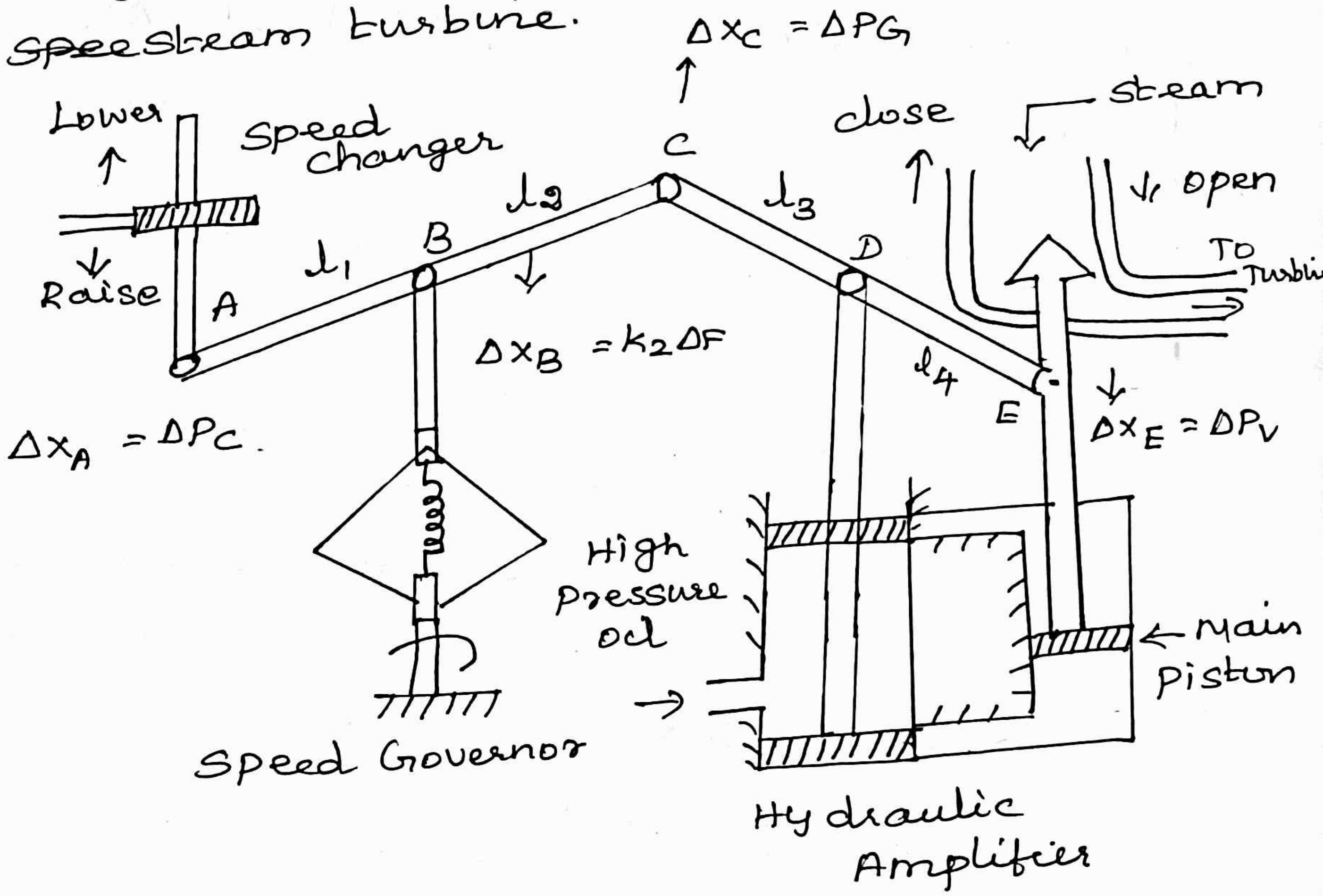
Basics of Speed Governing Mechanism &

Modelling :

* The speed Governor is the main primary tool for the load frequency control.

* Fig shows the speed Governing system of steam turbine.



Speed Governor :

It is purely mechanical speed-sensitive device coupled directly to the hydraulic amplifier which adjusts the control value opening via the linkage mechanism.

* As load increases, speed of turbine decreases & speed changer gives raise command. So fly ball move outwards &

Linkage Mechanism :

=) ABC is rigid link pivoted at B & CDE is another rigid line pivoted at D.

=) The function of link mechanism, is to control the steam valve or gate.

Speed changer :

-) Its downward movement opens the upper pilot valve.

=) High pressure oil enters upper opening of piston. This opens the main control valve.

-) More steam is admitted to the turbine.

Modelling of speed Governor :-

Let point A moves downwards by small amount Δx_A.

This comment causes the turbine output power to change,

$$\Delta x_A \propto \Delta P_C$$

ΔP_C -) Commanded increase in power.

$$\Delta x_A = k_C \Delta P_C \quad \text{—— (1)}$$

Movement of C due to movement of point A:

(i) $\Delta x_C <^{A}_{B}$ $\quad \Delta x_C \propto \Delta x_A$.

$$\Delta x_c = -k_1 \Delta x_A \quad \text{--- (2)}$$

Movement of c due to movement at point B

$$\Delta x_c \propto \Delta x_B$$

$$\Delta x_B \propto \Delta f .$$

$$\Delta x_c = k_2 \Delta f \quad \text{--- (3)}$$

from (2) + (3)

$$\Delta x_c = k_2 \Delta f - k_1 \Delta x_A$$

Sub eqn (1) in above eqn :

$$\Delta x_c = k_2 \Delta f - k_1 k_c \Delta P_c \quad \text{--- (3-a).}$$

Movement of Δx_D $\left(< \begin{matrix} C \\ E \end{matrix} \right)$

$$\Delta x_D \propto \Delta x_c$$

$$\Delta x_D \propto \Delta x_E \quad \text{--- (4)}$$

$$\Delta x_D = k_3 \Delta x_c + k_4 \Delta x_E$$

Movement of Δx_E

$$\Delta x_E \propto \Delta x_D$$

The volume of oil admitted to the cylinder is thus proportional to the line integral of Δx_D .

$$\Delta x_E = -k_5 \int \Delta x_D . dt \quad \text{--- (5)}$$

Eqn (4) + (5) & (6),

$$\left.\begin{aligned} \Delta x_c &= -k_1 k_c \Delta P_c + k_2 \Delta f \\ \Delta x_D &= k_3 \Delta x_c + k_4 \Delta x_E \\ \Delta x_E &= -k_5 \int \Delta x_D . dt \end{aligned}\right\} \quad \text{--- (7).}$$

Taking Laplace Transform,

$$\Delta x_c(s) = -k_1 k_c \Delta P_c(s) + k_2 \Delta F(s) \quad \text{—— (8).}$$

$$\Delta x_D(s) = k_3 \Delta x_c(s) + k_4 \Delta \alpha(s) \quad \text{—— (9).}$$

$$\Delta x_E(s) = \frac{-k_5}{s} \Delta x_D(s) \quad \text{—— (10).}$$

sub eqn (9) in (10):

$$\Delta x_E(s) = \frac{-k_5}{s} \left[k_3 \Delta x_c(s) + k_4 \Delta x_E(s) \right].$$

sub eqn (8) in above equation:

$$\Delta x_E(s) = \frac{-k_5}{s} \left[k_3 (-k_1 k_c \Delta P_c(s) + k_2 \Delta F(s)) \right.$$
$$\left. + k_4 \Delta x_E(s) \right).$$

$$\Delta x_E(s) + \frac{k_4 k_5 \Delta x_E(s)}{s} = \frac{k_1 k_3 k_5 k_c \Delta P_c(s)}{s}$$
$$\frac{-k_3 k_2 k_5 \Delta F(s)}{s}$$

$$\Delta x_E(s) \left[1 + \frac{k_4 k_5}{s} \right] = \frac{k_1 k_3 k_5 k_c \left[\Delta P_c(s) - \frac{k_2}{k_1 k_c} \Delta F(s) \right]}{s}.$$

$$\Delta x_E(s) \left[\frac{s + k_4 k_5}{\cancel{s}} \right] = \frac{k_1 k_3 k_5 k_c \left[\Delta P_c(s) - \frac{k_2}{k_1 k_c} \Delta F(s) \right]}{\cancel{s}}.$$

$$\Delta X_E(S) = \frac{K_1 K_3 K_5 K_C \left[\Delta P_C(S) - \frac{K_2}{K_1 K_C}\Delta F(S)\right]}{S + K_4 K_5}$$

$$= \frac{K_1 K_3 K_5 K_C \left[\Delta P_C(S) - \frac{K_2}{K_1 K_C}\Delta F(S)\right]}{K_4 K_5 \left[1 + \frac{S}{K_4 K_5}\right]}$$

sub $R = \frac{K_1 K_C}{K_2}$; speed regulation of Governor Hz/MW.

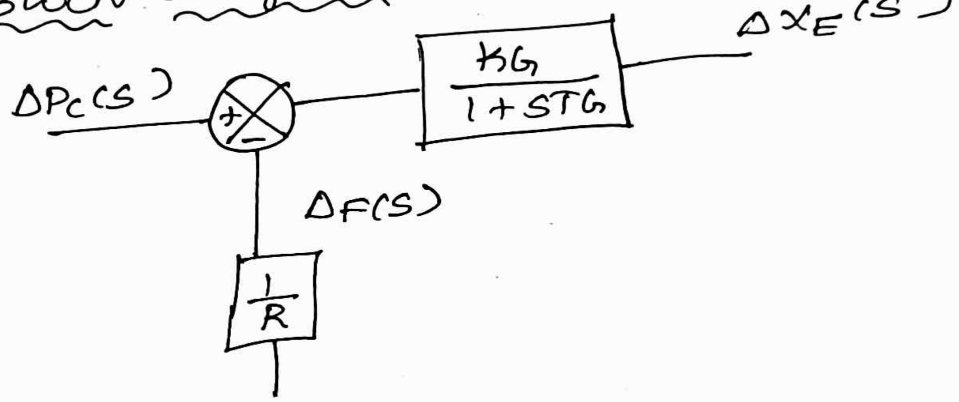
$K_G = \frac{K_1 K_3 K_C}{K_4}$; Gain of speed Governor.

$T_G = \frac{1}{K_4 K_5}$; Time constant of speed Governor.

$$\Delta X_E(S) = \frac{K_G \left[\Delta P_C(S) - \frac{1}{R}\Delta F(S)\right]}{1 + S T_G}$$

$$\Delta X_E(S) = \frac{K_G}{1 + S T_G}\left[\Delta P_C(S) - \frac{1}{R}\Delta F(S)\right]$$

Block diagram :



Turbine Model

The block diagram can be drawn directly :

$$\Delta X_E(s) \text{ or } \Delta P_V \longrightarrow \boxed{\dfrac{K_t}{1+sT_t}} \longrightarrow \Delta P_t(s)$$

$T_t \Rightarrow$ Time constant of Turbine

$K_t \Rightarrow$ Gain of turbine

$\Delta P_t \Rightarrow$ Turbine output

$\Delta X_E \Rightarrow$ Value position.

$\Delta P_V \Rightarrow$ Per unit change in value position from nominal value.

Generator-Load Model:

$\Delta P_G \rightarrow$ Generator power.

$\Delta P_D \rightarrow$ Load demand.

$\Delta P_G - \Delta P_D$ is accounted by,

(i) Rate of increase of stored kinetic energy in rotor or by increasing kinetic energy.

Initially, $f = f^0$

Stored kinetic energy,

$$W^0_{K.E} = HP_r \text{ (kW.sec)} \quad \text{—— (11).}$$

H : inertia constant.

P_r : turbo-generator rating (kW)

$(\frac{1}{2} mv^2)$

WKT,

$$W^0_{K.E} = \frac{J\omega_0^2}{2} \quad \text{—— (12).}$$

$$\omega_0 = 2\pi f_0 .$$

$$W^0_{K.E} = \frac{J(2\pi f)^2}{2}$$

$$W^0_{K.E} \propto f_0^2 \quad \text{—— (13).}$$

Then at $(f^0 + \Delta f)$

$$W_{K.E} \propto (f^0 + \Delta f)^2 \quad \text{—— (14).}$$

Eqn (14)/(13)

$$\frac{W_{K.E}}{W^0_{K.E}} = \frac{(f^0 + \Delta f)^2}{f_0^2}$$

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

$$= W^{0}_{K.E}\left(1+\frac{\Delta f}{f_0}\right)^2 \longrightarrow \text{(expand)}$$

$$= W^{0}_{K.E}\left(1+\frac{2\Delta f}{f_0}+\frac{\Delta f^2}{f_0^2}\right).$$

Neglecting higher orders,

$$W_{K.E} = W^{0}_{K.E}\left[1+\frac{2\Delta f}{f_0}\right].$$

differentiating above eqn., we get

$$\frac{d}{dt}(W_{K.E}) = 0 + \frac{2W^{0}_{K.E}}{f_0}\cdot\frac{d\Delta f}{dt}.$$

sub eqn (11) $W^{0}_{K.E} = HP_r$.

$$\frac{d}{dt}W_{K.E} = \frac{2HP_r}{f_0}\cdot\frac{d\Delta f}{dt} \quad\text{—— (15).}$$

(ii) As f changes from f_0 to Δf:

rate of change of load w.r.to f $= \frac{\partial P_D}{\partial f} = B$.

B : damping co-efficient (MW/Hz).

For small change in f is Δf.

$$\frac{\partial P_D}{\partial f}\cdot\Delta f = B.\Delta f \quad\text{—— (16).}$$

$\Delta P_G - \Delta P_D$ is accounted by eqn : (15) + (16)

$$\Delta P_G - \Delta P_D = \frac{2HP_r}{f_0}\frac{d\Delta f}{dt} + B\Delta f.$$

$\div P_r$ we get in (p.u) form,

$$\Delta P_{G(p.u)} - \Delta P_{D(p.u)} = \frac{2H}{f_0}\frac{d}{dt}(\Delta f) + B_{p.u}\Delta f.$$

Taking Laplace Transform,

$$\Delta P_G(s) - \Delta P_D(s) = \frac{2H(s)}{f_0} s\Delta F(s) + B\Delta F(s).$$

$$= \Delta F(s)\left[\frac{2H(s)}{f_0} + B\right].$$

$$\Delta F(s) = \frac{\Delta P_G(s) - \Delta P_D(s)}{\frac{2H(s)}{f_0} + B}$$

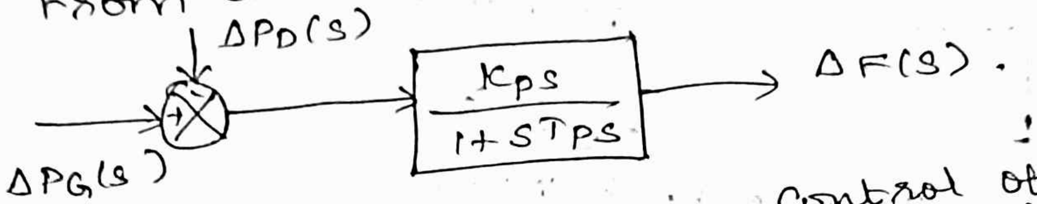
$$= \frac{\Delta P_G(s) - \Delta P_D(s)}{B\left[1 + \frac{2H(s)}{f_0 B}\right]}$$

Sub $\frac{1}{B} = K_{ps}$; Power system gain constant (Hz/MW)

$\frac{2H}{f_0 B} = T_{ps}$; Power system Time constant (s).

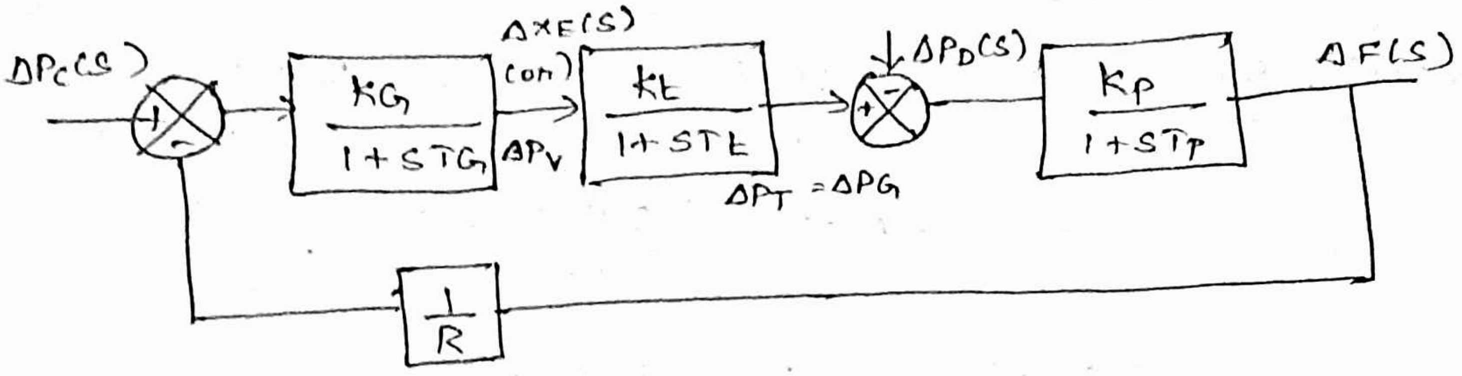
$$\Delta F(s) = \Delta P_G(s) - \Delta P_D(s)\left[\frac{K_{ps}}{1+sT_{ps}}\right] \quad -(17)$$

From above eqn draw the Block diagram



Model of Load frequency control of a single area system:

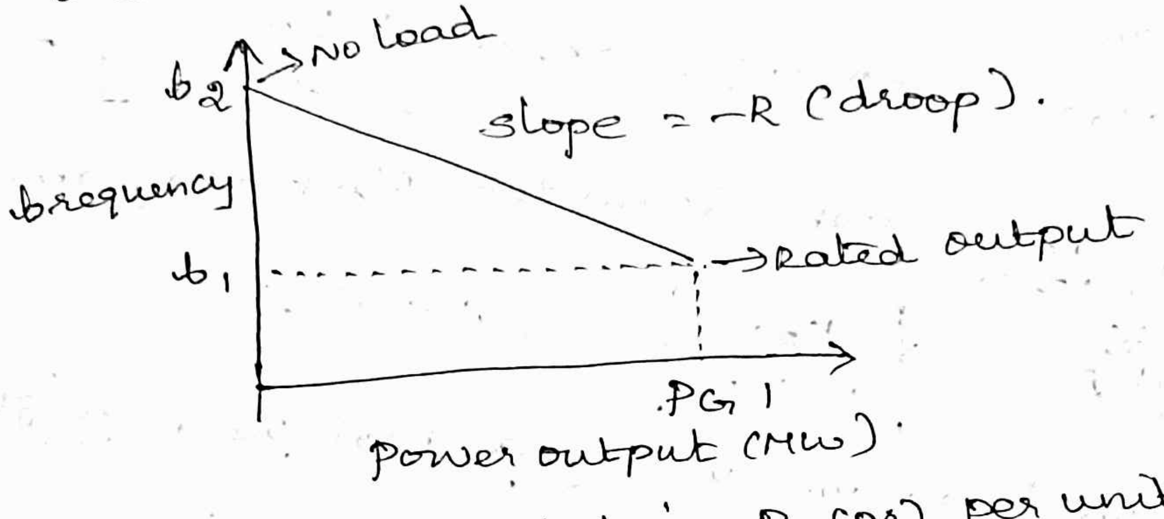
Combining the generator model, turbine model & Generator load model, we get the complete block diagram of LFC of isolated power system.



Speed-Load characteristics

Load sharing between two synchronous machines in parallel (or) Parallel operation of two alternators.

→ The speed (i.e frequency N ∝ f) Vs Power output characteristics of generating units are drawn like this:



The speed regulation R (or) per unit droop (slope) of the generating unit is defined as the magnitude of the change in steady state speed, expressed in p.u of rated speed, when the output of unit is gradually reduced from 1.0 pu rated power to zero.

$$R_{p.u} = \frac{(f_2 - f_1)/f_r}{P_{Gr}/P_r} \quad \text{--- (1)}.$$

$f_2 \rightarrow$ frequency at no load in Hz.

$f_1 \rightarrow$ frequency at rated megawatt output P_{Gr}.

$f_r \rightarrow$ Rated frequency (Base).

$P_r \rightarrow$ Megawatt Base.

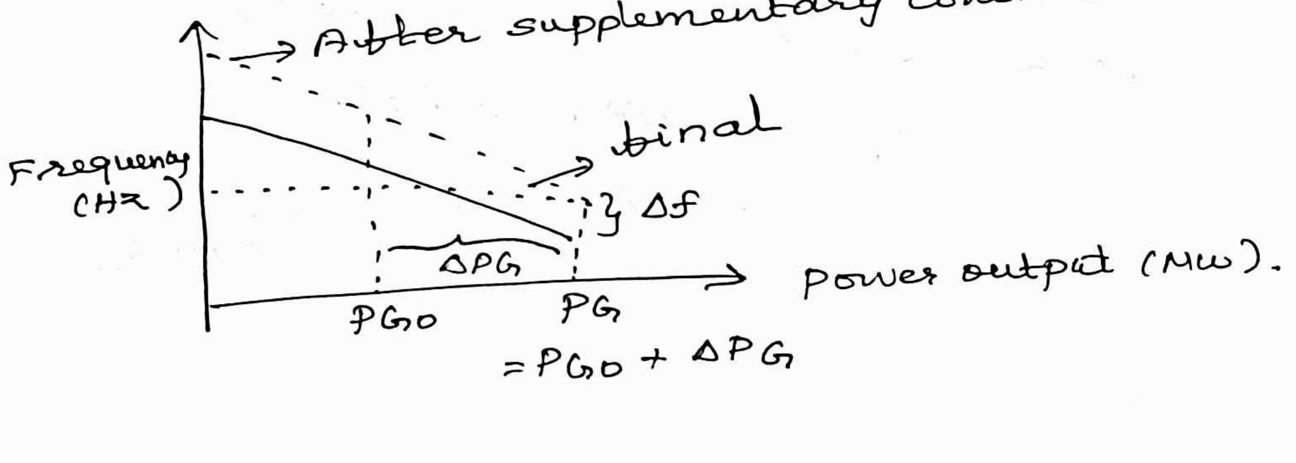
$\times$ly eqn (1) with $\frac{f_r}{P_r}$.

Regulation slope (R)
$$R_{p.u} = \frac{f_2 - f_1/f_r}{P_{Gr}/P_r} \times \frac{f_r}{P_r}.$$

$$= \frac{f_2 - f_1}{P_{Gr}} \; (\text{Hz}/\text{MW}) \quad \text{--- (2)}.$$

$$= R_{p.u} \times \frac{f_r}{P_r}.$$

Suppose the unit is supplying the output power P_{G0} at frequency f_0, when the load is increased to $P_G = P_{G0} + \Delta P_G$.



From fig,

$$\text{slope} = \frac{\Delta f}{\Delta P_G} = -R \quad \text{——— (3)}$$

$$\Delta f = -R \cdot \Delta P_G \quad \text{——— (4)}$$

$$\Delta f = -\left[R_{p.u} \cdot \frac{f_r}{P_r}\right] \Delta P_G \quad \text{——— (5)}$$

$$\Delta P_G = \frac{-\Delta f \cdot P_r}{R_{p.u} \cdot f_r} \; (MW) \quad \text{——— (6)}$$

Due to supplementary control action of speed changer, (or) set point change in speed governor, the regulation characteristics can be parallel shifted to final position.

→ The changes in outputs of units are given by, from (6) ⇒

$$\text{Unit 1, } \Delta P_{G1} = \frac{-P_{r1} \cdot \Delta f}{R_{p.u1} \cdot f_r} \; (MW) \quad \text{——— (7)}$$

$$\text{Unit 2, } \Delta P_{G2} = \frac{-P_{r2} \cdot \Delta f}{R_{p.u2} \cdot f_r} \; (MW) \quad \text{——— (8)}$$

Adding (7) + (8)

Total load change in output,

$$\Delta P = \Delta P_{G1} + \Delta P_{G2}.$$

$$= -\frac{\Delta f}{f_r}\left[\frac{P_{r1}}{R_{p.u1}} + \frac{P_{r2}}{R_{p.u2}}\right].$$

The system frequency change,

$$\frac{\Delta f}{f_r} = \frac{-\Delta P}{\left[\frac{P_{r1}}{R_{p.u1}} + \frac{P_{r2}}{R_{p.u2}}\right]}$$

$$\Delta f = \frac{-\Delta P . f_r}{\left[\frac{P_{r1}}{R_{p.u1}} + \frac{P_{r2}}{R_{p.u2}}\right]} = \frac{-\Delta P}{\frac{1}{f_r}\left[\frac{P_{r1}}{R_{p.u1}} + \frac{P_{r2}}{R_{p.u2}}\right]}$$

$$= \frac{-\Delta P}{\frac{P_{r1}}{f_r . R_{p.u1}} + \frac{P_{r2}}{f_r . R_{p.u2}}} \Rightarrow \frac{-\Delta P}{\frac{1}{R_1} + \frac{1}{R_2}}$$

$$\Delta f = \frac{-\Delta P}{\frac{1}{R_1} + \frac{1}{R_2}}$$

The co-ordinated control of the set points of the speed Governor is to bring all the units at desired frequency f_0, & to achieve any desired load division within the capabilities of the generating units.

<u>Parallel operation</u> :

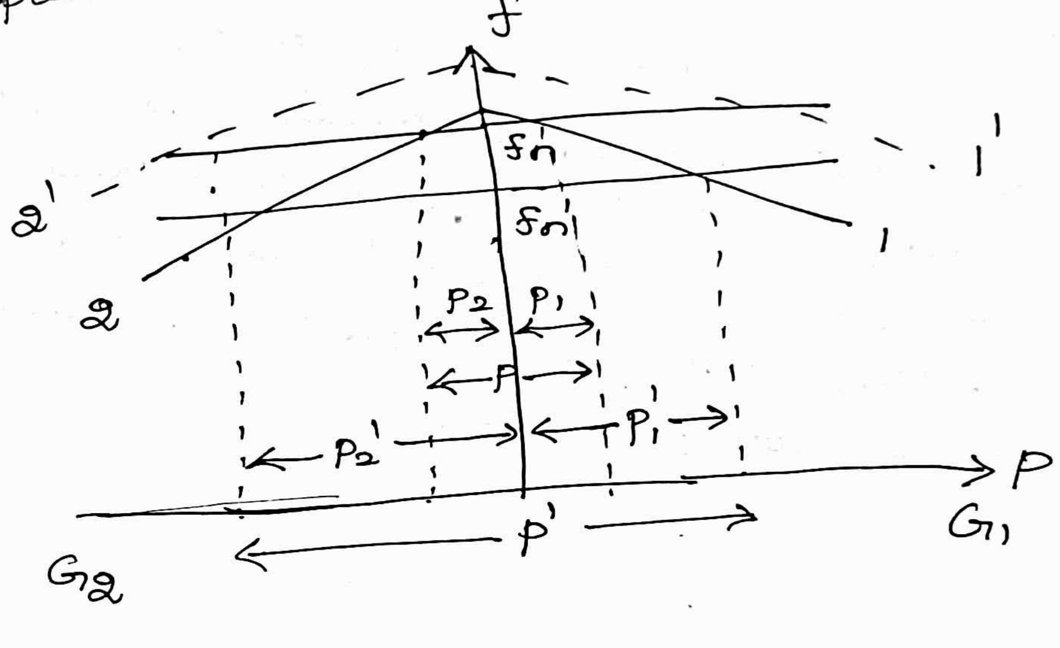
In a power system, the generators are connected to grids. A national level grid may comprise even hundreds of generators. Here we dealt with 2 generators (or) alternators in parallel.

→ The active power-sharing b/w paralled generator is dependent upon the droop of the frequency (ie) speed power characteristics.

→ 2 different controls are carried out on characteristics :

① Parameter R is adjusted during off-line condition to ensure the proper co-ordination with other units.

② The straight line characteristics is shifted parallel to itself, to change the load distribution, among the generators connected in parallel as well as to maintain the system frequency. This method is called supplementary control.



suppose initially the total load is P and it is so shared by ~~two~~ two units

$P = P_1 + P_2$ & frequency is f_n.

→ If load is increased to P', the frequency falls to f_n'. $P' = P_1' + P_2'$.

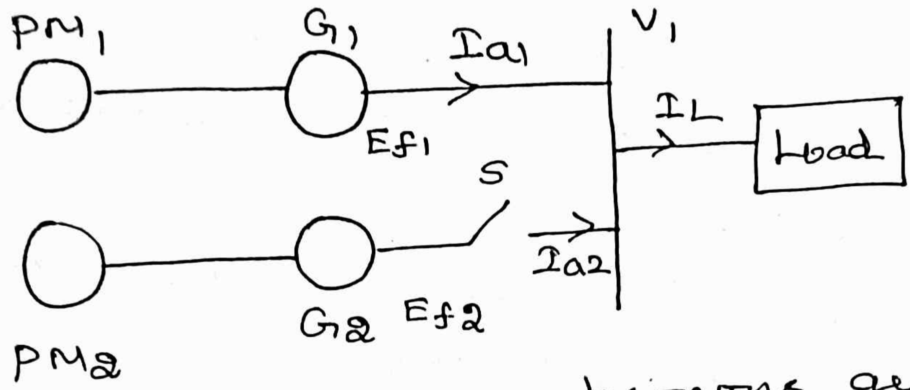


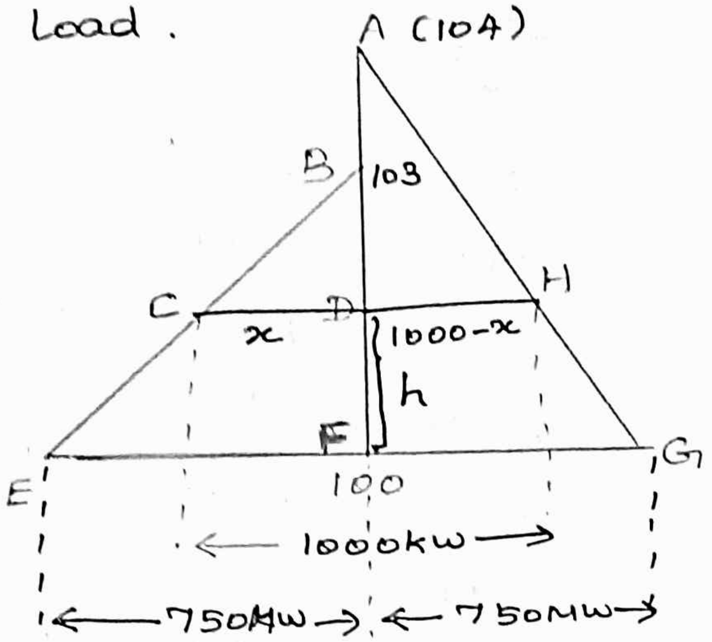
Fig shows two synchronons generators along with their prime movers to be operated in parallel.

→ Active and Reactive powers supplied to common load by each generator are controlled by their prime mover throttles.

→ For the Given load & equal sharing of real load, excitation of G_1 is increased & G_2 reduced simultaneously in such a manner to keep the terminal voltage unchanged.

But it is not possible.

1) Two 750 kW alternators operates in parallel. The speed regulation of 1 set is 100% to 103% from the full load to no load and that of other is 100% to 104%.. How will the two alternators share a load of 1000 kW and at what load will one machine cease to supply any portion of the load.



Total load = 1000kW

Unit I = 3% droop

Unit II = 4% droop.

Let x : power Generation of unit I

For similar triangle ΔBCD & ΔBEF

$$\frac{CD}{EF} = \frac{BD}{BF}$$

$$\frac{x}{750} = \frac{3-h}{3}$$

$$3x = 750(3-h).$$

$$3x = 2250 - 750h.$$

$$x = 750 - 250h \quad \text{——} \ (1)$$

From similar Triangle, ΔADH, ΔAFG,

$$\frac{DH}{FG} = \frac{AD}{AF}$$

$$\frac{1000-x}{750} = \frac{4-h}{4}$$

$$4(1000-x) = 750(4-h).$$

$$4000 - 4x = 3000 - 750h.$$

$$-4x = 3000 - 750h - 4000.$$

$$-4x = -1000 - 750h.$$

$$x = 250 + 187.5h \quad \text{——} \ (2).$$

Equating (1) & (2),

$$750 - 250h = 250 + 187.5h.$$

$$500 = 437.5h.$$

$$\boxed{h = 1.142}$$

Substitute $h = 1.142$ in eqn (1),

$$x = 750 - 250 \times 1.142$$

$$x = 464.28 \text{ kW}$$

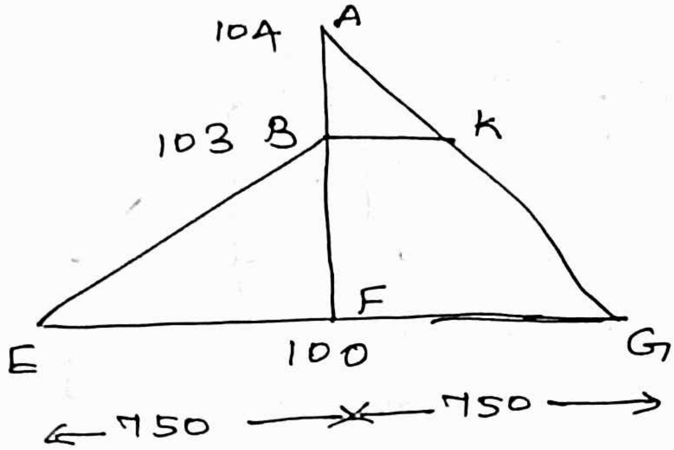
$$\therefore PG_1 = 464.28 \text{ kW}.$$

$$PG_2 = 1000 - 464.28 = 535.7 \text{ kW}.$$

Two alternators PG_1, PG_2, share 1000kw load as, $PG_1 = 464.28$ kw ; $PG_2 = 535.7$ kw.

② Machine 1 cease (stop) to supply any load when line $\overset{CD}{\cancel{DH}}$ is shifted to point 'B'.

At these point, machine 2 will supply load equal to BK.



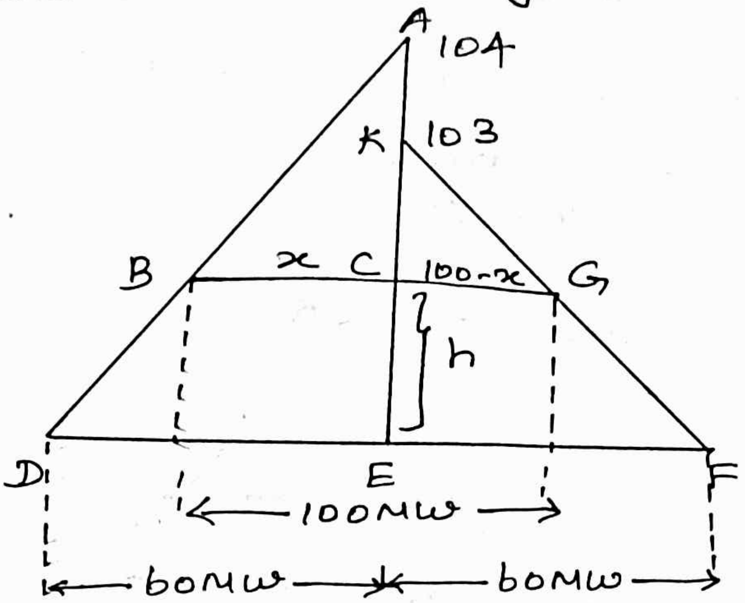
From ΔABK, ΔAFG,

$$\frac{BK}{FG} = \frac{AB}{AF}$$

$$\frac{BK}{750} = \frac{1}{4}$$

$$BK = 750 \times 1/4 = 187.5 \text{ kw.}$$

② Two identical 60 MW synchronous machine operate in parallel, the governor settings on the machine are such that they have 4% & 3% droops (no load to full load % speed drop). Determine a) Load taken by each machine for a total load of 100 MW b) The % no load speed to be made by the speeder motor if the machine are to share the load equally.



From similar ΔABC & ΔADE,

$$\frac{BC}{DE} = \frac{AC}{AE}$$

$$\frac{x}{60} = \frac{4-h}{4}$$

$$x = 60 - 15h \quad \text{---} (1).$$

From similar ΔKEF & ΔKCG.

$$\frac{CG}{EF} = \frac{KC}{KE}$$

$$\frac{100-x}{60} = \frac{3-h}{3}$$

$$x = 40 + 20h \quad \text{---} (2)$$

Equating (1) & (2)

$$60 - 15h = 40 + 20h.$$

$$\boxed{h = 0.5714}$$

sub h in ①

$$x = 60 - 15 \times 0.5714$$

$$= 51.42 \text{ MW}$$

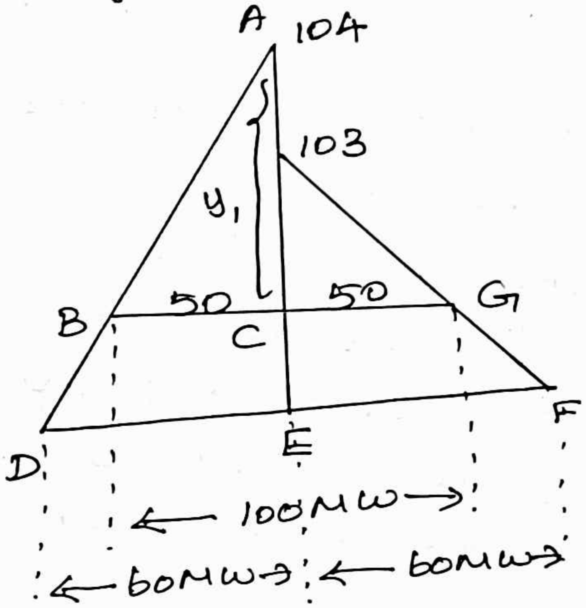
a) $P_{G1} = 51.42$ MW

$P_{G2} = 48.58$ MW $(100 - 51.42)$

b) If both machines share equally,

$$P_{G1} = P_{G2} = \frac{P_o}{2} = \frac{100}{2} = 50 \text{ MW}.$$

The diagram can be redrawn as,



From similar Triangle ΔABC + ΔADE

$$\frac{AC}{AE} = \frac{BC}{DE}$$

$$\frac{y_1}{4} = \frac{50}{60}$$

$$y_1 = 3.33.$$

From similar ΔHCG & ΔHEF;

$$\frac{HC}{HE} = \frac{CG}{EF}$$

$$\frac{3-y_2}{3} = \frac{50}{60}$$

$$3-y_2 = \frac{50}{60} \times 3$$

$$y_2 = 0.5.$$

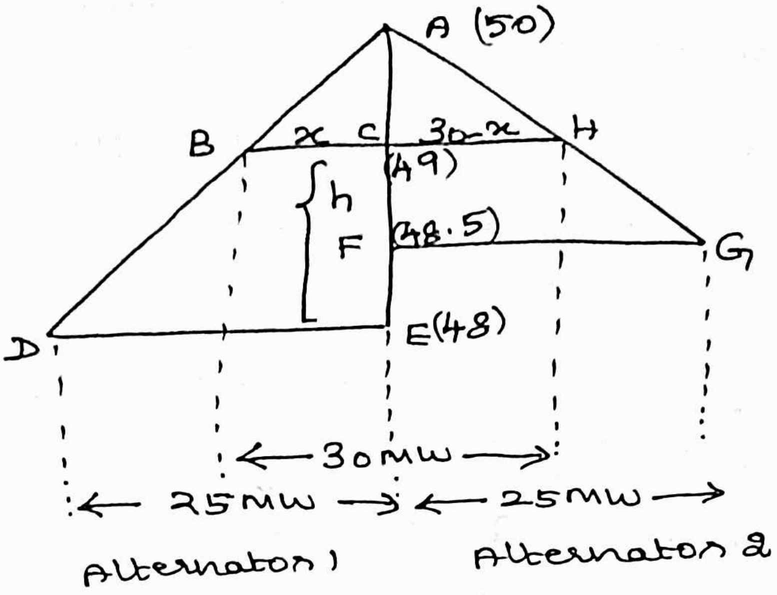
Speed of operation is $(100 + 0.5)\%$

$= 100.5\%$.

(3) Two turbo alternators are rated at 25 MW each. They are running in parallel. The speed load characteristics of the driving turbines are such that the frequency of alternator 1 drops uniformly from 50 Hz on no load to 48 Hz on full load, and that of alternator 2 from 50 Hz to 48.5 Hz.

a) How will the two machines share a load of 30 MW and find the bus-bar frequency at this load?

b) compute the maximum load that these units can deliver without overloading either of them:



Similar $\triangle ABC$ & $\triangle ADE$

$$\frac{BC}{DE} = \frac{AC}{AE}$$

$$\frac{x}{25} = \frac{2-h}{2}$$

$$x = 25 - 12.5h \quad \text{—— (1)}$$

Similar $\triangle ACH$ & $\triangle AFG$,

$$\frac{AC}{AF} = \frac{CH}{FG}$$

$$\frac{AF - FC}{AF} = \frac{30-x}{25}$$

$$\frac{1.5 - (h - 0.5)}{1.5} = \frac{30-x}{25}$$

$$25(1.5 - h + 0.5) = 1.5(30 - x).$$

$$37.5 - 25h + 12.5 = 45 - 1.5x.$$

$$50 - 25h = 45 - 1.5x.$$

$$1.5x = -50 + 45 + 25h.$$

$$x = -3.33 + 16.67h \quad \text{—— (2).}$$

Equating (1) & (2),

$$25 - 12.5h = -3.33 + 16.67h.$$

$$h = 0.971$$

Sub $h = 0.971$ in (1)

$$x = 25 - 12.5 \times 0.971$$

$$\boxed{x = 12.85\,MW}$$

$PG_1 = 12.85\,MW$

$PG_2 = 17.15\,MW \quad \therefore (30 - 12.85)$

System frequency $f = 48 + h.$

$= 48 + 0.971$

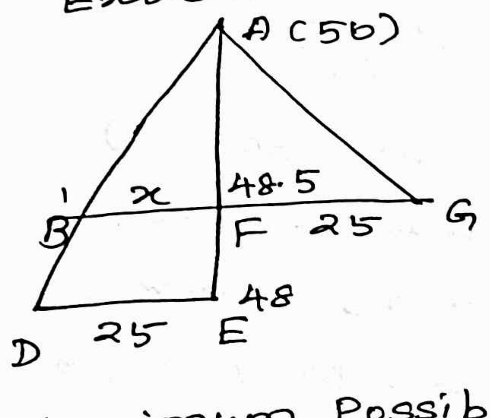
$= 48.971\,Hz.$

b) compute the maximum load that these two units can deliver without overloading either of them,

→ full load will come on alternator 2 first

full load $= 25\,MW$ at $f = 48.5\,Hz.$

Extend BC to B'F.



From similar △ AB'F & △ ADE

$$\frac{B'F}{DE} = \frac{AF}{AE}$$

$$B'F = \frac{1.5 \times 25}{2}$$

$B'F = 18.75\,MW.$

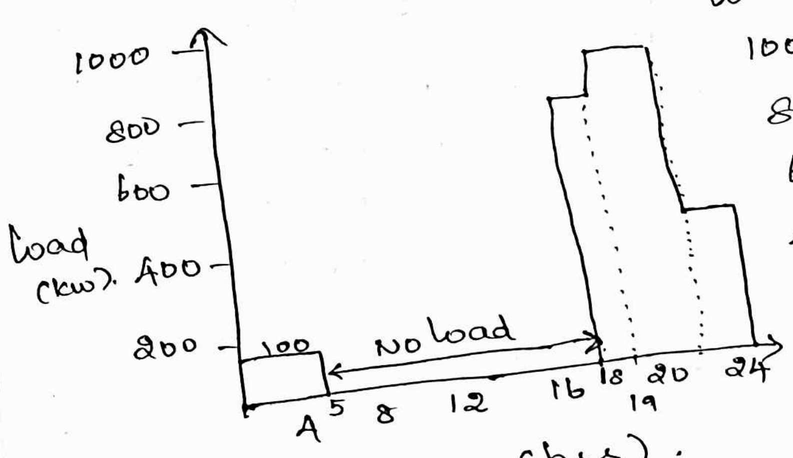
Maximum Possible load $= 25 + 18.75$

$= 43.75\,MW.$

(1) A generation station of 1MW supplied a region which has the following demands :

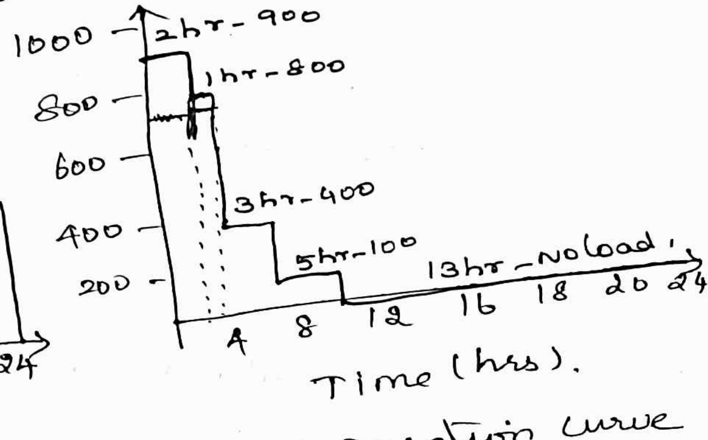
From	To	Demand (kw)
Midnight	5 am	100
5 am	6 pm	No load
6 pm	7 pm	800
7 pm	9 pm	900
9 pm	midnight	400.

Neglect Transmission line losses and find the following : i) Plot the daily load curve and the load duration curve ii) Find the load factor, reserve capacity, plant capacity factor, plant use factor, the hours that the plant has been off and utilization factor.



Time (hrs).

Load curve



Time (hrs).

Load Duration curve

$$\text{Load Factor} = \frac{\text{Average load}}{\text{Maximum demand}}$$

$$\text{Average load} = \frac{\text{unit generated / day}}{24 \text{ hr}}$$

$$= \frac{900 \times 2 + 800 \times 1 + 400 \times 3 + 100 \times 5 + 0 \times 13}{24}$$

$$= \frac{4300}{24} = 179.1 \text{ kw.}$$

$$\text{Load factor} = \frac{179.1}{900} = 0.19.$$

$$\text{Reserve capacity} = \text{Plant capacity} - \text{Maximum demand}$$

$$= 1000 - 900 = 100 \text{ kw.}$$

$$\text{Plant capacity factor} = \frac{\text{Average load}}{\text{Plant capacity}} = \frac{179.1}{1000}$$

$$= 0.179.$$

$$\text{Plant use factor} = \frac{\text{Energy generated / day}}{\text{Maximum Energy Generated}}$$

$$= \frac{4300}{900 \times 2} = 2.388.$$

The hrs that the plant has been off is 13 hrs.

$$\text{utilization factor} = \frac{\text{Maximum Demand}}{\text{plant capacity}}$$

$$= \frac{900}{1000} = 0.9.$$

$$\text{utilization Factor} = 0.9.$$

(2) The maximum load on a thermal power plant of 60 MW capacities is 50 MW at an annual load factor of 50 %. The loads having maximum demands of 25 MW, 20 MW, 8 MW, 5 MW are connected to the power station. Determine

i) Average load on power station.

ii) Energy generated per year.

iii) Demand factor.

iv) Diversity factor.

Diversity factor = $\dfrac{\text{sum of individual maximum demand}}{\text{actual maximum demand of the group.}}$

$$= \frac{25+20+8+5}{50}$$

$$= \frac{58}{50}$$

Diversity factor = 1.16.

Average load. = maximum demand x load factor.

= 50 x 0.5

= 25 MW.

Energy generated per year = Average load x 24 x 365.

= 25 x 24 x 365

= 219000 MWh.

$$\text{Demand factor} = \frac{\text{Annual peak load of the system}}{\text{Sum of the Individual maximum demand}}$$

$$= \frac{50}{25+20+8+5}$$

$$= \frac{50}{58}$$

Demand factor. $= 0.862$.

daily energy consumption $= 113.75 \times 24.$

$= 2,730$ MWh.

over all load factor $= \dfrac{\text{Average demand}}{\text{Maximum Demand}}$

$= \dfrac{113.75}{60}$

$= 1.895.$

Demand factor $= \dfrac{\text{Maximum Demand}}{\text{connected load}}$

connected load $= \dfrac{\text{Maximum Demand}}{\text{Demand factor}}$

$= \dfrac{60}{0.70 + 0.90 + 0.98}.$

$= \dfrac{60 MW}{2.58}.$

$= 23.25$ MW.

① The following loads are connected to a power plant :

Type of load	Max. Demand (MW)	Load ~~Diversity~~ factor	Demand factor.
Domestic	15	1.25	0.70
commercial	25	1.20	0.90
industrial	50	1.30	0.98.

overall diversity factor is 1.5, determine the

i) Maximum load.

ii) Daily energy consumption.

iii) overall load factor.

iv) connected load of each type.

$$\text{Diversity factor} = \frac{\text{sum of individual Maximum Demand}}{\text{actual maximum Demand of the group}}.$$

$$1.5 = \frac{15 + 25 + 50}{\text{Maximum Demand}}.$$

$$1.5 = \frac{90}{\text{Maximum Demand}}.$$

$$\text{Maximum demand} = \frac{90}{1.5} = 60 \text{ MW}.$$

$$\text{Load factor} = \frac{\text{Average demand}}{\text{maximum demand}}.$$

$$\text{Average demand} = \text{Load factor} \times \text{Maximum demand}.$$

$$= 15 \times 1.25 + 25 \times 1.20 + 50 \times 1.30.$$

$$= 18.75 + 30 + 65 = 113.75 \text{ MW}.$$

Economics of generation

1) **Load curve:**

The curve showing the variation of load on the power station with respect to time is known as Load curve.

Load on the power system is not constant. It varies from time to time.

Types of Load curve:

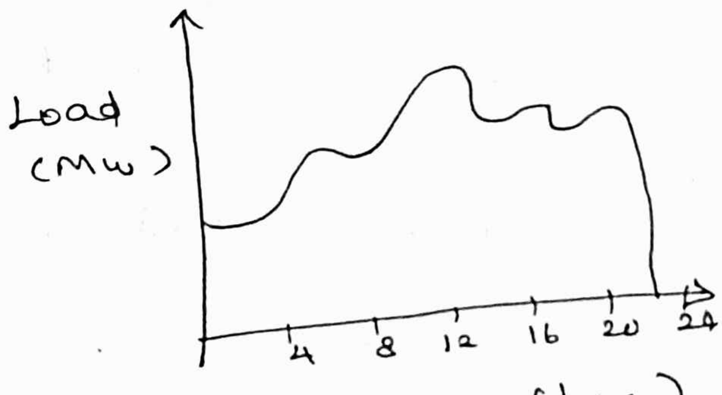
a) Daily load curve

b) Monthly load curve

c) Yearly (or) Annual load curve.

a) **Daily load curve:**

The curve showing the variation of load on a whole day (or) 24 hours with respect to time is called as daily load curve.



b) **Monthly load curve:**

The curve showing the variation of load for a month (or) 30 x 24 hrs with respect to time is called monthly load curve.

(c) Yearly Load curve (OR) Annual load curve:

The curve showing the variation of load for a year (OR) 365 x 24 hrs with respect to time is called yearly load curve.

Load curve gives the following information:

(i) The area under the curve represents the total number of units generated in a day.

(ii) The peak of the curve represents the maximum demand on the station.

(iii) The area under the load curve divided by the number of hours, gives the average load on the power system

(iv) The ratio of average load to the maximum demand gives the load factor.

(2) Load Duration curve:

The loads are arranged in descending order of magnitudes with respect to time is called load duration curve.

Greater load on the left and lesser load on the right.

Important terms for deciding the type and Rating of Generating plant :

(i) connected Load :

The sum of the continuous rating of all the electrical equipment connected to the supply system is known as connected load.

(ii) Maximum Demand :-

The greatest demand occure on the power system for a short interval of time is called maximum demand.

(iii) Demand factor :

The ratio of actual maximum demand on the system to the total rated load connected to the system.

Always less than Unity.

$$\text{Demand factor} = \frac{\text{Maximum Demand}}{\text{connected Load}}$$

(iv) Average Load :

The average loads (or) demands on the power station is the average of loads occuring at various events.

$$\text{Daily average load} = \frac{\text{No. of units generated in day (kwhr)}}{24 \text{ (No of hrs in a day)}}$$

Monthly average load $= \dfrac{\text{No. of units generated in a month}}{30 \times 24 \text{ (No of hrs in a month)}}$

Annual average load $= \dfrac{\text{No of units generated in a year}}{365 \times 24 \text{ (No of hrs in a year)}}$

v) Load Factor :

The ratio of average load to the Maximum demand during a certain period of time.

$$\text{Load factor} = \frac{\text{Average Load}}{\text{Maximum Load}}$$

If the plant is operated for 'T' hours,

$$\text{Load factor} = \frac{\text{Average load} \times T}{\text{Maximum} \times T}$$

$T = 24$ for daily load curve

$T = 24 \times 7$ for weekly load curve.

$T = 24 \times 365$ for Annual load curve.

vi) Diversity Factor :

The ratio of sum of the Individual maximum demands of all the consumers to the maximum demand of the power station is called the Diversity factor.

$$\text{Diversity factor} = \frac{\text{Sum of Individual Maximum demand}}{\text{Maximum demand of power station.}}$$

It is always greater than unity.

If diversity factor is more, the cost of generation of power is low.

vii) Coincidence Factor:

The reciprocal of diversity factor is called coincidence factor.

viii) capacity factor (OR) plant factor:

It is the ratio of the average load to the rated capacity of the power plant.

$$\text{Capacity factor} = \frac{\text{Average demand}}{\text{Rated capacity of power plant.}}$$

$$= \frac{\text{Units (or) kwhr generated}}{\text{plant capacity} \times \text{Number of hours.}}$$

ix) utilisation factor:

It is the ratio of Maximum demand to the rated capacity of the power plant.

$$\text{utilisation factor} = \frac{\text{Maximum demand on the power station}}{\text{Rated capacity of the power station.}}$$

x) Plant operating factor (or) plant use Factor:

It is defined as the ratio of the actual energy generated during a given period to the product of capacity of plant and number of hours the plant has been actually operated during the period.

$$\text{Plant use factor} = \frac{\text{Total kwhr Generated}}{\text{Rated capacity of the plant} \times \text{No of operating hours}}$$

xi) Reserve Capacity:

It is the difference between the plant capacity and Maximum demand.

Reserve capacity = Plant capacity − Maximum Demand.

P- F Control loop :-

This control loop circuit is divided into primary and secondary Automatic Load Frequency control (ALFC) loop.

Primary ALFC :

→ The circuit primarily controls the steam value leading to the turbine. A speed sensor senses the speed of the turbine. This is compared with a reference speed, Governor whose main activity is to control the speed of the steam by closing and opening of the control value. Differential speed is low, the control value is opened to let out the steam at high speed, thereby increasing turbine's speed & vice versa.

Secondary ALFC :

→ This circuit involves a frequency sensor that senses the frequency of the bus bar and compare it with the Tie line Power frequencies in the signal mixer.

→ The output of this is an Area Control Error (ACE) which is sent to the speed changer through Integrator.

→ Integral controller is used to reduce the steady state frequency change to zero. using the relation, speed $N = \frac{120f}{P}$.

$f \rightarrow$ Frequency (Hz).

$P \rightarrow$ No. of. poles.

Basic P-F and Q-V control loops :-

1) Static changes in ΔP_i in the real bus power affect the bus phase angle, and not the bus voltage magnitudes.

2) Static changes ΔQ_i in the reactive power affect the bus voltage magnitudes and the phase angle.

3) Static changes in the reactive bus power affects the bus voltage at the particular bus.

Q-V Control loop :-

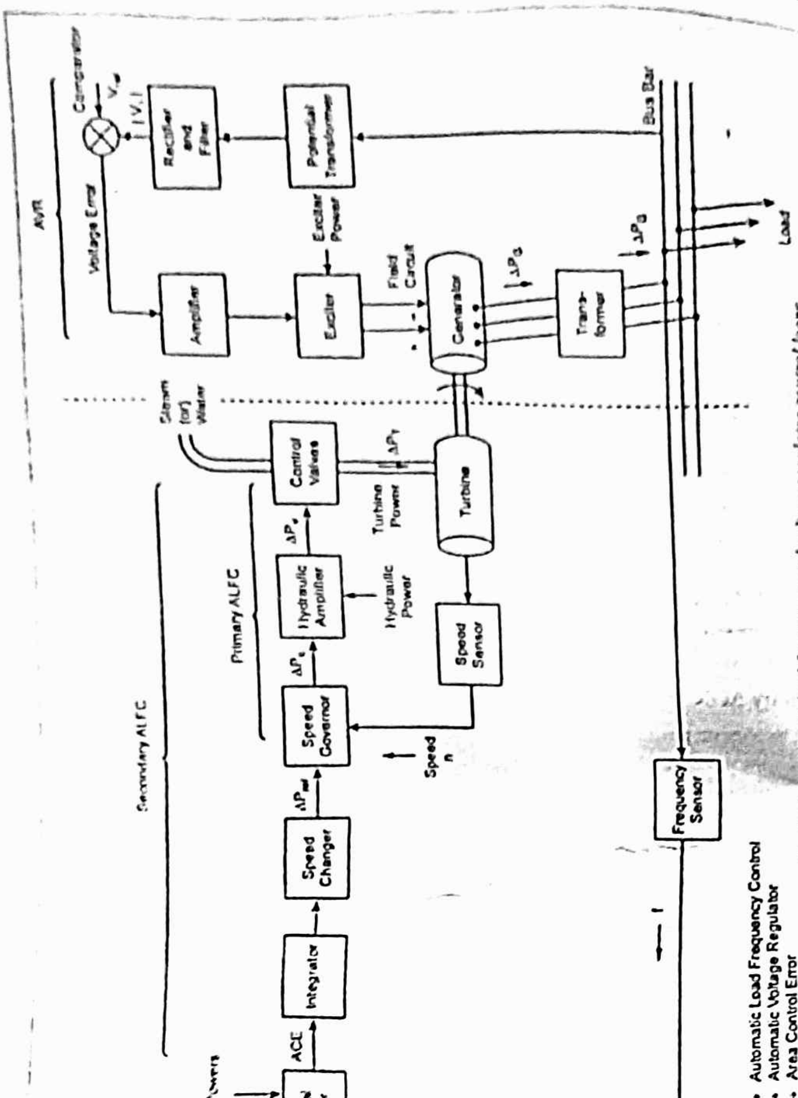
→ This loop is used for voltage control. This bus-bar voltage (say, 11 kV) is stepped down using a potential Transformer to a small value of voltage.

→ This is sent to the rectifier circuit which converts the AC voltage into DC voltage and a filter circuit used in this removes the harmonics.

→ The voltage V_i, compared with a reference voltage V_{ref} in the comparator and a voltage error signal is generated.

→ The amplified form of this voltage gives a condition for the exciter to increase or decrease the field current based on its polarity.

→ The output of the generator is stepped up using a Transformer and fed to the bus bar.



ALFC → Automatic Load Frequency Control
AVR → Automatic Voltage Regulator
ACE → Area Control Error

Fig. 1.15. Automatic load frequency and voltage regulator control loops

Load Frequency Control : Single Area Power System :

Concept of control Area :

→ A control area is defined as a system to which a common generation control scheme is applied.

→ All Generators swing in synchronised to single frequency.

→ A large interconnected power system is divided into no. of control areas.

→ Static Analysis.

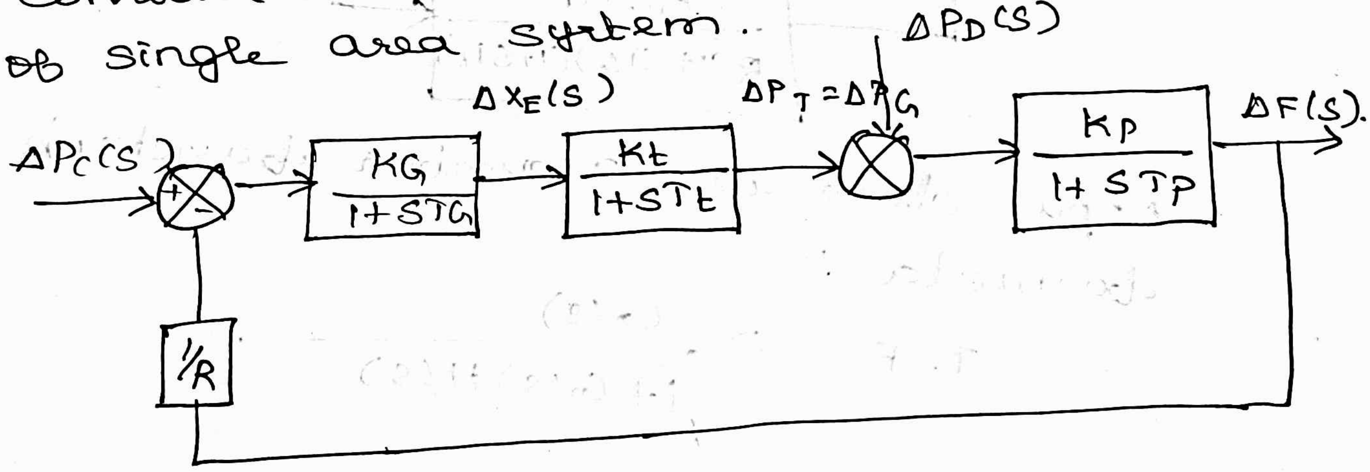
→ Dynamic Analysis.

Steady state (or) static Response of single Area system :

→ uncontrolled case.

→ controlled case.

Consider the (Model) Block diagram of LFC of single area system.

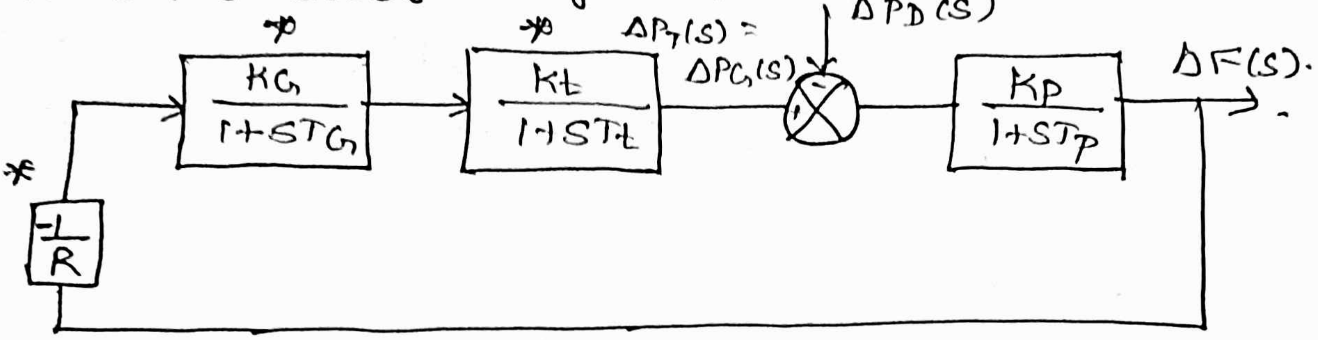


case (i) Uncontrolled case :

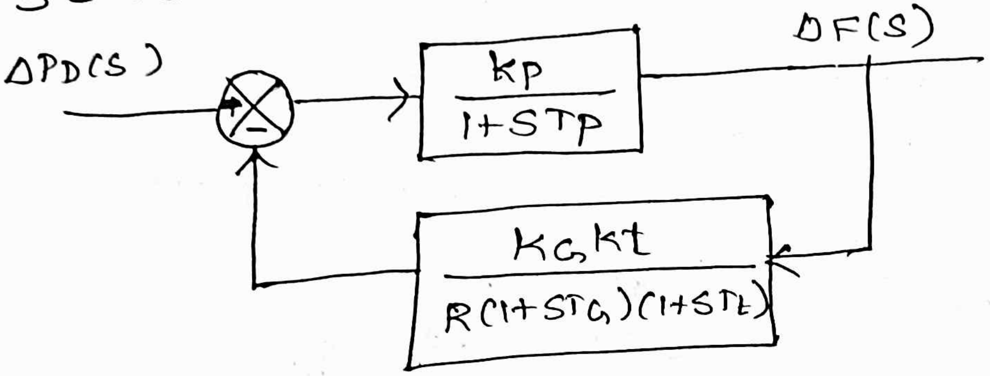
For steady state, consider that the speed changer has fixed setting. (called free Governor operation).

$\Delta P_C(s) = 0$. $\Delta P_C \rightarrow$ incremental control i/p.

Now the Block diagram becomes.



using Block diagram reduction Techniques:
3 blocks in series, so multiply Them.



Apply close loop transfer function formula :

$$T.F = \frac{G(s)}{1+G(s)H(s)}.$$

$$\frac{\Delta F(S)}{-\Delta P_D(S)} = \frac{\dfrac{K_P}{1+ST_P}}{1+\left(\dfrac{K_P}{1+ST_P}\right)\left(\dfrac{K_G K_t}{R\,(1+ST_G)(1+ST_t)}\right)}.$$

Take $(1+ST_P)$ term in the denominator alone for LCM.

$$= \frac{\dfrac{K_P}{1+\cancel{ST_P}}}{\dfrac{1+ST_P + K_P K_G K_t}{(1+\cancel{ST_P})\,(1+ST_G)(1+ST_t)R}}.$$

$$\frac{\Delta F(s)}{-\Delta P_D(s)} = \frac{K_P}{1+ST_P + \dfrac{K_P K_G K_t}{(1+ST_G)(1+ST_t)R}}$$

For step load change $\Delta P_D(s) = \frac{\Delta P_D}{S}$.

$$\Delta F(S) = \frac{K_P}{1+ST_P + \dfrac{K_P K_G K_t}{(1+ST_G)(1+ST_t)R}} \left[-\frac{\Delta P_D}{S}\right].$$

Apply final value Theorem.

$$\Delta f_{stat} = \underset{S\to 0}{Lt}\; S\,\Delta F(S).$$

$$= \underset{s \to 0}{Lt} \; \cancel{s} \left[\frac{-k_p \cdot \Delta P_D}{\cancel{s} \left[1 + sT_p + \frac{k_p k_G k_t}{(1+sT_G)(1+sT_t) R} \right]} \right]$$

$$\Delta f_{stat} = \frac{-k_p \cdot \Delta P_D}{1 + \frac{k_p k_G k_t}{R}}$$

Practically $k_G k_t = 1$.

$$\Delta f_{stat} = \frac{-k_p}{1 + \frac{k_p}{R}} \cdot \Delta P_D \, .$$

where $B = \frac{\partial P_D}{\partial f}$ $= MW/Hz.$

sub $\frac{1}{k_p} = B$ (or) $k_p = 1/B$.

$$\Delta f_{stat} = \frac{-1 \cdot \Delta P_D}{B \left(1 + \frac{1}{BR}\right)}$$

$$\Delta f_{stat} = \frac{-\Delta P_D}{B + 1/R} \quad \text{--- (1)} .$$

Assume $B << 1/R$.

$$\Delta f_{stat} = \frac{-\Delta P_D}{1/R} \quad \text{--- (2)}$$

$$\boxed{-R = \frac{\Delta f_{stat}}{\Delta P_D}} \quad (Hz/MW).$$

$R \rightarrow$ speed regulation defined as the ratio of change in steady state speed to increase in load.

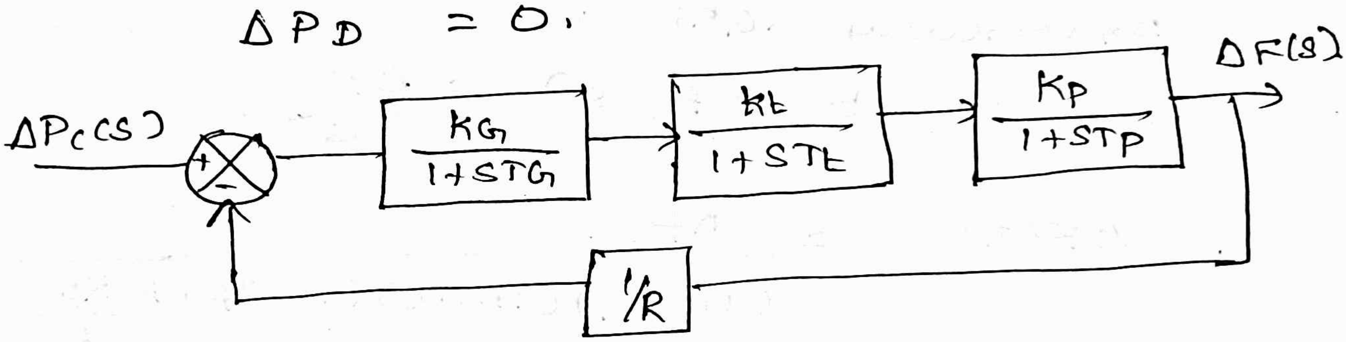
→ when many Generators with Governor speed regulations $R_1, R_2 \dots R_n$ are connected to the system, then steady state deviation in frequency is given by,

$$\boxed{\Delta f_{stat} = \frac{-\Delta P_D}{B + \frac{1}{R_1} + \frac{1}{R_2} + \dots \frac{1}{R_n}}}$$

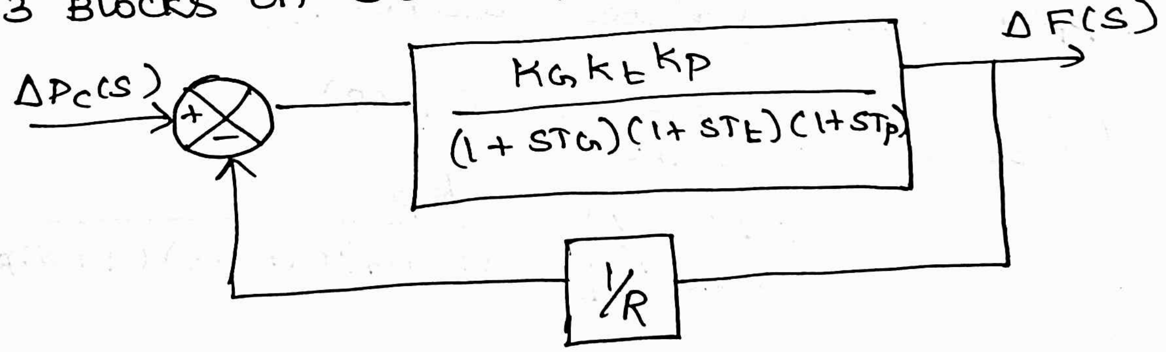
case (ii) Controlled case :-

There is a control in speed changer setting but here the load demand ΔP_D remains fixed.

$\Delta P_D = 0.$



3 Blocks in series,



Apply closed loop T.f $= \dfrac{G(s)}{1+G(s)H(s)}$.

$$\frac{\Delta F(s)}{\Delta P_c(s)} = \frac{\dfrac{K_G K_t K_p}{(1+sT_G)(1+sT_t)(1+sT_p)}}{1 + \dfrac{K_G K_t K_p}{(1+sT_G)(1+sT_t)(1+sT_p)} \times \frac{1}{R}}$$

$$= \frac{\dfrac{K_G K_t K_p}{(1+sT_G)(1+s\cancel{T_t})(1+sT_p)}}{\dfrac{(1+sT_G)(1+sT_t)(1+sT_p) + (K_G K_t K_p)/R}{(1+sT_G)(1+s\cancel{T_t})(1+sT_p) \times \cancel{R}}}$$

$$\frac{\Delta F(s)}{\Delta P_c(s)} = \frac{K_G K_t K_p}{(1+sT_G)(1+sT_t)(1+sT_p) + \dfrac{K_G K_t K_p}{R}}$$

Practically $K_G K_t = 1$.

Step input, $\Delta P_c(s) = \dfrac{\Delta P_c}{s}$.

$$\Delta F(s) = \frac{K_p}{(1+sT_G)(1+sT_t)(1+sT_p) + \dfrac{K_p}{R}} \times \frac{\Delta P_c}{s}.$$

Apply final value Theorem,

$$\Delta f_{stat} = \underset{s\to 0}{Lt}\; s\,\Delta F(s).$$

$$= \underset{s\to 0}{Lt}\; \cancel{s}\left[\frac{K_p}{(1+sT_G)(1+sT_t)(1+sT_p) + \dfrac{K_p}{R}}\right]\frac{\Delta P_c}{\cancel{s}}$$

$$\Delta f_{stat} = \frac{k_p}{1 + \frac{k_p}{R}} \times \Delta P_c .$$

$$\Delta f_{stat} = \frac{k_p}{1 + \frac{k_p}{R}} \cdot \Delta P_c .$$

sub $k_p = 1/B$.

$$= \frac{\frac{1}{B}}{1 + 1/BR} \Delta P_c .$$

$$\Delta f_{stat} = \frac{1}{B + 1/R} \Delta P_c .$$

$$\frac{\Delta f_{stat}}{\Delta P_c} = \frac{1}{B + 1/R} \quad (Hz/MW).$$

Dynamic Analysis :-

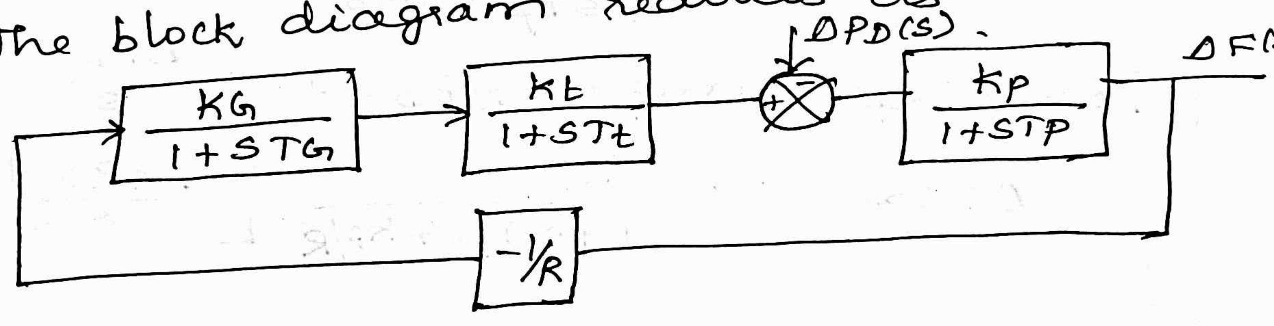
(i) Uncontrolled

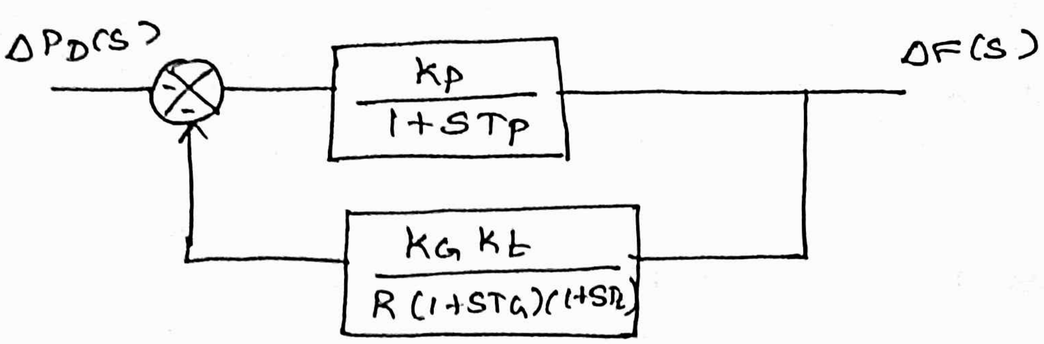
(ii) Controlled.

case(i) Uncontrolled :

For uncontrolled case $\Delta P_c(s) = 0$.

The block diagram reduces as shown below:





$$\Delta F(S) = \frac{\dfrac{K_P}{1+ST_P}}{1 + \dfrac{K_P}{1+ST_P} \times \dfrac{K_G K_t}{R(1+ST_G)(1+ST_t)}} \times -\Delta P_D(S).$$

Approximately $T_G = T_t = 0$. $\qquad T_P = 20S$.

$K_G K_t = 1$. $\qquad T_G = 0.4S$.

$T_t = 0.5S$.

$$\Delta F(S) = \frac{\dfrac{K_P}{1+ST_P}}{1 + \dfrac{K_P}{1+ST_P} \times \dfrac{1}{R}} [-\Delta P_D(S)].$$

$$= \frac{\dfrac{K_P}{1+\cancel{ST_P}}}{\dfrac{1+ST_P + K_P/R}{1+\cancel{ST_P}}} [-\Delta P_D(S)].$$

$$= \frac{K_P}{1+ST_P+K_P/R} [-\Delta P_D(S)].$$

For step change $\Delta P_D(S) = \dfrac{\Delta P_D}{S}$

$$\Delta F(S) = \frac{K_P}{1+ST_P+K_P/R}\left[-\frac{\Delta P_D}{S}\right].$$

Take Tp as common,

$$= \frac{kp(-\Delta PD)}{Tp \cdot s\left[\frac{1}{Tp} + s + \frac{kp}{RTp}\right]}$$

$$= \frac{kp(-\Delta PD)}{Tp \cdot s\left[s + \frac{1}{Tp} + \frac{kp}{RTp}\right]}$$

$$= \frac{-\Delta PD \cdot kp}{Tp \cdot s\left[s + \frac{R+kp}{RTp}\right]}$$

Applying Partial fraction Method,

$$\frac{1}{s\left[s + \frac{R+kp}{RTp}\right]} = \frac{A}{s} + \frac{B}{s + \frac{R+kp}{RTp}} \quad \text{--- (1)}$$

$$1 = A\left[s + \frac{R+kp}{RTp}\right] + Bs.$$

$$As + A\left(\frac{R+kp}{RTp}\right) + Bs = 1. \quad \text{--- (1)}$$

comparing co-efficients of 's'

$$A + B = 0.$$

$$\boxed{A = -B.} \quad \text{--- (2)}$$

sub (2) in (1)

$$-\cancel{Bs} + (-B)\left(\frac{R+kp}{RTp}\right) + \cancel{Bs} = 1.$$

$$\boxed{B = -\left(\frac{RTp}{R+kp}\right)}$$

$$A = -B.$$

$$= -\left[-\frac{RT_p}{R+k_p}\right].$$

$$\boxed{A = \frac{RT_p}{R+k_p}}$$

Sub A & B in (i).

$$\frac{1}{s\left(s+\frac{R+k_p}{RT_p}\right)} = \frac{RT_p/R+k_p}{s} + \frac{(-RT_p/R+k_p)}{s+\frac{R+k_p}{RT_p}}.$$

$$\Delta F(s) = -\frac{\Delta P_D\, k_p}{T_p}\left\{\left[\frac{RT_p}{R+k_p}\left[\frac{1}{s} - \frac{1}{s+\frac{R+k_p}{RT_p}}\right]\right]\right\}.$$

Taking inverse Laplace Transform,

$$\Delta f(t) = L^{-1}[\Delta F(s)].$$

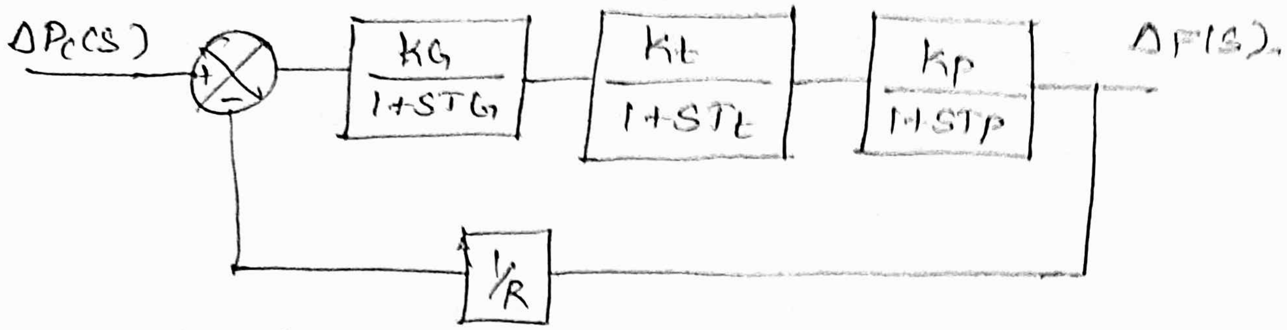
$$\Delta f(t) = -\frac{\Delta P_D\, k_p R}{R+k_p}\left[1-e^{-\left(\frac{R+k_p}{RT_p}\right)t}\right].$$

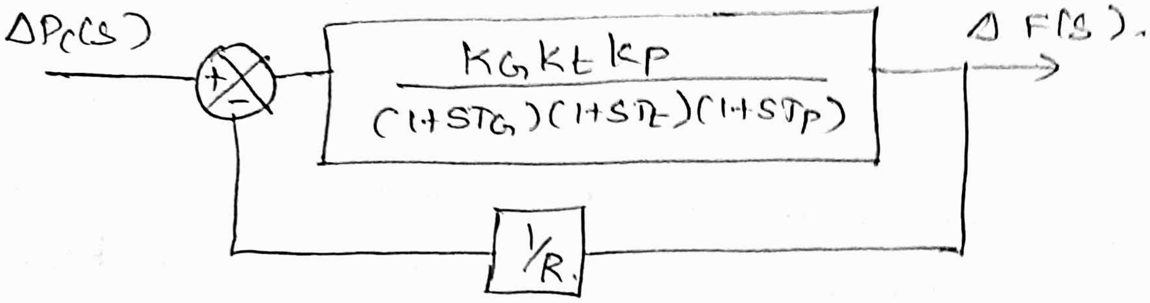
$$\Delta f(t) = -M\cdot\frac{R k_p}{R+k_p}\left[1-e^{-\left(\frac{R+k_p}{RT_p}\right)t}\right].$$

(ii) Controlled case :-

$$\Delta P_D(s) = 0.$$

Block diagram reduces as,





Here $K_G, K_t = 1.$

$T_G, T_t = 0.$

$$\frac{\Delta F(s)}{\Delta P_c(s)} = \frac{\dfrac{K_p}{1+ST_p}}{1+\left(\dfrac{K_p}{1+ST_p}\right)\times 1/R}$$

$$= \frac{\dfrac{K_p}{\cancel{1+ST_p}}}{\dfrac{1+ST_p+K_p/R}{\cancel{1+ST_p}}}.$$

$$\Delta F(s) = \frac{K_p}{1+ST_p+\frac{K_p}{R}} \cdot \Delta P_c(s).$$

For step change, $\Delta P_c(s) = \dfrac{\Delta P_c}{s}.$

$$\Delta F(s) = \frac{K_p}{1+ST_p+\frac{K_p}{R}}\left[\frac{\Delta P_c}{s}\right].$$

Take T_p outside,

$$= \frac{\Delta P_c K_p}{T_p \cdot s \left[\frac{1}{T_p} + s + \frac{k_p}{R \cdot T_p} \right]}$$

From uncontrolled case,

$$\Delta f(t) = \frac{\Delta P_c k_p R}{R + k_p} \left(1 - e^{-\left(\frac{R + k_p}{R T_p}\right)t} \right).$$

→ The meaning of dynamic response is how the frequency changes as a function of time immediately after disturbance before it reaches the new steady state condition.

→ The inverse Laplace Transform of $\Delta F(s)$ gives the variation of frequency with respect to time for a given step change in load demand.

→ Reduce 3^{rd} order to I^{st} order s/m.

→ Assumption $T_g < T_t < T_p$.

Typical values are

$T_g = 0.4\ s$

$T_t = 0.5\ s$

$T_p = 20\ s.$

Load frequency control of a single area system with integral controller:

The purpose of the integral controller (IC) is to actuate the load reference point until the frequency deviation becomes zero.

Static Response of uncontrolled case:-

→ The steady load frequency characteristics has considerable droop from No_load to full load.

→ The speed changes setting be adjusted automatically by monitoring the frequency changes.

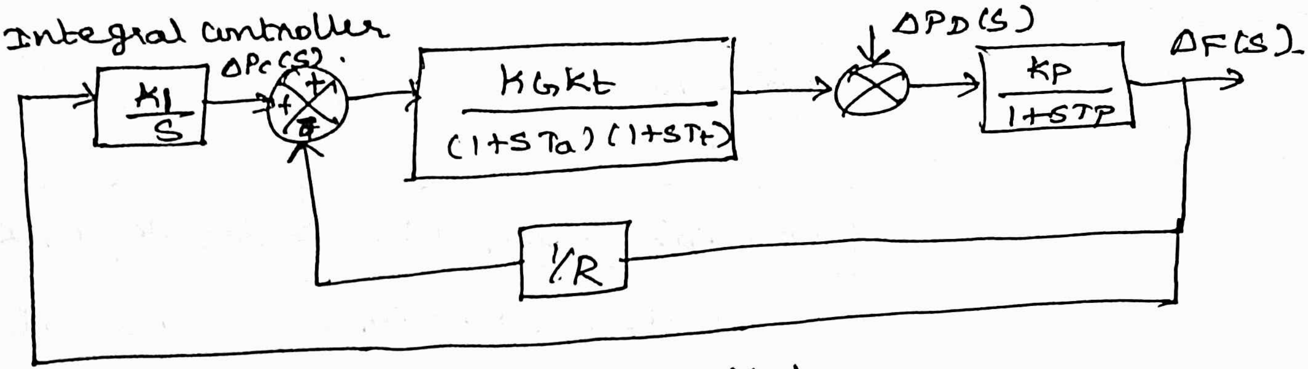
→ A signal from Δf is fed through an integrator to the speed changer.

→ proportional plus Integral controller gives zero steady state error.

Assume that $\Delta P_c = 0$.

→ In Load frequency control (LFC). the change in frequency is known as area control error (ACE).

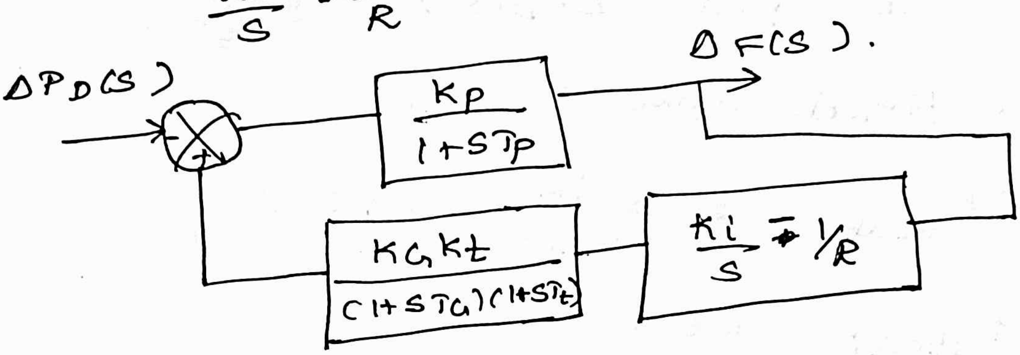
Integral controller



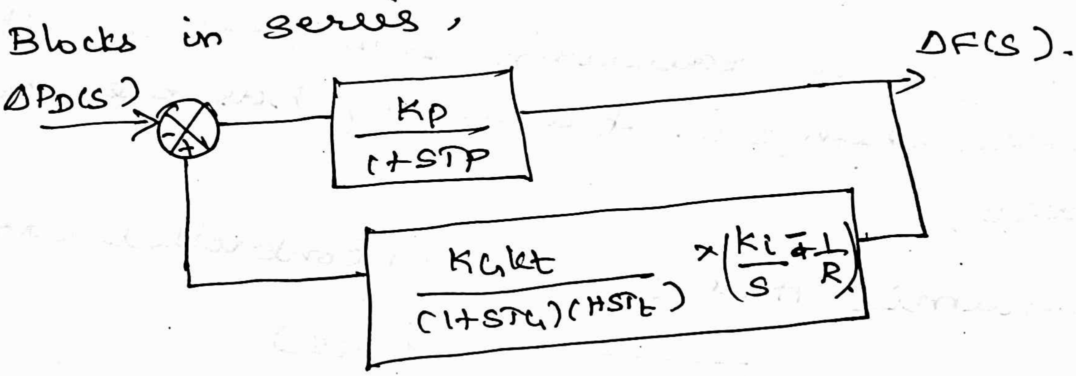
$\frac{K_i}{S}$ $\mp$ $\frac{1}{R}$ are in parallel.

By Block reduction Techniques

$\frac{K_i}{S} \mp \frac{1}{R}$



Blocks in series,



closed loop,

$$\Delta F(S) = \frac{\frac{K_p}{1+sT_p} \times -\Delta P_D(S)}{1 + \frac{K_p}{(1+sT_p)} \times \frac{K_G K_t \times RK_i \mp S}{(1+sT_G)(1+sT_t)\,SR}}.$$

$K_G K_t = 1,$

$$\Delta F(s) = \frac{\dfrac{-k_p \, \Delta P_D(s)}{(1+sT_p)}}{\dfrac{(1+sT_p)(1+sT_G)(1+sT_t)sR + k_p(Rk_i+s)}{(1+sT_p)(1+sT_G)(1+sT_t)sR}}$$

$$= \frac{-k_p \Delta P_D(s)(1+sT_G)(1+sT_t)sR \, \Delta P_D(s)}{(1+sT_p)(1+sT_G)(1+sT_t)sR + k_p(Rk_i+s)}$$

For step input, $\Delta P_D(s) = \frac{\Delta P_D}{s}$.

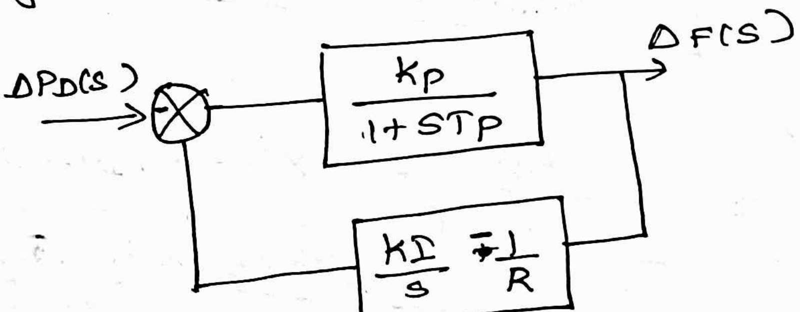
Apply final value theorem,

$$\Delta f_{static} = \lim_{s \to 0} s \, \Delta F(s).$$

$$\Delta f_{static} = 0.$$

The above equation says that the steady state change in frequency has been reduced to zero,

Dynamic Analysis of uncontrolled case:



Assume $k_g k_t = 1$, $T_g = T_t = 0$. The above block diagram is obtained.

For a step change $\Delta P_D(S) = \frac{\Delta P_D}{S}$.

$$\Delta F(S) = \frac{-K_P}{(1+ST_P) + K_P\left(\frac{K_I}{S} + \frac{1}{R}\right)} \times \frac{\Delta P_D}{S}.$$

$$= \frac{-K_P \cdot R \cdot \Delta P_D}{T_P \cdot R S^2 + S(R+K_P) + K_P K_I \cdot R}.$$

$$\Delta F(S) = \frac{-K_P \cdot \Delta P_D \cdot R}{T_P \cdot R\left[S^2 + S\left(\frac{R+K_P}{RT_P}\right) + \frac{K_P K_I}{T_P}\right]}$$

For calculating the poles,

$$S^2 + S\left(\frac{R+K_P}{RT_P}\right) + \frac{K_P K_I}{T_P} = 0.$$

$$S = \frac{-\frac{R+K_P}{RT_P} \pm \sqrt{\left(\frac{R+K_P}{RT_P}\right)^2 - 4\frac{K_P K_I}{T_P}}}{2}$$

The two roots are equal for a critical case and calculate K_I critical.

$$\left(\frac{R+K_P}{T_P R}\right)^2 - 4\frac{K_P K_I}{T_P} = 0.$$

$$\frac{4 K_P K_{I\,critical}}{T_P} = \left(\frac{R+K_P}{T_P R}\right)^2.$$

$$K_{I\,critical} = \frac{(R+K_P)^2}{4 K_P T_P R^2}$$

$$= \frac{R^2 + 2K_pR + K_p^2}{4K_pT_pR^2}$$

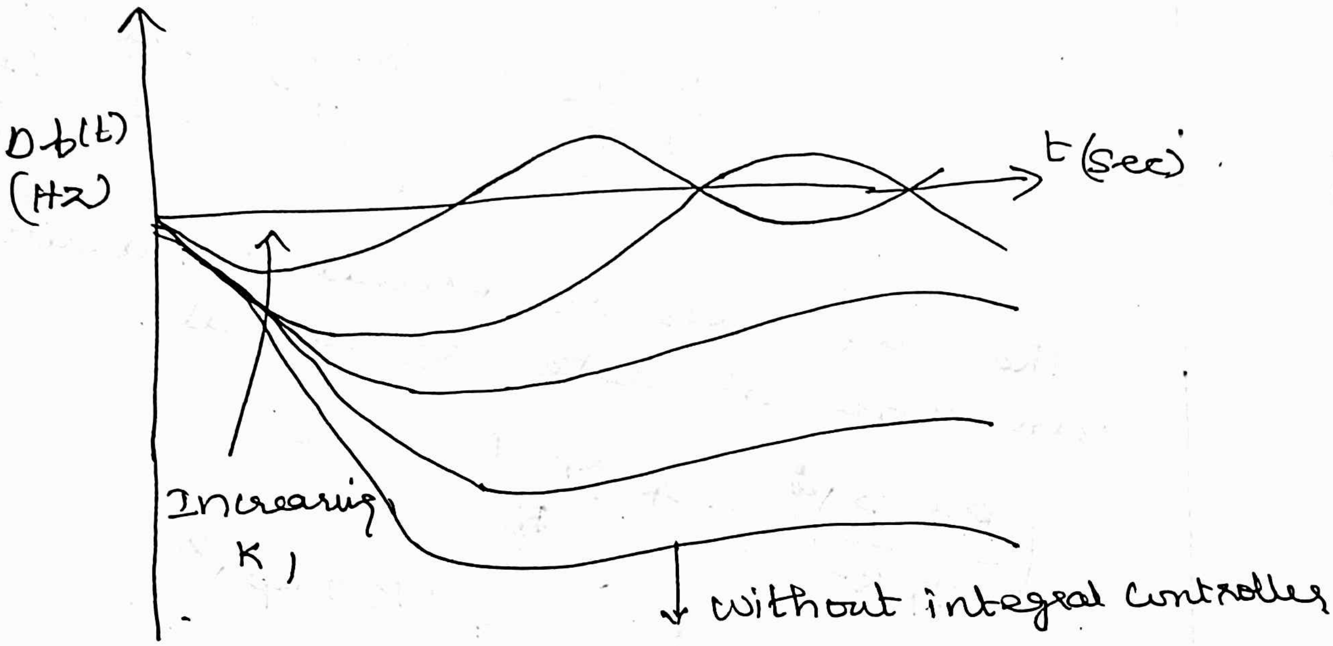
$$K_I \text{ critical} = \frac{1}{4K_pT_p}\left[1 + \frac{K_p}{R}\right]^2 .$$

$$\text{Sub } K_p = \frac{1}{D} \text{ \& } T_p = \frac{2H}{Df_0} .$$

$$K_I \text{ critical} = \frac{f_0}{8H}\left(D + \frac{1}{R}\right)^2 .$$

Time response $\Delta f(t)$ is obtained after taking inverse laplace Transform :

$$s^2 + s\left(\frac{R+K_p}{RT_p}\right) + \frac{K_pK_I}{T_p} .$$



Two area Load frequency control Modeling

For better load frequency control, the larger power system can be divided into number of load frequency control areas.

This load frequency control areas are interconnected by means of tie lines. This tie line transport power in or out of a area as per the inter area power contracts.

Location of tie line in LFC model :

The incremental Power Balance Equation is

$$\Delta P_{G1} - \Delta P_{D1} = \frac{2H_1}{f^0} \frac{d}{dt} \Delta f_1 + B_1 \Delta f_1 + \Delta P_{tie\,1}$$

$$\Delta P_{G1} - \Delta P_{D1} - \Delta P_{tie,1} = \frac{2H_1}{f^0} \frac{d}{dt} \Delta f_1 + B_1 \Delta f_1 .$$

All quantities other than frequency are in P.U

Taking Laplace Transform

$$\Delta P_{G1}(S) - \Delta P_{D1}(S) - \Delta P_{tie}^{1}(S) = \frac{2H_1 S}{f^0} \Delta F_1(S) + B_1 \Delta F_1(S).$$

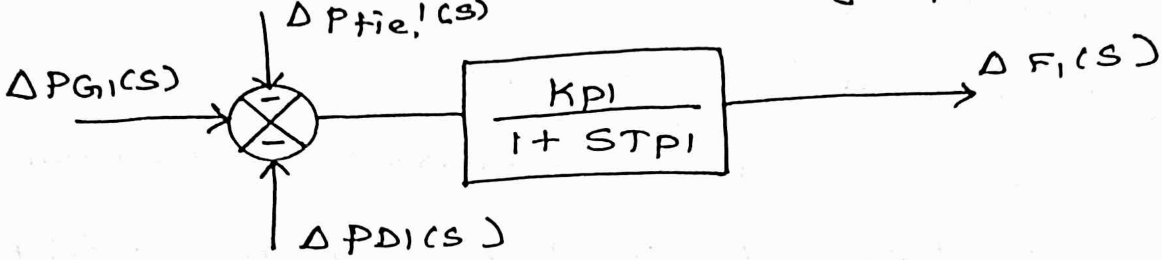
$$\Delta P_{G1}(S) - \Delta P_{D1}(S) - \Delta P_{tie}^{1}(S) = \Delta F_1(S)\left[\frac{2H_1 S}{f^0} + B_1\right]$$

$$\Delta F_1(S) = \frac{\Delta P_{G1}(S) - \Delta P_{D1}(S) - \Delta P_{tie}^{1}(S)}{\frac{2H_1 S}{f^0} + B_1}$$

$$\Delta F_1(s) = \frac{\Delta P_{G1}(s) - \Delta P_{D1}(s) - \Delta P_{tie1}(s)}{B_1\left[1 + \frac{s\,2H_1}{f^0 B_1}\right]}$$

$$\Delta F_1(s) = \frac{K_{p1}}{1+sT_{p1}}\left[\Delta P_{G1}(s) - \Delta P_{D1}(s) - \Delta P_{tie1}(s)\right]$$

$$K_{p1} = \frac{1}{B_1} \; ; \quad T_{p1} = \frac{2H_1}{f^0 B_1}.$$



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$$\Delta F_2(s) = \frac{K_{p2}}{1+sT_{p2}}\left[\Delta P_{G2}(s) - \Delta P_{D2}(s) - \Delta P_{tie}'(s)\right].$$

Modeling of tie line:

Power transported out of area 1 is given by,

$$P_{tie}' = \frac{|V_1||V_2|}{X_{12}} \sin(\delta_1^0 - \delta_2^0).$$

For an Incremental change in tie line Power

$$\Delta P_{tie,}' = \frac{|V_1||V_2|}{X_{12}} \cos(\delta_1^0 - \delta_2^0)\left(\frac{\partial \delta_1^0}{\partial \delta_{12}} - \frac{\partial \delta_2^0}{\partial \delta_{12}}\right).$$

$$\Delta P_{tie,1} = \frac{|V_1||V_2|}{X_{12}\cdot P_{r1}} \cos(\delta_1^0 - \delta_2^0)(\Delta\delta_1^0 - \Delta\delta_2^0).$$

$$\Delta P_{tie,1}\ (p.u) = T_{12}(\Delta\delta_1 - \Delta\delta_2)$$

where, $$T_{12} = \frac{|V_1||V_2|}{X_{21}P_{r1}} \cos(\delta_1^\circ - \delta_2^\circ) \rightarrow (1).$$

$$\omega = 2\pi f, \quad f = \frac{\omega}{2\pi}$$

$$f = \frac{1}{2\pi}\frac{d\delta}{dt}$$

$$f = \frac{1}{2\pi}\Delta\delta$$

$$\Delta f = \frac{1}{2\pi}\frac{\partial}{\partial t}\Delta\delta$$

$$\int \Delta f \cdot dt = \frac{1}{2\pi}\int \frac{\partial}{\partial t}\Delta\delta \cdot dt.$$

$$\int \Delta f \cdot dt = \frac{1}{2\pi}\Delta\delta.$$

$$\Delta\delta = 2\pi\int \Delta f \cdot dt.$$

$$\Delta\delta_1 = 2\pi\int \Delta f_1 \cdot dt.$$

$$\Delta\delta_2 = 2\pi\int \Delta f_2 \cdot dt.$$

$$\Delta P_{tie,1}\ (p.u) = T_{12}\left[2\pi\int \Delta f_1\, dt - 2\pi\int \Delta f_2 \cdot dt\right]$$

$$\Delta P_{tie,1}\ (p.u) = 2\pi, T_{12}\left[\int \Delta f_1\, dt - \int \Delta f_2\, dt\right]$$

Taking laplace Transform,

$$\Delta P_{tie,1}\ (s) = 2\pi T_{12}\left[\frac{\Delta F_1(s)}{s} - \frac{\Delta F_2(s)}{s}\right]$$

$$\Delta P_{tie,1}(s) = \frac{2\pi T_{12}}{s}\left[\Delta F_1(s) - \Delta F_2(s)\right]. \quad (2)$$

||ly

$$\Delta P_{tie,2}(s) = \frac{2\pi T_{21}}{s}\left[\Delta F_2(s) - \Delta F_1(s)\right]$$

$$\Delta P_{tie,2}(s) = \frac{-2\pi T_{21}}{s}\left[\Delta F_1(s) - \Delta F_2(s)\right]$$

From Equation ① we can write,

$$T_{21} = \frac{|V_2||V_1|}{X_{21} P_{r2}} \cos(\delta_2^{\circ} - \delta_1^{\circ})$$

$$T_{21} = \frac{|V_1||V_2|}{X_{12} P_{r2}} \cos(\delta_1^{\circ} - \delta_2^{\circ}) \times \frac{P_{r1}}{P_r}$$

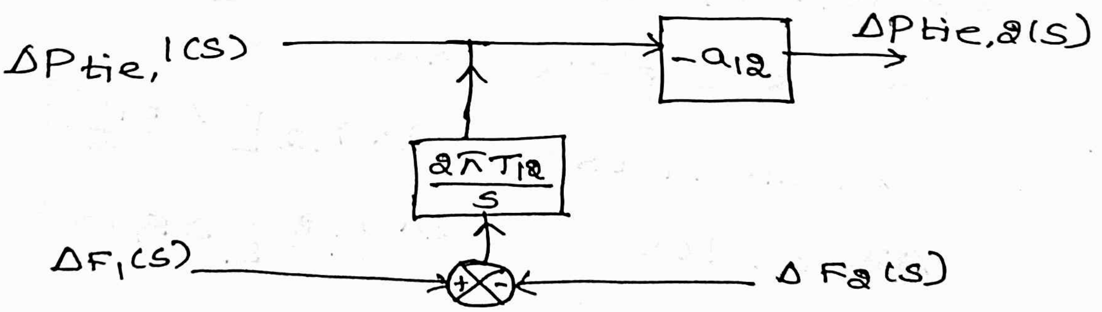
$$T_{21} = \frac{|V_1||V_2|}{X_{12} P_{r1}} \cos(\delta_1^{\circ} - \delta_2^{\circ}) \times \frac{P_{r1}}{P_{r2}}$$

$$T_{21} = \frac{|V_1||V_2|}{X_{12} P_{r1}} \cos(\delta_1^{\circ} - \delta_2^{\circ}) \times a_{12}$$

$$\boxed{T_{21} = T_{12} a_{12}}$$

$$\boxed{\Delta P_{tie,2}(s) = \frac{-2\pi T_{12} a_{12}}{s}\left[\Delta F_1(s) - \Delta F_2(s)\right]} \quad ③$$

Refering the equations ② & ③, we can develop the Block diagram representation of tie line is



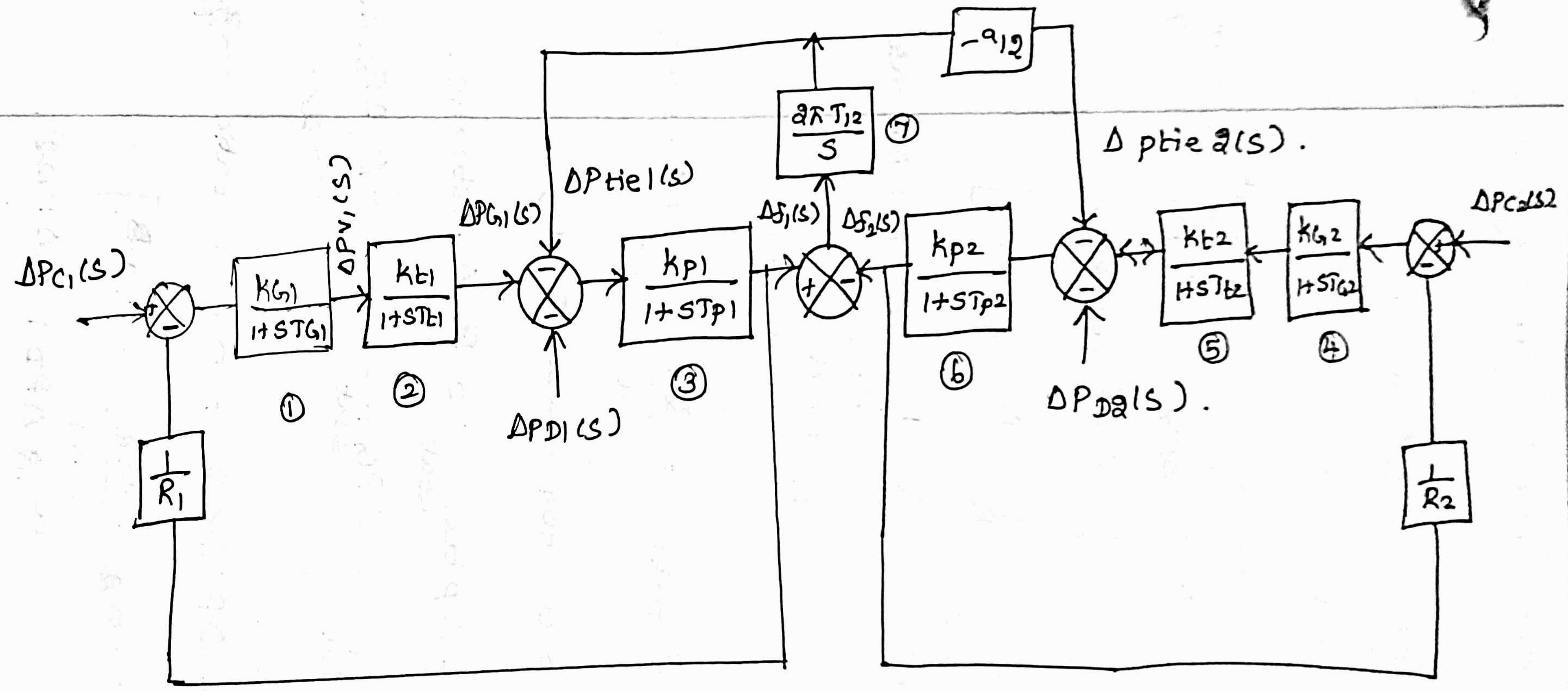


Fig: Block diagram of Two Area system.

Static Analysis of Two Area system for uncontrolled case :

Assume that $\Delta P_{c1} = \Delta P_{c2} = 0$.

The frequency deviation is,

$$\Delta F_{1\,static} = \Delta F_{2\,static} = \Delta F_{static}$$

In steady state, $R = \dfrac{-\Delta f}{\Delta P_G}$; $R \rightarrow$ Speed regulation (or) per unit droop.

$$\left.\begin{aligned} \Delta P_{G1\,static} &= -\frac{1}{R_1}\Delta F_{static} \\ \Delta P_{G2\,static} &= -\frac{1}{R_2}\Delta F_{static} \end{aligned}\right\} \quad (1).$$

Incremental power Balance equation is :

$$[\Delta P_{G1} - \Delta P_{D1} - \Delta P_{tie1}] \left[\frac{\dfrac{1}{B_1}}{1 + \dfrac{2HS}{f_0 B_1}}\right] = \Delta F_{static}$$

$$= B_1 \Delta F_{static} + \frac{2H}{f_0} \cdot \frac{d}{dt}(\Delta F_{static}).$$

For steady state

$\dfrac{d}{dt}\Delta F_{static} = 0$ for area1 then,

$$\Delta P_{G1\,stat} - \Delta P_{D1} - \Delta P_{tie\,1\,stat} = B_1 \Delta F_{static}.$$

$$\Delta P_{tie\,1\,stat} = \Delta P_{G1\,stat} - \Delta P_{D1} - B_1 \Delta F_{static} \quad -(2).$$

Ily for area 2,

$$\Delta P_{G2} - \Delta P_{D2} = \Delta P_{tie2} + B_2 \Delta F_{static} \quad -(3)$$

$$\cancel{\Delta F_{static}}\left[\frac{-1}{R_2} - B_2 - \frac{a_{12}}{R_1} - a_{12}B_1\right] = a_{12}\Delta P_{D1} + \Delta P_{D2}.$$

Relation Between ΔP_{tie1} & ΔP_{tie2}

The relation between ΔP_{tie1} & ΔP_{tie2} can be obtained from eqn (2):

$$\Delta P_{tie,1} = T_{12}\,(\Delta\delta_1 - \Delta\delta_2)$$

$$\Delta P_{tie,2} = T_{21}\,(\Delta\delta_2 - \Delta\delta_1).$$

$$\frac{\Delta P_{tie,1}}{\Delta P_{tie,2}} = \frac{T_{12}\,(\Delta\delta_1 - \Delta\delta_2)}{T_{21}\,(\Delta\delta_2 - \Delta\delta_1)}$$

WKT, $T_{21} = a_{12}\,T_{12}$.

$$\frac{\Delta P_{tie,1}}{\Delta P_{tie,2}} = \frac{\cancel{T_{12}}\,\cancel{(\Delta\delta_1 - \Delta\delta_2)}}{-a_{12}\,\cancel{T_{12}}\,\cancel{(\Delta\delta_1 - \Delta\delta_2)}}$$

$$= -\frac{1}{a_{12}}$$

$$\Delta P_{tie,2} = -a_{12} \times \Delta P_{tie,1\,stat} \quad -(4).$$

sub eqn (4) in (3),

$$\Delta P_{G2,stat} - \Delta P_{D2} = B_2\,\Delta f_{stat} - a_{12}\,\Delta P_{tie1,stat}$$

sub eqn (2) in above equation

$$\Delta P_{G2,stat} - \Delta P_{D2} = B_2\,\Delta f_{stat} - a_{12}\,[\Delta P_{G1\,stat} - \Delta P_{D1} - B_1\,\Delta F_{stat}]$$

sub eqn (1) in above equation

$$\frac{\Delta f_{static}}{-R_2} - \Delta P_{D2} = B_2\,\Delta f_{stat} - a_{12}\left[-\frac{\Delta f_{static}}{R_1} - \Delta P_{D1} - B_1\,\Delta F_{stat}\right].$$

Grouping Δf_{stat} terms,

$$-\frac{\Delta f_{stat}}{R_2} - B_2 \Delta f_{stat} - a_{12} \frac{\Delta f_{stat}}{R_1} - a_{12} B_1 \Delta f_{stat} = a_{12} \Delta P_{D1} + \Delta P_{D2}.$$

$$\Delta f_{stat}\left[-\frac{1}{R_2} - B_2 - \frac{a_{12}}{R_1} - a_{12} B_1\right] = a_{12} \Delta P_{D1} + \Delta P_{D2}.$$

$$\Delta f_{stat} = \frac{a_{12} \Delta P_{D1} + \Delta P_{D2}}{-\left[B_2 + \frac{1}{R_2} + a_{12}\left(B_1 + \frac{1}{R_1}\right)\right]}$$

$$\Delta f_{stat} = \frac{-\left[a_{12} \Delta P_{D1} + \Delta P_{D2}\right].}{\left[B_2 + \frac{1}{R_2} + a_{12}\left(B_1 + \frac{1}{R_1}\right)\right]} \quad \text{--- (5)}$$

From eqn (2),

$$\Delta P_{tie1, stat} = \Delta P_{G1, stat} - \Delta P_{D1} - B_1 \Delta f_{stat}$$

sub eqn (1) in above Equation, for $\Delta P_{G1\,stat}$

$$\Delta P_{tie1, stat} = \frac{-\Delta f_{static}}{R_1} - \Delta P_{D1} - B_1 \Delta f_{stat}.$$

Group Δf_{static},

$$\Delta P_{tie1, stat} = \Delta f_{stat}\left[-\frac{1}{R_1} - B_1\right] - \Delta P_{D1}.$$

$$\Delta P_{tie1, stat} = -\Delta f_{stat}\left[\frac{1}{R_1} + B_1\right] - \Delta P_{D1} \quad \text{--- (6).}$$

sub Δf_{stat} from eqn (5) in (6).

$$\Delta P_{tie1, stat} = -\left[\frac{-(\Delta P_{D2} + a_{12} \Delta P_{D1})}{\left(B_2 + \frac{1}{R_2}\right) + a_{12}\left(B_1 + \frac{1}{R_1}\right)}\right]\left[\frac{1}{R_1} + B_1\right] - \Delta P_{D1}.$$

Take LCM,

$$= \frac{\left[\Delta P_{D2} + a_{12}\Delta P_{D1}\right]\left[\frac{1}{R_1}+B_1\right] - \Delta P_{D1}\left[B_2+\frac{1}{R_2}+a_{12}\left(B_1+\frac{1}{R_1}\right)\right]}{B_2+\frac{1}{R_2}+a_{12}\left(B_1+\frac{1}{R_1}\right)}$$

$\times$ ly.

$$= \frac{\left[\Delta P_{D2} + a_{12}\Delta P_{D1}\right]\left[\frac{1}{R_1}+B_1\right] - \Delta P_{D1}\left[B_2+\frac{1}{R_2}\right] - \Delta P_{D1}a_{12}\left[B_1+\frac{1}{R_1}\right]}{B_2+\frac{1}{R_2}+a_{12}\left(B_1+1/R_1\right)}$$

$$= \frac{\Delta P_{D2}\left[\frac{1}{R_1}+B_1\right] + \cancel{a_{12}\Delta P_{D1}\left[\frac{1}{R_1}+B_1\right]} - \Delta P_{D1}\left[B_2+\frac{1}{R_2}\right] - \cancel{\Delta P_{D1}a_{12}\left[B_1+1/R_1\right]}}{B_2+\frac{1}{R_2}+a_{12}\left(B_1+1/R_1\right)}$$

$$= \frac{\Delta P_{D2}\left[\frac{1}{R_1}+B_1\right] - \Delta P_{D1}\left[B_2+\frac{1}{R_2}\right]}{B_2+\frac{1}{R_2}+a_{12}\left[B_1+1/R_1\right]} \quad \text{—(7).}$$

$$\left.\begin{aligned} \text{Let } \beta_1 &= B_1+\frac{1}{R_1} \\ \beta_2 &= B_2+\frac{1}{R_2} \end{aligned}\right\} \quad \text{—(8).}$$

Sub above in eqn (7) & (5).

(9) $\Rightarrow$. $\Delta P_{tie\,1,stat} = \dfrac{\beta_1\Delta P_{D2} - \beta_2\Delta P_{D1}}{\beta_2 + a_{12}\beta_1}$

$\beta \rightarrow$ area frequency response co-efficient (or) characteristics (AFRC) PU MW/Hz

⑤ $\Rightarrow$ $\Delta f_{stat} = -\left[\dfrac{\Delta P_{D2} + a_{12}\,\Delta P_{D1}}{\beta_2 + a_{12}\beta_1}\right]$.

For 2 identical areas '1' & '2'

$$\beta_1 = \beta_2 = \beta$$

$$R_1 = R_2 = R.$$

$$B_1 = B_2 = B.$$

$$P_{r1} = P_{r2}$$

$$a_{12} = \frac{P_{r1}}{P_{r1}} = 1.$$

Then Δf_{stat} becomes,

$$\Delta f_{stat} = -\left[\frac{\Delta P_{D2} + \Delta P_{D1}}{\beta + \beta}\right].$$

$$= -\left[\frac{\Delta P_{D2} + \Delta P_{D1}}{2\beta}\right].$$

$$\Delta P_{tie1,\,stat} = \Delta P_{tie2,\,stat} = \frac{\beta\,\Delta P_{D2} - \beta\,\Delta P_{D1}}{\beta + \beta}$$

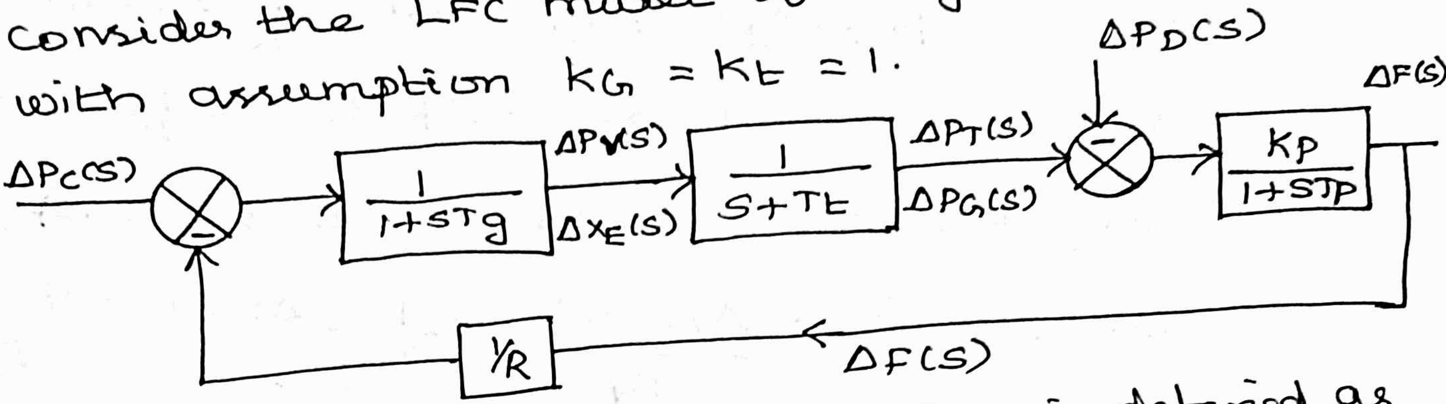
$$= \beta\left[\frac{\Delta P_{D2} - \Delta P_{D1}}{2\beta}\right].$$

$$= \frac{\Delta P_{D2} - \Delta P_{D1}}{2}$$

State Variable Model of Load Frequency Control

Optimum Linear Regulator (OLR) design results in a controller that minimizes both transient variable oscillations and control effects. OLR design is based upon the availability of a dynamic system model is called state variable model.

Consider the LFC model of single area, ~~which~~ with assumption $K_G = K_t = 1$.



The state variable of a system is defined as,

$$\dot{x}(t) = Ax(t) + Bu(t) + p(t) \longrightarrow (1)$$

$x(t)$ is the state variables of the LFC, they are ΔP_V, ΔP_T & Δf. Therefore the state variables,

$$\left.\begin{aligned} x_1 &= \Delta P_V \\ x_2 &= \Delta P_T \\ x_3 &= \Delta f \end{aligned}\right\} \quad (2)$$

$\dot{x}(t)$ is the derivative of the state variables.

$$\left.\begin{aligned} \dot{x}_1 &= \frac{d}{dt}(\Delta P_V) \\ \dot{x}_2 &= \frac{d}{dt}(\Delta P_T) \qquad \dot{x}_3 = \frac{d}{dt}(\Delta f) \end{aligned}\right\} \quad (3)$$

u(t) is the control variable,

$$u = \Delta P_c \rightarrow (4)$$

p(t) is the Disturbance variable,

$$p = \Delta P_D \rightarrow (5)$$

From the Block diagram,

$$\Delta P_V(s) = \left(\frac{1}{1+sT_g}\right)\left(\Delta P_c(s) - \frac{1}{R}\Delta F(s)\right)$$

$$\Delta P_V(s)(1+sT_g) = \Delta P_c(s) - \frac{1}{R}\Delta F(s)$$

$$\Delta P_V(s) + sT_g\,\Delta P_V(s) = \Delta P_c(s) - \frac{1}{R}\Delta F(s).$$

$$sT_g\,\Delta P_V(s) = \Delta P_c(s) - \frac{1}{R}\Delta F(s) - \Delta P_V(s).$$

$$s.\Delta P_V(s) = \frac{\Delta P_c(s)}{T_g} - \frac{1}{RT_g}\Delta F(s) - \frac{\Delta P_V(s)}{T_g}$$

Taking Inverse Laplace,

$$\frac{d}{dt}(\Delta P_V) = \frac{\Delta P_c}{T_g} - \frac{\Delta f}{RT_g} - \frac{\Delta P_V}{T_g}.$$

From Equations 2, 3, 4 & 5

$$\dot{x}_1 = \frac{u}{T_g} - \frac{x_3}{RT_g} - \frac{x_1}{T_g} \rightarrow (6)$$

$$\Delta P_T(s) = \left(\frac{1}{1+sT_t}\right)\Delta P_V(s).$$

$$\Delta P_T(s)[1+sT_t] = \Delta P_V(s).$$

$$\Delta P_T(s) + sT_t\,\Delta P_T(s) = \Delta P_V(s).$$

$$sT_t\,\Delta P_T(s) = \Delta P_V(s) - \Delta P_T(s)$$

$$s\Delta P_T(s) = \frac{\Delta P_V(s)}{T_t} - \frac{\Delta P_T(s)}{T_t}$$

Taking Inverse Laplace Transform.

$$\frac{d}{dt}(\Delta P_T) = \frac{\Delta P_V}{T_t} - \frac{\Delta P_T}{T_t}$$

From Equations ②, ③, ④ & ⑤

$$\dot{x}_2 = \frac{x_1}{T_t} - \frac{x_2}{T_t} \quad \text{——} (7)$$

$$\Delta F(s) = \frac{K_p}{1+sT_p}\left[\Delta P_T(s) - \Delta P_D(s)\right]$$

$$\Delta F(s)\left[1+sT_p\right] = K_p \Delta P_T(s) - K_p \Delta P_D(s).$$

$$\Delta F(s) + sT_p \Delta F(s) = K_p \Delta P_T(s) - K_p \Delta P_D(s).$$

$$\Delta F(s) + sT_p \Delta F(s) = K_p \Delta P_T(s) - K_p \Delta P_D(s).$$

$$sT_p \Delta F(s) = K_p \Delta P_T(s) - K_p \Delta P_D(s)$$

$$s\Delta F(s) = \frac{K_p}{T_p}\Delta P_T(s) - \frac{K_p}{T_p}\Delta P_D(s)$$

Taking inverse Laplace Transform,

$$\frac{d}{dt}(\Delta f) = \frac{K_p}{T_p}\Delta P_T - \frac{K_p}{T_p}\Delta P_D.$$

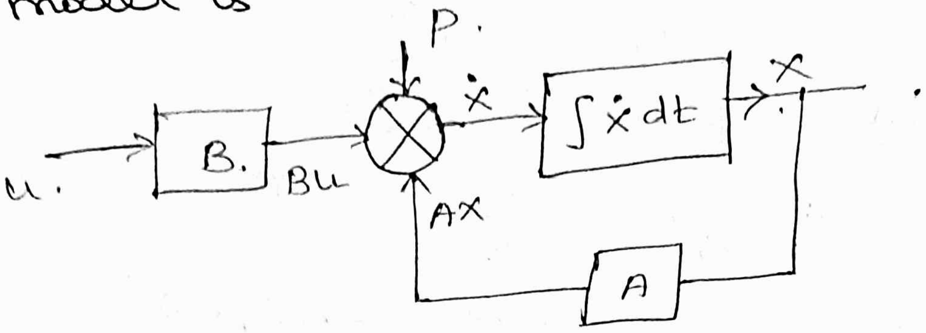
From eqn ②, ③, ④ & ⑤,

$$\dot{x}_3 = \frac{K_p}{T_p}x_2 - \frac{K_p}{T_p}P \longrightarrow ⑧.$$

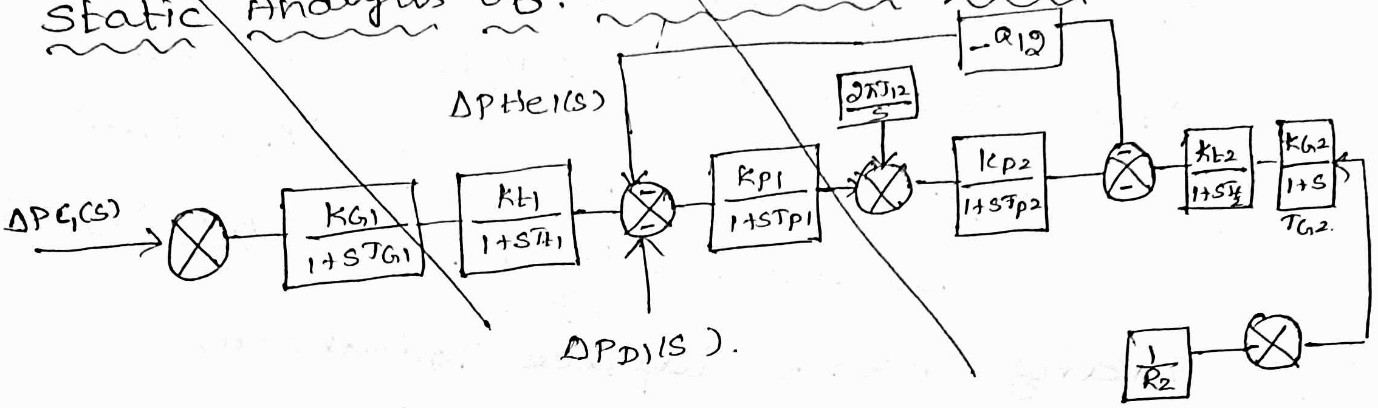
From ⑥, ⑦, ⑧ we can frame the LFC model as state variables eqn of

$$\begin{bmatrix}\dot{x}_1\\ \dot{x}_2\\ \dot{x}_3\end{bmatrix} = \begin{bmatrix}-1/T_g & 0 & -1/RT_g\\ 1/T_t & -1/T_t & 0\\ 0 & K_p/T_p & 0\end{bmatrix}\begin{bmatrix}x_1\\ x_2\\ x_3\end{bmatrix} + \begin{bmatrix}1/T_g\\ 0\\ 0\end{bmatrix}u + \begin{bmatrix}0\\ 0\\ -\frac{K_p}{T_p}\end{bmatrix}P$$

The block diagram of state variable model is



Static Analysis of uncontrolled case :-



① A 100 MW generator has regulation parameter R of 5% by how much will the turbine power increases if the frequency drops by ~~0.1 HZ~~ 0.1 HZ with the reference unchanged.

Actual change in frequency $= 5\%$ of 50 Hz.

$$= \frac{5}{100} \times 50$$

$$= 2.5\ HZ.$$

$$R = \frac{2.5}{100MW}$$

$$-R = \frac{\Delta f_{stat}}{\Delta P_D} \ (HZ/MW).$$

$$-R = \frac{2.5}{100} = -0.025\ HZ/MW.$$

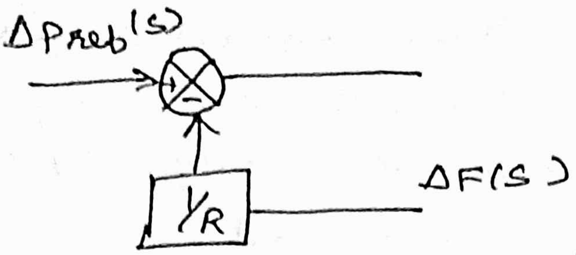
$$\Delta f = -0.1\ HZ \text{ (drops)}$$

Turbine power increase, $\Delta P_D = \frac{\Delta f}{R}$

$$= \frac{-0.1}{-0.025}$$

$$= 4\ MW.$$

2) A 100 MW generator with $R = 0.025\ HZ/MW$ has its frequency fallen by 0.1 HZ. If the turbine power remains unchanged. by how much the reference power setting be changed.



$$\Delta P_{ref}(s) - \frac{1}{R}\Delta F(s) = 0.$$

$$\Delta P = \frac{\Delta f}{R} = \frac{0.1}{0.025} = 4\,MW.$$

(3) Two generator with ratings 100 MW & 300 MW operate at 50 Hz frequency. The system load increases by 100 MW when both the generators are operating at about half of their capacity. Then frequency falls at 49.5 Hz. If the generators are to share the increased load in propotion to their ratings what should be the individual regulations? what should be regulations if expressed in p.u Hz/p.u Mega watt?

$$\boxed{\Delta P = -\frac{1}{R}\Delta f}.$$

$$\Delta P_1 = -\frac{1}{R_1}\Delta f$$

$$\Delta P_2 = -\frac{1}{R_2}\Delta f.$$

$\Delta f = 0.5\,Hz.$ (falls 50 Hz to 49.5 Hz).

Power is shared in proportional to their ratings (300 + 100 = 400).

$$\Delta P_1 = 100 \times \frac{100}{400}.$$

$$= 25 MW.$$

$$\Delta P_2 = 100 \times \frac{300}{400}$$

$$= 75 MW$$

(i) $$R_1 = \frac{-\Delta f}{\Delta P_1} = \frac{-0.5}{25} = 0.02$$

$$R_2 = \frac{-\Delta f}{\Delta P_2}. = \frac{-0.5}{75} = 6.66 \times 10^{-3}$$

(ii) Regulations expressed in $\left(\frac{pu\ Hz}{p.u\ MW}\right)$

$$f = 50 Hz.$$

$$R_1 = \frac{-\Delta f}{\Delta P} = \frac{0.02}{50} \times \frac{100}{1}$$

$$= 0.04 \left(\frac{p.u\ Hz}{p.u\ MW}\right).$$

$$R_2 = -\frac{0.0066}{50} \times \frac{300}{1}.$$

$$= 0.04 \left(\frac{p.u\ Hz}{p.u\ MW}\right).$$

4) Determine the primary load frequency control loop parameters for a control area having the following data :

Total rated area capacity $(P_r) = 1000\,MW$.

Normal operating load $= 500\,MW$.

Inertia constant $H = 4.0\,sec$.

Regulation $R = 2.5\,Hz/p.u\,MW$.

(i) Load Damping $B = \frac{\partial P}{\partial f} = \frac{500}{50}\,MW$

$= 10\,(MW/Hz)$.

in (p.u) $= \frac{10}{1000} = 0.0\,(p.u\,MW/Hz)$.

$T_p = \frac{2H}{f_0 B} = \frac{2 \times 4}{50 \times 0.01}$

$= 16\,s$

$K_p = \frac{1}{B} = \frac{1}{0.01} = 100\,Hz/p.u\,MW$.

5) Determine the area frequency response characteristic & the static frequency error for a s/m with following data, when 1 % load change occurs ?

$B = 0.01\,p.u\,MW/Hz$.

$R = 2.5\,Hz/pu\,MW$.

$T_p = 16\,sec$.

$K_p = 100\,Hz/p.u\,M.W$.

(i) AFRC, $\beta = B + \frac{1}{R}$.

$= 0.01 + \frac{1}{2.5}$

$= 0.41$ (MW/Hz).

(ii) static frequency error,

$$\Delta f_{stat} = \frac{-\Delta P_D}{B + \frac{1}{R}} = \frac{-\Delta P_D}{\beta}$$

$$= -\frac{(1/100)}{0.41} \quad \leftarrow (1\%)$$

$= 0.0243$ Hz.

(8). In the previous example, the ~~genera~~ governor is blocked so that it does not change the generation. In that case what would be the steady state freq. error.

when generator is not acting, the feedback loop is not existing, In such case R is α

$\beta = B + 1/R$

$\beta = B = 0.01$ p.u MW/Hz.

$$\Delta f_{stat} = \frac{-\Delta P_1}{\beta} = -\frac{(1/100)}{0.01} = -1 \text{ Hz}.$$

note: (frequency falls by 1Hz i.e (50−1) Hz.

$\boxed{f = 49 \text{ Hz}}$ (without g)

(7) A 100MVA synchronous generator operates initially at 3000 rpm, 50Hz, A 25MW load is suddenly applied to the m/c & the steam value to the turbine opens only after 0.5 sec. due to the time lag in generator action. Calculate the frequency to which the generator voltage drops before the steam blow commences to increase to meet the new load. The value of stored energy for the m/c is 5 kw-sec / KVA of generator energy. Also calculate the value of H constant for the generator.

Stored energy = 5 kw per / KVA.

(i.e) 500 MW sec

load increase = 25 MW.

Energy required to supply this load for 0.5 sec = 25 MW sec.

Frequency at 500 MW sec stored energy = 50Hz

Freq. fall = Δf.

$$\frac{\Delta f}{f} = \frac{\Delta f}{50} = \frac{25 \times 0.5}{500} \text{ MW sec.}$$

$$\Delta f = \frac{50 \times 25 \times 0.5}{500}$$

$$= 1.25 \text{ Hz}.$$

Frequency falls to 50 − 1.25 = 48.75 Hz.

$$H = \frac{\text{Stored K.E at rated frequency}}{\text{Machine Rating}}$$

$$= \frac{5\ \text{MW.sec}}{\text{MVA}} \times \frac{100\ \text{MVA}}{100\ \text{MVA}}$$

$$= 5\ \text{sec.}$$

2) A 125 MVA turbo alternator operator on full load operates at 50 Hz. A load of 50 MW is suddenly reduction on the m/c. The steam valves to the turbine commence to close after 0.5 s, due to time lag in the governor s/m. Assuming the inertia to be constant, H = 6 kW-s / kVA of generator capacity, calculate the change in frequency that occurs in this time.

$$H = \frac{\text{Stored Energy}}{\text{Capacity of Machine}}$$

Energy stored at no load $= 6 \times 125 \times 1000$

$= 750\ \text{MJ}$.

Excessive energy i/p to rotating parts in 0.5 s.

$= 50 \times 0.5 \times 1000$

$= 25\ \text{MJ}$.

As a result of this, there is an increase in speed of the motor & hence an increase in frequency,

$$W_{K.E} = W^{0}_{K.E}\left[\frac{f^{0}+\Delta f}{f^{0}}\right]^{2}$$

$$f_{new} = \sqrt{\frac{750+25}{750}} \times 50.$$

$$= 50.83\,HZ.$$

9) An isolated control area consists of a 200-MW generator with an inertia, H = 5 kw-s/kVA having following parameters :

Power s/m gain constant $k_{ps} = k_p = 100.$

" " Time constant $T_{ps} = T_p = 20s.$

speed Regulation $R = 3.$

Normal frequency, $f^{0} = 50\,HZ.$

obtain the frequency error & plot the graph of deviation of frequency when a step load disturbances of (i) 0.5 %. (ii) 1 %. (iii) 2 %.

$$G_p = \frac{k_p}{1+ST_p} = \frac{100}{1+20s}.$$

$$R = 3.$$

$$\frac{1}{R} = 1/3.$$

(i) 0.5 %. $B = 1/K_P = \frac{1}{100} = 0.01.$

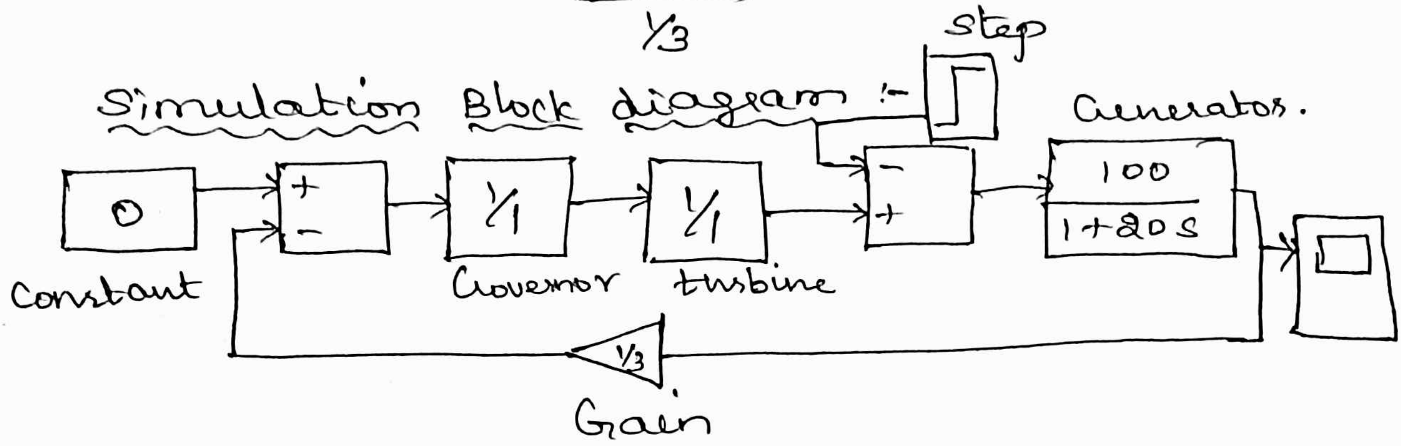
$$\Delta f = \frac{-\Delta PD}{\frac{1}{R}+B} = \frac{-0.5/100}{\frac{1}{3}+0.01}$$

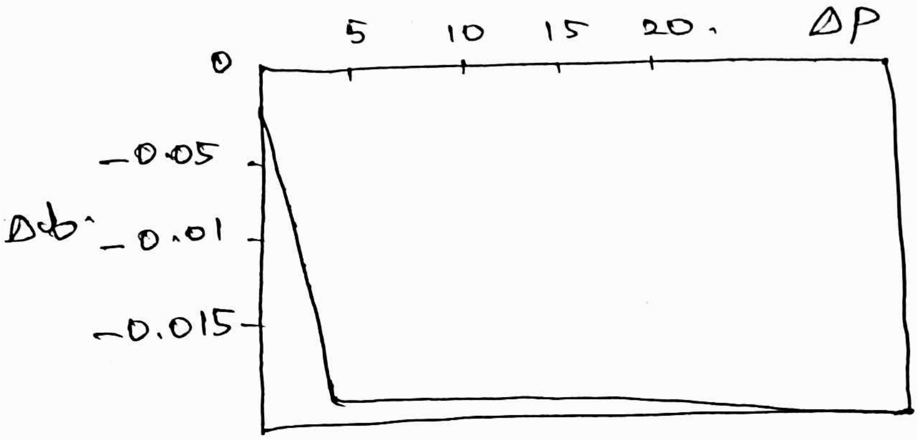
$$= 0.0145\,HZ.$$

(ii) 1 %. $\Delta f = \dfrac{-1/100}{\frac{1}{3}+0.01} = 0.029\ Hz.$

(iii) 2 %. $\Delta f = \dfrac{2/100}{1/3} = 0.583\ Hz.$

Simulation Block diagram :-





UNIT-III - Reactive Power - Voltage Control

Generation and absorption of reactive Power - Basics of reactive power control - Automatic voltage Regulator (AVR) - Brushless AC excitation system - Block diagram representation of AVR loop - Static and dynamic analysis - stability compensation - voltage drop in transmission line - methods of reactive power injection - tap changing transformers, SVC (TCR + TSC) & STATCOM for voltage control.

Generation and Absorption of Reactive Power :-

Synchronous Generators :

Synchronous generators can generate or absorb reactive power. Reactive power (Q) is supplied by synchronous generators depending upon the short circuit Ratio (SCR).

$$SCR = \frac{1}{X_S}$$

$$X_S = \text{Synchronous Reactance.}$$

Shunt capacitors : It offers the cheapest means of reactive power supply.

Shunt reactors : It offers the cheapest means of reactive power absorption and these are connected in transmission line during light load conditions.

Transformers : Transformers always absorb, reactive power regardless of their loading.

At no load - shunt magnetizing reactance effect is predominant.

At full load - Series leakage inductance effect is predominant.

$$\text{P.u reactance}, X_T = \frac{\text{Actual } X}{\text{Base value}} = \frac{\text{Actual } X}{\frac{V}{I}}$$

$$\text{Actual } X = X_T \times \frac{V}{I}$$

$$X = X_T \times \frac{KV}{I} \times 1000$$

$$I_{ph} = \frac{KVA}{\sqrt{3}\, KV}$$

$$X = \frac{X_T \times KV \times 1000}{\frac{KVA}{\sqrt{3}\, KV}}$$

$$= \frac{X_T \times \sqrt{3} \times (KV)^2 \times 1000}{KVA}$$

Reactive power absorbed (or) loss $Q_T = 3|I|^2 \times$ VAR

$$= \frac{3|I|^2 \times X_T \times \sqrt{3} \times KV^2 \times 1000}{KVA}$$

$$= 3\,\frac{KVA^2}{3KV^2} \times \left(\frac{X_T \times \sqrt{3} \times KV^2 \times 1000}{KVA}\right).$$

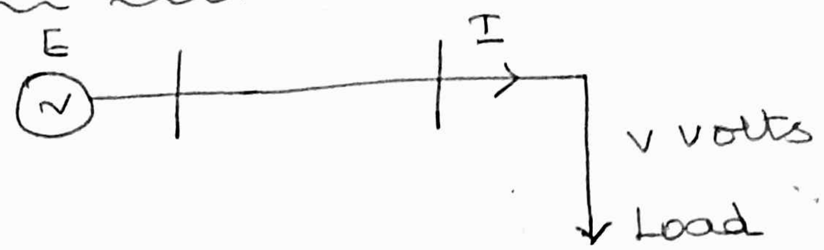
$$= \sqrt{3}\; KVA \times (X_T \,.\, KVAR).$$

where I = current in amps flowing through the transformer.

X = Transformer reactance per phase.

Cables : cables generate more reactive power than transmission lines because the cables have high capacitance.

Overhead Lines :



Transmission lines are considered as generating KVAR in their shunt capacitance and consuming KVAR in their series inductance. The inductive KVAR vary with the line current, whereas, the capacitive KVAR vary with the system potential.

Consider transmission line be loaded such that load current be I amperes and load voltage V volts shown in fig :

Assume transmission line to be lossless, reactive power absorbed by the line will be,

$$\Delta Q_L = |I|^2 X_L$$

$$= |I|^2 \omega L .$$

Due to the capacitance of the line, the reactive power generated by the line,

$$\Delta Q_C = \frac{|V|^2}{X_C} = |V|^2 \omega C$$

suppose $\Delta Q_L = \Delta Q_C$

$$|I|^2 \omega L = |V|^2 \omega C$$

$$\left|\frac{V}{I}\right|^2 = \frac{\omega L}{\omega C} = \frac{L}{C}$$

$$Z_n = \frac{V}{I} = \sqrt{\frac{L}{C}}$$

Z_n - surge impedance of the line

A line is said to be operating at its surge impedance loading when it is terminated by a resistance equal to its surge impedance. The power transmitted under this condition is called natural or surge power.

$$P = \frac{|E||V|}{X} \sin \delta .$$

At $\delta = 90^\circ$, maximum power be transferred:

$$P_{max} = \frac{|E||V|}{X} \text{ MW}$$

By varying $X, \delta, |V|$ can get control of power transfer.

case (i):

$$\Delta Q_L > \Delta Q_C$$

$$|I|^2 \omega L > |V|^2 \omega C .$$

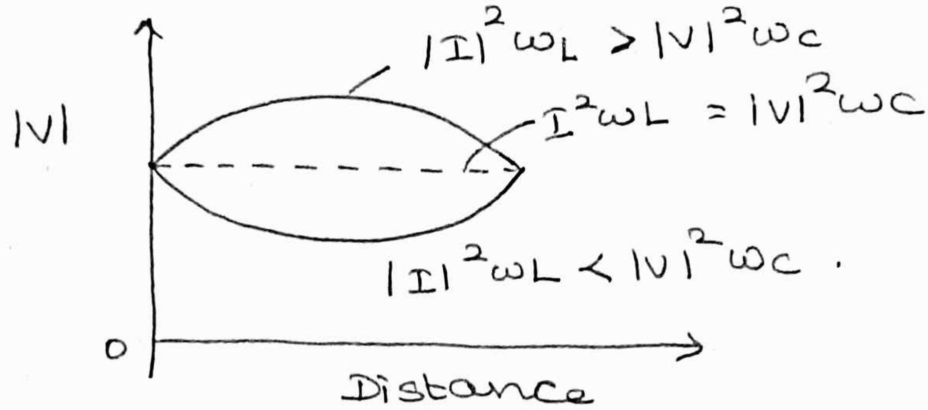


Fig : variation of voltage as a function of distance of line.

Here the line is loaded below Z_n, i.e light load condition.

$$\Delta Q_L < \Delta Q_C$$

$$|I|^2 \omega L < |V|^2 \omega C.$$

Loads : Loads absorb reactive power. Load change occurs depending on the day, season and weather conditions. Both active and reactive power of the composite loads vary as a function of voltage magnitudes.

Analysis of Reactive Power Absorbed and Generated by the Transmission line :-

consider π-model of the transmission line:

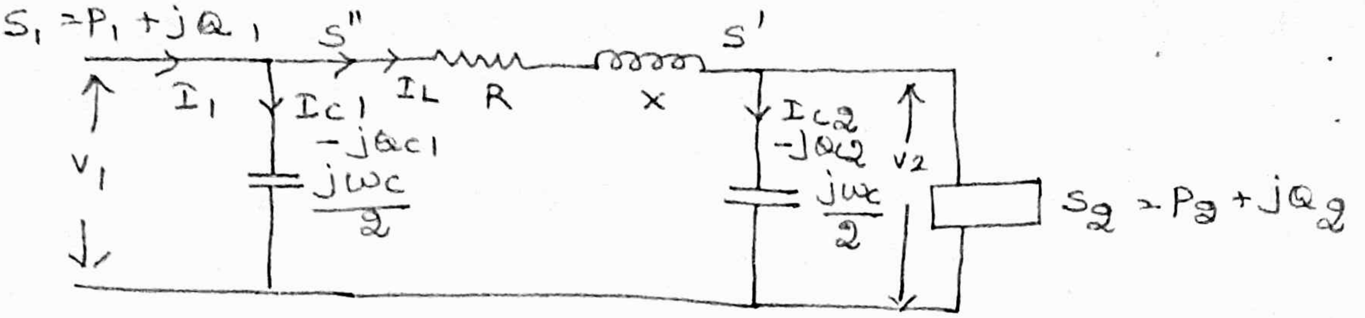


Fig: Equivalent circuit for π model.

KVR generated by the line $Q_c = Q_{c1} + Q_{c2}$.

$$= |V_1|^2 \frac{\omega c}{2} + |V_2|^2 \frac{\omega c}{2} \text{ VAR/phase}$$

The rated voltage is used for finding power generated:

$$Q_{c1} = Q_{c2} = |V_r|^2 \frac{\omega c}{2} \text{ VAR/phase.}$$

The reactive power absorbed by the line/phase

$$\Delta Q_L = |I_L|^2 X \text{ VAR/phase.}$$

$X \rightarrow$ Reactance of the line (Ω).

Most of the industrial loads are inductive loads the power sending end can be calculated as,

$$S' = S_2 + (-jQ_{c2}) = P_2 + jQ_2 - jQ_{c2}.$$

$$S'' = S' + \Delta P_L + j\Delta Q_L$$

$$S'' = S' + |I_L|^2 R + j|I_L|^2 X.$$

Power at the sending end is $S_1 = P_1 + jQ_1$.

$$= S'' - jQ_{c1}$$

$$= S' + |I_L|^2 R + j|I_L|^2 X - jQ_{c1}.$$

$$= P_2 + jQ_2 - jQ_{c2} + |I_L|^2 R + j|I_L|^2 X - jQ_{c1}.$$

$$= P_2 + jQ_2 + |I_L|^2 R + j|I_L|^2 X - jQ_{c1} - jQ_{c2}$$

$$= P_2 + jQ_2 + |I_L|^2 R + j|I_L|^2 X - j|V_r|^2 \omega c$$

$$\boxed{I_L = \left|\frac{S'}{V_r}\right| = \frac{\sqrt{P_2^2 + (Q_2 - Q_{c2})^2}}{|V_r|}}$$

Basics of Reactive Power Control :-

→ When the load on power system changes, the terminal voltage of generator changes.

→ To maintain the terminal voltage within permissible standards the excitation of generator must be decreased or increased.

→ This can be achieved by automatic voltage regulator (AVR).

→ Reactive power is proportional to voltage.

→ The voltage can be controlled by controlling field current.

→ The field current is controlled by controlling the excitation system. AVR control is used.

→ In addition to voltage regulators, shunt capacitors, synchronous compensators, static VAR system are also used for voltage control.

Excitation System :-

→ The excitation system provides direct current to synchronous machines.

→ Also it performs control & ~~product~~ protective functions by controlling the field voltage thereby the field current.

Types of Excitation system:

1) DC Excitation system
2) AC excitation system
3) Static Excitation system.

D.C Excitation system :-

This System uses DC generators as Sources of excitation power.

A.C Excitation system :-

This System uses AC machines as sources of excitations power. The AC output is rectified to provide DC.

Static Excitation system :

→ The components are static.

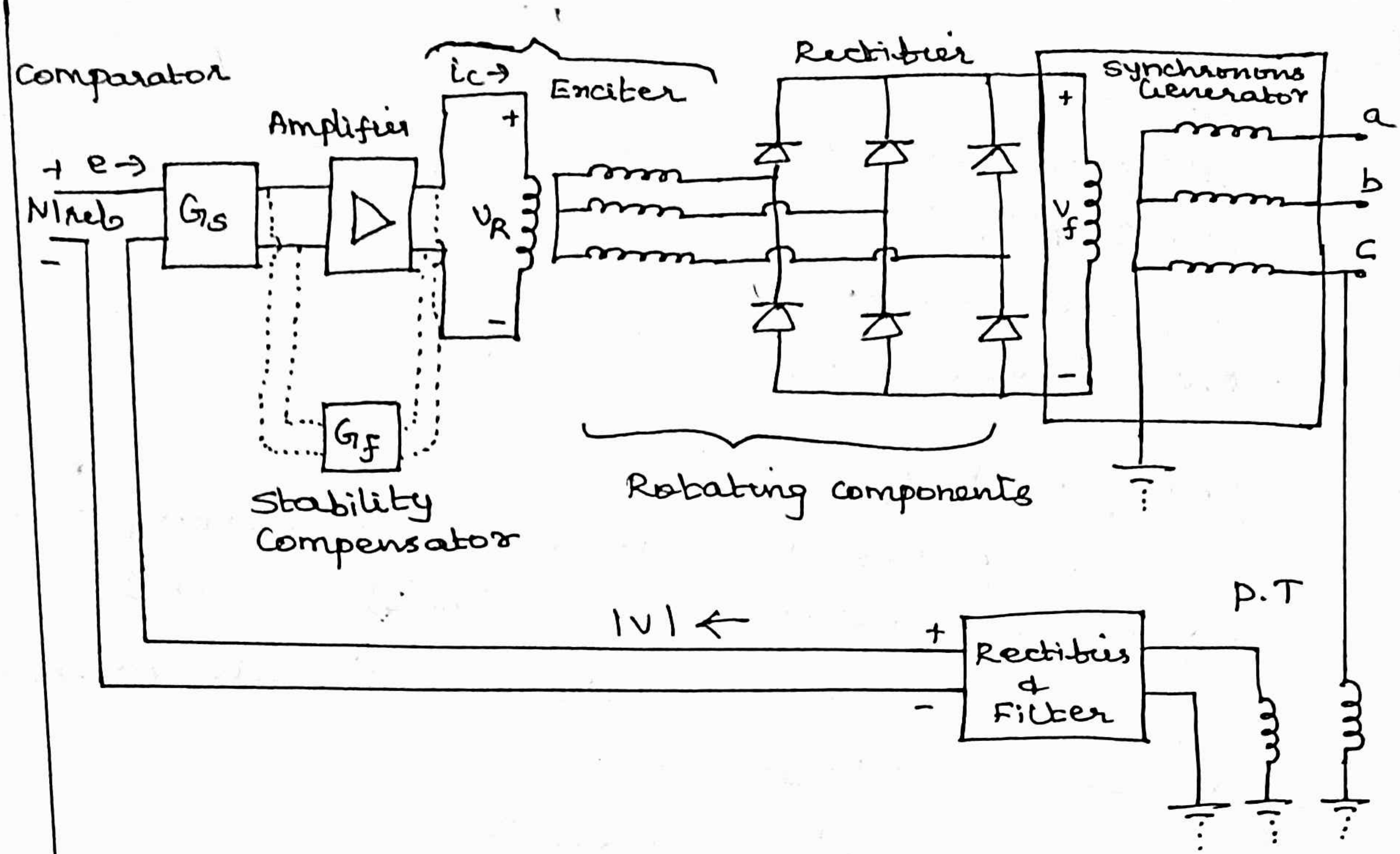
→ The static rectifier either controlled or uncontrolled supplies the excitation current.

→ The source of power to rectifier is from main generator through a step down Transformer.

→ At the time of starting, field is supplied through battery.

Typical Excitation system (OR) Modelling of Automatic Voltage regulator :-

→ This AC armature Voltage is rectified by "diode bridge" mounted on rotating shaft and fed directly to main generator field.



Modelling of typical Excitation system (or) Modelling of Automatic Voltage Regulator :

→ Assume that the generator terminal voltage has decreased. This results in error voltage 'e'.

(i) Potential Transformer :-

The terminal voltage is stepped down to value required for control signal.

(ii) Rectifier :-

AC signal is rectified to DC to be send to the comparator.

Models :

(i) comparator

(ii) Amplifier

(iii) Exciter

(iv) Generator.

Comparator :

→ It compares the measured voltage signal |V| with reference D.C signal (V_{ref}).

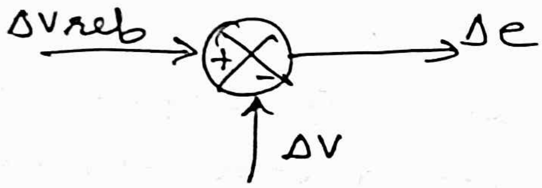
→ The difference b/w these 2 signals produce an error voltage 'V_e'.

→ Error signal is given by,

$$\Delta e = \Delta |V_{ref}| - \Delta |V| \qquad (1)$$

Taking Laplace Transform,

$$\Delta V_{ref}(s) - \Delta V(s) = \Delta e(s).$$



Amplifier :-

The amplifier amplifies the input error signal :

$$\Delta V_R \propto \Delta e$$

$$\Delta V_R = K_A \Delta e \qquad (2)$$

where, K_A = Amplifier gain constant.

ΔV_R = o/p voltage of amplifier.

Taking Laplace Transform,

$$\Delta V_R(s) = G_A \, \Delta e(s).$$

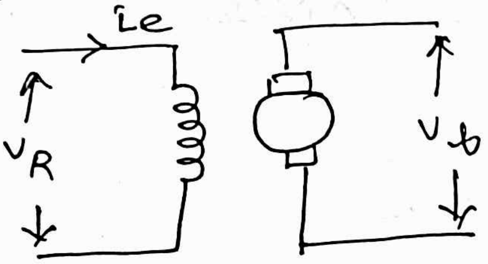
$$G_A = \frac{\Delta V_R(s)}{\Delta e(s)}.$$

In General, $G_A = \dfrac{K_A}{1+sT_A}$.

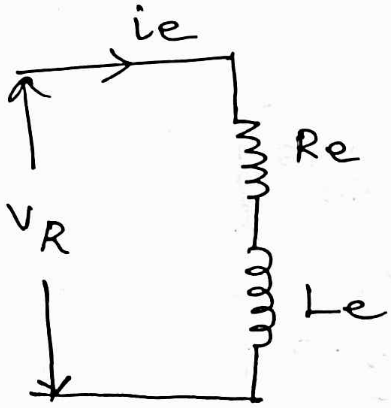
$T_A \rightarrow$ Time constant.

Block diagram :

Exciter :-



circuit



Equivalent circuit.

$$\Delta V_R = R_e \Delta i_e + L_e \cdot \frac{d}{dt} \Delta i_e \quad \text{——— (3).}$$

Output of exciter is,

$$\Delta V_f \propto \Delta i_e .$$

$$\Delta V_f = K_1 \Delta i_e . \quad \text{——— (4)}$$

Taking Laplace Transform for eqn (3) & (4):

$$\left.\begin{aligned} \Delta V_R(s) &= [R_e + sL_e] \, \Delta i_e(s) \\ \Delta V_f(s) &= K_1 \Delta i_e(s) \end{aligned}\right\} \quad (5).$$

Transfer function of exciter is

$$G_e = \frac{\Delta V_f(s)}{\Delta V_R(s)} .$$

$$= \frac{K_1 \cancel{\Delta i_e(s)}}{(R_e + sL_e) \cancel{\Delta i_e(s)}} .$$

$$= \frac{K_1}{R_e + sL_e}$$

Take Re outside,

$$= \frac{K_1}{R_e \left[1 + \frac{L_e}{R_e} s \right]} .$$

$$= \frac{K_1 / R_e}{1 + \frac{L_e}{R_e} . S} .$$

Sub $K_e = \frac{K_1}{R_e}$; Gain of exciter.

$T_e = \frac{L_e}{R_e}$; Time constant of exciter.

Block diagram :

$$\Delta V_e \longrightarrow \boxed{\frac{K_e}{1+sT_e}} \longrightarrow \Delta V_f$$

Synchronous Generator :

The terminal voltage of generator is maintained constant during the varying load conditions using excitation system.

The terminal voltage is given by,

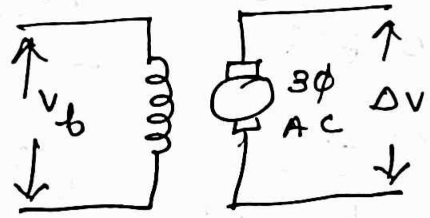
$\Delta V = \Delta E$.

where $\Delta E \Rightarrow$ Induced emf.

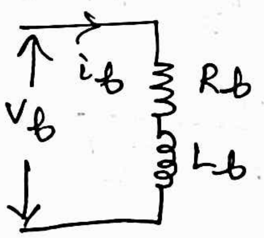
$\Delta V = \Delta E$ (neglecting drop).

* Taking Laplace Transform.

$\Delta V(s) = \Delta E(s)$ ——— (6).



Circuit Diagram.



Equivalent circuit.

Apply KVL,

$$\Delta V_f = R_f \Delta i_f + L_f \frac{d}{dt} \Delta i_f \quad \text{—— (7).}$$

$$E_{Max} = I_f X_L.$$

$$= I_f 2\pi f L_{fba}$$

$$= I_f \omega L_{fba}.$$

$$E_{Max} = \left(\frac{I_f}{\sqrt{2}}\right) \omega L_{fba}.$$

$$\Delta I_f = \frac{\sqrt{2} \cdot \Delta E_{max}}{\omega L_{fba}} \quad \text{—— (8).}$$

sub eqn (8) in (7) :

$$\Delta V_f = R_f \cdot \frac{\sqrt{2} \cdot \Delta E_{max}}{\omega L_{fba}} + L_f \cdot \frac{d}{dt}\left(\frac{\sqrt{2}}{\omega L_{fba}} \cdot \Delta E_{max}\right).$$

$$= \frac{\sqrt{2}}{\omega L_{fba}}\left[R_f \cdot \Delta E_{max} + L_f \cdot \frac{d}{dt} \Delta E_{max}\right].$$

Taking Laplace Transform,

$$\Delta V_f(s) = \frac{\sqrt{2}}{\omega L_{fba}}\left[R_f + L_f \cdot s\right] \Delta E(s).$$

Transfer function:

$$\frac{V(s)}{\Delta V_f(s)} = \frac{\Delta E(s)}{\Delta V_f(s)} = \frac{1}{\frac{\sqrt{2}}{\omega L_{fba}}(R_f + L_f \cdot s)}$$

$$= \frac{\omega L_{fba}}{\sqrt{2} R_f \left(1 + s \cdot \frac{L_f}{R_f}\right)}.$$

$$= \frac{K_f}{1 + s T_{do}'}.$$

Methods of Voltage Control :-

Voltage Control is done by controlling the generation, absorption & reactive power flow in the system.

The following are the methods of voltage control:

1) By Excitation control
2) By static shunt capacitor.
3) By static series capacitor
4) By static shunt reactor
5) By synchronous Condensers.
6) Tap changing Transformer
7) Booster Transformer
8) Regulating Transformer
9) static VAR Compensators.

Importance of Voltage Control :-

→ If the supply voltage to an incandescent lamp decreases by 6 % of rated value, Illuminating power may decrease by 20 %.

→ If the supply voltage is 6 % above the rated value, life of the lamps may be reduced by 50 % due to rapid deterioration of the filament.

→ If the supply voltage is above the normal, the motor may operate with saturated magnetic circuit, with consequent magnetising current, heating & low power factor.

→ If the voltage is too low, it will reduce the starting torque of motor considerably.

→ Too wide variations of voltage cause excessive heating of distribution Transformers. This may reduce their ratings.

1) Excitation control :-

The voltage of the alternator can be kept constant by changing the field current of the alternator. This is called excitation control.

capacitors
- → series capacitors
- → shunt capacitors

Static shunt capacitors :

shunt capacitor banks are used to supply reactive power at both transmission & distribution level, along lines or substations of loads.

capacitors are either directly connected to a bus-bar or to the tertiary winding of main transformer.

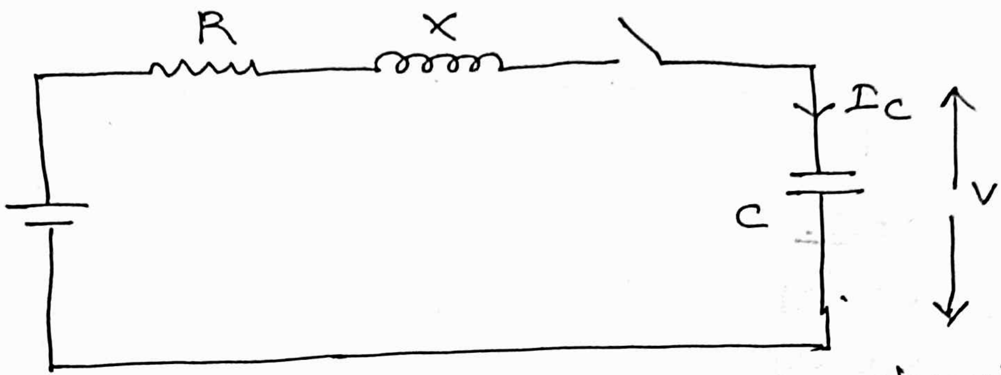
They may be switched ON & OFF depending on the changes in load demand.

⇒ when they are in <u>parallel</u> with a load, having lagging power factor, capacitors supply reactive power.

⇒ capacitive power output varies with the square of V.

$$KVAR, V_2 = KVAR, V_1 \left|\frac{V_2}{V_1}\right|^2.$$

<u>Rise in voltage due to shunt capacitance</u>:-



Static shunt capacitor.

Voltage drop without shunt capacitor,

$$\Delta V = \frac{P_2 R + Q_2 X}{|V|}$$

Voltage drop with shunt capacitor (including Q_c)

$$\Delta V' = \frac{P_2 R + (Q_2 - Q_c) X}{|V|}$$

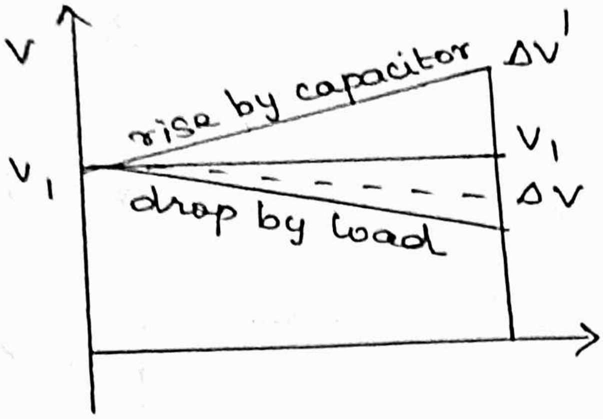
capacitor raisen voltage,

$$\Delta V_c = \Delta V - \Delta V'$$

$$= \frac{P_2 R + Q_2 X}{|V|} - \frac{P_2 R + (Q_2 - Q_c) X}{|V|}$$

$$= \frac{P_2 R}{|V|} + \frac{\cancel{Q_2 X}}{|V|} - \frac{\cancel{P_2 R}}{|V|} - \frac{\cancel{Q_2 X}}{|V|} + \frac{Q_C X}{|V|}.$$

$$\Delta V_C = \frac{Q_C X}{|V|}$$



Advantages :

1) Less costly.
2) Flexibility
3) Power factor improvement
4) Efficiency of Transmission & distribution of Power is high.
5) Reactive Power Compensation.

Disadvantages :

1) They cannot be overloaded.
2) The reactive power supplied by static capacitors tends to decrease in case of voltage dip. [$KVAR \propto V^2$].

Problems :

1) Switching inrush currents at higher frequencies & switching overvoltages.

2) Harmonic resonance problems.

3) Limited overvoltage withstand capability.

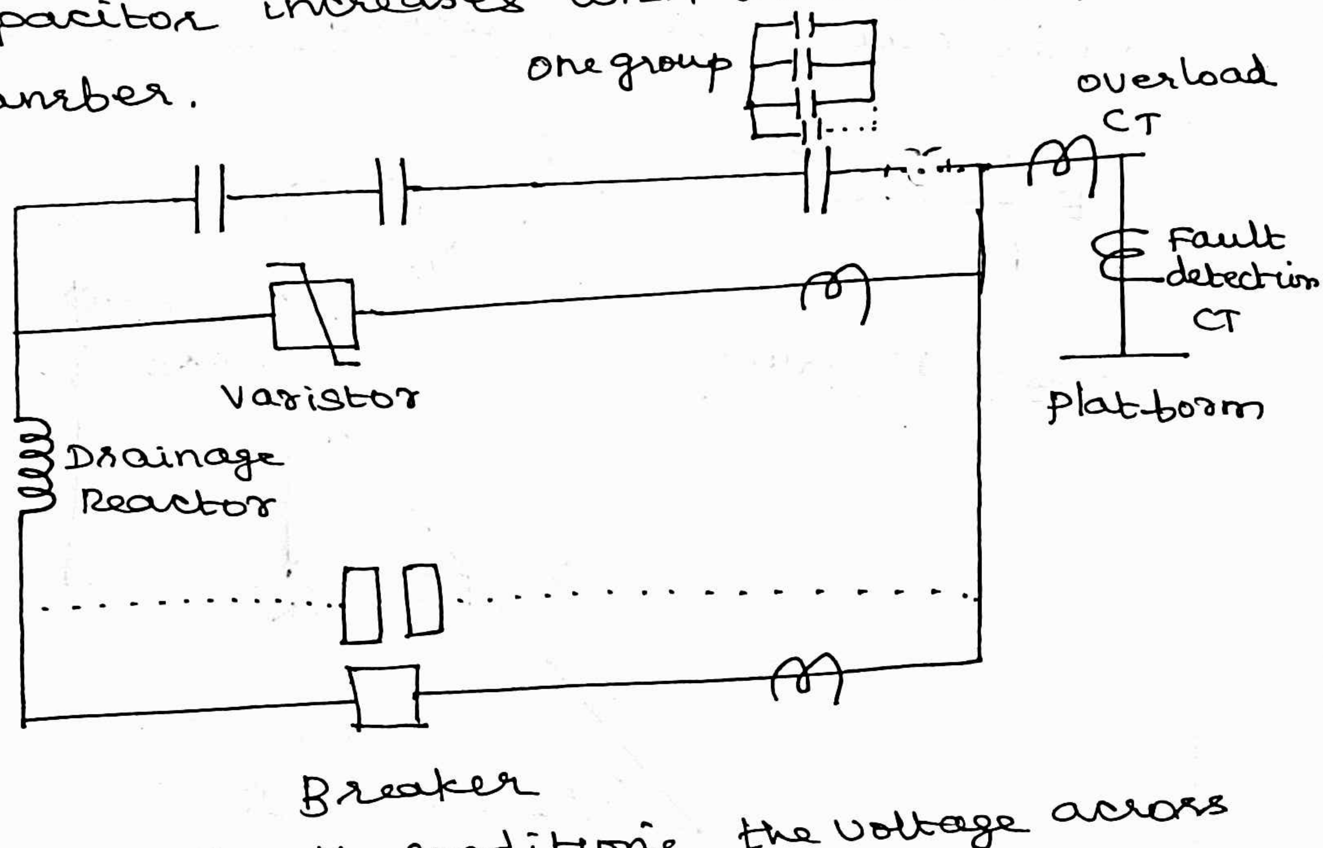
4) possibility of self-excitation of motors.

Series capacitor :

* capacitors are connected in series to compensate the reactive power.

* It increases maximum power that can be transmitted & reduces reactive power loss.

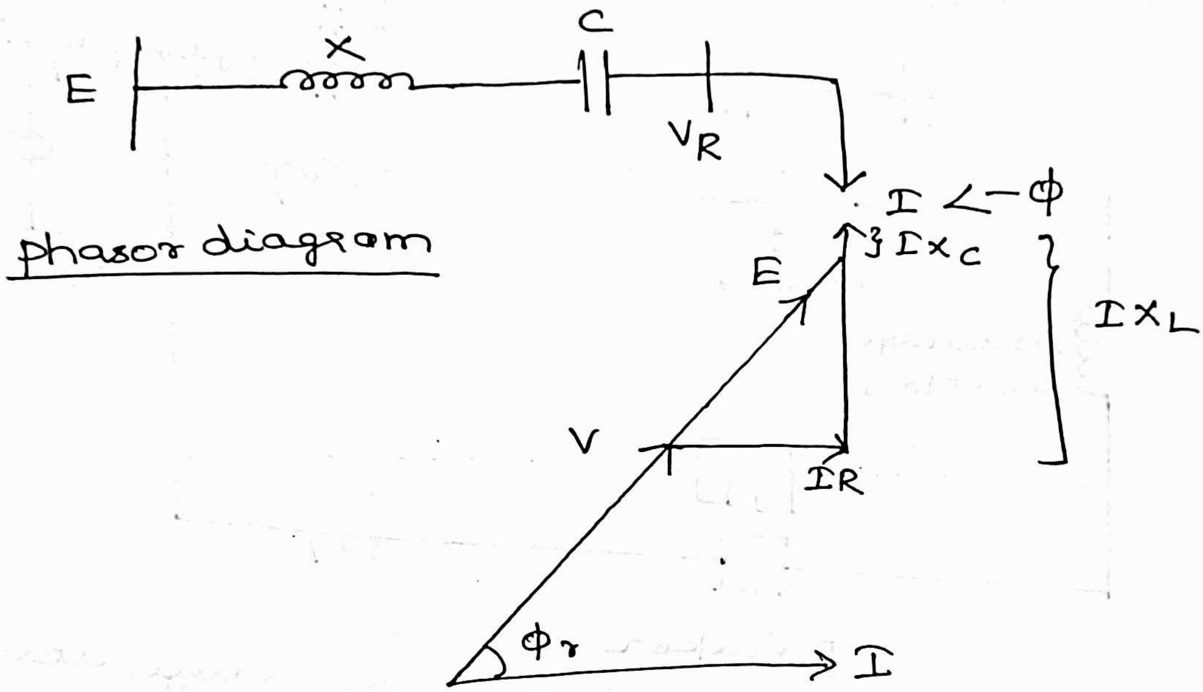
* Reactive power produced by the series capacitor increases with increase in power transfer.



* Under fault conditions, the voltage across the capacitor rises.

* A series capacitor experiences many times its rated voltage due to fault currents.
* A zinc oxide Varistor in parallel with the capacitor may be adequate to limit this voltage.
* For high fault currents a parallel triggered gap is introduced. It operates for more severe fault.
* When the spark gap triggers, it is followed by closure of the bypass breaker.
* The drainage reactor limits the frequency & magnitude of current through the capacitor when gap sparks.

Series capacitor connected in a line :-



The voltage drop across the line is,

$$\boxed{IR\cos\phi_r + I(X_L - X_C)\sin\phi_r}$$

* X_C value is chosen that the factor $(X_L - X_C)\sin\phi_r$ becomes negative, and numerically equal to $R\cos\phi_r$, so that the voltage drop becomes zero.

$$\text{Percentage Compensation} = \frac{X_C}{X_L}$$

The voltage boost produced by series capacitor is :

$$\Delta V = I X_C \sin\phi_r .$$

where X_C : capacitive reactance.

IX_C : Drop across capacitor.

$I^2 X_C$: VAR rating (reactive. power).

Drawbacks of series capacitor :

1. High over voltage is produced, under short circuit conditions. Therefore very high protective equipment is used.

   E.g : spark gap.

2. The drop across the capacitor is $I_f X_C$, where $I_f \Rightarrow 20$ times the full load current at certain conditions.

Location :-

The series capacitors are located in :

i) Midpoint of the line

ii) Line Terminals

iii) 1/3 or 1/4 of the line.

Advantages :

1) Improves voltage regulation of distribution & industrial feeders.

2) Reduces light flicker problems.

3) Improves system stability.

Shunt Reactor :

* Shunt Reactors absorb Reactive power.

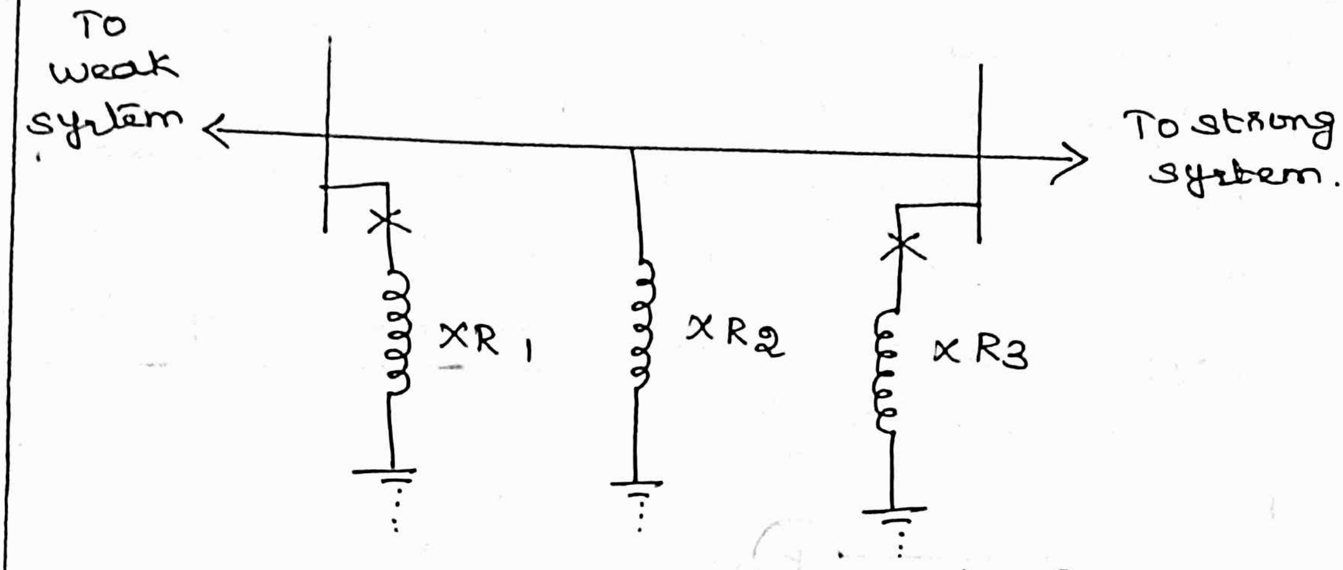
* They are usually used for EHV lines longer than and when the far end line is opened.

* The receiving line charging current flowing through the large source inductive reactance will ~~ra~~ rise the voltage.

* Ferranti effect ($V_R > V_S$) will cause a further rise in receiving end voltage due to shunt capacitance.

The following figure shows, the shunt reactors added to EHV bus.

. . T (P + 1x) — (1).



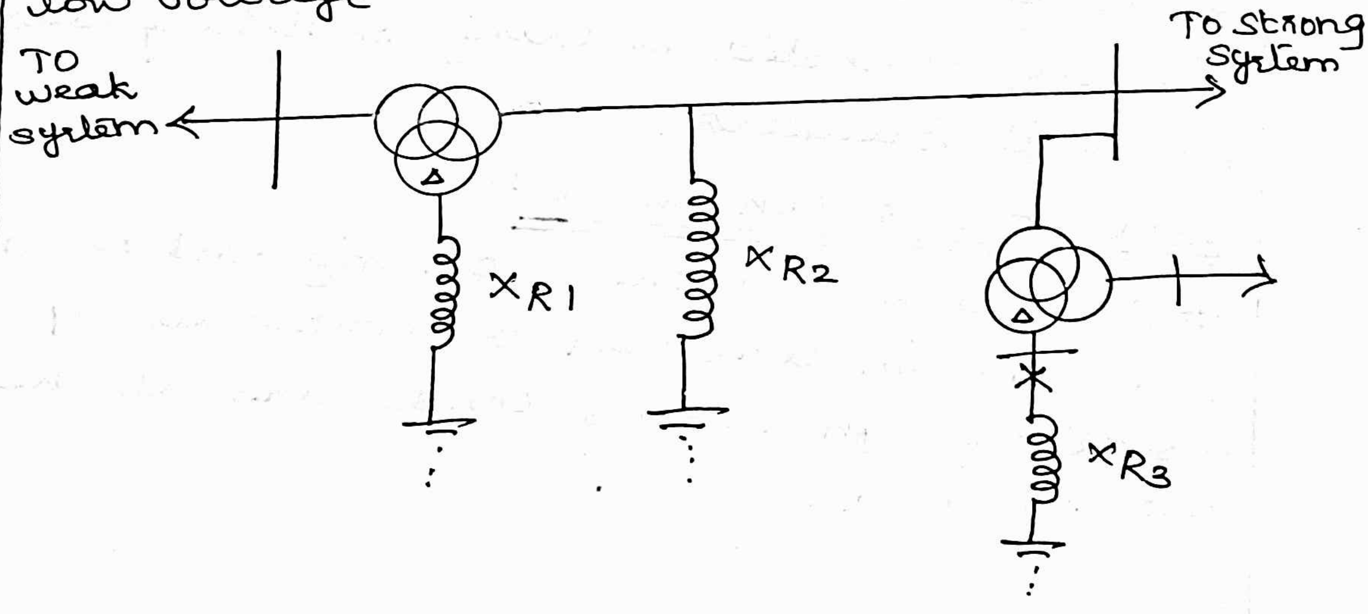
X_{R1}, X_{R3} — Switchable Reactors.

X_{R2} — Permanently Connected Reactor.

* Shunt reactors are switched in when the line is to be charged or during line is on low load.

* During high loads, series inductive reactance of the line produces $I \times L$ drop, and the receiving end voltage drops, then shunt reactors are switched OFF.

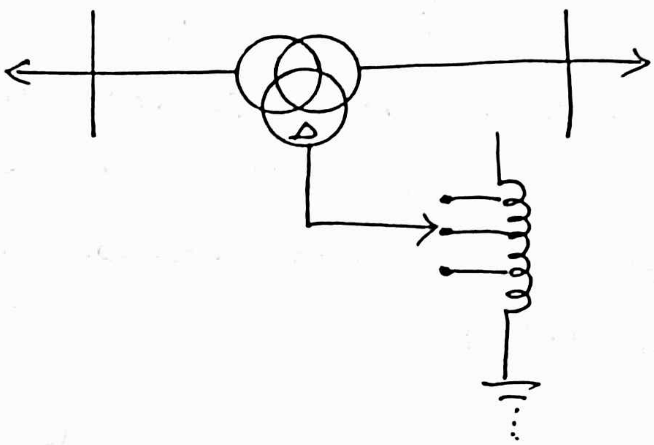
* Shunt reactors may be connected to the low voltage tertiary winding of Transformers.



shunt reactors are used to reduce or limit voltage rise due to open circuit (or) light load.

* During heavy loads some of the reactors may have to be disconnected.

Tapped reactors with on-load tap changer is shown below :



Advantages :-

* Limits temporary overvoltages.
* Limits switching Transients.
* To maintain normal voltage under light load conditions.
* During heavy load, some of the reactor can be disconnected by using switching reactors & circuit Breakers.

Synchronous condenser :-

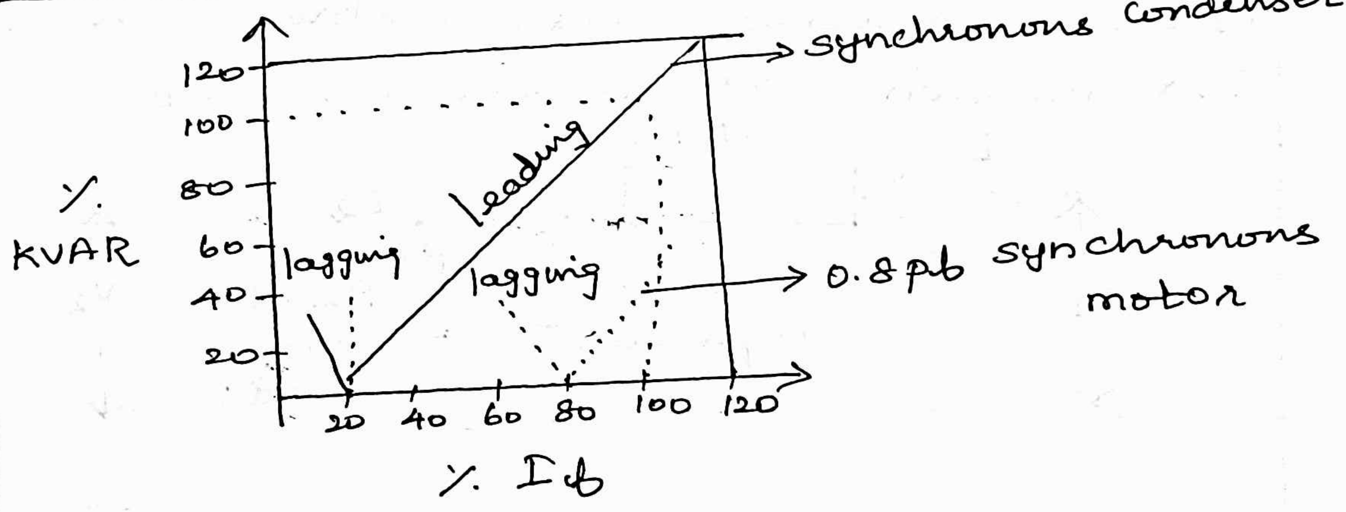
* The voltage at the receiving end of a Transmission line can be controlled by installing synchronous condensers at the receiving end.

* By controlling the field excitation, it can be made to generate or absorb reactive power.
* It can be automatically adjust reactive power output to maintain constant terminal voltage.
* It supplies VARs when over excited during peak load conditions.
* It consumes VARs when under excited during light load conditions.

$$Q = \frac{|V|}{|X_s|}\left[|E_g|\cos\delta - |V|\right].$$

If $|E_g|\cos\delta > |V|$; then $Q > 0$
synchronous condenser supplies reactive power.
If $|E_g|\cos\delta < |V|$; then $Q < 0$.
synchronous condenser absorb reactive power.

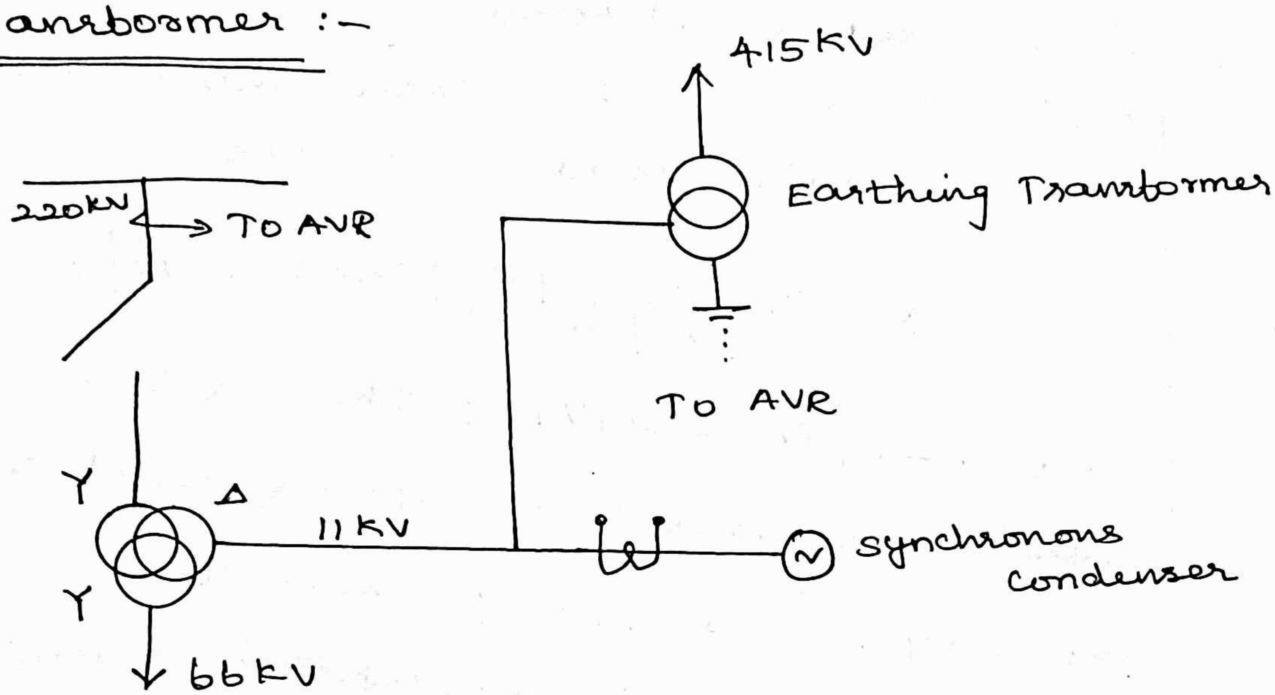
V curves :-



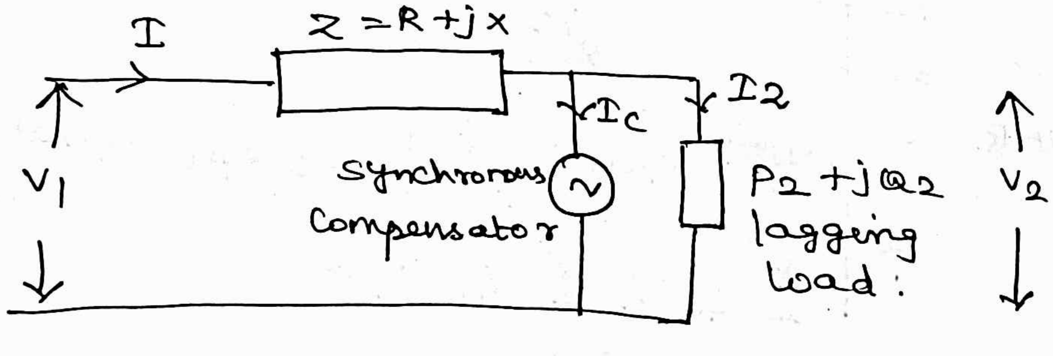
In a synchronons Condenser at 100 % excitation full load leading KVAR is obtained.

* At about 10 % of excitation current, leading KVAR output falls to minimum due to losses.

Synchronons condenser connected to main Transformer :-



* A synchronons Condenser is connected to the tertiary winding of main transformer for voltage & reactive power control at both Transmission & subtransmission levels.



$$V_1 = V_2 + I(R+jX) \quad \text{—— (1).}$$

$$\vec{I} = \vec{I_c} + \vec{I_2} \quad \text{—— (2).}$$

Approximately, $[\vec{I} = I(\cos\theta - j\sin\theta)]$.

$$|V_1| = |V_2| + IR\cos\theta + IX\sin\theta \quad \text{—— (3).}$$

adj. side $=$ hyp. $\cos\theta$.

$= I\cos\theta, \; I_2\cos\phi_2$.

$$|I|\cos\theta = |I_2|\cos\phi_2 \quad \text{—— (4).}$$

opp. side $=$ hyp. $\sin\theta$.

$= I\sin\theta, \; I_2\sin\phi_2$.

$$|I|\sin\theta = |I_2|\sin\phi_2 - I_c \quad \text{—— (5).}$$

sub (4) & (5) in (3) :

$$|V_1| = |V_2| + I_2\cos\phi_2 \cdot R + (|I_2|\sin\phi_2 - I_c)X$$

$$= |V_2| + |I_2| R\cos\phi_2 + |I_2| X\sin\phi_2 - I_c X \text{ — (6)}$$

wkT,

$$(7) \Leftarrow \begin{cases} P_2 = V_2 I_2 \cos\phi_2 \Rightarrow I_2\cos\phi_2 = P_2/V_2. \\ Q_2 = V_2 I_2 \sin\phi_2 \Rightarrow I_2\sin\phi_2 = Q_2/V_2. \\ Q_c = |V_2| I_c \Rightarrow I_c = \dfrac{Q_c}{V_2}. \end{cases}$$

sub (7) in (6) $\Rightarrow$

$$|V_1| = |V_2| + \frac{R.P_2}{|V_2|} + \frac{Q_2 X}{|V_2|} - \frac{Q_c X}{|V_2|}.$$

$$\left.\begin{aligned} |V_1| &= |V_2| + \frac{RP_2 + X(Q_2 - Q_c)}{|V_2|} \\ |V_2| &= |V_1| - \frac{RP_2 + X(Q_2 - Q_c)}{|V_2|} \end{aligned}\right\} \longrightarrow (8).$$

If $|V_1|$, $|V_2|$ values are known, the necessary capacity of synchronous condenser can be found from above eqn :

Advantages :

1) Reactive power production is not affected by system voltage.

2) Flexibility.

3) Smooth variation of reactive power.

4) Used in HVDC converter stations.

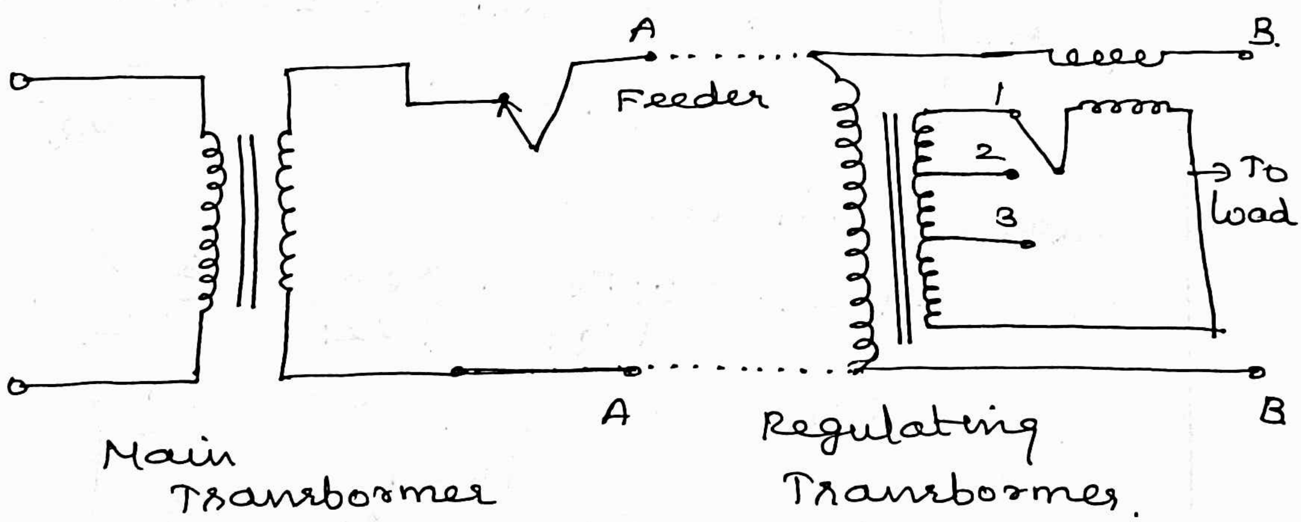
Disadvantages :

1) Installation cost is high.

2) It can fall out of step which may result in large sudden change in voltage.

Booster Transformer & Regulating Transformer :-

* To control the voltage of a transmission line at a point far away from the main transformer, booster transformer can be used.



* The secondary of the booster Transformer is connected in series with the line whose voltage is to be controlled.
* The primary of this Transformer is supplied from a regulating Transformer filled with on-load tap changing gear.
* The boost Transformer secondary injects a voltage in phase with the line voltage.
* The voltage at AA is maintained constant by tap changing gear in the main Transformer.
* There may be considerable voltage drop between AA & BB due to long feeder & tapping of loads.
* The voltage at BB is controlled by use of regulating Transformer + Boost Transformer.
* By changing the tapping on the regulating Transformer, the magnitude of voltage injected into the line can be varied.
* This permits to keep the voltage at BB to desired value.

Disadvantages :

1) Expensive than on-load tap changing Transformer
2) Less efficient owing to losses in the Booster.
3) More floor space is required.

Tap changing Transformer :

In this method a number of tappings are provided on the secondary of Transformer.

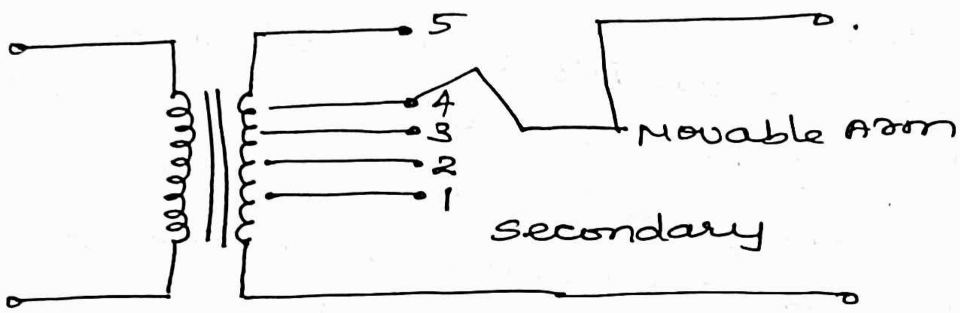
The voltage drop in the line is supplied by changing the secondary e.m.f of transformer through the adjustment of its number of turns.

Two methods :

i) OFF load Tap-changing Transformer.

ii) ON load Tap-changing Transformer.

OFF load Tap-changing Transformer :



* As the position of tap is varied on the secondary side, the effective number of secondary turns is varied & hence the output voltage of secondary can be changed.

Arm makes contact with stud 1.

⇒ Secondary voltage is minimum.

Arm makes contact with stud 5.

⇒ Secondary voltage is maximum.

Light load condition :

The movable arm is placed on stud 1.

Heavy Load condition :-

=) The movable arm is moved to a higher stud.

Disadvantage :

1) It cannot be used for tap-changing on-load.

Why off load Tap changing Transformer cannot be used for tap-changing on-load ?

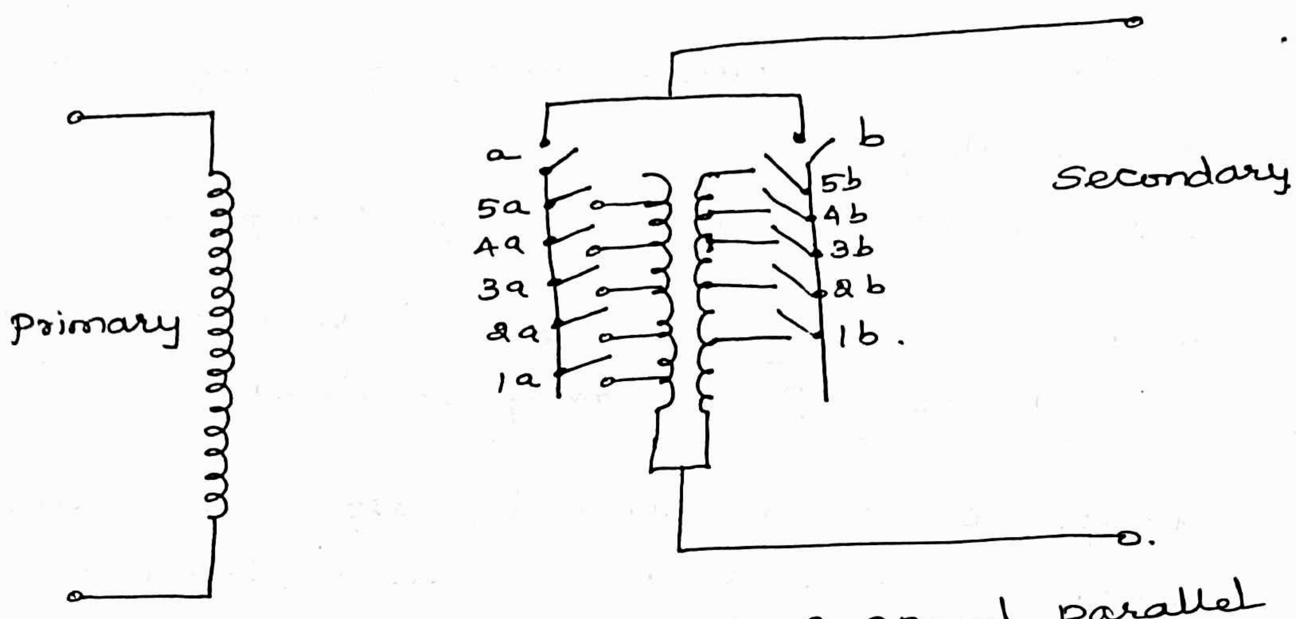
* suppose for a moment, tapping is changed from stud ① to stud ②, when the transformer is supplying load.

* In contact with stud ① is broken before contact with stud ② is made, there is break in the circuit & arcing result.

* If contact with stud ② is made before contact with stud ① is broken, coils b/w there 2 tappings are short circuited. & carry damaging heavy currents.

(ii) ON-load Tap changing Transformer :

The tap changing is performed on-load, so there is no interruption of supply.



The secondary consists of 2 equal parallel windings which have similar tappings 1b, 2b, 3b, 4b, 5b, 1a, 2a, 3a, 4a, 5a, ~~b~~

⇒ 2 switches a & b are provided.

Secondary voltage → maximum

switches a, b closed.

tappings 5a, 5b closed.

Secondary voltage → minimum

switches a, b closed.

Tappings 1a, 1b closed.

Working :

1) Suppose Transformer is working with tapping position at 4a, 4b.

If we want to change the position to 5a, 5b.

2) If we want to change the position to 5a, 5b.

3) First switch a is opened, tapping is changed from 4a to 5a.

4) Now secondary winding controlled by switch b carries the total current which is twice its rated capacity.

→ switch 'a' is closed.

→ Then switch b is opened, tapping is changed from 4b to 5b.

→ switch 'b' is closed.

→ In this way tapping position is changed

→ without interrupting the supply.

Disadvantages :

1) During switching, impedance of transformer is increased & there will be voltage surge.

2) There are twice as many tappings.

UNIT - IV ECONOMIC OPERATION OF POWER SYSTEM

Statement of economic dispatch problem - input and output characteristics of thermal plant - Incremental cost curve - optimal operation of thermal units without and with transmission losses (no derivation of transmission loss coefficients) - base point and participation factors method - statement of unit commitment (UC) problem - constraints on UC problem - solution of UC problem using priority list - special aspects of short term and long term hydrothermal problems.

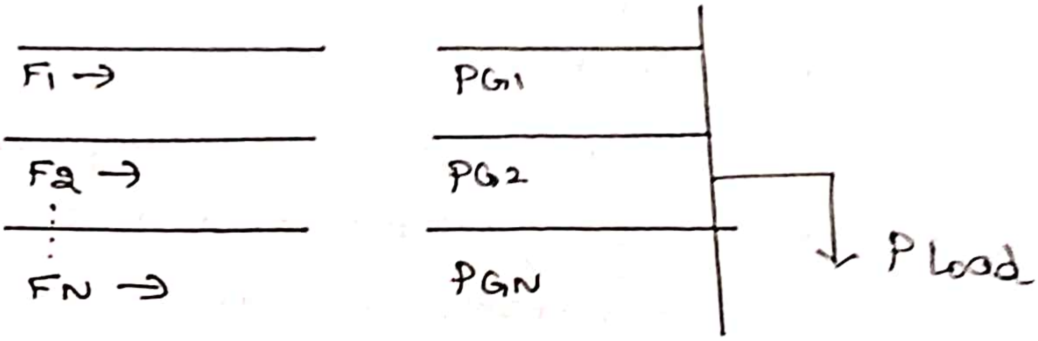
Economic Dispatch control :

The purpose of economic dispatch or optimal dispatch is to reduce fuel costs for the power system.

By economic load scheduling, we mean to find the generation of the different generators, so that the total fuel cost is minimum and at the same time the total demand + losses at any instant must be met by the total generation.

The economic dispatch problem involves the solution of 2 different problems.
1) Unit committment 2) ON-time dispatch.

Statement of Economic Dispatch problem:



→ Consider a system consisting of N-thermal generating units connected to a single bus-ba serving a load of P_{load}.

→ F_1 is the cost rate of the unit.

→ The output $P_{G1}, P_{G2} \ldots\ldots P_{GN}$ is the electrical power generated.

→ The total cost is the sum of individual units

$$F_T = F_1 + F_2 + \ldots\ldots + F_N .$$

$$\boxed{F_T = \sum_{i=1}^{N} F_i (P_i)}$$

The problem is to minimize F_T.

Cost of Generation :-

→ The total generator operating cost includes fuel cost, cost of Transmission loss, labour and maintenance load.

→ For simplicity, fuel cost is considered to be variable.

→ Fuel cost is meaningful in thermal & nuclear cases only.

But for hydrostations, where the ... of storage is free & not considered.

Constraints :

The cost of generation depends on the operating constraints :

i) Equality constraint

ii) Inequality constraint

iii) Generator constraint

iv) Voltage constraint

v) Running space capacity constraints

vi) Transformer tap settings.

vii) Transmission ~~loss~~ line constraints

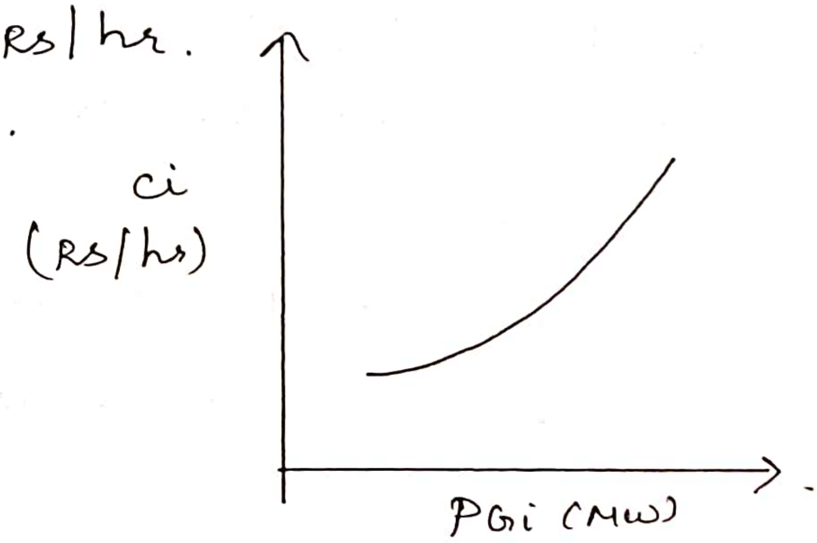
viii) Network security.

Input - output curve of a Generating Unit:

The curve drawn between cost of fuel Vs generator power output P_{Gi}.

$C_i(P_{Gi})$ in Rs/hr.

P_{Gi} in MW.



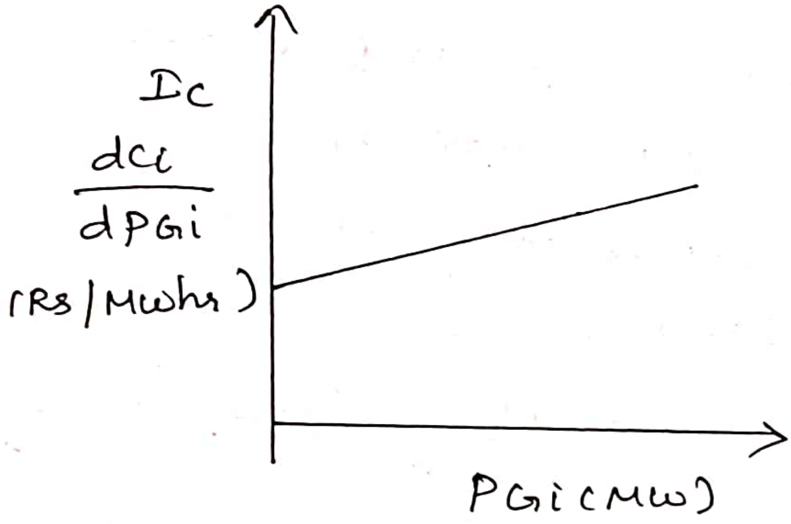
Incremental cost curve : (IC)

The curve drawn between $\frac{dc_i}{dP_{Gi}}$ Vs P_{Gi} is called incremental cost curve.

WKT, $C_i(P_{Gi}) = a_i P_{Gi}^2 + b_i P_{Gi} + c_i$ (Rs/hr).

$$IC = \frac{dc_i}{dP_{Gi}} = 2a_i P_{Gi} + b_i.$$

It is a linear equation, so the curve will be like below :



(Q) In a Power system having 2 units, the loss co-efficient are,

$B_{11} = 0.0015$/MW

$B_{21} = -0.0006$/MW

$B_{12} = -0.0006$/MW

$B_{22} = -0.0024$/MW.

The incremental production costs of the units are:

$$\frac{dF_1}{dP_{G1}} = 0.08 P_{G1} + 20 \text{ Rs/Mwhr}.$$

$$\frac{dF_2}{dP_{G2}} = 0.09 P_{G2} + 16 \text{ Rs/Mwhr}.$$

Find the generation schedule for $\lambda = 20$ & 25. Find also the change in transmission losses between the 2 schedules.

$$B_{ij} \text{ (or) } B_{mn} = \begin{bmatrix} 0.0015 & -0.0006 \\ -0.0006 & 0.0024 \end{bmatrix}.$$

$$IC_1 = 0.08 P_{G1} + 20$$

$$IC_2 = 0.09 P_{G2} + 16$$

$$(ITL)_1 = 2 B_{11} P_{G1} + 2 B_{12} P_{G2}$$

$$= 2 \times 0.0015 P_{G1} + 2(-0.0006) \times P_{G2}$$

$$(ITL)_1 = 0.003 P_{G1} - 0.0012 P_{G2}.$$

$$(ITL)_2 = 2 B_{22} P_{G2} + 2 B_{12} P_{G1}.$$

$$= 2 \times 0.0024 \times P_{G2} + 2(-0.0006) \times P_{G1}$$

$$= 0.0048 P_{G2} - 0.0012 P_{G1}.$$

From co-ordination equation:

$$\frac{IC_1}{1 - ITL_1} = \frac{IC_2}{1 - ITL_2} = \lambda.$$

when $\lambda = 20$

$$\frac{0.08 P_{G1} + 20}{1 - (0.003 P_{G1} - 0.0012 P_{G2})} = \frac{0.09 P_{G2} + 16}{1 + 0.0012 P_{G1} - 0.0048 P_{G2}}$$

$$= 20$$

$$\frac{0.08 P_{G1} + 20}{1 - 0.003 P_{G1} + 0.0012 P_{G2}} = 20$$

$$0.02 P_{G1} - 0.024 P_{G2} = 0 \quad \text{—— (1).}$$

$$\frac{0.09 P_{G2} + 16}{1 + 0.0012 P_{G1} - 0.0048 P_{G2}} = 20 \quad \text{—— (2).}$$

From (1) & (2)

$$P_{G1} = 27.397 \text{ MW}$$

$$P_{G2} = 22.82 \text{ MW}$$

$$P_L = 0.0015 \times 27.397^2 + 2 \times (-0.0006) \times 27.397 \times 22.82$$

$$+ 0.0024 \times 22.82^2$$

$$\boxed{P_L = 1.628 \text{ MW}}$$

$\lambda = 25$,

$$\frac{0.08 P_{G1} + 20}{1 - 0.003 P_{G1} + 0.0012 P_{G2}} = 25 \quad \text{—— (3)}$$

$$\frac{0.09 P_{G1} + 16}{1 + 0.0012 P_{G1} - 0.0048 P_{G2}} = 25. \quad \text{—— (4).}$$

From (3) & (4) :

$P_{G1} = 42.647$ MW.

$P_{G2} = 53.667$ MW.

$P_L = 0.0015 \times 42.647^2 + 2(-0.0006) \times 42.647 \times 53.667 + 0.0024 \times 53.667^2$.

$= 6.894$ MW.

Change in Transmission loss $= 6.894 - 1.628$

$= 5.266$ MW.

(2) Three Power plants of total capacity of 425 MW are scheduled for operation to supply total system load of 300 MW. Find the optimum generation scheduling if the plants have following of cost characteristics & generation constraints.

$F_1 = 0.075 P_1^2 + 30 P_1 + 50$ Rs/hr $25 \le P_1 \le 125$ MW

$F_2 = 0.10 P_2^2 + 40 P_2 + 75$ Rs/hr, $30 \le P_2 \le 100$ MW

$F_3 = 0.09 P_3^2 + 15 P_3 + 35$ Rs/hr, $50 \le P_3 \le 200$ MW.

$$\lambda = \frac{300 + \left(\frac{30}{0.15} + \frac{40}{0.2} + \frac{15}{0.18}\right)}{\left(\frac{1}{0.15} + \frac{1}{0.2} + \frac{1}{0.18}\right)} = 45.48$$

$$P_1 = \frac{\lambda - b_1}{2a_1} = \frac{45.48 - 30}{2 \times 0.075} = 103.3$$

||ly $P_2 = 27.4$; $P_3 = 169.3$.

P_2 violates Limit ; $P_2 = P_{2,min} = 30\,MW$.

$P_{D,new} = 300 - 30 = 270\,MW$.

$$\lambda_{new} = \frac{270 + \left(\frac{30}{0.15} + \frac{15}{0.18}\right)}{\frac{1}{0.15} + \frac{1}{0.18}} = 45.31$$

$$P_{G1} = \frac{45.31 - 30}{2 \times 0.075} = 102\,MW.$$

$$P_{G3} = \frac{45.31 - 15}{2 \times 0.09} = 168\,MW.$$

(2) The fuel cost for 3 thermal plants in plan are given by,

$$F_1 = 0.004 P_{g1}^2 + 5.3 P_{g1} + 500$$

$$F_2 = 0.006 P_{g2}^2 + 5.5 P_{g2} + 400$$

$$F_3 = 0.009 P_{g3}^2 + 5.8 P_{g3} + 200$$

where P_{g1}, P_{g2} & P_{g3} are in MW. Find the optimal dispatch & the total cost when the load is 925 MW with the following generator limits :

$$100\,MW \le P_{g1} \le 450\,MW$$

$$100\,MW \le P_{g2} \le 350\,MW$$

$$100\,MW \le P_{g3} \le 225\,MW$$

Solution :

Step : 1 calculate λ

$$\lambda = \frac{P_D + \sum_{i=1}^{N} \frac{b_i}{2a_i}}{\sum_{i=1}^{N} \frac{1}{2a_i}}$$

$$= \frac{925 + \left[\frac{b_1}{2a_1} + \frac{b_2}{2a_2} + \frac{b_3}{2a_3}\right]}{\frac{1}{2a_1} + \frac{1}{2a_2} + \frac{1}{2a_3}}$$

$$= \frac{925\left[\frac{5.3}{2\times 0.004} + \frac{5.5}{2\times 0.006} + \frac{5.8}{2\times 0.009}\right]}{\left[\frac{1}{2\times 0.004} + \frac{1}{2\times 0.006} + \frac{1}{2\times 0.009}\right]}$$

$$\lambda = 8.9737$$

Step 2 : Calculate P_{G1}, P_{G2}, P_{G3}

$$P_{Gi} = \frac{\lambda - b_i}{2a_i}$$

$$P_{G1} = \frac{8.9737 - 5.3}{2\times 0.004} = 459.2125 \text{ MW.}$$

$$P_{G2} = \frac{8.9737 - 5.5}{2\times 0.006} = 289.475 \text{ MW.}$$

$$P_{G3} = \frac{8.9737 - 5.8}{2\times 0.009} = 176.3167 \text{ MW}$$

Step: 3 Checking for limits :

$100MW \le P_{g1} \le 450MW$

$100MW \le P_{g2} \le 350MW$

$100MW \le P_{g3} \le 225MW$

P_{g1} is violating the limit

$P_{g1} > 450 MW$

set $P_{g1} = P_{gi,Max}$

$P_{g1} = 450$

Step : 5 Redistributed the Load P_D

$P_{D,new} = 925 - 450$

$= 475 MW$

$$\lambda_{new} = \frac{475 + \left[\frac{b_2}{2a_2} + \frac{b_3}{2a_3}\right]}{\frac{1}{2a_2} + \frac{1}{2a_3}}$$

$$= \frac{475 + \left[\frac{5.5}{2 \times 0.006} + \frac{5.8}{2 \times 0.009}\right]}{\frac{1}{2 \times 0.006} + \frac{1}{2 \times 0.009}}$$

$= 9.04$

Step 7

$$P_{G2} = \frac{9.04 - 5.5}{2 \times 0.006} = 295 MW.$$

$$P_{G3} = \frac{9.04 - 5.8}{2 \times 0.009} = 180 MW.$$

$P_{G1} = 450 MW$

$P_{G2} = 295 MW$

$P_{G3} = 180 MW$.

Fuel cost :

$F_1 = 0.004 \times 450^2 + 5.3 \times 450 + 500$

$= 3695$

$F_2 = 0.006 \times 295^2 + 5.5 \times 295 + 400$

$= 2544.65$

$F_3 = 0.009 \times 180^2 + 5.8 \times 180 + 200$

$= 1535.6$

Total cost $= F_1 + F_2 + F_3$

$= 3695 + 2544 + 1535.6$

$= 7775.$

Fuel constraints :

—x—x—x—

A system in which some units have limited fuel or else have constraints that require them to burn a specified amount of fuel in a given time presents a most challenging Unit committment problem.

The fuel cost of two units are given by,

$$F_1 = 1.6 + 25\,Pg_1 + 0.1\,Pg_1^2 \quad (Rs/hr)$$

$$F_2 = 2.1 + 32\,Pg_2 + 0.1\,Pg_2^2 \quad (Rs/hr).$$

If the total demand on the generator is 250MW. Find the economic load scheduling of 2 units :

$$P_D = 250MW.$$

(Limit not Given)

Step :1) calculate λ

$$\lambda = \frac{P_D + \sum_{i=1}^{N} \frac{b_i}{2a_i}}{\sum_{i=1}^{N} \frac{1}{2a_i}}$$

$$= \frac{250 + \left[\frac{250}{2\times 0.1} + \frac{32}{2\times 0.1}\right]}{\left[\frac{1}{2\times 0.1} + \frac{1}{2\times 0.1}\right]}$$

$$= 53.5$$

Step 2 : calculate P_{Gi} i.e P_{G1}, P_{G2}.

$$P_{G1} = \frac{\lambda - b_1}{2a_1} = \frac{53.5 - 25}{2\times 0.1} = 142.5$$

$$P_{G2} = \frac{\lambda - b_2}{2a_2} = \frac{53.5 - 32}{2\times 0.1} = 107.5$$

Step : 3

Calculate $\sum_{i=1}^{N} P_{Gi}$

$= P_{G1} + P_{G2}$

$= 142.5 + 107.5$

$\sum_{i=1}^{N} P_{Gi} = 250.$

Step : 4 check power Balance Equation :

$$\sum_{i=1}^{N} P_{Gi} = P_D$$

$$250 = 250$$

Hence satisfied

$P_{G1} = 142.5$ MW

$P_{G2} = 107.5$ MW

optimum load scheduling is reached.

(3) A plant has 2 generator supplying the plant bus and neither is to operate below 20MW or above 135MW. Incremental costs with $P_{G1} + P_{G2}$ in MW are :

$$\frac{dF_1}{dP_{G1}} = 0.14 P_{G1} + 21 \quad (\text{Rs}/\text{MWhr})$$

$$\frac{dF_2}{dP_{G2}} = 0.225 P_{G2} + 16.5 \quad (\text{Rs}/\text{MWhr}).$$

Find the optimum schedule when
(i) $P_D = 45$ MW (ii) $P_D = 125$ MW (iii) $P_D = 250$ MW.

$$F_1 = a_1 P_{G1}^2 + b_1 P_{G2} + c_1 .$$

$$\frac{dF_1}{dP_{G1}} = 2a_1 P_{G1} + b_1$$

$2a_1 = 0.14$; $b_1 = 21$.

Limits $20\,MW \le P_G \le 135\,MW$.

(i) $P_D = 45\,MW$:

$$\lambda = \frac{45 + \left[\frac{21}{2\times0.07} + \frac{16.5}{2\times0.1125}\right]}{\left[\frac{1}{2\times0.07} + \frac{1}{2\times0.1125}\right]}$$

$$= 23.15$$

$$P_{G1} = \frac{\lambda - b_1}{2a_1} = \frac{23.15 - 21}{2\times0.07} = 15.41\,MW$$

$$P_{G2} = \frac{\lambda - b_2}{2a_2} = \frac{23.15 - 16.5}{0.225} = 29.55\,MW$$

Check for limits :

P_{G1} is violating

$P_{G1} = P_{G1,min} = 20\,MW$

Check for optimality,

$$\frac{dF_1}{dP_{G1}} > \lambda$$

$$0.14P_{G1} + 21 > \lambda$$

$$0.14\times20 + 21 > \lambda$$

$$23.8 > 23.15$$

Optimality condition is satisfied.

$P_{G1} = 20\,MW$; $P_{G2} = P_D - P_{G1} = 25\,MW$.

(ii) $P_D = 125\,MW$

$$\lambda = \frac{P_D + \sum_{i=1}^{N} \frac{b_i}{2a_i}}{\sum_{i=1}^{N} \frac{1}{2a_i}}$$

$$= \frac{125 + \left[\frac{21}{0.14} + \frac{16.5}{0.225}\right]}{\left[\frac{1}{0.14} + \frac{1}{0.225}\right]}$$

$= 30.06$.

$$P_{G1} = \frac{\lambda - b_1}{2a_1} = \frac{30.06 - 21}{0.14} = 64.72$$

$$P_{G2} = \frac{\lambda - b_2}{2a_2} = \frac{30.06 - 16.5}{0.225} = 60.26$$

Both P_{G1} & P_{G2} are within the limits.

Hence optimum schedule,

$P_{G1} = 64.72$

$P_{G2} = 60.26$.

(iii) $P_D = 250\,MW$:

$$\lambda = \frac{250 + \left[\frac{21}{0.14} + \frac{16.5}{0.225}\right]}{\frac{1}{0.14} + \frac{1}{0.225}} = 40.849$$

$$P_{G1} = \frac{\lambda - b_1}{2a_1} = \frac{40.849 - 21}{2 \times 0.07} = 141.78.$$

$$P_{G2} = \frac{\lambda - b_2}{2a_2} = \frac{40.849 - 16.5}{0.225} = 108.21$$

P_{G1} is violating the limit,

$$P_{G1} > P_{G,max}$$

$$P_{G1} = 135\ MW$$

Check for optimal condition:

$$\frac{dF_1(P_{G1})}{dP_{G1}} \leq \lambda$$

$$0.14 P_{G1} + 21 < \lambda$$

$$0.14 \times 135 + 21 < 40.849$$

$$39.9 < 40.849$$

Condition satisfied,

Hence optimum schedule,

$$P_{G1} = 135\ MW$$

$$P_{G2} = P_D - P_{G1}$$

$$= 250 - 135$$

$$\boxed{P_{G2} = 115\ MW}$$

4. Determine the economic generation schedule of 3 generating units in a power system to meet the system load of 925 MW. The operating limit & cost function is given below:

$$250\ MW \leq P_{G1} \leq 450\ MW$$

$$200\ MW \leq P_{G2} \leq 350\ MW$$

$$125\ MW \leq P_{G3} \leq 225\ MW$$

Cost function:

$$F_1 = 0.0045 P_{G1}^2 + 5.2 P_{G1} + 580$$

$$F_2 = 0.0056 P_{G2}^2 + 4.5 P_{G2} + 640$$

$$F_3 = 0.0079 P_{G3}^2 + 5.8 P_{G3} + 820.$$

Step 1 :

$$\lambda = \frac{925 + \left[\frac{5.2}{2\times 0.0045} + \frac{4.5}{2\times 0.0056} + \frac{5.8}{2\times 0.0079}\right]}{\left[\frac{1}{2\times 0.0045} + \frac{1}{2\times 0.0056} + \frac{1}{2\times 0.0079}\right]}$$

$$= 8.6149 .$$

Step 2 $\quad P_{Gi} = \frac{\lambda - b_i}{2a_i}$

$$P_{G1} = \frac{8.6149 - 5.2}{2\times 0.0045} = 379.43$$

$$P_{G2} = \frac{8.6149 - 4.5}{2\times 0.0056} \simeq 367.401$$

$$P_{G3} = \frac{8.6149 - 5.8}{2\times 0.0079} \simeq 178.158 .$$

Step 3 $\quad$ check for limits :

P_{G2} is violating the limit,

$200 \leq P_{G2} \leq 350\, MW$

$P_{G2} = P_{G\,max} = 350\, MW$

Step 4 $\quad$ calculate P_{D}, new

P_{D}, new $= P_{D}$, old $-$ sum of fixed generations

$= 925 - 350$

$= 575\, MW.$

Step 5 $\quad \lambda_{new} = \frac{P_{D}\,new + \sum_{i=1}^{N} \frac{b_i}{2a_i}}{\sum_{i=1}^{N} \frac{1}{2a_i}}$

$$= \frac{575 + \left[\frac{5.2}{2\times 0.0045} + \frac{5.8}{2\times 0.0079}\right]}{\frac{1}{2\times 0.0045} + \frac{1}{2\times 0.0079}}$$

$$= 8.7147$$

Step 6 : $P_{G1} = \frac{\lambda_{new} - b_1}{2a_1} = \frac{8.7147 - 5.2}{2\times 0.0045} = 390.5$

$P_{G3} = \frac{\lambda_{new} - b_3}{2a_3} = \frac{8.7147 - 5.8}{2\times 0.0079} = 184.47$

$P_{G1} = 390.5$ MW

$P_{G2} = 350$ MW

$P_{G3} = 184.47$ MW

Step 7 check for optimality :

$$\frac{dF_2}{dP_{G2}} \leq \lambda_{new}$$

$$2\times 0.0056 P_{G2} + 4.5 \leq 8.7147$$

$$2\times 0.0056 \times 350 + 4.5 \leq 8.7147$$

$$8.42 \leq 8.71.$$

optimal condition satisfied.

Therefore optimum schedule is,

$P_{G1} = 390.5$ MW

$P_{G2} = 350$ MW

$P_{G3} = 184.47$ MW.

Consider previous example & determine economic dispatch by changing the limit for 3^{rd} unit $180MW \leq P_{G3} \leq 220MW$.

Solve using Equal incremental cost rule

(From co-ordination Equation)

$$\lambda = \frac{dF_i}{dP_{Gi}}$$

$$\frac{dF_1}{dP_{G1}} = \frac{dF_2}{dP_{G2}} = \frac{dF_3}{dP_{G3}} \ldots\ldots$$

For optimum scheduling $\boxed{\lambda_1 = \lambda_2 = \lambda_3}$

Step 1

$$\lambda = \frac{925 + \left[\frac{5.2}{2\times0.0045} + \frac{4.5}{2\times0.0056} + \frac{5.8}{2\times0.0079}\right]}{\left[\frac{1}{2\times0.0045} + \frac{1}{2\times0.0056} + \frac{1}{2\times0.0079}\right]}$$

$$= 8.6149.$$

$$P_{G1} = \frac{\lambda - b_1}{2a_1}$$

$$= \frac{8.6149 - 5.2}{2\times0.0045} = 379.4MW$$

$$P_{G2} = \frac{\lambda - b_2}{2a_2} = 367.4MW$$

$$P_{G3} = \frac{\lambda - b_3}{2a_3} = 178.15MW.$$

check for limits :

P_{G2}, P_{G3} are violating

$P_{G2} \geq P_{G2,max}$.

$P_{G2} = 350MW$.

$P_{G3} < P_{G3,min}$

$P_{G3} = 180 MW.$

$P_{D,new} = P_{D,old}$ − (sum of fixed generations)

$= 925 - (350 + 180).$

$= 925 - 530$

$= 395 MW.$

check for optimality.

$\lambda = \lambda_1$; since it is within limits

$$\lambda_2 = \frac{dF_2}{dP_{G2}} = 2 \times 0.0056 P_{G2} + 4.5$$

$$= 2 \times 0.0056 \times 350 + 4.5$$

$$= 8.42.$$

$8.42 < \lambda_{new}.$

$$\boxed{P_{G2} = 350 MW}$$

$$\lambda_3 = \frac{dF_3}{dP_{G3}} = 2 \times 0.0079 \times P_{G3} + 5.8.$$

$$= 2 \times 0.0079 \times 178.15 + 5.8$$

$$= 8.614$$

$8.614 > \lambda_{new}$

optimality not satisfied

$P_{G3} \neq P_{G3,min}.$

P_{G2} is fixed, hence optimal condition satisfied.

Hence $(925 - 350) = 575 MW$ shared b/w unit 1 & 3 using equal incremental cost rule.

$\lambda_1 = \lambda_3$

$2 \times 0.0045 \times PG1 + 5.2 = 2 \times 0.0079 \times PG3 + 5.8.$

$0.009 PG1 + 5.2 = 0.0158 PG3 + 5.8.$

$0.009PG1 - 0.0158PG3 = 5.8 - 5.2$

$0.009PG_1 - 0.0158PG3 = 0.6$ — (1).

$PG1 + PG3 = 575$ — (2)

solving (1) & (2)

$PG1 = 390.52$ MW

$PG2 = 184.47$ MW.

optimum schedule is,

$PG1 = 390.52$ MW

$PG2 = 350$ MW

$PG3 = 184.47$ MW.

Problems with Transmission losses :-

The incremental cost of 2 generating plants are,

$$IC1 = \frac{dF_1}{dPG1} = 20 + 0.1 PG_1 \text{ (Rs/MWhr)}$$

$$IC2 = \frac{dF2}{dPG2} = 22.5 + 0.15 PG2 \text{ (Rs/MWhr)}$$

The system is operating on economic dispatch with $PG1 = PG2 = 100$ MW & $\frac{\partial PL}{\partial PG2} = 0.2$. Find penality factor of plant 1.

Given,

$$\frac{dF_1}{dPG1} = IC1 \; ; \quad \frac{dF_2}{dPG2} = IC2 .$$

$$\frac{\delta PL}{\delta PG2} = ITL_2 = 0.2$$

Penality Factor

$$L_i = \frac{1}{1 - ITL_i}$$

$$PG1 = PG2 = 100MW$$

$$L_1 = ?$$

For optimum operating condition,

$$\lambda = \frac{IC1}{1 - ITL1} = \frac{IC2}{1 - ITL2} \quad \text{--- (1)}$$

$$L_2 = \frac{1}{1 - ITL2} = \frac{1}{1 - 0.2} = 1.25$$

$$\boxed{L_2 = 1.25}.$$

From eqn (1)

$$IC1 \times L_1 = IC2 \times L_2 .$$

$$(20 + 0.1\,PG_1) \times L_1 = (22.5 + 0.15\,PG_2) \times 1.25$$

$$(20 + 0.1 \times 100) \times L_1 = (22.5 + 0.15 \times 100) \times 1.25 .$$

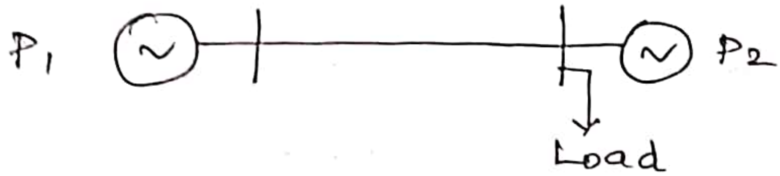
$$\boxed{L_1 = 1.5625}$$

(2) A 2 bus system is shown in fig. If 50MW is transmitted from plant 1 to the load, a transmission loss of 10 MW is incurred. Find the required generation for each plant, and the power received by load, when the system λ is Rs 22 Mwhr.

The cost function is given by,

$$C_1 = 720 + 16 P_{G1} + 0.01 P_{G1}^2$$

$$C_2 = 900 + 20 P_{G2} + 0.02 P_{G2}^2.$$



Given :

$$P_L = 10\,MW.$$

$$P_{G1} = 50\,MW. \quad \text{(plant 1 to load)}.$$

$$IC_1 = 16 + 0.02 P_{G1}.$$

$$IC_2 = 20 + 0.04 P_{G2}.$$

Find $P_{G2} = ?$ $P_D = ?$

Solution :

since load is at bus 2, alone P_{G2} will not have any effect on power loss.

$$B_{22} = 0 \; ; \; B_{12} = B_{21} = 0.$$

Transmission loss will depend on P_{G1}.

$$P_L = B_{11} P_{G1}^2 + B_{22} P_{G2}^2 + 2 B_{12} P_{G1} P_{G2}.$$

$$= B_{11} P_{G1}^2 + 0 + 0.$$

$$P_L = B_{11} P_{G1}^2.$$

$$B_{11} = \frac{P_L}{P_{G1}^2} = \frac{10}{(50)^2}$$

$$B_{11} = 0.004.$$

$$(ITL)_1 = \frac{\partial P_L}{\partial P_{G1}} = 2 B_{11} P_{G1} + 2 B_{12} P_{G2}.$$

$$= 2 B_{11} P_{G1} + 0.$$

$$= 2 B_{11} P_{G1}$$

$$= 2 \times 0.004 \times P_{G1}.$$

$$(ITL)_2 = \frac{\partial PL}{\partial PG2} = 2B_{22}PG2 + 2B_{12}PG1$$
$$= 0.$$

wkT, $\frac{(IC)_1}{1-(ITL)_1} = \frac{(IC)_2}{1-(ITL)_2} = \lambda.$

$$\frac{16+0.02PG1}{1-(2\times0.004PG_1)} = \frac{20+0.04PG2}{1-0} = 22.$$

Equating separately,

$$20 + 0.04PG2 = 22.$$
$$PG2 = \frac{22-20}{0.04}$$
$$\boxed{PG2 = 50MW}$$

$$\frac{16+0.02PG1}{1-2\times0.004\ PG1} = 22$$
$$16+0.02PG1 = 22(1-2\times0.004\ PG_1).$$
$$0.02PG1 = 22 - 0.176PG1 - 16.$$
$$0.02PG1 + 0.176PG1 = 6$$
$$\boxed{PG1 = 30.612\ MW.}$$
$$PL = B_{11}PG1^2 = 0.004\times(30.612)^2$$
$$= 3.748\ MW.$$

$PD = ?$

PD = Generation - Losses.
$$= (PG1+PG2) - PL.$$
$$= (30.612+50) - 3.748..$$
$$\boxed{PD = 76.863MW}$$

① A plant has 2 generator supplying the plant Bus and neither is to operate below 20 MW or above 135 MW. Incremental costs with P_{G1} + P_{G2} in MW are

$$\frac{dF_1}{dP_{G1}} = 0.14 P_{G1} + 21 \quad (\text{Rs}/\text{MWhr}).$$

$$\frac{dF_2}{dP_{G2}} = 0.225 P_{G2} + 16.5 \quad (\text{Rs}/\text{MWhr}).$$

Find the ~~optimum~~ λ schedule, when the demand equals a) 45 MW b) 125 MW. c) 250 MW.

WKT, $F_1 = a_1 P_{G1}^2 + b_1 P_{G2} + C_1.$

$$\frac{dF_1}{dP_{G1}} = 2a_1 P_{G1} + b_1 .$$

where $2a_1 = 0.14$; $b_1 = 21$

$$\boxed{a_1 = 0.07 \; ; \; b_1 = 21}$$

$$\frac{dF_2}{dP_{G2}} = 2a_2 P_{G2} + b_2 .$$

$2a_2 = 0.225$; $b_2 = 16.5$.

$$\boxed{a_2 = 0.1125 \; ; \; b_2 = 16.5}$$

Limits : $20\,\text{MW} \leq P_G \leq 135\,\text{MW}$.

(i) $P_D = 45$ MW :

$$\lambda = \frac{P_D + \sum_{i=1}^{N} \frac{b_i}{2a_i}}{\sum_{i=1}^{N} \frac{1}{2a_i}} = \frac{20 + \left[\frac{21}{2\times 0.07} + \frac{16.5}{2\times 0.1125}\right]}{\left[\frac{1}{2\times 0.07} + \frac{1}{2\times 0.1125}\right]}$$

$= 23.15$.

$$P_{G1} = \frac{\lambda - b_1}{2a_1} = \frac{23.15 - 21}{2 \times 0.07} = 15.41\,MW.$$

$$P_{G2} = \frac{\lambda - b_2}{2a_2} = \frac{23.15 - 16.5}{0.225} = 29.55\,MW.$$

check for limits :

P_{G1} is violating

$$P_{G1} = P_{G1,min} = 20\,MW.$$

check for optimality,

$$\frac{dF_1}{dP_{G1}} > \lambda.$$

$$0.14 P_{G1} + 21 > \lambda$$

$$0.14 \times 20 + 21 > \lambda.$$

$$23.8 > 23.15.$$

optimality ~~cost~~ condition is satisfied.

$$P_{G1} = 20\,MW.$$

$$P_{G2} = P_D - P_{G1} = 45 - 20$$

$$= 25\,MW.$$

(ii) $P_D = 125\,MW$:

$$\lambda = \frac{P_D + \sum_{i=1}^{N} \frac{b_i}{2a_i}}{\sum_{i=1}^{N} \frac{1}{2a_i}}$$

$$= \frac{125 + \left[\frac{21}{0.14} + \frac{16.5}{0.225}\right]}{\left[\frac{1}{0.14} + \frac{1}{0.225}\right]}$$

$= 30.06.$

$$P_{G1} = \frac{\lambda - b_1}{2a_1} = \frac{30.06 - 21}{0.14} = 64.72.$$

$$P_{G2} = \frac{\lambda - b_2}{2a_2} = \frac{30.06 - 16.5}{0.225} = 60.26.$$

Both P_{G1} & P_{G2} are within the limits:

Hence optimum schedule,

$P_{G1} = 64.72$

$P_{G2} = 60.26.$

(iii) $P_D = 250MW,$

$$\lambda = \frac{250 + \left[\frac{21}{0.14} + \frac{16.5}{0.225}\right]}{\left[\frac{1}{0.14} + \frac{1}{0.225}\right]}$$

$= 40.849.$

$$P_{G1} = \frac{\lambda - b_1}{2a_1} = \frac{40.849 - 21}{0.14} = 141.78.$$

$$P_{G2} = \frac{\lambda - b_2}{2a_2} = \frac{40.849 - 16.5}{0.225} = 108.21.$$

P_{G1} is violating the limit,

$$P_{G1} > P_{G1,max}.$$

$$P_{G1} = 135 \text{ MW}.$$

Check for optimal cost :

$$\frac{dF_1}{dP_{G1}} \leq \lambda.$$

$$0.14 P_{G1} + 21 < \lambda.$$

$$0.14 \times 135 + 21 < 40.849.$$

$$39.9 < 40.849.$$

condition satisfied.

Hence optimum schedule,

$$P_{G1} = 135 \text{ MW}.$$

$$P_{G2} = P_D - P_{G1}.$$

$$= 250 - 135.$$

$$P_{G2} = 115 \text{ MW}.$$

UNIT-V Computer Control of Power Systems

Need of Computer Control of Power Systems - Concept of energy control centers and functions - PMU - System monitoring, data acquisition and controls - System hardware configurations - SCADA and EMS Functions - state estimation problem - measurements and errors - weighted least square estimation - various operating states - state transition diagram.

Energy Management System (EMS)

Energy management is the process of monitoring, coordinating and controlling the generation, transmission and distribution of electrical energy. It is performed at centres called system control centres, by a computer system called Energy Management system (EMS). Data acquisition and remote control is performed by the computer system called SCADA, which forms the front end of EMS.

Energy management system consists of energy management, AGC, Security control, SCADA, load Management.

The functions of energy management systems are :-

1) System load forecasting - Hourly energy 1 to 7 days.
2) Unit commitment - 1 to 7 days.
3) Fuel scheduling to plants.
4) Hydro-thermal scheduling - upto 7 days.
5) MW interchange evaluation - with neighbouring system.

6) Transmission loss minimization.
7) security constrained dispatch.
8) Maintenance scheduling.
9) Production cost calculation.

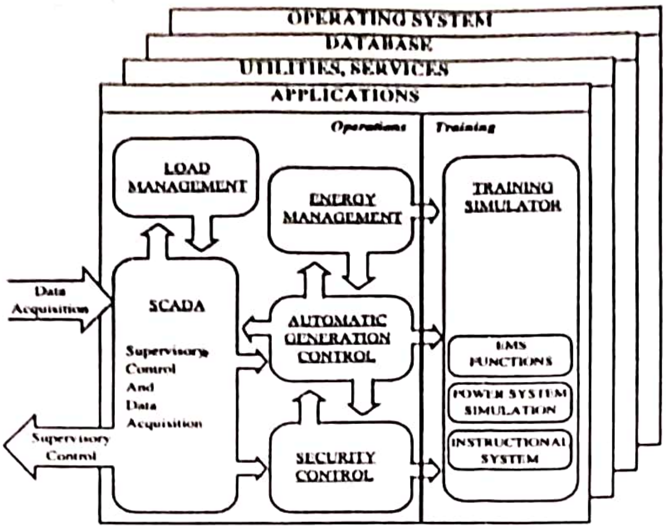
Load Management - carried out at Distribution control centre

Load management :

Remote terminal unit (RTU) installed at distribution substations, can provide status and measurements for distribution substation.
RTU can monitor switches, interruptors, control voltage, customer meter reading etc..,

Functions of Load management are :-

1) Data acquisition
2) Monitoring, sectionalizing switches and create circuit configuration.
3) Feeder switch control & preparing distribution map
4) Preparation of switching orders.
5) customer meter reading.
6) Load management - control customer load.
6) Load management - control customer load.
7) Fault location & circuit topology configuration.
8) Service restoration.
9) Power factor and voltage control.
10) Implementation time dependent pricing.
11) Circuit continuity analysis.
12) To control customer load through appliance switching (Heater).



Layers of a modern EMS.

Energy control centre (or) systems control centre:-

When the power system increases in size - the number of substations, transformers, switchgear and so on - their operation and interaction become more complex. It is essential to monitor this information simultaneously for the total system is called as energy control centre.

The system gets information about the power system from remote terminal units (RTU) that encode measurement transducer outputs and opened/closed status information into digital signals that are transmitted to the operations centre.

The control centre can transmit control information such as raise/lower commands to the speed changer and in turn to the generators and open/close commands to circuit Breakers (CB).

Real time operations are in two aspects :

(a) Three level control :

1) Turbine - governor to adjust generation to balance changing load instantaneous control.

2) AGC (called Load Frequency Control (LFC) maintains frequency and net power interchange - action repeated at 2-6 sec, interval.

3) Economic Dispatch control (EDC) distributes the load among the units such that fuel cost is minimum - executed at 5-10 minutes intervals.

(b) ~~Auto~~ Primary Voltage Control :

i) Excitation controls regulate generator bus Voltage.

ii) Transmission voltage control devices include SVC (Static VAR Controllers), Shunt capacitors, Transformer taps, etc.,

Automatic Generation Control (AGC) :

The objectives are :

1) To hold frequency at or very close to a specified nominal value.

2) To maintain the correct value of interchange Power between Control Values.

3) To maintain each unit's generation at the most economic value.

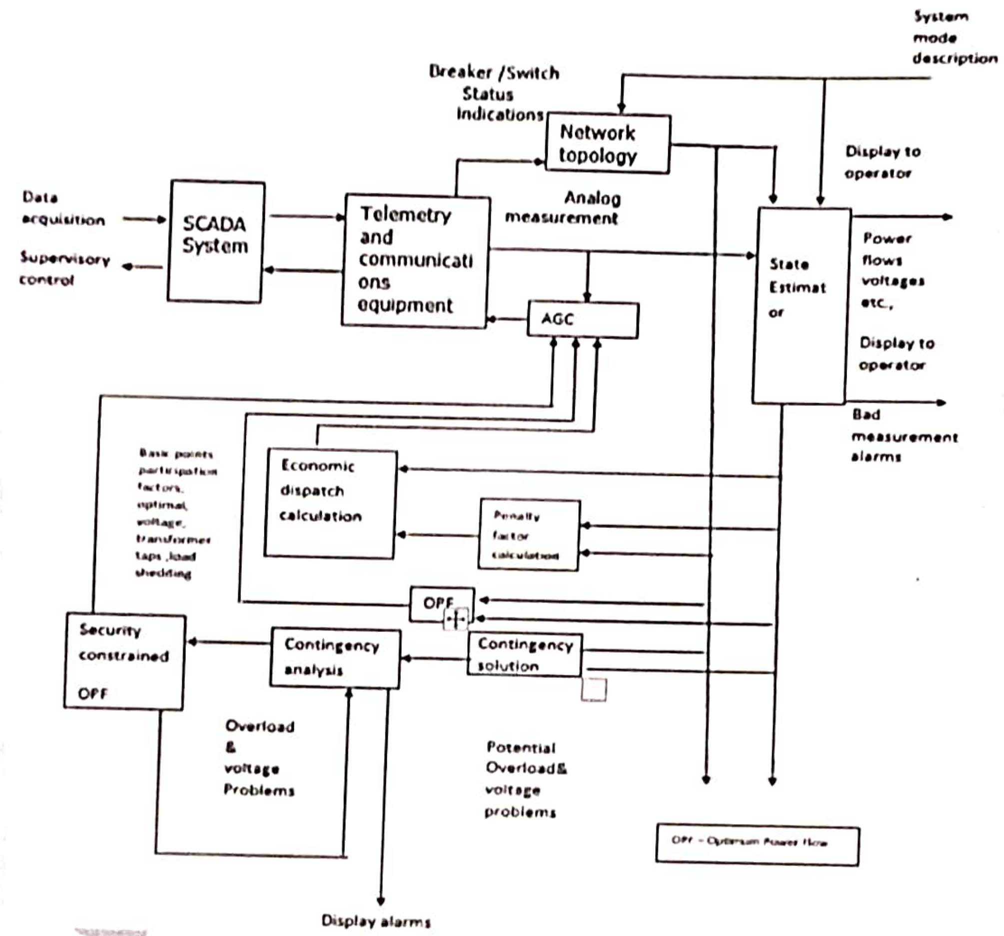


Fig. Energy control centres

Energy Control Centre Functions

① **Monitoring :**

The digital computer is used to process the incoming stream of data to detect abnormalities and then alarm the human operator via lights, buzzers and CRT presentations.

② **Data Acquisition and control :-**

Data acquisition and remote control is performed by computer systems called supervisory control and Data acquisition (SCADA) systems.
A SCADA system consists of a master station and remote terminal unit (RTU).

Energy Control centre Functions :-

i) Load Forecasting :

Forecast	Lead Time	Application
Very short term	Few minutes to half an hour	Real time control, Real time security evaluation.
Short term	Half an hour to a few hours	Allocation of spinning reserve, Unit commitment, maintenance scheduling.
Medium term	Few days to a few weeks.	Planning for seasonal peak - winter, summer.
Long term	Few months to a few years	To plan the growth of the generation capacity.

2) Power System Planning :

→ For generation

→ For Transmission & Distribution.

3) Unit commitment :

The constraints are - spinning reserve, minimum up time, minimum down time, hydro constraints and fuel constraints.

4) Maintenance scheduling : The planned maintenance outages of the generation equipment over a given future period.

5) Security Monitoring : The on-line process using real time data for analyzing the effects of outages contingencies on the steady state performance of the system.

6) State Estimation : It is the process of estimating the state. When based on system monitoring data, it produces best estimates of the power system state.

7) Economic Dispatch : It is to distribute the load among the generating units so as to minimize the total cost of the system.

8) LFC (Load Frequency Control) :

It interconnected system with 2 or more independently controlled areas, in addition to control of frequency, generation within each area has to be controlled to maintain scheduled power interchange.

Energy control centre Levels :

Level	System	Monitoring & Control
First level	Generating stations & Sub-stations	Local control centre (RTO)
Second level	Sub-Transmission & Transmission network	Area load dispatch centre.
Third level	Transmission system	state load dispatch centre.
Fourth level	Interconnected Power systems	Regional control centre.

SCADA (Supervisory control and Data Acquisition)

→ It consists of a master station and RTU linked by communication channel. The hardware components classified into :

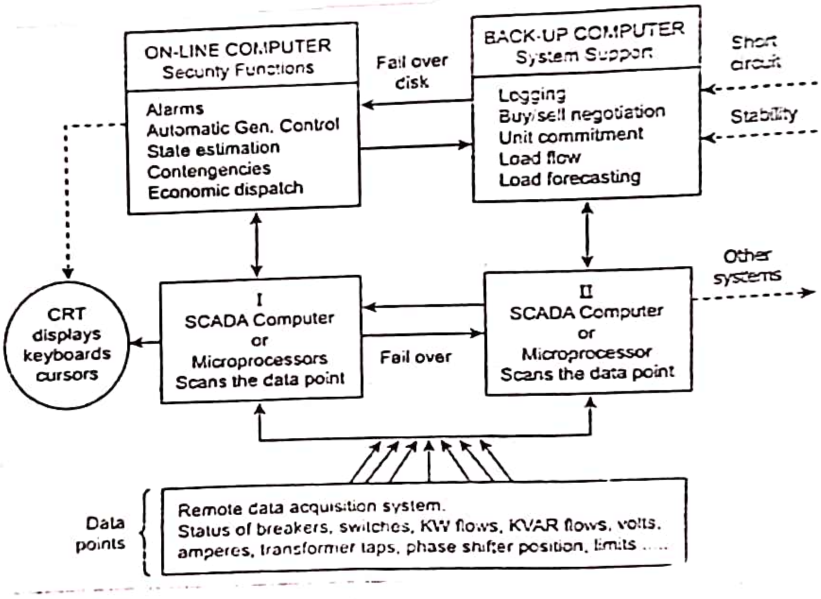
1) Process Control & Associated hardware at the Energy Control centre.

2) RTUs and associated hardware at the remote stations.

3) Communication equipment that links the RTUs & process computers at the master station.

System Hardware Configuration :-

usually one computer, the on-line unit is monitoring and controlling the power system. The on-line computer periodically updates a disk memory shared between the two computers.



→ The microprocessors can transfer data in and out of computer memory without interrupting the central processing unit.

→ Besides hardware, new digital code to control the system may be compiled and tested in the backup computer, then switched to on-line status.

The following categories are scanned every 2 seconds :

1) All status points such as switchgear position, substation loads and voltages, Transformer tap position & capacitor Banks.

2) Tie-line flows and interchanges schedules.

3) Generator loads, voltage, operating limits and boiler capacity.

4) Telemetry verification to detect failures and errors in the remote bilateral communication

Types of SCADA Systems and Area of Applications:

Type 1 : Small distribution systems (substation control centre), small hydro stations, HVDC links.

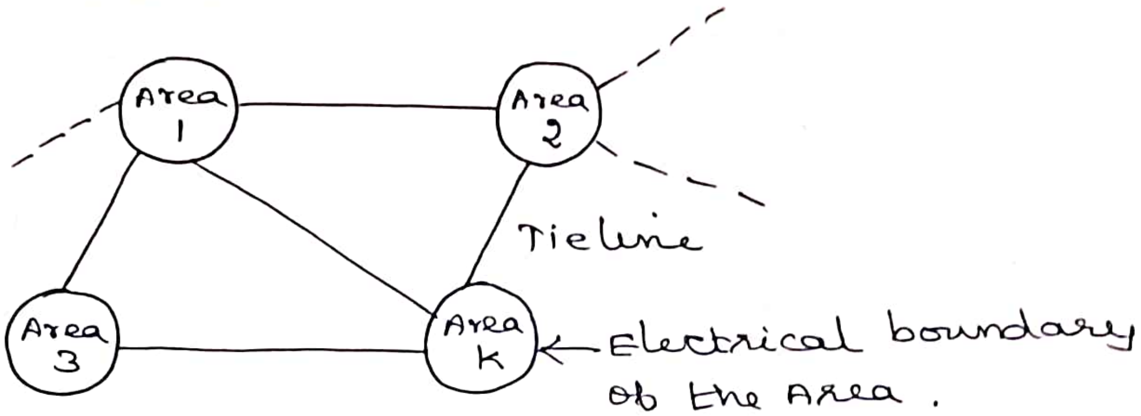
Type 2 : Medium sized power systems (plant control centre), Power station HVDC link, distribution systems.

Type 3 : Regional control centre, distribution systems in large urban areas several hydro power station with cascade control.

Type 4 : National and Regional control centres distributed systems in large urban areas, several hydro power station with cascade control.

Automatic Generation Control for a Power System:

Automatic Generation Control (AGC) is an online computer control that maintains the overall system frequency and the net tie-line load exchange between the power companies in the interconnection.



The power systems employ tie-lines for the following reasons:

1) Tie-lines allow a local or pool exchange and sale of power between the power companies on a predetermined schedule.

2) Tie-lines allow areas experiencing disturbances to draw on other areas for help.

3) Tie-lines provide a long distance Transmission line for the sale & Transfer of power.

Area Control Error:

To maintain a net interchange of power with its neighbours, an AGC uses real power flow measurements of all tie-lines emanating from the area and subtracts the scheduled interchange to calculate an error value.

$$ACE = \sum_{k=1}^{n} P_k + P_s + 10b(f_{act} - f_o) \text{ (MW)}$$

P_k = MW tie flow defined as positive out of the area.

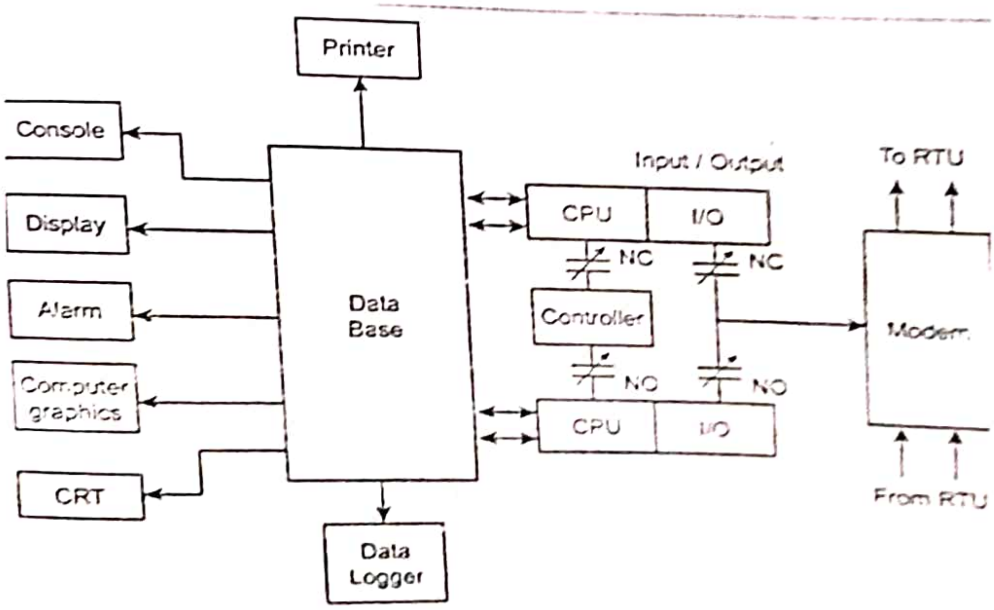
P_s = scheduled MW interchange.

f_o = scheduled base frequency.

Master station :

The hardware at the master station includes the following :

1) Process computer
2) CRT display
3) Printer
4) Data logger
5) Computer Graphics
6) Control console
7) keyboard
8) Alarm panel.
9) Instrument panel
10) Modem
11) Multiplexer.



Remote Terminal Units :- (RTU)

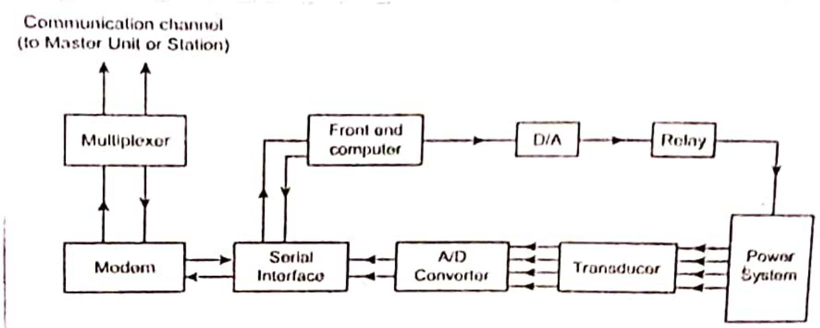
The RTUs are installed at selected power stations and substations. The hardware components of RTU may include the following :

1. Transducers
2. A/D & D/A converters
3. Serial Interface
4. Modems
5. Multiplexers
6. Front end computer
7. Control relays.

=) The analog quantities like voltage, MW, MVAR and frequency measured at stations are converted into DC voltage or current signals, through transducers and fed to the A/D converters which convert the analog signals into digital form suitable for Transmission.

=) The digital signal is fed to the front end ~~of~~ computer and modems through the serial interface.

=) MODEM sends the information to the master unit through multiplexer.



Functions of SCADA : (Supervisory Control and Data Acquisition)

1) Data acquisition : It provides telemetered measurements and status information to operator.

2) Information Display (limit violations, unplanned events).

3) Supervisory control (CB) : on/off, Generator, stop/start raise/lower command).

a) Electrical Breaker Control
b) Voltage Regulation
c) Tap changer control
d) Capacitor control
e) Loss reduction
f) Miscellaneous device control.
g) Load Management
h) Fault Isolation
i) Service Restoration.

4) Information storage & results display. (Reports such as energy accounting, reserve calculation, interchange evaluation).

5) Sequence of events acquisition.

6) Remote terminal unit processing.

7) General Maintenance.

8) Runtime status verification.

9) Economic modelling.

10) Remote start/stop.

11) Load matching based on economics.

12) Load shedding.

Logging :

1) Data is stored in compressed format.

2) Logging / archiving can be frequency.

3) Logs all operator entry, alarms for selected information.

4) Logging of user actions together with user ID.
5) VCR facility for playback of stored data.

General Functions of Archiving Unit :-

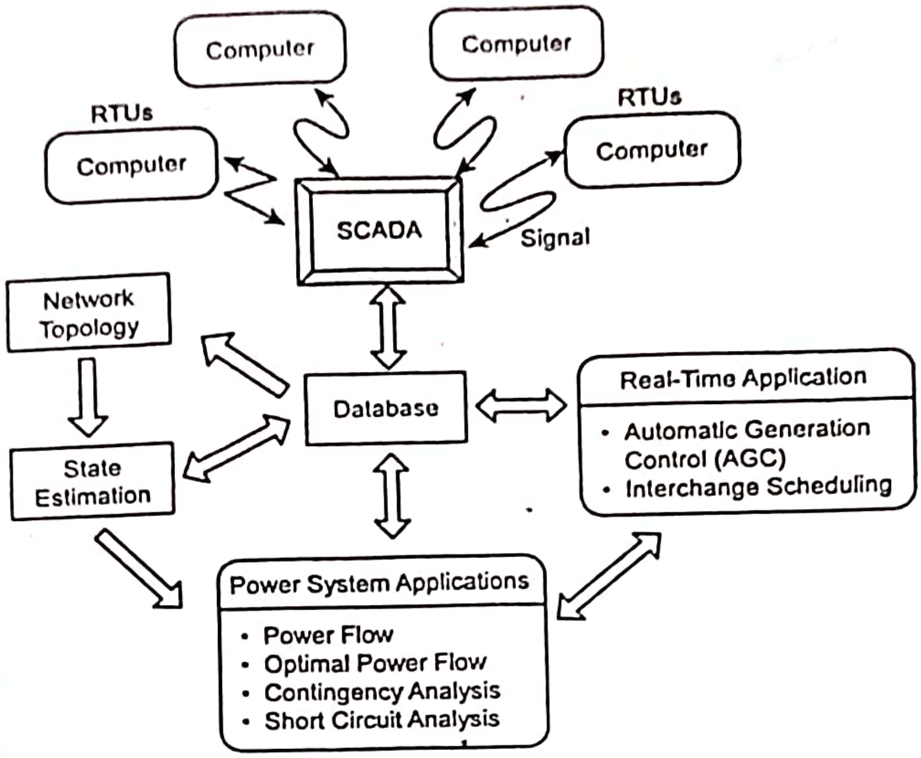
1) Invert or add. zero symbols to existing library.
2) Interface new peripherals. (printer, plotter etc).
3) Define operators and select their system access rights.
4) Download new configurations into RTU.
5) Modify logbook and list appearance.

Substation Control Functions of SCADA :-

1) Alarm functions.
2) Control and Indication
3) Control of position of devices.
4) Data collections.
5) Protective functions.
6) Control & Monitoring functions.

Other Functions of SCADA & EMS are

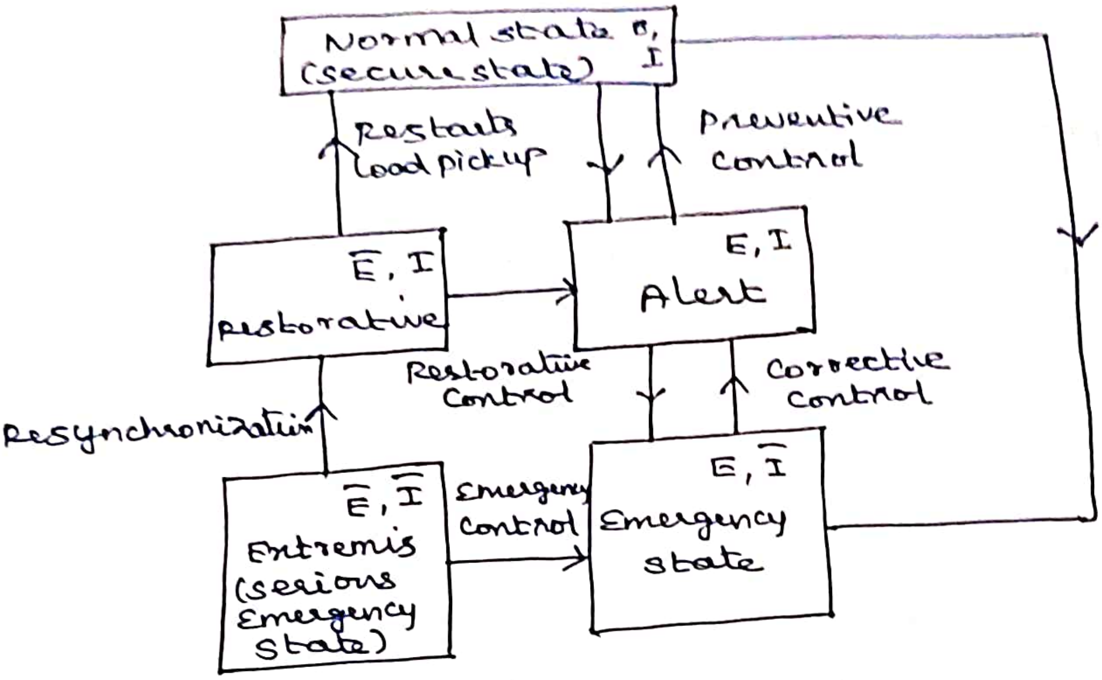
1) Network topology determination
2) State Estimation
3) Security Analysis & Control.



state Transition Diagram and control strategies

A power system may be operated in several operating states. They are :

1) Normal state
2) Alert state.
3) Emergency state
4) Extremis state
5) Restorative state.



E = Equality constraint

I = Inequality constraint.

— = Negation.

(1) Normal state :-

A system is said to be in normal, if both load and operating constraints are satisfied. It is one in which the total demand on the system is met by satisfying all the operating constraints.

If all the postulated contingency states (frequency, bus voltage, current flows in all transmission lines) are satisfied, then normal state is said to be in secure state.

If one of the postulated contingency states limits are violated, then normal state is moved to alert state.

(2) Alert state :

When the security level falls below a certain level, the system may in alert state.

The occurrence of disturbance increases, the system may not satisfy all the Inequality constraints, then the system will push onto Emergency state.

If a proper preventive action is taken, the system is bring back to secure state instead of Emergency state.

(3) Emergency state :

The system is said to be in Emergency state, if one (or) more operating constraints are violated but the load constraint is satisfied.

In this state, the equality constraints are unchanged by means of corrective control actions, the system will return to the normal state (or) alert state. otherwise it will move into the extreme state.

(4.) Extremis State :

If there is no proper corrective action is taken in time, then the system is in Emergency state goes to Extremis state.

In this State, both operating and load constraints are not satisfied. By means of any emergency control action the system is bring back to the Emergency state otherwise the system is pushed to Restorative state

Restorative state:

The system may be brought back either to alert state or secure state. The secure state is a slow process. Hence in certain cases, First the system is brought back to alert state and then to the secure state. This is done using restorative control action.