CMR INSTITUTE OF TECHNOLOGY

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Internal Assesment Test - II

Sub:	Power System Operation and Control						Code:	10EE82
Date:	10/5/2017	Duration:	90 mins	Max Marks:	50	Sem:		Branch:	EEE

Answer any FIVE Full Questions

		Marks	OBE CO	OBE RBT
1	Explain with a neat block diagram the digital computer configuration of SCADA systems.	[10]	CO1	L2
2(a)	Two synchronous generators and initially supplying a common load at 1 pu freq(60 Hz).The rating of unit 1 is 337 MW and has 0.03 pu droop built into its governor. Unit 2 is rated at 420 MW and has a 0.05 pu droop. Find each units share of a 0.10 pu(75.7 MW or 10 % of total load generation)increase in the load demand. Also find the new line frequency.	[5]	CO2	L3
2(b)	Explain the parallel operation of generators with droop characteristic graph.	[5]	CO1	L2
3	Derive the expression for the tie line power and frequency deviation for two area system.	[10]	CO1	L2
4	Obtain the transfer function model and explain the ALFC loop of a single area of an isolated power system.	[10]	CO2	L2
5	Explain and model the AVR loop of a single area of an isolated power system.	[10]	CO2	L2
6(a)	Determine the primary ALFC loop parameters for a control area having the following data. Total rated area capacity,Pr=2000MW Normal Operating ,Pd=1000MW Inertia constant=5 s Regulation R= 2.4 Hz/puMW(all area generators)Assume load frequency dependency is linear ie) load increase one percent for one percent frequency increase.	[5]	CO3	L3
6(b)	Find the static frequency drop for 2 GW system in previous example following a one percent load increase.	[5]	CO3	L3

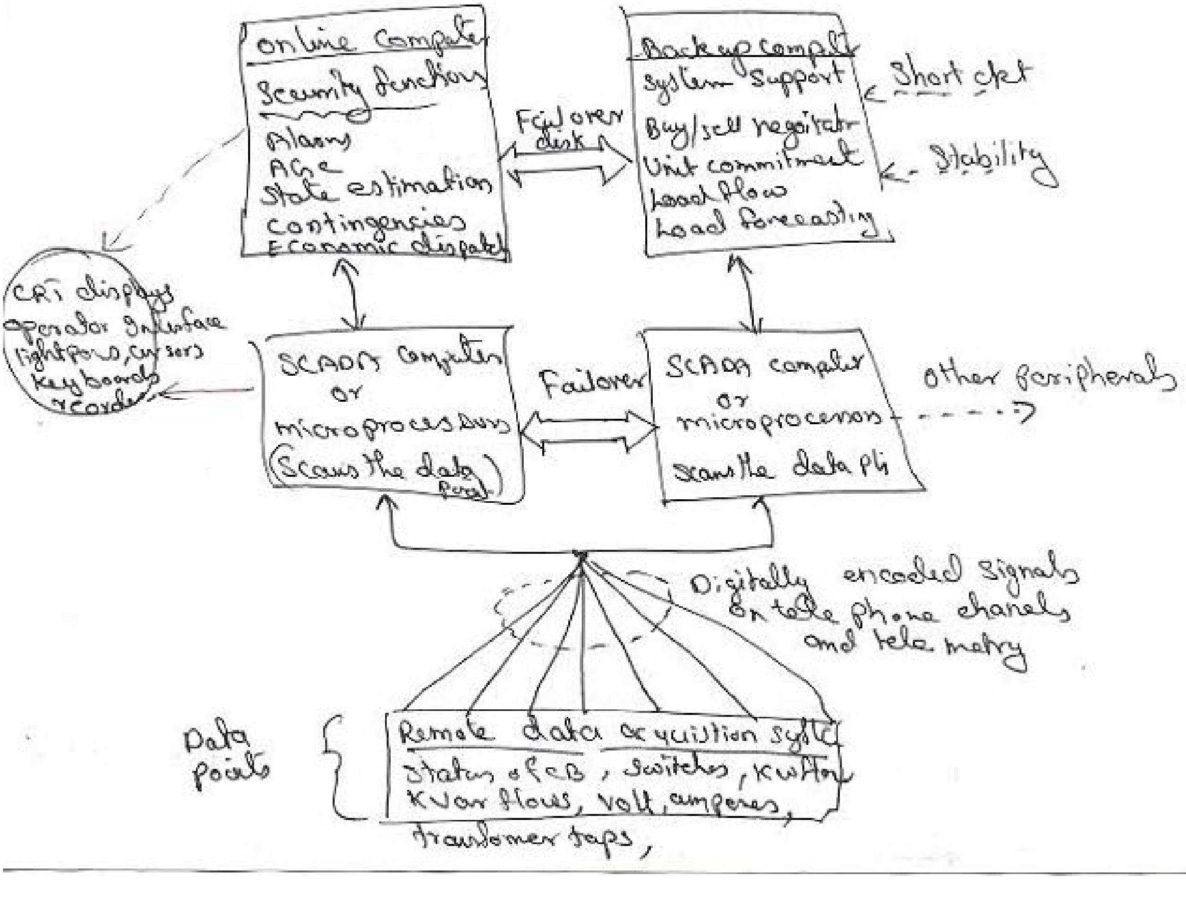
Digital computer configuration

Redundant set of dual digital compu[ters]

for the functions of remote data acquisition control, energy management and system security.

Both have its own memory and I/O devices.

- One computer (on line unit)
  monitor and control the P.S.
- Back up computer
  executing the off line batch programs (load forecas[ting])



The dual computer configuration has some peripheral equipment. All these peripheral equipments are interfaced with the computer through input-output microprocessor which can be programmed. It can transfer the data in and out of computer memory without affecting CPU and pre process the analog information, check for limits and convert into another system of units. It can also be used to switch to spare units upon detecting the malfunction

- All critical hardware functions has 99.8% or more availabi
- S/w allow the initialization of application program if failure occur.
- critical operating functions are maintained during ~~exit~~ preventive or corrective maintenance
- Digital code to control the system can be compiled and tested in the backup computer and then switched to on line status.

Digital computer
- fixed cycle operating mode with priority interrupts

Normal computer performs a list of operations.
- critical functions has fastest scan cycle

\

Regions scanned in every 2sec.

- transformer tap position
- sub station loads and voltages
- capacitor banks
- Generator loads, voltage

Some non critical programs are executed hourly basis.

- recording of load
- which generator to start up or stop.

low priority programs (less frequently) executed by opera on demand.

- S/w ~~and~~ compilers and data handlers are designed to be versatile (ready to accept operator inputs).

2a)

2) a)

$P_1 = 337$ MW (rated)

$R_1 = 0.03$

$P_2 = 420$ MW (rated)

$R_2 = 0.05$

$$\Delta P_1 + \Delta P_2 = 75.7 \text{ MW}$$

$$\frac{\Delta P_1}{\Delta P_2} = \frac{R_1 \times P_2\, rate}{R_2 \times P_1\, rate}$$

$$\Rightarrow \frac{x}{(75.7 - x)} = \frac{-0.03 \times 420}{-0.05 \times 337}$$

$$\Rightarrow -16.85x = -953.82 + 12.6x$$

$$\Rightarrow -16.85x - 12.6x = -953.82$$

$$\Rightarrow +29.45x = +953.82$$

$$x = 32.38 \text{ MW}$$

$$\boxed{\Delta P_1 = x = 32.38 \text{ MW}}$$

$$\boxed{\Delta P_2 = (75.7 - x) = 43.32 \text{ MW}}$$

$$R_1 = \frac{\Delta f / 60}{\Delta P / P_1\, rate}$$

$$\Delta f = \frac{\Delta AD}{10 B_A X_A + 10 B_D X_D}$$

$$\Delta f = \frac{75.7}{-10 \times 0.03 \times 337 - 10 \times 0.05 \times 420}$$

$$\Delta f = \frac{75.7}{311.1}$$

$$\Delta f = 0.243 \text{ HZ}$$

The new line frequency = 59.757 HZ

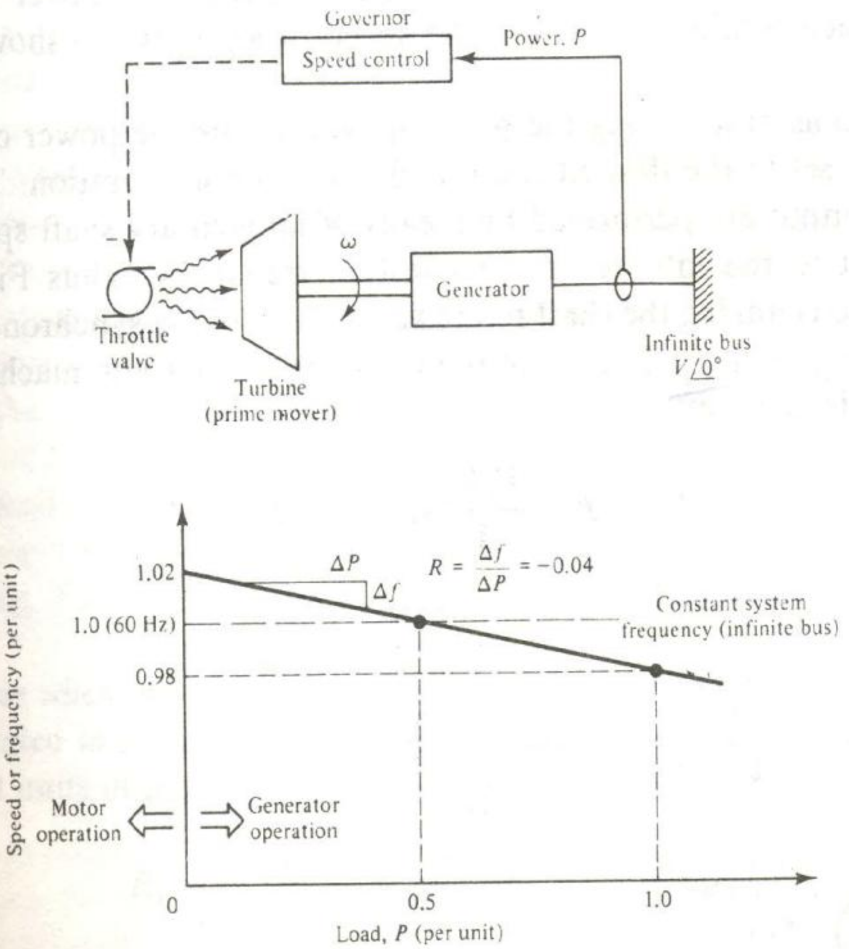
2b)

The tie-line flows and frequency droop described for interconnected power areas are composite characteristics based on parallel operation of generators. That areas must have speed or frequency droop as opposed to isochronous (constant-speed) operation is obvious, for if each area could maintain its speed $\omega = 2\pi f$ despite synchronizing torques, then a load common to both areas, by superposition, would have the terminal voltage

$$V_{\text{load}} = V_1 \sin \omega_1 t + V_2 \sin \omega_2 t \tag{1.13}$$

where subscripts 1 and 2 refer to the areas and t is time in seconds. Combining the terms of equation 1.13 results in line frequencies that are the sum and difference of f_1 and f_2, which is objectionable. Although it is possible to use a reference frequency for both areas, in principle both areas as well as generating units must be capable of independent operation should communications links be interrupted.

A generator speed versus load characteristic is a function of the type of governor used on the prime mover (type 0 for a speed-droop system, type 1 for an isochronous system, etc.) as well as the capacity of the generator. Consider an extreme case where generator 1, of limited capacity, is paralleled to an infinite bus of constant frequency, as shown in Figure 1.17. (An infinite bus can absorb or supply unlimited power at constant voltage and constant frequency.) In this figure, the generator-droop characteristic is such that it is loaded to 50%



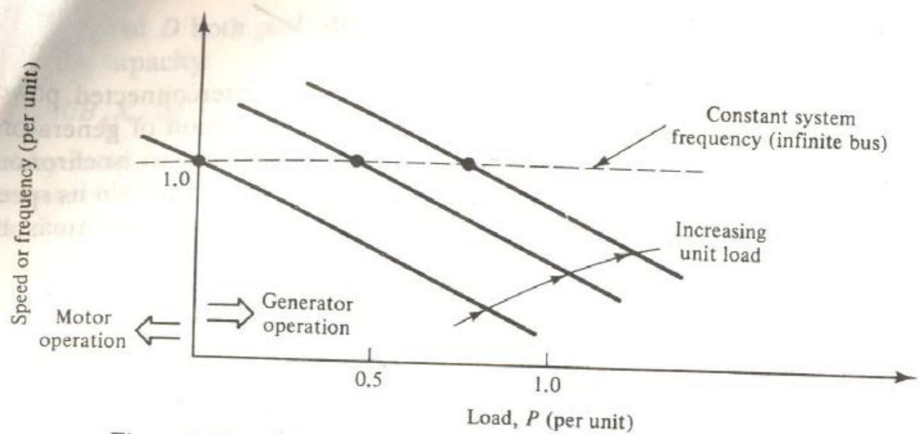


Figure 1.18 Adjusting prime-mover torque to load a generator.

of its capacity when paralleled to the bus. The regulation of the unit with an implicit algebraic sign is defined as

$$\text{unit speed regulation} = R = \frac{\Delta f(\text{p.u.})}{\Delta P(\text{p.u.})} = \frac{\Delta f(\text{Hz})/60(\text{Hz})}{\Delta P(\text{MW})/P_{\text{rate}}(\text{MW})} \tag{1.14}$$

where P_{rate} is the megawatt rating of the generator and p.u. represents "per unit." The regulation is assumed to be constant for the range of interest here. The governor shown in Figure 1.17 has a steady-state regulation of 4%. If it is desired to increase the load on the generator, the prime-mover torque is increased, which results in a shift of the speed-droop curve as shown in Figure 1.18.

By means of adjusting the prime-mover torque the power output of the generator is set to the desired level, including motor operation. The shifts in generator output are performed by means of momentary shaft speed changes with respect to the infinite bus at constant frequency. Thus Figure 1.18 is equivalent to changing the shaft reference angle θ_1 of the synchronous machine shown in Figure 1.19. For a simplified, cylindrical rotor machine the real power flow is given by

$$P = \frac{V_1 V_2}{X} \sin(\theta_1 - \theta_2) \tag{1.15}$$

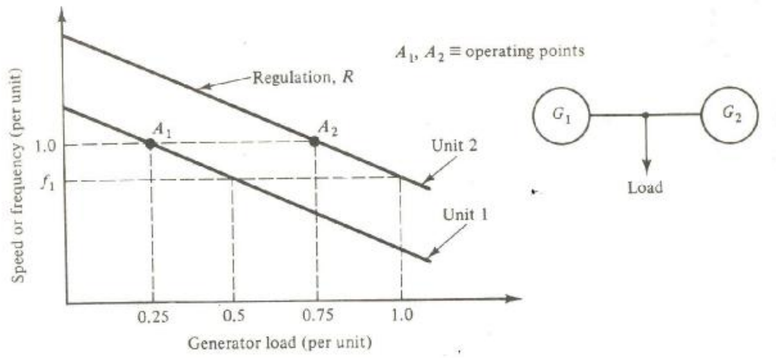


Figure 1.20 Parallel operation of identical units with different speed settings.

where X is the synchronous reactance and the voltages are expressed as phasors. The phasors and reactances are discussed in Chapter 2.

Steady-state output power changes for the generator of Figures 1.18 and 1.19 are due to prime-mover steady-state changes, and no description is given here of the transients necessary to reach this operating point. The transients will be a function of the generator inductances and resistances, the voltage regulators, and the prime-mover dynamic characteristics.

Generally, two generating units that are paralleled both have different governor-speed-droop characteristics, or the characteristics may vary with load. When parallel, the power exchange between machines forces them to synchronize at a common frequency as the coupling impedance between machines (e.g., impedance of the transmission lines) is small compared to the load equivalent impedances. Consider the case of two parallel units of equal capacity which have equal regulation and are initially operating at 1.0 base speed, as shown in Figure 1.20.

When the paralleled system is operated at base speed, unit 1 at point A_1 satisfies 25% of the total load, and unit 2 at point A_2 supplies 75%. If the total load is increased to 150%, the frequency decreases to f_1. Since the droop curves are linear, unit 1 will increase its load to 50% of rating and unit 2 will reach 100% of rating. Further increases in system load will cause unit 2 to be overloaded.

The case when two units of different capacity and regulation characteristics are operated in parallel is shown schematically in Figure 1.21. For these two different units in parallel, their regulation characteristics are

$$R_1 = \frac{\Delta f(\text{p.u.})}{\Delta P_1(\text{p.u.})} = \frac{\Delta f/60}{\Delta P_1/P_{1\text{rate}}} \quad \text{p.u.} \qquad (1.16a)$$

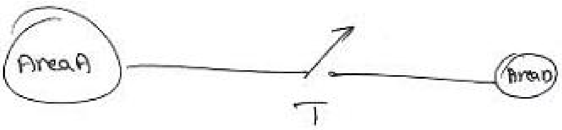
$$R_2 = \frac{\Delta f/60}{\Delta P_2/P_{2\text{rate}}} \quad \text{p.u.} \qquad (1.16b)$$

3

without AGC — only one input — disturbance are stabilised by change

operation without central computers or AGC

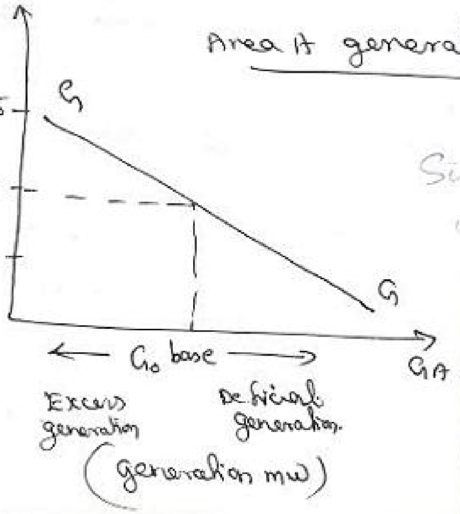
Ps are capable of operating without a central computer and/or AGC. This is due to turbine generator speed controls built into generating stations and natural load regulation. with this generators within an area share load and cause for the inter connected power areas.



The breaker is open. No tie line flow b/w

Area D is — operating area of the interconnection. in which If a sudden load or generation change occurs Then areas A share the disturbance in proportion to the generation capacity size and operating characteristics. These fundamentals are based on operating experience

Area A generation freq. characteristics curve



Since the slope is negative it ... drooping characteristic

T = P×ω → for load
T is the load on generator T ↑
then P↑ ω↓ i.e. freq. ...
↓ $N_s = \frac{120f}{P}$ ↓

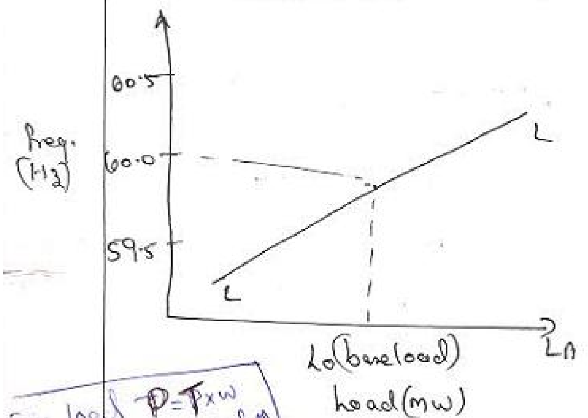
For Primemovers shaft speed ∴ frequency changes with load reflected onto the primemover.

Here the generation freq. curve is having negative slope

⇒ type 0

— normally Primemovers have 5% speed drop from NL to FL

Area connected load is defined by curve LL.



For load P = T×ω
P↑ then ω↑ i.e. f↑

The general equ. for generation and load are.

$$G_A = G_0 + 10\beta_1(f_{act} - f_0)\ MW$$

$$L_A = L_0 + 10\beta_2(f_{act} - f_0)\ MW$$

G_A – total generation on Sy. A MW

G_0 – Base generation " MW at 60 Hz.

L_A – Total load on Sys. A MW

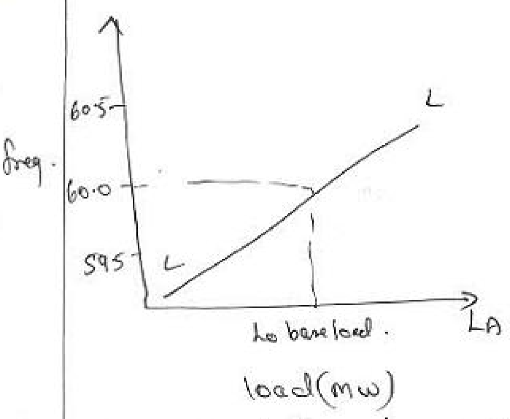
L_0 – Base load " MW at 60 Hz

f_{act} – Sys. freq. Hz

f_0 – Base freq.

β_1 – Cotangent of generation freq. char in MW/0.1 Hz.
- It is negative, $\beta_1 < 0$
- called natural generation governing.

β_2 – Cotangent of load freq. char. MW/0.1 Hz, $\beta_2 > 0$



Area A Load freq. char. curve

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For a steady state frequency, total generation must equal to total effective load.

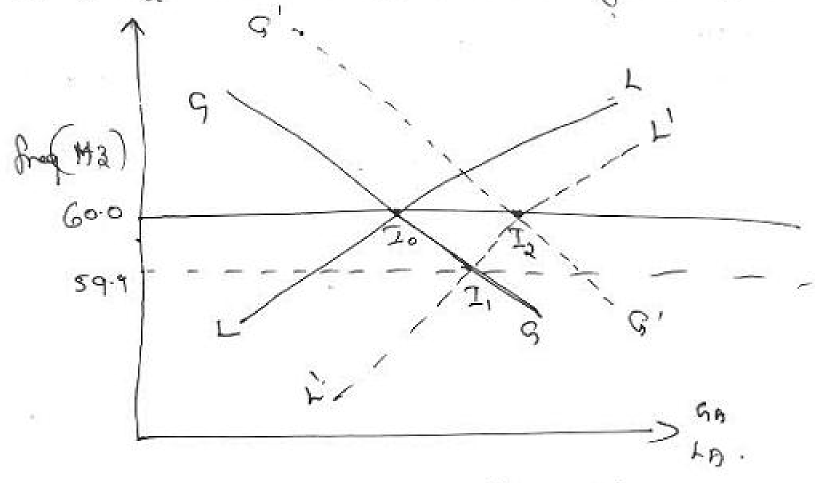
and Prevailing frequency is defined by the point of intersection I_0 of the GG and LL curves at 60 Hz.

Combined area char is by adding algebraically the generation char and load char.

Composite generation load freq. char.

$$G_A - L_A = G_0 + 10\beta_1(f_{act} - f_0) - L_0 - 10\beta_2(f_{act} - f_0)$$

The load is increased by L'L'. So new freq. is given by I_1. If you want to get 60.0 Hz shift GG to G'G' intersect at pt I_2. The combined char is given C'C'



$$G_A - L_A = G_0 + 10\beta_1(f_{act} - f_0) - L_0 - 10\beta_2(f_{act} - f_0)$$

If there is no isochronous (const frequency) sensing in AGC to perform corrective action only individual generators and load regulate and frequency varies.

In terms of increments (beta)

$$\Delta_A = G_A - G_0 + L_0 - L_A = 10\beta_1(f_{act} - f_0) - 10\beta_2(f_{act} - f_0)$$

(capital B)

$$= 10 B_A x_A (f_{act} - f_0)$$

$$= 10 B_A x_A \Delta f \text{ MW}$$

B_A is the natural reg. char of area A in percentage generation/%.

x_A is the generating capacity of area A in MW

By load increase $+\Delta_A$ MW or generation decrease in area A the freq. deviation is $\Delta f = \frac{\Delta_A}{10 B_A x_A}$ Hz.

df is -ve b'coz B_A is negative.

System speed decrease due to added load.

combined effect on freq. for a load increase and +ve tie line flow on area A is

$$\Delta f = \frac{\Delta_A + \Delta T_L}{10 B_A x_A}$$; $\Delta_A + \Delta T_L$ is the net MW change

Tie line flow (fig before)

Consider area A and D only connected with breaker T is closed with generation and load equal to 60 Hz in both areas. So no tie line flow b/w A and D. Some disturbance occurs in D and causes the freq to drop to 59.9 Hz. Since they are interconnected the generation no longer matches with effective load in area A. The difference is obtained by I_1 & I_2.

As a contribution to the disturbance in area D, the net excess power in the area flows out of A over the tie line (diff b/w the generation & load).

— it is comprised of two components

— $-\Delta L_A$, decrease in load power in area A.

— ΔG increase in generation in area A. with 1

The tie line flow b/w A and D is

$$\Delta T_L = \Delta G_A - \Delta L_A \text{ MW}.$$

ΔT_L is the net change in tie line power from initial cond

The tie line flows with a decrease in load and there will be a change in freq due to disturbance in D i) Δ_D

$$\Delta f = \frac{\Delta_D - \Delta T_L}{10 B_D X_D} \text{ Hz}.$$

$D_{AD} = D_D$ mag of disturbance in D

$D_A = 0$

freq is common to both systems.

$$\Delta f = \frac{\Delta T_L}{10 B_A X_A} = \frac{\Delta_{AD} - \Delta T_L}{10 B_D X_D} \text{ Hz}.$$

from this,

$$\Delta T_L = \frac{(10 B_A X_A)\, \Delta_{AD}}{10 B_A X_A + 10 B_D X_D} \text{ MW}$$

The net power change in area D is

$$\Delta_{AD} - \Delta T_L = \frac{(10 B_D X_D)\, \Delta_{AD}}{10 B_A X_A + 10 B_D X_D} \text{ MW}$$

The interconnected system comprising b/w A and D share the disturbance as weighted by their generating capacity.

$$\Delta_{AD} = 10 B_A X_A \Delta f + 10 B_D X_D \Delta f = (10 B_A X_A + 10 B_D X_D)\,\Delta f \text{ MW}.$$

Thus by interconnecting the systems the freq. fluctuations due to disturbance is reduced and system perform is improved by means of tie line flows.

$$\frac{\Delta f}{\Delta_{AD}} = \frac{1}{10 B_A X_A + 10 B_D X_D} \text{ Hz/MW}$$

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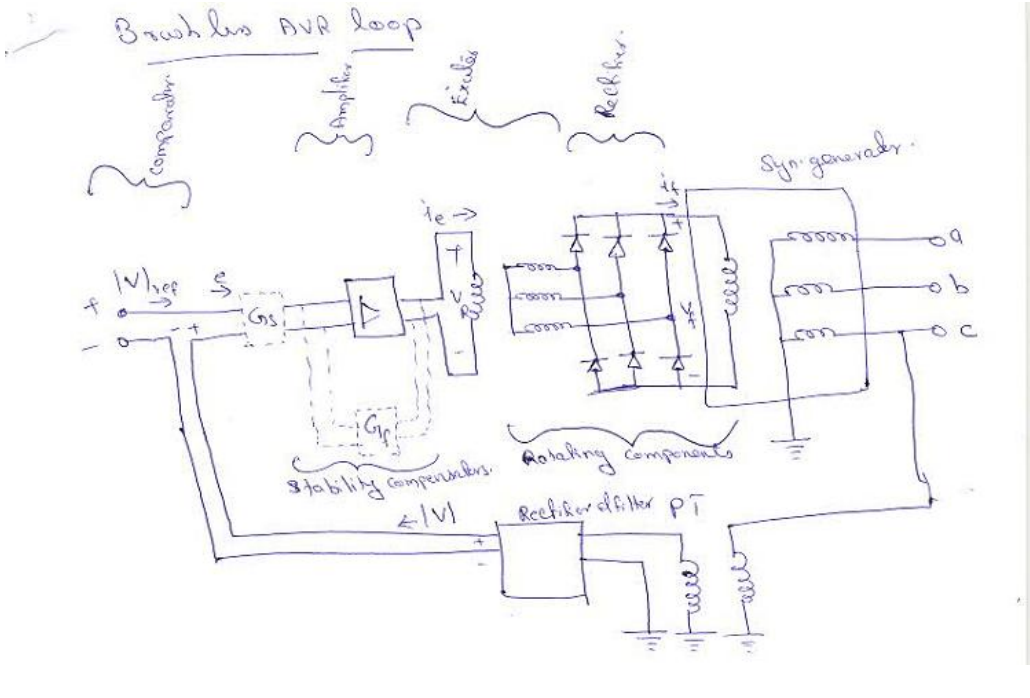

Automatic voltage Regulator (AVR)

The exciter is the main component in the AVR loop. It delivers dc power to the generator field. It must have adequate power capacity and sufficient speed of response. The basic role of AVR is to provide ~~const~~ constancy of the terminal voltage in normal small and slow changes in the load.

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Exciter types

In old power plants, the exciter was a dc generator driven by main generator shaft. But it requires sliprings and brushes.

Moder exciter can be either of brushless or static design.

The brushless AVR loop consist of an inverted 3φ syn. generator. It has 3φ armature on the rotor and dc field on the stator. Ac armature voltage is rectified in diodes mounted on the shaft and then directly fed into the main generator field. This eliminates the need for sliprings and brushes.

Exciter modelling

consider the terminal voltage is decreas

$\Delta|V|_{ref} - \Delta|V| = \Delta e$, error voltage.

$\Delta V_R = K_A \Delta e$, K_A is the amplifier gain

Taking Laplace

$\Delta|V|_{ref}(s) - \Delta|V|(s) = \Delta e(s)$

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

G_A is the amplifier T.F. DATE :

considering the amplifier delay represented by time const T_A.

$$G_A = \frac{\Delta V_R(s)}{\Delta e(s)} = \frac{K_A}{1+sT_A}$$

consider R_e, L_e is the resistance and inductance of the exciter field.

$$\Delta V_R = R_e \Delta i_e + L_e \frac{d}{dt}(\Delta i_e)$$

Across the main field the exciter produces K_1 armature volts/ampere of field current i_e

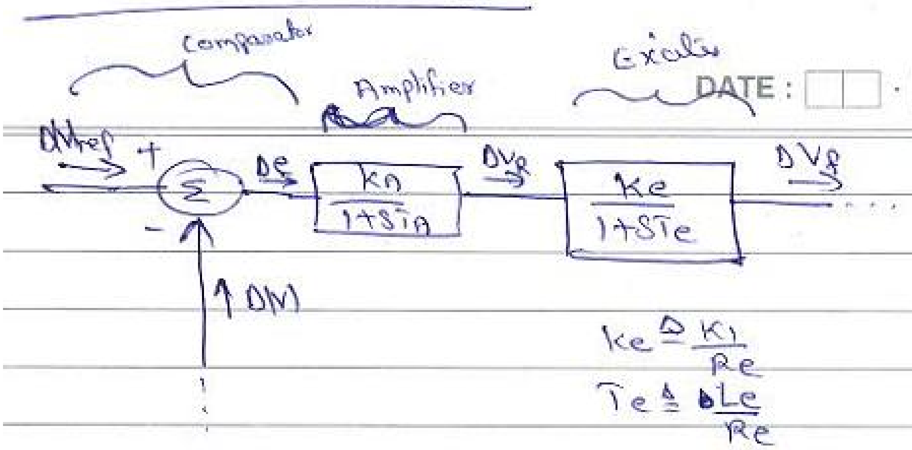
$$\Delta V_f = K_1 \Delta i_e$$

Laplace of last two equ.

$$G_e \triangleq \frac{\Delta V_f(s)}{\Delta V_R(s)} = \frac{K_e}{1+sT_e}$$

$$K_e = \frac{K_1}{R_e} , \quad T_e = \frac{L_e}{R_e}$$

Generator modelling



$K_e \triangleq \frac{K_1}{R_e}$

$T_e \triangleq \frac{L_e}{R_e}$

We need to close the loop from ΔV_f to $\Delta|V|$. Terminal voltage equals the internal emf minus the voltage drop across the impedance.

At zero or low loading, V is approximately equal to internal emf E.

$\phi_{f_a} = \phi_{f_a} \cos \omega t$
$= -\phi_{f_a} \sin(\omega t - \pi/2)$

$e = -\frac{d\phi_f}{dt} = \omega \phi_{f_a} \cos(\omega t - \pi/2)$

rms value of emf

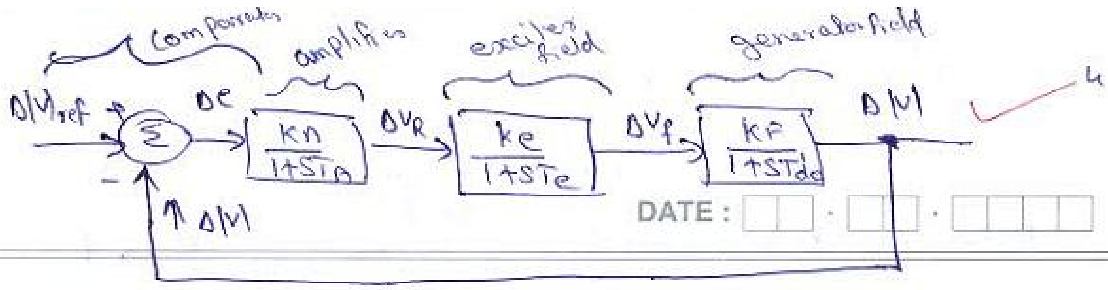
$|E| = \frac{\omega \phi_{fa}}{\sqrt{2}} = \frac{\omega L_{fa} i_f}{\sqrt{2}}$

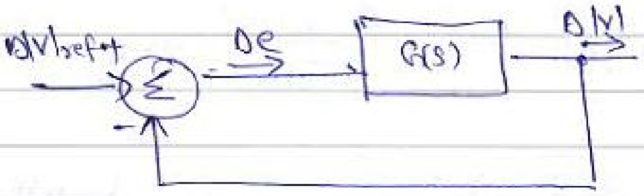
$$\Delta V_f = R_f \Delta i_f + L_{ff}\frac{d}{dt}(\Delta i_f) =$$

$$= \frac{\sqrt{2}}{\omega L_{fa}}\left[R_f \Delta E + L_{ff}\frac{d}{dt}\Delta E \right]$$

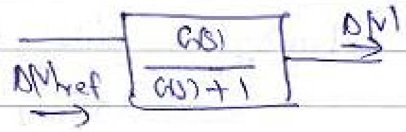
$$\frac{\Delta E(s)}{\Delta V_f(s)} \simeq \frac{\Delta |V|(s)}{\Delta V_f(s)} = \frac{K_F}{1+ST'_{do}}$$

$$K_F \triangleq \frac{\omega L_{fa}}{\sqrt{2} R_f}$$





Condensed model.



closed loop.

open loop T.F $G(s) = \frac{K}{(1+sT_A)(1+sT_e)(1+sT'_{do})}$

open loop gain $K = K_A \cdot K_e \cdot K_F$.

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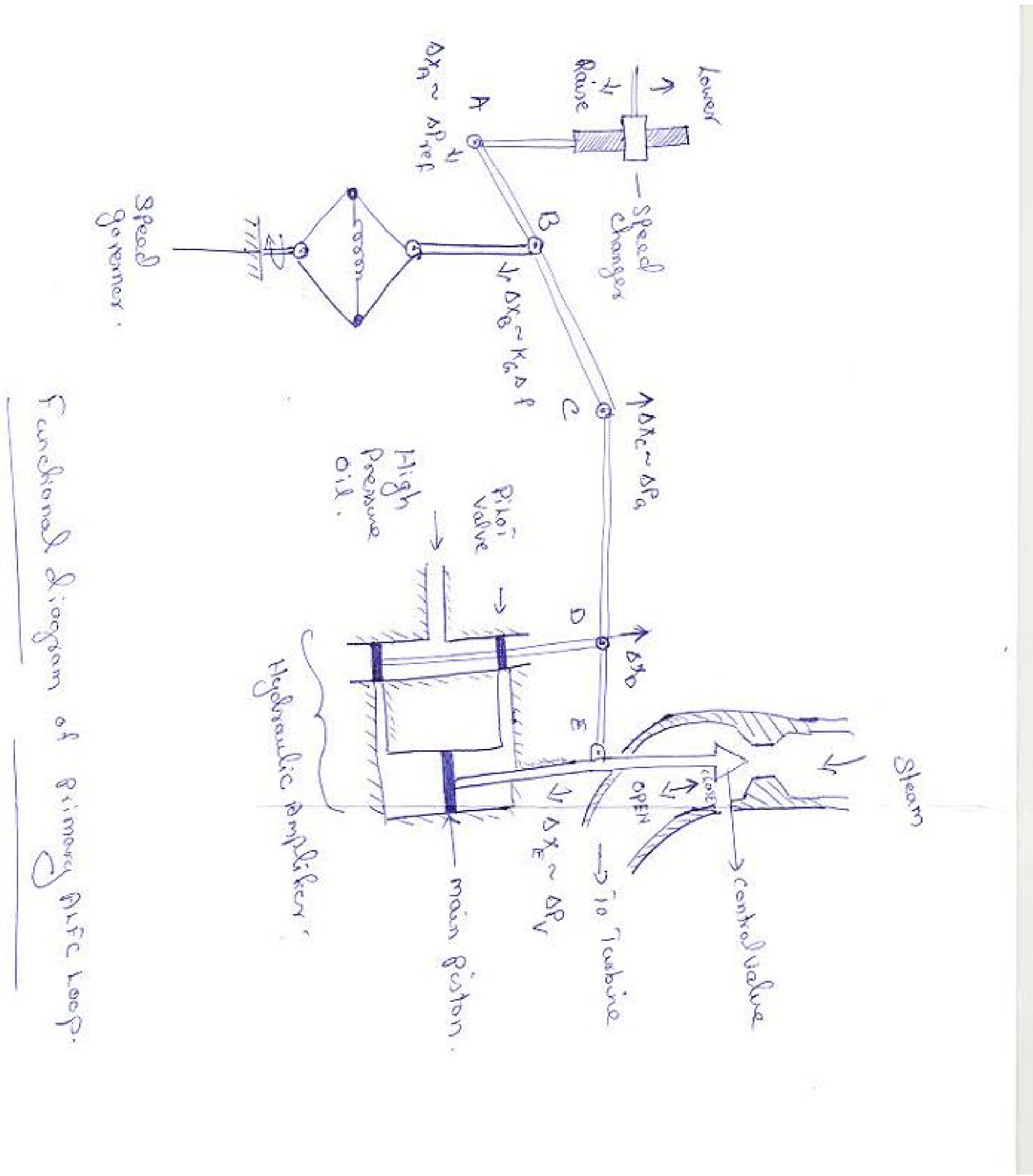
Lower
Raise
Speed changer
A
B
C
D
E
Speed governor
Pilot valve
High pressure oil.
Hydraulic amplifier
main piston.
OPEN
CLOSE
To Turbine
control valve
Steam
Functional diagram of Primary ALFC Loop.

Automatic load frequency control of single area systems

The basic role of ALFC is to maintain desired megawatt o/p of generator and freq of inter connection. It also controls the net interchange of power b/w pool members at predetermined values. ~~ALFC loop cont with maintain~~

Speed governing system Diagram from photostat (Elgerd)

Introduction about the components from Nagrath. Pg. 292
→ flyball
→ Hydraulic amplifier
→ Speed changer.

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Operation

As load ↑ N ↓, B flyball move towards eachother B moves up, C up, D up and HP oil enter top of piston and open the control value and more steam supply to turbine.

As load ↓, reverse.

By controlling the position x_E of the control valve we can control the flow of high pressure steam through the turbine. Downward movement of E increases the steam which is increases the value power represented by ΔP_V which in turn increases the turbine power represented by ΔP_T. Large mechanical forces are needed to position the main value against high steam and this is obtained with the help of hydraulic amplifiers. Input to hydraulic amplifier is x_D, position of pilot value and o/p is position x_E, main piston.

The governor o/p ΔP_g is measured by the position change Δx_C. It change due to

- changes in ΔP_{ref} (reference power setting)
- changes Δf, of the generator measured by Δx_B.

$$\Delta P_g = \Delta P_{ref} - \frac{1}{R} \Delta f \text{ MW}$$

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

Droop curve

$\Delta f \times 1/R = \Delta P$.

$0.5 \times 1/R = 2.5$

Increase in ΔP_g results from increase in ΔP_{ref} and decrease in Δf.

Hydraulic value actuator

$$\Delta x_D = \Delta P_g - \Delta P_V \text{ MW}$$

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Δx_D increases with increase in ΔP_g and decreases with increase in ΔP_V

$\Delta x_D = 0$, with equal increasment in ΔP_g and ΔP_V.

For Small changes Δx_D ~~Considering~~ the oil flow into the hydraulic motor which is proportional to Δx_D of pilot valve Position of main piston is written as

$$\Delta P_V = K_H \int \Delta x_D \, dt.$$

K_H depends on cylinder geometrices and fluid Pres.

$$\Delta P_V(s) = \frac{K_H}{s}\left[\Delta P_g(s) - \Delta P_V(s)\right]$$

$$\Delta P_V(s)\left[1 + \frac{K_H}{s}\right] = \frac{K_H}{s}\Delta P_g(s)$$

$$G_H(s) = \frac{\Delta P_V(s)}{\Delta P_g(s)} = \frac{K_H/s}{1 + K_H/s} = \frac{1}{1 + s/K_H} = \frac{1}{1 + sT_H}$$

$$T_H = 1/K_H$$

Turbine

Turbine T.F. is given by

$G_T(s) = \frac{\Delta P_T}{\Delta P_V}$ For non reheat steam turbine

$G_T(s) = \frac{1}{1+sT_T}$

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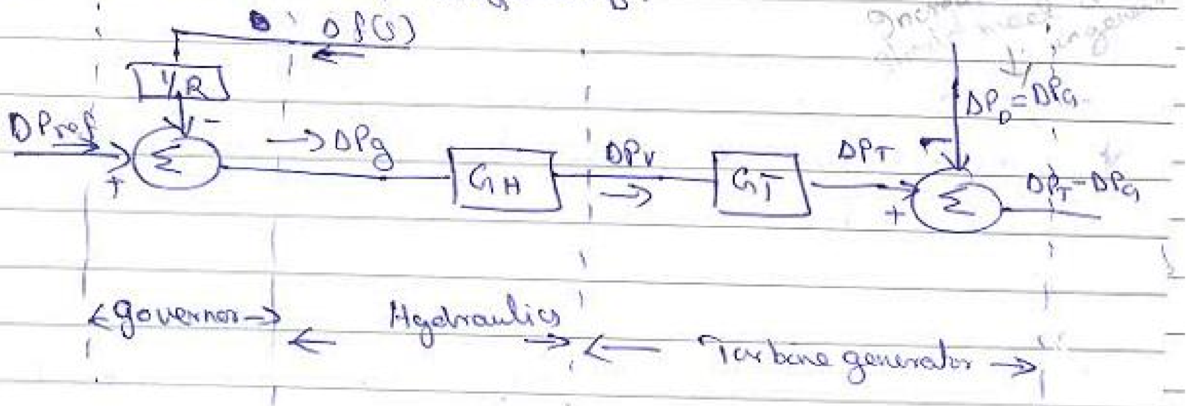
<u>load</u>

Generator increament ΔP_G depends on changes in the load ΔP_D. Generator o/p should meet the load demand.. (i) $\Delta P_G = \Delta P_D$.



The increment in power input to the generator load system is

$\Delta P_g - \Delta P_D$ is

$\Delta P_g = \Delta P_T$ incremental turbine power o/p

ΔP_D is the load increment

$\Delta P_G = P_D +$ losses

The increment in power input to the system is accounted for in two ways.

$\Delta P_T = \Delta P_D + \_ + \_$

(1) Rate of increase of stored K.E in the generator rotor: At scheduled freq (f°), the stored energy is

$W_{ke}^{0} = H \times P_r$ KW | P_r - KW rating of turbo generator
H - inertia const.

→ K.E at freq $(f^0 + \Delta f^0)$ is given by: K.E ∝ speed² (freq²) | $\frac{1}{2} I \omega^2$

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

$$\cong W_{ke}^{0} \left[1 + \frac{\Delta f}{f^0}\right]^2$$

$$= W_{ke}^{0} \left[1 + \frac{2\Delta f}{f^0} + \left(\frac{\Delta f}{f^0}\right)^2\right]$$ neglect second order term

$$W_{ke} = W_{ke}^{0} \left[1 + \frac{2\Delta f}{f^0}\right]$$

$$= H P_r \left[1 + \frac{2\Delta f}{f^0}\right]$$

Rate of change of K.E is given by

$$\frac{d}{dt}(W_{ke}) = \frac{2 H P_r}{f^0} \cdot \frac{d}{dt} \Delta f$$

(2) As the frequency changes, the motor load changes being sensitive to speed, rate of change of load w.r.t frequency

i.e) $\frac{\partial P_D}{\partial f}$ is almost const for small changes in f

$$\frac{\partial P_D}{\partial f} \Delta f = B \Delta f$$

MW/Hz

B is a const and it is positive for predominantly motor load

Power balance eqn can be written as

$$\Delta P_{T} - \Delta P_D = \frac{2HP_r}{f^0}\frac{d}{dt}(\Delta f) + B\,\Delta f$$

(MW ke)

Divide by P_r (Pu inertia constant)

$$\Delta P_{T(pu)} - \Delta P_{D(pu)} = \frac{2H}{f^0}\frac{d}{dt}\Delta f + B_{(pu)}\Delta f \qquad \text{Pu MW}$$

Taking L.T

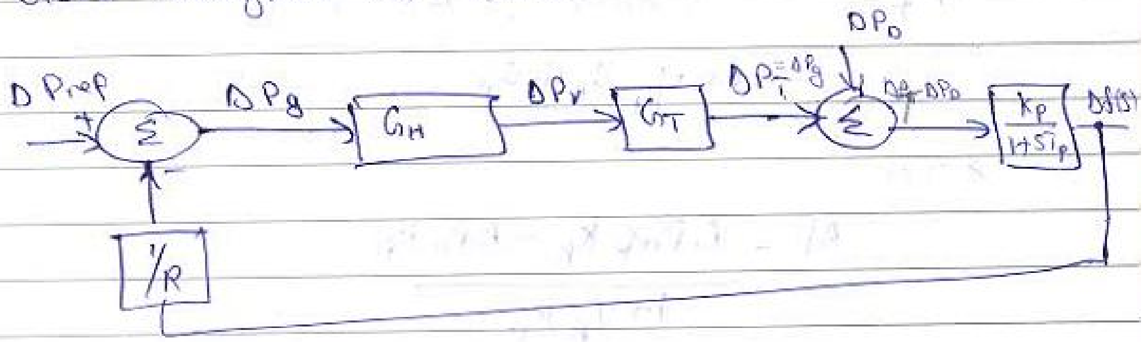
$$\Delta f(s) = \frac{\Delta P_g(s) - \Delta P_D(s)}{\left(B + \frac{2HS}{f^0}\right)} = \frac{\Delta P_g(s) - \Delta P_D(s)}{B\left[1 + \frac{2HS}{f^0 B}\right]}$$

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

$$K_p = \frac{1}{B}, \quad T_p = \frac{2H}{Bf^0}$$

$$T.F = \frac{\Delta f(s)}{\Delta P_g(s) - \Delta P_D(s)} = \frac{K_p}{1+sT_p} = G_p(s)$$

Block diagram of ALFC.



6 A & B

$P_r = 2000 MW$

$P_d = 1000 MW$

$H = 5s$

$R = 2.4\ Hz/pu\ MW$

load frequency = 60 Hz.

1% increase in P_D → there is 1% increase in f.

$$\therefore D = \frac{\partial P_D}{\partial f} = \frac{1000 \times 1/100}{60 \times \frac{1}{100}} = 16.667\ MW$$

in pu $$D = \frac{16.667}{2000} = 8.333 \times 10^{-3}\ pu\ MW/Hz$$

$$K_p = \frac{1}{D} = 120\ \text{~~Hz/pu MW~~}$$

$$T_p = \frac{2H}{Df^0} = \frac{2 \times 5}{8.333 \times 10^{-3} \times 60} = 20$$

$$G_p = \frac{K_p}{1+sT_p} = \frac{120}{1+s(20)}$$

~~[illegible]~~ $M = P_r\ 1\% = 2000 \times \frac{1}{100} = 20 MW$

~~As~~ inertia constant M

for 2GW system is

$$M = \frac{20M}{2G} = 0.01\ pu$$

$$\Delta f = -\frac{M}{\beta}$$

$$\beta = \frac{1}{K_p} + \frac{1}{R} = D + \frac{1}{R} = 8.333 \times 10^{-3} + \frac{1}{2.4} = 0.42499$$