2024-2025
Fall Semester

Course of Power System Analysis

Frequency control in power systems

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Outline

Introduction

Generator model

Load model

Prime mover model

Governor model

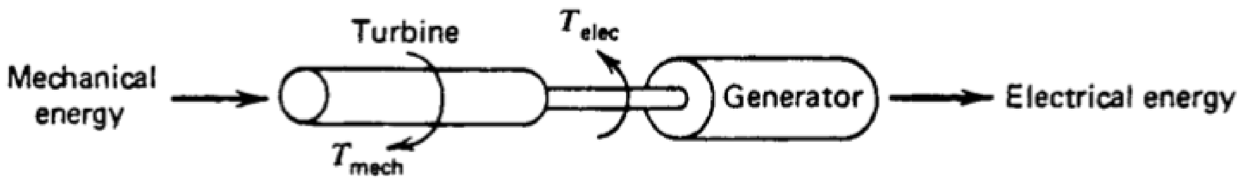
Tie-line model

Generation control

Introduction

The control of generator units was the **first problem** faced in early **power-system design**. The methods developed for the control of individual generators, and eventually control of large interconnected power grids, play a vital role in modern control centres.

A generator driven by a turbine can be represented as a **large rotating mass** with **two opposing torques** acting on the rotation as shown in the figure below.



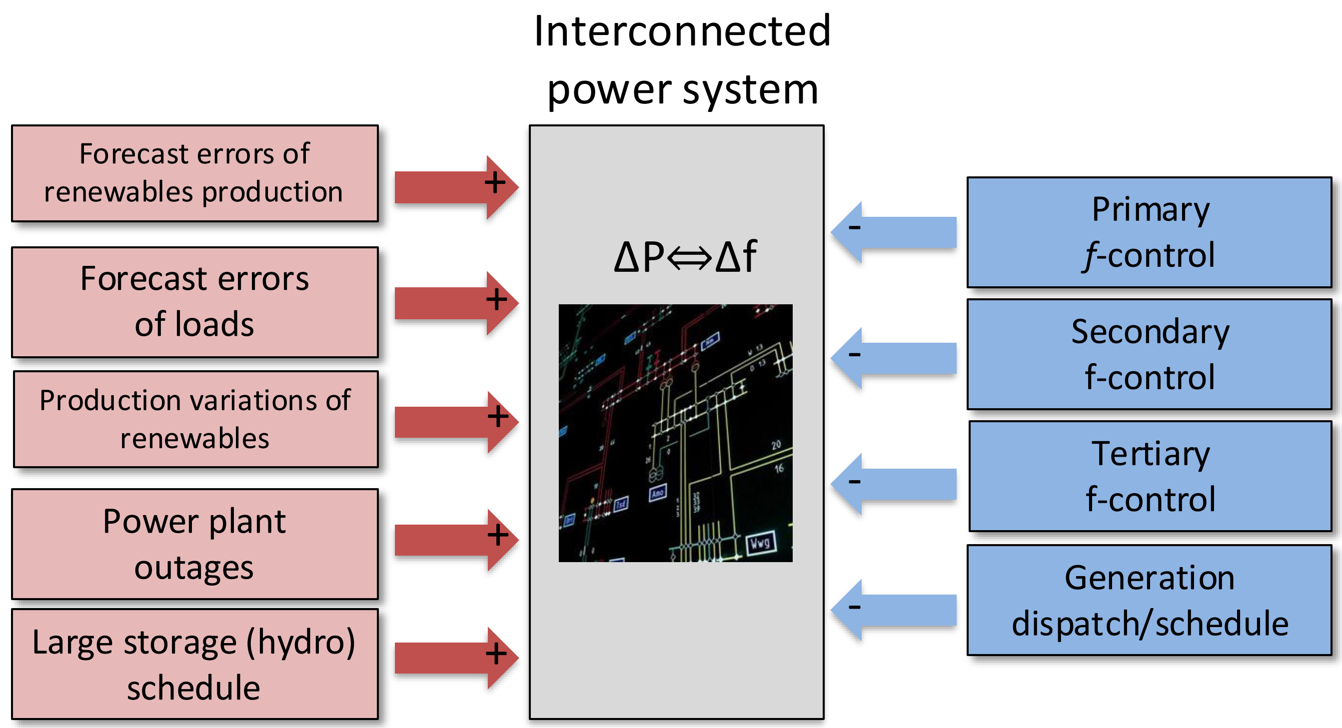
- $\boldsymbol{T_{mech}}$, the **mechanical torque**, acts to increase the rotational speed
- $\boldsymbol{T_{elec}}$, the **electrical torque**, acts to slow it down.

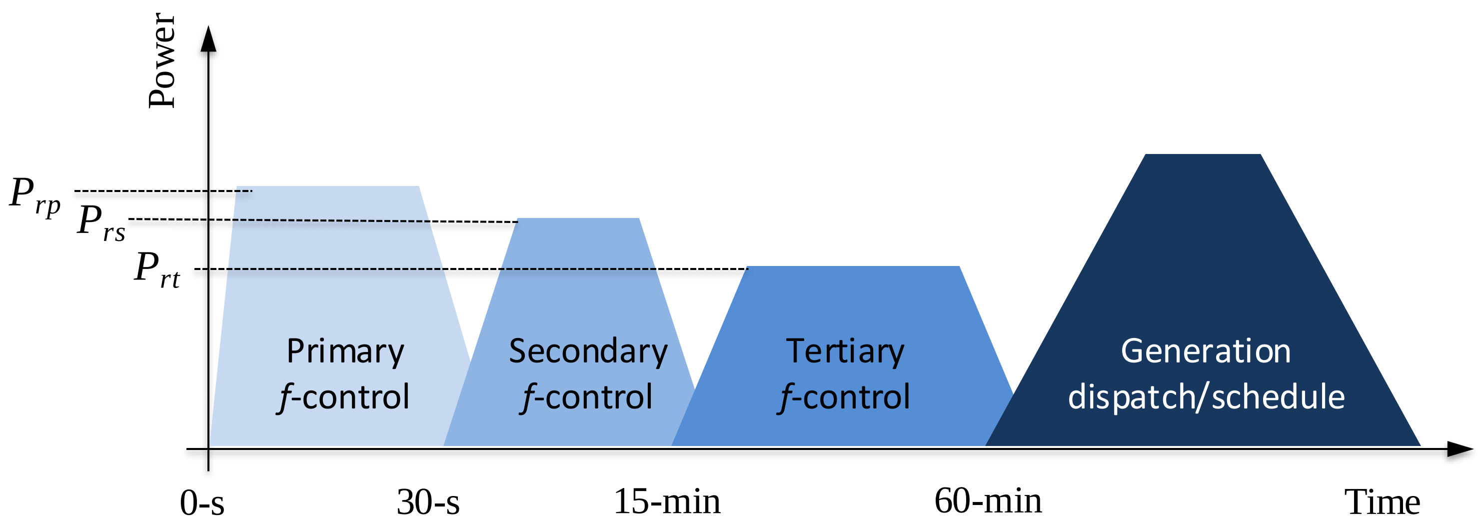
If $\boldsymbol{T_{mech} = T_{elec}}$ the rotational speed $\boldsymbol{\omega}$ will be constant.

If the electrical load is increased $(T_{elec} > T_{mech})$, the entire rotating system will begin to slow down (and vice versa).

Since it would be damaging to let the rotating equipment slow down too far (or speed-up too fast), something must be done to increase (or decrease) the mechanical torque T_{mech} to **restore the equilibrium.**

Introduction





Introduction

As already seen, the **link between the power imbalance and the network frequency** (that constitutes the ***control variable***) involves three time-frames of the frequency control scheme.

Primary-frequency controllers are locally installed in generation units and act immediately after a power imbalance resulting in a frequency deviation (locally measured).
Droop regulators usually compose these controllers.
The amount of the primary-control reserve (P_{rp} in the previous figure) represents the **maximum amount of power available in the interconnected network after a frequency imbalance** and is referred to as **frequency containment reserve**. This concept can be applied to a single generation unit or to the whole system.

Introduction

As already seen, the **link between the power imbalance and the network frequency** (that constitutes the ***control variable***) involves three time-frames of the frequency control scheme.

Secondary-frequency controllers are, in general, centralised for each area that composes the interconnected power system and are responsible for compensating the frequency deviation from the rated value after the primary control intervention. The time-frame of the secondary-frequency control ranges from a **few tens of second to a few minutes**. In an area of the interconnected network, the **total amount of power to perform the secondary frequency control** is called **frequency restoration reserve** (P_{rs} in the previous figure) represents the **power responsible for bringing the frequency back to its rated value** (i.e. 50 or 60 Hz).

Introduction

As already seen, the **link between the power imbalance and the network frequency** (that constitutes the ***control variable***) involves three time-frames of the frequency control scheme.

The power that can be connected, automatically or manually, in order to provide an **adequate secondary control reserve**, belongs to the **tertiary-frequency control** and is known as the **frequency replacement reserve** (P_{rt} in the previous figure). This reserve must be used in such a way that it will contribute to the **restoration of the secondary control reserve**.
In general, we have that $P_{rp} \geq P_{rs} \geq P_{rt}$.

Introduction

Activation of primary, secondary and tertiary frequency controls as a consequence of a power plant outage

Primary control / containment reserve
0.5 min. after outage

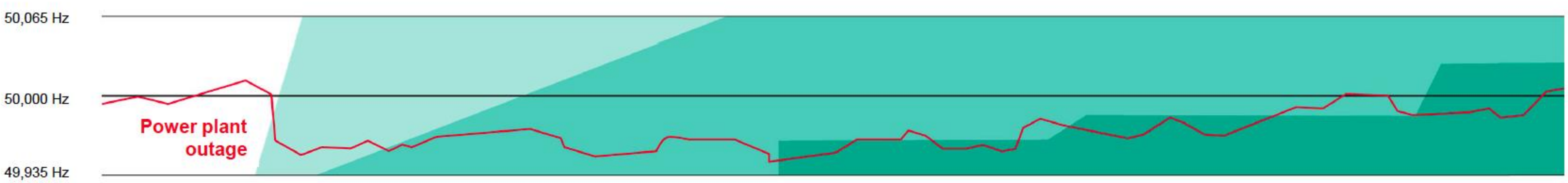
- Frequency measurement in the power plants
- Automatically activated in the generator of the power plant
- Across Europe

Secondary control / frequency restoration reserve
5 min. after outage

- Measurements at the Swiss cross-border lines
- Activated by the central load frequency controller at Swissgrid
- Across Switzerland

Tertiary control / frequency replacement reserve
15 min. after outage

- Easing of secondary control
- Activated by the operator
- Contracts with individual providers



Introduction

- The control of generation must be repeated constantly on a power system because the **loads change constantly along with distributed generation from renewables.**
- The so-called **governor** on each synchronous machine maintains its speed while supplementary control, usually originating at a remote control centre, acts to allocate generation. Figure 7.1 shows an overview of the generation control problem.

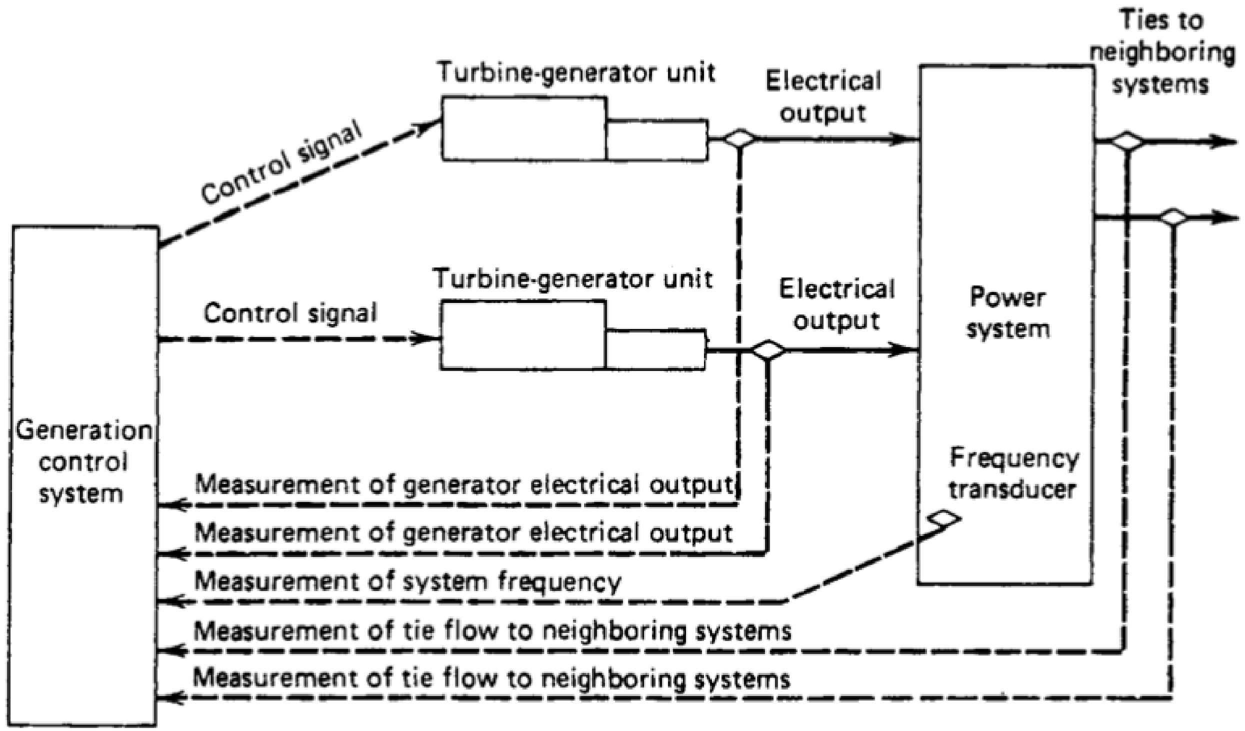


Fig. 7.1 Overview of generation control problem

Introduction

In the following slides, we analyse the system behaviour subsequent to **small deviations from the steady-state value** for the following elements:

- Generator
- Load
- Prime mover
- Tie line

After developing a model for each of these power system components, the last part of the lecture analyses how to perform **generation control.**

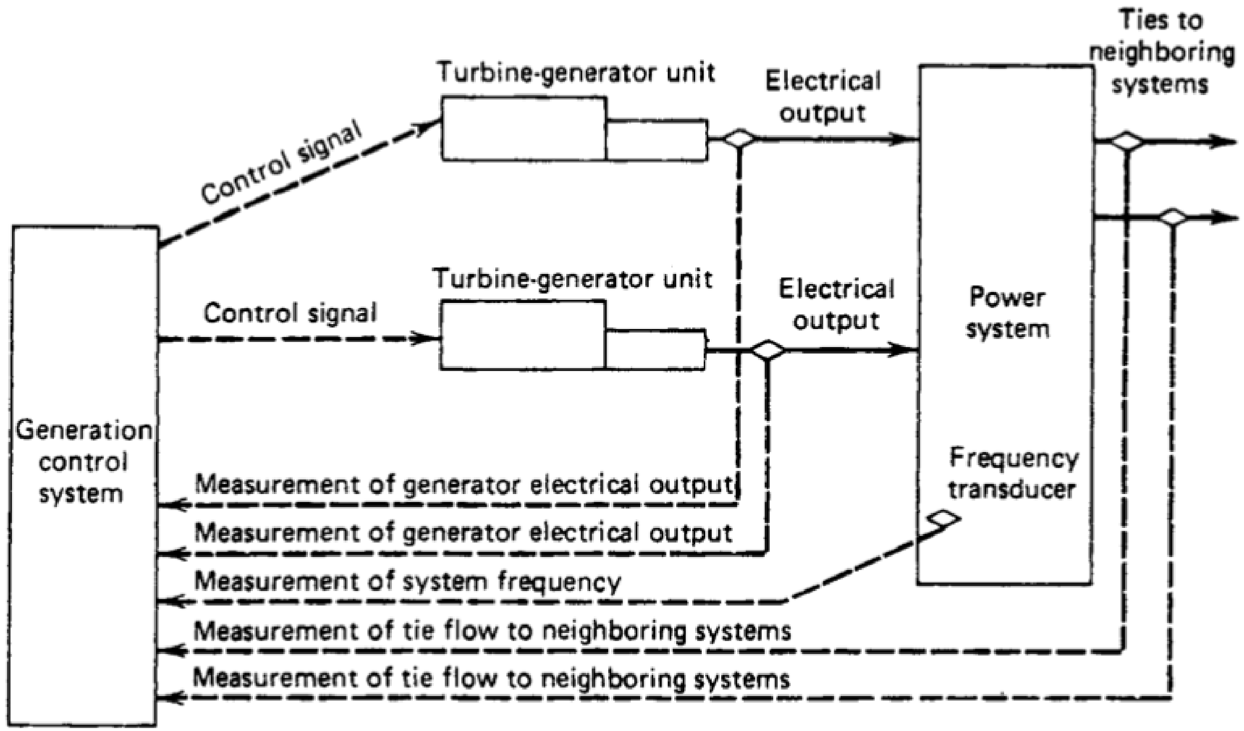


Fig. 7.1
Overview of generation control problem

Introduction

Before starting, it is useful to define the nomenclature:

ω = mechanical rotational speed of the generator (rad/sec)
α = mechanical rotational acceleration of the generator
θ_m= mechanical phase angle of a rotating machine

T_{net} = net accelerating torque in a generator
T_{mech} = mechanical torque exerted on the generator by the turbine
T_{elec} = electrical torque exerted on the generator by its electrical load

P_{net} = net accelerating power of the generator
P_{mech} = mechanical power input of the generator
P_{elec} = electrical power output of the generator

I = moment of inertia for the generator + the turbine
M = angular momentum of the machine + the turbine

where **all quantities** (except phase angle) **will be in per-unit** on the generator base, or, in the case of ω, on the standard system frequency base.

Outline

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Generator model

Let's consider a **single rotating machine.** We are interested **in deviations of quantities from steady-state values**.

- Steady-state values have a "0" subscript (e.g. ω_0, T_{net_0})
- Deviations from the steady-state are designated by a " Δ " (e.g., $\Delta\omega$, ΔT_{net}).

We assume that the machine starts with:

- a steady speed ω_0;
- a mechanical phase angle θ_{m_0}.

The machine is subjected to differences in mechanical and electrical torque, causing it to accelerate or decelerate.

We are interested in the **deviations of speed, $\Delta\omega$**, and deviations in phase angle, $\Delta\theta_m$, from the initial steady-state.

Assuming the machine subjected to an acceleration α, $\boldsymbol{\Delta\theta_m}$, is equal to the **difference of the machine phase angle machine and a reference axis rotating at $\boldsymbol{\omega_0}$**. If the speed of the machine under acceleration is

$$\omega = \omega_0 + \alpha t \qquad (1.1)$$

then

$$\Delta\theta_m = \int(\omega_0 + \alpha t)dt - \int \omega_0 dt = \frac{1}{2}\alpha t^2 \qquad (1.2)$$

Generator model

The deviation from the initial speed, $\Delta\omega$, may then be expressed as:

$$\Delta\omega = \alpha t = \frac{d}{dt}(\Delta\theta_m) \quad (1.3)$$

The relationship between phase angle deviation ($\Delta\theta_m$), speed deviation ($\Delta\omega$), and net accelerating torque (T_{net}) is:

$$T_{net} = I\alpha = I\frac{d}{dt}(\Delta\omega) = I\frac{d^2}{dt^2}(\Delta\theta_m) \quad (1.4)$$

We are interested **in the deviations in mechanical and electrical power to the deviations in rotating speed** and mechanical torques. The relationship between net accelerating power and the electrical and mechanical powers is:

$$P_{net} = P_{mech} - P_{elec} \quad (1.5)$$

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

$$P_{net} = P_{net_0} + \Delta P_{net} \quad (1.6)$$

Where:

$$P_{net_0} = P_{mech_0} - P_{elec_0} \qquad \Delta P_{net} = \Delta P_{mech} - \Delta P_{elec} \quad (1.7)$$

Generator model

As a direct consequence:

$$P_{net} = \left(P_{mech_0} - P_{elec_0}\right) + \left(\Delta P_{mech} - \Delta P_{elec}\right) \quad (1.8)$$

$$T_{net} = \left(T_{mech_0} - T_{elec_0}\right) + \left(\Delta T_{mech} - \Delta T_{elec}\right) \quad (1.9)$$

Knowing that $P = \omega T$, we can see that:

$$P_{net} = (\omega_0 + \Delta\omega)(T_{net}) \quad (1.10)$$

Substituting (1.8)-(1.9) into (1.10), we obtain:

$$\left(P_{mech_0} - P_{elec_0}\right) + \left(\Delta P_{mech} - \Delta P_{elec}\right) = (\omega_0 + \Delta\omega)\left[\left(T_{mech_0} - T_{elec_0}\right) + (\Delta T_{mech} - \Delta T_{elec})\right] \quad (1.11)$$

Assuming that:

- **The steady-state quantities can be factored out** since $P_{mech_0} = P_{elec_0}$ and $T_{mech_0} = T_{elec_0}$
- **The second-order terms** involving products of $\Delta\omega$ with ΔT_{mech} and ΔT_{elec} **can be neglected**.

we obtain:

$$\Delta P_{mech} - \Delta P_{elec} = \omega_0(\Delta T_{mech} - \Delta T_{elec}) \quad (1.12)$$

Generator model

$$\Delta P_{mech} - \Delta P_{elec} = \omega_0(\Delta T_{mech} - \Delta T_{elec}) \quad (1.13)$$

As shown in (1.4), the net torque is related to $\Delta\omega$ as follows:

$$\underbrace{\left(T_{mech_0} - T_{elec_0}\right)}_{=0} + (\Delta T_{mech} - \Delta T_{elec}) = I\frac{d}{dt}(\Delta\omega) \quad (1.14)$$

We can combine (1.13) and (1.14) to get:

$$\boxed{\Delta P_{mech} - \Delta P_{elec} = \omega_0 I\frac{d}{dt}(\Delta\omega) = M\frac{d}{dt}(\Delta\omega)} \quad (1.15)$$

Where M is the angular momentum of the machine.

The units for M are $\left[\frac{W}{rad/\,\sec^2}\right] = \left[\frac{W}{\frac{rad}{sec}\cdot\frac{1}{sec}}\right] = \left[\frac{pu\ Power}{pu\ Speed/sec}\right]$. We will always use per-unit power over per-unit speed per second, where the per-unit refers to the **machine rating as the base.**

Generator model

Eq. (1.15) can be expressed with the **Laplace transform** operator notation:

$$\boxed{\Delta P_{mech} - \Delta P_{elec} = Ms\,\Delta\omega} \qquad (1.16)$$

The previous equation models:

- **A single rotating machine (generator)**
- **Deviations of quantities about steady-state values**
- ***ΔP* as a function of $\boldsymbol{\Delta\omega}$**

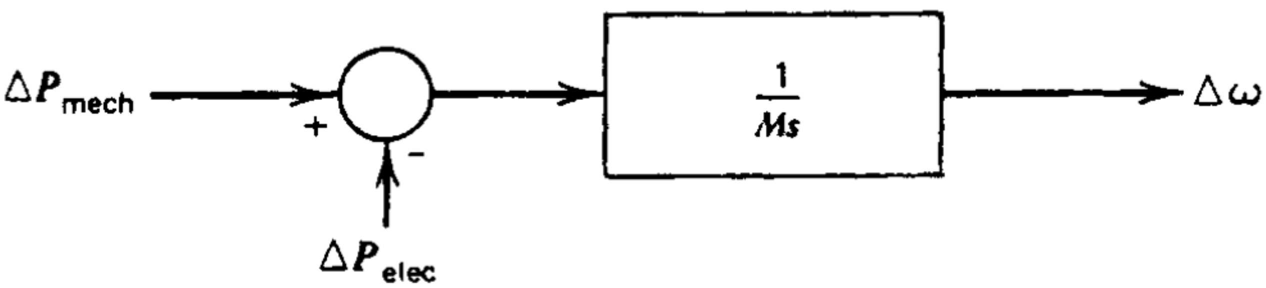

Fig. 7.2 Relationship between mechanical and electrical power and speed change.

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Generator model

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Tie-line model

Generation control

Load model

- The loads on a power system consist of a variety of electrical devices:
  - Purely resistive,
  - Motor loads (with variable power - frequency characteristics)
  - Others
- Since **motor loads are a dominant part of the electrical load**, there is the need to model the effect of a change in frequency on the net load drawn by the system.
- The relationship between **the change in load due to the change in frequency** is given by

$$\Delta P_{L\,(freq)} = D\,\Delta\omega \qquad \text{or} \qquad D = \frac{\Delta P_{L\,(freq)}}{\Delta\omega} \tag{2.1}$$

where D is the damping coefficient of the load, expressed as percent change in load divided by percent change in frequency.

Example #1: if the load changes by 1.5 % for a 1 % change in frequency, then D would equal 1.5.

Consideration #1: the value of D must be changed if the system base MVA is different from the nominal value of the load.

Load model

Example #1: if the load changes by 1.5 % for a 1 % change in frequency, then D would equal 1.5.

Consideration #1: the value of D must be changed if the system base MVA is different from the nominal value of the load.

- Assume that D is referred to a load of $1200\ MVA$ and the problem were to be set up for a $1000\ MVA$ system base.
- The load would change by $1.5\ pu$ for $1\ pu$ change in frequency, namely $(1.5 \cdot 1200\ MVA) = 1800\ MVA$ for a $1\ pu$ change in frequency.
- When expressed on a $1000\ MVA$ base, D simply becomes

$$D_{1000-MVA\ base} = 1.5\left(\frac{1200}{1000}\right) = 1.8$$

Load model

The net change in P_{elec} (which is an input for the generator model) is:

$$\Delta P_{elec} = \underbrace{\Delta P_L}_{\text{Non frequency-sensitive load change}} + \underbrace{D\Delta\omega}_{\text{Frequency sensitive load change } \Delta P_{L\,(freq)}} \tag{2.2}$$

By including this load behaviour in the block diagram of Fig. 7.2, we obtain the one in Figure 7.3

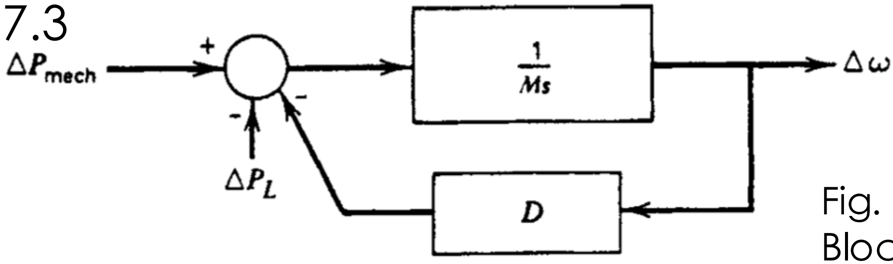

Fig. 7.3
Block diagram of rotating mass and load as seen by the prime-mover output.

Load model

$$\Delta P_{elec} = \Delta P_L + D\Delta\omega \qquad (2.2)$$

The **damping coefficient of the load D** in Eq. (2.2) plays a **fundamental role in power system stability**.

In fact, let us consider a load step variation $\Delta P_L > 0$ with no reaction from the generator, namely $\Delta P_{mech} = \Delta P_{elec} = 0$. The system will go through the following steps

- $\Delta P_{elec} \uparrow$ and the frequency will start decreasing according to (1.16)
- While $\omega \downarrow$, the frequency sensitive load change $\Delta P_{L(freq)} = D\Delta\omega$ will be negative and reducing in magnitude.
- When $D\Delta\omega = -\Delta P_L$ the system will find a new equilibrium with a speed variation of:

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

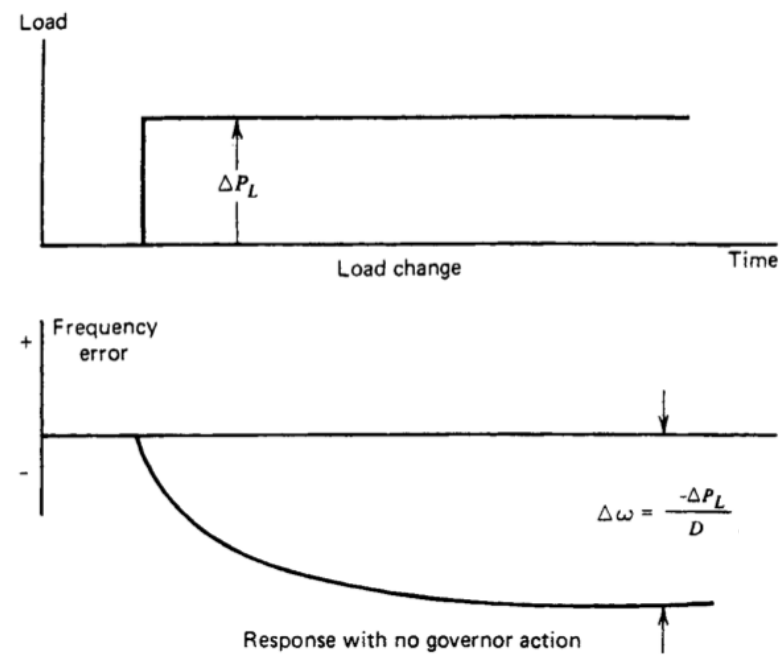

Fig. 7.4 Frequency response to load change in absence of mechanical variation in the generators.

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Prime-mover model

The prime mover driving a generator unit may be a steam/gas turbine or a hydro-turbine.

For a steam/gas turbine the model must consider:

- The steam/gas supply characteristic
- Boiler/burner control system characteristics

while for a hydro turbine:

- The penstock characteristics

Only the **simplest prime-mover model** will be used here. The model, shown in Figure 7.5, relates the position of the turbine fluid valve that controls the emission of steam into the turbine to the power output of the turbine:

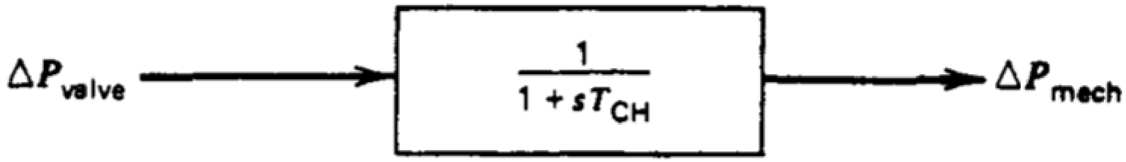

Fig. 7.5 Prime-mover model

where

T_{CH} = "charging time" time constant;

ΔP_{valve} = per unit change in (steam, water, gas, etc.) valve position from nominal.

Prime-mover model

The combined **prime-mover + generator + load model** for a single generating unit can be built by combining all the information we obtained so far.

Generator:

$$\Delta P_{mech} - \Delta P_{elec} = Ms\,\Delta\omega \qquad (1.16)$$

Prime mover:

$$\Delta P_{mech} = \frac{\Delta P_{valve}}{(1+s\,T_{CH})} \qquad (3.1)$$

Load:

$$\Delta P_{elec} = \Delta P_L + D\Delta\omega \qquad (2.2)$$

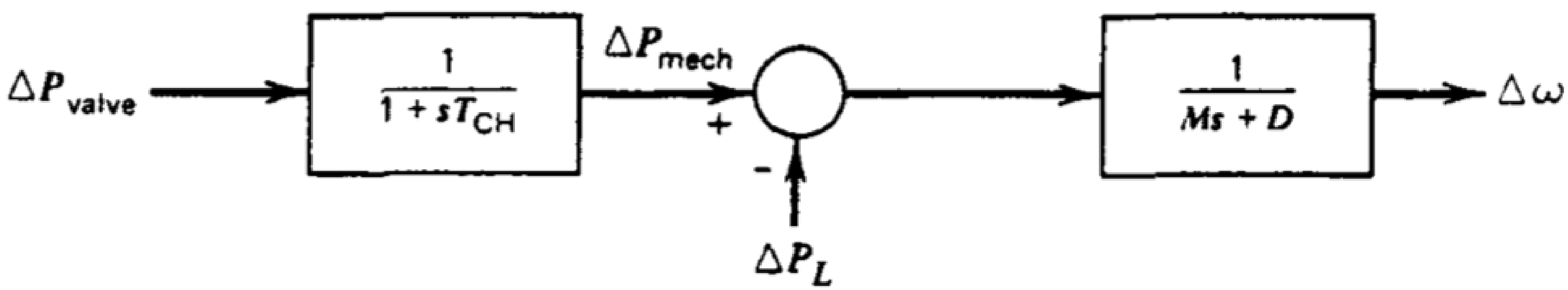

Fig. 7.6 Prime-mover – generator –load model

Outline

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Governor model

Suppose **a generating unit is operated with fixed mechanical power output from the turbine.**

Now, if the load changes:

- The generator speed (i.e. frequency) changes
- This change causes the frequency-sensitive load to change
- The frequency-sensitive load exactly compensate for the load change

However, this condition would allow system frequency to drift far outside acceptable limits.

To solve this problem a governor is needed.

A governing mechanism senses the generator speed and adjusts the turbine valve to change the mechanical power output to compensate for load changes and, in the first instants after the load change, slow down as fast as possible the frequency decrease and, subsequently, restore the frequency to the nominal value.

Governor model

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

- Simply connecting the output of the speed-sensing mechanism to the valve through a direct linkage, it would never bring the frequency to nominal. Therefore, to force the frequency error to zero, one must provide a "reset action".
- The reset action is accomplished by integrating the frequency (or speed) error.

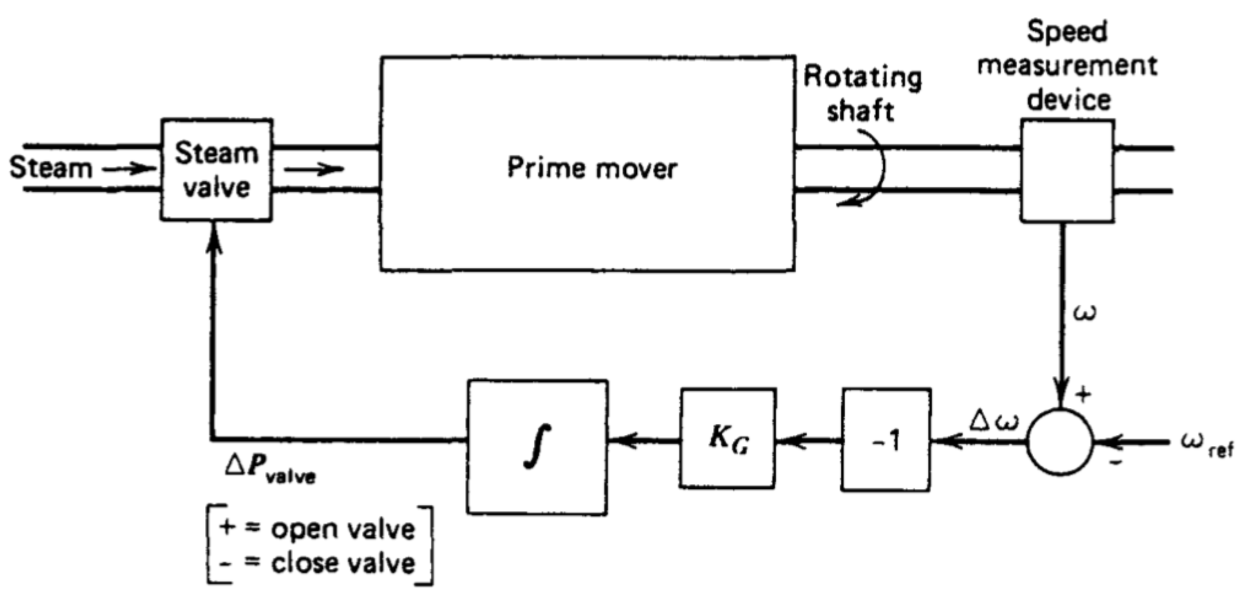


Fig. 7.7. Scheme of the isochronous governor

Governor model

Isochronous governor - Operating principle :

1. The speed-measurement device output, ω, is compared with a reference ω_{ref} to produce an error signal, $\Delta\omega$.
2. The error $\Delta\omega$ is negated and then amplified by a gain K, and integrated to produce a control signal, ΔP_{valve}
3. ΔP_{valve} causes the main steam supply valve to open (ΔP_{valve} position) when $\Delta\omega$ is negative.

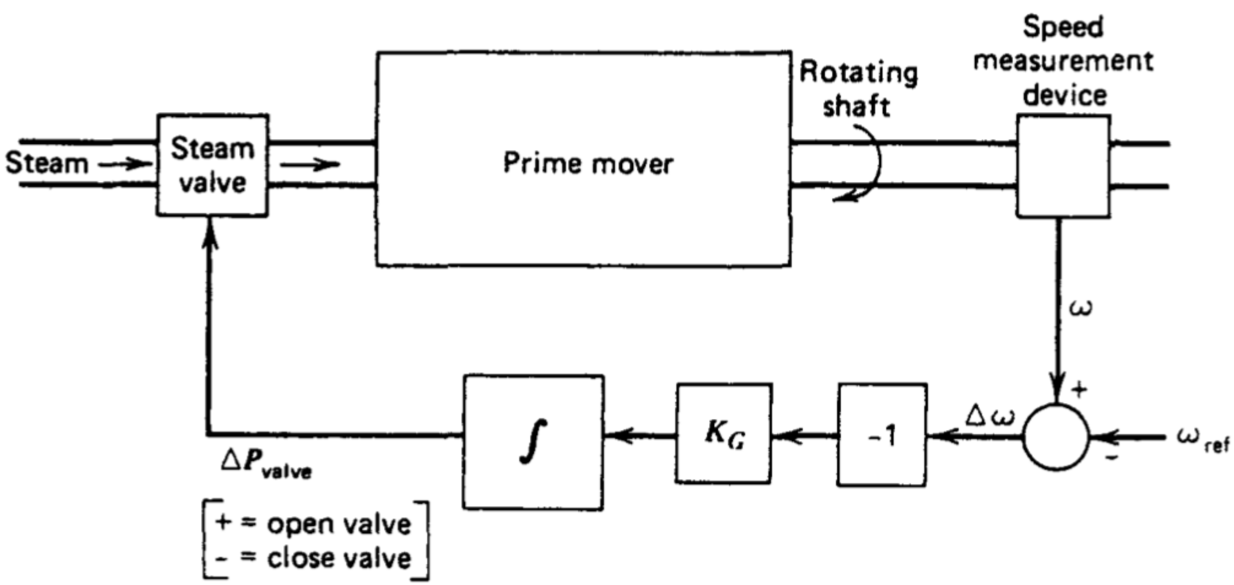


Fig. 7.7. Scheme of the isochronous governor

Governor model

Isochronous governor - Example

The machine is running at reference speed. The electrical load increases:

1. ω will fall below ω_{ref}, $\Delta\omega$ will be negative.
2. The action of the gain and integrator will be to open the steam valve.
3. The turbine increases its mechanical output.
4. The electrical output increases as well as the speed ω.
5. When ω exactly equals ω_{ref} the steam valve stays at the new position (further opened) to allow the turbine generator to meet the increased electrical load.

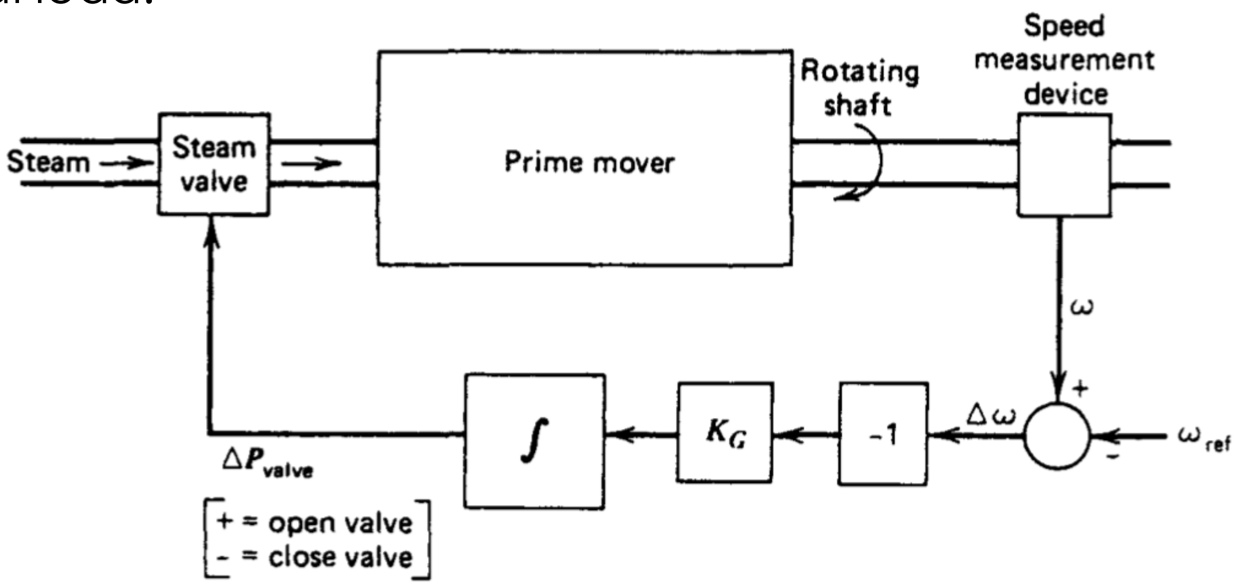


Fig. 7.7. Scheme of the isochronous governor

Governor model

If two or more generators are connected to the same system the **isochronous governor cannot be used**. Each generator would have to have precisely the same speed setting or they would "fight" each other, each trying to pull the system's speed (or frequency) to its own setting.

To be able to run two or more generating units in parallel on a generating system, the governors are provided with a **feedback signal that causes the speed error to go to zero at different values of generator output.**

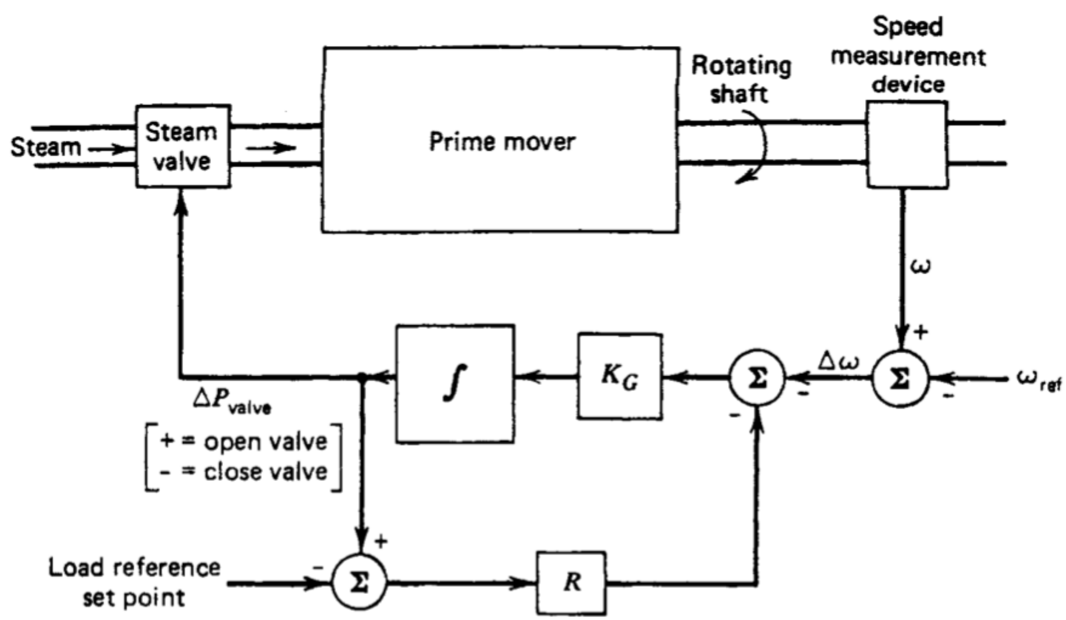


Fig. 7.8. Governor with speed-droop feedback loop.

Governor model

The block diagram for this governor is shown in Figure 7.9, where the governor now has a net gain of $1/R$ and a time constant T_G. Note that there is a new input, called **load reference.**

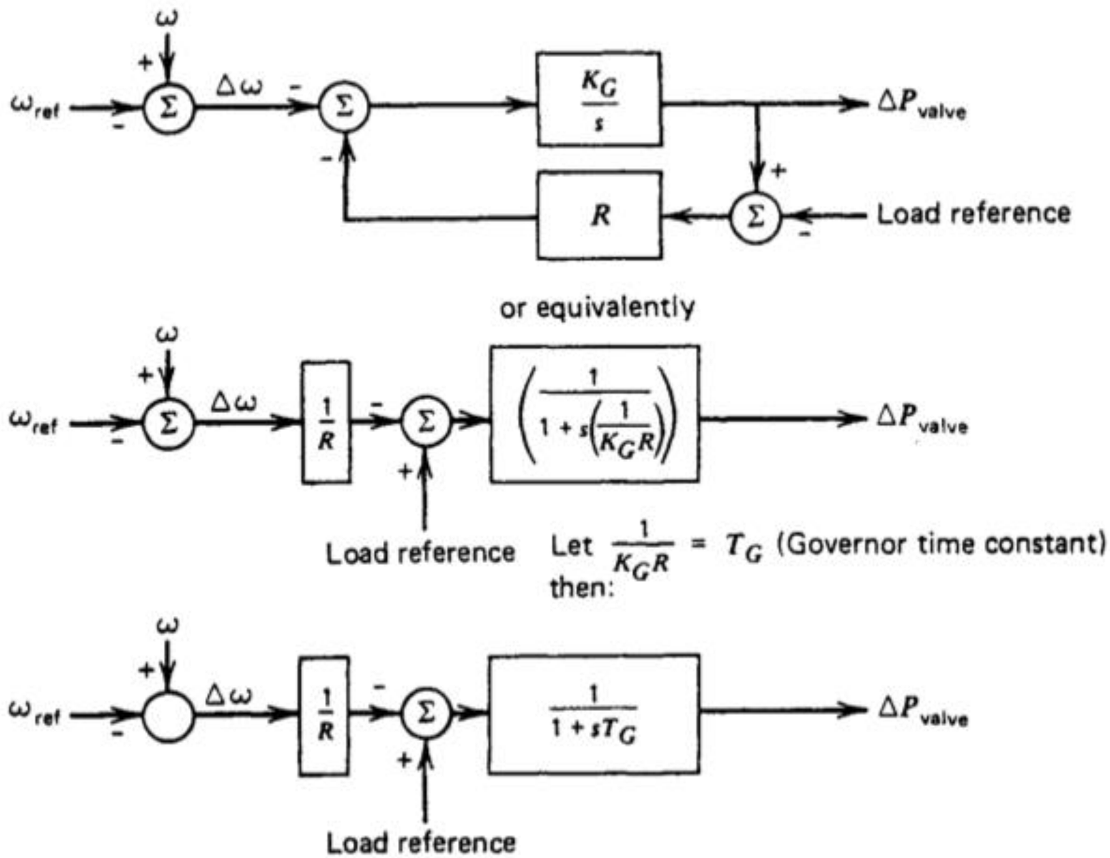


Fig. 7.9. Block diagram of governor with droop

Governor model

The result of adding the feedback loop with gain R is a governor characteristic as shown in Fig. 9.12, also called **droop control**

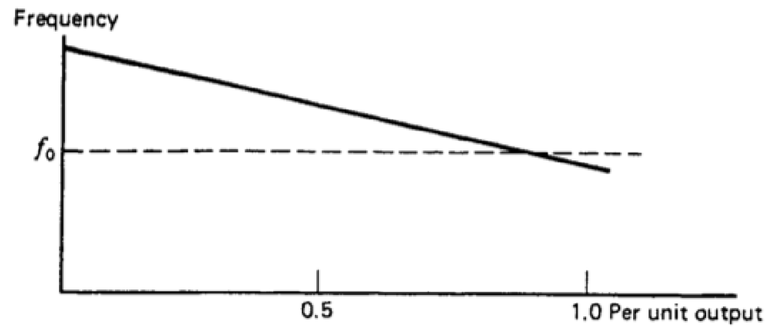


Fig. 7.10. Speed-droop characteristic.

The value of ***R*** **determines the slope of the characteristic**. That is, R determines the change on the unit's output for a given change in frequency.

$$R = \frac{\Delta\omega}{\Delta P} \quad pu \tag{4.1}$$

R is usually set in each generating unit so that a change from 0 to 100% (i.e., rated) output will result in the same frequency change for each unit. As a result, **a change in electrical load on a system will be compensated by generator unit output changes proportional to each unit's rated output**.

Governor model

If two generators with different 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.

This is illustrated in Figure 7.11, showing two units with **drooping** characteristics connected to a common load.

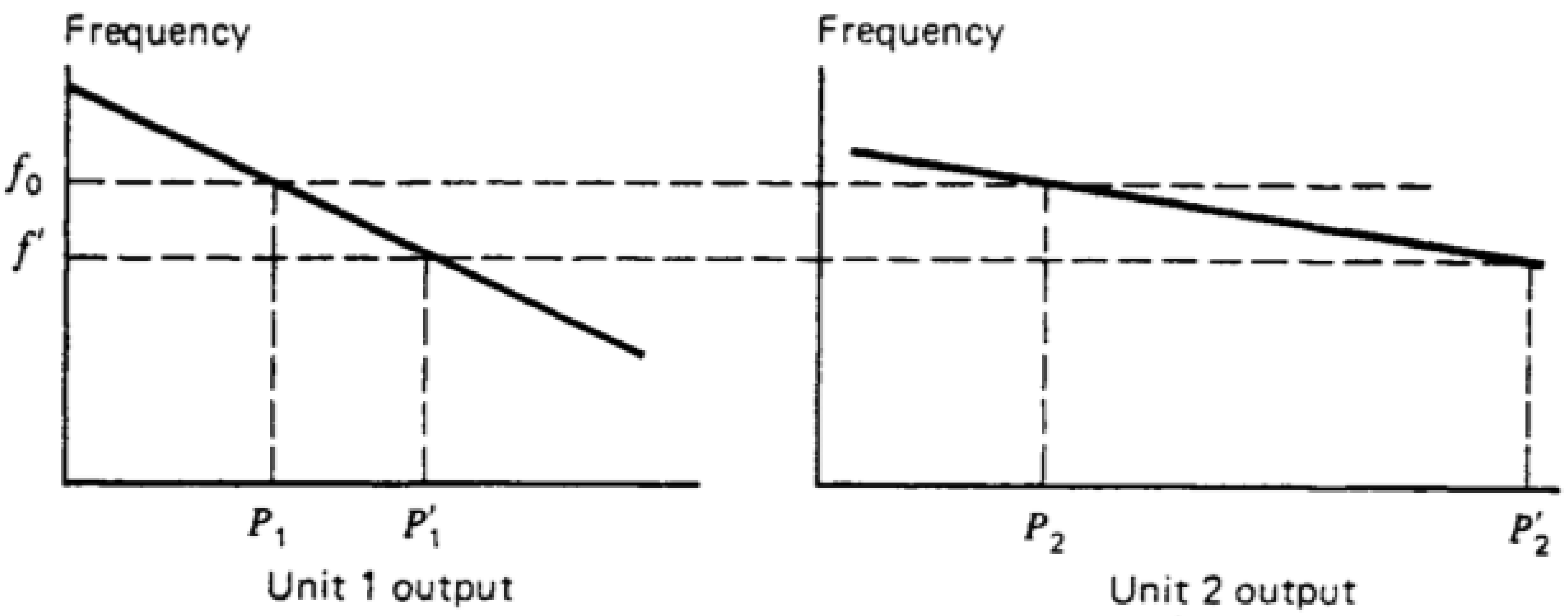


Fig. 7.11. Allocation of unit outputs with governor droop.

Governor model

Example of Figure 7.11:

1. Two units start at a nominal frequency of f_0 .
2. A load increase ΔP_L causes the units to slow down
3. The governors increase output until the units seek a new, common operating frequency f'
4. The load pickup on each unit is proportional to the slope of its droop characteristic.
5. Unit 1 increases its from P_1 to P_1' , Unit 2 increases its from P_2 to P_2'
6. The net generation increase, $P_1' - P_1 + P_2' - P_2 = \Delta P_L$

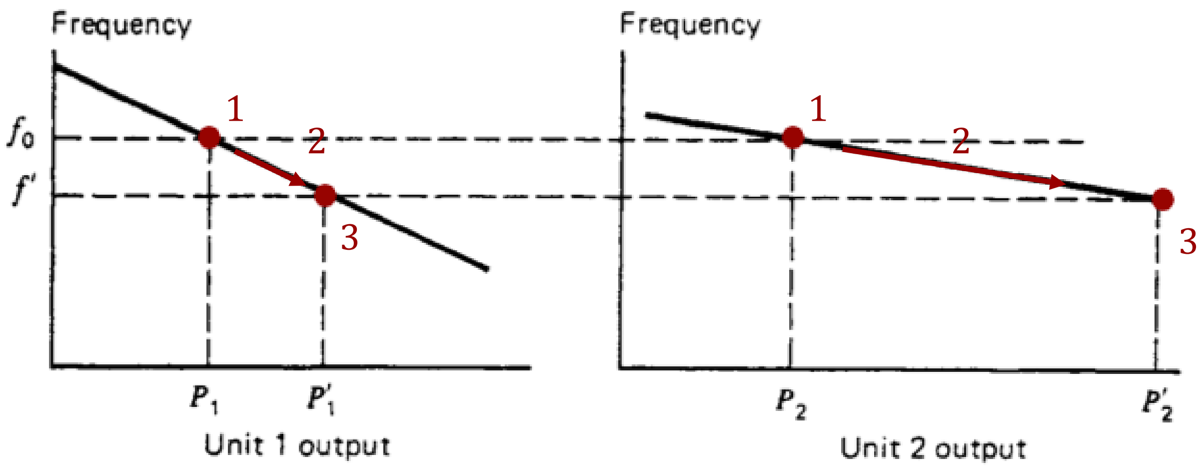


Fig. 7.11. Allocation of unit outputs with governor droop.

Governor model

Figure 7.8 shows an input labelled "load reference set point."

By changing the load reference, the governor characteristic can be set to give reference frequency at any desired unit output.

The load reference setpoint is the basic control input to a generating unit.

By adjusting this set point on each unit, dispatch can be maintained while holding system frequency close to the desired nominal value.

A steady-state change in ΔP_{valve} of $1.0\,pu$ requires a value of R pu change in frequency, $\Delta\omega$

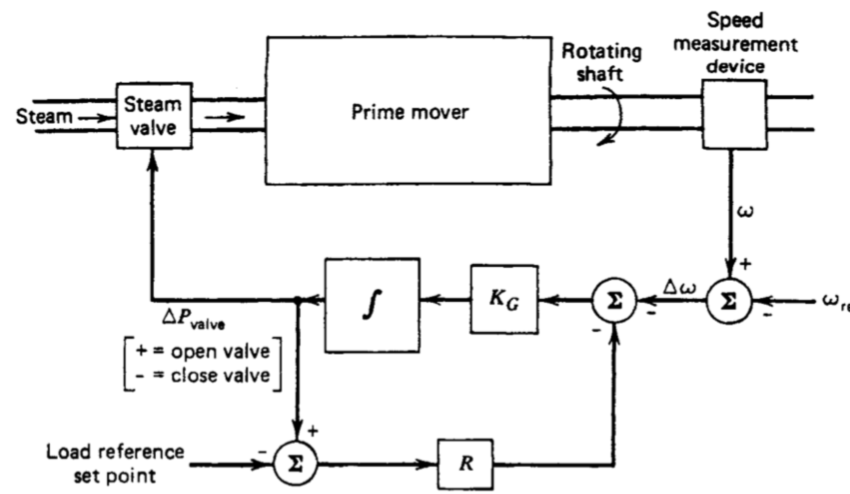


Fig. 7.8.
Governor with speed-droop feedback loop.

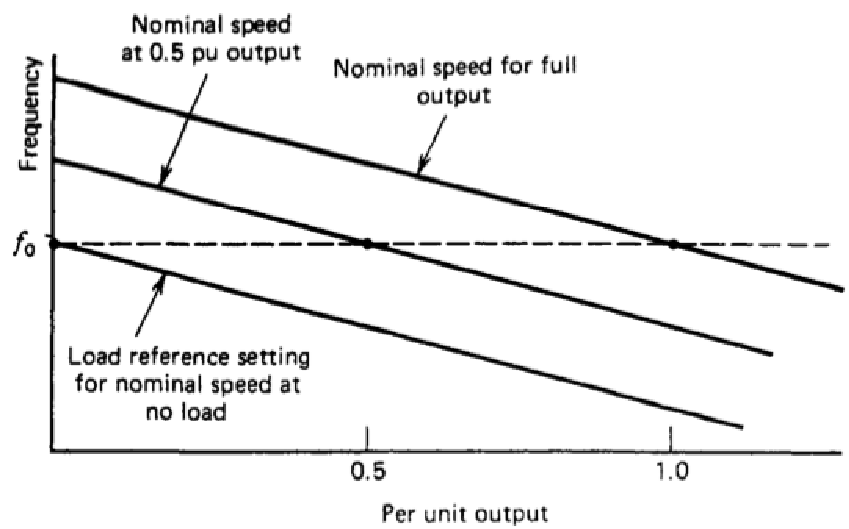


***Fig. 7.12**. Speed-changer settings*

Governor model

We can, therefore, construct a block diagram of a **governor-prime-mover-rotating mass/load model** as shown in Figure 7.13.

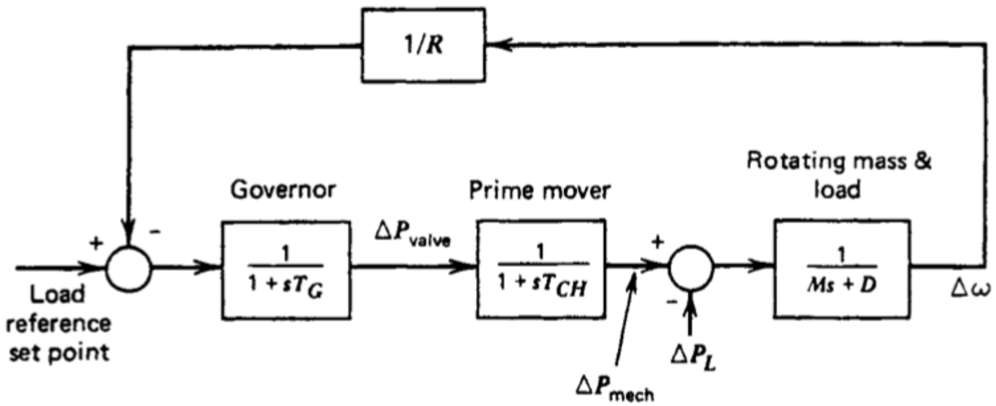


Fig. 7.13. Block diagram of governor, prime mover, and rotating mass.

Suppose that this generator experiences a step increase in load

$$\Delta P_L(s) = \frac{\Delta P_L}{s} \tag{4.2}$$

The transfer function relating the load change, ΔP_L ,to the frequency change $\Delta\omega$, is

$$\Delta\omega(s) = \Delta P_L(s)\left[\frac{\frac{-1}{Ms+D}}{1+\frac{1}{R}\left(\frac{1}{1+sT_G}\right)\left(\frac{1}{1+sT_{CH}}\right)\left(\frac{1}{Ms+D}\right)}\right] \tag{4.3}$$

Governor model

The steady-state value of $\Delta\omega(s)$ may be found by

$$\Delta\omega_{steady\ state} = \lim_{s\to 0}\,[s\ \Delta\omega(s)] = \frac{-\Delta P_L\left(\frac{1}{D}\right)}{1+\left(\frac{1}{R}\right)\left(\frac{1}{D}\right)} = \frac{-\Delta P_L}{\frac{1}{R}+D} \tag{4.4}$$

Observation#1:
Note that if D were zero, the change in speed would simply be

$$\Delta\omega = -R\Delta P_L \tag{4.5}$$

Observation#2:
If several generators (each having its own governor and prime mover) were connected to the system, the frequency change would be

$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R_1}+\frac{1}{R_2}+\cdots+\frac{1}{R_n}+D} \tag{4.6}$$

Outline

Introduction

Generator model

Load model

Prime mover model

Governor model

Tie-line model

Generation control

Tie line model

The power flowing across a transmission line (called *tie line*) can be modelled by recalling Eq. (2.8) from the Lecture #2.

$$P = \frac{3E_pE_a}{X}\sin(\theta)$$

This equation has been obtained by relying on the following HPs:

- θ is the phase difference between the voltage phasors, E_p and E_a, at the line terminals, $\theta = \theta_p - \theta_a$;
- The line is lossless;
- The transversal capacities are negligible.

On top of these hypotheses, if we assume:

1. The voltage angle differences to be small
   - $\sin\ (\theta) = \theta$
   - $\cos\ (\theta) = 1$
2. Magnitudes of bus voltages to not move too far from 1.0 per unit (i.e. we assume to have a flat voltage profile):

$$\sqrt{3}E_p = V_p = 1\ pu \qquad \sqrt{3}E_a = V_a = 1\ pu$$

we obtain the power flowing across a transmission line with the so-called DC load flow approximation:

$$P_{tie\ flow} = \frac{1}{X_{tie}}(\theta_1 - \theta_2) \tag{5.1}$$

Tie line model

$$P_{tie\ flow} = \frac{1}{X_{tie}}(\theta_1 - \theta_2) \qquad (5.2)$$

This tie flow is a **steady-state quantity**. For purposes of analysis here, we will perturb Eq. 5.2 to obtain deviations from the nominal power flow as a function of deviations in phase angle from nominal.

$$P_{tie\ flow} + \Delta P_{tie\ flow} = \frac{1}{X_{tie}}[(\theta_1 + \Delta\theta_1) - (\theta_2 + \Delta\theta_2)] = \frac{1}{X_{tie}}(\theta_1 - \theta_2) + \frac{1}{X_{tie}}(\Delta\theta_1 - \Delta\theta_2)$$

Then:

$$\Delta P_{tie\ flow} = \frac{1}{X_{tie}}(\Delta\theta_1 - \Delta\theta_2) \qquad (5.3)$$

By assuming for simplicity to have only synchronous machines with a single pair of poles, $\boldsymbol{\Delta\theta_1}$ and $\boldsymbol{\Delta\theta_2}$ are equivalent to $\boldsymbol{\Delta\theta_{m_1}}$ and $\boldsymbol{\Delta\theta_{m_2}}$ as defined in (1.4).

Then, by knowing that $\Delta\omega = \frac{d}{dt}(\Delta\theta_m), \Delta\omega(\mathrm{s}) = \mathrm{s}\Delta\theta_m$

$$\Delta P_{tie\ flow} = \frac{\mathrm{T}}{s}(\Delta\omega_1 - \Delta\omega_2) \qquad (5.4)$$

where $T = \frac{2\pi f^*}{X_{tie}}$ may be thought of as the **"tie-line stiffness" coefficient.**

** Note that $\Delta\theta$ must be in radians for $\Delta P_{tie\ flow}$ to be in per unit megawatts, but $\Delta\omega$ is in per unit speed change. A factor of 2πf has to be considered.*

Tie line model

Suppose now that we have an interconnected **power system broken into two areas each having one generator.**

- The areas are connected by a single transmission line.
- The tie power flow was defined as going from area 1 to area 2;
- The flow appears as a load (< 0) to area 1 and a power source (> 0) to area 2.
- If one assumes that mechanical powers are constant, the rotating masses and tie-line exhibit damped oscillatory characteristics known as synchronizing oscillations

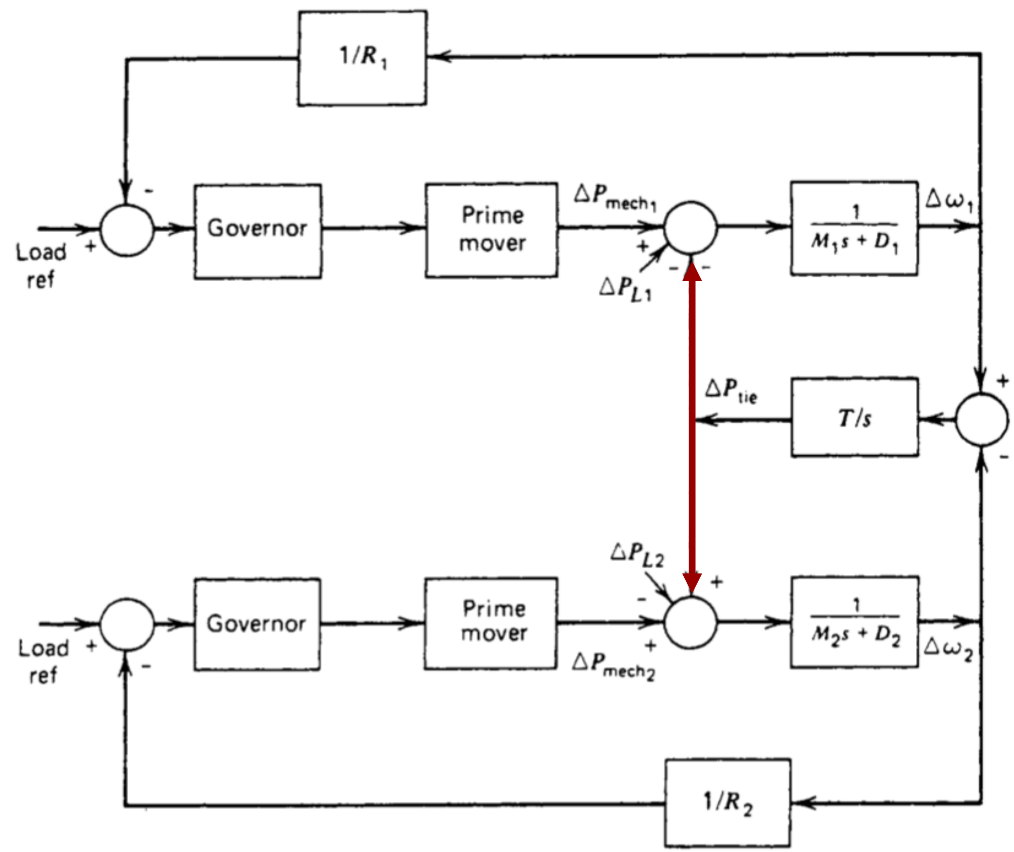


Fig. 7.14. Block diagram of interconnected areas

Tie line model

Let there be a load change ΔP_{L_1} in area 1. In the steady-state, after all synchronizing oscillations have damped out, the frequency will be constant and equal to the same value on both areas.

$$\Delta\omega_1 = \Delta\omega_2 = \Delta\omega \qquad \text{and} \qquad \frac{d(\Delta\omega_1)}{dt} = \frac{d(\Delta\omega_1)}{dt} = 0 \qquad (5.5)$$

In Area 1:

$$\Delta P_{mech_1} - \Delta P_{tie} - \Delta P_{L_1} = \Delta\omega D_1$$

$$\Delta P_{mech_1} = \frac{-\Delta\omega}{R_1}$$

In Area 2:

$$\Delta P_{mech_2} + \Delta P_{tie} = \Delta\omega D_2$$

$$\Delta P_{mech_2} = \frac{-\Delta\omega}{R_2}$$

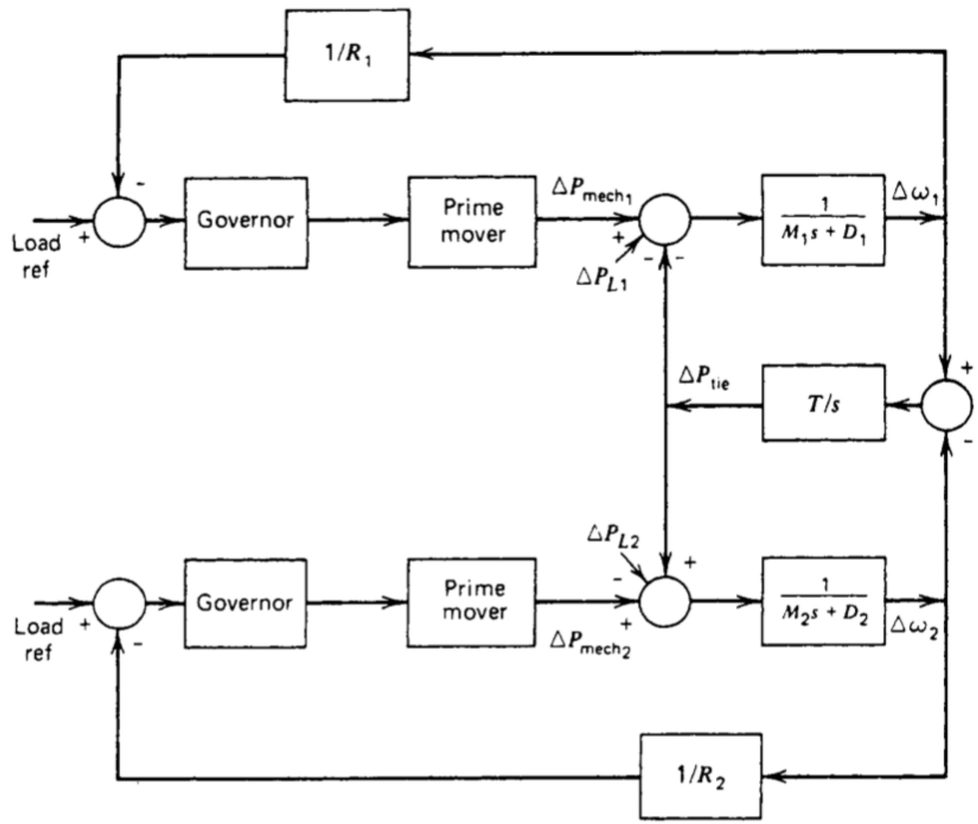


Fig. 7.14. Block diagram of interconnected areas

Tie line model

In Area 1:

$$\Delta P_{mech_1} - \Delta P_{tie} - \Delta P_{L_1} = \Delta\omega D_1$$

$$\Delta P_{mech_1} = \frac{-\Delta\omega}{R_1}$$

$$-\Delta P_{tie} - \Delta P_{L_1} = \Delta\omega\left(\frac{1}{R_1} + D_1\right)$$

In Area 2:

$$\Delta P_{mech_2} - \Delta P_{tie} = \Delta\omega D_2$$

$$\Delta P_{mech_2} = \frac{-\Delta\omega}{R_2}$$

$$\Delta P_{tie} = \Delta\omega\left(\frac{1}{R_2} + D_2\right)$$

(5.6)

Area 1 + Area 2:

$$\Delta\omega = \frac{-\Delta P_{L_1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2}$$

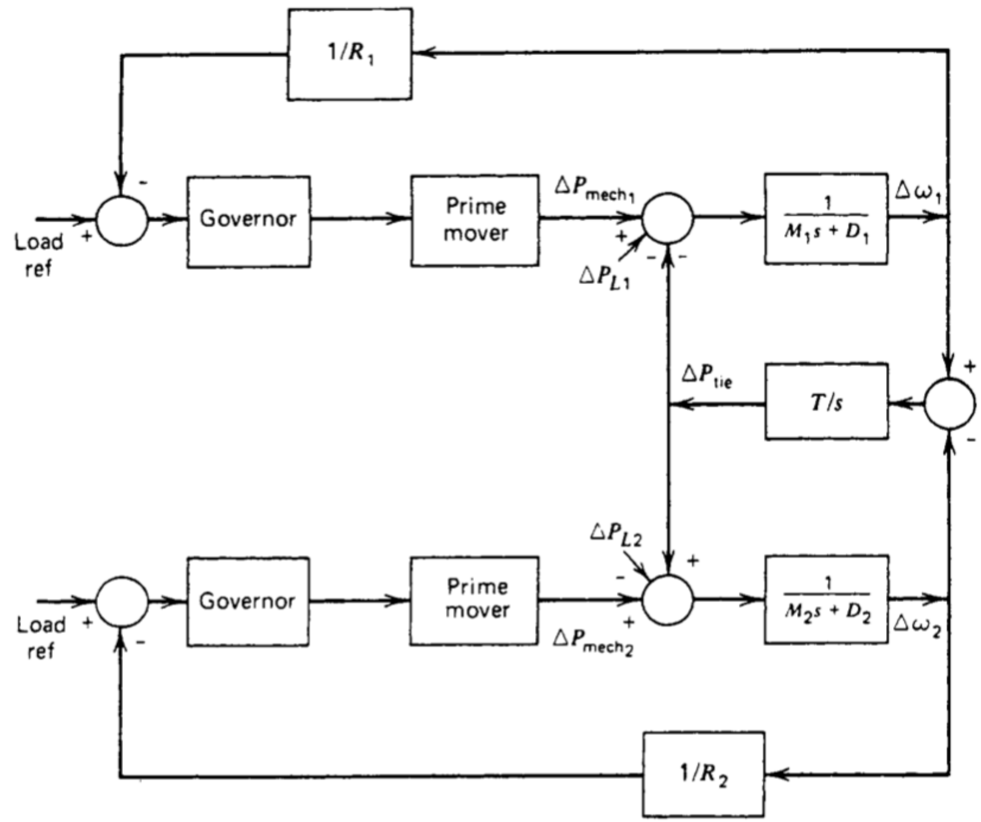


Fig. 7.14. Block diagram of interconnected areas

Tie line model

From:

$$\boxed{\Delta\omega = \frac{-\Delta P_{L_1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2}} \qquad (5.7)$$

we can derive the change in tie flow:

$$\Delta P_{tie} = \frac{-\Delta P_{L_1}\left(\frac{1}{R_2} + D_2\right)}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} \qquad (5.8)$$

Note that these last conditions are for the **new steady-state conditions after the load change**.

The new tie flow is determined by the net change in load and generation in each area.
We do not need to know the tie stiffness to determine this new tie flow, although the tie stiffness will determine how much difference in **phase angle** across the tie will result from the new tie flow.

Tie line model

$$\Delta\omega = \frac{-\Delta P_{L_1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} \qquad (5.7)$$

Eq. (5.7) describe the **new steady-state conditions after the load change**.

If we were to analyse **the dynamics of the two-area systems**, we would find that a step-change in load would always result in **a frequency error.**

This is illustrated in Figure 7.15 which shows the frequency response of the system to a step-load change (omitting any high-frequency oscillations).

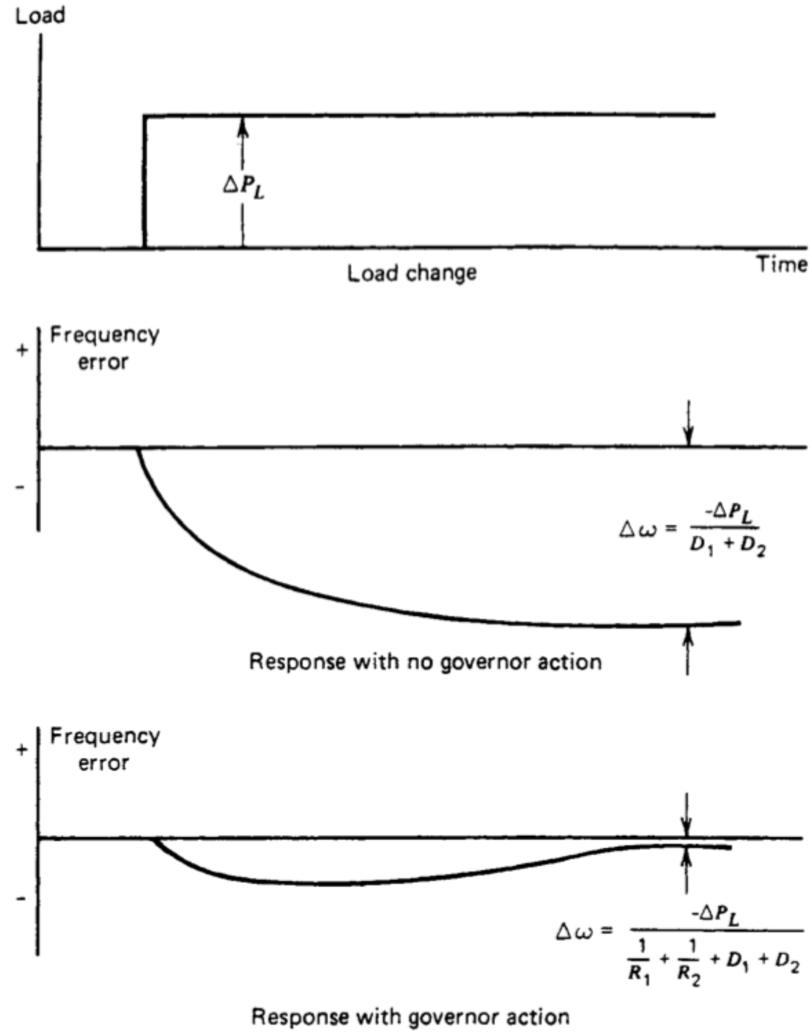


Fig. 7.15. Frequency response to load change.

Outline

- Introduction
- Generator model
- Load model
- Prime mover model
- Governor model
- Tie-line model
- Generation control

Generation control

Automatic generation control (AGC) is the name given to a control system having three major objectives:

1. **To hold system frequency** at or very close to a specified **nominal value** (e.g., 50 Hz)
2. To maintain the **correct value of interchange power** between control areas.
3. To maintain each unit's generation at the **most economic value**.

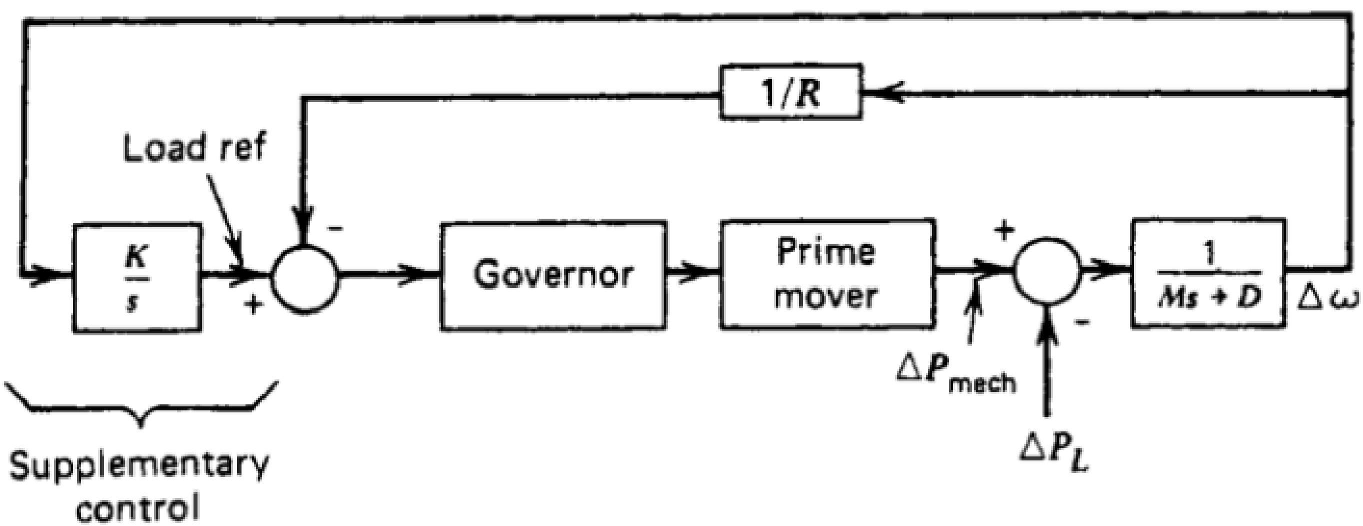


Fig. 7.16. Supplementary control added to generating init.

Generation control

Supplementary control action:

Let's consider a single generating unit supplying load to an isolated power system.

As shown in the Governor section of the slides, **a load change will produce a frequency change** with a magnitude that depends on

- The droop characteristics of the governor
- The frequency characteristics of the system load.
- The load change magnitude

$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R} + D} \tag{4.4}$$

Since $\Delta\omega \neq 0$, a **supplementary control must act to restore the frequency to the nominal value**. This can be accomplished by adding a reset (integral) control to the governor, as shown in Figure 7.16.

The reset control action of the supplementary control will force the frequency error to zero by adjustment of the speed reference set point.

Generation control

Tie-Line Control:

The case of a single generating unit supplying load to an isolated power system is very rare **since usually power systems are interconnected**. This happens for several reasons:

- To be able to **buy and sell power** with neighbouring systems whose operating costs make such transactions profitable.
- If one system has a sudden loss of a generating unit, **the units throughout all the interconnection** will experience a frequency change and **can help in restoring frequency.**

Interconnections present a very interesting control problem with respect to the allocation of generation to meet load.

In the following slides, a problem with two interconnected systems will be presented.

Generation control

Assume that:

- Two systems have equal characteristics $R_1 = R_2$ (gen)and $D_1 = D_2$ (load)
- *System 1* is sending 100 MW to *System 2* under an interchange agreement made between the operators of each system.
- *System 2* experience a sudden load increase of 30MW.

Then:

- Since $R_1 = R_2$ and $D_1 = D_2$ both units experience a 15 MW increase
- The 30 MW load increase in system 2 is satisfied by a $\Delta P_2 = 15$ MW plus $\Delta P_1 = 15$ MW
- The tie line will experience an increase in flow from 100 MW to 115 MW.

Problem:

***System 1* contracted to sell only 100 MW, not 115 MW.**

Its generating costs have just gone up without anyone to bill the extra cost to.

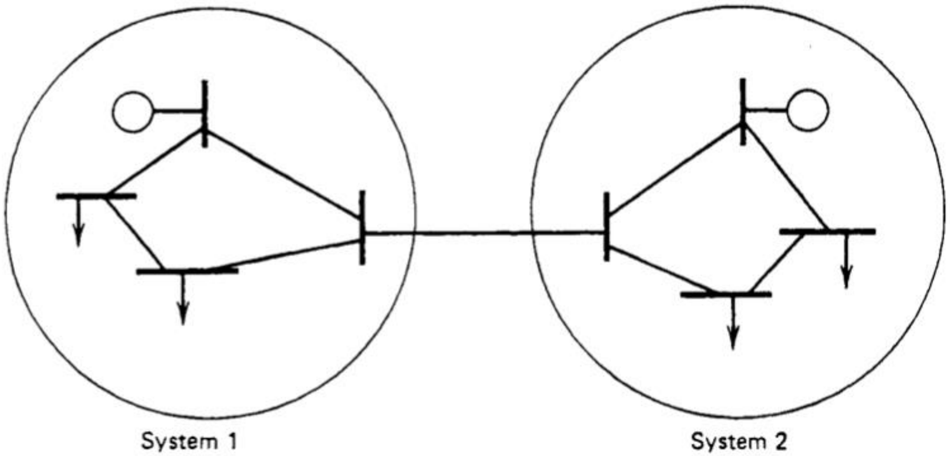


Fig. 7.17. *Two-area system*

Generation control

Problem:

***System 1* contracted to sell only 100 MW, not 115 MW but the flow has changed due to a load increase in System 2.**

Solution:

- We need a control scheme that recognizes the fact that the 30 MW load increase occurred in system 2 and, therefore, would increase generation in system 2 by 30 MW while restoring frequency to the nominal value.
- It would also restore generation in system 1 to its output before the load increase occurred.

Such a control system must use two pieces of information:

1. The system frequency
2. The net power flowing in or out over the tie lines

In fact:

- If $\boldsymbol{f} \downarrow$ and $\boldsymbol{P_{net_{out}}} \uparrow$, a load increase has occurred outside the system
- If $\boldsymbol{f} \downarrow$ and $\boldsymbol{P_{net_{out}}} \downarrow$, a load increase has occurred inside the system

Generation control

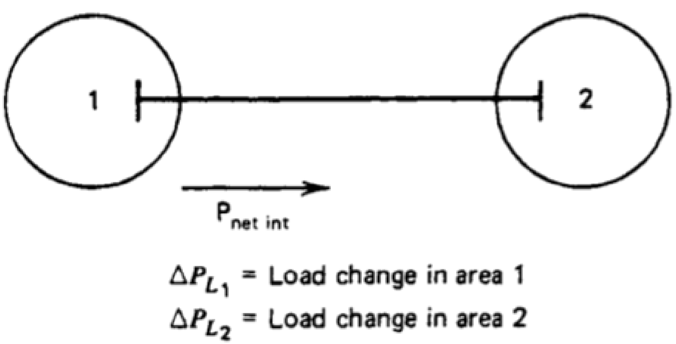
The same can be extended to cases where frequency increases. We will make the following definitions:

$\boldsymbol{P_{net\ int}}$ = total actual net interchange
(+ for power leaving the system)
(- for power entering)

$\boldsymbol{P_{net\ int\ sched}}$ = scheduled or desired value of interchange

$$\Delta P_{net\ int} = P_{net\ int} - P_{net\ int\ sched}$$

A summary of the tie-line frequency control scheme can be given as in the table in Figure 7.18.



$\Delta\omega$	$\Delta P_{net\ int}$	Load change		Resulting control action
−	−	ΔP_{L_1}	+	Increase P_{gen} in system 1
		ΔP_{L_2}	0	
+	+	ΔP_{L_1}	−	Decrease P_{gen} in system 1
		ΔP_{L_2}	0	
−	+	ΔP_{L_1}	0	Increase P_{gen} in system 2
		ΔP_{L_2}	+	
+	−	ΔP_{L_1}	0	Decrease P_{gen} in system 2
		ΔP_{L_2}	−	

Fig. 7.18. Tie-line frequency control actions for two-area system.

Generation control

<u>Control area:</u>

We define a ***control area*** to be **a part of an interconnected system** within which the load and generation will be controlled as per the rules in Fig. 7.18.

- **The control area's boundary is simply the tie-line points** where power flow is metered.
- All tie lines crossing **the boundary must be metered** so that total control area net interchange power can be calculated.
- The rules set forth in Figure 7.18 can be implemented by a control mechanism that weighs frequency deviation, $\Delta\omega$, and net interchange power, $\Delta P_{net\ int}$.
- The frequency response and tie flows resulting from a load change, ΔP_{L_1}, in the two-area system of Figure 7.14 are derived in Equations (5.7) and (5.8). These results are repeated here:

$$\Delta\omega = \frac{-\Delta P_{L_1}}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} \qquad (5.7)$$

$$\Delta P_{tie} = \frac{-\Delta P_{L_1}\left(\frac{1}{R_2} + D_2\right)}{\frac{1}{R_1} + \frac{1}{R_2} + D_1 + D_2} \qquad (5.8)$$

Generation control

Eqs.(5.7)-(5.8) correspond to the first row of the table in Figure 7.18 ; we would require that:

$$\Delta P_{gen_1} = \Delta P_{L_1} \tag{6.1}$$

$$\Delta P_{gen_2} = 0 \tag{6.2}$$

The required change in generation, historically called the ***area control error*** or $\boldsymbol{ACE}$, **represents the shift in the area's generation required to restore frequency and net interchange to their desired values**.

The equations for $\boldsymbol{ACE}$ for each area are:

$$ACE_1 = -\Delta P_{net\ int_1} - B_1 \Delta\omega \tag{6.3}$$

$$ACE_2 = -\Delta P_{net\ int_2} - B_2 \Delta\omega \tag{6.4}$$

where B_1, and B_2, are called ***frequency bias factors.*** We can see from Eq. (5.8) that setting bias factors as follows:

$$B_1 = \left(\frac{1}{R_1} + D_1\right) \tag{6.5}$$

$$B_2 = \left(\frac{1}{R_2} + D_2\right) \tag{6.6}$$

Generation control

Results in:

$$ACE_1 = \left(\frac{\Delta P_{L_1}\left(\frac{1}{R_2}+D_2\right)}{\frac{1}{R_1}+\frac{1}{R_2}+D_1+D_2}\right) - \underbrace{\left(\frac{1}{R_1}+D_1\right)}_{\text{Frequency bias factors } B_1}\underbrace{\left(\frac{-\Delta P_{L_1}}{\frac{1}{R_1}+\frac{1}{R_2}+D_1+D_2}\right)}_{\Delta\omega} = \Delta P_{L_1} \qquad (6.7)$$

$$ACE_2 = \left(\frac{-\Delta P_{L_1}\left(\frac{1}{R_2}+D_2\right)}{\frac{1}{R_1}+\frac{1}{R_2}+D_1+D_2}\right) - \left(\frac{1}{R_2}+D_2\right)\left(\frac{-\Delta P_{L_1}}{\frac{1}{R_1}+\frac{1}{R_2}+D_1+D_2}\right) = 0$$

This control can be carried out using the scheme outlined in Figure 7.19.

Note that the values of B_1, and B_2 , would have to change each time a unit was committed or decommitted, in order to have the exact values as given in Eq.(6.5)-(6.6).

Actually, the integral action of the supplementary controller will guarantee a reset of **ACE** to zero even when B_1, and B_2 are in error.

Generation control

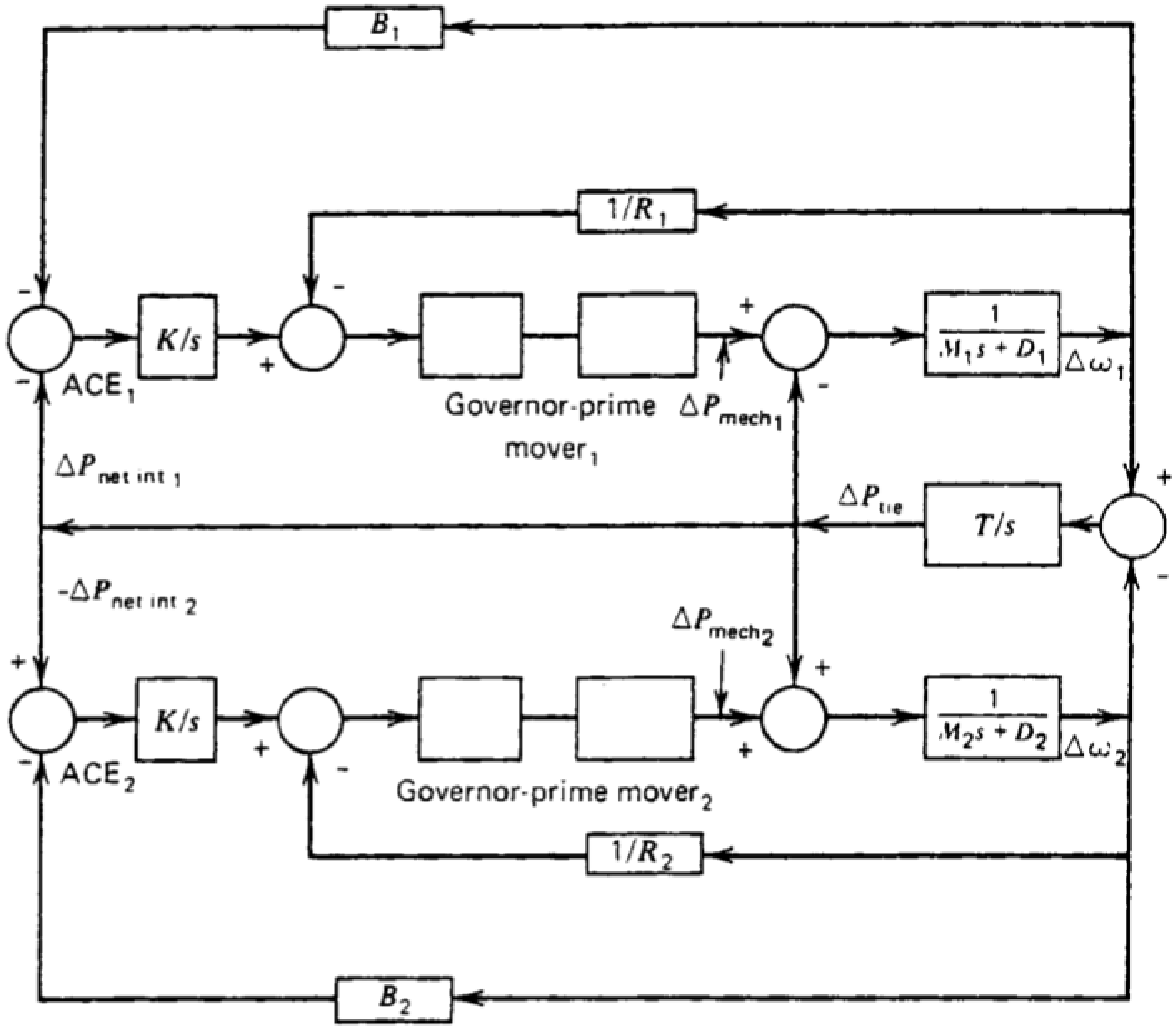


Fig. 7.19. Tie-line bias supplementary control for two areas

Generation control

- If each control area in an had **a single generating unit**, this control system would suffice to provide stable frequency and tie-line interchange.
- Power systems consist of control areas with **many generating units** with outputs that must be set according to economics

- We need to consider both **economic dispatch** calculation and **control mechanism**

- The **load** on a power system **varies continually**

- It is necessary to be able to specify a total generation, calculate the economic dispatch for each unit, and then give the control mechanism the values of megawatt output for each **very quickly**.

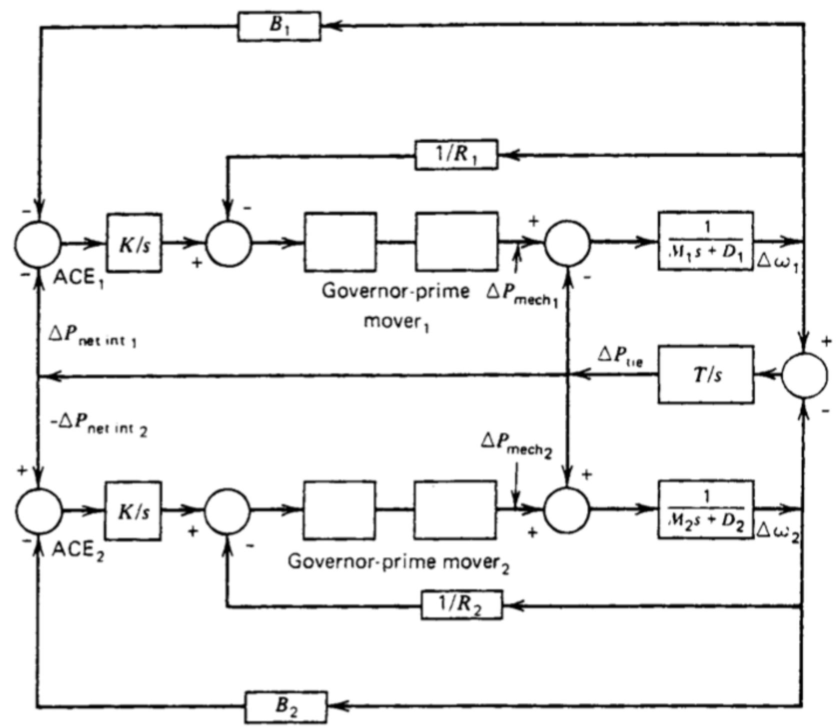


Fig. 7.19. Tie-line bias supplementary control for two areas

Generation control

- It is desirable to be able to carry out the economic-dispatch calculations at intervals of **one to several minutes**.
- **The allocation of generation must anyway be made instantly when the required area total generation changes.**
- The economic-dispatch calculation is executed with a total generation equal to the sum of the present values of unit generation as measured.
- The result of this calculation is a **set of base-point generations**, $P_{i_{base}}$, which is equal to the most economic output for each generator unit.
- The rate of change of each unit's output with respect to a change in total generation is called the unit's **participation factor, PF**

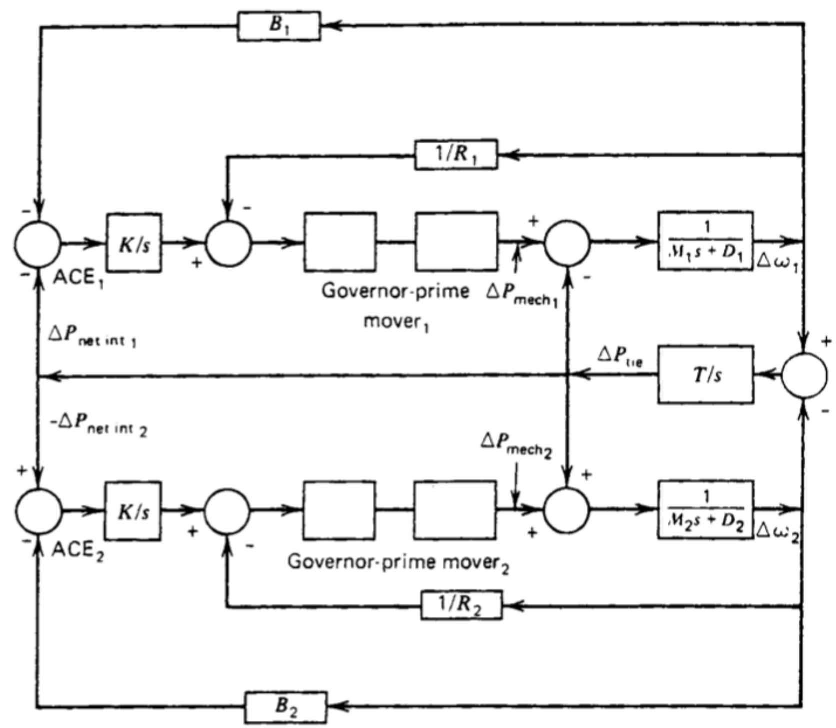


Fig. 7.19. Tie-line bias supplementary control for two areas

Generation control

The base point and participation factors are used as follows

$$\boxed{\begin{aligned} P_{i_{des}} &= P_{i_{base}} + PF_i \cdot \Delta P_{total} \\ \Delta P_{total} &= P_{new\,total} - \textstyle\sum_{all\,gen} P_{i_{base}} \end{aligned}}$$

(6.8)

Where

(6.9)

And

$P_{i_{des}}$ = new desired output from unit i
$P_{i_{base}}$ = base-point generation for unit i
PF_i = participation factor for unit i
ΔP_{total} = change in total generation
$P_{new\,total}$ = new total generation

Note that **by definition the participation factors must sum to unity.**

In a direct digital control scheme, the generation allocation would be made by running a computer code that was programmed to execute according the above mentioned equations.