / p.u. MW;}\quad T_p = \frac{2H}{f^0 D} = \frac{2 \times 5}{50 \times 0.01} = 20\text{ sec.}$$

$$\text{Thus}\quad G_p(s) = \frac{K_p}{1 + s\,T_p} = \frac{100}{1 + 20\,s}$$

4. PRIMARY ALFC LOOP – UNCONTROLLED CASE

The primary ALFC loop in Fig. 6 has two inputs ΔP_{ref} and ΔP_D and one output Δf.



For uncontrolled case, (i.e. for constant reference input) $\Delta P_{ref} = 0$ and the block diagram shown in Fig. 6 can be simplified as shown.

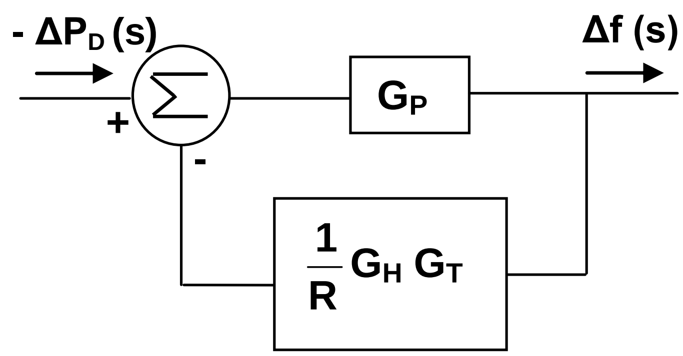


Fig. 6 a Reduced block diagram

From this simplified diagram, we can write

$$\Delta f\,(s) = -\frac{G_p}{1+\frac{1}{R}\,G_H\;G_T\;G_p}\,\Delta P_D\,(s) \qquad (27)$$

4.1 STATIC FREQUENCY DROP DUE TO STEP LOAD CHANGE

For a step load change of constant magnitude $\Delta P_D = M$, we have $\Delta P_D(s) = \dfrac{M}{s}$

Using the final value theorem, we readily obtain from eq. (27),

$$\Delta f(s) = -\frac{G_p}{1+\frac{1}{R}G_H\,G_T\,G_p}\,\Delta P_D(s) \quad (27)$$

the static frequency drop as

$$\Delta f_0 = \lim_{s \to 0}\,[\,s\,\Delta f(s)\,] = -\frac{K_p}{1+\frac{K_p}{R}}\,M = -\frac{M}{D+\frac{1}{R}}\ \text{Hz} \qquad (28)$$

We introduce here the so-called Area Frequency Response Characteristic (AFRC) β, defined as

$$\beta = D + \frac{1}{R} \quad \text{p.u. MW / Hz} \qquad (29)$$

Then the static frequency drop is given by

$$\Delta f_0 = -\frac{M}{\beta}\ \text{Hz} \qquad (30)$$

Example 6

Find the static frequency drop for 2000 MW system in the previous example following load increase of 1% of system rating.

Solution

Load increase M = 1% of 2000 MW

= 20 MW = 0.01 p.u. MW

As in previous example, D = 0.01 p.u. MW / Hz; R = 2 Hz / p.u. MW

$$\beta = D + \frac{1}{R} = 0.01 + \frac{1}{2} = 0.51 \text{ p.u. MW / Hz}$$

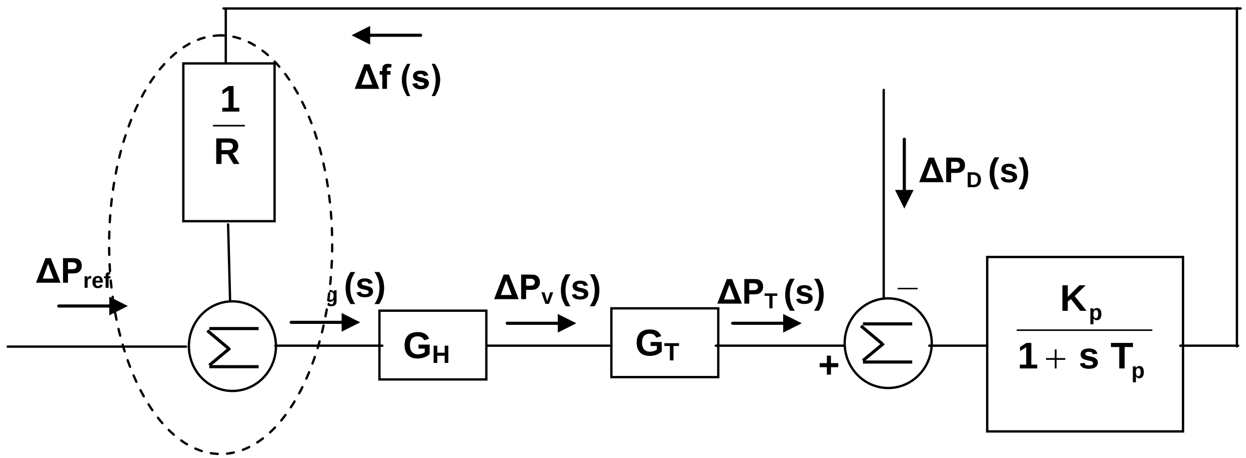
$$\text{Therefore } \Delta f_0 = -\frac{0.01}{0.51} = -0.0196 \text{ Hz};$$

or frequency drop = 0.0392 % of normal frequency

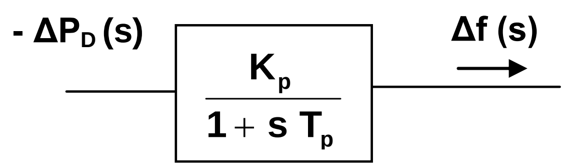
Example 7

What would the frequency drop in the previous example if the speed-governor loop were non-existent or open?

Solution



ALFC loop reduces to



$$\Delta f\ (s) = -\frac{K_p}{1 + s\,T_p}\,\Delta P_D(s)$$

For a sudden load increase of M, $\Delta P_D\ (s) = \dfrac{M}{s}$

Then $\Delta f_0 = \lim_{s \to 0}\ s\,\Delta f\ (s)\ ] = -\ K_p\ M = -\dfrac{M}{D}$ **Hz; Thus** $\beta\ =\ D = 0.01$ **p.u. MW / Hz**

Therefore $\Delta f_0 = -\dfrac{0.01}{0.01} = -\ 1.0$ **Hz; or frequency drop = 2 % of normal frequency**

5. DYNAMIC RESPONSE OF PRIMARY ALFC LOOP - UNCONTROLLED CASE

We know that

$$\Delta f\,(s) = -\frac{G_p}{1+\dfrac{1}{R}\,G_H\,G_T\,G_p}\,\Delta P_D\,(s) \qquad (27)$$

Finding the dynamic response, for a step load, is quite straight forward. Eq. (27) upon inverse Laplace transformation yields an expression for Δf (t). However, as G_H, G_T and G_p contain at least one time constant each, the denominator will be a third order polynomial resulting in unwieldy algebra.

We can simply the analysis considerably by making the reasonable assumption that the action of speed governor plus the turbine generator is “instantaneous” compared with the rest of the power system. The latter, as demonstrated in Example 5 has a time constant of 20 sec, and since the other two time constants are of the order of 1 sec, we will perform an approximate analysis by setting $T_H = T_T = 0$.

From eq. (27), $$\Delta f\,(s) = -\frac{G_p}{1+\dfrac{1}{R}\,G_H\,G_T\,G_p}\,\Delta P_D\,(s) \qquad (27)$$ we get

$$\Delta f\,(s) \approx -\frac{\dfrac{K_p}{1+sT_p}}{1+\dfrac{1}{R}\,\dfrac{K_p}{1+sT_p}}\,\frac{M}{s} = -\frac{R\,K_p}{R\,(1+sT_p)+K_p}\,\frac{M}{s} \qquad (31)$$

$$\Delta f(s) \approx - \frac{\dfrac{K_p}{1+sT_p}}{1+\dfrac{1}{R}\dfrac{K_p}{1+sT_p}} \frac{M}{s} = - \frac{R K_p}{R(1+sT_p)+K_p} \frac{M}{s} \tag{31}$$

Dividing numerator and denominator by R T_p we get

$$\Delta f(s) = - \frac{K_p}{T_p} M \frac{1}{s\left(s+\dfrac{R+K_p}{R T_p}\right)} \tag{32}$$

Using the fact

$$\frac{A}{s(s+\alpha)} = \frac{A}{\alpha}\left[\frac{1}{s} - \frac{1}{s+\alpha}\right] \text{ and noting } \frac{A}{\alpha} = -M \frac{K_p}{T_p}\frac{R T_p}{R+K_p} = -M \frac{R K_p}{R+K_p}$$

equation (32) becomes

$$\Delta f(s) = - M \frac{R K_p}{R+K_p}\left[\frac{1}{s} - \frac{1}{s+\dfrac{R+K_p}{R T_p}}\right] \tag{33}$$

$$\Delta f(s) = -\ M \ \frac{R\,K_p}{R + K_p}\ \left[\ \frac{1}{s}\ -\ \frac{1}{s + \dfrac{R + K_p}{R\ T_p}}\ \right] \qquad (33)$$

Making use of previous numerical values: M = 0.01 p.u. MW; R = 2.0 Hz / p.u. MW; K_p = 100 Hz / p.u. MW; T_p = 20 sec.

$$M\ \frac{R\,K_p}{R + K_p} = \frac{2}{102} = 0.01961; \quad \frac{R + K_p}{R\ T_p} = \frac{102}{40} = 2.55$$

$$\Delta f(s) = -\ 0.01961\ \left[\frac{1}{s}\ -\ \frac{1}{s + 2.55}\ \right]$$

The approximate time response is purely exponential and is given by

$$\Delta f(t) = -\ 0.01961\ (\ 1 - e^{-\ 2.55\ t}\ )\ \ Hz \qquad (34)$$

Alternatively, the above result can be obtained from the reduced block diagram shown in Fig. 6 a . Then

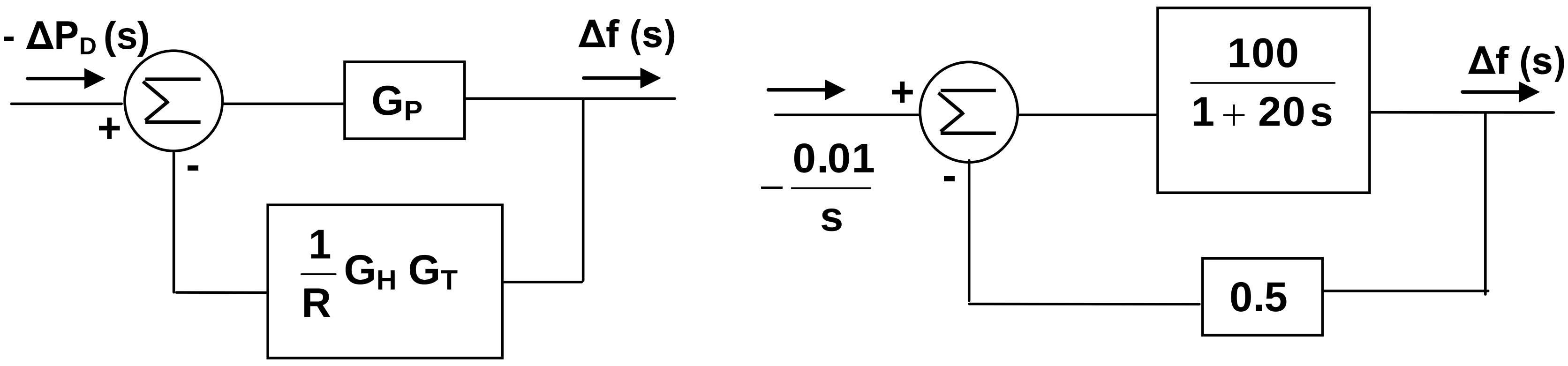


Fig. 6 a Reduced block diagram

$$\text{Thus}\quad \Delta f(s) = -\frac{\frac{100}{1+20s}}{1+\frac{50}{1+20s}}\frac{0.01}{s} = -\frac{100}{1+20s+50}\frac{0.01}{s} == \frac{1}{s(20s+51)} = -\frac{0.05}{s(s+2.55)}$$

$$= \quad -\frac{0.05}{2.55}\left[\frac{1}{s}-\frac{1}{s+2.55}\right] = -0.01961\left[\frac{1}{s}-\frac{1}{s+2.55}\right]$$

$$\Delta f(t) = -0.01961\,(1 - e^{-2.55\,t})\ \text{Hz} \tag{34}$$

Fig. 7 shows this response. For comparison, the response with the inclusion of the time constants T_H and T_T is also shown.

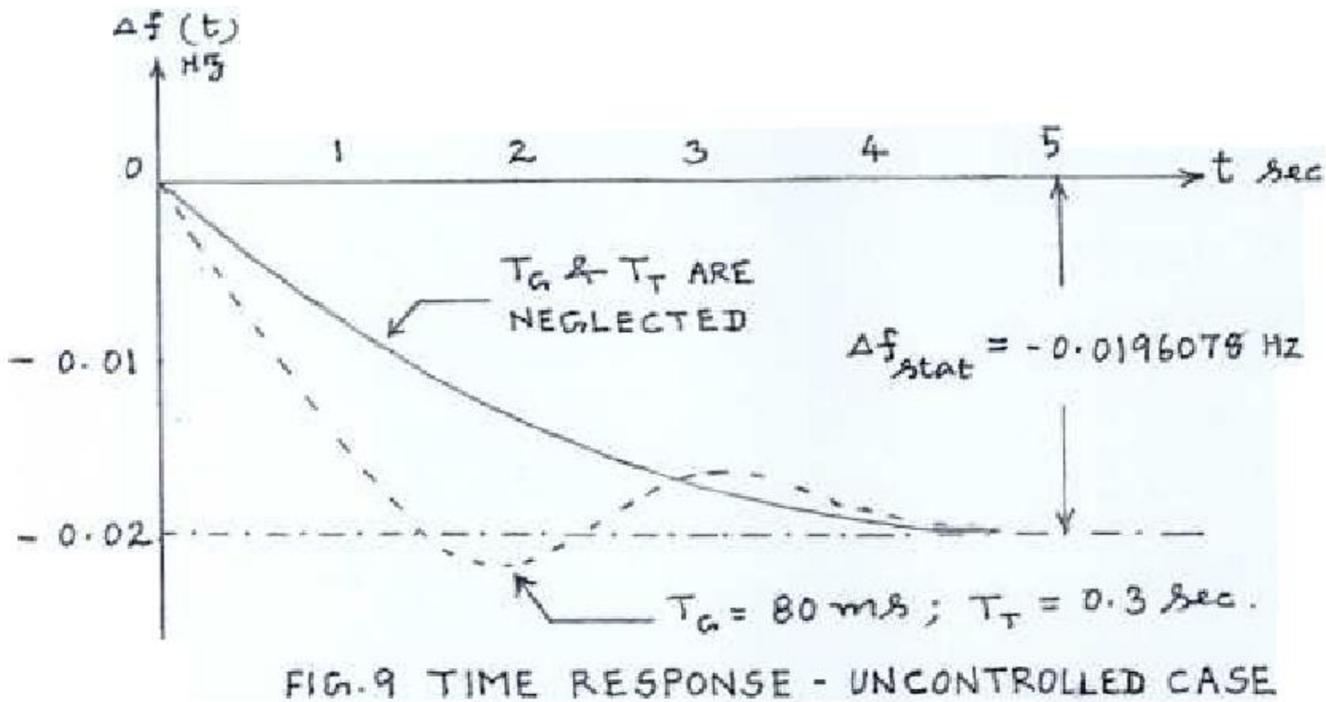


Fig. 7 Response of primary loop of ALFC

It is to be observed that the primary loop of ALFC <u>does not give the desired objective of maintaining the frequency constant.</u> We need to do something more to bring the frequency error to zero. Before discussing the necessary control which can make the frequency error to zero, we shall shed some light on to the physical mechanism in the primary loop of ALFC.

5.1 PHYSICAL INTERPRETATION OF RESULTS

When the load is suddenly increased by 1% (20 MW), where did this power come from? Certainly it must have come from somewhere as the load increase of 20 MW has been met with instantaneously.

In the milliseconds following the closure of the switch, the frequency has not changed a measureable amount, speed governor would not have acted and hence turbine power would not have increased. In those first instants the total additional load demand of 20 MW is obtained from the stored kinetic energy, which therefore will decrease at an initial rate of 20 MW. Release of KE will result in speed and frequency reduction. As seen in eq.(34),

$$\Delta f(t) = -0.01961\,(1 - e^{-2.55\,t})\ \text{Hz} \tag{34}$$

initially frequency reduces at the rate of 0.01961 x 2.55 = 0.05 Hz / sec. The frequency reduction causes the steam valve to open and result in increased turbine power. Further, the “old” load decreases at the rate of D = 20 MW / Hz.

In conclusion, the contribution to the load increase of 20 MW is made up of three components:

1. **Rate of decrease of kinetic energy from the rotating system**
2. **Increased turbine power**
3. **"Released" old customer load**

Initially the components 2 and 3 are zero. Finally, the frequency and hence the KE settle at a lower value and the component 1 becomes zero. In between, component 1 keeps decreasing and components 2 and 3 keep increasing. Let us compute components 2 and 3 <u>at steady state condition.</u>

We know that with 4% regulation

$$R = \frac{4\% \text{ of } 50}{2000} = \frac{2}{2000} = 0.001 \text{ Hz / MW. Further } \Delta f^0 = -\,0.01961 \text{ Hz.}$$

$$\text{Increased generation } \Delta P_G = \Delta P_T = -\frac{1}{R}\,\Delta f^0 = \frac{0.01961}{0.001} = 19.61 \text{ MW}$$

Value of D (Example 5) = 20 MW / Hz

Released "old" customer load = D x Δf^0 = 20 x 0.01961 = 0.392 MW

These two components add up to 20 MW. Note that the largest contribution is from new generation.

6. PROPORTIONAL PLUS INTEGRAL CONTROL (Secondary ALFC loop)

It is seen from the previous discussion that with the speed governing system installed in each area, for a given speed changer setting, there is considerable frequency drop for increased system load.

In the example seen, the frequency drop is 0.01961 Hz for 20 MW. Then the steady state drop in frequency from no load to full load (2000 MW) will be 1.961 Hz.

System frequency specification is rather stringent and therefore, so much change in frequency cannot be tolerated. In fact, it is expected that the steady state frequency change must be zero. In order to maintain the frequency at the scheduled value, <u>the speed changer setting must be adjusted automatically by monitoring the frequency changes.</u>

For this purpose, INTEGRAL CONTROLLER is included. In the integral controller the frequency error is first amplified and then integrated. Further, a negative polarity is also included so that a NEGATIVE frequency deviation will give rise to RAISE command. The signal fed into the integrator is referred as Area Controlled Error (ACE). For this case ACE $= \Delta f$. Thus

$$\Delta P_{ref} = -K_I \int \Delta f \; dt \tag{35}$$

Taking Laplace transformation

$$\Delta P_{ref}(s) = -\frac{K_I}{s} \; \Delta F(s) \tag{36}$$

The gain constant K_I controls the rate of integration and thus the speed of response of the loop.

$$\Delta P_{ref}(s) = -\frac{K_I}{s}\ \Delta F(s) \tag{36}$$

For this signal Δf (s) is fed to an integrator whose output controls the speed changer position resulting in the block diagram configuration shown in Fig. 8.

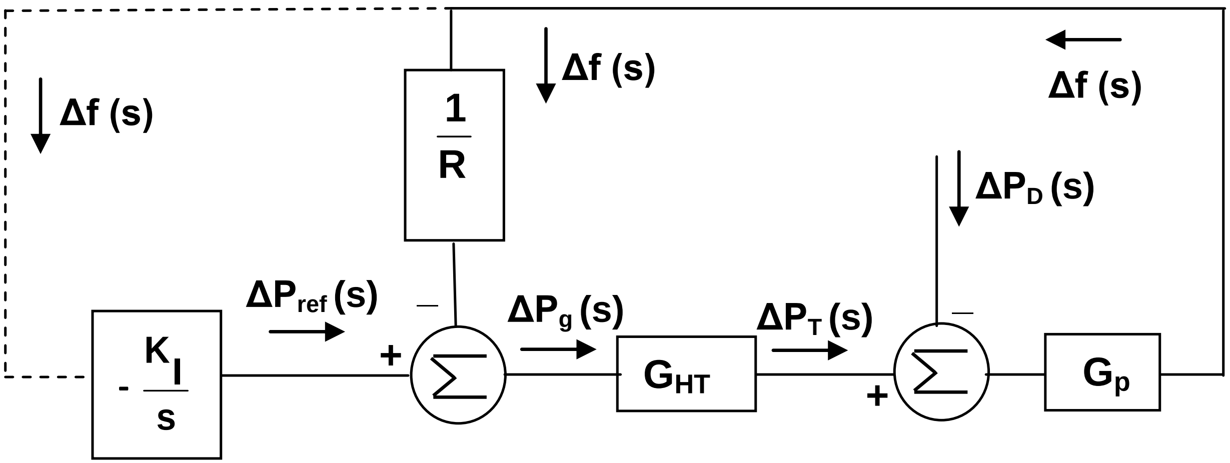


Fig. 8 Block diagram corresponding to complete ALFC

As long as an error remains, the integrator output will increase, causing the speed changer to move. When the frequency error has been reduced to zero, the integrator output ceases and the speed changer position attains a constant value.

Integral controller will give rise to ZERO STEADY STATE FREQUENCY ERROR following a step load change because of the reason stated above.

Referring to the block diagram of single control area with integral controller shown in Fig. 8, input to G_{HT} is $- \frac{K_I}{s} \Delta f(s) - \frac{1}{R} \Delta f(s)$ i.e. $- \left[\frac{K_I}{s} + \frac{1}{R} \right] \Delta f(s)$. Using this, the block diagram in Fig. 8 can be reduced as shown in Fig. 9 and 10.

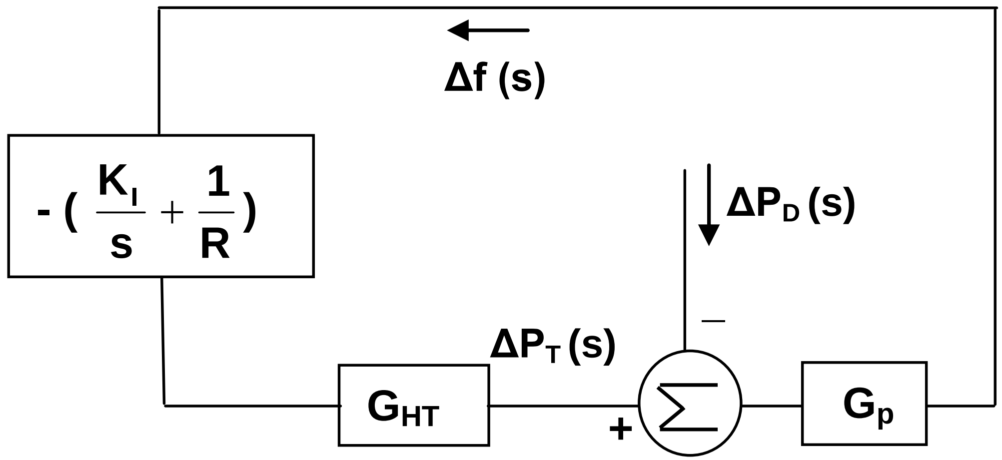


Fig. 9 Reduced block diagram

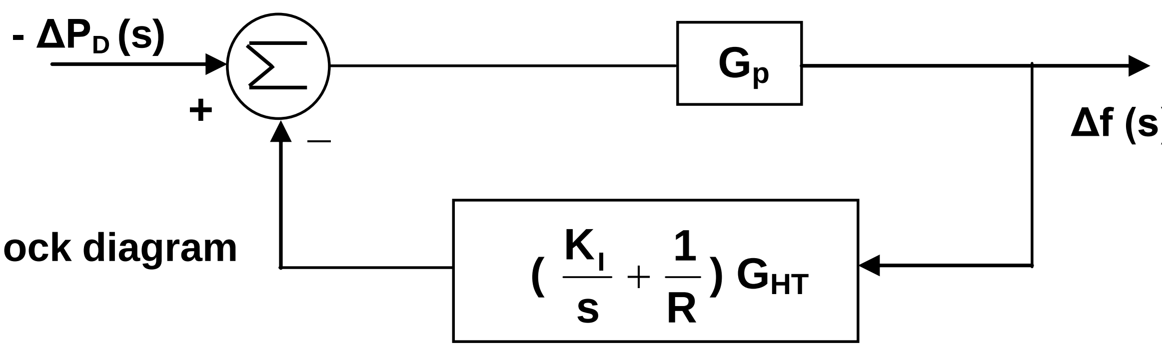


Fig. 10 Reduced block diagram

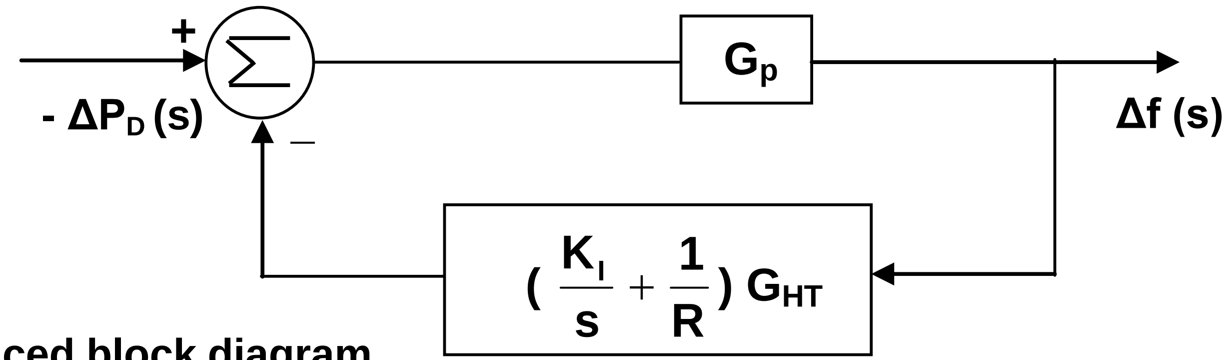


Fig. 10 Reduced block diagram

Therefore $$\Delta f\,(s) = -\frac{G_p}{1+\frac{K_I}{s}G_{HT}\;G_p+\frac{1}{R}G_{HT}\;G_p}\,\Delta P_D\,(s) \qquad (37)$$

The above equation is much more general. For a given $\Delta P_D(s)$, $\Delta f(t)$ can be obtained by taking Laplace inverse transform.

By setting K_I as zero, we get the expression for Δf (s) corresponding to uncontrolled case, as seen by eq. (27).

$$\Delta f\,(s) = -\frac{G_p}{1+\frac{1}{R}G_H\;G_T\;G_p}\,\Delta P_D\,(s) \qquad (27)$$

$$\Delta f(s) = -\frac{G_p}{1+\frac{K_I}{s}G_{HT}\ G_p + \frac{1}{R}G_{HT}\ G_p}\Delta P_D(s) \qquad (37)$$

6.1 STATIC FREQUENCY DROP FOLLOWING A STEP LOAD CHANGE

Let the step load change be ΔP_D, which is equal to M. Then $\Delta P_D(s) = \frac{M}{s}$

Using final value theorem,

$$\Delta f_0 = \lim_{s \to 0} [\, s\, \Delta f(s)\,] \qquad (38)$$

$$= -\left.\frac{G_p\ M}{1+\frac{K_I}{s}G_{HT}\ G_p + \frac{1}{R}G_{HT}\ G_p}\right|_{s \to 0} = -\left.\frac{K_p\ M}{1+\frac{K_I}{s}K_p + \frac{1}{R}\ K_p}\right|_{s \to 0}$$

$$= 0 \qquad (39)$$

Thus static frequency drop due to step load change becomes zero, which is a desired feature we were looking. This is made possible because of the integral controller that has been introduced.

6.2 DYNAMIC ANALYSIS

$$\Delta f(s) = -\frac{G_p}{1 + \frac{K_I}{s} G_{HT}\ G_p + \frac{1}{R} G_{HT}\ G_p} \Delta P_D(s) \qquad (37)$$

Let us assume time constants T_H and T_T as zero as we did in Section 5. Then

$G_{HT} = 1$. For a step load change of $\Delta P_D = M$, from eq. (37) we get

$$\Delta f(s) = -\frac{\frac{K_p}{1 + s\,T_p}}{1 + \frac{K_I}{s}\frac{K_p}{1 + s\,T_p} + \frac{1}{R}\frac{K_p}{1 + s\,T_p}} \frac{M}{s} \qquad (40)$$

Multiplying the numerator and denominator by $s\,R(1 + s\,T_p)$ we get

$$\Delta f(s) = -\frac{R\,K_p\ M}{sR(1 + sT_p) + RK_I K_p + sK_p} \qquad (41)$$

$$\Delta f(s) = -\frac{R K_p M}{sR(1+sT_p) + RK_I K_p + sK_p} \tag{41}$$

Dividing the numerator and denominator by R T_p the above equation becomes

$$\begin{aligned}\Delta f(s) &= -\frac{K_p}{T_p}\,\frac{M}{s^2 + \dfrac{R+K_p}{R T_p}\, s + \dfrac{K_I K_p}{T_p}} \\ &= -\frac{K_p}{T_p}\,\frac{M}{s^2 + \dfrac{1+\dfrac{K_p}{R}}{T_p}\, s + \dfrac{K_I K_p}{T_p}}\end{aligned} \tag{42}$$

$$\Delta f(s) = -\frac{K_p}{T_p}\,\frac{M}{s^2 + \dfrac{1+\dfrac{K_p}{R}}{T_p}\,s + \dfrac{K_I K_p}{T_p}} \tag{42}$$

We obtain the time response $\Delta f(t)$ upon Laplace inverse transformation of this expression in the right hand side of above equation. Since response depends upon the poles of the denominator polynomial, let us examine it.

$$s^2 + \frac{1+\dfrac{K_p}{R}}{T_p}\,s + \frac{K_I K_p}{T_p} = 0 \tag{43}$$

A second order system of type $as^2 + bs + c = 0$ will be stable if the coefficients a, b and c are greater than zero. Since this condition is met with, the system under consideration is STABLE.

For a second order equation $s^2 + bs + c = 0$, the roots are $s_1, s_2 = -\frac{b}{2} \pm \sqrt{\frac{b^2}{4} - c}$

The nature of the roots depends on $\frac{b^2}{4} - c$

$$s^2 + \frac{1+\frac{K_p}{R}}{T_p} s + \frac{K_I K_p}{T_p} = 0$$

<u>For critical case</u>

$$\frac{b^2}{4} - c = 0 \quad \text{i.e.} \quad b^2 = 4c$$

Now, both the roots are real, equal and negative. For this critical case

$$\left(\frac{1+\frac{K_p}{R}}{T_p}\right)^2 = \frac{4 K_I K_p}{T_p} \qquad \text{Thus} \qquad K_{I\,crit} = \frac{1}{4K_p T_p}\left(1+\frac{K_p}{R}\right)^2 \qquad (44)$$

<u>Super critical case</u>

When $b^2 < 4c$ the roots are complex conjugate and the solution is exponentially damped sinusoidal. For this case the integral gain constant K_I is obtained from

$$\left(\frac{1+\frac{K_p}{R}}{T_p}\right)^2 < \frac{4 K_I K_p}{T_p} \qquad \text{i.e.} \quad K_I > K_{I\,crit} \qquad (45)$$

When $K_I > K_{I\,crit}$ the system is said to be super-critical. Due to damping present, the final solution will tend to zero. However, the solution will be oscillatory type.

Sub-critical case

When $b^2 > 4c$ the roots are real and negative. For this case, the integral gain constant K_I is given by

$$\left(\frac{1+\frac{K_p}{R}}{T_p}\right)^2 > \frac{4 K_I K_p}{T_p} \quad \text{i.e.} \quad K_I < K_{I\,crit} \qquad (46)$$

This case is referred as sub-critical integral control. In this case the solution contains terms of the type $e^{-\alpha 1t}$ and $e^{-\alpha 2t}$ and it is non-oscillatory. However, finally the solution will tend to zero.

Thus the integral controller system is STABLE and ISOCHRONOUS i.e. following a step load change, the frequency error always returns to zero. The dynamic response for different values of K_I are shown in Fig. 11.

In practical system T_H and T_T will not be zero; but will have small values. When T_H = 80 m sec; T_T = 0.3 sec and T_p = 20 sec., dynamic response for different integral gain constant K_I will be as shown in Fig. 12.

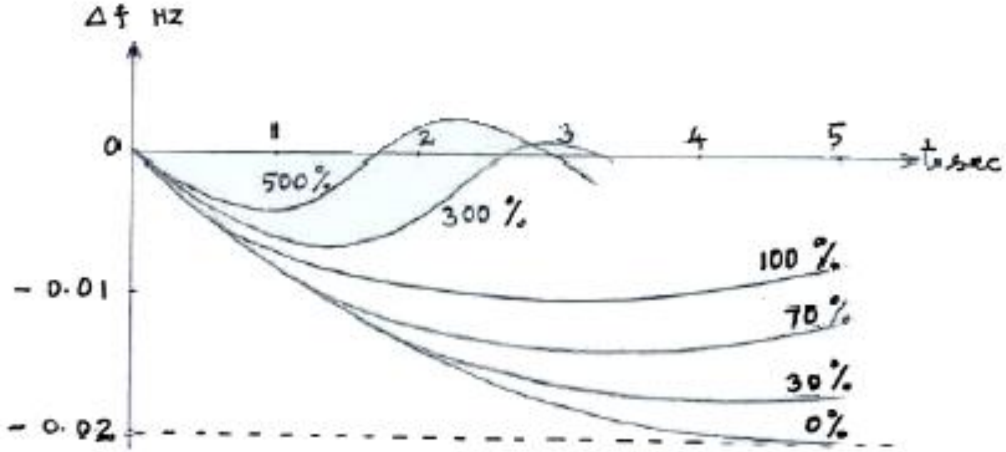


FIG. 13 DYNAMIC RESPONSE FOR DIFFERENT K_I

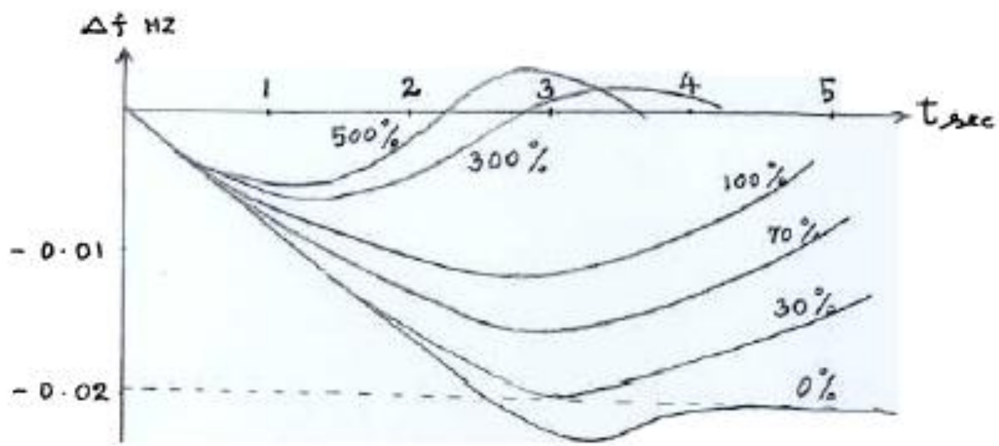


FIG. 14 DYNAMIC RESPONSE CONSIDERING T_G & T_T

7. TWO-AREA SYSTEM

A control area is characterized by the same frequency throughout. This tantamount to saying that the area network is "rigid" or "strong". In the single-area case we could thus represent the frequency deviation by the *single* variable Δf. In the present case we assume each area individually "strong". Having interconnected them with a "weak" tie-line therefore leads us to the assumption that the frequency deviations in the two areas can be represented by *two* variables Δf_1 and Δf_2 respectively.

7.1 MODELING THE TIE-LINE and BLOCK DIAGRAM FOR TWO-AREA SYSTEM

In normal operation the power flows in the tie-line connecting the areas 1 and 2 is given by

$$P^0_{12} = \frac{|V_1^0||V_2^0|}{X} \sin(\delta_1^0 - \delta_2^0) \tag{47}$$

where δ_1^0 and δ_2^0 are the angles of end voltages V_1 and V_2 respectively. The order of the subscripts indicates that the tie-line power is defined in direction 1 to 2.

Knowing $dy/dx = \Delta y/\Delta x$, for small deviations in angles δ_1 and δ_2 the tie-line power changes by an amount

$$\Delta P_{12} \approx \frac{|V_1^0||V_2^0|}{X}\cos(\delta_1^0 - \delta_2^0)(\Delta\delta_1 - \Delta\delta_2) \qquad (48)$$

We now define the "synchronizing coefficient" of a line as

$$T^0 = \frac{|V_1^0||V_2^0|}{X}\cos(\delta_1^0 - \delta_2^0) \quad \text{MW / rad.} \qquad (49)$$

Then the tie-line power deviation is $\Delta P_{12} = T^0 (\Delta\delta_1 - \Delta\delta_2)$ MW (50)

We like to have ΔP_{12} in terms of frequency deviations Δf_1 and Δf_2. We know

$$f = \frac{\omega}{2\pi} = \frac{1}{2\pi}\frac{d\delta}{dt}; \quad \text{i.e. } d\delta = 2\Pi\, f\, dt \qquad \text{Thus } \delta = 2\pi\int_0^t f\, dt \qquad (51)$$

and hence $\Delta\delta = 2\pi \int^t \Delta f\, dt$ (52)

Expressing tie-line power in terms of Δf_1 and Δf_2 we get

$$\Delta P_{12} = 2\pi T^0 \left(\int^t \Delta f_1\, dt - \int^t \Delta f_2\, dt\right) \qquad (53)$$

$$\Delta P_{12} = 2\,\pi\, T_0 \left(\int^{t} \Delta f_1 \, dt \; - \; \int^{t} \Delta f_2 \, dt \right) \qquad (53)$$

Taking Laplace transformation of the above eq. we get

$$\Delta P_{12}(s) \;=\; \frac{2\;\pi\; T_0}{s} \left[\, \Delta f_1 (s) - \Delta f_2 (s) \,\right] \qquad (54)$$

Representing this equation in terms of block diagram symbols yields the diagram in Fig. 13.

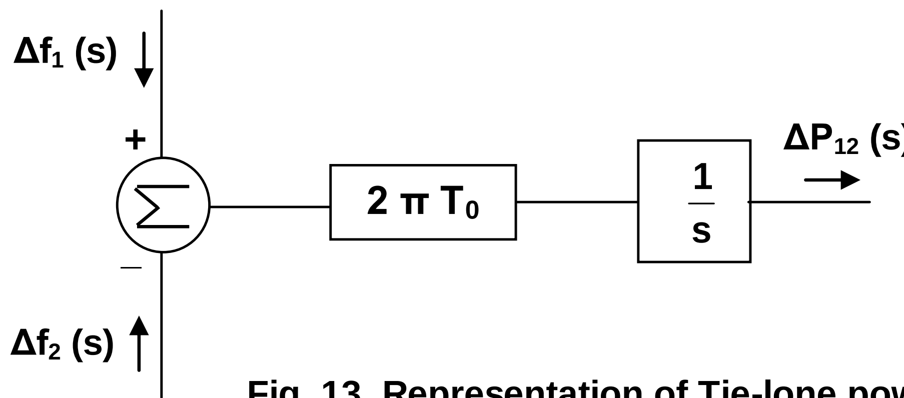


Fig. 13 Representation of Tie-lone power flow

Tie-line power ΔP_{12} shall be treated as load in area 1. Similar to power balance eq.

$\Delta f\,(s) \;=\; G_p\,(s) \;[\, \Delta P_T(s) - \Delta P_D(s) \,]$ (22) we can write

$$\Delta f_1\,(s) \;=\; G_{p1}\,(s) \;[\, \Delta P_{T1}(s) - \Delta P_{D1}(s) - \Delta P_{12}(s)] \qquad (54\ a)$$

Block diagram for two-area uncontrolled system is shown in Fig. 14.

$$\Delta f_1(s) = G_{p1}(s)\ [\Delta P_{T1}(s) - \Delta P_{D1}(s) - \Delta P_{12}(s)] \quad (54\ a)$$

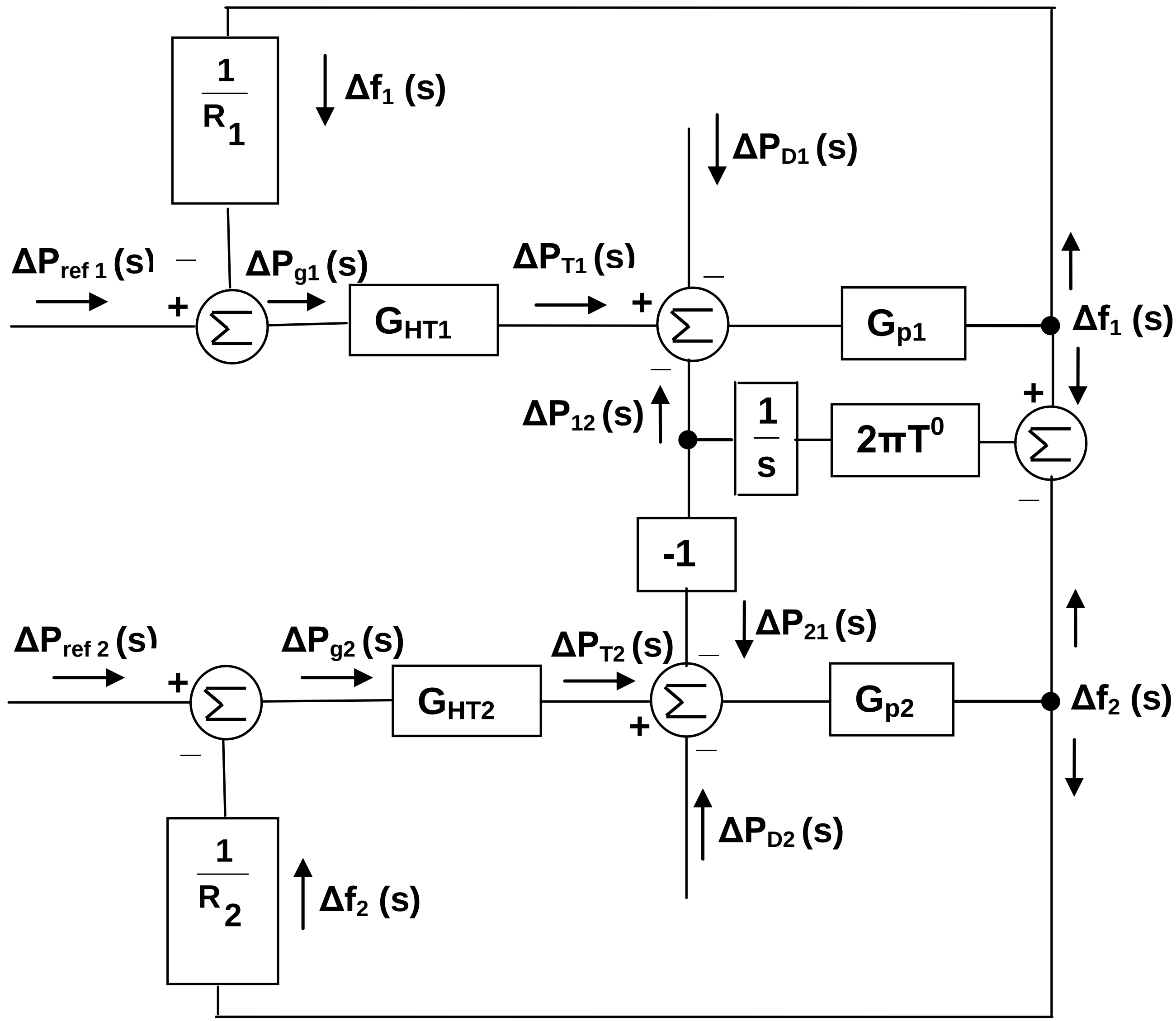


Fig. 14 Block diagram representation of two area system

Similarly we need to add ΔP_{21} in area 2. Defining the tie-line power in direction 2 to 1 as ΔP_{21}.

$$\Delta P_{21} = - \Delta P_{12} \qquad (55)$$

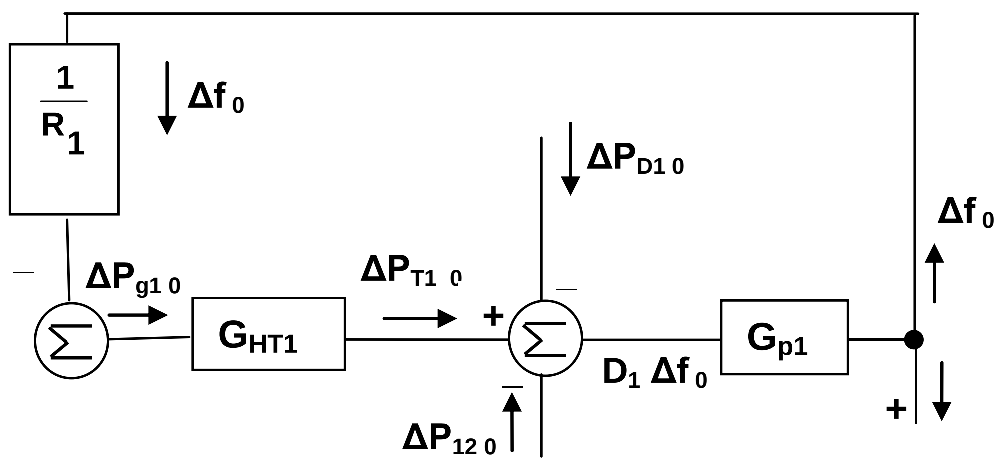
For this reason, transfer function of -1 is introduced in the block diagram.

Further, we remember that the powers in the single-area diagram were expressed in per unit of area rating. The parameters R, D and H, likewise were based on the same base power. When two or more areas of different ratings, are involved, we must refer all powers and parameters to the *one* chosen base power.

7.2 STATIC RESPONSE OF UNCONTROLLED TWO-AREA SYSTEM

We shall first investigate the static response of the two-area system **with fixed speed changer position; i.e. $\Delta P_{ref\,1} = \Delta P_{ref\,2} = 0$**

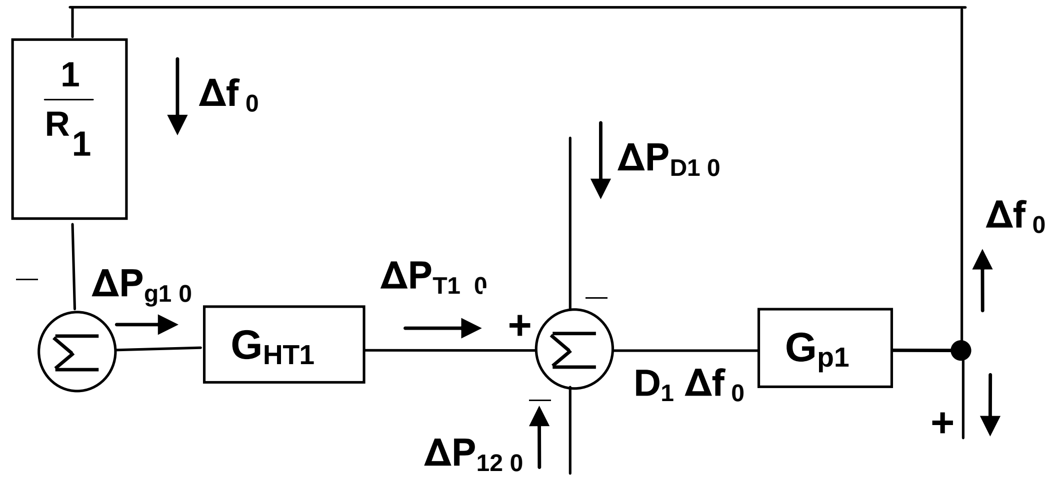
We assume that the loads in each area are suddenly increased by the constant incremental steps $\Delta P_{D1} = M_1$ and $\Delta P_{D2} = M_2$. At steady state, as seen from Fig. 15, $\Delta f_{1\,0} = \Delta f_{2\,0} = \Delta f_0$. We shall presently limit our analysis to **finding the static changes in frequency and tie-line power denoted by Δf_0 and $\Delta P_{12\,0}$ respectively.**



Note that $\Delta P_{T1\,0} = -\dfrac{1}{R_1}\Delta f_0$ and $\Delta P_{T2\,0} = -\dfrac{1}{R_2}\Delta f_0$ (56)

Knowing the output of G_{p1} as Δf_0 input to $G_{p1} = D_1\,\Delta f_0$. Similarly, input to $G_{p2} = D_2\,\Delta f_0$.

Consider the summing point with $\Delta P_{T1\,0}$, $\Delta P_{D1\,0}$, and $\Delta P_{12\,0}$.



$$-\frac{1}{R_1}\Delta f_0 - M_1 - \Delta P_{12\,0} = D_1\,\Delta f_0 \quad \text{and} \quad -\frac{1}{R_2}\Delta f_0 - M_2 + \Delta P_{12\,0} = D_2\,\Delta f_0 \quad \text{i.e.}$$

$$D_1\,\Delta f_0 + \frac{1}{R_1}\Delta f_0 + \Delta P_{12\,0} = -M_1; \qquad \text{i.e.}\ \ \beta_1\,\Delta f_0 + \Delta P_{12\,0} = -M_1 \tag{57}$$

$$D_2\,\Delta f_0 + \frac{1}{R_2}\Delta f_0 - \Delta P_{12\,0} = -M_2; \qquad \text{i.e.}\ \ \beta_2\,\Delta f_0 - \Delta P_{12\,0} = -M_2 \tag{58}$$

where area frequency response characteristic (AFRC) of each area are defined as

$$\beta_1 = D_1 + \frac{1}{R_1} \qquad\qquad \beta_2 = D_2 + \frac{1}{R_2} \tag{59}$$

$$\beta_1 \Delta f_0 + \Delta P_{12\,0} = -M_1 \qquad (57)$$

$$\beta_2 \Delta f_0 - \Delta P_{12\,0} = -M_2 \qquad (58)$$

Solving the above equations (57) and (58) for Δf_0 and $\Delta P_{12\,0}$ we get

$$\Delta f_0 = -\frac{M_1 + M_2}{\beta_1 + \beta_2} \qquad (60)$$

$$\Delta P_{12\,0} = -\Delta P_{21\,0} = \frac{\beta_1 M_2 - \beta_2 M_1}{\beta_1 + \beta_2} \qquad (61)$$

Eqns. (60) and (61) become simple if we assume identical area parameters; i.e.

$R_1 = R_2 = R$; $D_1 = D_2 = D$; Then $\beta_1 = \beta_2 = \beta$

We then get

$$\Delta f_0 = -\frac{M_1 + M_2}{2\beta} \tag{62}$$

$$\Delta P_{12\,0} = -\Delta P_{21\,0} = \frac{M_2 - M_1}{2} \tag{63}$$

For example, if a step load change occurs only in area 2, we get

$$\Delta f_0 = -\frac{M_2}{2\beta} \text{ Hz} \tag{64}$$

$$\Delta P_{12\,0} = -\Delta P_{21\,0} = \frac{M_2}{2} \text{ p.u. MW} \tag{65}$$

The above two equations tell us, in a nutshell, the advantages of pool operation:

1. The frequency drop will be only half that would be experienced if the areas were operating alone.
2. 50% of the added load in area 2 will be supplied by area 1 via. the tie-line.

Example 8

A 2000 MW control area 1 is interconnected with a 10000 MW area 2. The 2000 MW area has the system parameters as

R = 2.0 Hz / p.u. MW; D = 0.01 p.u. MW / Hz

Area 2 has the same parameters, but on a base of 10000 MW. A 20 MW load increase takes place in area 1. Find static frequency drop and tie-line power change.

Solution

Let us take 2000 MW as base power.

$$\beta_1 = 0.01 + \frac{1}{2} = 0.51 \text{ p.u. MW / Hz}$$

$\beta_2 = 0.51$ **p.u. MW / Hz on a base of 10000 MW**

$$= 0.51 \times \frac{10000}{2000} = 2.55 \text{ p.u. MW / Hz on a base of 2000 MW}$$

$$M_1 = \frac{20}{2000} = 0.01 \text{ p.u. MW}$$

$$\Delta f_0 = - \frac{0.01}{0.51 + 2.55} = - 0.003268 \text{ Hz}$$

$$\Delta P_{12\,0} = - \Delta P_{21\,0} = - \frac{2.55 \times 0.01}{0.51 + 2.55} = - 0.008333 \text{ p.u. MW} = - 16.67 \text{ MW}$$

Note that the frequency drop is only one sixth of that experienced by area 1 operating alone (0.01961 Hz compare Example 6).

Also note that this frequency support is accomplished by an added delivery of 16.67 MW from the larger area.

7.3 DYNAMIC RESPONSE OF UNCONTROLLED TWO-AREA SYSTEM

With the very simple turbine model that we have used, the two area system in Fig. 14 is of <u>eighth order</u> for a step load change. It would therefore meaningless, to attempt a direct analytic approach for finding the dynamic response of the system. Typical simulation results for a two-area system are shown in Fig. 15.

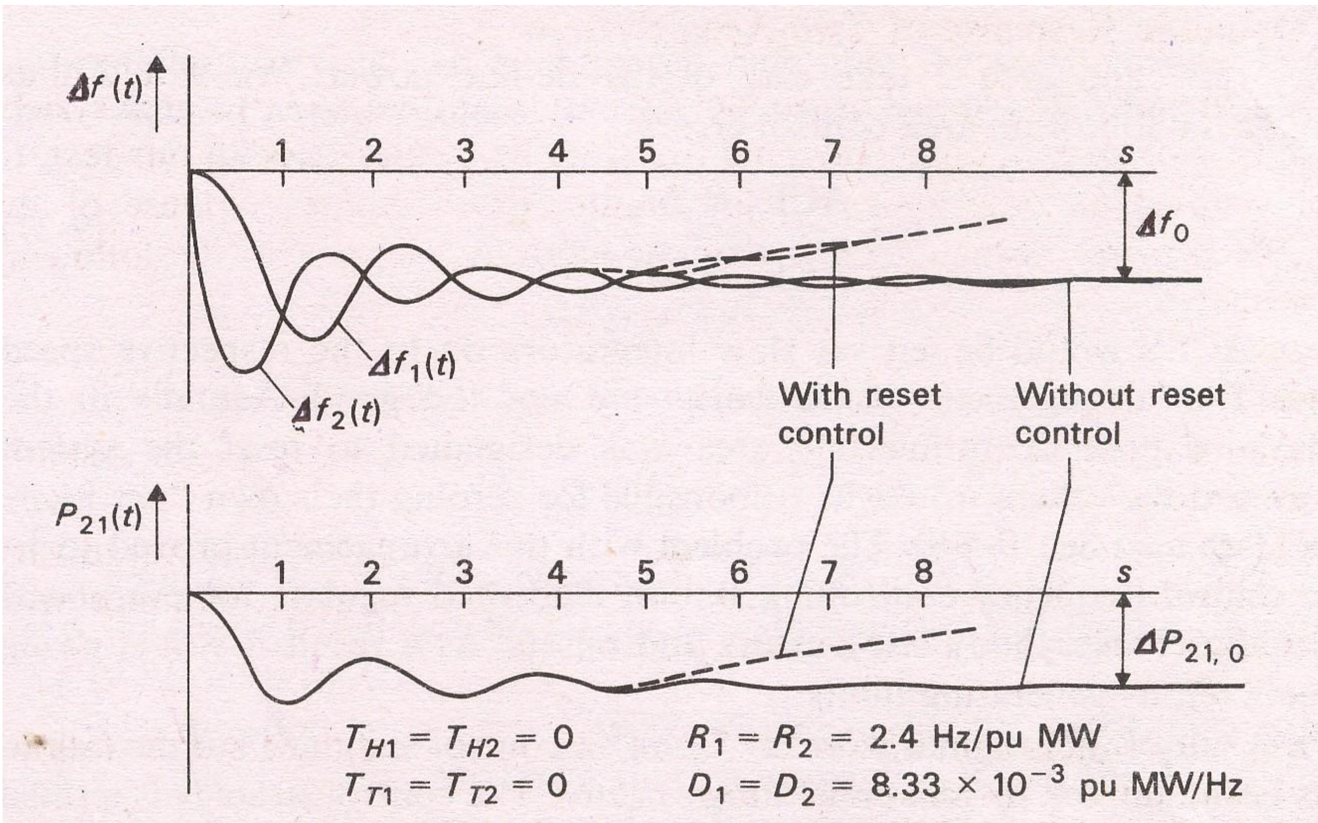


Fig. 15 Simulation results of a two-area system

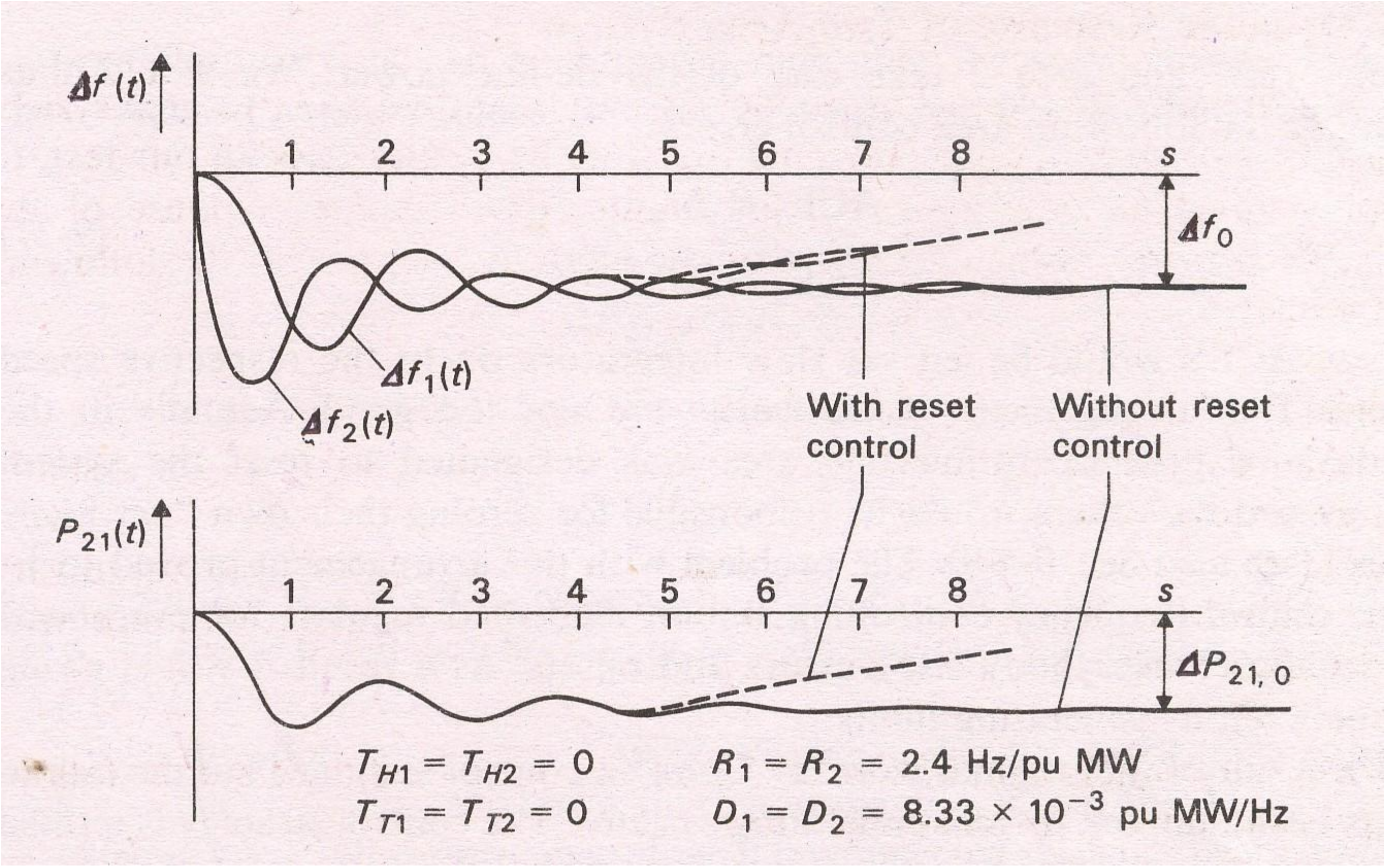


Fig. 15 Simulation results of a two-area system

It can be seen that the solution for $\Delta f_1(t)$ and $\Delta f_2(t)$ are oscillatory. However, because of system damping, finally they settle at a steady state value. Similarly, the solution of $\Delta P_{21}(t)$ has oscillation at beginning and finally settle at a steady state value.

7.4 TIE-LINE BIAS CONTROL FOR TWO-AREA SYSTEM

The persistent static frequency error is intolerable. Also, a persistent static error in tie-line power flow would mean that <u>one area would have to support the other on a steady state basis.</u> To circumvent this, some form of reset integral control must be added to the two-area system.

The control strategy of "tie-line bias control" is based upon the principle that all operating pool members must contribute their share to frequency control in addition to taking care of their own net interchange. This means that for two-area system, at steady state, both Δf_0 and $\Delta P_{12\,0}$ must be zero.

To achieve these objectives, the Area Control Error (ACE) for each area consists of a linear combination of frequency and tie-line error. Thus

$$ACE_1 = \Delta P_{12} + B_1 \Delta f_1 \tag{66}$$

$$ACE_2 = \Delta P_{21} + B_2 \Delta f_2 \tag{67}$$

The speed changer commands will thus be of the form

$$\Delta P_{ref\,1} = -K_{I1} \int (\Delta P_{12} + B_1 \Delta f_1)\, dt \quad (68)$$

$$\Delta P_{ref\,2} = -K_{I2} \int (\Delta P_{21} + B_2 \Delta f_2)\, dt \quad (69)$$

The constants $K_{I\,1}$ and $K_{I\,2}$ are integrator gains and the constants B_1 and B_2 are the frequency bias parameters. The minus sign must be included to ensure that, if there is positive frequency deviation or tie-line power deviation, then each area should decrease its generation

7.5 STATIC SYSTEM RESPONSE WITH TIE-LINE BIAS CONTROL

The chosen strategy will eliminate the steady-state frequency and tie-line deviations for the following reasons.

Following a step load change in either area, a new static equilibrium can be achieved only after the speed-changer commands have reached constant values.

But this evidently requires that both the integrants in eqns (68) and (69) be zero; i.e.

$$\Delta P_{12\,0} + B_1\,\Delta f_0 = 0 \tag{70}$$

and $\Delta P_{21\,0} + B_2\,\Delta f_0 = 0$ i.e. $-\Delta P_{12\,0} + B_2\,\Delta f_0 = 0$ (71)

The above two conditions can be met with only if

$$\Delta f_0 = 0 \text{ and } \Delta P_{21\,0} = -\Delta P_{12\,0} = 0 \tag{72}$$

Note that this result is independent of the values of B_1 and B_2. In fact, one of the bias parameters can be zero, and we still have a guarantee that eq. (72) is satisfied. Having checked use of the integral controller, let us see how they can be included in the block diagram.

Laplace transform of Equations (68) and (69) gives

$$\Delta P_{ref\,1}(s) = -\frac{K_{I1}}{s}\,[\Delta P_{12}(s) + B_1\,\Delta f_1(s)]; \qquad \Delta P_{ref\,2}(s) = -\frac{K_{I2}}{s}\,[\Delta P_{21}(s) + B_2\,\Delta f_2(s)]$$

$$\Delta P_{ref\,1}(s) = -\frac{K_{I1}}{s}\left[\Delta P_{12}(s) + B_1\,\Delta f_1(s)\right]; \qquad \Delta P_{ref\,2}(s) = -\frac{K_{I2}}{s}\left[\Delta P_{21}(s) + B_2\,\Delta f_2(s)\right]$$

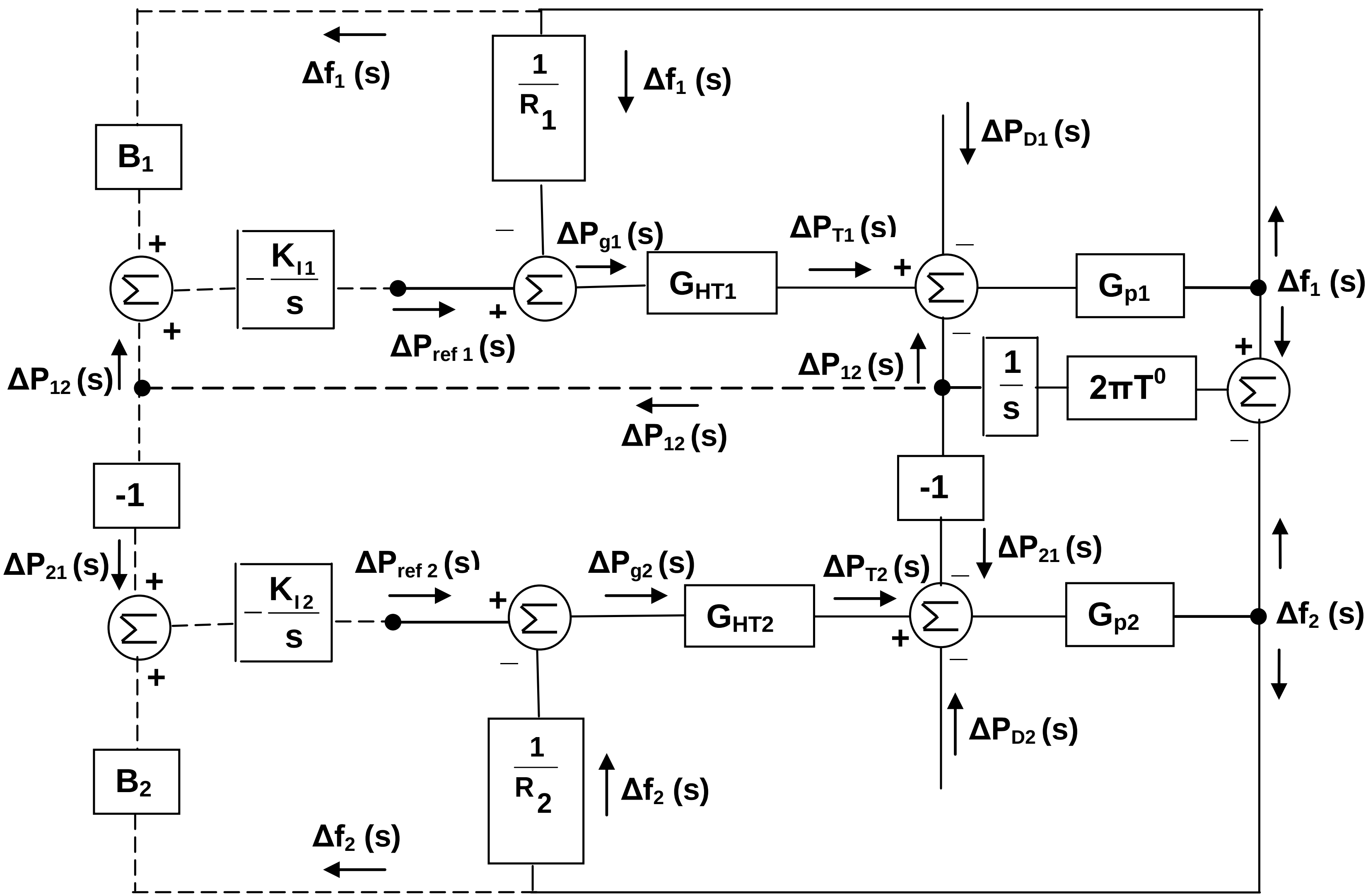


Fig. 16 Block diagram representation of two area system with tie-line bias control

Questions on “Automatic Load Frequency Control”

1. What is the basic role of ALFC?
2. Name the main parts in the real power control mechanism of a generator.
3. Draw the functional diagram of real power control mechanism of a generator.
   Explain how a “raise” command to the speed changer will result in increased generator output power.
   Discuss how speed drop will result in increased generator output power.
4. Draw the portion of real power control mechanism of a generator that corresponds to the speed changer and the speed governor and develop its block diagram.
5. Develop the block diagram corresponding to speed changer, speed governor and the hydraulic valve actuator
6. Consider an uncontrolled speed governing system of a generator. Obtain the relationship between frequency vs output power at steady state condition.

7. Consider the speed governing system of 50 Hz, 40 MW generator, having 4% speed regulation. Find the increase in turbine power, if the frequency drops by 0.15 Hz with the speed changer setting unchanged.
8. Consider the speed governing system of 50 Hz, 100 MW generator, having 6% speed regulation. Find the increase in frequency, if the turbine power is decreased by 4 MW with the speed changer setting unchanged.
9. Two 50 Hz generators of rating 100 MW and 300 MW are operating in parallel. Each of them has a speed regulation of 5%. They supply a total load of 320 MW. Assume that the speed changers are set to give rated frequency at 100% rated output power. Determine the output power of each generator and the operating frequency.

10. The following two synchronous generators are operating in parallel:

Generator 1	**50 MW**	**6 % speed regulation**
Generator 2	**50 MW**	**3 % speed regulation**

i) Determine the load taken by each generator for a total load of 80 MW when the speed changers are set to give rated speed at 100 % rated output.

ii) The speed changer of generator 1 is so adjusted that 80 MW load is equally shared. Find the output of generator 1 for rated speed its frequency at no load and the change to be made in the speed changer.

iii) The speed changer of generator 2 is so adjusted that 80 MW load is equally shared. Determine the output of generator 2 for rated speed, its frequency at no load and the change to be made in the speed changer.

11. Draw the block diagram representation of uncontrolled single area power system. Develop the expression for static frequency drop corresponding to step load increase. Also sketch the dynamic response i) neglecting the time constants of speed governor and turbine generator ii) including the time constants of speed governor and turbine generator.

12. The data pertaining to an uncontrolled single area power system are as follows:

Total rated capacity	= 2500 MW
Nominal operating load	= 1500 MW
Nominal frequency	= 50 Hz
Inertia constant	= 4 sec.
Governor drop	= 4 %

Assume that the load frequency characteristic of the system is linear.

For a decrease of 20 MW load, determine

a) Steady state frequency deviation and frequency.

b) Change in generation (in MW) and increase in original load (in MW) under steady state conditions.

c) Find the Transfer Function of the power system.

d) Also obtain the dynamic response neglecting time constants of speed governor and turbine generator and sketch it.

13. **Following data pertain to uncontrolled single area power system. System rating = 200 MW; Load = 100 MW; Regulation = 4%; System frequency = 50 Hz. Load increase = 10 MW; 1% frequency increase causes 0.8% load increases. Inertia constant = 4 sec. Find steady state frequency deviation and the transfer function of power system.**

14. **What is the necessity of proportional plus integral controller?**

15. **Draw the complete block diagram representation of ALFC of single area system and describe the role of different components.**

16. **For a two area system, develop the expression for change in tie-line power flow in terms of change in frequency of both the areas and represent it in the form a block diagram.**

17. **What are advantages of interconnected two area system over single area system?**

18. **Draw the block diagram representation of uncontrolled two area system and briefly explain.**

19. **Develop the expression for static frequency deviation and static tie line power deviation for two area system subjected to sudden load changes. From these expressions, justify the advantages of interconnected system.**

20. **Two uncontrolled interconnected power systems, A and B, each has a speed regulation of 5 Hz / p.u. MW and stiffness D of 1.0 p.u. MW / Hz (on respective capacity bases). The capacity of system A is 1500 MW and of B is 1000 MW. The two systems are interconnected through a tie line and are initially at 50 Hz. If there is a 100 MW load change in system A, calculate the change in steady state values of frequency and tie line power.**

21. **What do you understand by tie-line bias control?**

22. **Draw the block diagram representation of uncontrolled two-area system. Explain how this could be modified to include the tie-line bias control.**

23. **Draw the block diagram representation of two area system with tie-line bias control.**

24. Two uncontrolled areas 1 and 2 are connected by a tie-line. System parameters are:

Area 1 Rated capacity 5000 MW R = 2.5 Hz / p.u. MW D = 0.02 p.u. MW / Hz

Area 2 Rated capacity 2000 MW R = 2 Hz / p.u. MW D = 0.05 p.u. MW / Hz

Taking 5000 MW as the base, find the steady state frequency change and the change in tie-line power flow from area 1 to 2 when

i) 20 MW load increase takes place in area 1.

ii) 20 MW load increase takes place in area 2.

iii) 10 MW load increase takes place in areas 1 and 2.

iv) 20 MW load decease takes place in area 1.

ANSWERS

7. 3 MW 8. 0.12 Hz

9. 80 MW; 240 MW; 50.5 Hz

10. 43.3333 MW; 36.6667 MW

45 MW; 52.7 Hz

60 MW; 51.8 Hz

12. 0.015625 Hz; 50.015625 Hz

- 19.53125 MW; 0.46875 MW

$\frac{83.3333}{1 + 13.3333\ s}$; $0.015625\ (1 - e^{-3.2\ t})$ Hz

13. - 0.0984 Hz; $\frac{125}{1 + 20\ s}$

20. – 0.0333 Hz; - 40.02 MW; 40.02 MW

24. i) - 0.00625 Hz - 6.875 MW

ii) - 0.00625 Hz 13.125 MW

iii) - 0.00625 Hz 3.125 MW

iv) 0.00625 Hz 6.875 MW

SOLUTION

1. Mention four requirements of a power system.

    i) It must supply power, practically everywhere the customer demands.

    ii) It must be able to supply the ever changing load demand at all time.

    iii) The power supplied should be of good quality.

    iv) The power supplied should be economical.

    v) It must satisfy necessary safety requirements.

2. Over voltage: Increased motor speed; vibration and mechanical damage; Insulation failure

    Under voltage: Decreased motor speed; heating due to increased current

3. Mention three basic roles of Automatic Load Frequency Control.

i) To maintain desired output power of a generator.

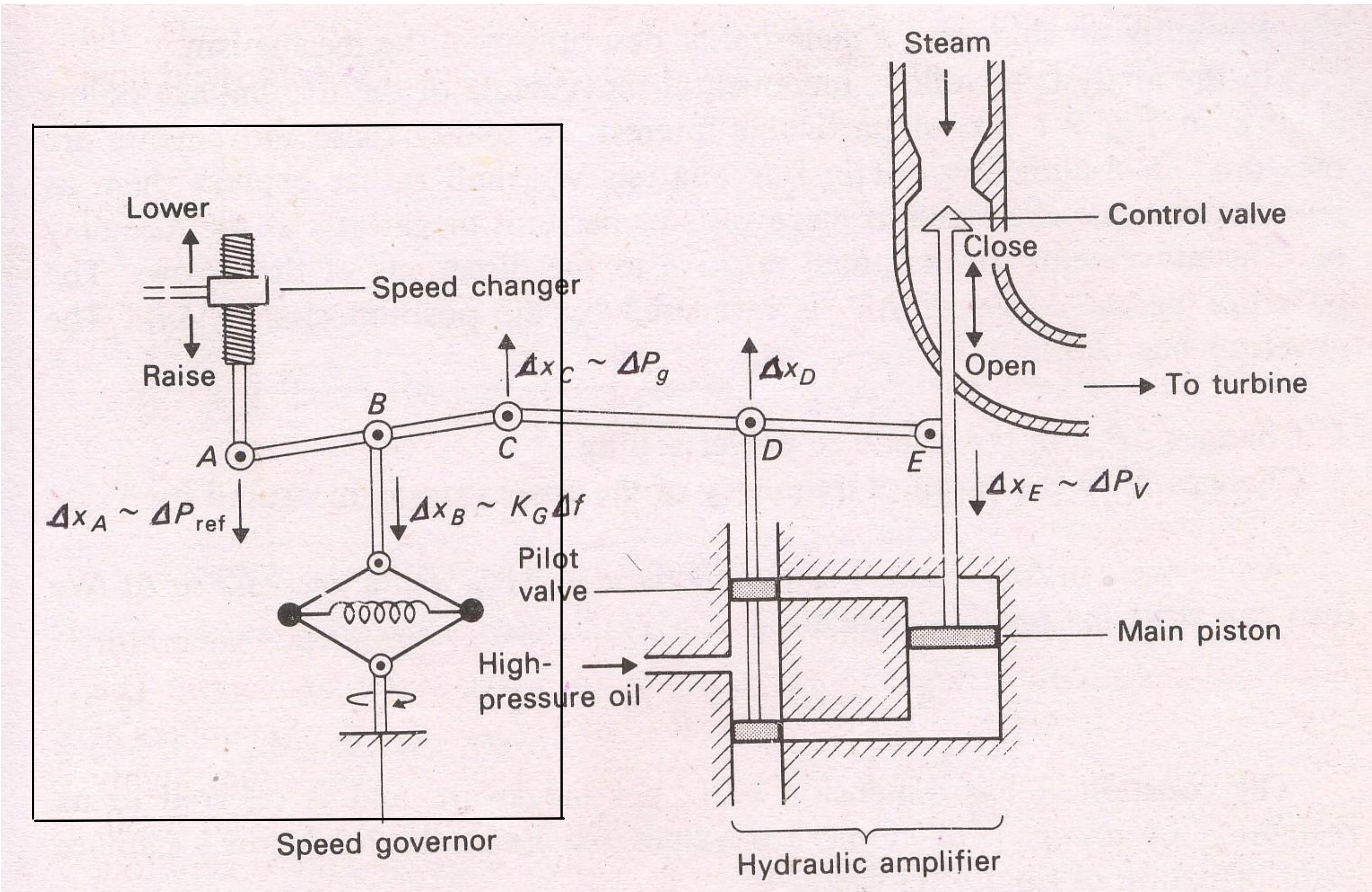
ii) To maintain the frequency constant.

iii) To maintain desired tie-line power.

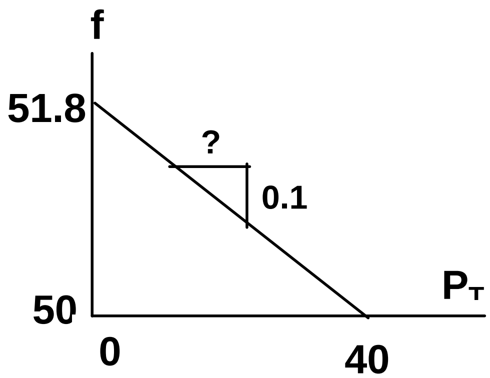
4. What do you understand by "Unit Commitment Problem"?

Generator units are to be switched on or off to match with the varying loads. The schedule of switching on and switching off the various generator units over a period, say one day, such that total cost of operation over the period is minimum subjected to certain constraints.

5. **Draw the schematic diagram of speed changer and speed governor and mark the linkages and linkage point movements.**



6. **The speed governing system of a 40 MW, 50 Hz generator, has 3.6% speed regulation. Find change in turbine power, if the frequency increases by 0.1 Hz**



$$\frac{\Delta P_{T0}}{0.1} = \frac{40}{2.5} \; ; \quad \Delta P_{T0} = 1.6 \text{ MW}$$

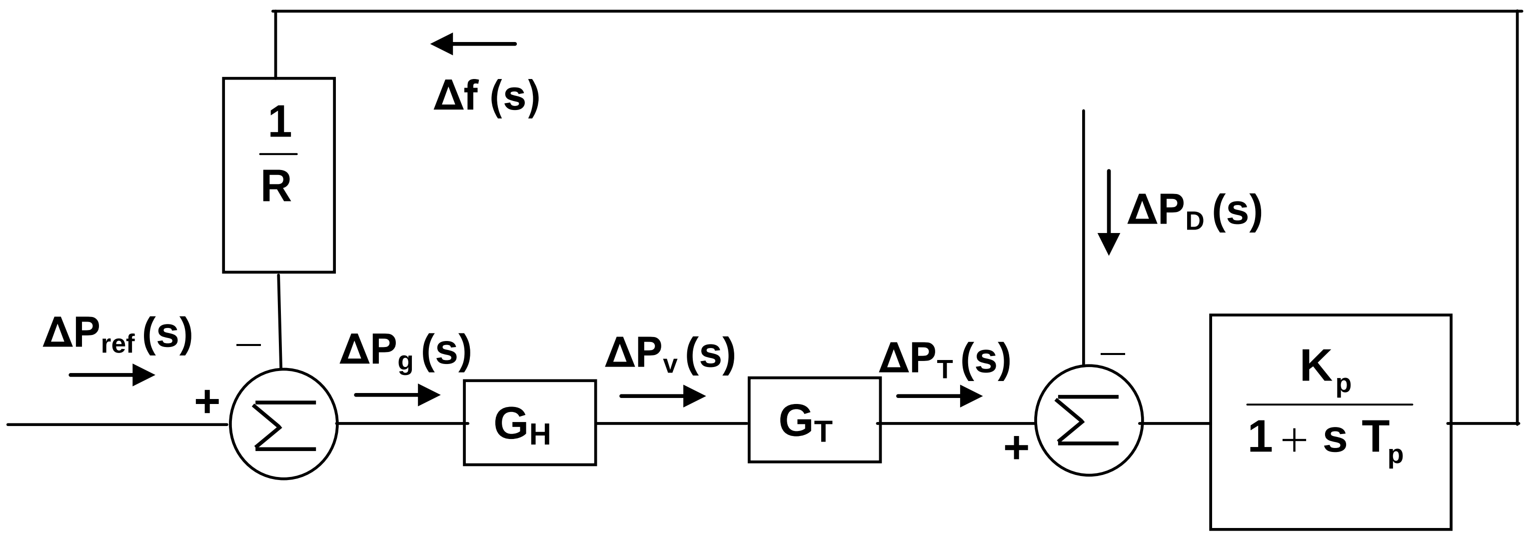
Decrease in P_{T0} = 1.6 MW

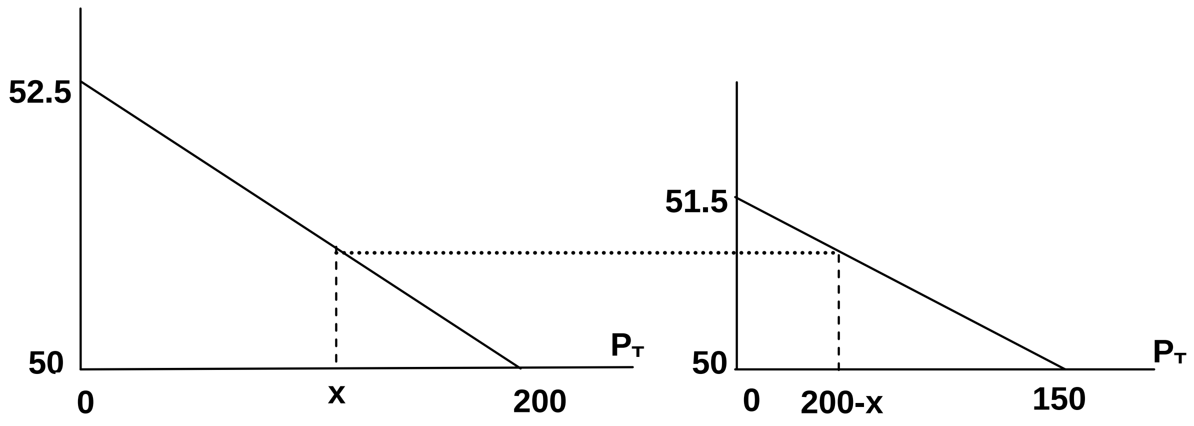
OR

$$\Delta P_{T0} = -\frac{1}{R}\Delta f_0 \qquad R = \frac{2.5}{40} = 0.0625 \text{ Hz / MW}; \quad \Delta f_0 = 0.1 \text{ Hz}$$

$$\Delta P_{T0} = -\frac{0.1}{0.0625} = -1.6 \text{ MW (decrease in turbine power)}$$

7. Draw the complete block diagram of uncontrolled single area ALFC loop.





Let load on Gen. 1 be x MW; Load on Gen. 2 = 240 – x;

Equating common fre. $52.5 - \frac{2.5}{200}x = 51.5 - \frac{1.5}{150}(240 - x)$;

On solving <u>P_{G1} = 151.11 MW</u> **;** <u>P_{G2} = 88.89 MW</u>

Operating frequency = $51.5 - \frac{2.5}{200}$ **X 151.11=** <u>**50.6111 Hz.**</u>

Corresponding to P_{G2}' **= 75 MW, frequency** $f' = 51.5 - \frac{1.5}{150}$ **X 75 = 50.75 Hz**

When f' = 50.75 Hz, with original characteristic, P_{G1}' **is obtained from**

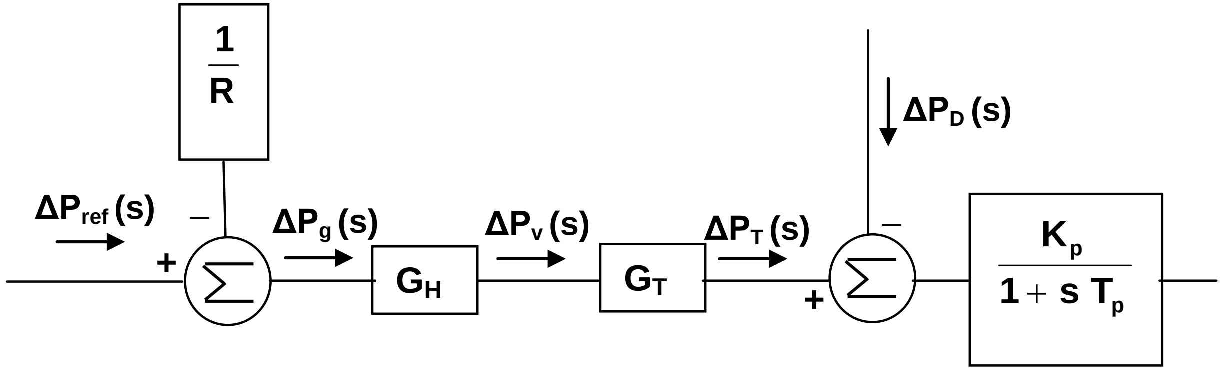
$52.5 - \frac{2.5}{200}P_{G1}' = 50.75$; **Thus** P_{G1}' **= 140 MW. However, to satisfy the total load of 240 MW,** P_{G1}' **must be 165 MW. This is achieved by giving** <u>**RAISE command of 25 MW.**</u>

1% of 50 Hz = 0.01 x 50 = 0.5 Hz;

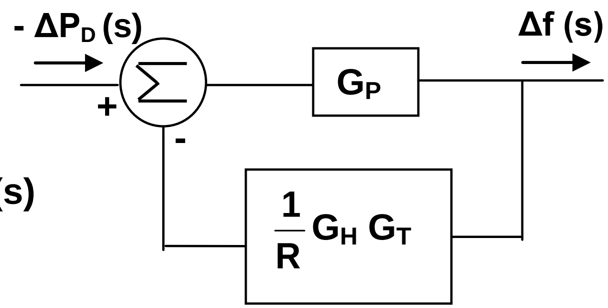
0.8% of 900 MW = 0.008 x 900 = 7.2 MW = 7.2 / 1400 = 0.005143 p.u. MW

$$D = \frac{0.005143}{0.5} = 0.01029 \text{ p.u. MW / Hz}; \quad K_p = \frac{1}{D} = \frac{1}{0.01029} = 97.18 \text{ Hz / p.u. MW}$$

$$T_p = \frac{2H}{f_0 D} = \frac{2 \times 4}{50 \times 0.01029} = 15.55 \text{ sec.}; \quad \text{Thus } G_p(s) = \frac{K_p}{1 + sT_p} = \frac{97.18}{1 + 15.55\, s}$$



This can be reduced as



$$\text{Thus } \Delta f(s) = -\frac{G_p}{1+\frac{1}{R}G_H\ G_T\ G_p}\ \Delta P_D(s)$$

Let $\Delta P_D = M$; Then $\Delta P_D(s) = \dfrac{M}{s}$ and hence

$$\Delta f(s) = -\frac{G_p}{1+\frac{1}{R}G_H\ G_T\ G_p}\ \frac{M}{s}$$

Using the final value theorem, the static frequency drop is

$$\lim_{s \to 0} s\,\Delta f(s)\,] = -\frac{K_p}{1+\frac{K_p}{R}}\ M = -\frac{M}{D+\frac{1}{R}}\ \text{Hz}$$

Fig. shows the configuration of EMS / SCADA system for a typical power system.

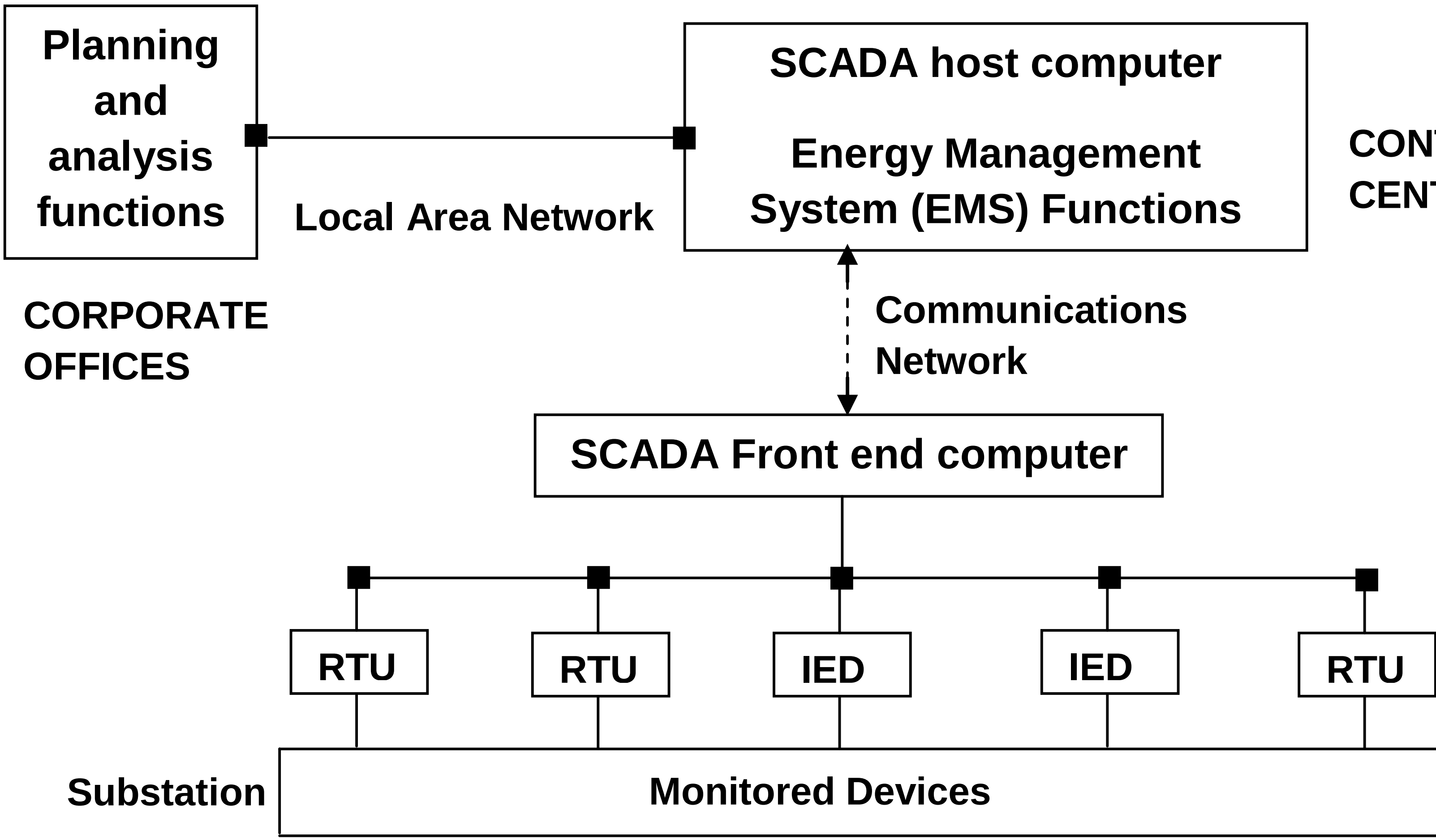


Fig. EMS / SCADA system configuration

In general case, changes may occur in both the speed changer setting and frequency in which case the relationship $\Delta P_{T\,0} = \Delta P_{ref\,0} - \dfrac{1}{R}\,\Delta f_{0}$ applies.

For a given speed changer setting, $\Delta P_{ref\,0} = 0$ and hence $\Delta f_0 = -R\,\Delta P_{T\,0}$. In a frequency-generation power graph, this represents a straight line with a slope = - R.

For a given frequency, $\Delta f_{0} = 0$ and hence $\Delta P_{T\,0} = \Delta P_{ref\,0}$. This means that for a given frequency, generation power can be increased or decreased by suitable raise or lower command.

Thus the relationship $\Delta P_{T\,0} = \Delta P_{ref\,0} - \dfrac{1}{R}\,\Delta f_{0}$ represents a family of lines with slope -R, each line corresponding to a specific speed changer setting.