Active Power (P) – Frequency (f) Control

Outline

1. Introduction
2. Power plant model
3. Overview of control tasks
4. Primary frequency control
5. Secondary frequency control
6. Summary

Introduction

Why constant frequency?

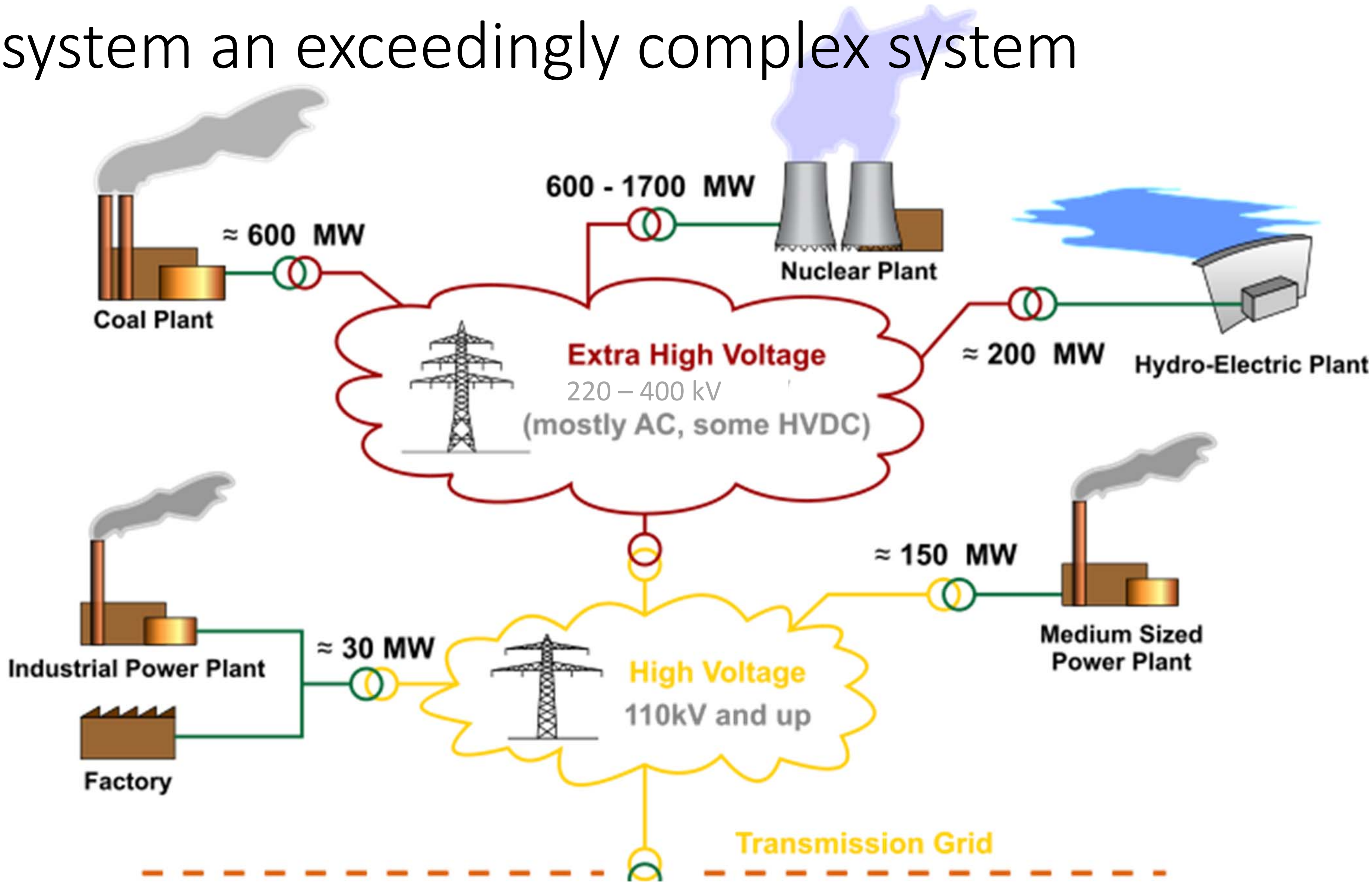
If frequency deviates significantly from the normal value:

- Turbines can sustain damage due to speeding up or sub-synchronous resonance.
- Transformers can heat up and damage themselves.
- The performance of consumer devices may suffer
  - ✓ protection system / relays trip out generators, lines, and transformers if the frequency deviations are too severe
  - ✓ System collapse can be the ultimate result in extreme cases

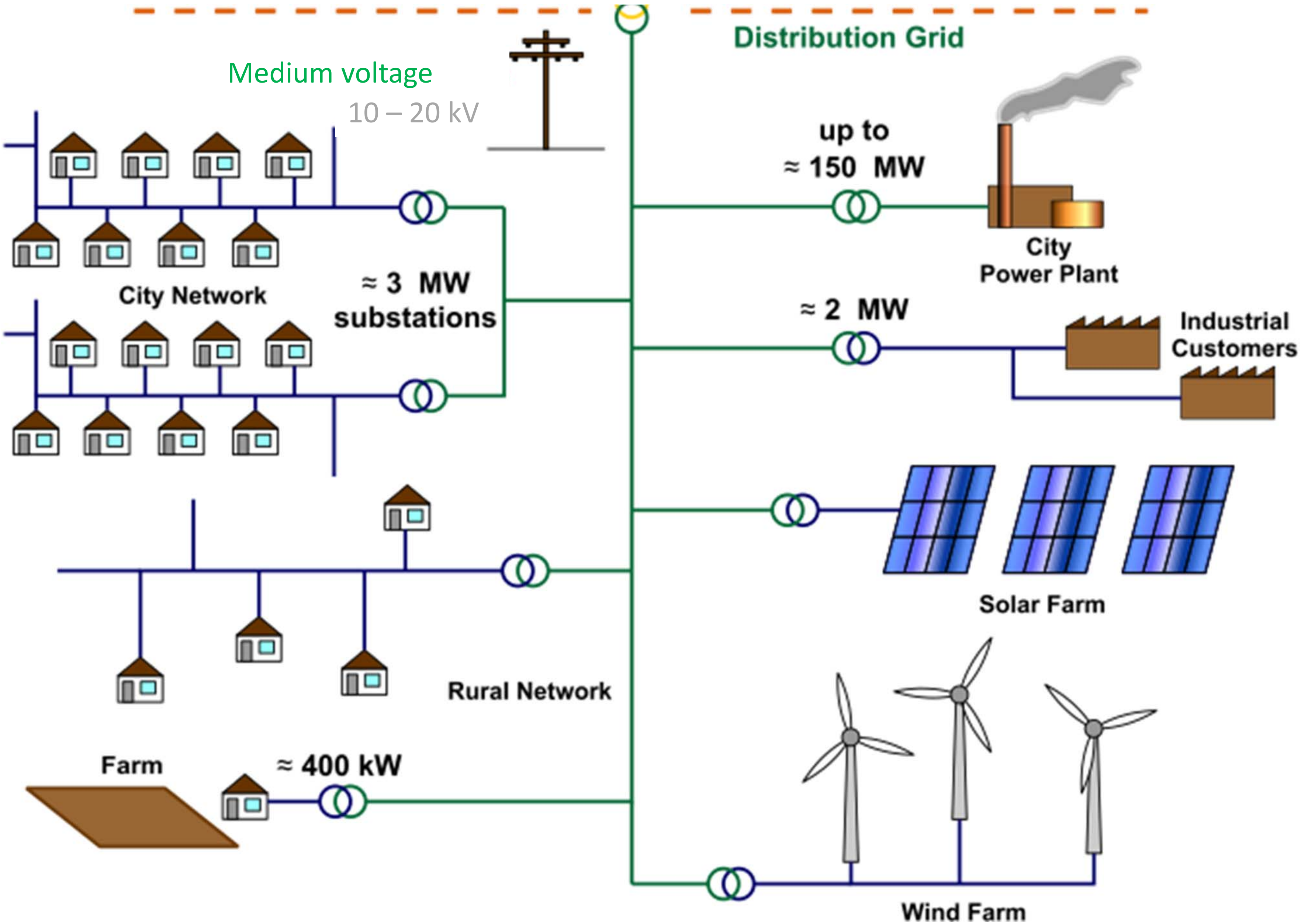
The condition for frequency remaining at or around the standard value (50/60 Hz):

Power generation = Power consumption + losses

Power system an exceedingly complex system



https://en.wikipedia.org/wiki/Electrical_grid


Distribution Grid
Medium voltage
10 – 20 kV
up to
≈ 150 MW
City
Power Plant
City Network
≈ 3 MW
substations
≈ 2 MW
Industrial
Customers
Solar Farm
Rural Network
Farm
≈ 400 kW
Wind Farm

Multiple layers of frequency control

- **A complex and large interconnected system spanning a large geographic area**
- **As electric power cannot be stored in any significant amount, generation must continually match demand**
- **If demand and supply fall out of balance, local or even widespread blackouts can result.**
  - ✓ **Multi timescale frequency control is required to match power generation with power consumption and keep frequency around the nominal value**

Frequency control as one of the ancillary services

- **Adequate generation capacity must be held in reserve for frquency control**
  - ✓ **one of the ancillary services**

Definition of „Ancillary Services“ by US Federal Energy Regulatory Commission (FERC):

„the specialty services and functions provided by the electric grid that facilitate and support the continuous flow of electricity so that supply will continually meet demand“

Ancillary service – operating reserve

- An operating reserve refers to generators that can quickly be dispatched to ensure that there is sufficient energy generation to meet power demand.
  - Spinning reserves are generators that are already online and can rapidly increase their power output to meet fast changes in demand. Spinning reserves are required because demand can vary on short timescales and rapid response is needed.
  - Other operating reserves are generators that can be dispatched by the operator to meet demand, but that cannot respond as quickly as spinning reserves.

Difference between scheduling and dispatch

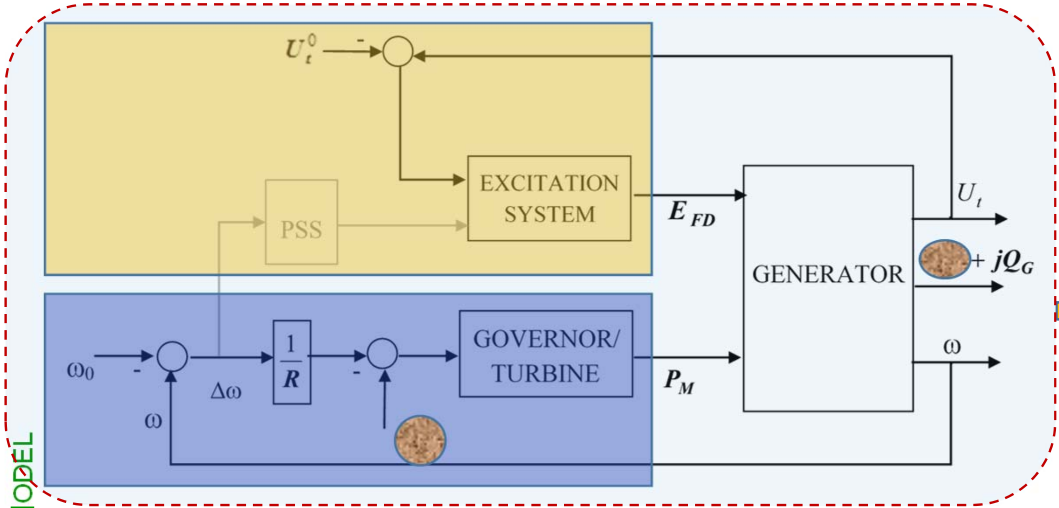
Scheduling refers to before-the-fact actions, e.g. scheduling a generator to produce a certain amount of power the next day, week, etc., while dispatch refers to the real-time control of the available resources.

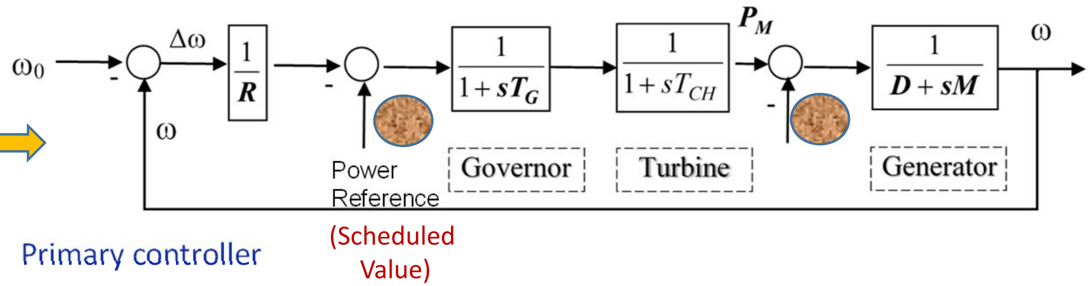
- Reactive power and voltage control (another ancillary service)
  - Compensating the voltage drops caused by current flow and maintaining voltages within the permissible range

Power Plant Model

- Generator model
- Turbine model
- Governor model
- Controller model

Power plant model



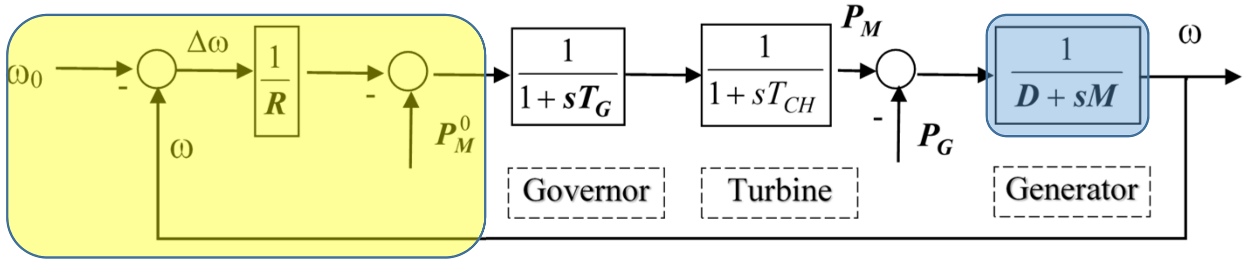


Generator Inputs	**Mechanical power input P_M from the turbine**
	The field voltage E_{FD} from the exciter
Generator Outputs	**The generated electrical output power $P_G + jQ_G$**
	The generator terminal voltage U_t
	Rotor speed ω

- The excitation system is fast (reaction time: 10 – 50 ms)
- The governor – turbine system is slow in its reaction to dynamic events (reaction time: 0.5 – 10 s)

- Therefore, the governor – turbine control loop can be decoupled from the excitation loop
  - ✓ since the voltage regulation is much faster than the speed - active power regulation

Generator model



Block diagram of governor/turbine/generator model

Mathematical model of the generator:

The generator's inertial response is described by the swing equation

$$J \cdot \frac{d^2\delta_m}{dt^2} = T_M - T_G \qquad \frac{d\delta_m}{dt} = \omega - \omega_0 = \Delta\omega \rightarrow$$

$$J \cdot \frac{d\Delta\omega}{dt} = T_M - T_G$$

where:

$J =$	The total moment of inertia of the synchronous machine and the attached rotating masses (in kg.m^2)
$\delta_m =$	The rotor angle (in mechanical radians) measured from the synchronously rotating reference frame
$T_M =$	The turbine mechanical input torque (in Nm). (Positive *Tm* : mechanical power fed into the machine, i.e. normal operation as a generator in steady state.)
$T_G =$	The electromagnetic and damping torques on the rotor (in Nm). (Electromagnetic torque is positive in normal operation as a generator.)

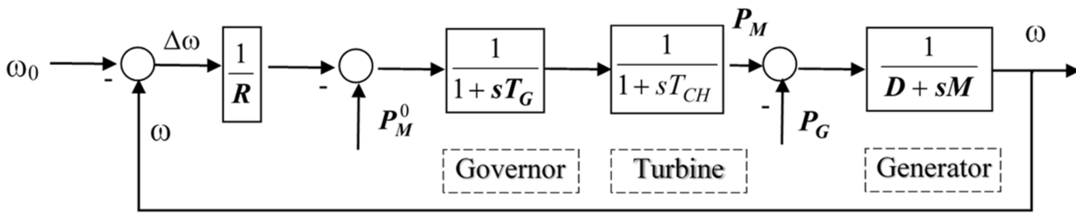
Governor - turbine – generator model

It is more convenient to work with power rather than torque. Thus,

$$J.\omega_m = \frac{d\Delta\omega}{dt} = P_M - P_G$$

with

$J.\omega_m = M$	$\omega_m.T_M = P_M$	$\omega_m.T_G = P_G$



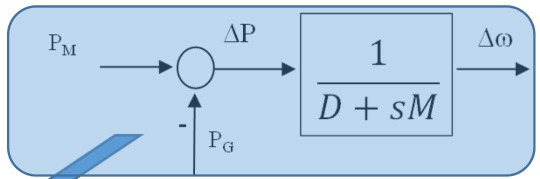
leading to another version of the swing equation:

$$M \cdot \frac{d\Delta\omega}{dt} = P_M - P_G$$

M = the machine's inertia constant (in form of angular momentum) in MW/s

The damping power of the system is given by the relationship:

$$P_d = D \cdot \frac{d\delta}{dt},$$ where D = the damping coefficient.

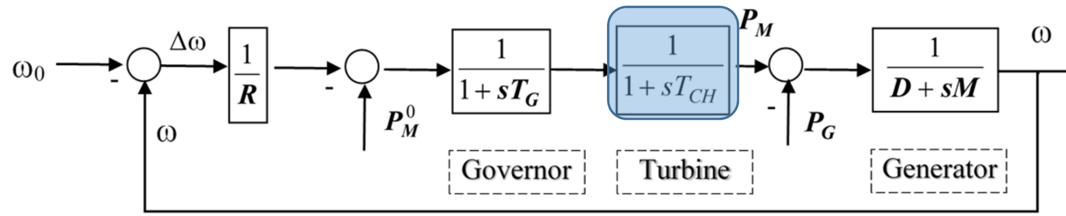


The swing equation including damping thus becomes (s: Laplace operator):

$$\boxed{M \cdot \frac{d\Delta\omega}{dt} = P_M - P_G - D\Delta\omega \qquad M.s.\Delta\omega = P_M - P_G - D.\Delta\omega \rightarrow (D + sM).\Delta\omega = P_M - P_G}$$

The turbine model

- Turbines are grouped broadly into steam and hydro turbines.



- Steam turbine
  - The basic time constant associated with a steam turbine is T_{CH}, which corresponds to the time constant of the steam chest. The simplest transfer function is:

$$\boxed{\frac{1}{1+sT_{CH}}}$$

(Steam chest is the compartment in a steam engine that contains the valve system and through which steam is delivered from the boiler to the turbine.)

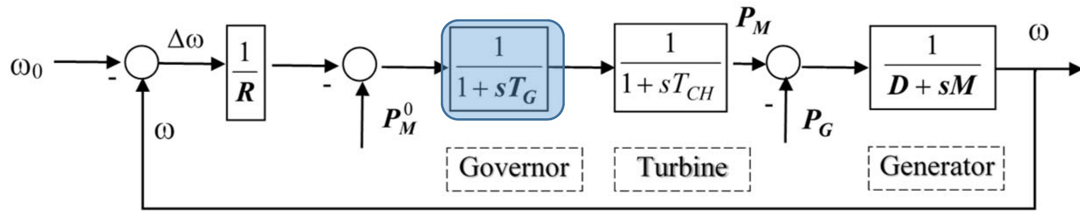
- Hydro turbine:
  - In case of hydro turbines, the time constant depends on the geometry of the system. A typical transfer function of a hydro turbine is:

$$T_{HT}(s) = \frac{(1 - 2sT_W)}{(1 + sT_W)}$$

T_W is known as the water time constant.

The governor model

- The simplest governor representation is a single block with time constant T_G



$$\longrightarrow \boxed{\frac{1}{1+sT_G}} \longrightarrow$$

- In a general case, the governor of a steam turbine (as an example) may be represented by the transfer function:

$$T_{GV}(s) = \frac{(1+sT_2)}{(1+sT_1)\cdot(1+sT_3)}$$

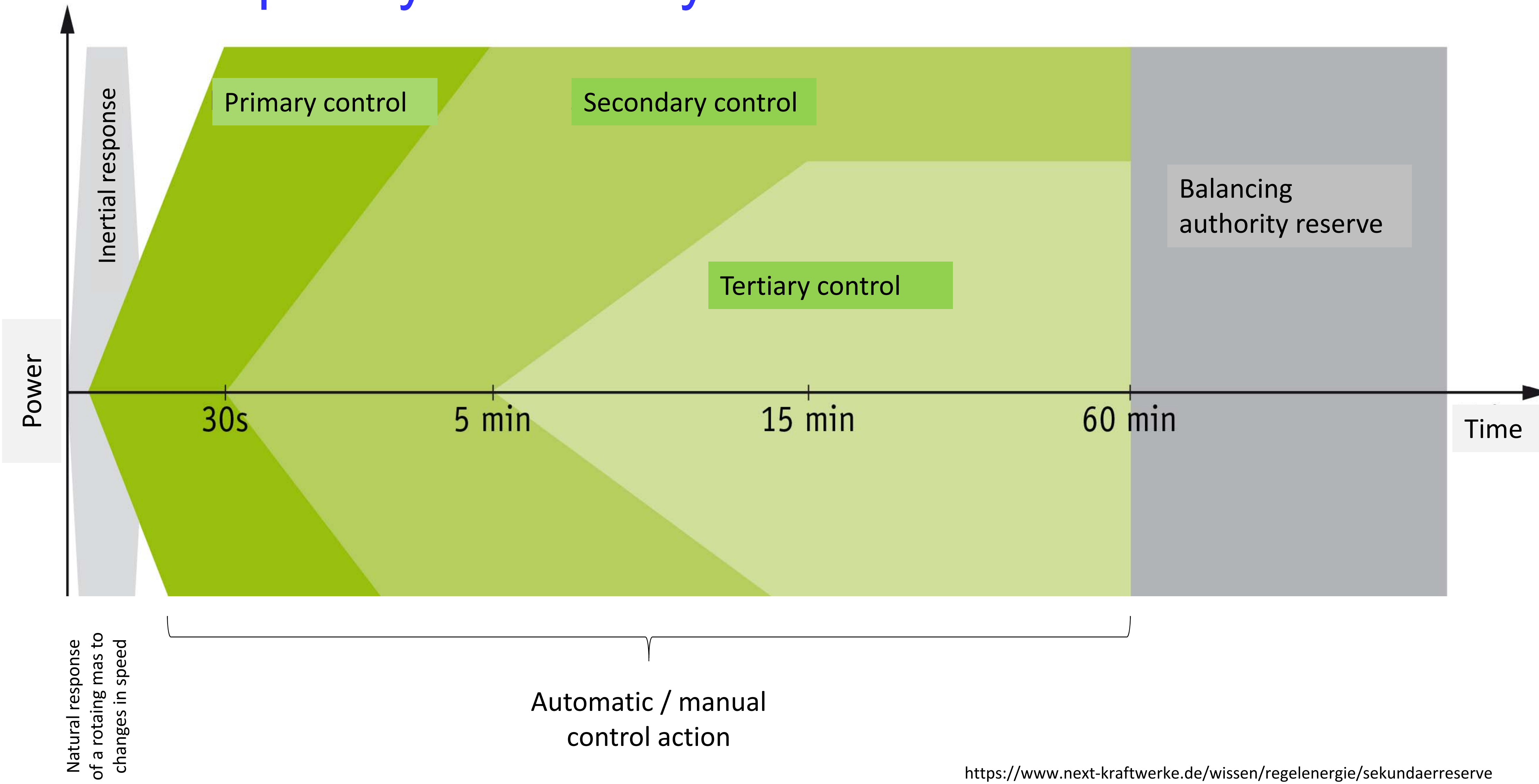
The time constants will, generally, have the following values.

For a mechanical hydraulic governor	$T_1 = 0.2 - 0.3$ s, $T_2 = 0.0$, $T_3 = 0.1$ s
For an electro hydraulic governor without steam feedback	$T_1 = 0.0$, $T_2 = 0.0$, $T_3 = 0.025 - 0.1$ s
For an electro hydraulic governor with steam feedback	$T_1 = 2.8$ s, $T_2 = 1.0$, $T_3 = 0.15$ s (It utilizes a feed forward mechanism; hence time constant T_2 in the numerator)

Frequency Control – an Overview

– Inertial response
– Primary control
– Secondary control
– Tertiary / manual control

Frequency control layers



https://www.next-kraftwerke.de/wissen/regelenergie/sekundaerreserve

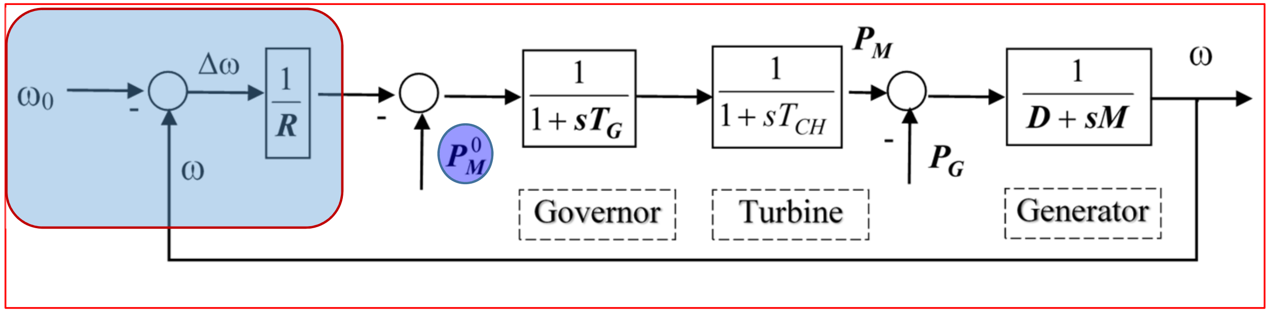
Inertial reponse

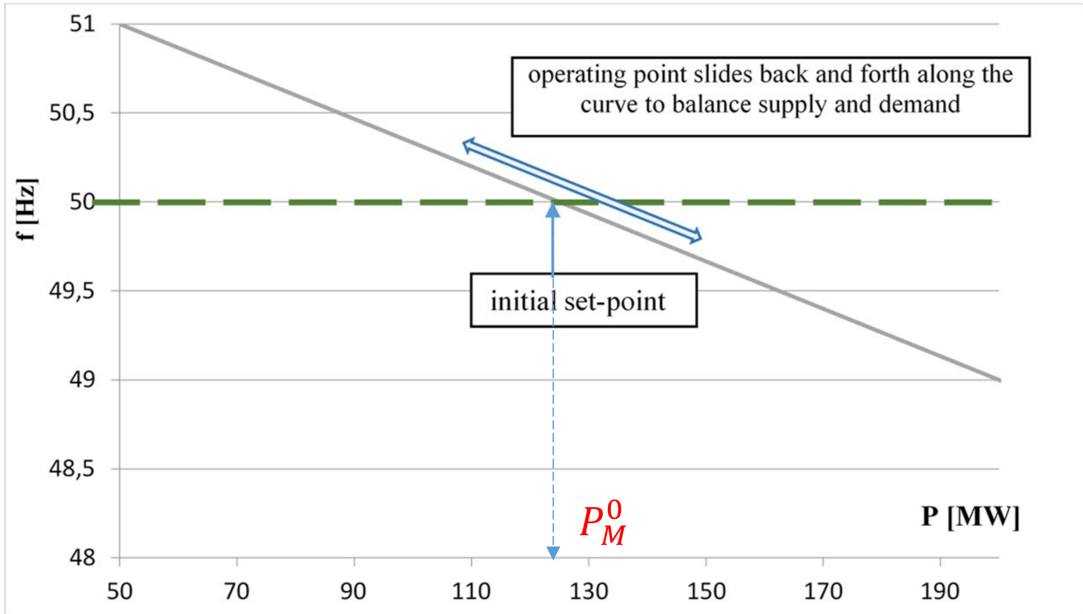
- The rotating masses of all generators, turbines, motors, etc. combine to produce system inertia (J) leading to the following equation of motion (also referred to as the "swing equation"

$$J\,\frac{d\omega}{dt} = T_m - T_e \;\rightarrow \frac{d\omega}{dt} = \frac{T_m - T_e}{J}$$

- The inertia of the system slows the angular acceleration of the generators – Thus the inertia of the system has a stabilizing effect.
- Asynchronous motors (in accordance with their operating principle) absorb less power when the line frequency drops, or higher power when the frequency increases.

Governor (primary) control model

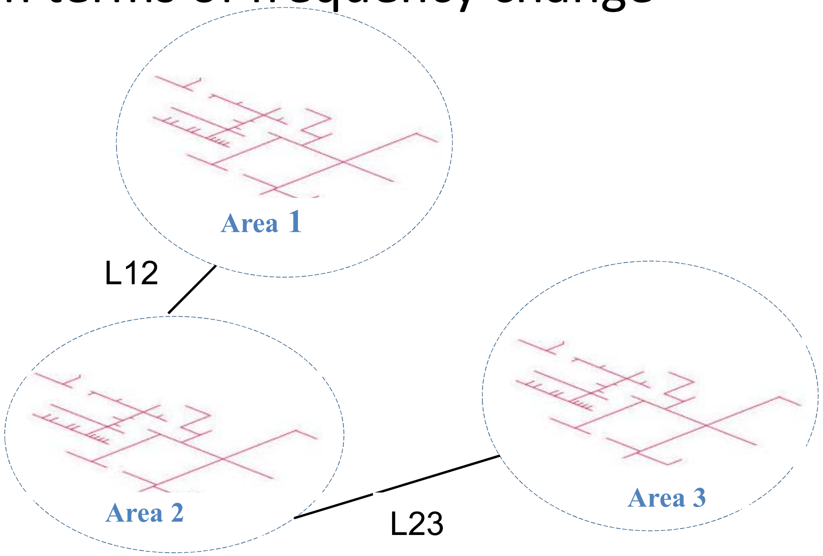




Basic droop characteristic.

Active Power and Frequency Control

- The system frequency depends on active power balance
- As frequency is a common variable throughout the system (including interconnected areas), a change in active power demand at one point is reflected throughout the system in terms of frequency change



L12, L23 : Tie lines

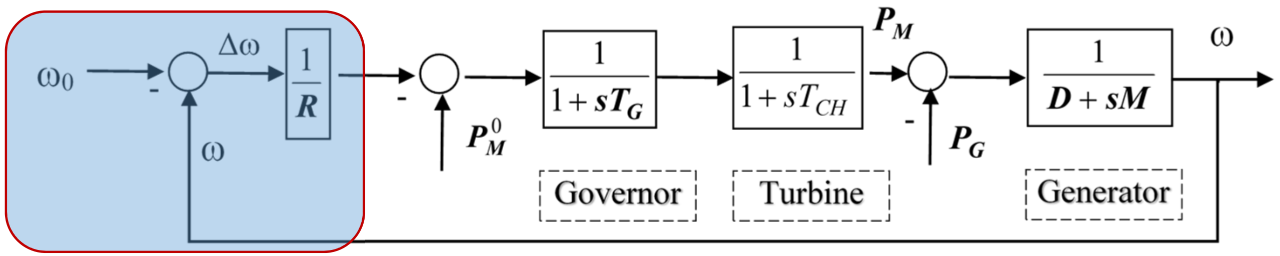
Example:
New power demand $\Delta P_L = \Delta P_G$ in Area 3 $\rightarrow$ Δf in Area1, Area2, Area3

- **Since there are many generators injecting power into an interconnected system, some means must be provided to allocate change in the demand to the generators in the system**
  - $\rightarrow$ **This is the objective of the primary control function**

Active Power and Frequency Control

Speed governor on each generating unit (participating on primary control):

- **provides primary speed control function**



- A change in load ΔP_L immediately results in a change in generation ΔP_G
- But mechanical power P_M can only change as a result of governor action

$$P_G = P_L$$
$$\Delta P_G = \Delta P_L$$

$$\Delta\omega = \omega - \omega_0$$

$$P_G + \Delta P_G \rightarrow = P_M^0 - \frac{\Delta\omega}{R} \rightarrow \quad \Delta\omega \neq 0 \; until \; \Delta P_G \; is \; matched \; by \; \Delta P_M$$

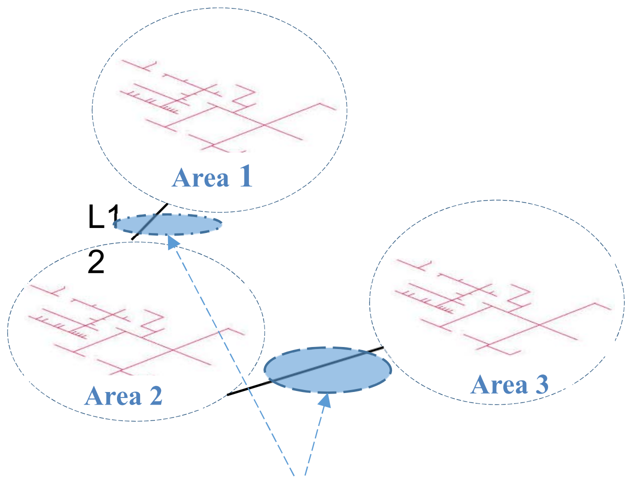
Objective of primary control (governor action):

- **ensure that a large and sudden frequency fall / rise is prevented**

Active Power and Frequency Control

Supplementary control / Secondary control:

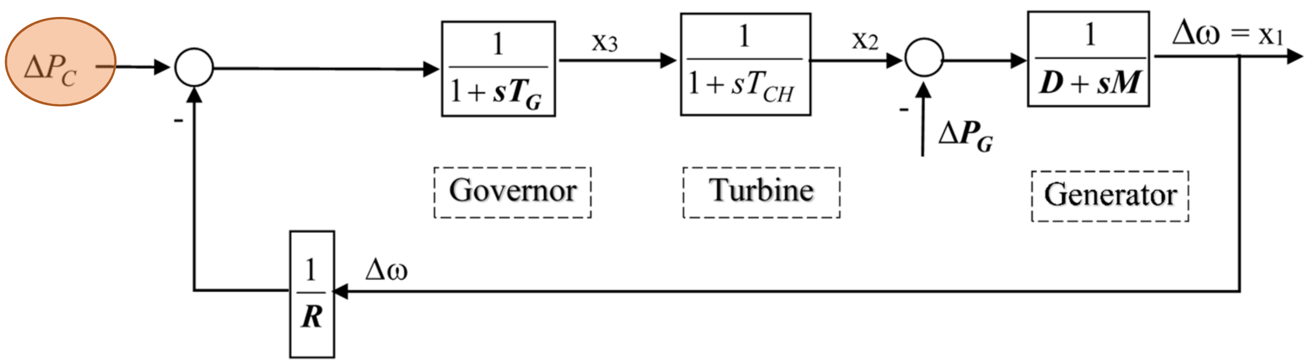
- originates from a central controller in the system control center
- allocates generation to ensure:
  - frequency is brought back to the nominal value
  - inter-area power flow is restored to the scheduled value



inter-area power flows P_{ij}

adjust $\Delta P_C \rightarrow \Delta\omega = 0$ & $\Delta P_{ij} = 0$

P_{ij}: power flow between Area i and Area j



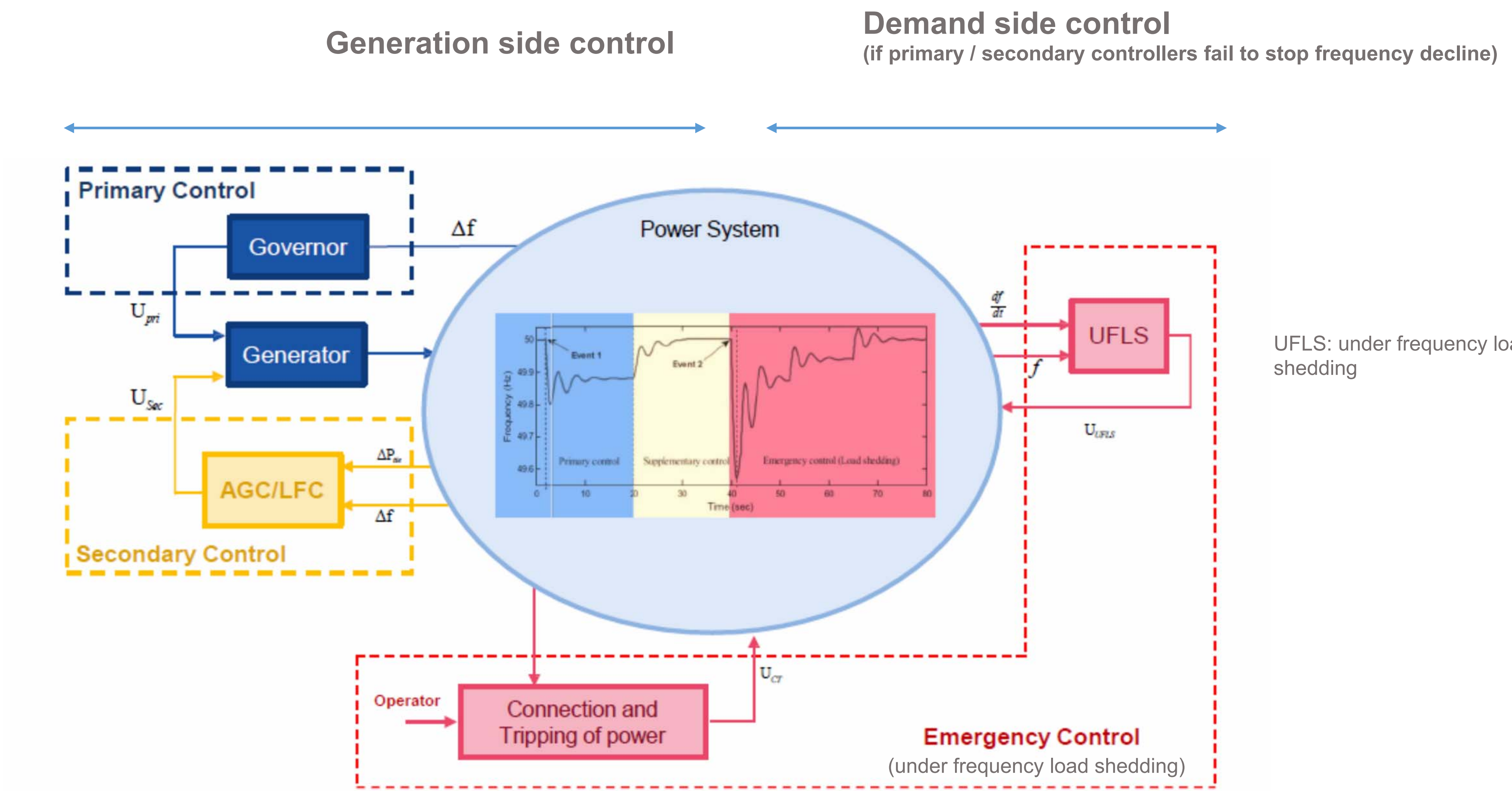
Secondary Frequency Control

Secondary control or Automatic Generation Control (AGC) ensures that:

- **frequency steady state error is corrected and**
- **the load reference(s) of governors is adjusted slowly in such a way that generators in a particular area take on the burden of their own load, i.e. unscheduled power exchange between areas is avoided**

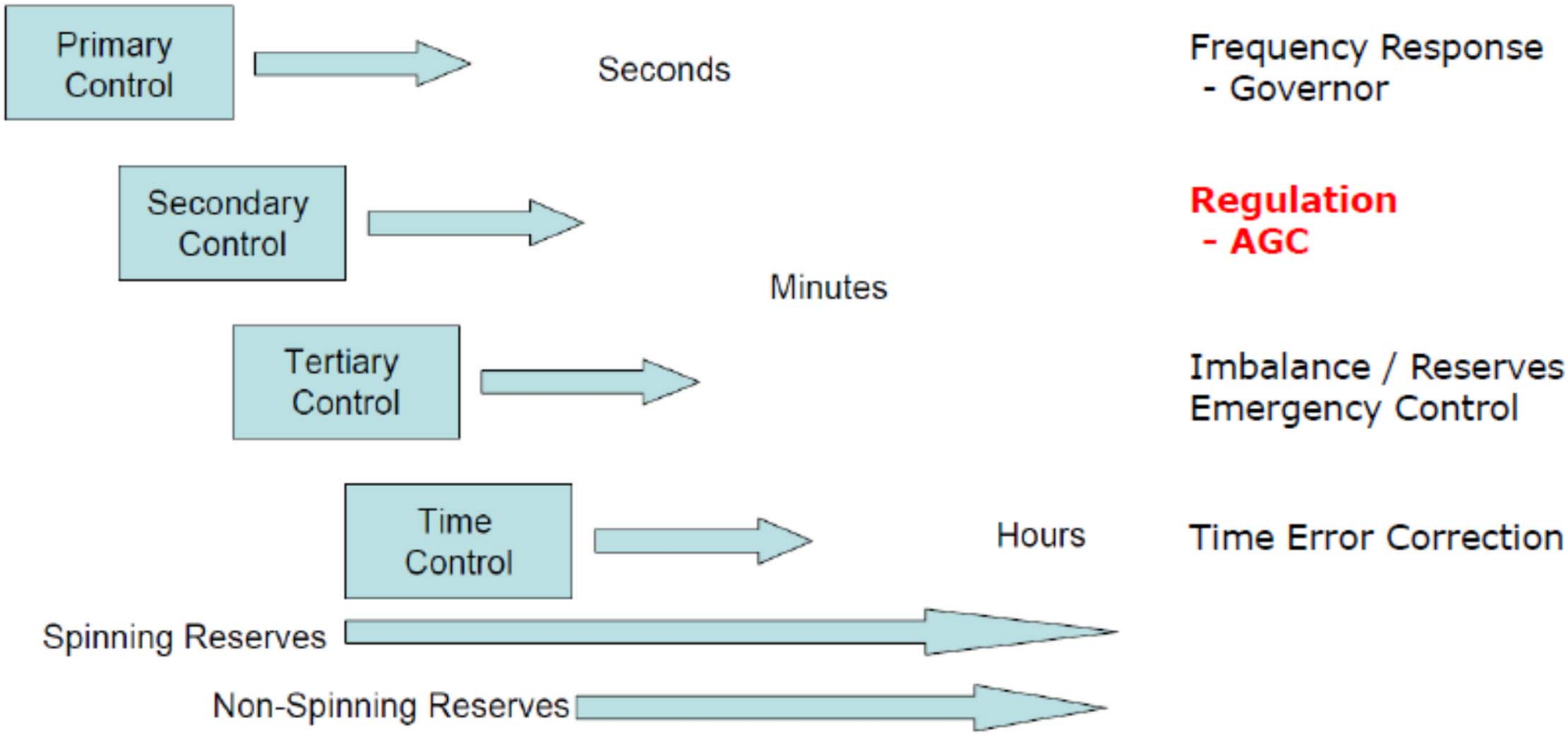
This control is also called "secondary control". This correction may be done over several minutes as opposed to 5-10 seconds for initial or "primary" control action of governors.

Load – Frequency Control - Overview



UFLS: under frequency load shedding

Load – Frequency Control - Overview



Load – Frequency Control - Overview

Spinning Reserve

- the on-line reserve capacity that is synchronized to the grid system and ready to meet power demand quickly (e.g. within 10 minutes of a dispatch instruction by the System Operator).
- to maintain system frequency stability during emergency operating conditions and unforeseen load swings.

Non-Spinning Reserve

- off-line generation capacity that can be ramped to capacity and synchronized to the grid after a dispatch instruction by the System Operator
- and that is capable of maintaining that output for at least two hours. Non-Spinning Reserve is needed to maintain system frequency stability during emergency conditions.

Primary Frequency Control

- Isochronous speed governor
- Speed droop governor
  - Droop constant
  - Allocation of primary reserve
- Frequency dependency of the load

Primary Speed Controls

- ***Isochronous* speed governor**

- **Governor with *Speed Droop***

Isochronous governor characteristic

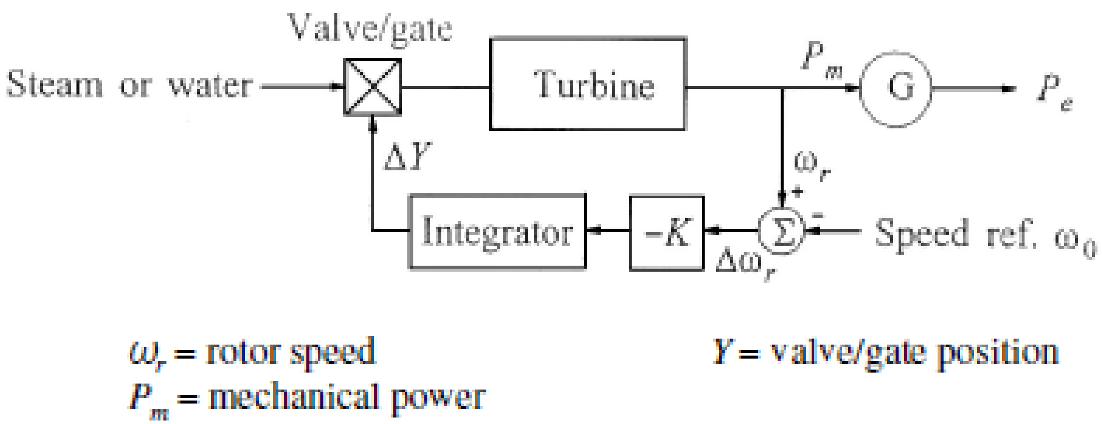


Figure 1: Schematic of an isochronous governor

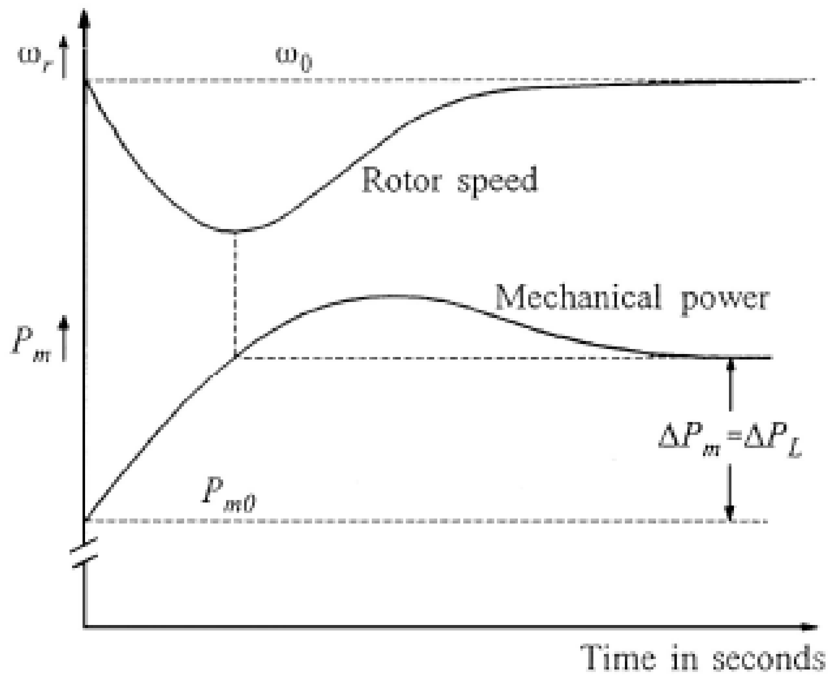


Figure 2: Response of generating unit with isochronous governor

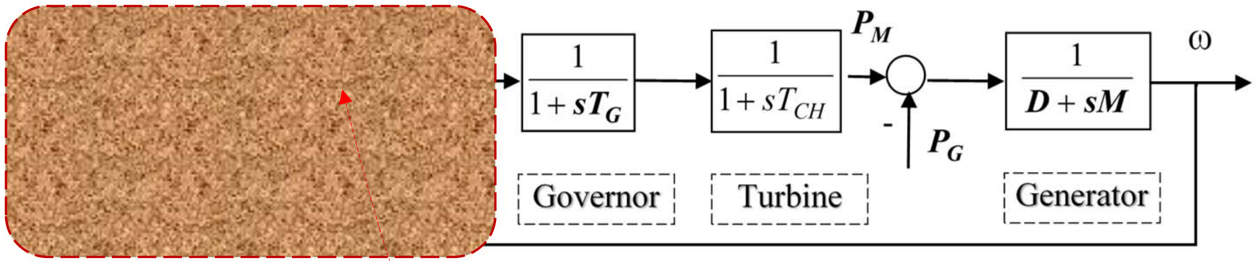
Isochronous speed control

Isochronous* speed governor is an *integral* controller resulting in *constant speed

- **not suitable for multi-machine systems,**
  - **because slight differences in speed settings would cause the machines to fight against each other**
- **can be used only when one generator is supplying an isolated load or when only one generator in a system is required to respond to load changes**

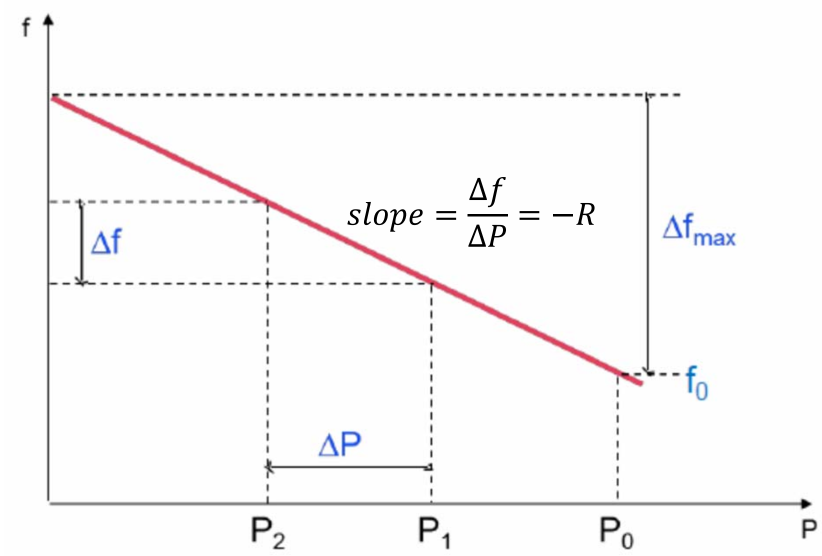
Primary Speed Controls

▪ Governor with *Speed Droop*



Governor speed droop control

Adds / subtracts input proportional to Δω
1/R proportionality factor



- **speed regulation or droop is provided to ensure proper load sharing**
- **a *proportional* controller with a gain of 1/R**
- **if the percent regulation of the units are nearly equal, change in output of each unit will be nearly proportional to its rating**
- **the speed-load characteristic can be *adjusted by changing governor settings***

Percent Speed Regulation or Droop

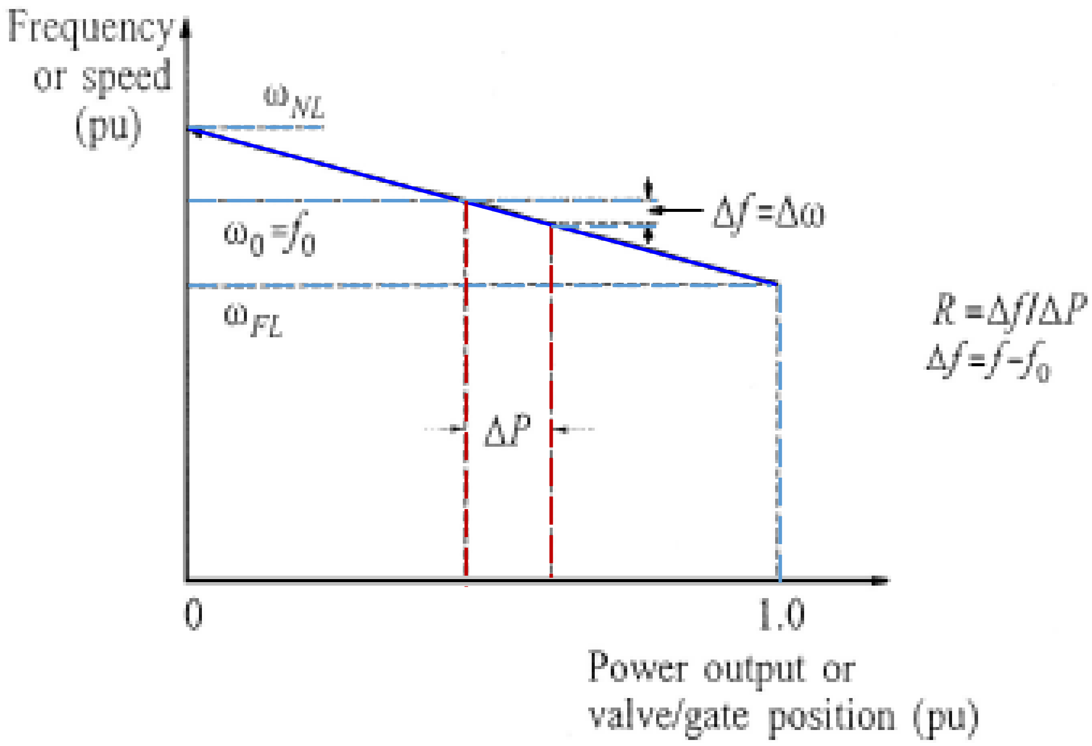


Figure 5: Ideal steady-state characteristics of a governor with speed droop

$$Percent\ R = \frac{Percent\ speed\ or\ frequency\ change}{Percent\ power\ output\ change} \times 100$$

$$= \frac{\omega_{NL} - \omega_{FL}}{\omega_0} \times 100$$

where

ω_{NL} = steady-state speed at no load
ω_{FL} = steady-state speed at full load
ω_0 = nominal or rated speed

For example, a 5% droop or regulation means that a 5% frequency deviation causes 100% change in valve position or power output.

Load Sharing by Parallel Units

$$\Delta P_1 = P_1' - P_1 = \frac{\Delta f}{R_1} \qquad \Delta P_2 = P_2' - P_2 = \frac{\Delta f}{R_2}$$

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

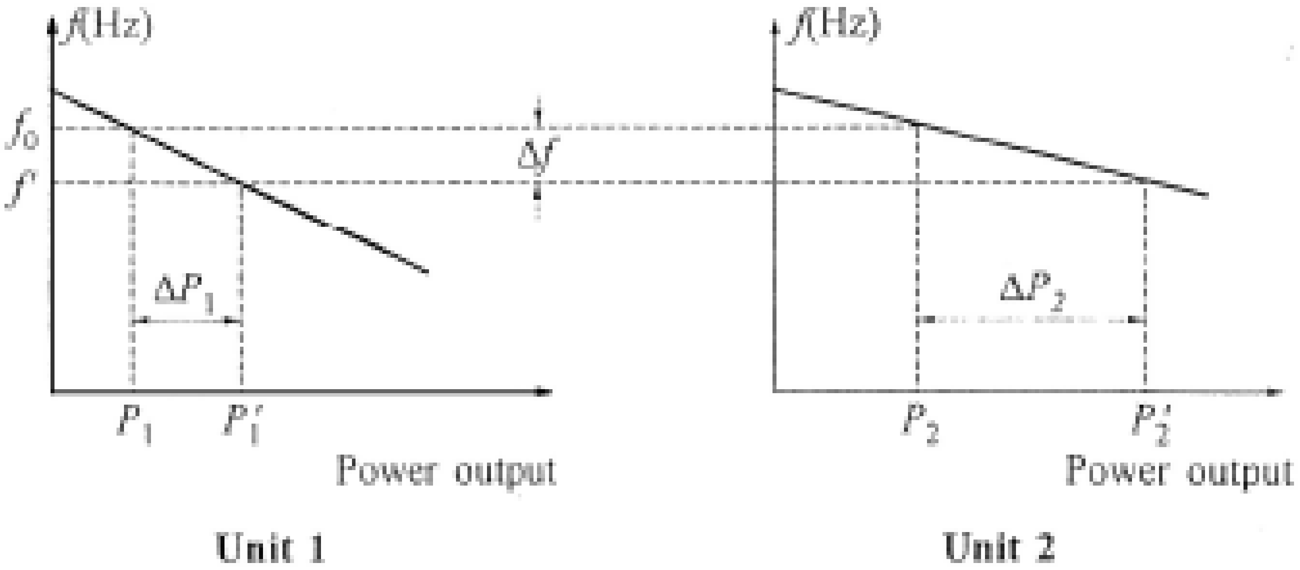


Figure 6: Load sharing by parallel units with drooping governor characteristics

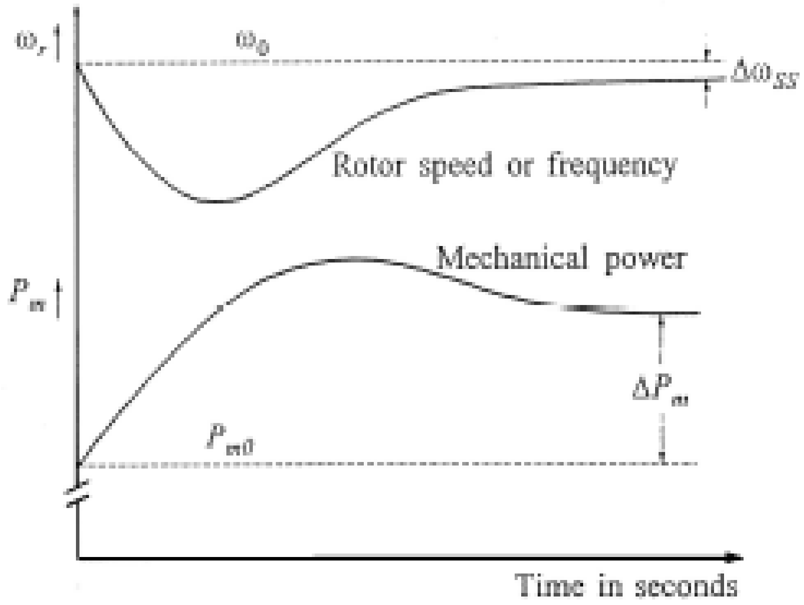
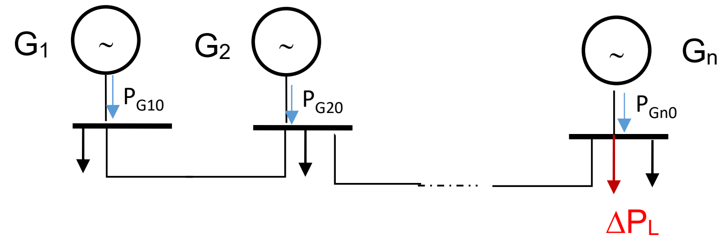
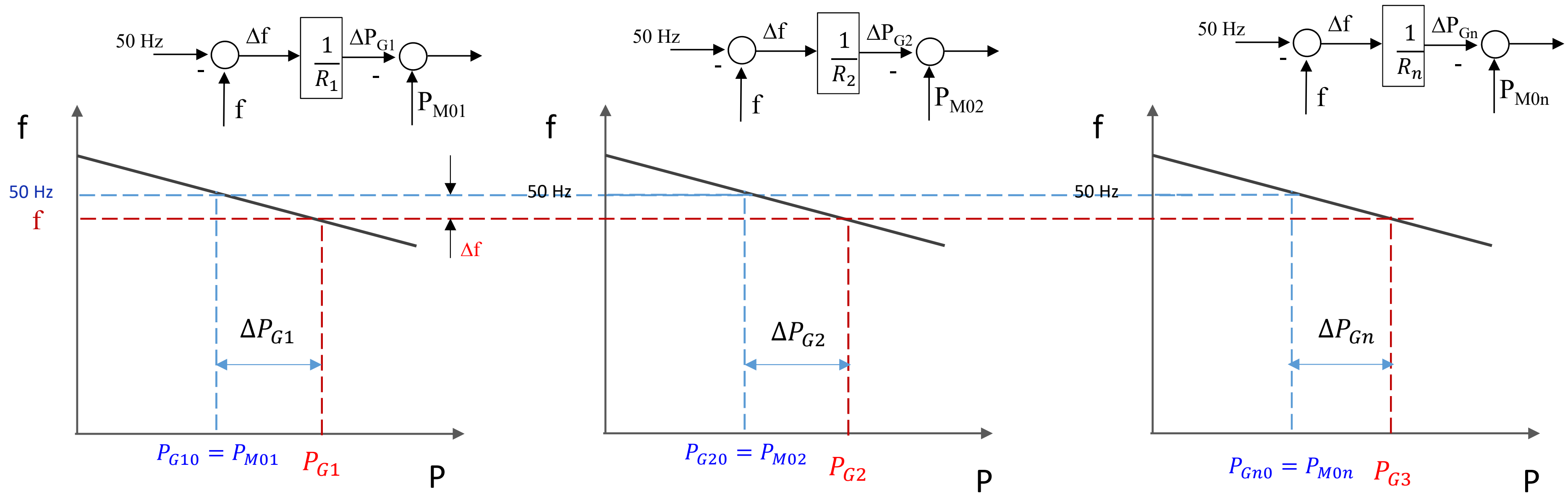


Figure 7: Response of a generating unit with a governor having speed-droop characteristics

Load Sharing by Parallel Units





$P_{G1} - P_{G10} = \Delta P_{G1} = -\Delta f \frac{1}{R_1}$

$P_{G2} - P_{G20} = \Delta P_{G2} = -\Delta f \frac{1}{R_2}$

$P_{Gn} - P_{Gn0} = \Delta P_{Gn} = -\Delta f \frac{1}{R_n}$

$$\boxed{\Delta P_{G1} + \Delta P_{G2} + \ldots + \Delta P_{Gn} = \Delta P_L = -\left(\Delta f \frac{1}{R_1} + \Delta f \frac{1}{R_2} + \ldots . + \Delta f \frac{1}{R_n}\right) \rightarrow \Delta f = -\frac{\Delta P_L}{\frac{1}{R_1} + \frac{1}{R_2} + \ldots + \frac{1}{R_n}}}$$

$$\frac{1}{R} = \frac{1}{R_1} + \frac{1}{R_2} + \ldots + \frac{1}{R_n}$$

Area droop

Load reference control

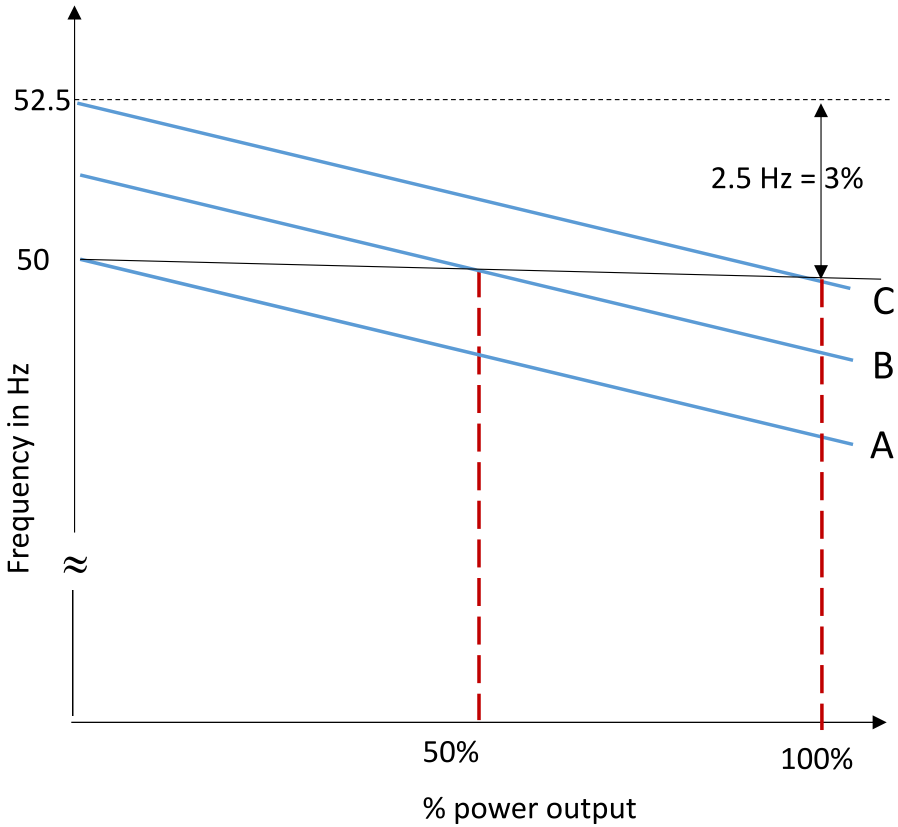


Figure 8: Effect of speed-changer setting on governor characteristic

- **Relationship between speed and load can be adjusted by changing "load reference set point"**

(Effect of load reference control is depicted in Figure on the left.)

- **three characteristics representing three load reference settings shown, each with 5% droop**
  - ☞ **at 50 Hz, characteristic A results in zero output;**
  - ☞ **characteristic B results in 50% output;**
  - ☞ **characteristic C results in 100% output**

Load reference control

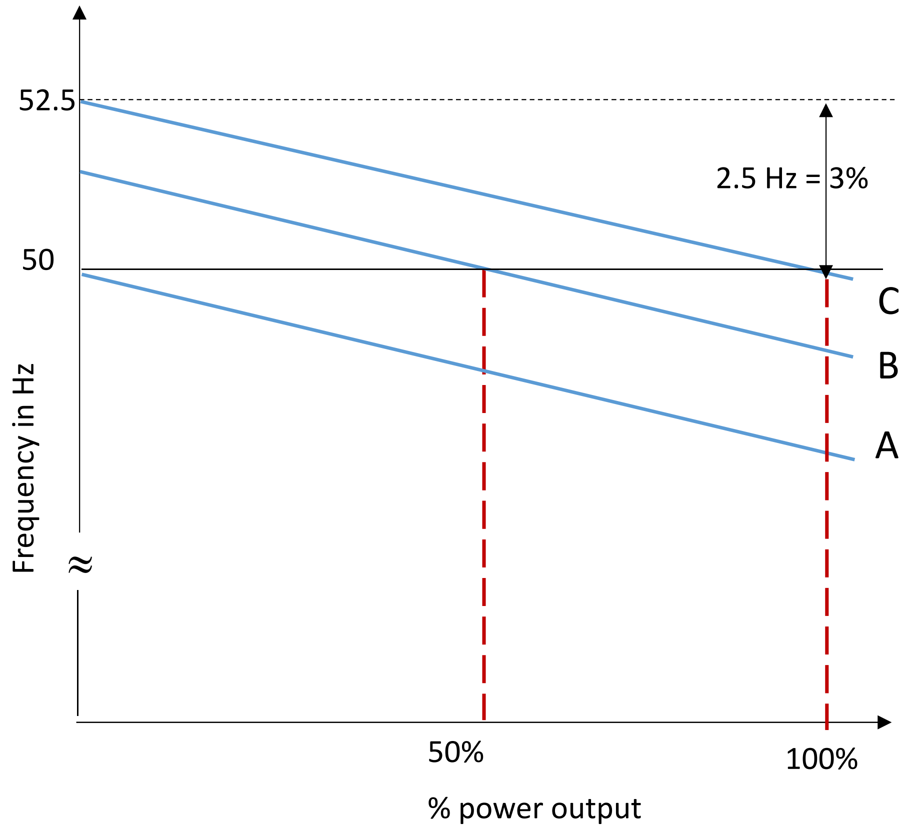


Figure 8: Effect of speed-changer setting on governor characteristic

- **Power output at a given speed can be adjusted to any desired value by controlling load reference**
- **When two or more units are operating in parallel:**
  - **adjustment of droop establishes proportion of load picked up when system has sudden changes**
  - **adjustment of load reference determines unit output at a given frequency**

Composite System Regulation Characteristic

- **System load changes with frequency. Assuming a load damping constant of D, frequency sensitive load change is:**

$$\Delta P_L = D.\ \Delta f$$

- **When load is increased, the frequency drops due to governor droop;**
- **Due to frequency sensitive load, the net reduction in frequency is not as high.**

- **The composite regulation characteristic includes prime mover characteristics and load damping.**

Composite System Regulating Characteristic

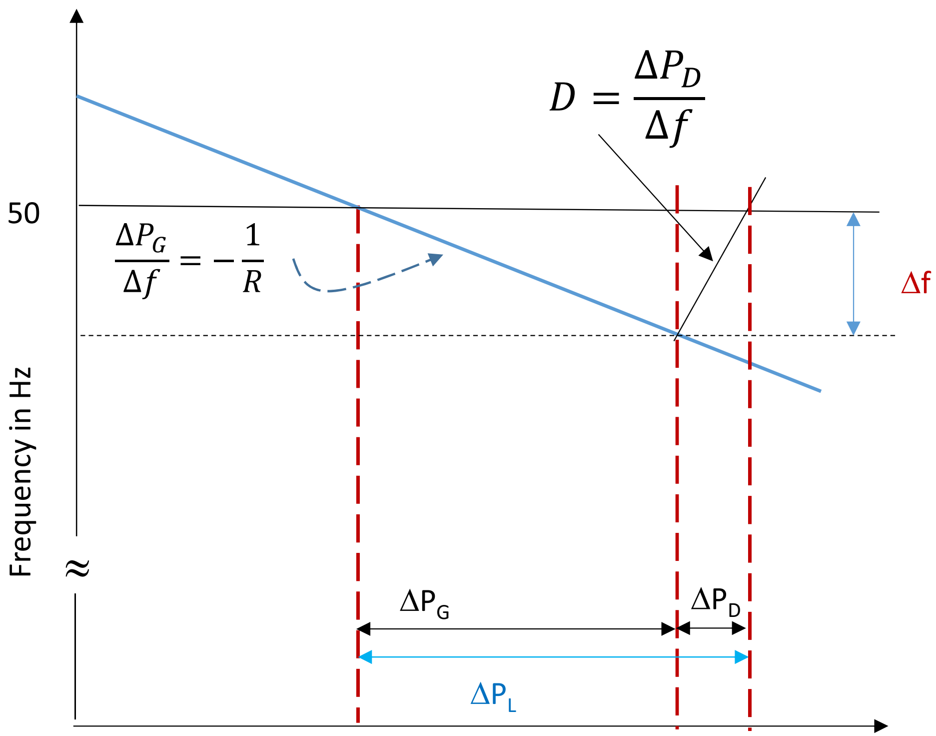
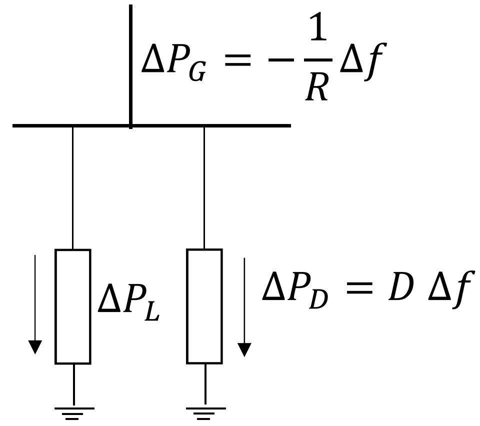


Figure 10: Composite governor and load characteristic



$$\Delta P_L = \Delta P_G - \Delta P_D \rightarrow$$

$$= -\frac{1}{R}\Delta f - D\,\Delta f$$

$$= \Delta f\left(-\frac{1}{R} - D\right)$$

$$\boxed{\rightarrow \Delta f = -\frac{\Delta P_L}{\frac{1}{R} + D}}$$

Composite System Regulating Characteristic

- **An increase of system load by ΔP_L (at nominal frequency) results in:**
  - **a generation increase of ΔP_G due to governor action, and**
  - **a load reduction of ΔP_D due to load characteristic**

$$\Delta f = \frac{-\Delta P_L}{\left(\frac{1}{R_1}+\frac{1}{R_2}+\cdots+\frac{1}{R_n}\right)+D} = \frac{-\Delta P_L}{\frac{1}{R_{eq}}+D}$$

Where:

$$R_{eq} = \frac{1}{\frac{1}{R_1}+\frac{1}{R_2}+\cdots+\frac{1}{R_n}}$$

$$\beta = \frac{-\Delta P_L}{\Delta f} = \frac{1}{R_{eq}} + D$$

- **The composite frequency response characteristic is normally expressed in MW/Hz. It is also sometimes referred to as the *stiffness* of the system.**
- **The composite regulating characteristic of the system is equal to 1/β**

Primary control - summary

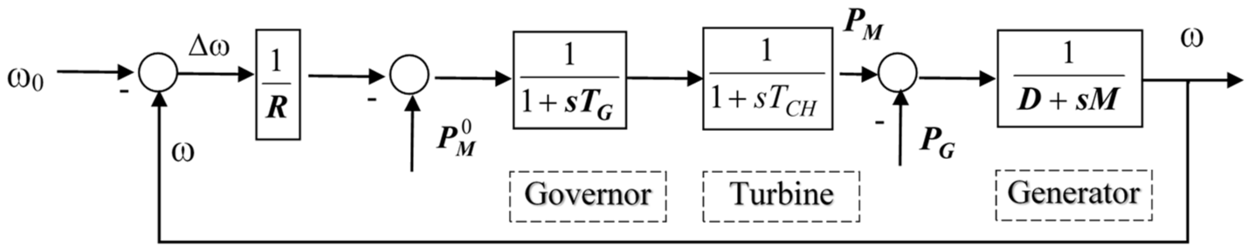
- Frequency- (speed) –control is a decentralized power control
- For its effectiveness a reserve in the valve setting is necessary
- Exhibits a proportional control behaviour

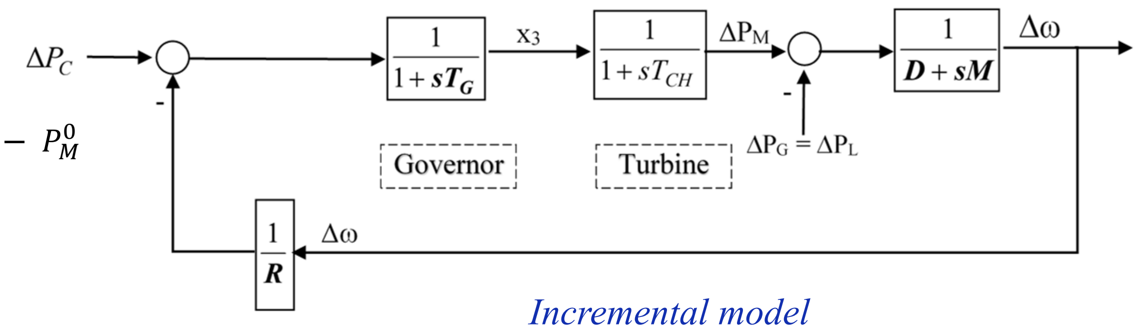
Primary control - summary

As per the German "Transmission Code"

- If f = 50 Hz ± 10 mHz (i.e. 49.99 Hz to 50.01 Hz) no control action is required
- Power plants participating in the primary control must be able to provide all the primary control power within 30 s within a quasi-stationary frequency deviation of ± 200 mHz, i.e. increase or decrease the power output in a linear manner and maintain this output up to 15 minutes
- The primary control power reserve must correspond to at least 2% of the rated capacity of the plant

Example





$\Delta P_c = P_M - P_M^0$

Incremental model

1. Assuming $\Delta P_C = 0$, what is the steady state $\Delta\omega$, if load disturbance equal to 100% occurs, i.e. $\Delta P_L = 100$ % ?

e.g. a total system load of 100 MW → 200 MW

A 100 % increase in load (power) demand will cause the frequency to drop by 5 % (2.5 Hz)

Given: R = 5%, D = 0

$$\Delta P_M = -\frac{1}{R}\,\Delta\omega$$

$$\Delta\omega = (\Delta P_M - \Delta P_L)\frac{1}{D + sM} \rightarrow$$

$$s\,\Delta\omega = \frac{1}{M}\left(-D\,\Delta\omega + \Delta P_M - \Delta P_L\right)$$

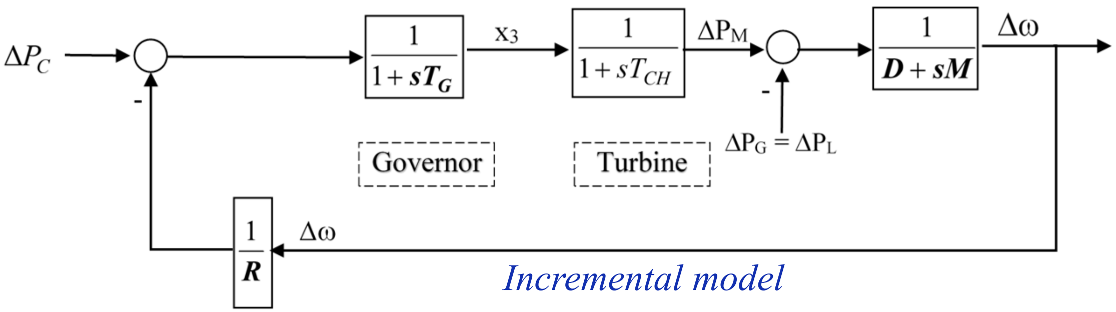
In steady state s = 0

$$0 = \frac{1}{M}\left(-D\,\Delta\omega + \Delta P_M - \Delta P_L\right) = 0 \rightarrow$$

$$-\frac{1}{R}\,\Delta\omega$$

$$\Delta\omega = \frac{-\Delta P_L}{\left(D + \frac{1}{R}\right)} = \frac{-1}{1/0.05} = -0.05 = -5\%$$

Example



$\Delta P_c = P_M - P_M^0$

Given: R = 5%, D ≠ 0; D' ≠ 0

D: machine damping coefficient
D': load frequency sensitivity factor

$$\Delta\omega = (\Delta P_M - \Delta P_L)\frac{1}{D + sM}$$

$$= \left(-\frac{1}{R}\Delta\omega - (\Delta P_L^0 + D'\,\Delta\omega)\right)\frac{1}{D + sM} \rightarrow$$

2. Assuming $\Delta P_C = 0$, what is the frequency error $\Delta\omega$, if the frequency dependency of the load is considered?

Assume $\Delta P_L = \Delta P_L^0 + D'\Delta\omega$ $\quad D' = 1\%\ (example)$

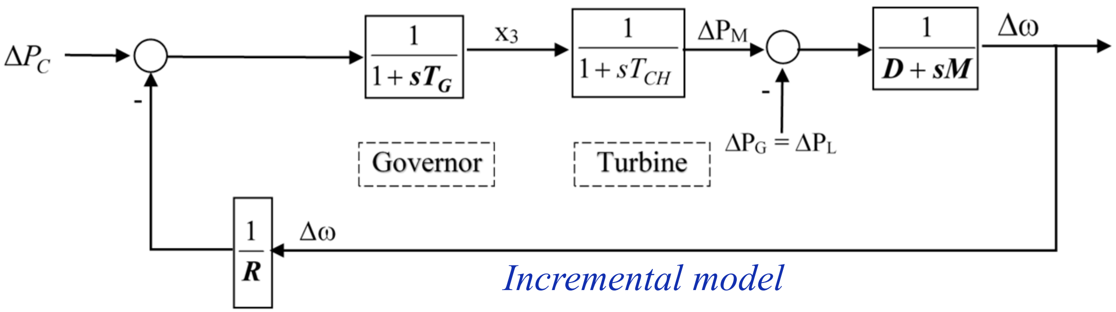
$$\Delta\omega\left(\frac{1}{R} + D' + D + sM\right) = -\Delta P_L^0 \rightarrow$$

$$\Delta\omega = \frac{-\Delta P_L^0}{\left(\frac{1}{R} + D' + D\right)} \qquad (s = 0)$$

Both the frequency dependency of the load and the machine damping coefficient reduce the speed change following a load change.

Example

$\Delta P_c = P_M - P_M^0$



Incremental model

2. What is the necessary ΔP_C, to make $\Delta\omega$ in steady state zero?

$$\Delta P_M = \Delta P_C - \frac{1}{R}\,\Delta\omega$$

$$\Delta\omega = (\Delta P_M - \Delta P_L)\frac{1}{D+sM} \rightarrow$$

$$s\,\Delta\omega = \frac{1}{M}\left(-D\,\Delta\omega + \Delta P_M - \Delta P_L\right)$$

In steady state s = 0

$$s\,\Delta\omega = \frac{1}{M}\left(-D\,\Delta\omega + \Delta P_M - \Delta P_L\right) = 0$$

$$\rightarrow\ \Delta P_M = \Delta P_L \rightarrow$$

$$\Delta P_C - \frac{1}{R}\,\Delta\omega = \Delta P_L = 1\ (for\ \Delta\omega = 0)$$

For the frequency error ($\Delta\omega$) to be zero, ΔP_C must be equal to ΔP_L. In other words, the increased power demand must be matched by a corresponding increase in generation

Secondary Frequency Control

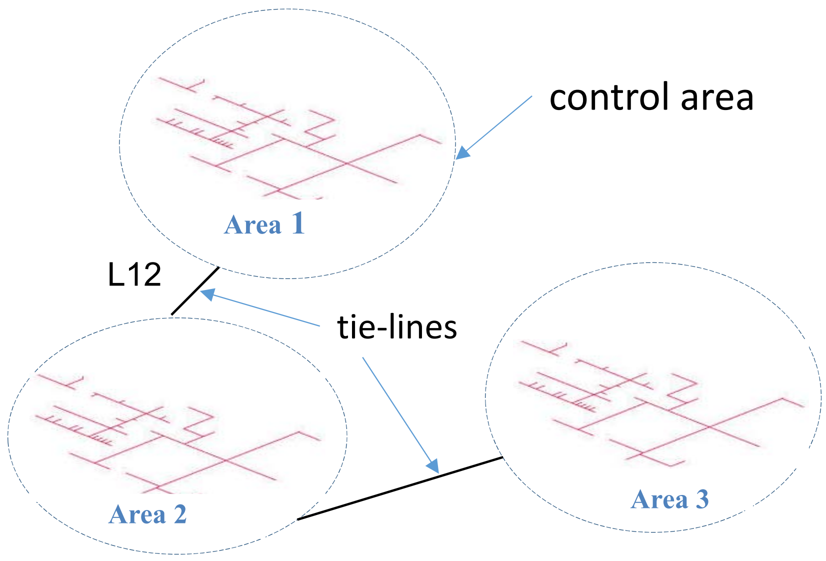
- Control area power balance
- Tie line flow
- Area control error (ACE)
- Automatic generation control (AGC)
- Characterisitc of secondray controller

Balancing Authority Areas

- A “balancing authority area” (also called a “control area”) represents the portion of the interconnected electric grid operated by a transmission entity.

- Transmission lines that join two areas are known as tie-lines.
- The net power out of an area is the sum of the flow on its tie-lines.
- The flow out of an area is equal to:

  total generation - total load - total losses = tie-line flow

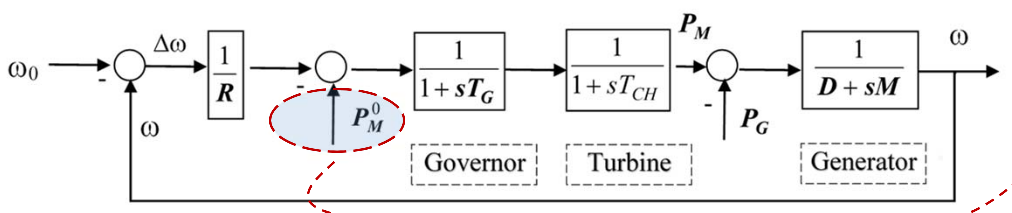


Supplementary Control of Isolated Systems

- **With primary speed control: a change in generation can occur ONLY if there is frequency deviation**
- **Restoration of frequency to rated value requires manipulation of the speed/load reference.**
- **This is achieved through supplementary control as shown in Figure 11.**
- **This control function is called „secondary control“ or „automatic generation control (AGC)“**

AGC: because the load references of generators participating on secondaary control are adjusted automatically as a result of a signal issued by the system control center

For the frequency error ($\Delta\omega$) to be zero, ΔP_C must be equal to ΔP_L. In other words, the increased power demand must be matched by a corresponding increase in generation



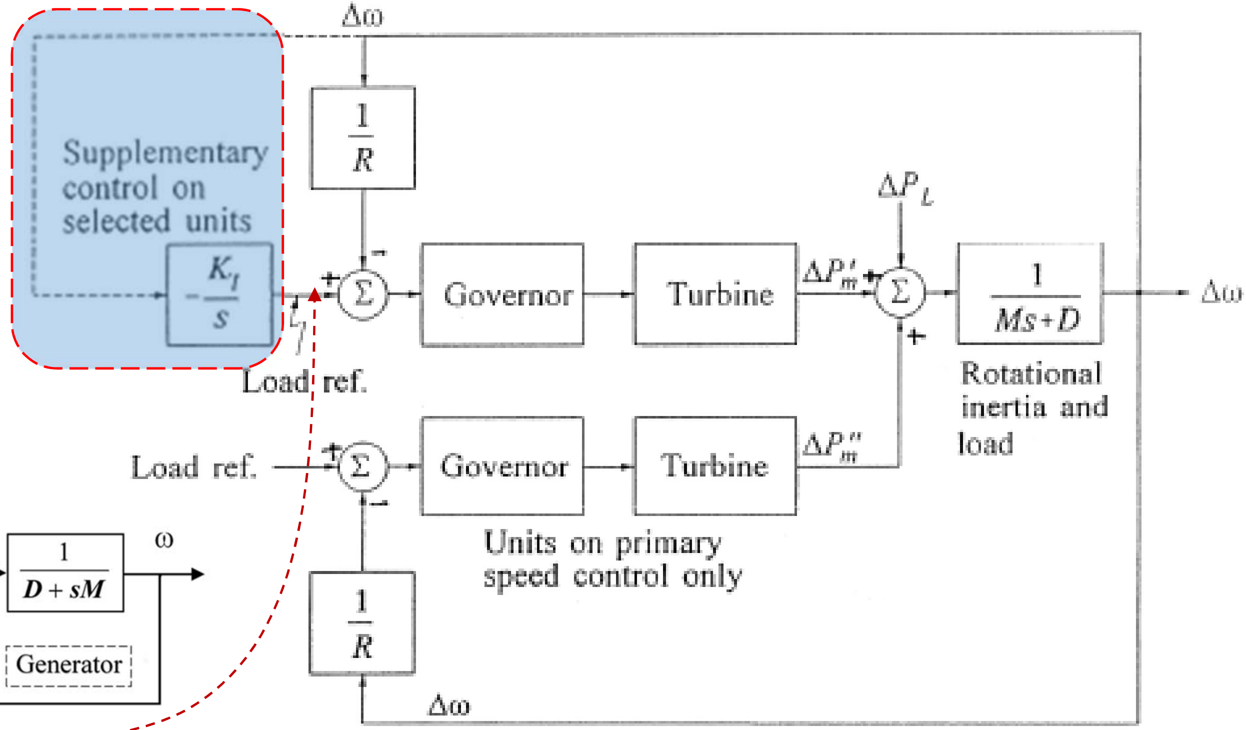


Figure 11: Addition of integral control on generating units selected for AGC

Area Control Error (ACE)

- Automatic generation control (AGC) is a major control function in the utility's energy control center aimed at:
  - adjusting the output power of one or multiple generators within the area in response to changes in the overall power demand in the system.
- A central controller takes into account:
  - the grid frequency
  - the power balance of the control area
    - then the control power required in the control area is determined and sent to the power plants designated for secondary control by means of a communication channel.

Area Control Error (ACE)

- The input to the secondary controller is the area control error (ACE). ACE is a combination of:
  - the deviation of frequency from the nominal value, and
  - the difference between the actual flow out of an area and the scheduled (agreed) flow.

$$ACE_{\mathrm{i}} = \sum -B_{\mathrm{i}}.\Delta\omega + \Delta P_{\mathrm{ij}}$$

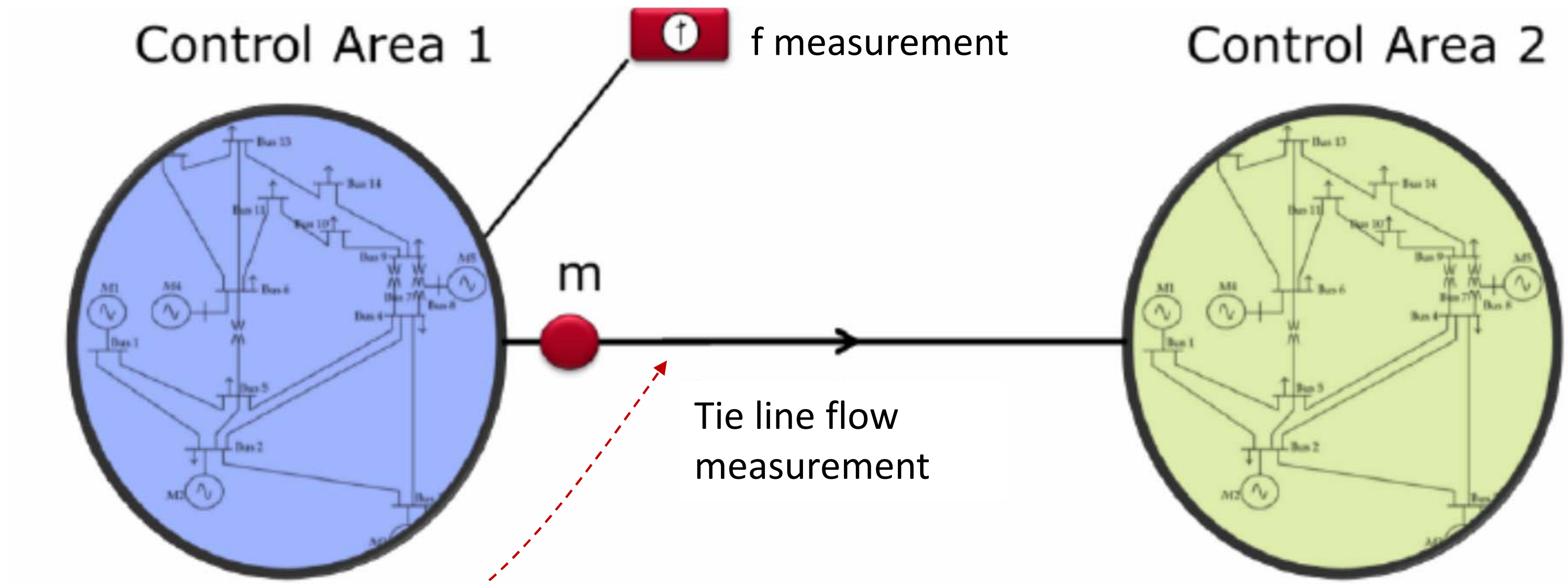
ΔP_{ij} the difference between the actual flow out of an area minus the scheduled flow

$$B_{\mathrm{i}} = D_{\mathrm{i}} + \frac{1}{R_{\mathrm{i}}} \quad \mathit{areas\ bias\ factor}$$

Area Control Error (ACE)

- This control strategy drives the frequency error to zero, i.e. $\Delta f=0$.
- The control strategy also drives transmission line flow error to zero thereby maintaining the tie-line flow at the pre-disturbance (scheduled) value.
- By so doing, the generation increases exactly matches the load increase in the areas where the load disturbance had taken place.
- Generally, this control strategy will yield a steady state response, in which each area will modulate its own generation to meet its own demand by keeping the inter-area line flows at scheduled (specified) values.

Supplementary Control of Interconnected Systems



Tie Line

- a transmission line connecting two different Control Areas is called a tie line
- all tie-lines in a system must be specified
- updated measurements of active power must be available for all tie-lines for AGC
- there may be more than one tie-line connecting two Control Areas, but only net interchange is controlled, individual tie-lines are not controlled.

Supplementary Control of Interconnected Systems

- Figure 12 illustrated calculation of ACE Bias factor, B, set nearly equal to regulation characteristic (I/R + D) of the area;
- gives good dynamic performance
- Additional function of AGC is to allocate generation economically

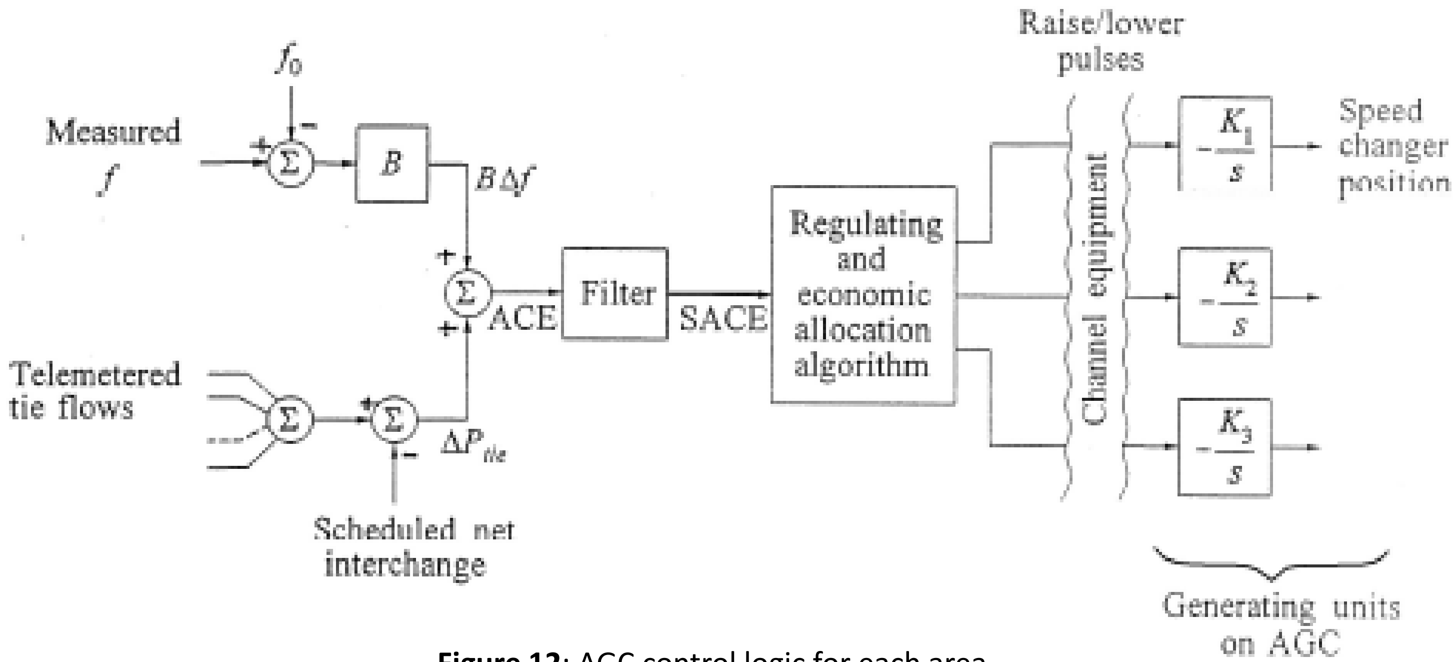


Figure 12: AGC control logic for each area

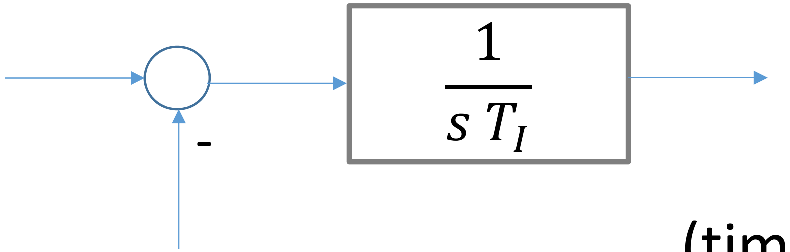
Automatic Generation Control

- Most systems use automatic generation control (AGC) to automatically change generation to keep their ACE close to zero.
- Usually the control center (either ISO or utility) calculates ACE based upon tie-line flows and frequency; then the AGC module sends control signals out to the generators every few seconds or so.

ISO: independent system operator
ACE: area control error
AGC: automatic generation control

Secondary control - summary

- Frequency- tie line power control
- One central controller for each control area
- PI- (I) Characteristics
- The control error remaining after the primary control has to be eliminated - thus I-characteristic



(time constant (T_I) in the range of several minutes)

Summary

Summary

Inertial response

- The rotating masses of all generators, turbines, motors, etc. combine to produce system inertia.

$$J\,\frac{d\omega}{dt} = T_m - T_e \;\rightarrow \frac{d\omega}{dt} = \frac{T_m - T_e}{J}$$

- The inertia of the system slows the angular acceleration of the generators – Thus the inertia of the system has a stabilizing effect.
- Asynchronous motors (in accordance with their operating principle) absorb less power when the line frequency drops, or higher power when the frequency increases.

Summary

<u>Primary control</u>

- The primary control acts within seconds of the frequency deviation exceeding 20 mHz. (Minor frequency deviations within a dead band of ±20 mHz are ignored to reduce wear and tear on turbine valves as a result of excessive activity.)
- Primary control does not require coordination between power plants; in each power plant participating on primary control, the grid frequency is measured locally and responded accordingly.
- The power change will be proportional to the deviation of the frequency
- As a proportional control, primary control reduces the frequency deviations, but does not bring them to zero.

<u>According to the German Transmission Code:</u>

- Power plants participating in the primary control must be able to provide all the primary control power within 30 s within a quasi-stationary frequency deviation of ± 200 mHz, i.e. increase or decrease the power output in a linear manner and maintain this output up to 15 minutes.
- The primary control power reserve must correspond to at least 2% of the rated capacity of the plant.
- So far, only large power plants (with more than 100 MW of power) participate on primary control
- The continental European power grid maintains in all 3000 MW reserve power for primary control.

Summary

Secondary control

- The secondary control takes place at the level of the transmission grids and reacts much slower.
- A central controller takes into account the grid frequency and the power balance of the respective control area.
- In each case, the entire control power required in the control zone is determined and distributed to the power plants slated for secondary control.
- The secondary reserve must be provided by the transmission system operators within 5 minutes to relieve the primary reserve in the event of new frequency events.
- Each TSO operates its own power frequency control, which distributes a secondary reserve requirement fully automatically.

Summary

Tertiary control

- The tertiary control (minute reserve) is used to assist and relieve the secondary control.
- Since there is enough time (approximately 15 minutes) for the request for tertiary control power following primary and secondary controls, and because it is needed less frequently, this request can be made by the transmission system operator by telephone.

Balancing authority reserve

- The extra generating capacity (spinning reserve) available by increasing the power output of generators that are already connected to the power system
- The non-spinning reserve or supplemental reserve is the extra generating capacity that is not currently connected to the system but can be brought online after a short delay. In isolated power systems, this typically equates to the power available from fast-start generators.
- However, in interconnected power systems, this may include the power available on short notice by importing power from other systems or retracting power that is currently being exported to other systems

The last resort – load shedding

- As a last resort, an unplanned load shedding for certain consumers can occur in the event of a strong underfrequency.
- There is a multi-stage plan for this (in Germany with five stages).
- Underfrequency load shedding starts with certain predetermined loads (contractually agreed loads); ordinary consumers are not affected at first.
- If the frequency continues to drop, immediate automatic load shedding occurs to further reduce the network load. This affects randomly selected smaller network areas, which are then separated from the rest of the network.
- If such emergency measures are no longer sufficient and the grid frequency continues to drop, an automatic shutdown of power plants starts. This is to avoid equipment damage due to mechanical resonances that may be caused by the incorrect speeds
- In extreme cases, the entire European network would collapse. However, this very serious case is very unlikely or only to be expected in very exceptional circumstances
- If such a collapse threatens to occur, individual networks are separated from each other in an orderly manner.