THE UNIVERSITY of ADELAIDE

Course:
ELEC ENG 3110 Electric Power Systems
ELEC ENG 7074 Power Systems PG
(Semester 2, 2021)

Power and Frequency Control (Part 2)

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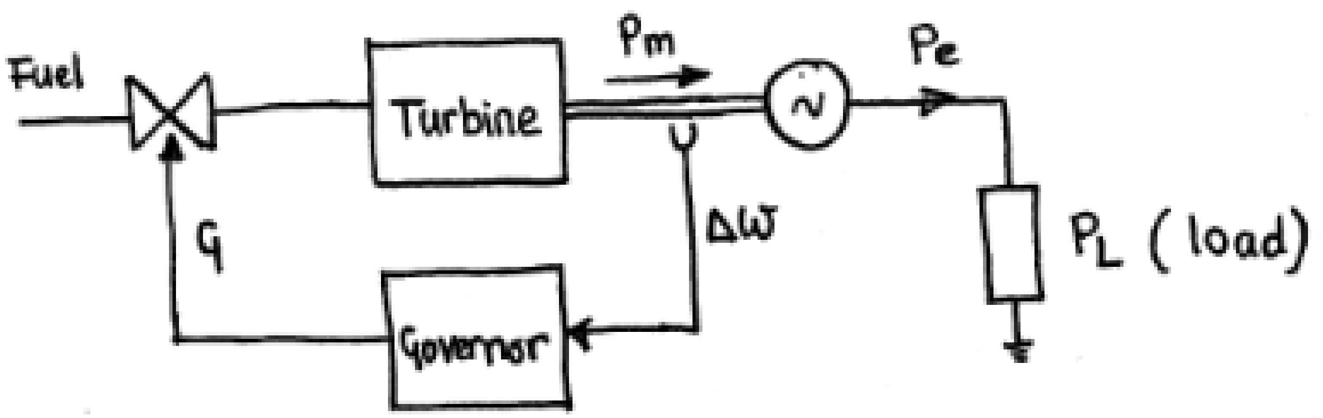
Example – Isolated Generator Supplying a Load – No Governor



Change in load ⇒ near instant change in generator electrical torque / power

⇒ mismatch between mechanical & electrical torque

⇒ speed variations according to rotor equations of motion

Example – Isolated Generator Supplying a Load – No Governor

Power system loads comprise many types of devices

- Resistive loads – lighting + heating
  - insensitive to frequency variation
- Motor loads – pumps, fans, compressors, etc
  - electrical power consumption is frequency dependent.

$$\underbrace{\Delta P_L}_{\substack{\text{Total load change} \\ (= \Delta P_e)}} = \underbrace{\Delta P_{L0}}_{\text{Frequency insensitive load change}} + \underbrace{D_L \Delta \omega}_{\text{Frequency/speed sensitive load change}}$$

$D_L \rightarrow$ load damping constant

$$\frac{\Delta P_L \text{ (pu)}}{\Delta \omega \text{ (pu)}}$$

Typically between 1.0 to 2.0 per-unit.

Example – Isolated Generator Supplying a Load – No Governor

Isolated mining site

3 × 120 MVA generators $\rightarrow S_b = 360$ MVA

200 MW load

$H = 3{\cdot}5$ pu for each unit on 120 MVA

$D_L = 1{\cdot}0$ pu

Determine the frequency response to the connection of a 9MW load, assuming no speed-governing

For the three units

$$H = 3{\cdot}5 \times \left(\frac{120}{360}\right) \times 3 = 3{\cdot}5 \text{ pu on } 360\text{MVA}$$

Include load that is connected

$$D_L = 1{\cdot}0 \times \frac{\boxed{(200+9)}}{360} = 0{\cdot}5806 \text{ pu on } 360\text{MVA}$$

Example – Isolated Generator Supplying a Load – No Governor

In generator rotor equation of motion assume generator damping constant $D=0$

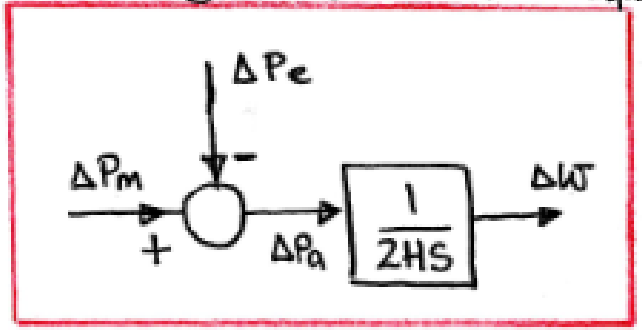
$$\frac{d\Delta\omega}{dt} = \frac{1}{2H}(\Delta P_m - \Delta P_e)$$

Take Laplace Transform $\rightarrow \frac{d}{dt} \rightarrow s$

$$\rightarrow s\,\Delta\omega = \frac{1}{2H}(\Delta P_m - \Delta P_e)$$

$$\Delta\omega = \frac{1}{2Hs}\underbrace{(\Delta P_m - \Delta P_e)}_{\substack{\Delta P_a \\ \text{accelerating power}}}$$

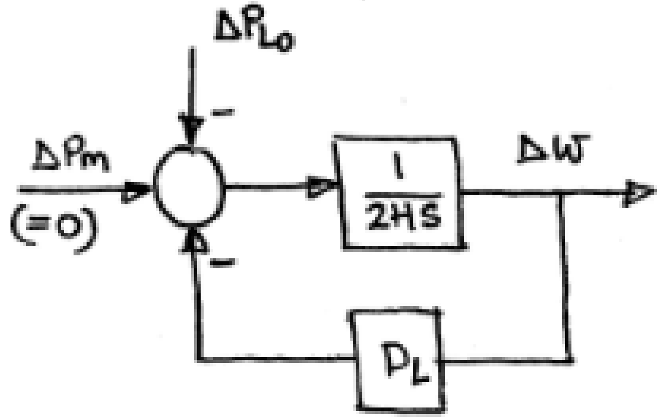
Block diagram of acceleration Eqn.



$$\Delta P_e = \Delta P_{L_o} + D_L\,\Delta\omega$$

$$\Delta\omega = \frac{1}{2Hs}(\Delta P_m - \Delta P_{L_o} - D_L\,\Delta\omega)$$

$$\Delta\omega = \frac{1}{2Hs + D_L}(\Delta P_m - \Delta P_{L_o})$$

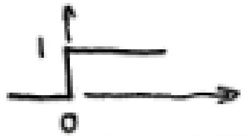


Example – Isolated Generator Supplying a Load – No Governor

Since $\Delta P_M = 0$ (no governing action)

$$\Delta\omega = -\frac{1}{2H\left(s+\frac{D_L}{2H}\right)} \cdot \Delta P_{Lo}$$

$$\delta P_{Lo} = \frac{9}{360} = 0.025 \text{ pu on } 360\,\text{MVA}$$



$\xrightarrow{\mathcal{L}}$ $\frac{1}{s}$

$$\Delta\omega = -\frac{1}{2H\left(s+\frac{D_L}{2H}\right)} \cdot \boxed{\frac{\delta P_{Lo}}{s}}$$

$\Delta P_{Lo}(s)$

Partial Fraction Expansion

$$\Delta\omega = \underbrace{-\frac{1}{2H\left(s+\frac{D_L}{2H}\right)} \cdot \frac{\delta P_{Lo}}{s}}_{\text{PRODUCT FORM}} = \underbrace{\frac{A}{\left(s+\frac{D_L}{2H}\right)} + \frac{B}{s}}_{\text{SUM FORM}}$$

- Use Heaviside cover-up method to determine residues. (ok for distinct poles)
- To determine A cover-up $\left(s+\frac{D_L}{2H}\right)$ in the product and substitute $s = -\frac{D_L}{2H}$ elsewhere $\Rightarrow$

$$A = \frac{\delta P_{Lo}}{D_L}$$

- To determine B cover-up s in the product and substitute $s = 0$ elsewhere $\Rightarrow$

$$B = \frac{-\delta P_{Lo}}{D_L}$$

- $$\Delta\omega = \frac{\delta P_{Lo}}{D_L}\left(\frac{1}{s+\frac{D_L}{2H}} - \frac{1}{s}\right)$$

Example – Isolated Generator Supplying a Load – No Governor

$$\Delta\omega(s) = -\left(\frac{\delta P_{Lo}}{D_L}\right)\left(\frac{1}{s} - \frac{1}{s+\left(\frac{D_L}{2H}\right)}\right) \xrightarrow{\mathcal{L}^{-1}} \Delta\omega(t) = -\left(\frac{\delta P_{Lo}}{D_L}\right)\left(1 - e^{-\left(t \times \frac{D_L}{2H}\right)}\right)$$

Define $T = \frac{2H}{D_L} = \frac{2 \times 3.5}{0.5806} = 12.057\ \text{s}$ Time Constant

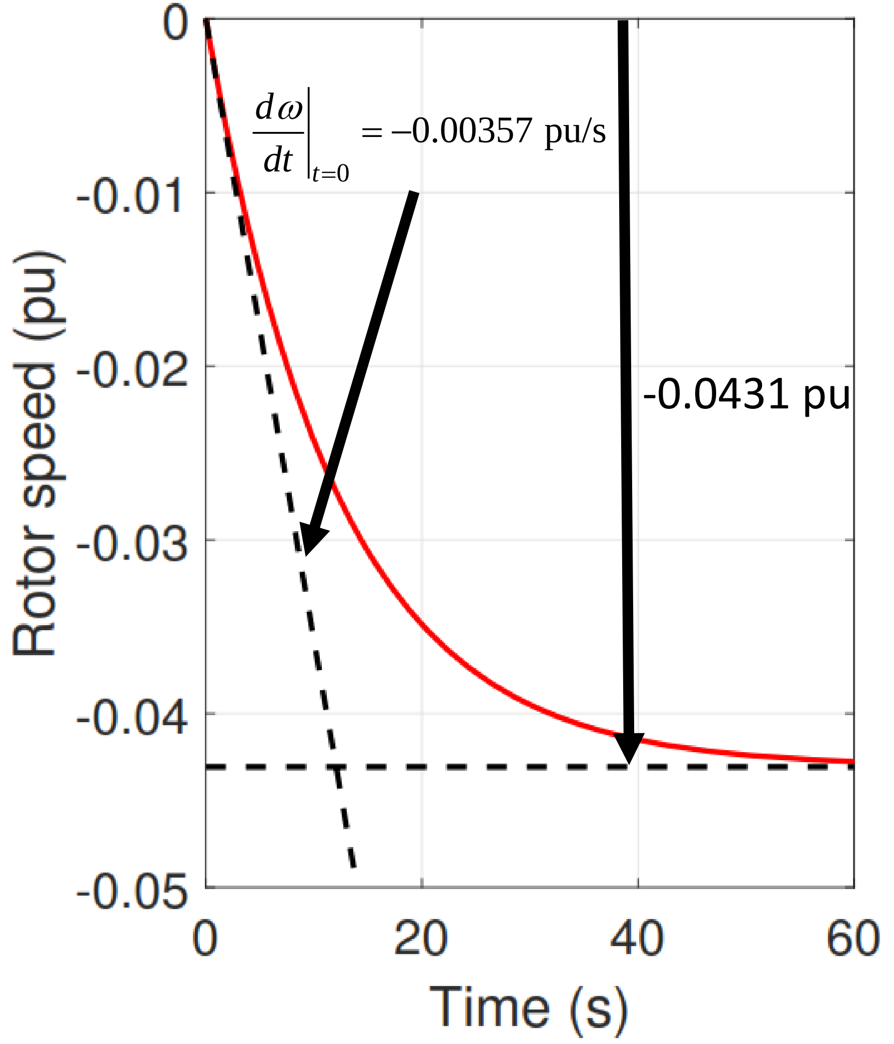
$$\delta\omega = -\left(\frac{\delta P_{Lo}}{D_L}\right) = -\left(\frac{0.025}{0.5806}\right) = -0.0431\ \text{pu}$$ Speed change

$$\Delta\omega(t) = \delta\omega\left(1 - e^{-(t/T)}\right) = -0.0431\left(1 - e^{-t/12.057}\right)$$

$$\frac{d\,\Delta\omega}{dt} = \frac{\delta\omega}{T} \cdot e^{-(t/T)}$$

At $t=0$, $$\left.\frac{d\Delta\omega}{dt}\right|_{t=0} = \frac{\delta\omega}{T} = -\left(\frac{\delta P_{Lo}}{2H}\right) = \frac{-0.025}{7} = -0.00357\ \text{pu/s}$$

Initial Rate of change of rotor-speed



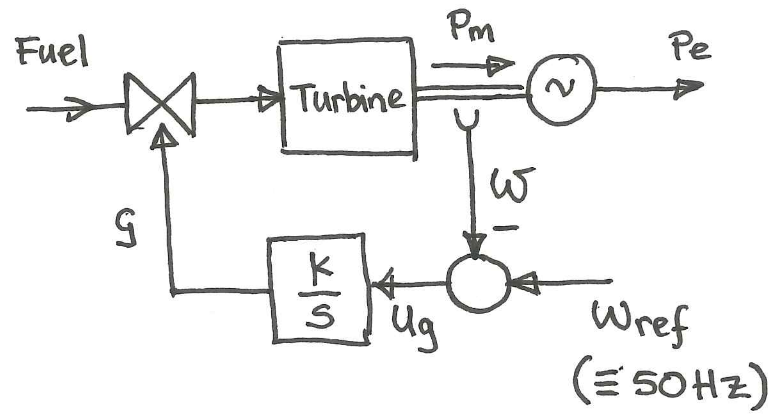
Constant Speed Governor

* Isochronous governor

* Adjusts fuel flow by adjusting valve position (G) to restore rotor-speed (i.e. frequency) to setpoint (ω_{ref})

* Speed-error $u_g = \omega_{ref} - \omega$ amplified and integrated to produce control signal G that actuates fuel supply valve.

* Due to integral action G will reach a new steady-state after a disturbance when $u_g = 0$ ($\omega = \omega_{ref} \equiv 50\text{Hz}$)



$$G = \frac{K}{s} \cdot u_g$$

$$\Rightarrow sG = K u_g \xrightarrow{\mathcal{L}^{-1}} \frac{dG}{dt} = K u_g$$

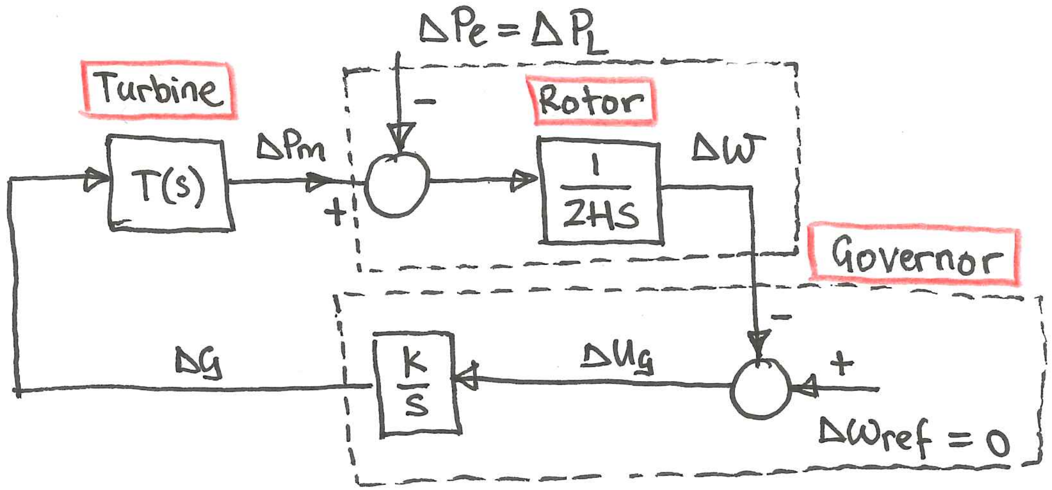
$$\text{Steady-state} \Rightarrow \frac{dG}{dt} = 0$$

$$\Rightarrow u_g = 0$$

Constant Speed Governor

Illustrative dynamic model

* Model represents perturbations from initial steady-state operating condition – P_{m_0}, $P_{e_0} = P_{L_0}$, $\omega_0 = \omega_{ref} = 1{\cdot}0$ pu (synchronous speed)



* The turbine is represented by a general transfer-function $T(s)$

* For simplicity the frequency-dependence of Loads is neglected

* The transfer-function from ΔP_L (perturbation in load) to the rotor-speed ($\Delta\omega$) is derived

Treat ΔP_L as input, $\Delta\omega_{ref} = 0$

$$\Delta P_m(s) = -T(s).\left(\frac{K}{S}\right)\Delta\omega(s)$$

$$\Delta\omega(s) = \frac{(\Delta P_m(s) - \Delta P_L(s))}{2HS}$$

$$2HS\,\Delta\omega(s) = -T(s)\,\frac{K}{S}\,\Delta\omega(s) - \Delta P_L(s)$$

$$\frac{\Delta\omega(s)}{\Delta P_L(s)} = \frac{-1}{2Hs + T(s).\left(\frac{K}{s}\right)}$$

$$= \frac{-s}{2Hs^2 + K.T(s)}$$

Constant Speed Governor

Illustrative dynamic model – Example

Suppose a step-change in load is applied

i.e. $\Delta P_L(s) = \dfrac{\delta P_L}{s}$

Then $$\Delta \omega(s) = \frac{-s}{2Hs^2 + K\,T(s)} \cdot \frac{\delta P_L}{s}$$

$$= \frac{-\delta P_L}{2Hs^2 + K\,T(s)}$$

Assuming that the poles of $\Delta\omega(s)$ are negative (i.e. system is stable) then by the final value theorem :

$$\lim_{t\to\infty} \Delta\omega(t) = \lim_{s\to 0} s\,\Delta\omega(s)$$

$$= \lim_{s\to 0} \frac{-\delta P_L\, s}{2Hs^2 + K\,T(s)}$$

$$= 0$$

This confirms the earlier point that following a disturbance to a generator with an isochronous governor the rotor will reach a new steady-state when $\Delta\omega = 0$ (i.e. $\omega = \omega_{ref}$)

The final value of ΔP_m is expected to be $\Delta P_m = \delta P_L$

– Explain why

Constant Speed Governor

Illustrative dynamic model - Example

Derive the transfer-function for the turbine-governor-generator model in which the turbine transfer-function is

$$T(s) = \underbrace{\left(\frac{1+sT_A}{1+sT_B}\right)}_{\text{Governor Phase compensation}} \underbrace{\frac{1}{(1+sT_T)}}_{\text{Turbine characteristic}}$$

$$\frac{\Delta\omega(s)}{\Delta P_L(s)} = \frac{-s}{2Hs^2 + \underline{KT(s)}} \;..$$

$$= \frac{-s}{2Hs^2 + \boxed{\dfrac{K(1+sT_A)}{(1+sT_B)(1+sT_T)}}}$$

$$\frac{\Delta\omega(s)}{\Delta P_L(s)} = \frac{-s(1+sT_B)(1+sT_T)/K}{\left(\frac{2H}{K}\right)s^2(1+sT_B)(1+sT_T) + 1}$$

Example parameters:

$H = 3{\cdot}5$ pu.s, $T_T = 0{\cdot}5$ s, $K = 0{\cdot}2$ pu.s

$T_A = 10$ s, $T_B = 1$ s

Calculate and plot the time-response of the rotor-speed ($\Delta\omega(t)$) and mechanical power ($\Delta P_m(t)$) perturbations due to a 5% step increase in the load (i.e. $\Delta P_L(t) = 0{\cdot}05\,\underbrace{u(t)}_{\text{unit-step}}$)

Constant Speed Governor

Example time-response

* Following step-increase in load the generator rotor decelerates

$$\frac{d\Delta\omega}{dt} = \frac{1}{2H}(\Delta P_m - \Delta P_e) < 0$$

$\Rightarrow \Delta\omega$ decreases

* Governor, in response to $\Delta\omega < 0$ begins to open valve to increase fuel flow $\Rightarrow$ begin to increase ΔP_m

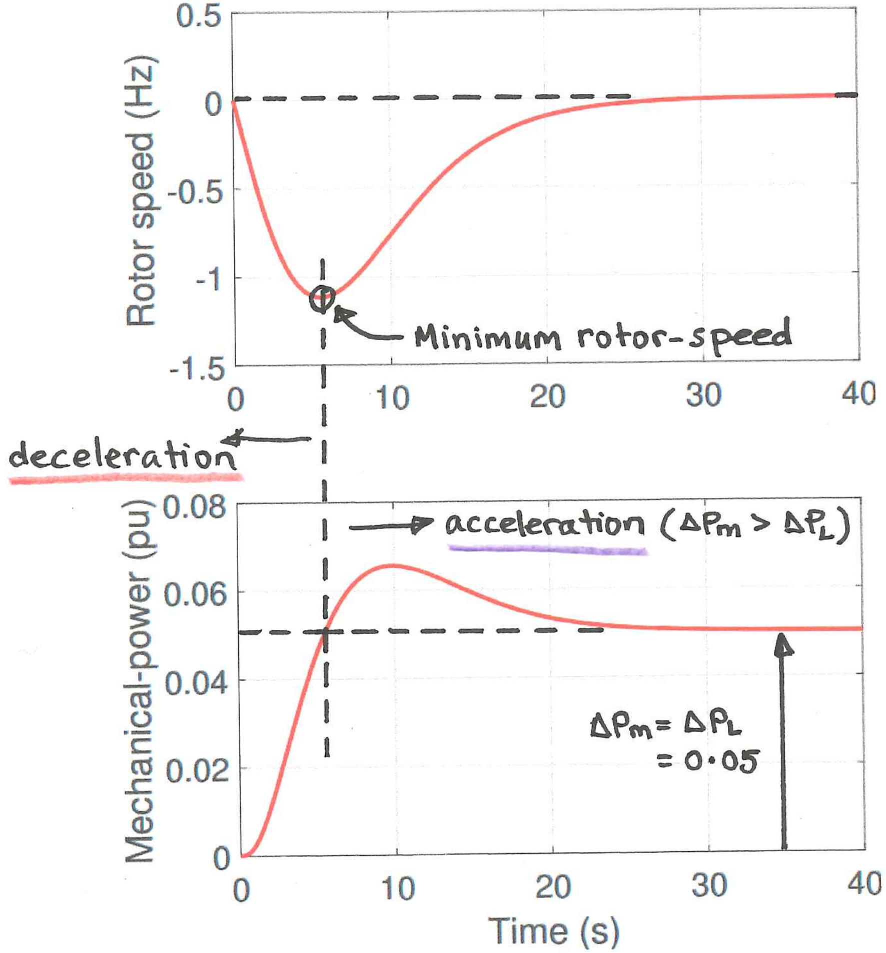
* At $t = 5{\cdot}48$ s $\Delta P_m = \Delta P_e = \Delta P_L = 0{\cdot}05$ pu

  $\Rightarrow$ minimum frequency (rotor-speed)

* For $t > 5{\cdot}48$s, $\Delta P_m > \Delta P_L \Rightarrow$ acceleration

  $\Rightarrow$ rotor-speed begins to increase

* Due to integral control speed returns to synchronous speed (i.e. $\Delta\omega = 0$).

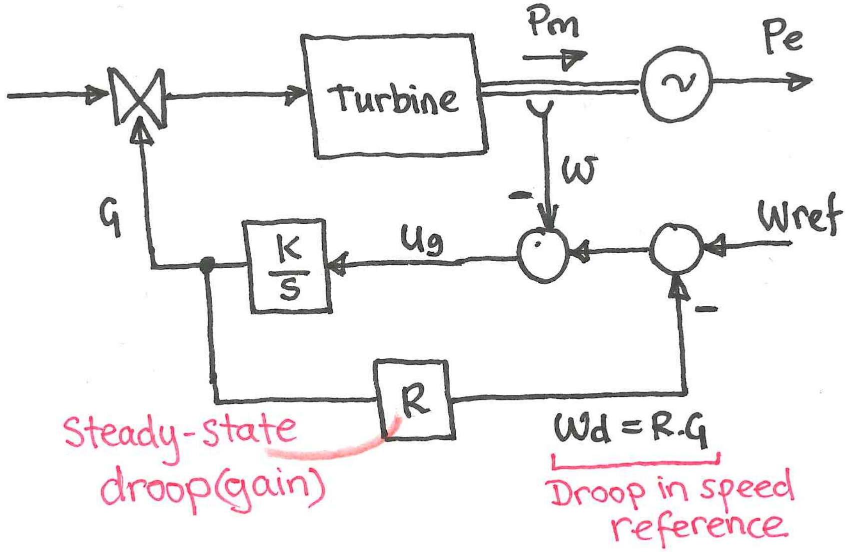


Governors with steady-state droop Characteristic

* Two or more generators operating in parallel cannot use isochronous governors
  - → multiple units attempting to reduce their measurement of the speed-error signal to zero
  - → small differences in measurement and/or setpoint between units results in sustained ramping of mechanical power of the interconnected generators
  - → controllers 'fight' for control of common system frequency (i.e. common rotor synchronous speed)

Solution – introduce steady-state droop characteristic so that interconnected machines 'share' the load.

The speed reference of the governor is reduced in proportion to the control valve opening



Governors with steady-state droop

* Suppose the generating unit is operating with steady-state gate position and power output of G_0 and $P_{m_0} = P_{e_0}$ respectively and that the machine is spinning at synchronous speed - $\omega_0 = 1$ pu.

* Suppose now that the rotor-speed is changed by $\Delta\omega$.

* What is the associated change in gate position?

* $u_g = (\omega_{ref} - R(G_0 + \Delta G)) - (\omega_0 + \Delta\omega)$

* The final value of $u_g = 0 \Rightarrow$

$$\omega_0 + \Delta\omega = \omega_{ref} - R(G_0 + \Delta G)$$
$$= \underbrace{(\omega_{ref} - R \cdot G_0)}_{\omega_0} - R\Delta G$$

* $\Delta\omega = -R\Delta G$

* $\Delta G = -\dfrac{\Delta\omega}{R}$

* Thus, the value of R (droop) determines the steady-state relationship between rotor-speed and turbine valve position.

* Since, under steady-state conditions the valve position G_0 is related to the turbine power P_{m_0} and for small perturbations

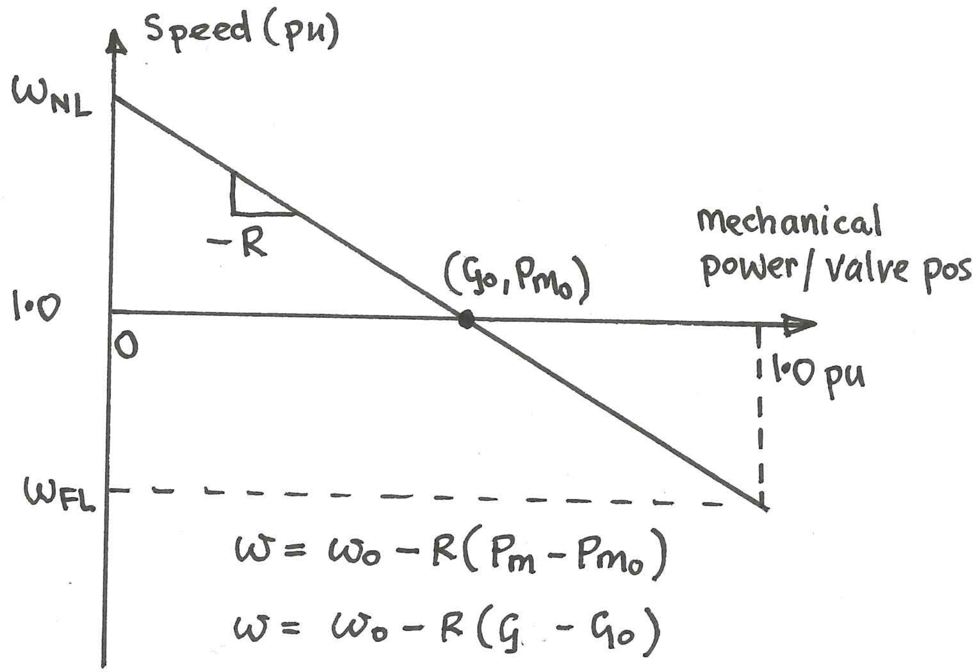
$$\Delta P_m = K_t \cdot \Delta G$$

it follows that

$$\Delta P_m = -\left(\frac{K_t}{R}\right) \cdot \Delta\omega$$

Governors with steady-state droop Characteristic

* In the ideal case – which is well approximated in modern governors – the perturbation relationships above extend over the full range of valve opening / power output



Governor steady-state characteristic

* For the ideal case :

$$G = G_0 + \Delta G = G_0 - \left(\frac{\omega - \omega_0}{R}\right)$$

* With appropriate choice of base values $K_t = 1$ and

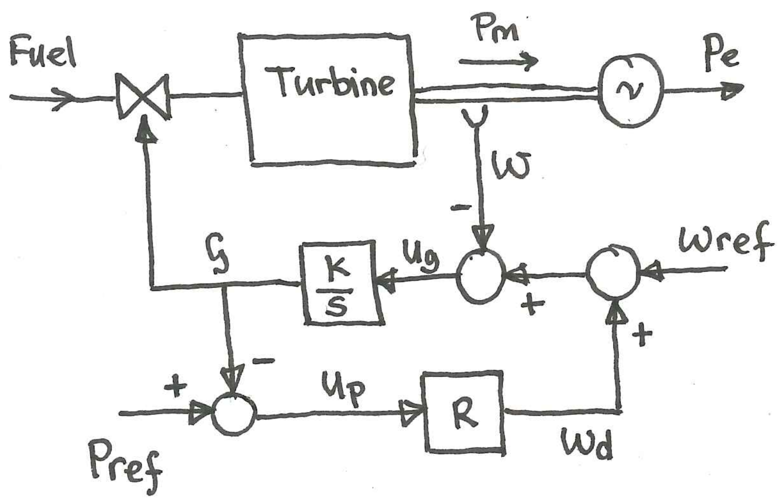
$$P_m = P_{m_0} - \left(\frac{\omega - \omega_0}{R}\right)$$

$$\boxed{R = \frac{\text{p.u. decrease in speed}}{\text{p.u. increase in turbine power output}}}$$

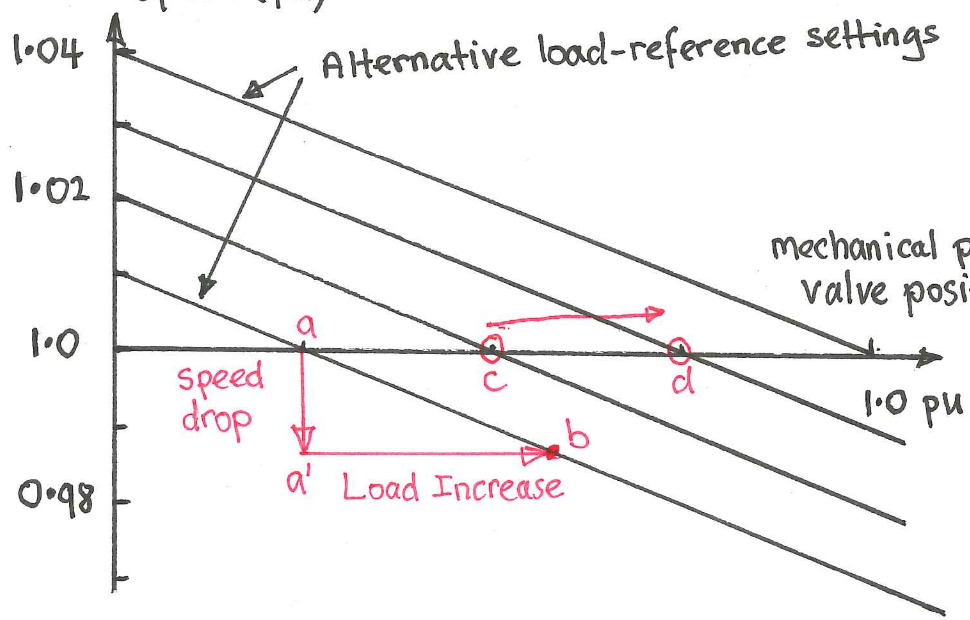
R → Droop

Governors with steady-state droop characteristic

Control of power output → Load reference



(Load-reference)



c → d Load increase, constant speed – Load reference

a → a' → b Load increase ⇒ speed drop ⇒ increase in turbine output (a → b)

* Under steady-state conditions

$\omega = \omega_{ref} = 1$ pu (synchronous speed)

* $u_g = 0 = (\omega_{ref} + \omega_d - \omega) = \omega_d$

* $u_p = 0 \Rightarrow g_0 = P_{ref}$

Governors with steady-state droop characteristic

Illustrative dynamic model

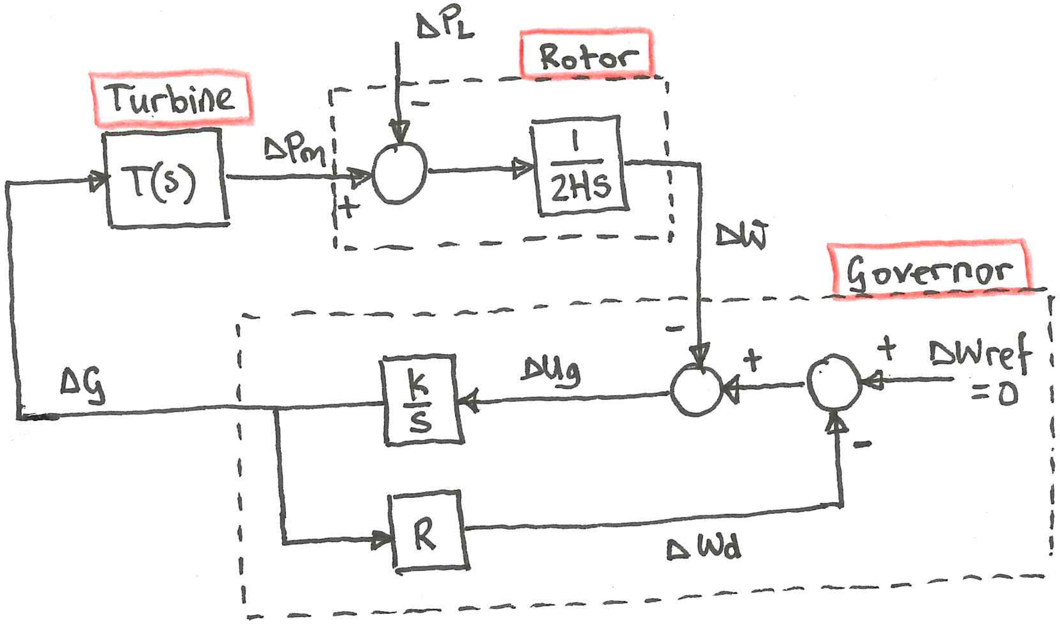
* Model represents perturbations from initial steady-state operating condition – P_{m_0}, $P_{e_0} = P_{L_0}$, $\omega_0 = \omega_{ref} = 1{\cdot}0$

* Turbine represented by general TF $T(s)$ – assumed to be proper.

* Neglect frequency-dependence of loads

* Derive TF from ΔP_L (load-perturbation) to rotor-speed ($\Delta\omega$)

* Assume that the steady-state gain of $T(s)$ is unity (i.e. $\Delta P_m = \Delta G$ in steady-state)



$$\Delta u_g = -(\Delta\omega + R\,\Delta G)$$

$$\Delta G = \frac{K}{s}\Delta u_g = -\frac{K}{s}(\Delta\omega + R\,\Delta G)$$

$$\Delta G = \frac{-(1/R)}{1+sT_g}\Delta\omega \quad , \quad T_g = \frac{1}{KR}$$

$$\Delta P_m = T(s).\Delta G = \frac{-(1/R)}{1+sT_g}.T(s).\Delta\omega$$

Governors with steady-state droop characteristic

Illustrative dynamic model – continued

$$\Delta\omega = \frac{\Delta P_m - \Delta P_L}{2Hs}$$

$$2Hs\,\Delta\omega = \frac{-(1/R)}{1+sT_g}\cdot T(s)\cdot\Delta\omega - \Delta P_L$$

$$\left[2Hs(1+sT_g) + (1/R)\cdot T(s)\right]\Delta\omega = -(1+sT_g)\,\Delta P_L$$

$$\frac{\Delta\omega}{\Delta P_L} = \frac{-(1+sT_g)}{2HT_g s^2 + 2Hs + (1/R)T(s)}$$

Find the final steady-state rotor-speed deviation following a step-change in load

$$\Delta P_L(s) = \frac{\delta P_L}{s}$$

$$\therefore \quad \Delta\omega = \frac{-(1+sT_g)}{2HT_g s^2 + 2Hs + (1/R)T(s)}\cdot\frac{\delta P_L}{s}$$

By the final value theorem (assuming the system is stable)

$$\Delta\omega(t\to\infty) = \lim_{s\to 0} s\,\Delta\omega(s)$$

$$= \lim_{s\to 0} \frac{-(1+sT_g)\,\delta P_L}{2HT_g s^2 + 2Hs + (1/R)T(s)}$$

$$= -R.\delta P_L$$

i.e. $\delta\omega = -R\,\delta P_L$

Confirming our earlier steady-state analysis.

Illustrative dynamic model

Derive the transfer-function for the turbine-governor-generator model in which the turbine TF is

$$T(s) = \frac{1}{1+sT_t}$$

$$\frac{\Delta\omega}{\Delta P_L} = \frac{-(1+sT_g)}{2HT_g s^2 + 2Hs + \frac{1}{R}T(s)}$$

$$= \frac{-(1+sT_g)(1+sT_t)/R}{2HRT_g s^2(1+sT_t) + 2HRs(1+sT_t) + 1}$$

$$= \frac{-(1/R)(1 + s(T_g+T_t) + s^2 T_g T_t)}{(2HRT_gT_t)s^3 + 2HR(T_g+T_t)s^2 + (2HR)s + 1}$$

Example parameters –

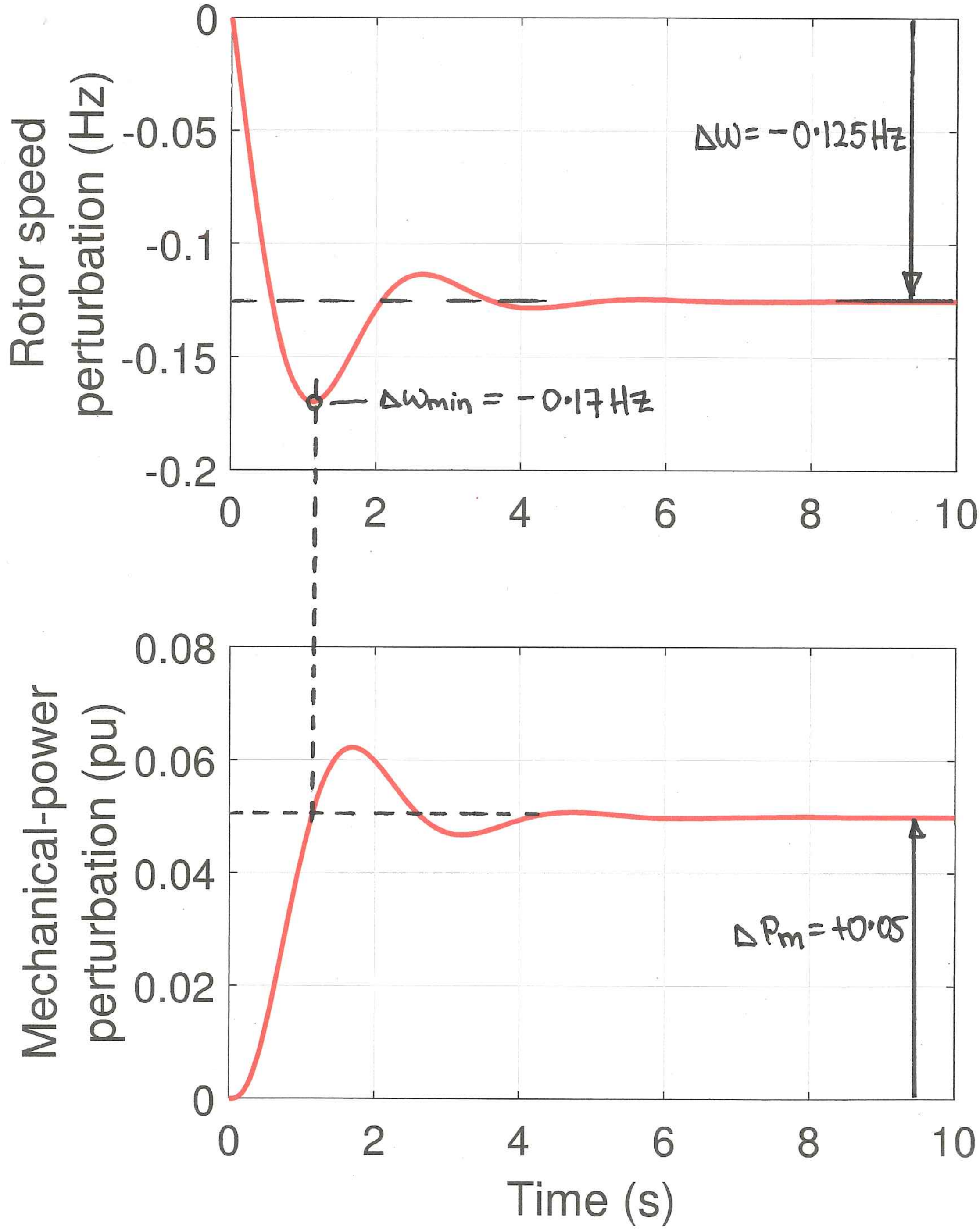
Representative of steam turbine without reheat

$H = 5.0$ pu.s, $T_T = 0.3$ s, $R = 0.05$ pu

$T_g = 0.2$ s

Calculate and plot the time-response of the rotor-speed ($\Delta\omega$) and mechanical power (ΔP_m) perturbations due to a 5% step increase in the load – $\Delta P_L = 0.05\, u(t)$

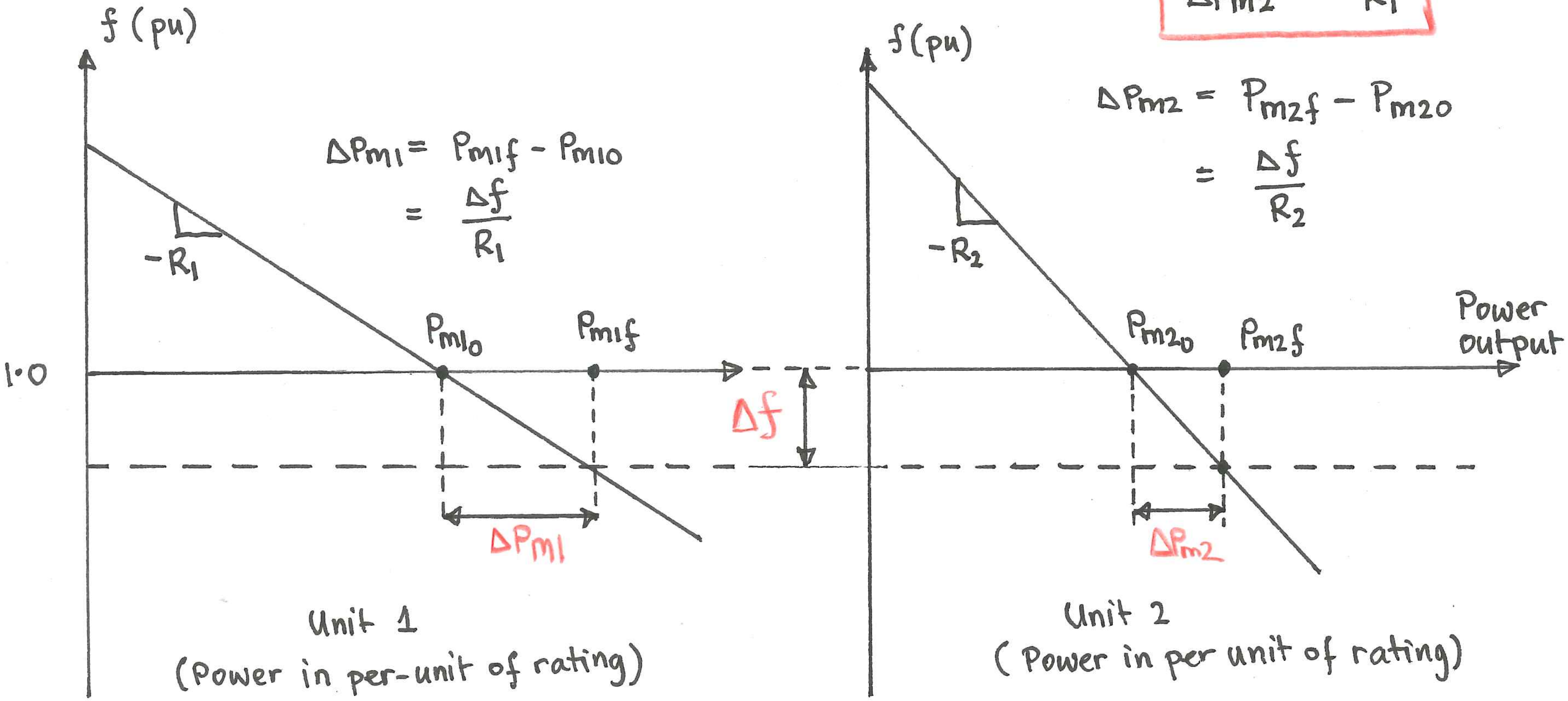
unit step.


0
-0.05
-0.1
-0.15
-0.2
Rotor speed perturbation (Hz)
ΔW = −0·125 Hz
ΔWmin = −0·17 Hz
0
2
4
6
8
10
0.08
0.06
0.04
0.02
0
Mechanical-power perturbation (pu)
ΔPm = +0·05
0
2
4
6
8
10
Time (s)

Consider two units with steady-state governor characteristics as shown below.

* Initial steady-state operation @ synchronous speed and outputs P_{m10} and P_{m20}.
* The load picked up by each generator depends on their respective droop characteristics

$$\boxed{\frac{\Delta P_{m1}}{\Delta P_{m2}} = \frac{R_2}{R_1}}$$



Unit 1
(Power in per-unit of rating)

Unit 2
(Power in per unit of rating)

Parallel Operation of Synchronous Generators

* From previous slide, the amount of load picked up by generators following a frequency change depends on their respective droop characteristics

$$\boxed{\frac{\Delta P_{m1}}{\Delta P_{m2}} = \frac{R_2}{R_1}}$$

* If the droop settings of the units are approximately equal (in per-unit of rating) then the units will share the required change in power output in proportion to their respective ratings – which is most desirable

Example : Two prime-movers supply an isolated 50Hz. Their ratings are 100 MW and 300 MW respectively and their initial outputs are 50 MW and 250MW respectively. The governor droop settings are 4% (i.e. R = 0·04 pu) on turbine rating.

what is the system frequency and what are the generator outputs following a 12 MW load increase.

$$\Delta P_L = \Delta P_{m1} + \Delta P_{m2} = 12 \text{ MW}$$

$$= -\frac{\Delta \omega}{R_1} - \frac{\Delta \omega}{R_2} = 12 \text{ MW}$$

$$R_1 = \frac{0{\cdot}04}{100} \text{ pu/MW} , \quad R_2 = \frac{0{\cdot}04}{300} \text{ pu/MW}$$

Parallel Operation of Synchronous Generators

$$-\Delta\omega\left(\frac{1}{R_1}+\frac{1}{R_2}\right) = 12 \text{ MW}$$

$$\Delta\omega = \frac{-12}{\frac{1}{R_1}+\frac{1}{R_2}}$$

$$= \frac{-12 * 0{\cdot}04}{100 + 300}$$

$$= \frac{-12 * 0{\cdot}04}{400}$$

$$= -1{\cdot}2 \times 10^{-3} \text{ pu}$$

$$= -0{\cdot}06 \text{ pu}$$

$$\Delta P_{m1} = \frac{1{\cdot}2\times10^{-3}}{R_1} = \frac{1{\cdot}2\times10^{-3}}{0{\cdot}04} = 0{\cdot}03 \text{ pu on } 100\text{MW}$$

$$\Delta P_{m2} = \frac{1{\cdot}2\times10^{-3}}{R_2} = \frac{1{\cdot}2\times10^{-3}}{0{\cdot}04} = 0{\cdot}03 \text{ pu on } 300\text{MW}$$

$$\Delta P_{m1} = 3 \text{ MW}$$

$$\Delta P_{m2} = 9 \text{ MW}$$

The increase in load is shared between the two generators in proportion to their respective ratings. This is a consequence of their governor droop settings being the same (on unit rating)

System Frequency Regulation

* Interested in combined performance of all generators in the system.

* Neglect intermachine oscillations and transmission system behaviour

* Assume that all generators respond coherently – i.e. rotor-speeds of all machines are assumed to be equal and also equal to the system frequency.

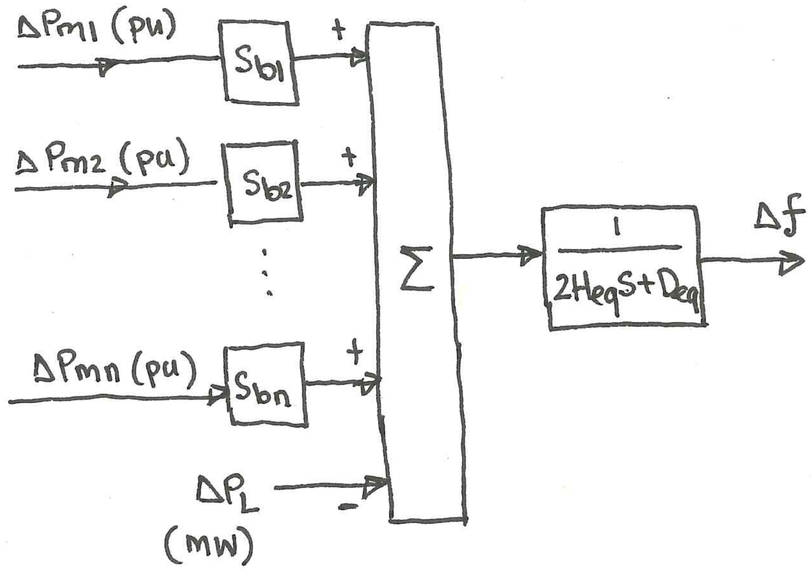
* Composite generator with inertia constant

$$H_{eq} = \sum_{i=1}^{n} (H_i * S_{bi}) \quad MW.s$$

* Composite load damping constant

$$D_{eq} = \frac{\Delta P_L \ (MW)}{\Delta f \ (pu)}$$

*



Composite system model for analysis of load-frequency controls

System Frequency Regulation

* Composite power/frequency characteristic of the system depends on combined effect of all generator speed-droop settings.

* The steady-state frequency deviation following a load change is derived as follows:

$$\Delta P_L = \sum_{i=1}^{n} \Delta P_{mi} - D_{eq}\,\Delta f$$

$$= -\Delta f \left[\underbrace{\sum_{i=1}^{n} \left(\frac{S_{bi}}{R_i} \right)}_{1/R_{eq}} + D_{eq} \right]$$

$$\therefore \Delta f = \frac{-\Delta P_L}{1/R_{eq} + D_{eq}}$$

* S_{bi} is the MVA base of the i^{th} generator, and is the base on which the droop R_i and inertia constant H_i are specified.

* The load damping characteristic is expressed as

$$D_{eq} = \frac{\Delta P_L \ (\text{mw})}{\Delta f \ (\text{pu})}$$

in the equation for Δf

However, the load-frequency sensitivity is given as

$$D_L = \frac{\%\ \text{change in load}}{\%\ \text{change in frequency}}$$

$\therefore D_{eq} = D_L * P_L$ where P_L is the total system load (mw) after any load change.

System Frequency Regulation

$$\Delta f = \frac{-\Delta P_L}{\frac{1}{R_{eq}} + D_{eq}} = \frac{-\Delta P_L}{k_{eq}}$$

$k_{eq} = \frac{1}{R_{eq}} + D_{eq}$ is the (frequency) stiffness of the system. The higher k_{eq} the lower is the frequency change for a given load change.

Example

Total system load 2000 MW at 50 Hz. The load increases by 1% for every 1% increase in frequency. Find the steady-state frequency deviation when 100 MW is suddenly connected.

(1) Assume all synchronous generation (2500 MW) is governing and that the droop settings are identical and equal to 4% on unit rating.

$$1/R_{eq} = \frac{2500}{0.04} \text{ MW/pu.}$$

$$D_{eq} = 1.0 \times 2\ 00 \text{ MW/pu}$$

$$k_{eq} = \frac{1}{R_{eq}} + D_{eq}$$

$$= \frac{2500}{0.04} + 2\ 00 = 64{,}600$$

$$\Delta f = -\frac{\Delta P_L}{k_{eq}} \text{ pu}$$

$$= -\frac{100}{64{,}600} \text{ pu}$$

$$= -1.548 \times 10^{-3} \text{ pu}$$

$$\Delta f = -0.0774 \text{ Hz}$$

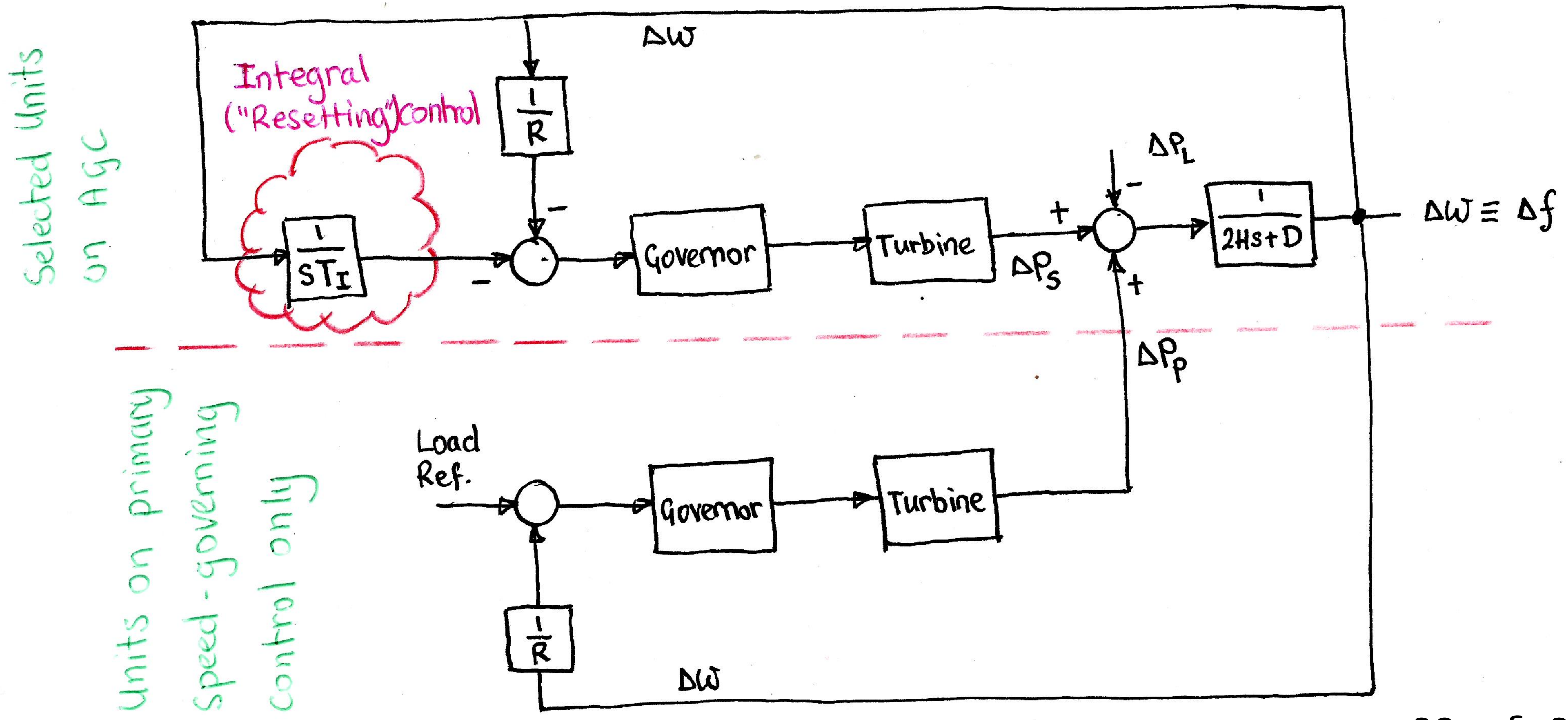
Primary, Secondary & Tertiary Frequency Controls

* Governor action — "primary control"
  - Due to droop characteristic there is a steady-state deviation in frequency
  - All generating units enabled for speed governing will contribute (more-or-less equally in proportion to unit rating) to the overall change in generation.
    - Irrespective of the location of change in load that causes the governing units to change output
    - Interconnector Power flows changed

Primary, Secondary & Tertiary Frequency Controls

* Automatic Generation Control (AGC) – "Secondary Control".

→ Restoration of system frequency to nominal (e.g. 50 Hz) requires supplementary control ⇒ AGC



Primary, Secondary & Tertiary Frequency Controls

* AGC (continued)

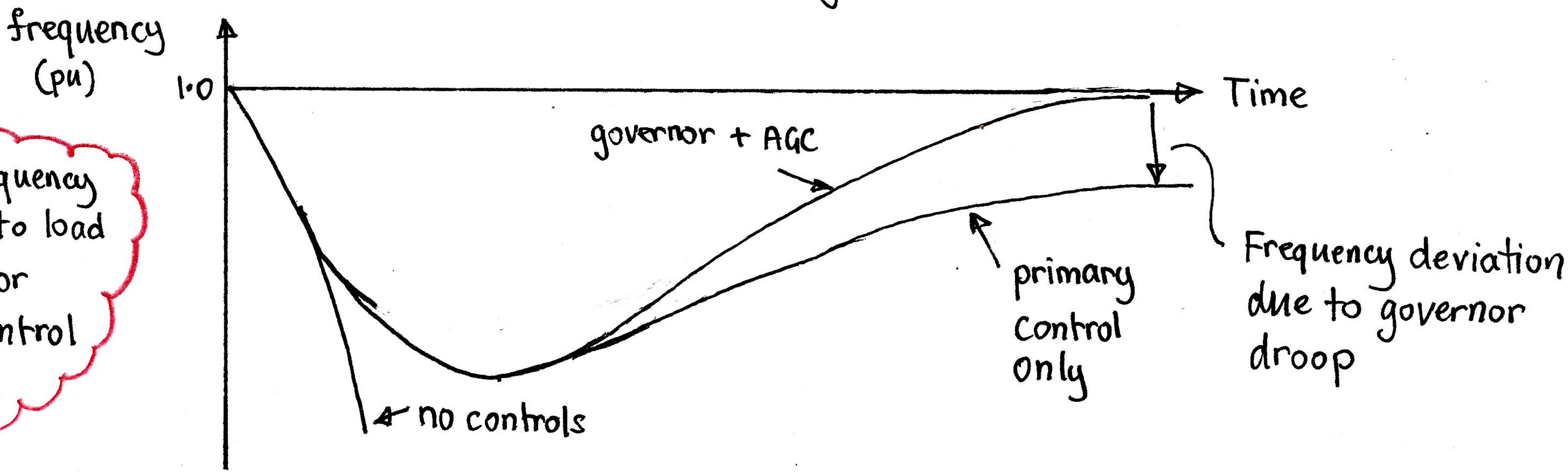
  → Selected units under AGC

  → Load set-points of AGC units automatically adjusted in response to frequency error.

  → AGC is integral (i.e. reset) control

  ▷ Frequency error ($-\Delta\omega$) reduced to zero in steady-state.

System frequency response to load increase for various control regimes



Primary, Secondary & Tertiary Frequency Controls

* Security constrained market disp — "Tertiary Control"
  → Centralized control system that determines change in generator outputs required to meet trend change in load
    - Generation dispatch determined in response to bids (\$/MWh) from generators to
      * achive least cost
      * subject to security constraints.
    - Dispatch orders sent to generators
      * respond by adjusting load reference set-points in a ramp-like fashion over the dispatch interval (~ 5min)

Primary, Secondary & Tertiary Frequency Control

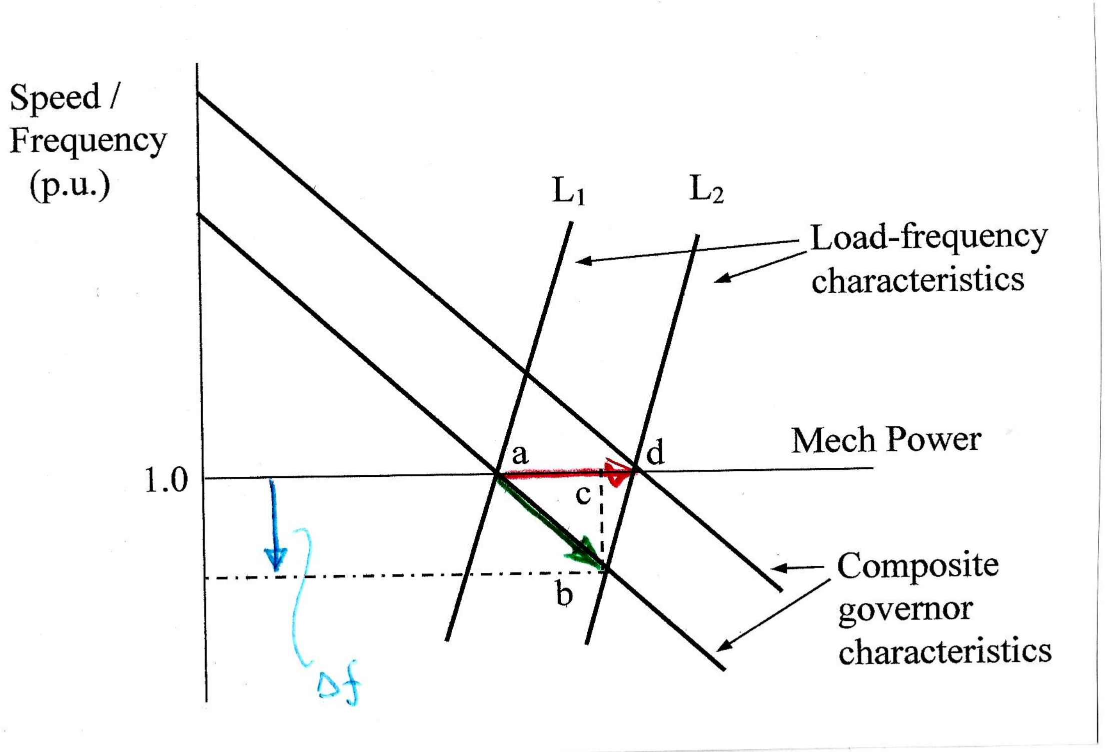
* Primary, Secondary & Tertiary controls act in concert and merge roughly into the following time frame

Excitation controls & rotor dynamics	0 – 5 seconds
Governor action & AGC	~2 s to ~3 min
Market Dispatch & boiler controls of steam turbines	2 min to 5+ minutes (Dispatch cycle: 5 min)

Primary, Secondary & Tertiary Frequency Controls

Summary of control actions

→ Consider a load increase a→d at 50 Hz



Governor action

* Accommodated by fall in frequency until a steady-state condition is reached at b due to governors
  - Due to load-frequency characteristic actual load increase (a→c) less than load increase at 50 Hz.
  - Mechanical power increase equivalent to a → c

AGC action

* Units on AGC receive orders to increase their load reference inputs.
  - Units with governors only return from b → a
  - AGC units take up load increase a → d

Market Dispatch

* Security constrained market dispatch
  - Load set-points of most cost-effective units increased to meet trend increase in load
  - AGC units reduce their outputs in response.