21EE72: POWER SYSTEM OPERATION & CONTROL

MODULE –2: Automatic Generation Control

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- Module-2: Automatic Generation Control

- Automatic generation control: Introduction
- The need of Automatic Generation Control
- Reasons for limiting frequency deviations
- Speed governing system

Automatic Generation Control

In an electric power system, **automatic generation control (AGC)** is a system for :

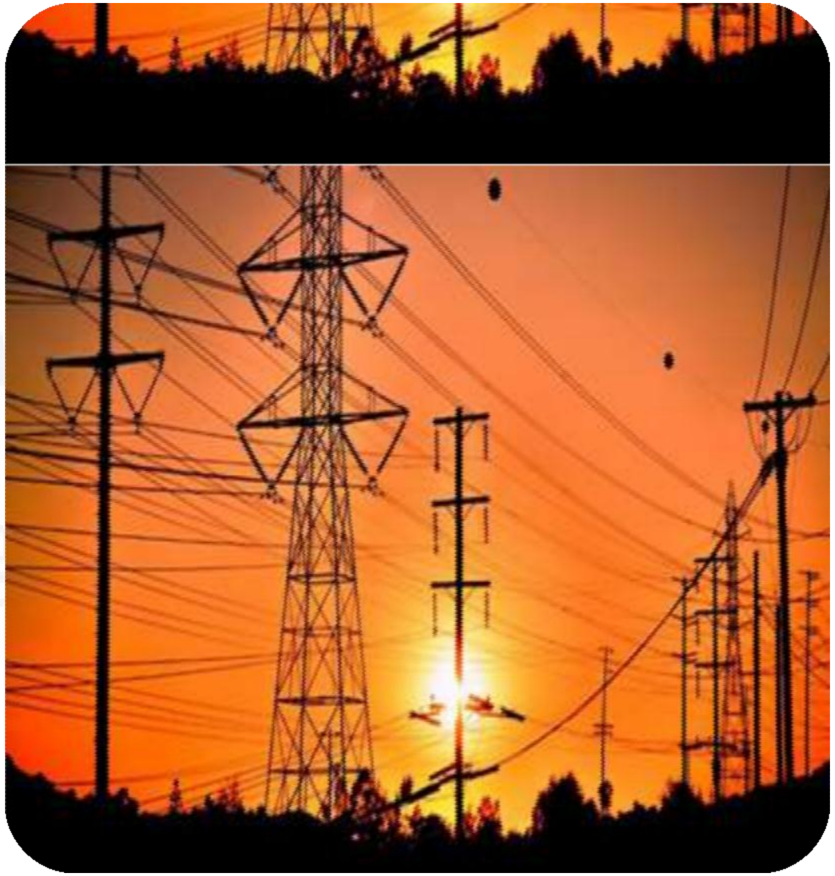
Adjusting the power output of multiple generators at different power plants, in response to changes in the load.

Since a power grid requires that generation and load closely balance moment by moment, frequent adjustments to the output of generators are necessary

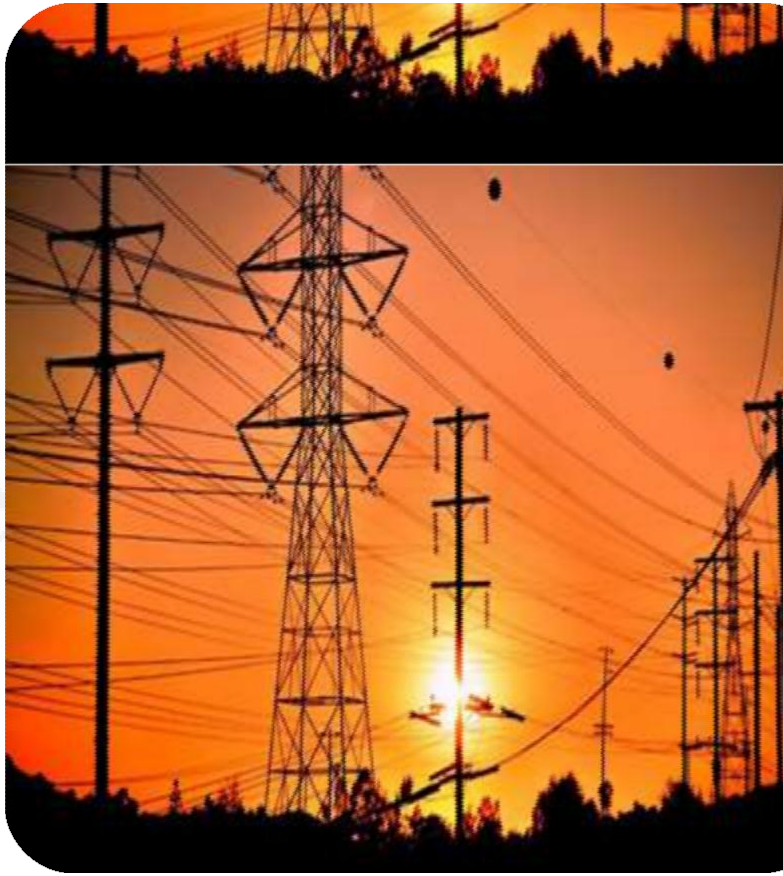
The Need of Automatic Generation Control

As our development has increased, there has been a higher demand of electrical **power loads both on industrial and domestic scale.**

As the number increases, it is also imperative to manage load properly since a failure to do so results in **frequency fluctuation and voltage drops.**



The Need of Automatic Generation Control



An effective regulatory strategy is available in the form of:

- **Automatic Voltage Regulator Systems (AVR)** and
- **Automatic Load Frequency Control (ALFC)**

The main function of ALFC system is to assess and rectify the power and frequency while that of **AVR system is to regulate voltage and reactive power.**

REASONS FOR LIMITING FREQUENCY DEVIATIONS

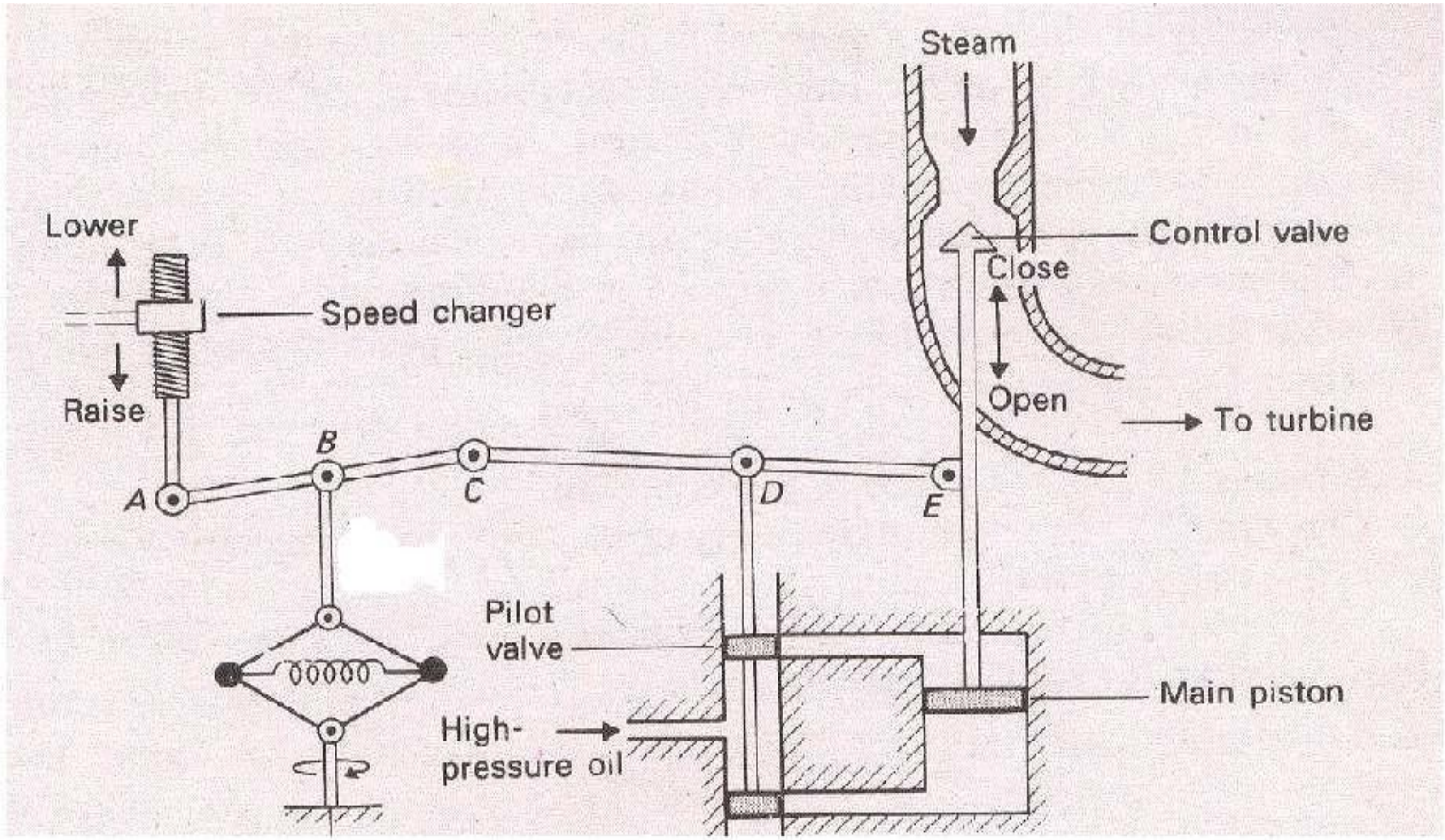
There are few reasons as to why there should be strict limitations on frequency deviations and keeping the system frequency constant. They are as follows:

- **The three phase a.c. motors running speed are directly proportional to the frequency.** So the variation of system frequency will directly affect the motor performance.

- The blades of the steam turbine and the water turbines are designed to operate at a particular speed and the frequency variations will cause change in the speed. **This will lead to excessive vibration and cause damage to the turbine blades.**

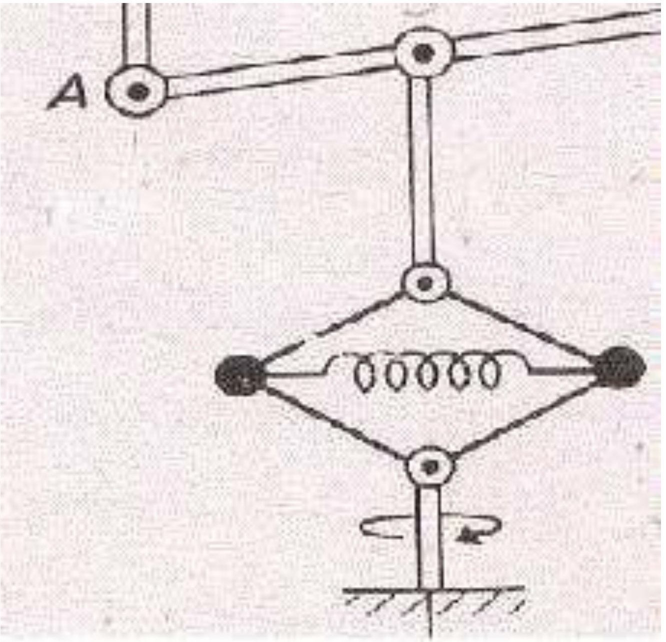
- **The frequency error may produce havoc in the digital storage and retrieval process.**

SPEED GOVERNING SYSTEM



The system consists of the following components:

I. Fly ball speed governor
II. Hydraulic amplifier
III. Linkage mechanism
IV. Speed changer

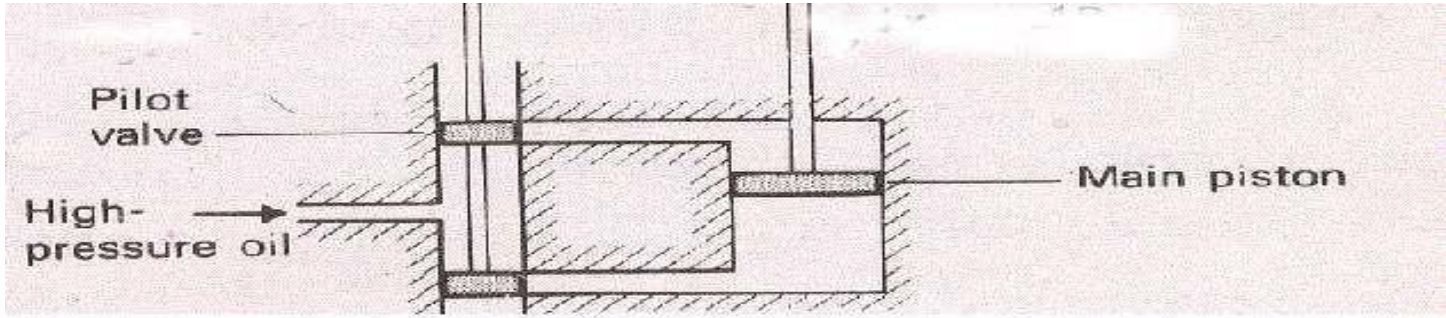


I. Fly ball speed governor:

This is the heart of the system which senses the change in speed frequency. As the speed increases the fly balls move outwards and the point B on linkage mechanism moves downwards. The reverse happens when the speed decreases

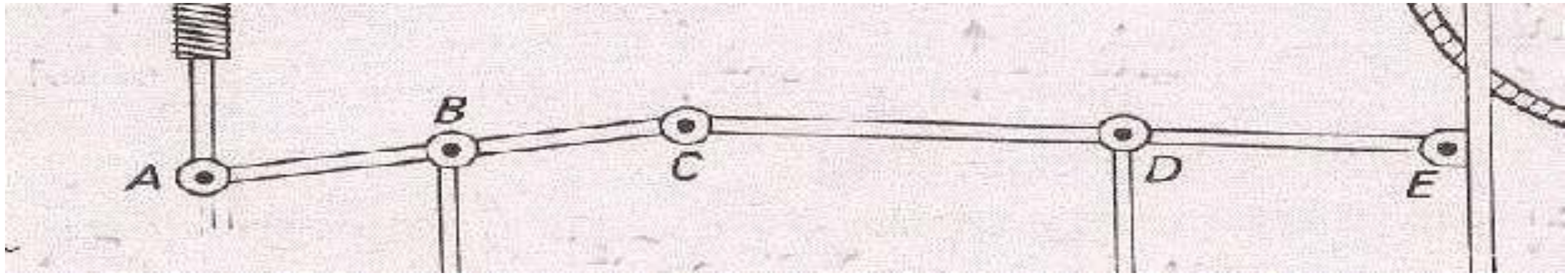
II.Hydraulic amplifier:

It comprises a pilot valve and main piston arrangement. Low power level pilot valve movement is converted into high power level piston valve movement. This is necessary in order to open or close the steam valve against high pressure steam.



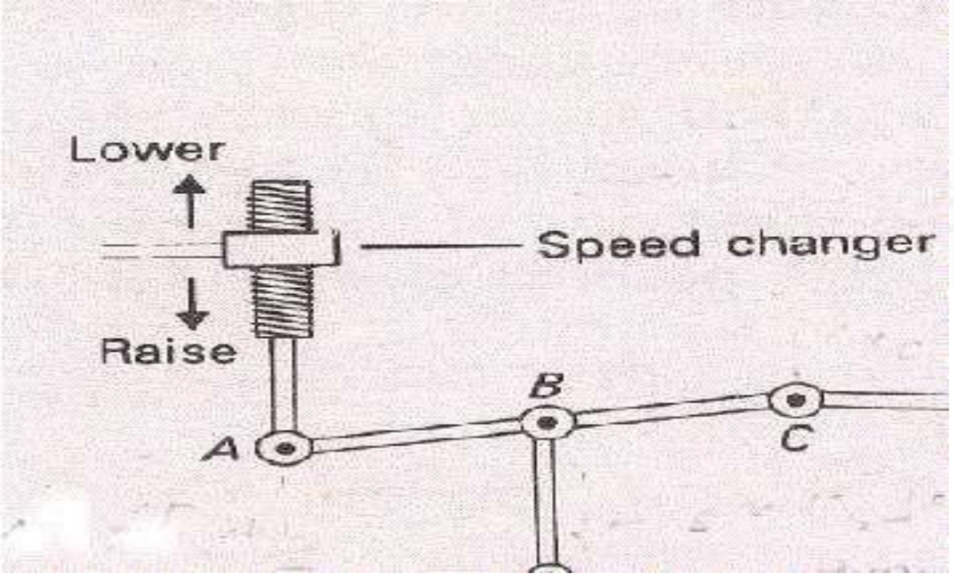
III.Linkage mechanism:

ABC is a rigid link pivoted at B and CDE is another rigid link pivoted at D. This link mechanism provides a movement to the control valve in proportion to change in speed. It also provides a feedback from the steam valve movement



IV. Speed changer:

It provides a steady state power output setting for the turbine. Its downward movement opens the upper pilot valve so that more steam is admitted to the turbine under steady conditions. The e reverse happens for upward movement of speed changer



INTRODUCTION

ADJUSTING POWER OUTPUT

- MULTIPLE GENERATORS
- Different Power Plants
- Response to Changes in Load

INTRODUCTION

S=P+JQ

P→ Depends on Frequency; Depends on Speed---→Speed Governor

Permissible Limit is +/- 0.5%

Q→ Depends on Excitation-→ Excitation Control

Permissible Limit is +/- 5%

Even though P~f and Q~V control loops are working simultaneously both frequency and voltage control loops do not interfere with each other?

Answer:

Different Time Constant

T (Gen-Field) < T(Speed Governor)

Transients in Excitation control vanishes faster and do not interfere with dynamics of frequency control

INTRODUCTION

In Power System, the Active and Reactive power are never Steady. It is time varying quantity.

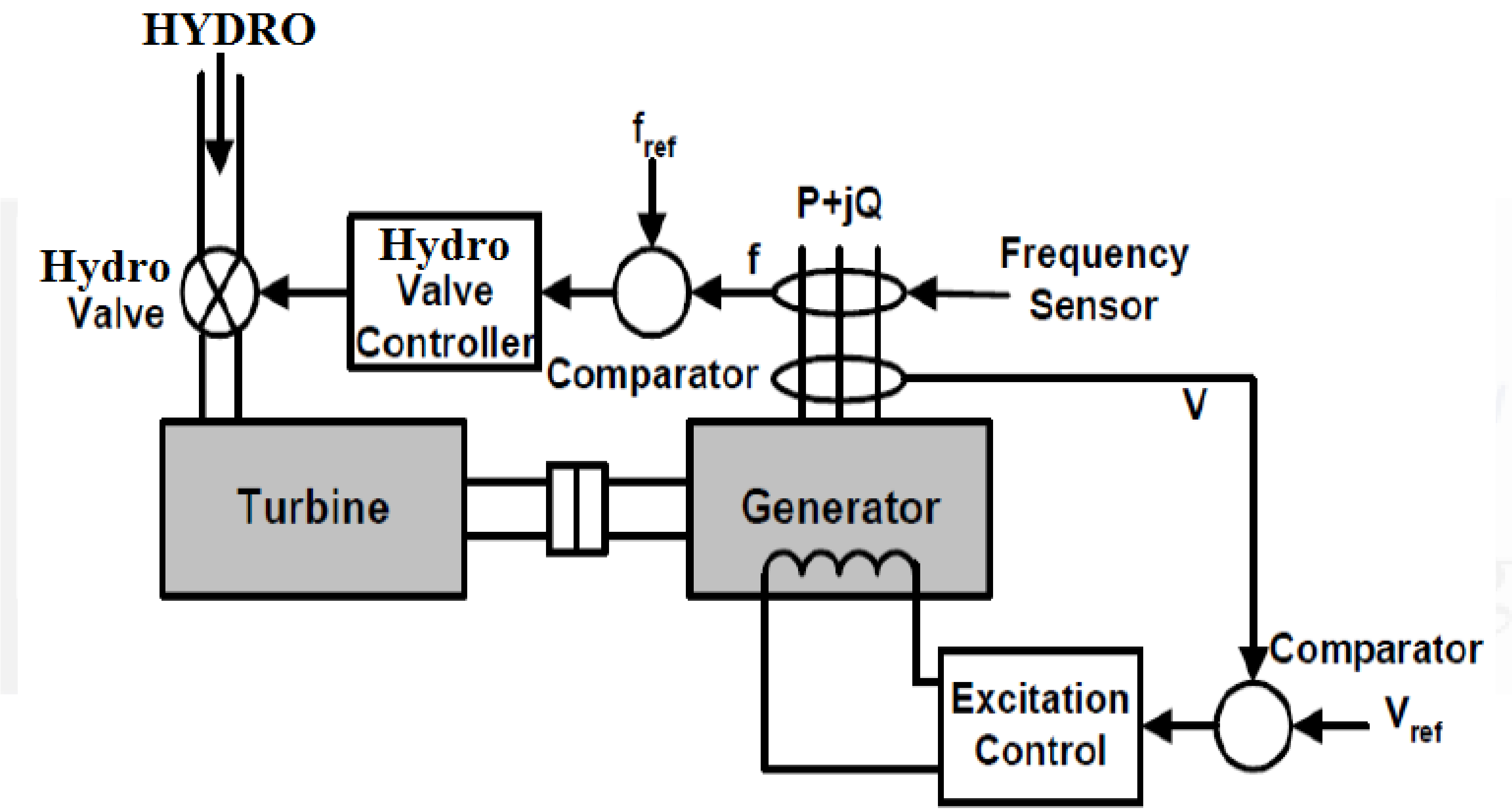
1. **When reactive power increase, the voltage starts dropping and when the demand of active power increases, the frequency of supply decreases.**
2. **To compensate frequency the steam input to turbo generator (or water input to hydro generator) must be continuously regulated.**

An effective regulatory strategy is available in the form of:

1. **Automatic Voltage Regulator Systems (AVR)**
2. **Automatic Load Frequency Control(ALFC)**

The main function of ALFC system is to assess and rectify the power and frequency while that of **AVR system is to regulate voltage and reactive power.**

INTRODUCTION



Block diagram representation of load frequency and excitation control

MATHEMATICAL MODEL

A) **GENERATOR MODEL**

B) **LOAD MODEL**

C) **PRIME MOVER MODEL**

D) **GOVERNOR MODEL**

MATHEMATICAL MODEL

Before starting, it will be useful for us to define our terms.

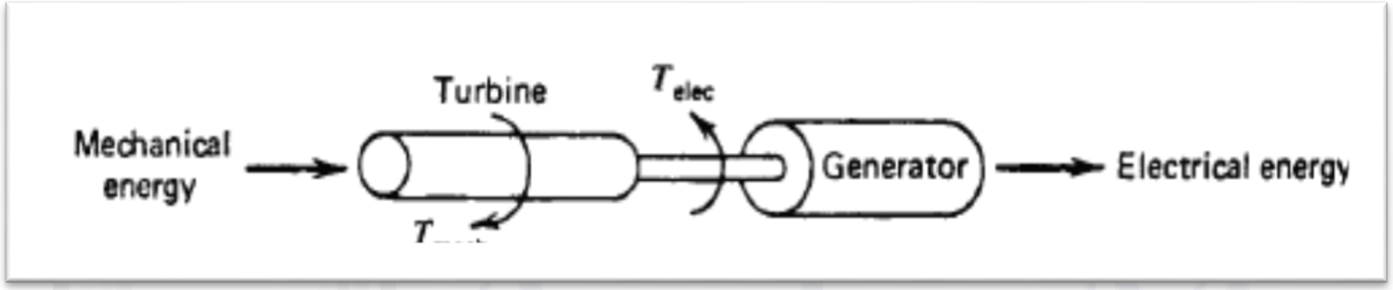
ω = rotational speed (rad/sec)

α = rotational acceleration

δ = phase angle of a rotating machine

GENERATOR MODEL

Mechanical and Electrical torques in a generating unit



T_{net} = net accelerating torque in a machine

T_{mech} = mechanical torque exerted on the machine by the turbine

T_{elec} = electrical torque exerted on the machine by the generator

P_{net} = net accelerating power

P_{mech} = mechanical power input

P_{elec} = electrical power output

I = moment of inertia for the machine

M = angular momentum of the machine

GENERATOR MODEL

$$I\alpha = T_{net}$$

$$M = \omega I$$

$$P_{net} = \omega T_{net} = \omega(I\alpha) = M\alpha$$

Due to various electrical or mechanical disturbances, the machine will be subjected to differences in mechanical and electrical torque, causing it to **accelerate or decelerate.**

deviations of speed, $\Delta\omega$,

deviations in phase angle, $\Delta\delta$,

$$\Delta\delta = \underbrace{\int (\omega_0 + \alpha t)\, dt}_{\text{Machine absolute phase angle}} - \underbrace{\int \omega_0\, dt}_{\text{Phase angle of reference axis}}$$

$$= \omega_0 t + \tfrac{1}{2}\alpha t^2 - \omega_0 t$$

$$= \tfrac{1}{2}\alpha t^2$$

$$\Delta\omega = \alpha t = \frac{d}{dt}(\Delta\delta)$$

GENERATOR MODEL

$$\Delta\omega = \alpha t = \frac{d}{dt}(\Delta\delta)$$

$$T_{net} = I\alpha = I\frac{d}{dt}(\Delta\omega) = I\frac{d^2}{dt^2}(\Delta\delta)$$

The relationship between net accelerating power and the electrical and mechanical powers is:

$$P_{net} = P_{mech} - P_{elec}$$

which is written as the sum of the steady-state value and the deviation term

$$P_{net} = P_{net_0} + \Delta P_{net}$$

$$P_{net_0} = P_{mech_0} - P_{elec_0}$$

$$\Delta P_{net} = \Delta P_{mech} - \Delta P_{elec}$$

$$P_{net} = (P_{mech_0} - P_{elec_0}) + (\Delta P_{mech} - \Delta P_{elec})$$

$$T_{net} = (T_{mech_0} - T_{elec_0}) + (\Delta T_{mech} - \Delta T_{elec})$$

GENERATOR MODEL

$$P_{net} = P_{net_0} + \Delta P_{net} = (\omega_0 + \Delta\omega)(T_{net_0} + \Delta T_{net})$$

$$(P_{mech_0} - P_{elec_0}) + (\Delta P_{mech} - \Delta P_{elec}) = (\omega_0 + \Delta\omega)[(T_{mech_0} - T_{elec_0}) + (\Delta T_{mech} - \Delta T_{elec})]$$

Assume that the steady-state quantities

$$P_{mech_0} = P_{elec_0}$$

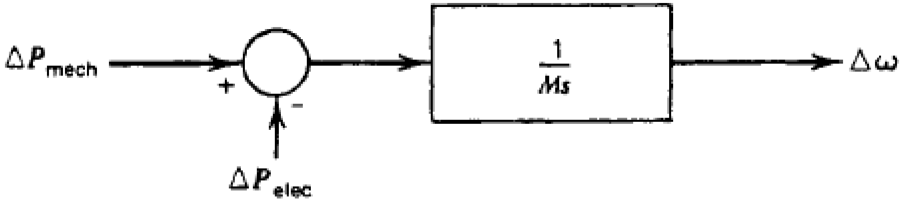
$$T_{mech_0} = T_{elec_0}$$

$$\Delta P_{mech} - \Delta P_{elec} = \omega_0(\Delta T_{mech} - \Delta T_{elec})$$

$$(T_{mech_0} - T_{elec_0}) + (\Delta T_{mech} - \Delta T_{elec}) = I\frac{d}{dt}(\Delta\omega)$$

since $T_{mech_0} = T_{elec_0}$,

$$\Delta P_{mech} - \Delta P_{elec} = \omega_0 I\frac{d}{dt}(\Delta\omega) = M\frac{d}{dt}(\Delta\omega)$$



LOAD MODEL

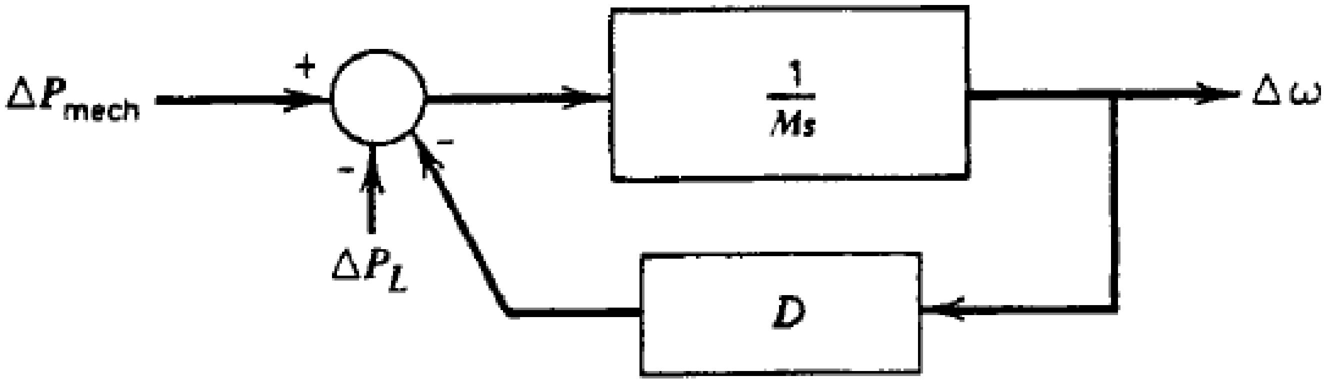
The relationship between the change in load due to the change in frequency is given by:

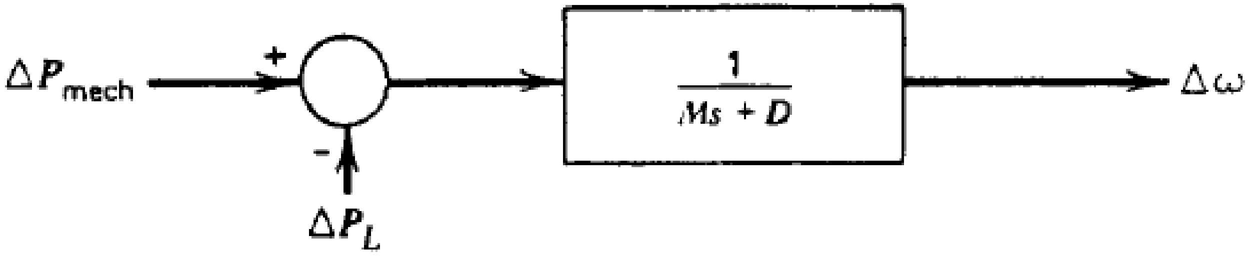
$$\Delta P_{L(freq)} = D\ \Delta\omega \quad \text{or} \quad D = \frac{\Delta P_{L(freq)}}{\Delta\omega}$$

D is % Change in Load / % Change in frequency

For example, if load changed by 1.5% for a 1% change in frequency, then ***D would equal 1.5.***

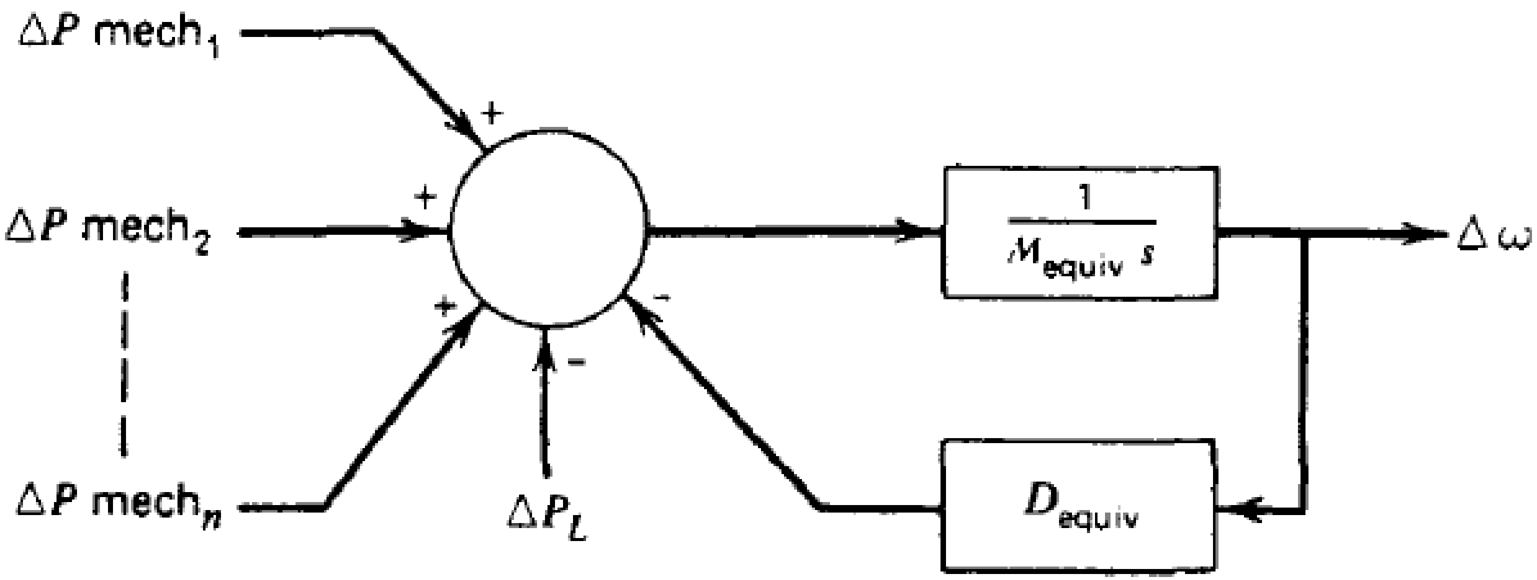
LOAD MODEL





Block diagram of rotating mass and load as seen by prime-mover output.

LOAD MODEL



Multi-turbine-generator system equivalent.

PRIME MOVER MODEL

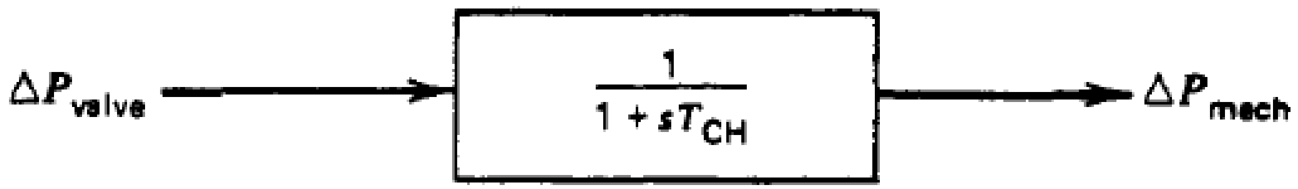
The prime mover driving a generator unit may be a steam turbine or a **hydroturbine.** The models for the prime mover must take account of the steam supply and boiler control system characteristics in the case of a steam turbine, or the **penstock characteristics for a hydro turbine.**

T_{CH} = "charging time" time constant

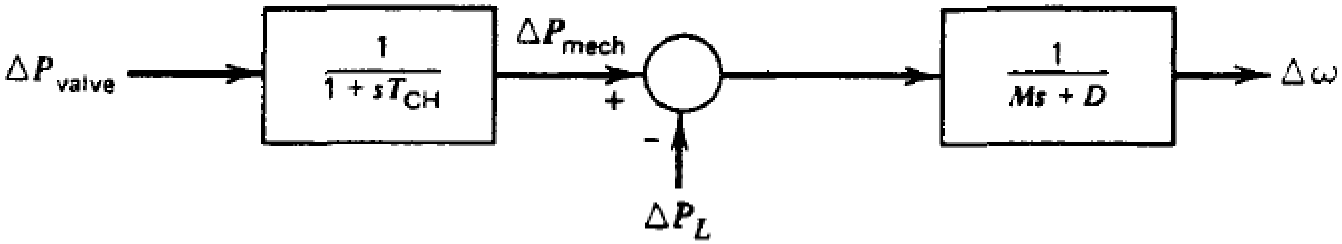
ΔP_{valve} = per unit change in valve position from nominal

PRIME MOVER MODEL

The combined prime-mover-generator-load model for a single generating unit



Prime-mover model.



Prime-mover–generator-load model.

GOVERNOR MODEL

1. Suppose a generating unit is operated with fixed mechanical power output from the turbine. The result of any load change would be a speed change sufficient to cause the frequency-sensitive load to exactly compensate for the load change . **This condition would allow system frequency to drift far outside acceptable limits.**
2. **This is overcome by adding a governing mechanism that senses the machine speed**, and adjusts the input valve to change the mechanical power output to compensate for load changes and to **restore frequency to nominal value**.

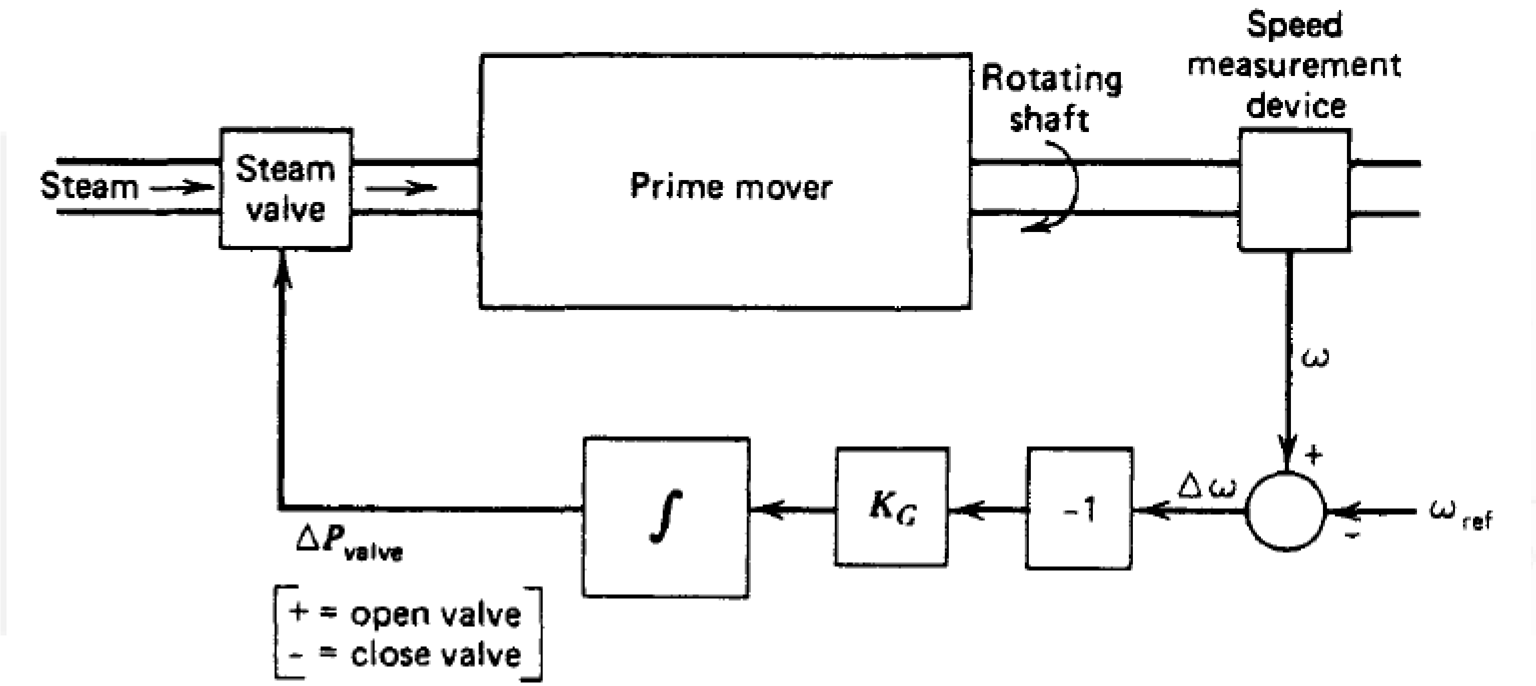
GOVERNOR MODEL

1. The earliest such mechanism used rotating **“flyballs”**

2. **Modern governors** use electronic means to sense speed changes and often use a combination of electronic, mechanical, and hydraulic means to effect the required valve position changes

3. The simplest governor, called the ***isochronous governor*, *adjusts the input valve to a point that brings frequency back*** to nominal value.

GOVERNOR MODEL

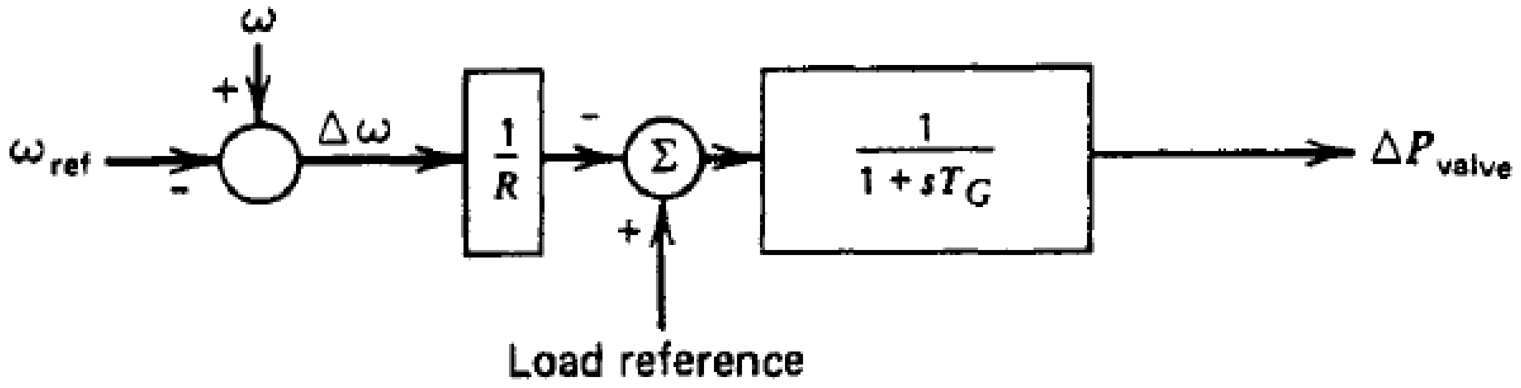


Isochronous governor.

The action of the **gain and integrator** will be to open the hydro valve, causing the turbine to increase its mechanical output, thereby increasing the electrical Output

GOVERNOR MODEL

If two generators with drooping governor characteristics are connected to a power system, there will always be a unique frequency, at which they will share a load change between them.



Block diagram of governor with droop.

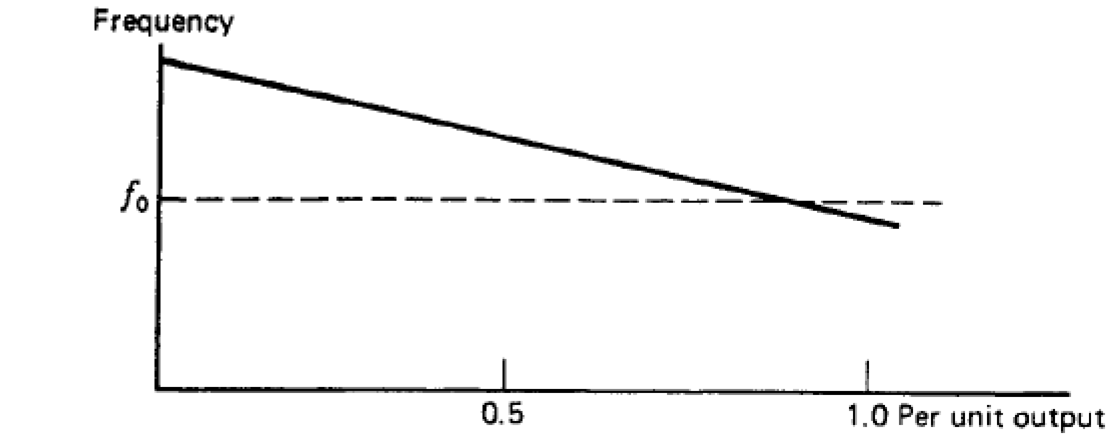
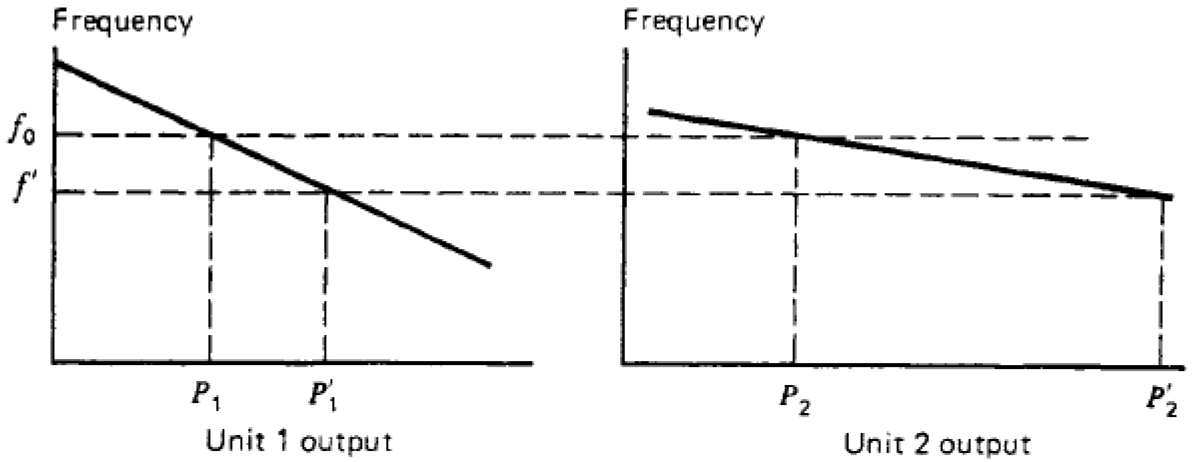
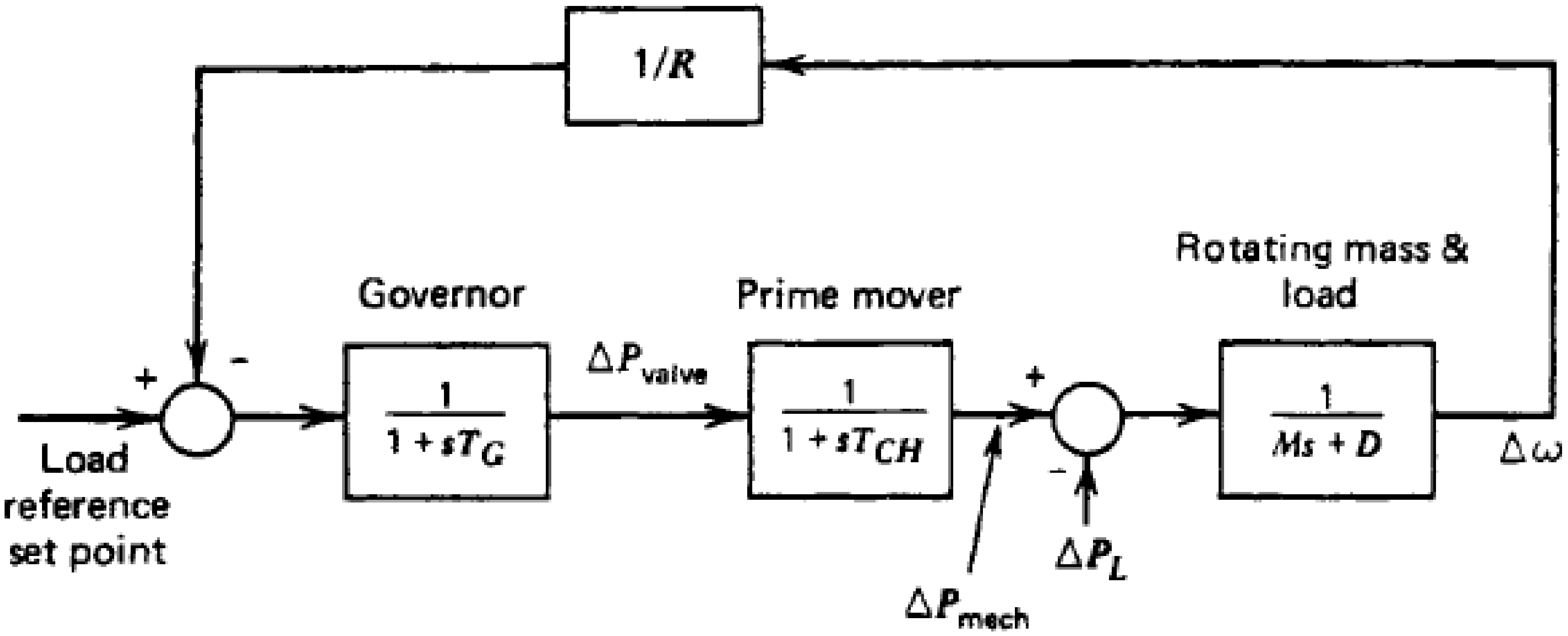


FIG. 9.12 Speed-droop characteristic.

$$R = \frac{\Delta\omega}{\Delta P} \text{ pu}$$



Allocation of unit outputs with governor droop.



Block diagram of governor, prime mover, and rotating mass.

TOPICS

- **Commonly Used Terms in AGC**
- **Functions of AGC**
- **Load Sharing in Parallel**
- **Modes of Speed Governor**
- **Numericals**

Common terms in AGC

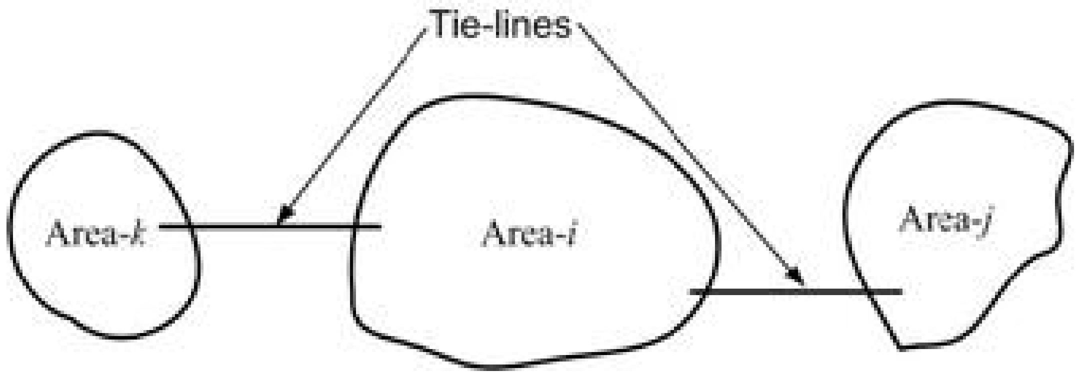
- **Control Area:**

  A control area is a part of the system to which common generation is applied.

- **Tie line:**

  The transmission lines connecting two or more areas are called **tie lines.**

  Active power flows from one area to another via the tie lines.



Common terms in AGC

Net interchange:

Between control areas, there is a mutually prearranged net power on the area tie lines, called the scheduled net interchange.

The algebraic sum of powers on the area tie lines of a control area is called the net interchange.

If the net interchange is positive, there is generation out of the area.

Frequency:

There are different frequencies commonly used.

System frequency: It is the actual frequency of the system AC voltage.

Standard frequency: It is the frequency intended to be used as **reference.**

Rated frequency: It is the frequency for which the generating equipment is designed.

Scheduled frequency: It is the frequency which the system attempts to maintain.

Common terms in AGC

- **Frequency bias:**

  It is the offset in the scheduled net power interchange of a control area. It is varied proportional to the frequency deviation and is in a direction so as to bring the **system frequency** to the **scheduled frequency.**

- **Time deviation:**

  It is the ratio of the **accumulated (or integrated) difference** between the **system frequency** and **rated frequency**, to the **rated frequency**.

- **Load-frequency characteristic:**

  For a control area, it is the **change in total area load** resulting from a change in system frequency.

- **Station control error:**

  It is the station generation minus the assigned station generation.

- **Unit control errors:**

  It is the unit generation minus the assigned unit generation.

FUNCTIONS OF AGC

- The frequency of the various bus voltages are maintained at the **scheduled frequency.**
- The **tie-line power flows** are maintained at the scheduled levels.
- The total power is shared by all generators economically (economic dispatch). **The first two functions are realized using the ALFC** whereas third using AVR

FUNCTIONS OF AGC

- **Yield a generation acceptably matching the changing load at scheduled frequency**
- **Should accumulate lower fuel cost**
- **Maintain sufficient level of reserved control range**
- **Provide higher security margins**
- **Provide meaningful alarms at control centres for deviations**

Load Regulation between Units in Parallel

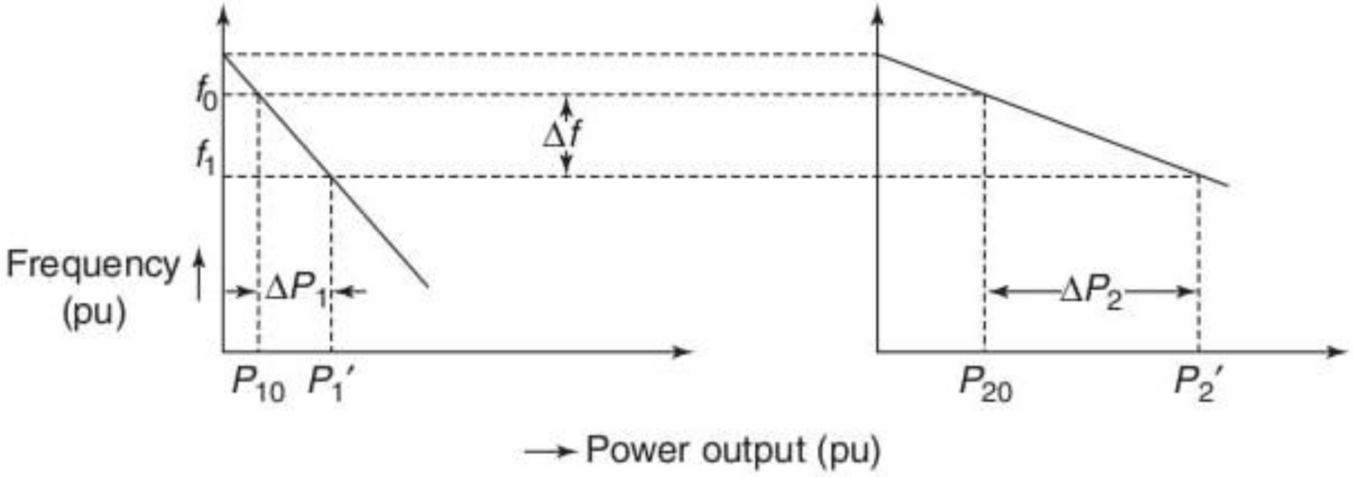
- W_{NL} -----→No load Speed
- W_{FL}--→ Full Load Speed
- W_0---→Nominal Speed

$$\%R = \left(\frac{\omega_{NL} - \omega_{FL}}{\omega_0}\right) \times 100$$

Load Regulation between Units in Parallel

- Assume that the Output of Two machines are P_{10} and P_{20} at frequency f_0
- If load increases by an amount ΔP_L the units slow down and speed governors bring it to the operating frequency
- The new outputs are P_1' and P_2'

Load Regulation between Units in Parallel



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

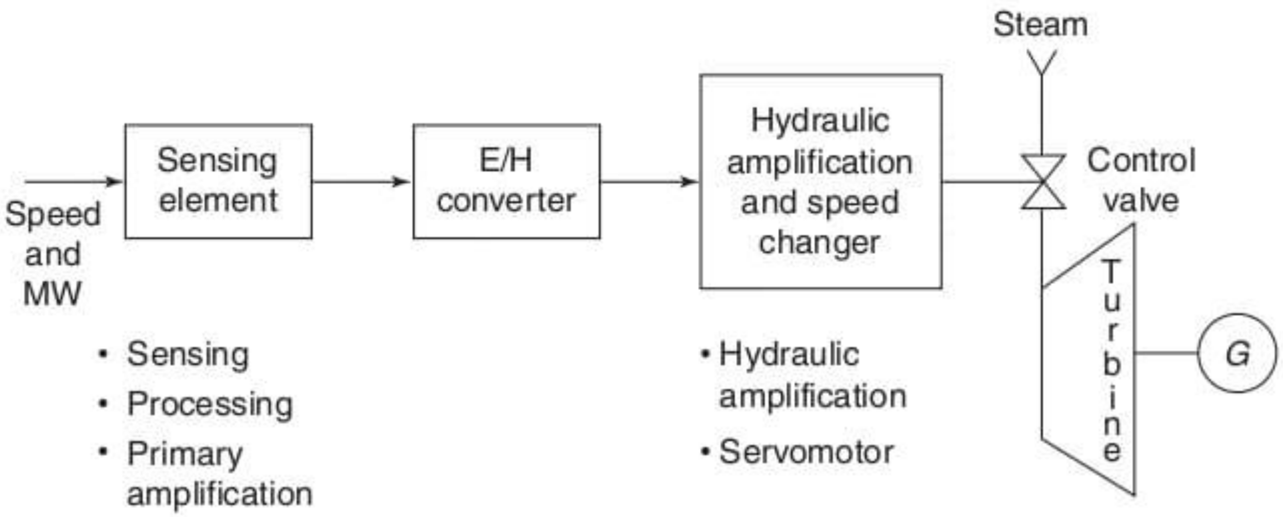
$$\Delta P_2 = \frac{\Delta f}{R_2}$$

$$\frac{\Delta P_1}{\Delta P_2} = \frac{R_2}{R_1}$$

The change in output of the generators is thus in the inverse ratio of the speed regulation.

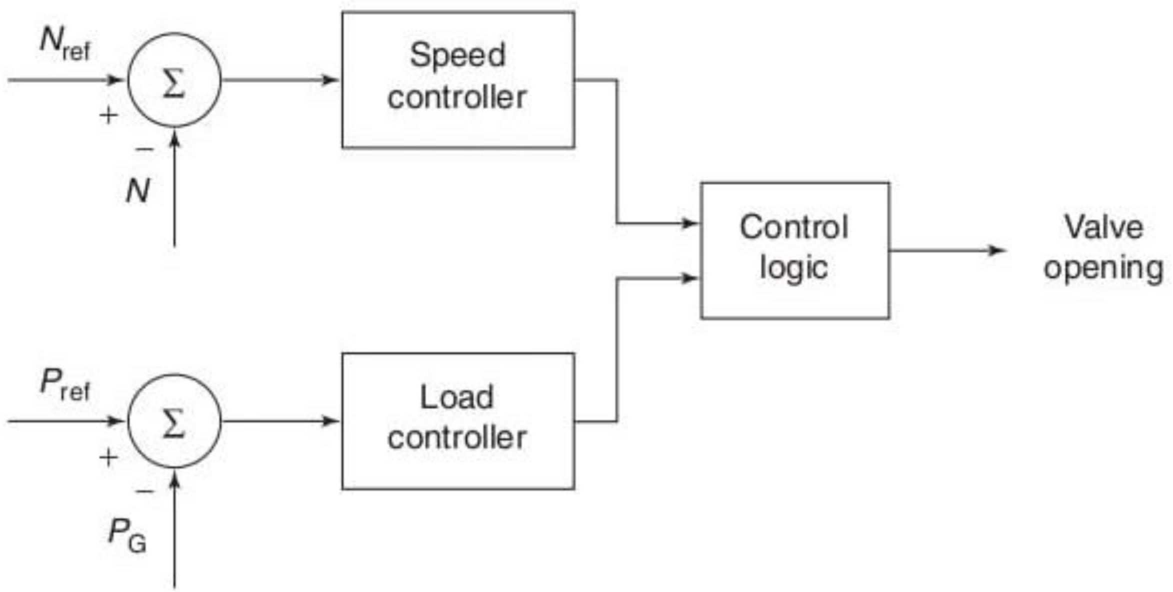
MODES OF SPEED GOVERNOR

- ELECTRONIC HYDRAULIC GOVERNING SYSTEM



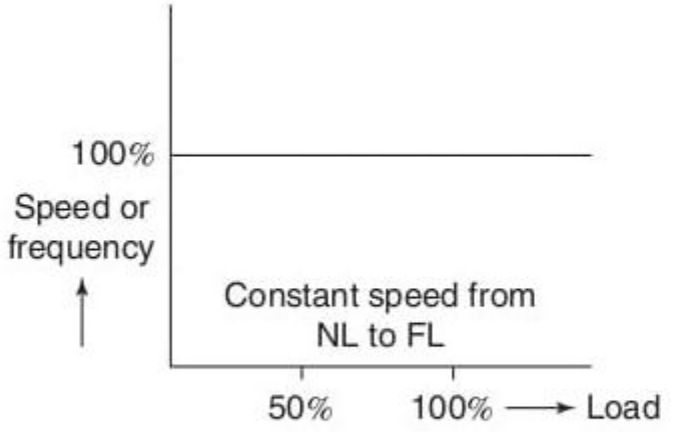
MODES OF SPEED GOVERNOR

- ELECTRONIC HYDRAULIC GOVERNING SYSTEM



MODES OF SPEED GOVERNOR

- ISOCHRONOUS GOVERNORS

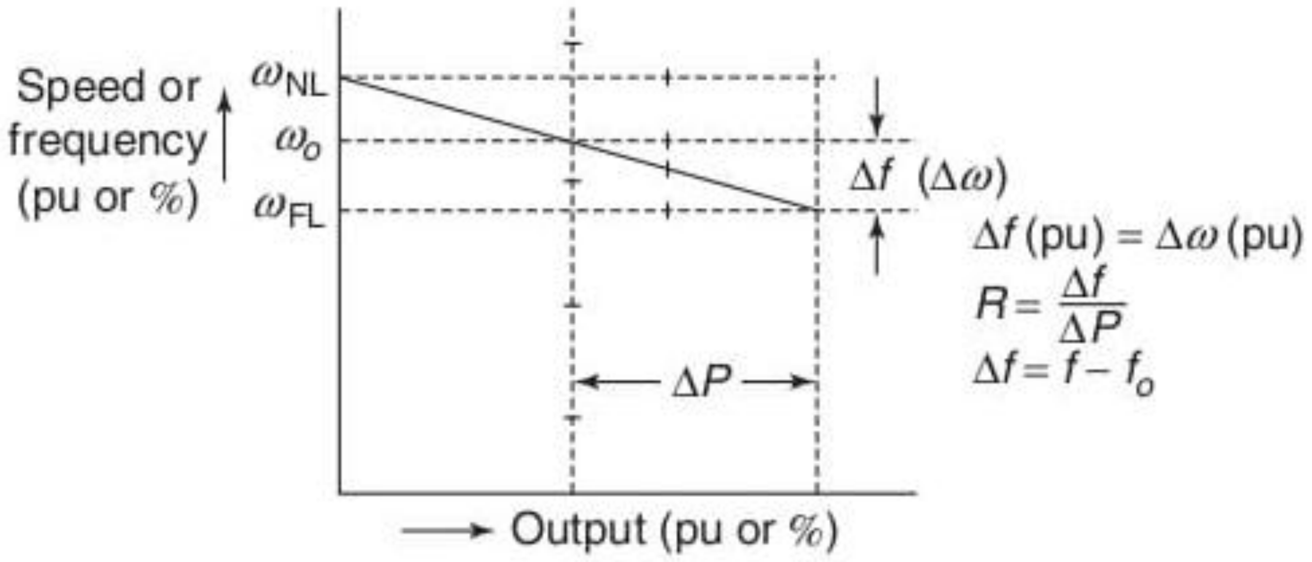


- **tained Constant from No-Load to Full**
-
- **sed in Isolated systems**
- **generator is required to meet demand**

MODES OF SPEED GOVERNOR

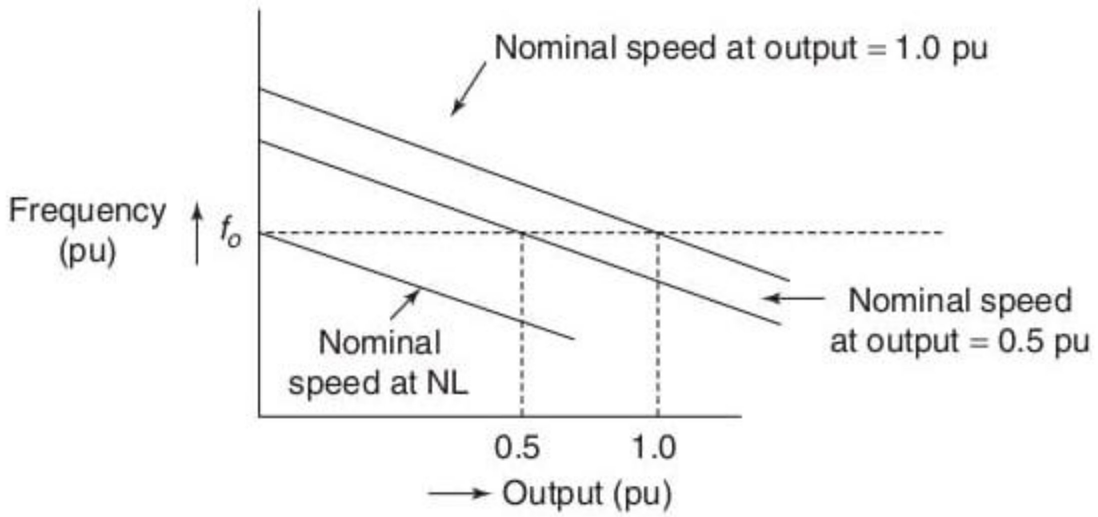
DROOP MODE

Speed Droop is a decrease in speed or frequency proportional to the load



Speed Droop Curve with Change in Governor Set Point

$$R = \Delta f / \Delta P$$



NUMERICAL

Example 6.1 Two prime mover generator sets are paralleled. Both have 3% droop. The frequency is 50 Hz on full load. Plot the speed droop characteristics and comment on the load sharing if one generator A has a rating of 500 MW and another B 300 MW.

Solution

The speed droop is 3%. Therefore, the frequency at no load is 3% more than at full load which is 51.5 Hz. The characteristic is shown in Fig. 6.8.

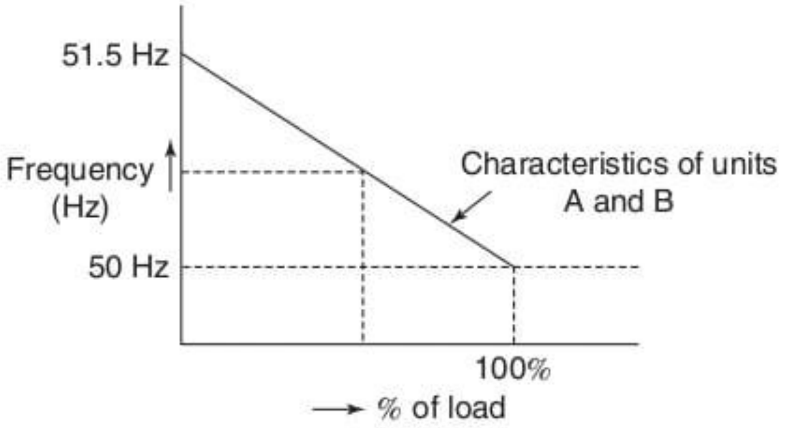


Figure 6.8 Generators with identical droop characteristics: Example 6.1.

3% --→0.03X50Hz
1.5Hz
50+1.5=51.5Hz

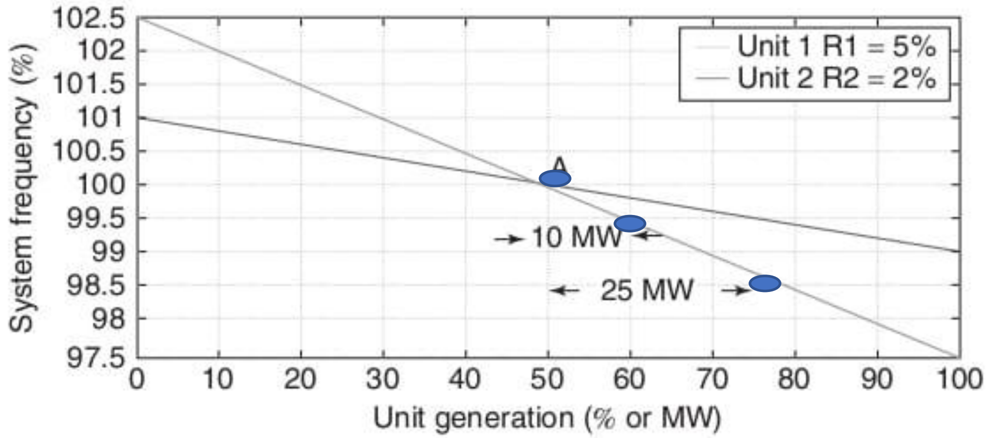
Here 100% load is the total capacity of the two units, that is, 500 + 300 = 800 MW. For any other load, the

NUMERICAL

Example 6.3 Two identical machines 1 and 2 have droop characteristics with 5% and 2% speed regulation, respectively. They share an initial load of 100 MW equally, operating at nominal frequency. If now there is an increase of 35 MW in the load, how would the additional load be shared? State any assumptions made.

Solution

Since we have just two units we can solve the problem graphically. The speed droop characteristics of the two machines are drawn, assuming that with the initial load the system frequency is 100% (nominal frequency of 50 Hz). We draw the graph as shown in Fig. 6.10. Here, we have taken 100% output = 100 MW. At 50 Hz, each is supplying 50 MW. Now if the load is increased by 35 MW, the new load is 135 MW.



NUMERICAL

The frequency decreases. We can draw horizontal lines, by trial and error locate the frequency at which the total load supplied by both is 135 MW. As seen in the figure, at $f = 99.5\%$ (49.75 Hz) we get $P_1 = 60$ MW and $P_2 = 75$ MW so that $P_1 + P_2 = 135$ MW. The increase in power output of machine 1 is 10 MW (60–50) and that of machine 2, 25 MW (75–50). We can solve it using Eq. (6.5).

$$\frac{\Delta P_1}{\Delta P_2} = \frac{R_2}{R_1}$$

$$\Delta P_2 = 35 - \Delta P_1$$

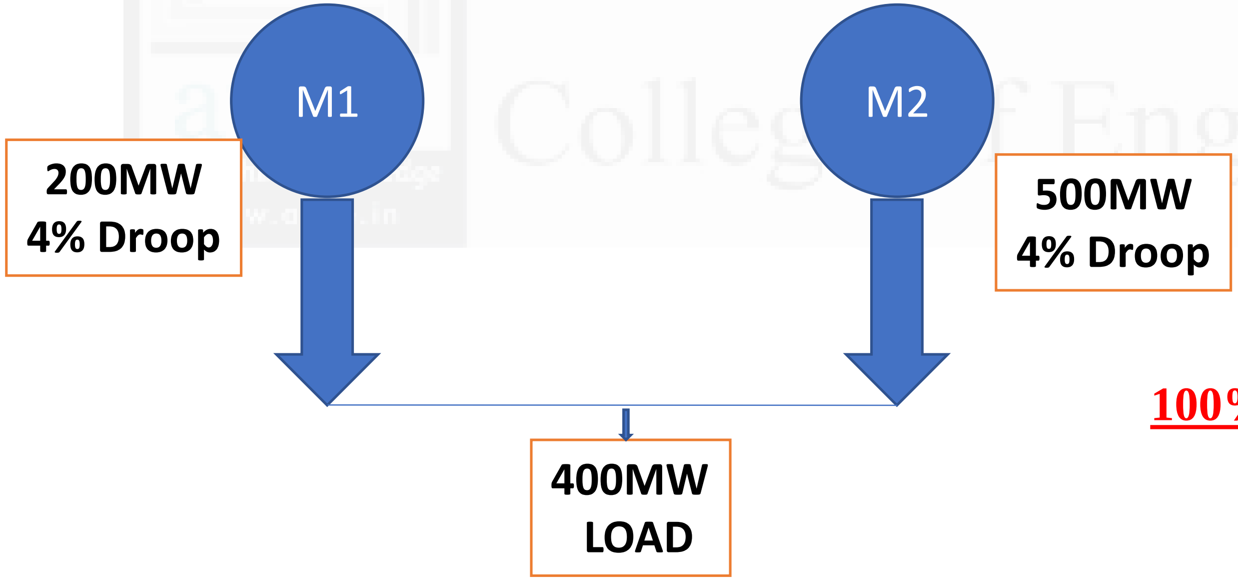
$$\frac{\Delta P_1}{35 - \Delta P_1} = \frac{2}{5} \Rightarrow \Delta P_1 = 10\text{ MW}; \Delta P_2 = 25\text{ MW}$$

So the output of machine 1 is increased by 10 MW and that of machine 2 is increased by 25 MW. When the load is increased by 25 MW, the units slow down, the governors increase the output until the units seek a new common operating frequency.

Numericals
Units connected in Parallel

Two machines operate in parallel to supply a load of 400MW. The capacities of the machines are 200MW and 500MW. Each has a droop characteristic of 4%. Their governors are adjusted so that the frequency is 100% on full load. Calculate the load supplied by each unit and the frequency at this load. This is a 50Hz system

Solution:



100% on full load---→50Hz

Numericals
Units connected in Parallel

Solution:

Step 1: **Plot the droop characteristics in p.u since machine have different ratings**

Step 2: Let us take the base power be **100MW**

Step 3: Full load output of Unit 1= Actual/ Base = **200/100= 2pu**

Full load output of Unit 2= Actual/Base =**500/100 =5pu**

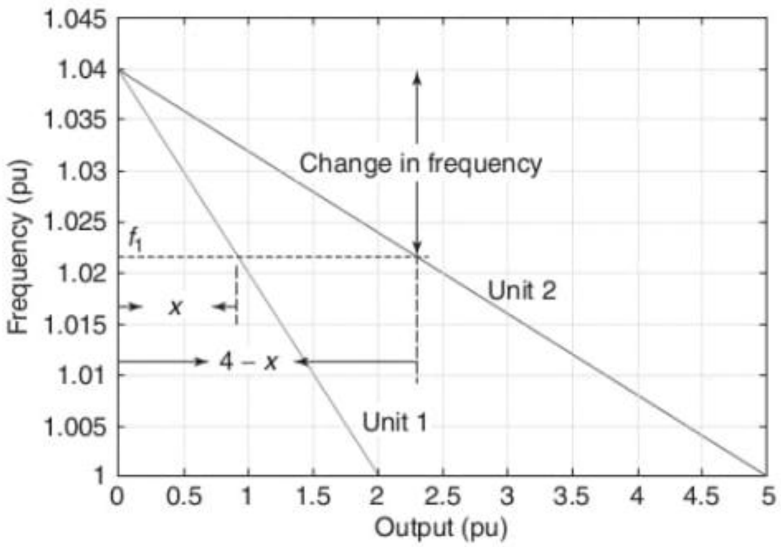
50Hz =1pu frequency

Step 4: Since droop characteristic has 4% droop, the no load speed is 4% greater than full load speed.

When load is thrown off frequency raises by 4% from 100--→**104% or 1.04pu**

Step 5: **For Unit 1** frequency drops from 1.04pu at no load to **1pu (2pu)**

For Unit 2 frequency drops from 1.04pu at no load to **1pu (5pu)**



Step 6: Load is 400MW=4pu

Step 7: Let Load supplied by **Unit 1** be x pu

Unit 2 be 4-x pu

Frequency deviation→ Δf

Step 8: $\Delta f / x = 0.04/2$ ---------(1)

$\Delta f/4\text{-}x = 0.04/5$ ----------(2)

Step 9: Dividing equations

4-x /x = 5/2

Solving

x=8/7 =1.142 pu

TOPICS: Numericals Units connected in Parallel

Step 10: From (1) $\Delta f = 0.02$ x **x = 0.02 x 1.142**

= 0.0228 pu

Step 11: New frequency f1= 1.04- **Δf**

=1.04-0.0228

=1.017PU

=1.017 x 50 =50.85Hz

Step 12: Power supplied by unit 1= 114.28MW

Power supplied by unit 2= 285.71MW

Frequency of system =**50.85Hz**

Numericals
Steady State Frequency Deviation

Example 6.7 Consider an isolated generator of 500 MVA, M = 8 pu MW/pu freq/s on the machine base. The unit is supplying a load of 400 MVA. The load changes by 1.5% for a 1% change in frequency. Draw the block diagram for the equivalent generator-load system. For an increase of 10 MVA in the load, determine the steady-state frequency deviation and the response.

Solution

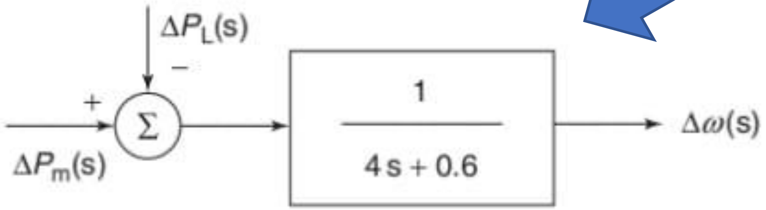
We can choose a convenient base. Note that M is on the generator base and D is on the load base. Let us choose a common base of 1,000 MVA.

$$M = 8 \times \frac{500}{1000} = 4 \text{(on a 1000 MVA base)}$$

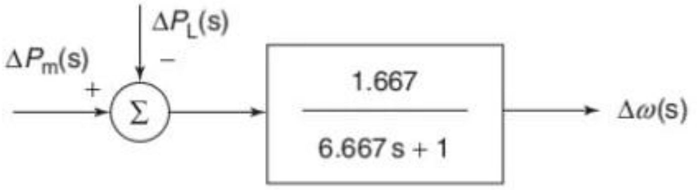
$$D = 1.5 \times \frac{400}{1000} = 0.6 \text{(on a 1000 MVA base)}$$

The block diagram is shown in Fig. 2.23.

1/Ms+D



Numericals
Steady State Frequency Deviation



(b)

Figure 6.23 Example 6.7.

Figure 2.23(b) is the equivalent block diagram as a standard first-order transfer function. The gain is 1.667 and the time constant is 6.667.

Now the load increases by 10 MVA $= \dfrac{10}{1000} = 0.01\,\text{pu}$ with the mechanical power remaining the same. Therefore,

$$\begin{aligned}
\Delta\omega(s) &= -(\Delta P_L(s))\left(\frac{1}{4s+0.6}\right)\\
&= -\frac{0.01}{s}\left(\frac{1}{4s+0.6}\right)\\
&= -\left(\frac{0.01}{s}\right)\left(\frac{0.25}{s+0.15}\right)\\
&= \frac{0.01667}{s+0.15} - \frac{0.01667}{s}
\end{aligned}$$

¼=0.25
4/4=1
0.6/4=0.15

0.25/0.15=1.667
1.667 x 0.01=0.0166

Taking inverse Laplace transform, we get

$$\Delta\omega(t) = 0.01667e^{-0.15t} - 0.01667$$

TOPICS: Numericals Steady State Frequency Deviation

Example 6.8 A system consists of four identical 100 MVA generators feeding a total load of 250 MW. The inertia constant $H = 5$ for each machine on its own base. The load varies by 1.2% for a 1% change in frequency. If there is a drop of 10 MW of load, determine the speed deviation and plot it.

Solution

Let us choose the base as 100 MVA.

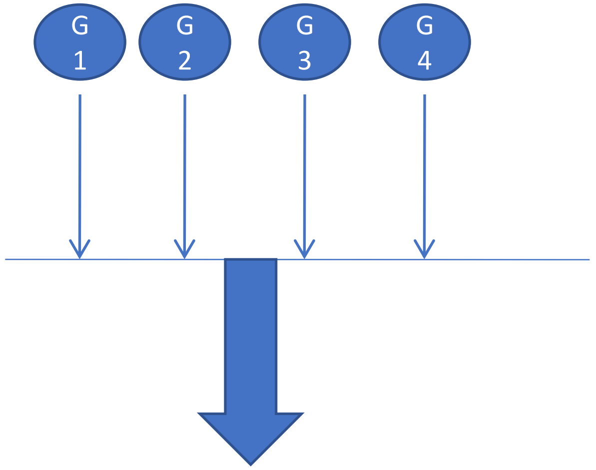
H of four units $= 5 \times 4 = 20$

Load after drop $= 250 - 10 = 240$ MW.

$\Delta P_L = 10\text{ MW} = \frac{10}{100} = 0.1$ pu

D for load of 240 MW on base 100 MVA is $D = 1.2 \times \frac{240}{100} = 2.88$

The block diagram is shown in Fig. 6.26.



Load 250MW

Load Drop: 250MW-10MW=240MW

TOPICS: Numericals
Steady State Frequency Deviation

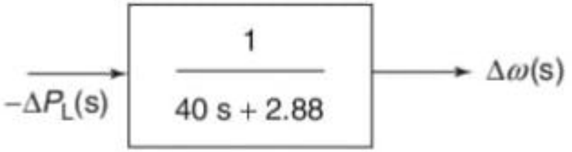


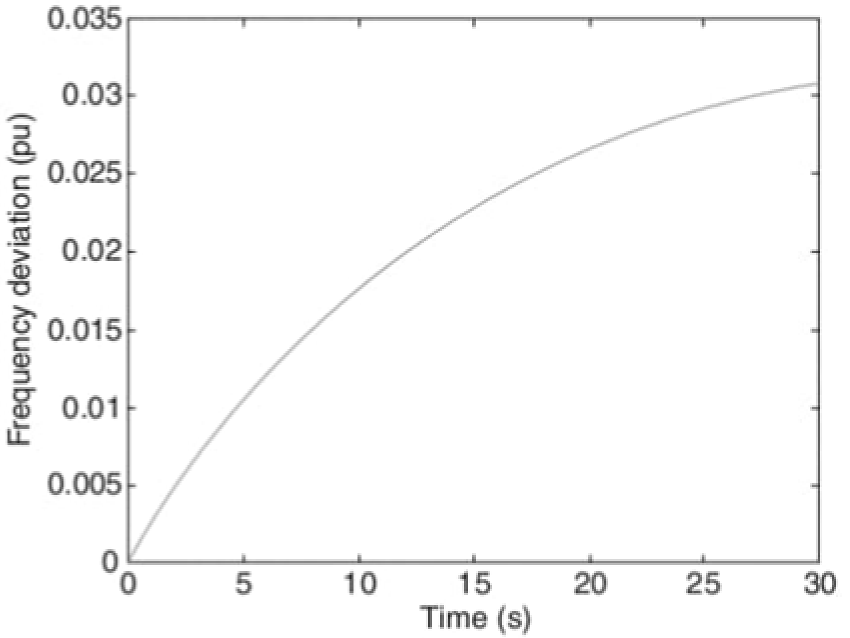
Figure 6.26 Block diagram of example 6.8

$$\Delta P_L(s) = -\frac{0.1}{s} \quad \text{(since load drops)}$$

$$\therefore\ \Delta\omega(s) = -\left(-\frac{0.1}{s}\right)\left(\frac{1}{40s+2.88}\right)$$

$$= \left(\frac{0.1}{s}\right)\left(\frac{0.025}{s+0.072}\right)$$

$$\Delta\omega(t) = 0.03472(1-e^{-0.072t})$$



The steady-state speed deviation = 0.03472 pu. This is also the steady-state frequency deviation. The steady-state frequency = 1.03472 pu = 51.736 Hz.

0.034 X 50 =1.7
1+0.034=1.034pu
50+1.73=51.73Hz

TOPICS: Numericals
Units connected in Parallel

Example 6.11 A single area consists of two generators as follows:
G_1: 200 MW, $R = 4\%$ (on machine base)
G_2: 400 MW, $R = 5\%$ (on machine base).

They are connected in parallel and share a load of 600 MW in proportion to their rating, at 50 Hz. 200 MW of load is tripped. What is the generation to meet the new load if $D = 0$? What is the frequency at new load? Repeat for $D = 1.5$ pu.

Solution

(Refer example 6.5 where it is solved graphically)

Choose a base of 200 MW. $D = 0$

$R_1 = 0.04$ pu (on 200 MW base)

$R_2 = 0.05 \times \frac{200}{400} = 0.025$ pu (on 200 MW base)

$$\Delta P_L = -200 \text{ MW(decrease)}$$
$$= -1 \text{ pu}$$

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{\frac{1}{R_1} + \frac{1}{R_2}} = \frac{-(-1)}{\frac{1}{0.04} + \frac{1}{0.025}} = 0.01538 \text{ pu}$$

Frequency at new load $= 1.01538$ pu
$= 50.769$ Hz

TOPICS: Numericals Units connected in Parallel

$$\Delta P_1 = \frac{-\Delta f}{R_1} = \frac{-0.01538}{0.04} = -0.3845\,\text{pu}$$

$$= -0.3845 \times 200$$

$$= -76.9\,\text{MW}$$

$$P_1 = 200 - 76.9 = 123.1\,\text{MW}$$

$$\Delta P_2 = \frac{-\Delta f}{R_2} = \frac{-0.01538}{0.025} = -0.6152\,\text{pu}$$

$$= -123.04\,\text{MW}$$

$$P_2 = 400 - 123.04 = 276.96\,\text{MW}$$

$$P_1 + P_2 = P_L = 400\,\text{MW}$$

TOPICS: Numericals
Units connected in Parallel

Now $D = 1.5$

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{\frac{1}{R_1} + \frac{1}{R_2} + D} = \frac{1}{\frac{1}{0.04} + \frac{1}{0.025} + 1.5} = 0.01504 \text{ pu}$$

Frequency at new load $= 1.01504$ pu
$= 50.752$ Hz

$$\Delta P_1 = \frac{-0.01504}{0.04} \times 200 = -75.2 \text{ MW}$$

$$P_1 = 200 - 75.2 = 124.8 \text{ MW}$$

$$\Delta P_2 = \frac{-0.01504}{0.025} \times 200 = -120.32 \text{ MW}$$

$$P_2 = 279.68 \text{ MW}$$

$$D\Delta\omega = \text{increase in load due to frequency change} = 1.5 \times 0.01504$$
$$= 0.02256 \text{ pu}$$
$$= 0.02256 \times 200$$
$$= 4.512 \text{ MW}$$

$$P_1 + P_2 = 404.5 \text{ MW}$$
$$= P_L + D\Delta\omega$$

The sum of the two generations should meet the load plus any increase in load because of frequency dependency.

Numericals
Speed Governor

Example 6.12 A control area has following data:
Total generation capacity = 2,000 MW
Normal load = 1,500 MW
$H = 4.8s$; $D = 1.2\%$; $f = 50$ Hz; $R = 2.5$ Hz/pu MW

- Determine the primary ALFC parameters.
- For an increase of 0.02 pu in the load find the frequency drop without governor control.
- Repeat (2) with governor control.
- Repeat (2) with governor control but frequency dependence of loads neglected.

Solution

(a) $D = 1.2\%$ means the load increases by 1.2% for a 1% increase in frequency.
1.2% load = 18 MW (1500 × 0.012)
1% frequency = 0.5 Hz

1/100 -→ 0.01 x50Hz =0.5

$$D = \frac{18}{0.5} = 36\text{ MW/Hz} = \frac{36}{2000} = 0.018\text{ pu MW/Hz}$$

$$T(S) = \frac{1}{2Hs + D} = \frac{1}{9.6s + 0.018} = \frac{55.55}{533.33s + 1}$$

Power system gain = 55.55 Hz/pu MW
Power system time constant = 533.33 pu

$$= \frac{533.33}{50} = 10.667s$$

TOPICS: Numericals Units connected in Parallel

(b) Without governor control

$$\Delta f = \frac{-\Delta P_L}{D}$$

$$\Delta P_L = 0.02 \text{ pu}$$

$$\Delta f = \frac{-0.02}{0.018} = -1.11 \text{ Hz [note that unit of } D \text{ is pu MW/Hz]}$$

(c) With governor control

$$\Delta f = \frac{-\Delta P_L}{D + \frac{1}{R}} = \frac{-0.02}{0.018 + \frac{1}{2.5}} = -0.0478 \text{ Hz}$$

(d) With $D = 0$,

$$\Delta f = \frac{-\Delta P_L}{\frac{1}{R}} = \frac{-0.02}{\frac{1}{2.5}} = -0.05 \text{ Hz}$$

A word of caution about units: Note that here we are using D and R in units of pu MW/Hz and Hz/pu MW. Therefore, the frequency deviations are obtained directly in Hz whereas the powers are in pu MW. Also note the way the power system gain and time constant are found out and the units used. Can we use D in % to solve here? We work as follows:

$$D = 1.2\% \text{ (for load of 1,500 MW).}$$

On a base of 2,000 MVA, $D = 1.2 \times \frac{1500}{2000}$

$$= 0.9\%$$

Thank You