ECE 522 - Power Systems Analysis II
Spring 2021

Frequency Regulation and Control

Spring 2021

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Content

- Modeling the speed governing system of a generator
- Automatic generation control (AGC)
- Under-frequency load shedding (UFLS)

- References:
  – Chapter 11.1 of Kundur's book
  – Chapter 12 of Saadat's book
  – Chapter 4 (Frequency Control) of EPRI Tutorial

Generator Control Loops

- For each generator,
  - Load Frequency Control (LFC) loop controls the frequency (or real power output)
  - Automatic Voltage Regulator (AVR) loop controls the voltage (or reactive power output)

- The LFC and AVR controllers are set for a particular steady-state operating condition to maintain frequency and voltage against small changes in load demand.

- Cross-coupling between the LFC and AVR loops is negligible because the excitation-system time constant is much smaller than the prime mover/governor time constants

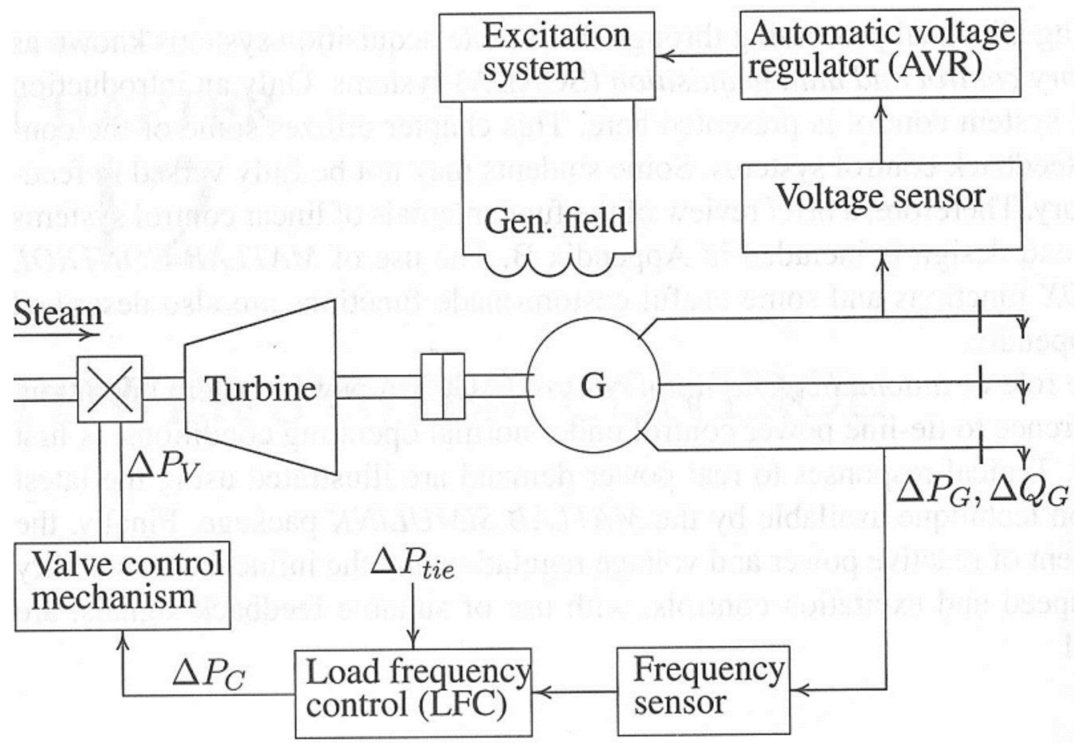


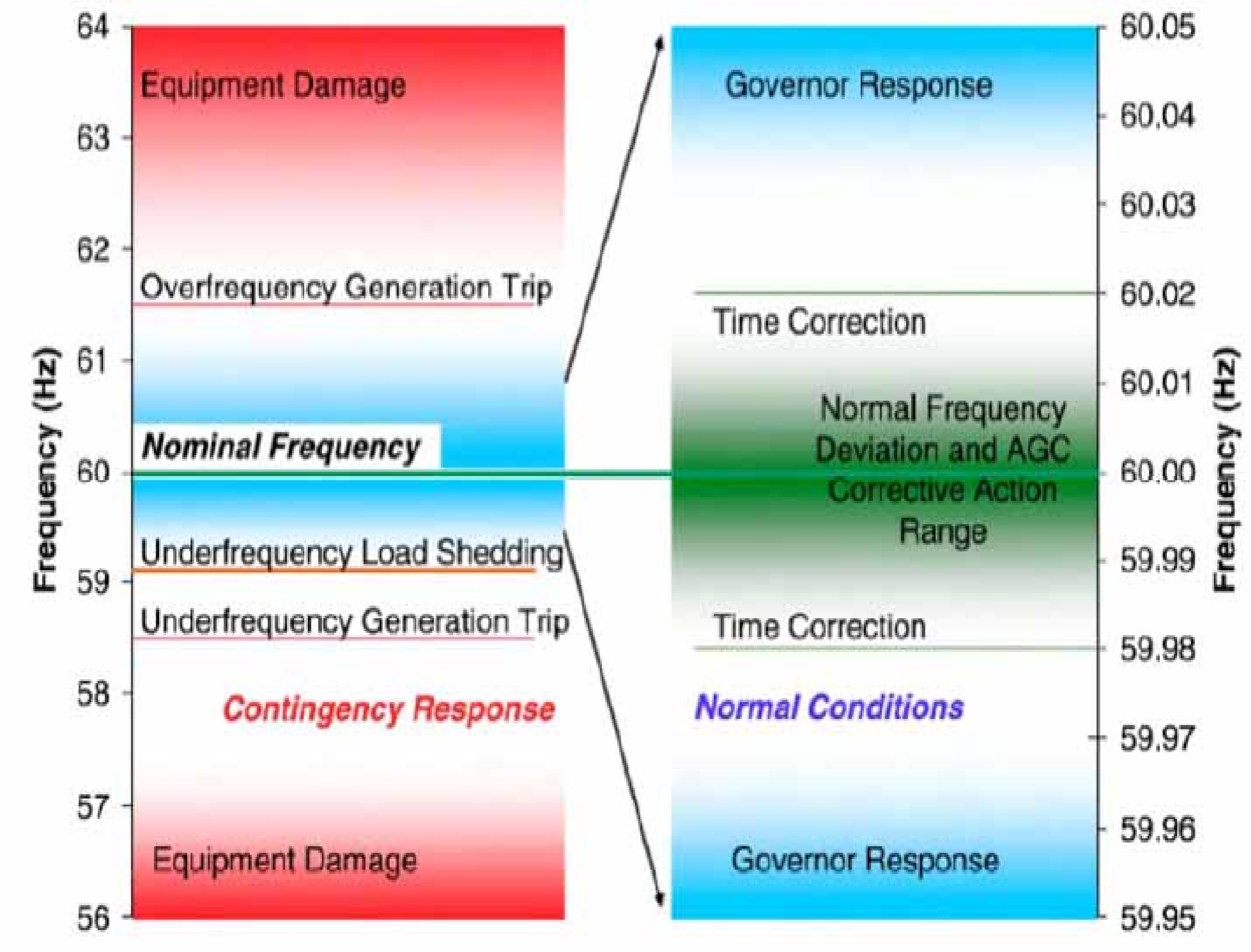
FIGURE 12.1
Schematic diagram of LFC and AVR of a synchronous generator.

Frequency Control

- The frequency of a system depends on real power balance.
  - Changes in real power affect mainly the system frequency.
  - Reactive power is less sensitive to changes in frequency and mainly depends on changes in voltage magnitude.
- As frequency is a common factor throughout the system, a change in real power at one point is reflected through the system by a change in frequency
- In an interconnected system with two or more independently controlled areas, in addition to control of frequency, the generation within each area has to be controlled so as to maintain scheduled power interchange.
- The control of generation and frequency is commonly referred to as Load Frequency Control (LFC), which involves
  - Speed governing system with each generator
  - Automatic Generation Control (AGC) for interconnected systems

Frequency Deviations

- Under normal conditions, frequency in a large Interconnected power system (e.g. the Eastern Interconnection) varies approximately ±0.03Hz from the scheduled value
- Under abnormal events, e.g. loss of a large generator unit, frequency experiences larger deviations.



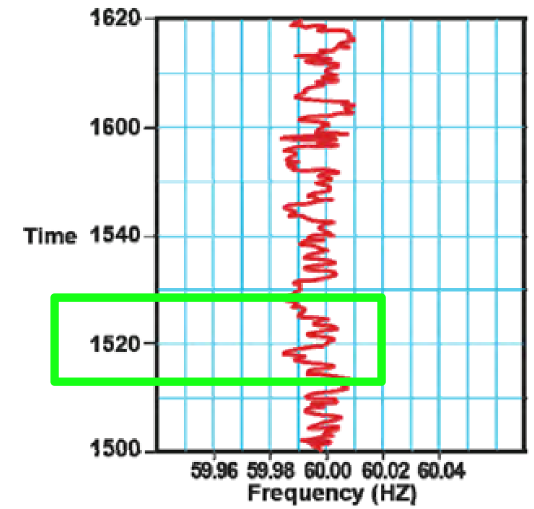


Figure 4-5. Normal Frequency Deviations

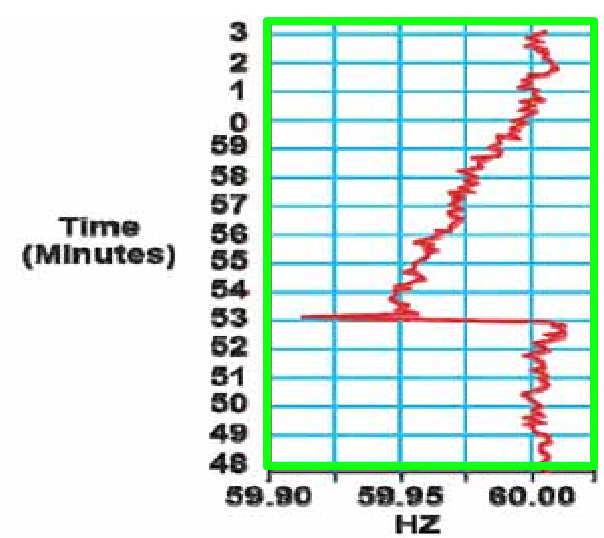
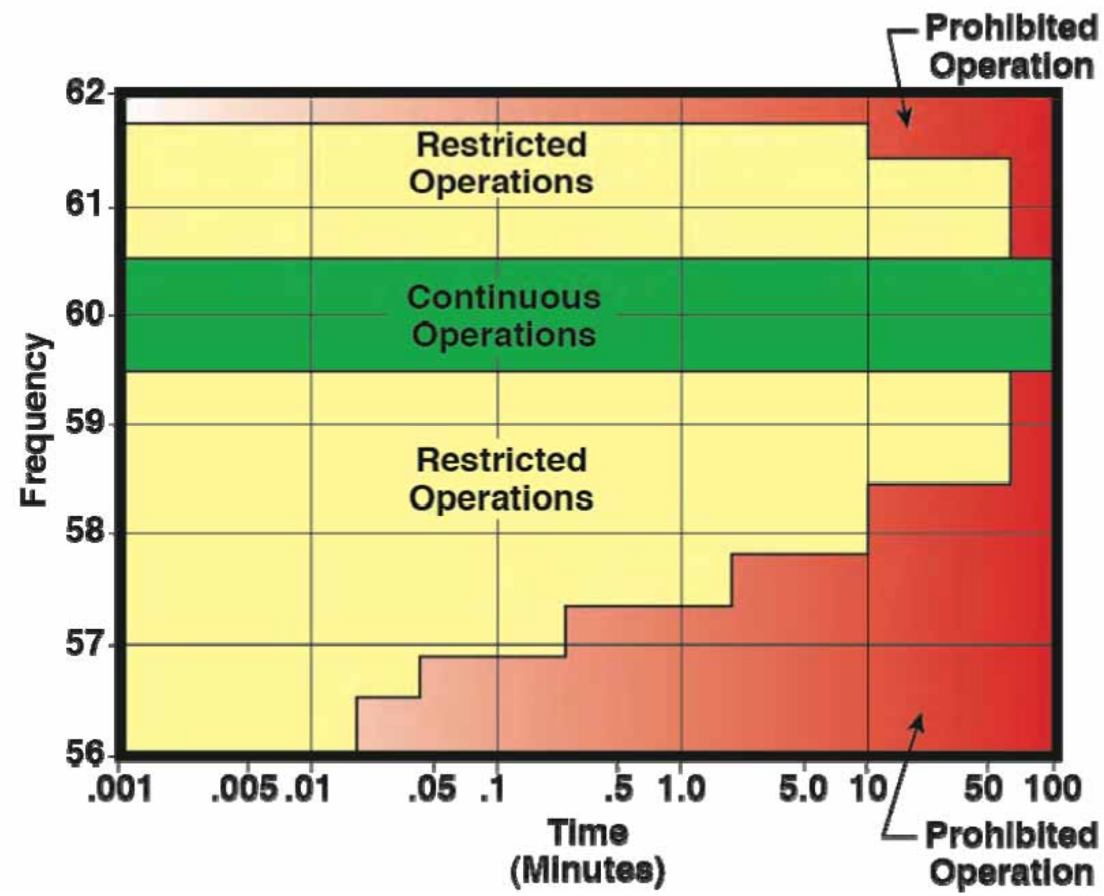


Figure 4-6. Abnormal Frequency Deviations

Impact of Abnormal Frequency Deviations

- Prolonged operation at frequencies above or below 60Hz can damage power system equipment.
- Turbine blades of steam turbine generators can be exposed to only a certain amount of off-frequency operation over their entire lifetime.
- Steam turbine generators often have under- and over-frequency relays installed to trip the unit if operated at off-frequencies for a period.



For example, at 58Hz, a typical steam turbine can be operated under load for 10 minutes over the lifetime before damage is likely to occur to the turbine blades.

Speed Governing System (LFC Loop)

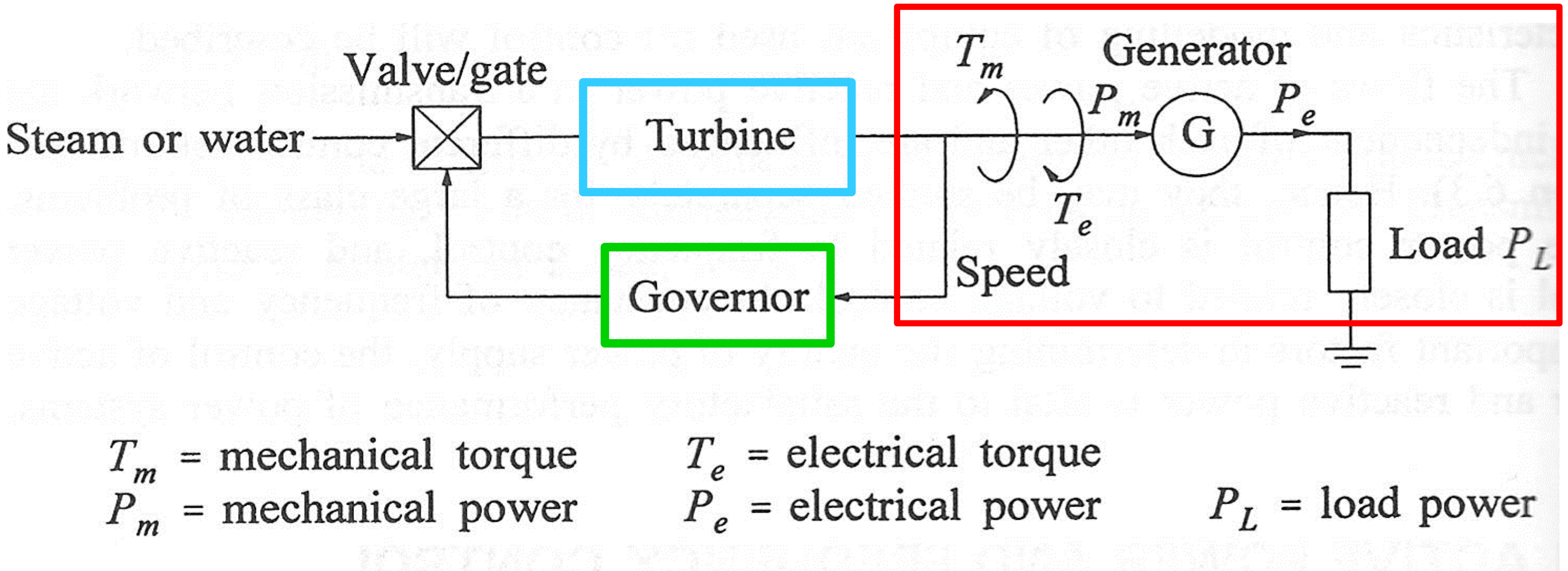


Figure 11.1 Generator supplying isolated load

$$P=\omega_r T$$

- Under the rated condition:

$$\omega_r=\omega_0=1 \text{ pu}, \quad P_m=P_e=P_0=\omega_0 T_0=T_0=T_m=T_e$$

- Under a small change ($\Delta\omega_r <<\omega_0$) around the rated condition:

$$\omega_r=1+\Delta\omega_r \text{ pu}, \quad \Delta P_m-\Delta P_e=P_m-P_e=(1+\Delta\omega_r)(T_m-T_e) \approx T_m-T_e=\Delta T_m-\Delta T_e$$

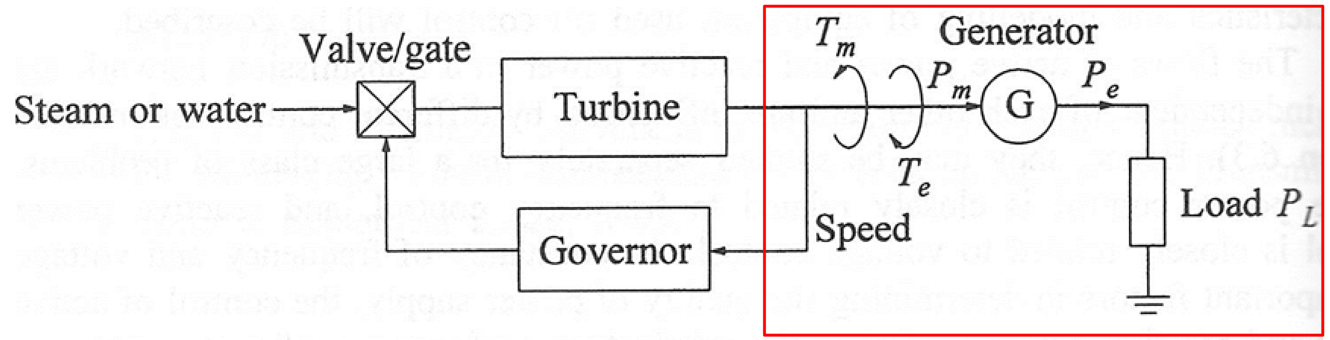
Consider both generator and load

- **Generator:**

$$2H\frac{d(\Delta\omega_r)}{dt} = T_m - T_e = P_m - P_e = \Delta P_m - \Delta P_e$$

$$\frac{1}{\omega_0}\frac{d\delta}{dt} = \Delta\omega_r$$

ω_r, T and P in pu, δ in rad, H and t in sec.



$$2Hs\Delta\omega_r = \Delta P_m - \Delta P_e = \Delta P_m - \Delta P_L - D\Delta\omega_r$$

$$(2Hs + D)\Delta\omega_r = \Delta P_m - \Delta P_L$$

- **Load:**

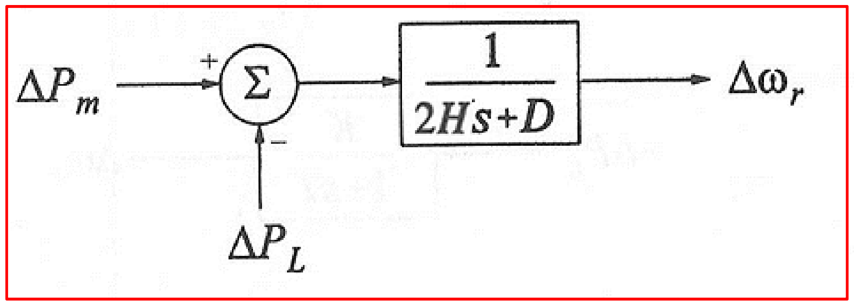
$$\Delta P_e = \Delta P_L + D\Delta\omega_r$$

$$\Delta P_e = \Delta P_{ZIP}(1 + K_{pf}\Delta f)$$

ΔP_L Frequency-insensitive load change (due to ZIP load)

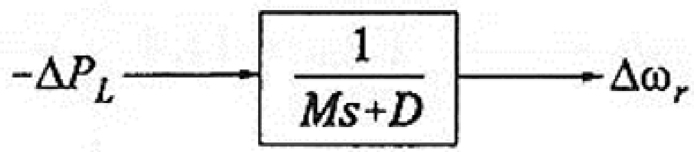
$D\Delta\omega_r$ Frequency-sensitive load change (due to the total effect of external frequency-dependent load and the damping coefficient of the generator)

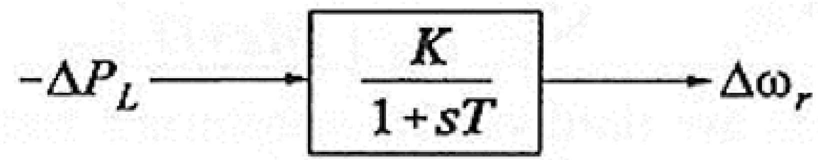
Damping constant D (pu) = % change in load per 1% frequency change



Frequency Deviation without LFC

M=2H	D	ΔP_L
10 sec	**0.75** pu (load varies by 0.75% by 1 % change in of frequency	**-0.01** pu (e.g. a 1MW decrease of 100MW unit)





$$K = \frac{1}{D} = \frac{1}{0.75} = 1.33$$

$$T = \frac{M}{D} = \frac{10}{0.75} = 13.33 \text{ s}$$

- For a step change of load by -0.01pu:

$$\Delta P_L(s) = \frac{-0.01}{s}$$

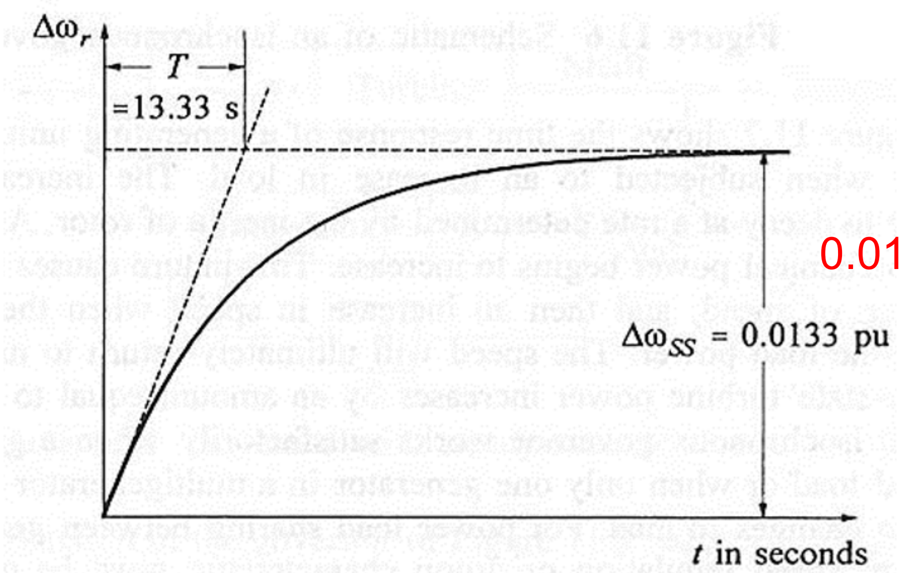
- Speed (or frequency) deviation:

$$\Delta\omega_r(s) = -\left(\frac{-0.01}{s}\right)\left(\frac{K}{1+sT}\right) = \frac{-0.01K}{s+1/T} + \frac{0.01K}{s}$$

$$\Delta\omega_r(t) = -0.01K e^{-\frac{t}{T}} + 0.01K$$

$$= -0.01\times1.33\, e^{-\frac{t}{13.33}} + 0.01\times1.33$$

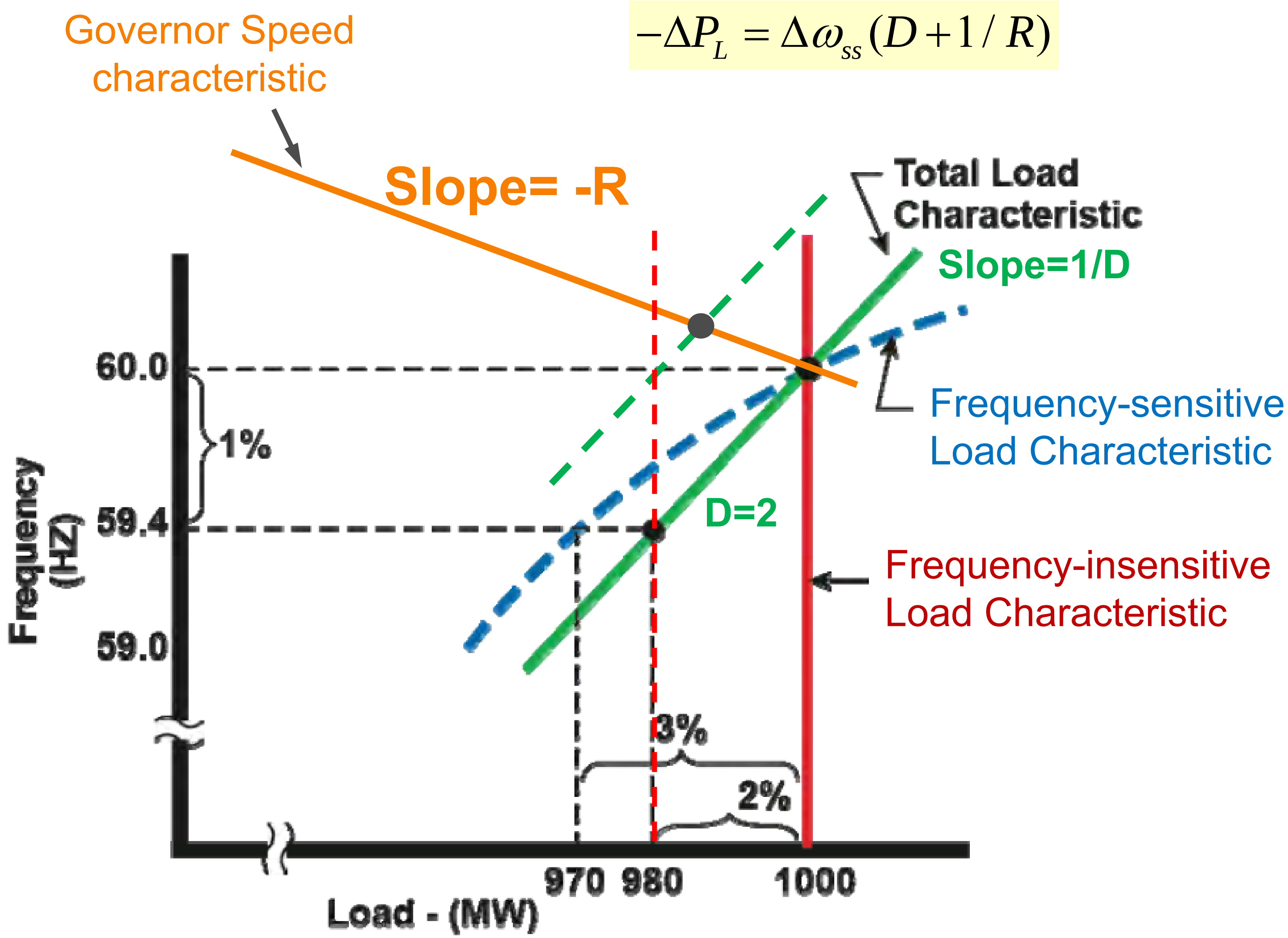
$$= -0.0133\, e^{-0.075t} + 0.0133$$



0.0133x60=0.8Hz

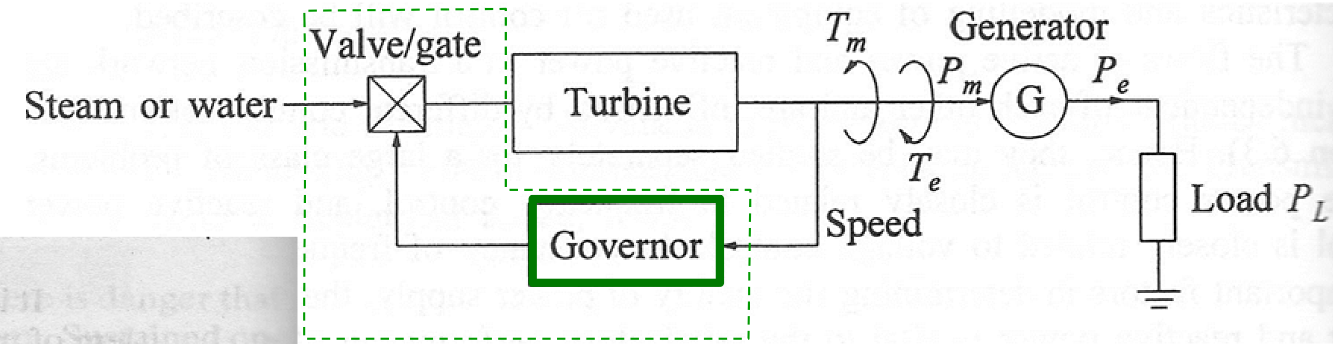
Relationships between Load, Speed Regulation and Frequency

$$-\Delta P_L = \Delta\omega_{ss}(D + 1/R)$$



- If D ↑ (more frequency-dependent load), then |Δf| ↓
- If R ↓ (stronger LFC feedback), then |Δf| ↓

Governor Model



Classic Watt Centrifugal Governing System

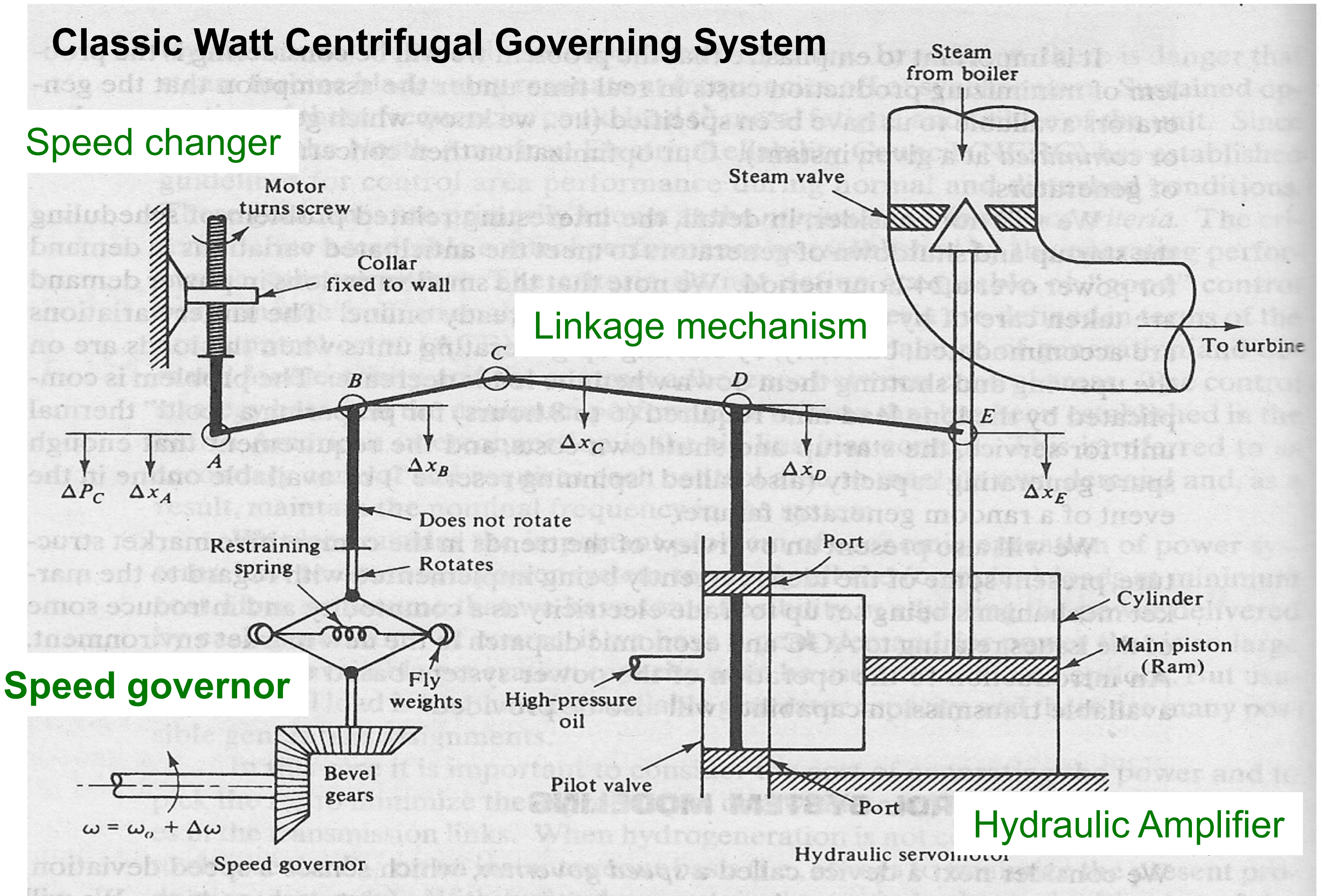
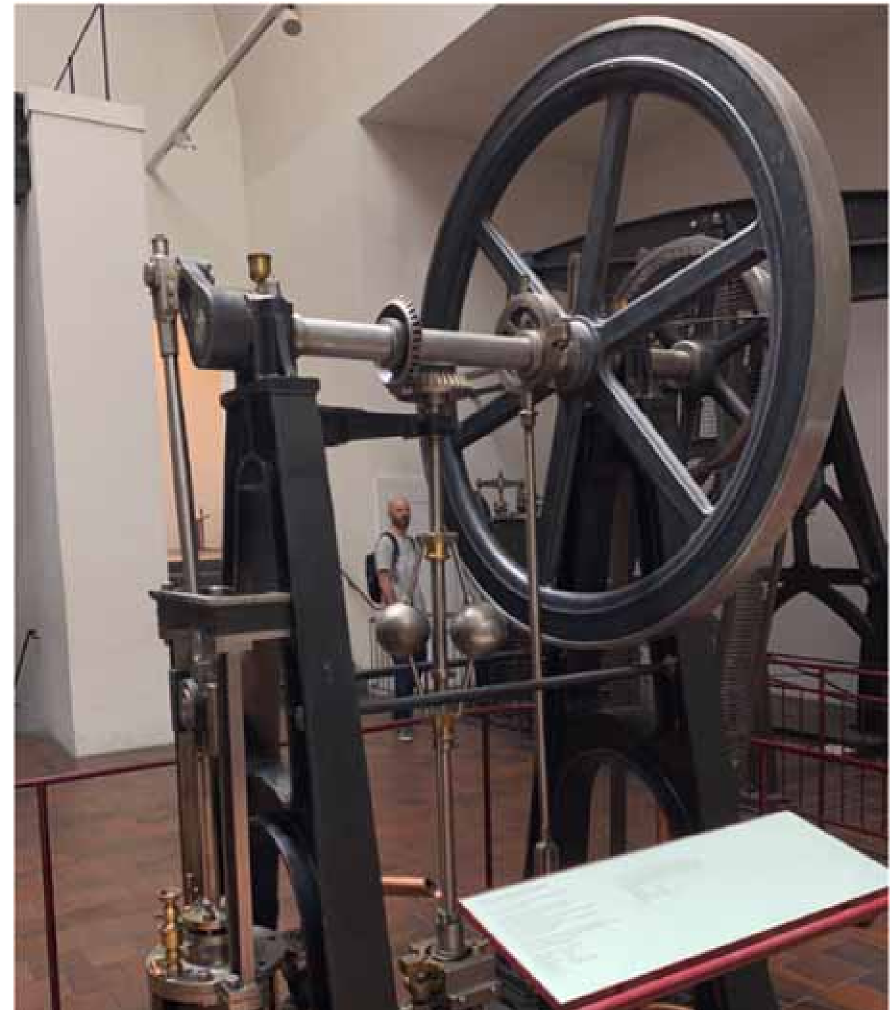


Figure 11.1 Servo-assisted speed governor.



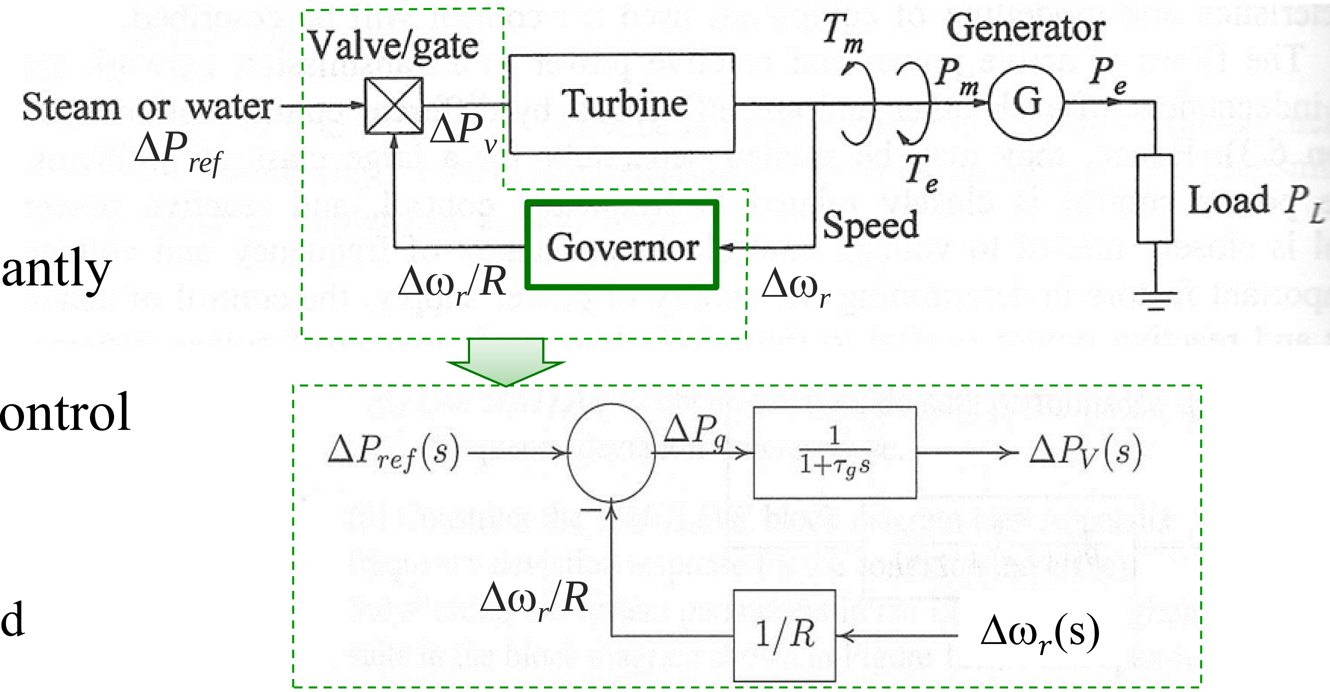
A centrifugal governor applied in a 19th century steam engine

Governor Model

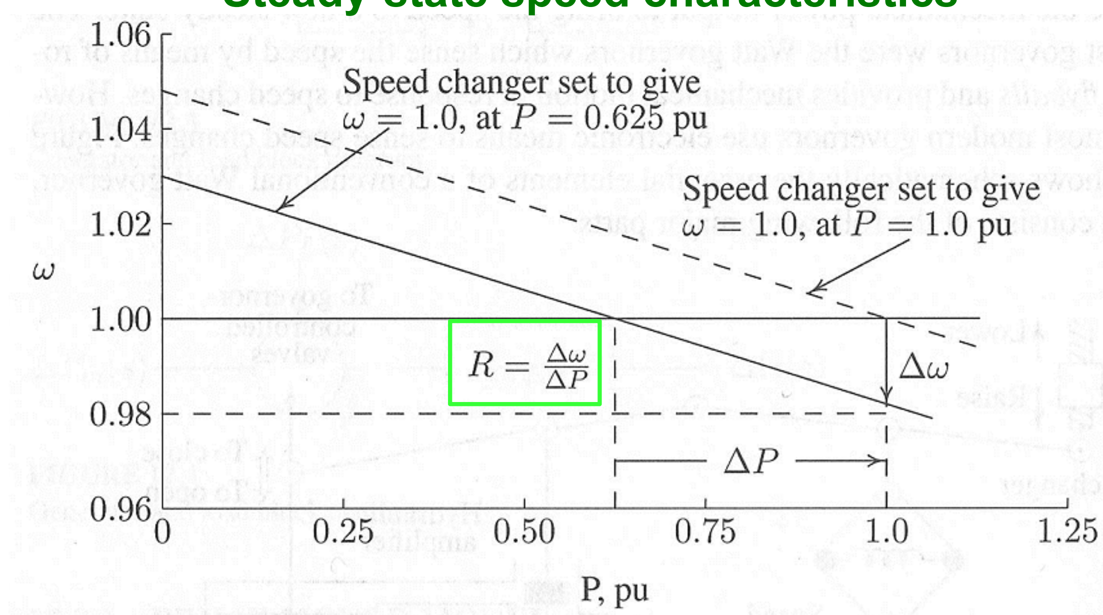
- Without a governor, the generator speed drops significantly ($\propto 1/D$) when load increases
- Speed governor closes the loop of negative feedback control
  - For stable operation, The governor reduces but does not eliminate the speed drop due to load increase.
  - Usually, speed regulation R is 5-6% from zero to full load
  - Governor output $\Delta\omega_r/R$ is compared to the change in the reference power ΔP_{ref}

$$\Delta P_g = \Delta P_{ref} - \Delta\, \omega_r / R$$

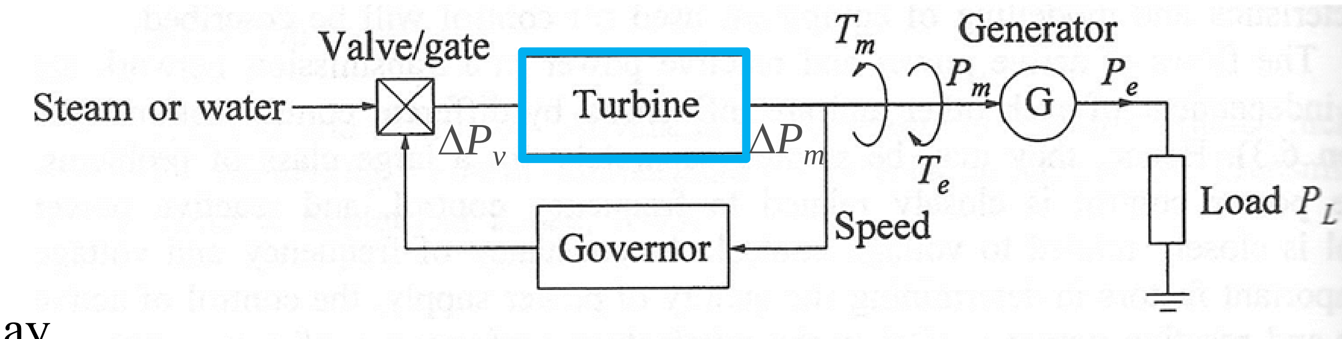
  - The difference ΔP_g is then transformed through the hydraulic amplifier to the steam valve/gate position command ΔP_v with time constant τ_g
  - Its steady-state speed characteristics tells how the speed drops as load increases.



Steady-state speed characteristics



Turbine Model



- The prime mover, i.e. the source of mechanical power, may be a hydraulic turbine at water falls, a steam turbine burning coal and nuclear fuel, or a gas turbine.

- The model for the turbine relates changes in mechanical power output ΔP_m to changes in gate or valve position ΔP_V.

$$\boxed{G_T(t) = \frac{\Delta P_m(s)}{\Delta P_V(s)} = \frac{1}{1+\tau_T s}}$$

τ_T is in 0.2-2.0 seconds

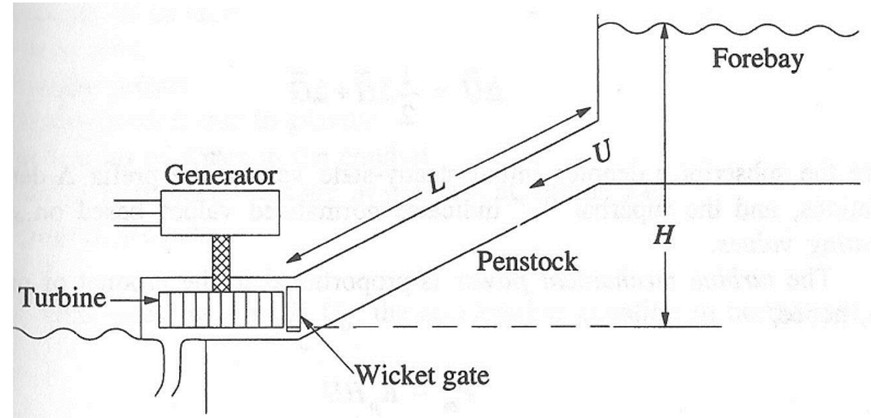


Figure 9.2 Schematic of a hydroelectric plant

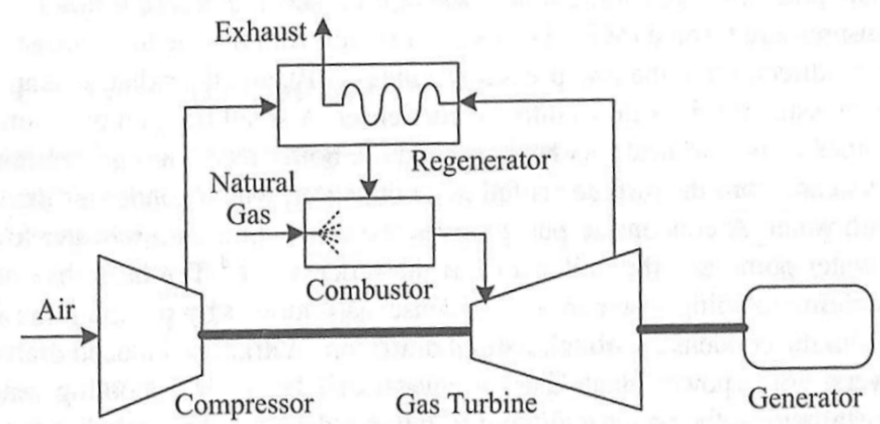
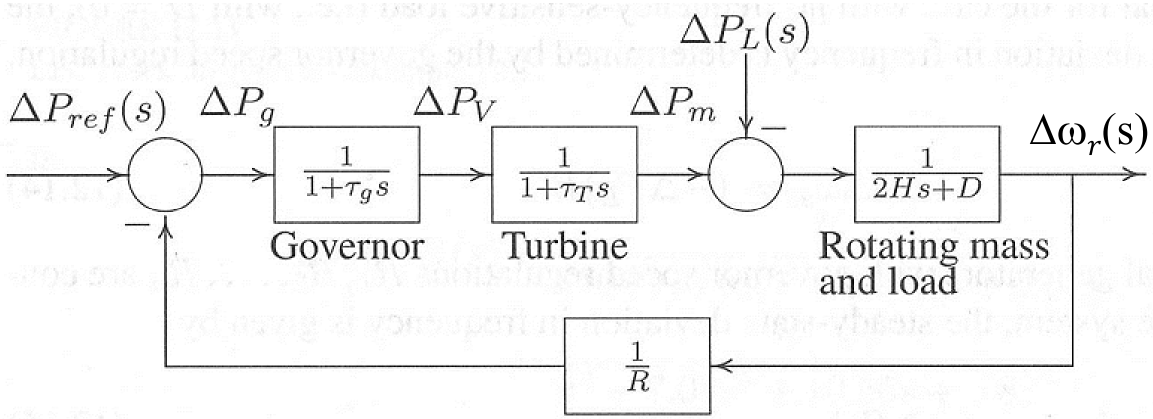


FIGURE 1.3
Schematic diagram of a simple gas turbine power plant.

Load Frequency Control block Diagram



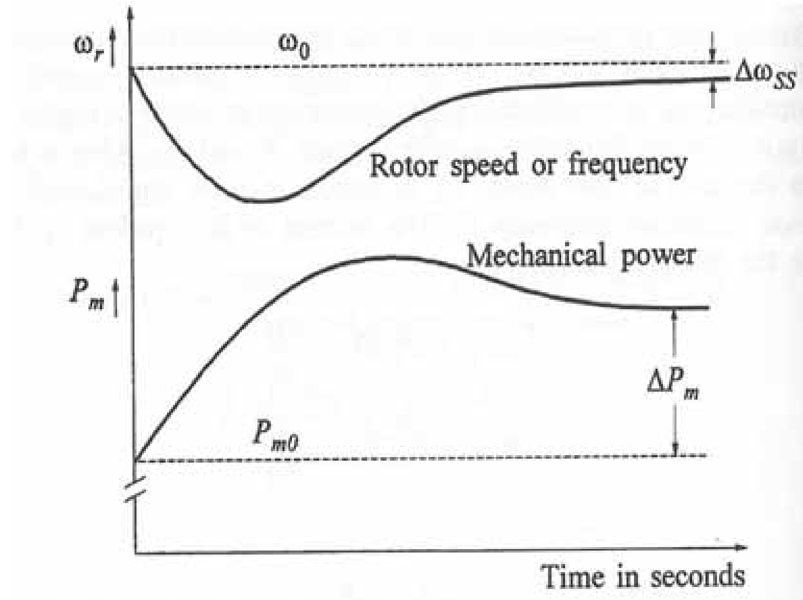


Figure 11.12 Response of a generating unit with a governor having speed-droop characteristic

$$\frac{\Delta\omega_r(s)}{-\Delta P_L(s)} = \frac{(1+\tau_T s)(1+\tau_g s)}{(2Hs+D)(1+\tau_T s)(1+\tau_g s)+1/R}$$

- For a step load change, i.e. $-\Delta P_L(s) = -\Delta P_L/s$

$$\Delta\omega_{ss} = \lim_{s\to 0} s\Delta\omega_r(s) \Rightarrow \Delta\omega_{ss} = \frac{-\Delta P_L}{D+1/R}$$

The smaller R the better?

- For n generators supporting the load:

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{D+1/R_{eq}}$$

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

Saadat's Example 12.1

Example 12.1 (chp12ex1)

An isolated power station has the following parameters

Turbine time constant $\tau_T = 0.5$ sec
Governor time constant $\tau_g = 0.2$ sec
Generator inertia constant $H = 5$ sec
Governor speed regulation = R per unit

The load varies by 0.8 percent for a 1 percent change in frequency, i.e., $D = 0.8$
(a) Use the Routh-Hurwitz array (Appendix B.2.1) to find the range of R for control system stability.
(b) Use *MATLAB* **rlocus** function to obtain the root locus plot.
(c) The governor speed regulation of Example 12.1 is set to $R = 0.05$ per unit. The turbine rated output is 250 MW at nominal frequency of 60 Hz. A sudden load change of 50 MW ($\Delta P_L = 0.2$ per unit) occurs.

(i) Find the steady-state frequency deviation in Hz.

(ii) Use *MATLAB* to obtain the time-domain performance specifications and the frequency deviation step response.

(d) Construct the *SIMULINK* block diagram (see Appendix A.17) and obtain the frequency deviation response for the condition in part (c).

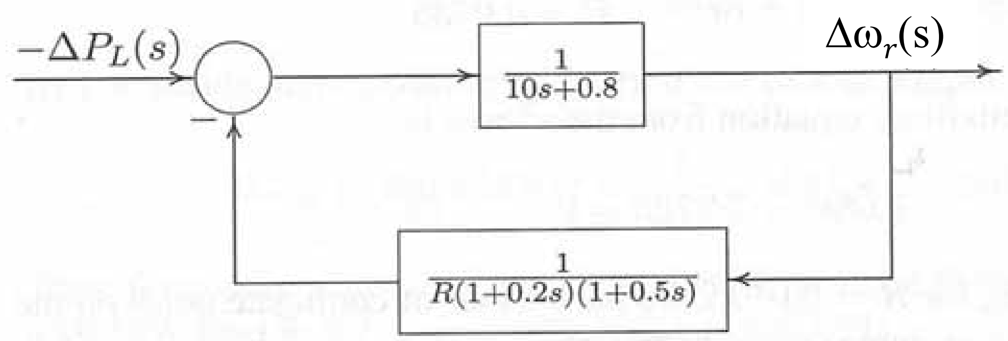


FIGURE 12.11
LFC block diagram for Example 12.1.

The open-loop transfer function is

$$KG(s)H(s) = \frac{K}{(10s+0.8)(1+0.2s)(1+0.5s)}$$
$$= \frac{K}{s^3 + 7.08s^2 + 10.56s + 0.8}$$

where $K = \frac{1}{R}$

(a) The characteristic equation is given by

$$1 + KG(s)H(s) = 1 + \frac{K}{s^3 + 7.08s^2 + 10.56s + 0.8} = 0$$

which results in the characteristic polynomial equation

$$s^3 + 7.08s^2 + 10.56s + 0.8 + K = 0$$

Necessary & sufficient condition for stability of a linear system:
All roots of the characteristic equation (i.e. poles of closed-loop transfer function) have negative real parts (in the left-hand portion of the s-plane)

Routh-Hurwitz Stability Criterion

- **Characteristic equation**

  $a_n s^n + a_{n-1} s^{n-1} + \ldots + a_1 s + a_0 = 0 \quad (a_n > 0)$

- **Routh table:**

  For $i>2$, $x_{ij} = (x_{i-2,j+1} x_{i-1,1} - x_{i-2,1} x_{i-1,j+1}) / x_{i-1,1}$

  where x_{ij} is the element in the i-th row and j-th column

$$
\begin{array}{l|llll}
s^n & a_n & a_{n-2} & a_{n-4} & \cdots \\
s^{n-1} & a_{n-1} & a_{n-3} & a_{n-5} & \cdots \\
s^{n-2} & b_1 & b_2 & b_3 & \cdots \\
s^{n-3} & c_1 & c_2 & c_3 & \cdots \\
\cdots & \cdots & \cdots & \cdots & \cdots
\end{array}
$$

$$b_1 = \frac{a_{n-1}a_{n-2} - a_n a_{n-3}}{a_{n-1}}, \quad b_2 = \frac{a_{n-1}a_{n-4} - a_n a_{n-5}}{a_{n-1}}, \quad \text{etc.}$$

$$c_1 = \frac{b_1 a_{n-3} - a_{n-1} b_2}{b_1}, \quad c_2 = \frac{b_1 a_{n-5} - a_{n-1} b_3}{b_1}, \quad \text{etc.}$$

- **Routh-Hurwitz criterion:**
  Number of roots of the equation having positive real parts = Number of times of sign changes in the 1st column of the Routh table

- **Necessary & sufficient condition for stability of a linear system:**
  The 1st column has all positive numbers

$$s^3 + 7.08 s^2 + 10.56 s + 0.8 + K = 0$$

$$
\begin{array}{l|cc}
s^3 & 1 & 10.56 \\
s^2 & 7.08 & 0.8+K \\
s^1 & \dfrac{73.965-K}{7.08} & 0 \\
s^0 & 0.8+K & 0
\end{array}
$$

- s^1 row>0 if $K<73.965$
- s^0 row>0 since $K>0$
- So $R=1/K>1/73.965=0.0135$

Root-Locus Method

$$KG(s)H(s) = \frac{K(s+z_1)(s+z_2)\cdots(s+z_m)}{(s+p_1)(s+p_2)\cdots(s+p_n)} \quad \text{(B.5)}$$

$-z_i$ is the i-th zero and $-p_j$ is j-th pole

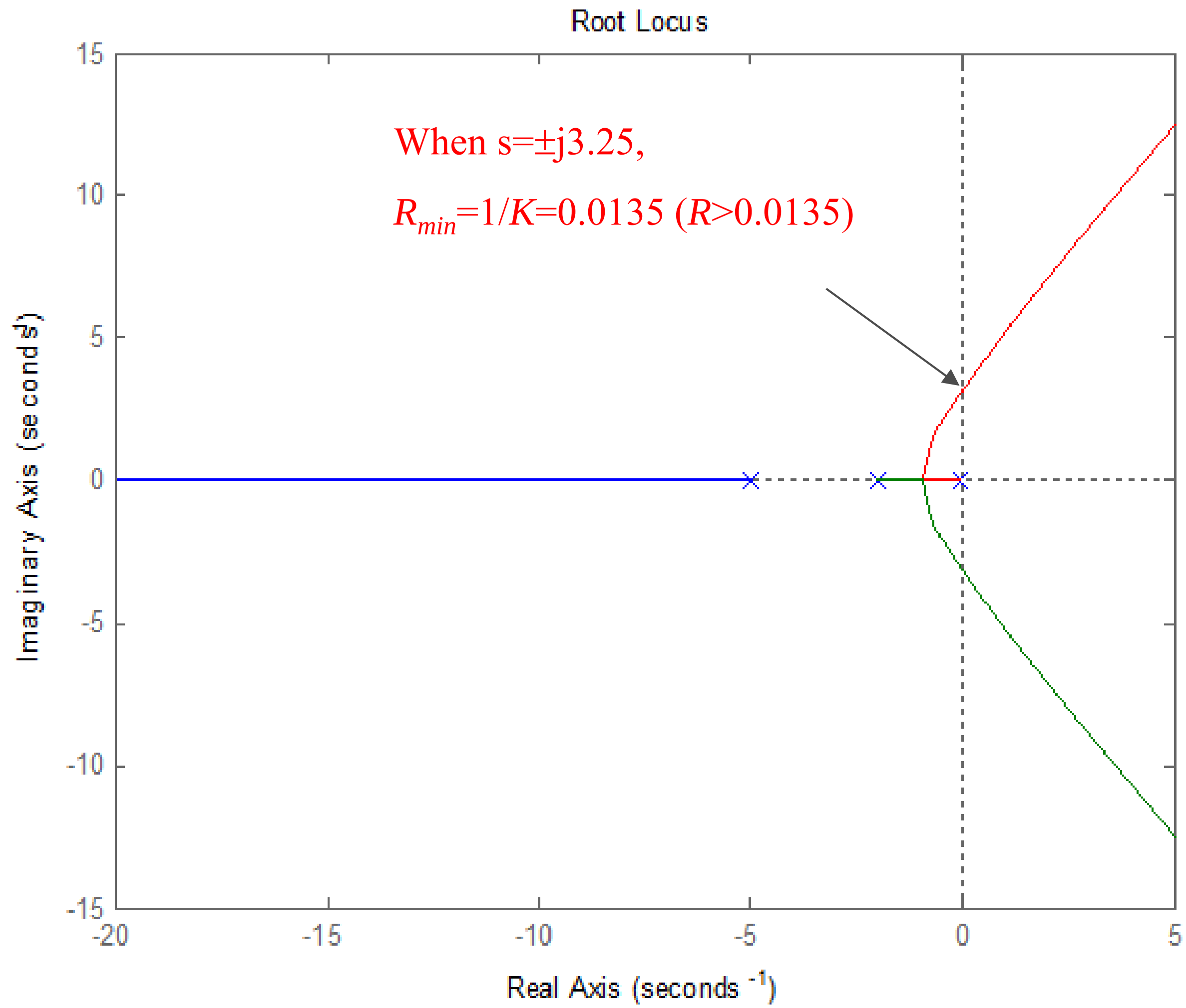
Conclusions (see Saadat's B2.22 for details):

- The loci of roots of $1+KG(s)H(s)$ begins at $KG(s)H(s)$'s poles and ends at its zeros as K=0→∞.
- Number of separate loci = Number of poles; root loci must be symmetrical with respect to the real axis.
- The root locus on the real axis always lies in a section of the real axis to the left of an odd number of poles and zeros.
- Linear asymptotes of loci are centered at a point $(x, 0)$ on the real axis with angle ϕ with respect to the real axis.

  where $x=[\sum_{j=1\ldots n}(-p_j) - \sum_{i=1\ldots m}(-z_i)]/(n-m)$

  $\phi=\pi\times(2k+1)/(n-m) \qquad k=0, 1, \ldots, (n-m-1)$

$$KG(s)H(s) = \frac{K}{(10s+0.8)(1+0.2s)(1+0.5s)}$$



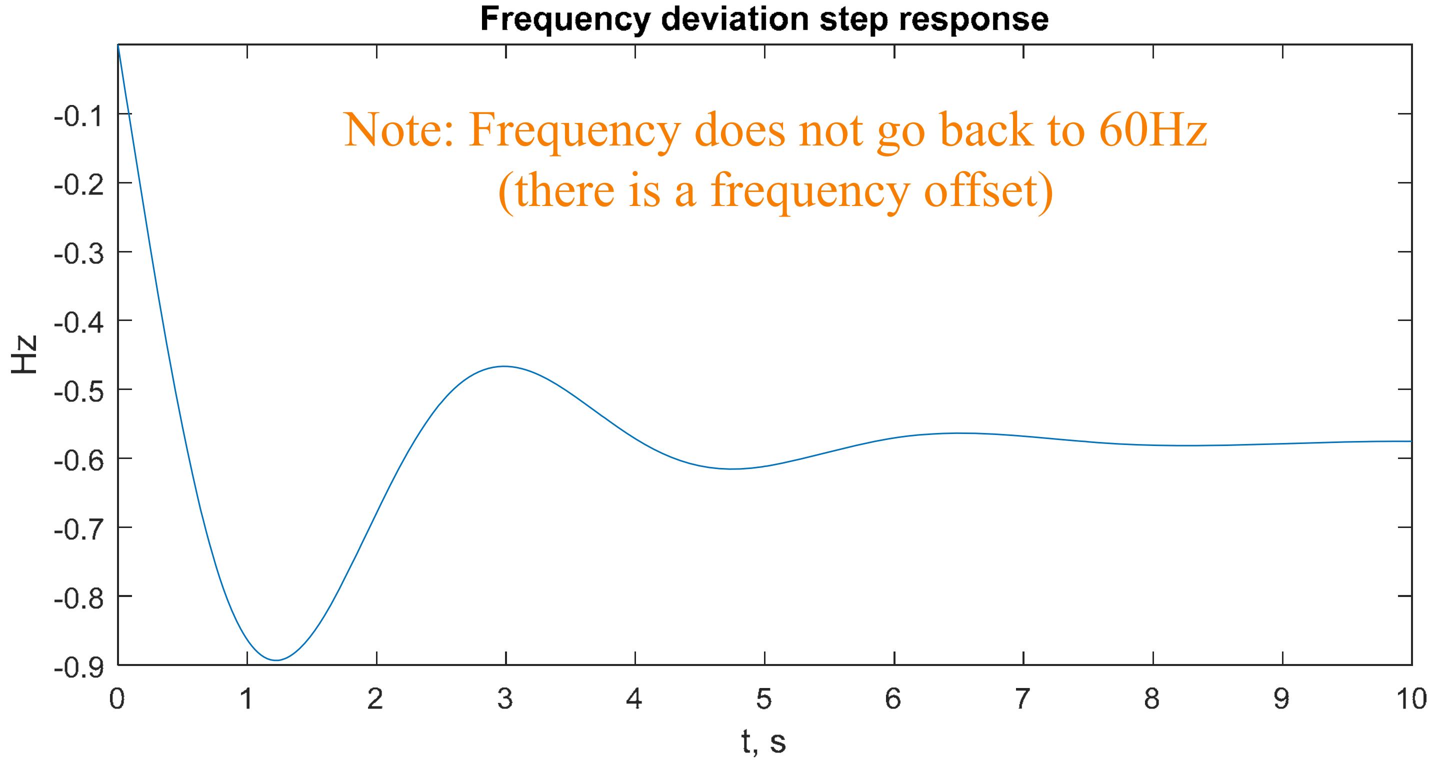
- Closed-loop transfer function with R=0.05pu (>0.0135):

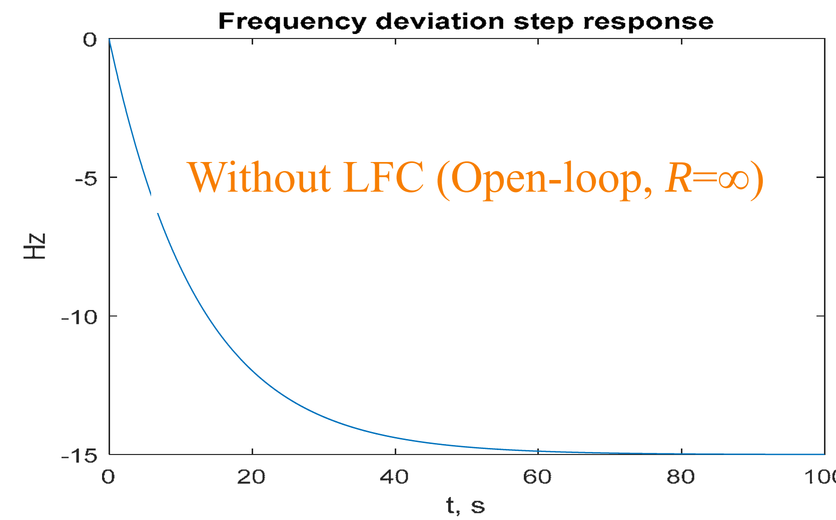
$$\frac{\Delta\omega_r(s)}{-\Delta P_L(s)}=\frac{(1+0.2s)(1+0.5s)}{(10s+0.8)(1+0.2s)(1+0.5s)+1/0.05}=\frac{0.1s^2+0.7s+1}{s^3+7.08s^2+10.56s+20.8}$$

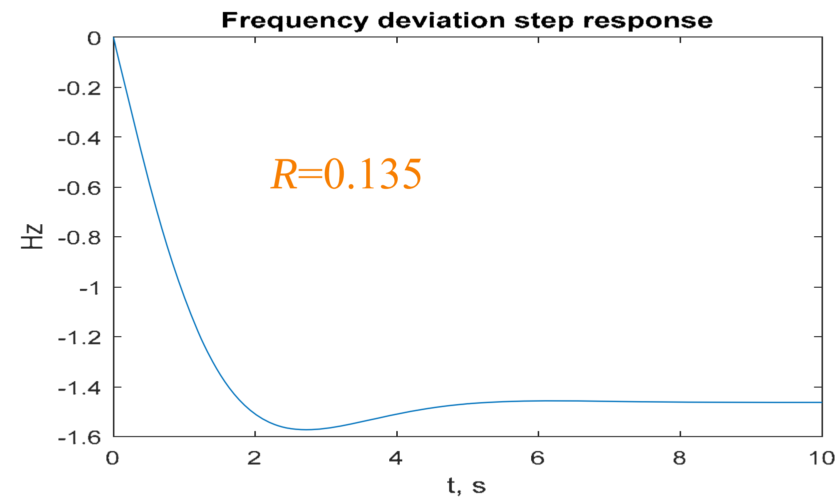
- Steady-state frequency deviation due to a step input:

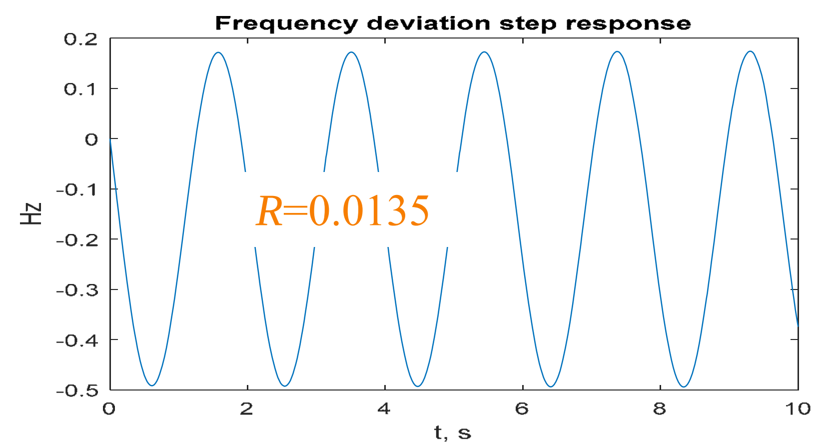
$$\Delta\omega_{ss}=\lim_{s\to 0}s\Delta\omega_r(s)=-\Delta P_L\frac{1}{D+1/R}=-0.2\times\frac{1}{20.8}=-0.0096\text{ p.u.}$$

$$\Delta f=-0.0096\times 60=0.576\text{ Hz}$$









Modeling of a realistic turbine-governor system

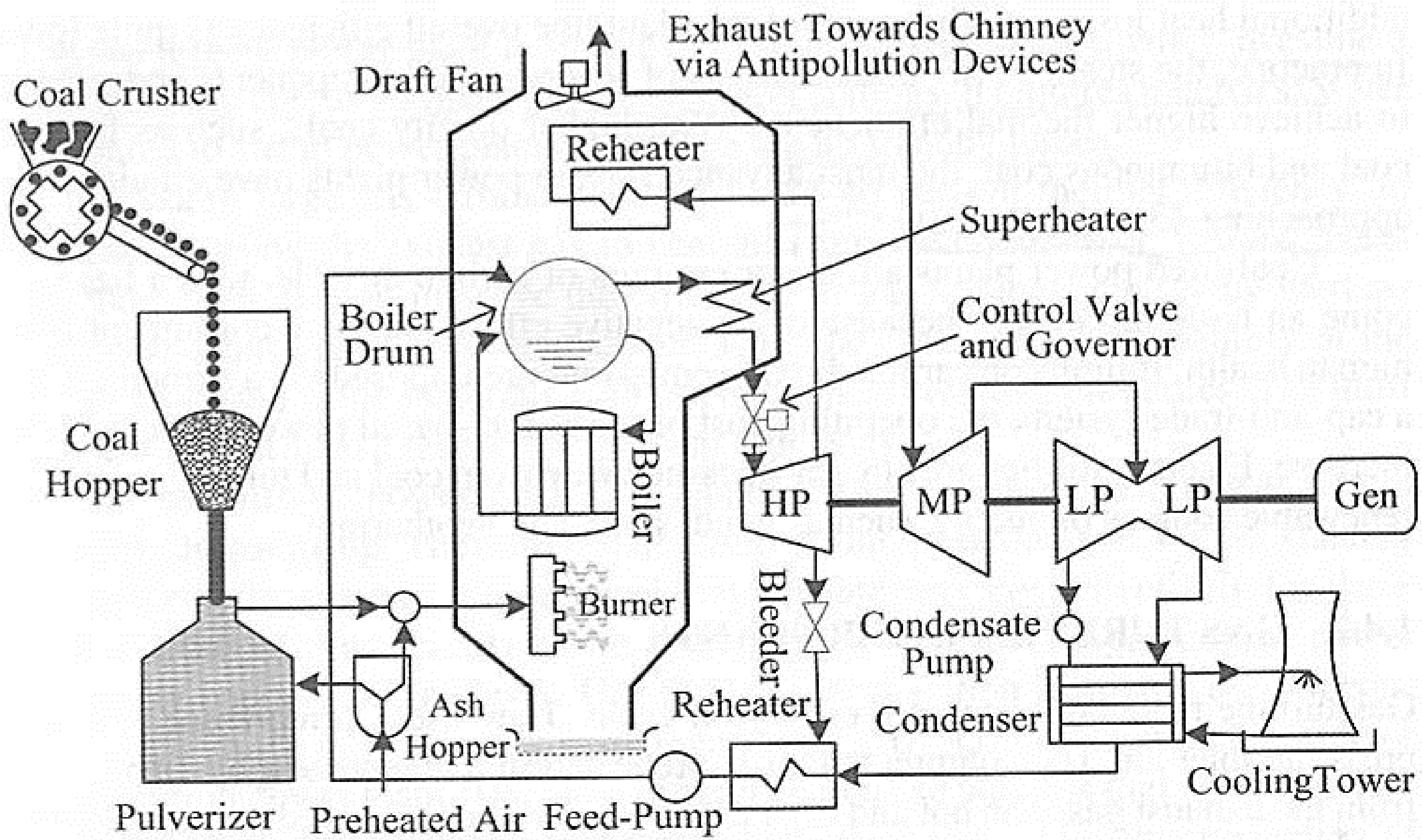
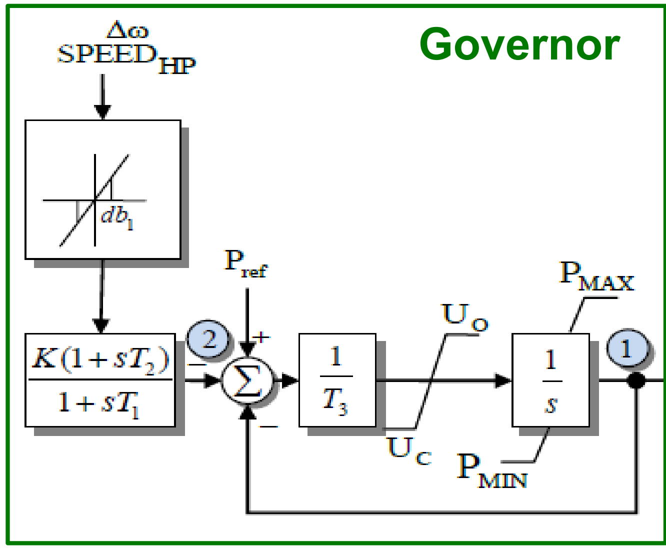
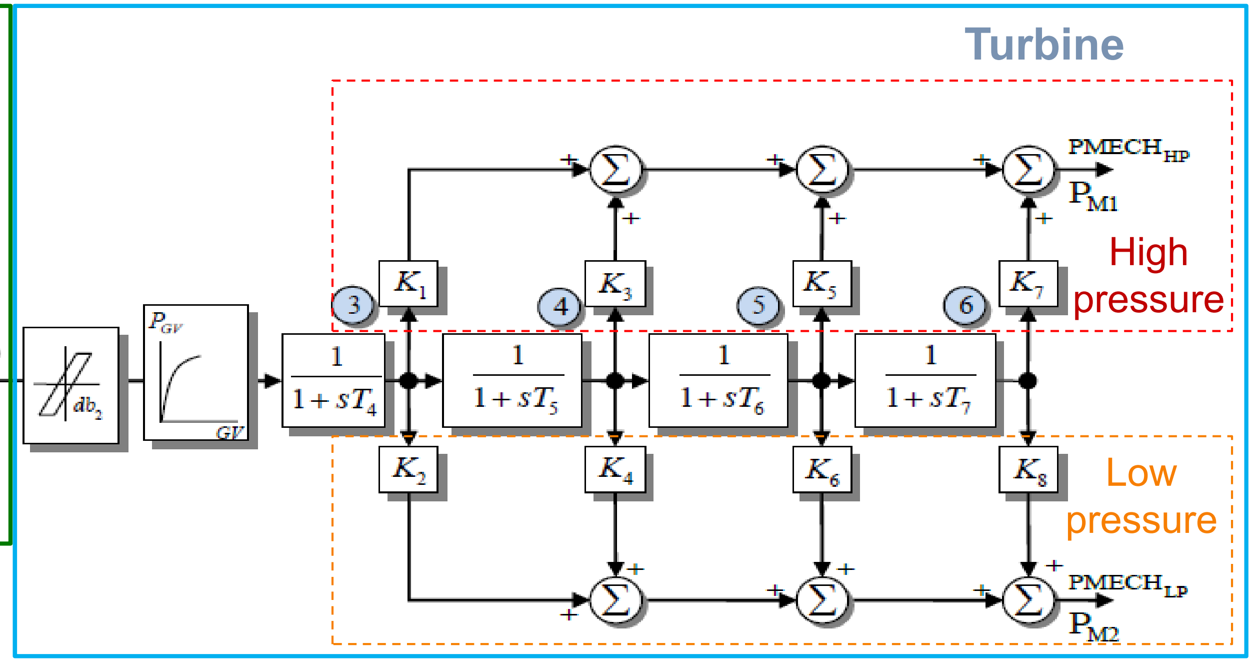


FIGURE 1.2
Simplified diagram of a conventional coal-fired steam generator.

IEEE Type 1 Speed-Governor Model: IEEEG1/IEEEG1_GE





States

1 - Governor Output

2 - Lead-Lag

3 - Turbine Bowl

4 - Reheater

5 - Crossover

6 - Double Reheat

IEEEG1_GE is supported by PSLF. PowerWorld ignores the db2 term. All values are specified on the turbine rating which is a parameter in PowerWorld and PSLF. If the turbine rating is omitted or zero, then the generator MVABase is used. If there are two generators, then the SUM of the two MVABases is used.

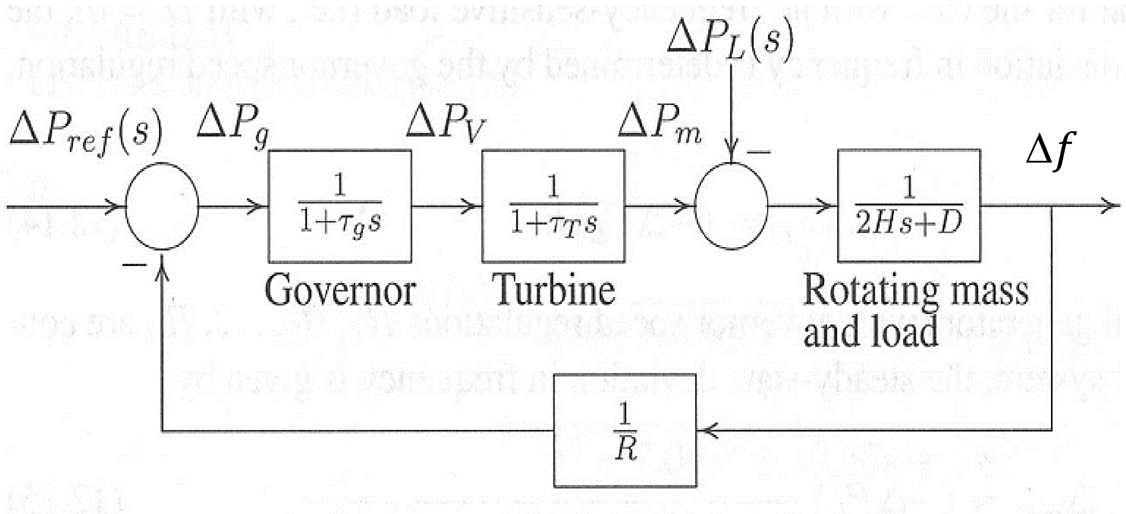
IEEEG1 is supported by PSSE. PSSE does not include the db2, db1, non-linear gain term, or turbine rating. For the IEEEG1 model, if the turbine rating is omited then the MVABase of only the high-pressure generator is used.

GV1, PGV1...GV6, PGV6 are the x,y coordinates of P_{GV} vs. GV block

Form Edit - IEEEG1

IBUS	4	Bus	CORONADO	Area	10	Zone	10
I	1	JBUS	0	M	0	K	20.0000 =1/R
T1	0.1000	T2	0.0000	T3	0.2000	Uo	1.0000
Uc	-1.0000	PMAX	0.9500	PMIN	0.0000	T4	0.1000
K1	0.0000	K2	0.0000	T5	0.0000	K3	0.0000
K4	0.0000	T6	0.0000	K5	0.3000	K6	0.0000
T7	8.7200	K7	0.7000	K8	0.0000	MVA Base	1462.4000
Pgen (Powerflow)	541.4351	Pmax (Powerflow)	9999.0000	Status	1		

Composite Governor and Load Characteristic



Under steady-state conditions (s=0):

$$\Delta f\,(\text{pu}) = \Delta\omega_{ss}\,(\text{pu}) = \frac{-\Delta P_L\,(\text{pu})}{D+1/R}$$

$$\Delta P_m = -\frac{\Delta\omega_{ss}}{R} = \Delta P_L + D\Delta\omega_{ss} = \Delta P_L + \Delta P_D$$

Multiple generators:

$$\Delta\omega_{ss} = -\Delta P_{mi} R_i = \frac{-\Delta P_L\,(\text{pu})}{D+\sum_i \frac{1}{R_i}}$$

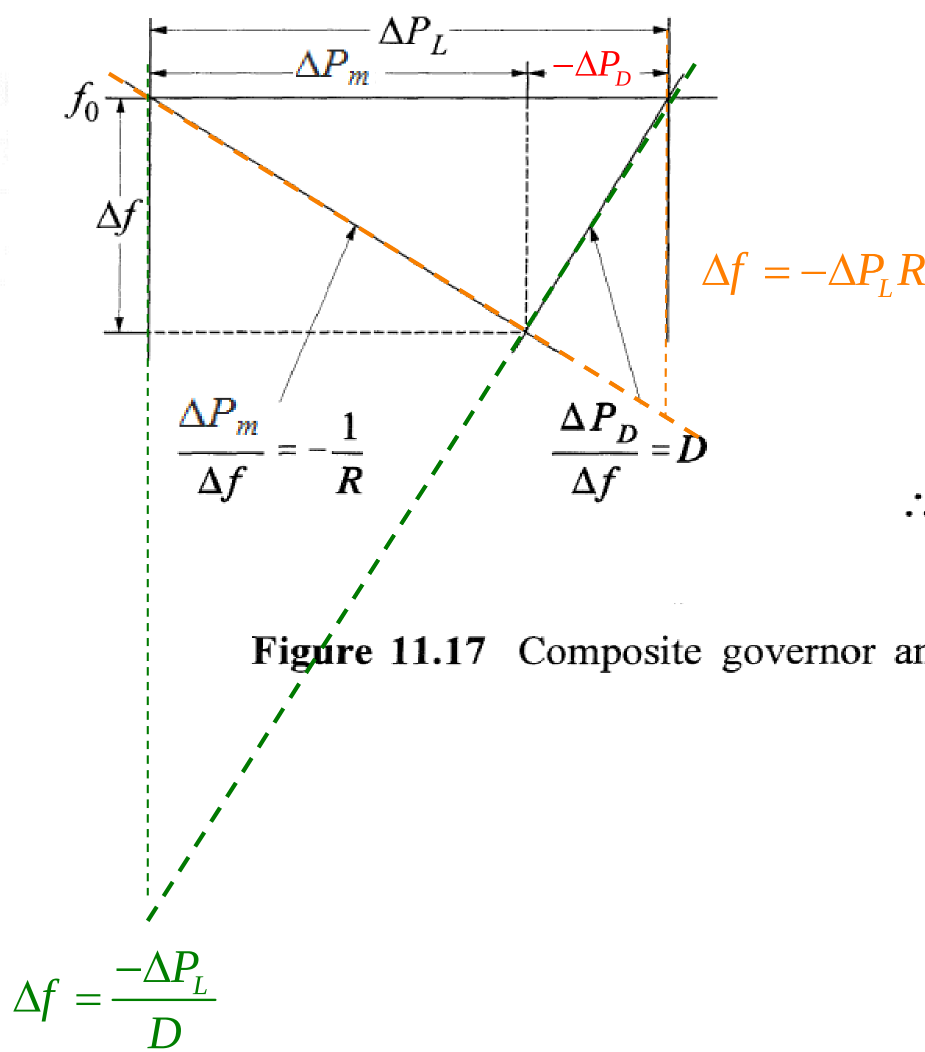
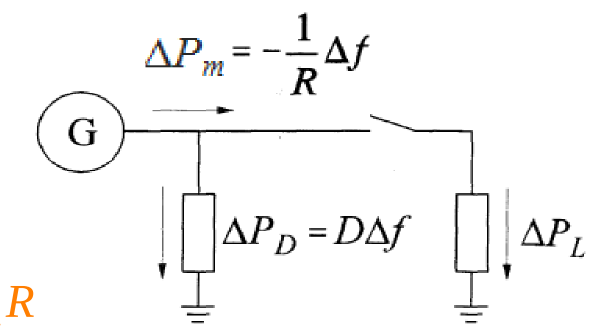


Figure 11.17 Composite governor and load characteristic



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

$$\therefore\ \Delta f = \frac{-\Delta P_L}{1/R + D}$$

Saadat's Example 12.2

Example 12.2 (chp12ex2)

A single area consists of two generating units with the following characteristics.

Unit	Rating	Speed regulation R (pu on unit MVA base)
1	600 MVA	6%
2	500 MVA	4%

The units are operating in parallel, sharing 900 MW at the nominal frequency. Unit 1 supplies 500 MW and unit 2 supplies 400 MW at 60 Hz. The load is increased by 90 MW.

(a) Assume there is no frequency-dependent load, i.e., $D = 0$. Find the steady-state frequency deviation and the new generation on each unit.

(b) The load varies 1.5 percent for every 1 percent change in frequency, i.e., $D = 1.5$. Find the steady-state frequency deviation and the new generation on each unit.

$$\Delta\omega_{ss} = -\Delta P_{mi} R_i = \frac{-\Delta P_L\,(\text{pu})}{D + \sum_i \frac{1}{R_i}}$$

Note: Two generators use different MVA bases. Select 1000MVA as the common MVA base. Change the per unit value on the machine base (B1) to a new per unit value on the common base (B2).

$$R^{B1} = \frac{\overline{\Delta\omega_{ss}}}{-\Delta\overline{P}_m^{B1}} = \frac{\overline{\Delta\omega_{ss}}}{-\Delta\overline{P}_m^{B2} \times \frac{S_{B2}}{S_{B1}}} = \frac{S_{B1}}{S_{B2}} \times \frac{\overline{\Delta\omega_{ss}}}{-\Delta\overline{P}_m^{B2}} = \frac{S_{B1}}{S_{B2}} \times R^{B2} \Rightarrow \boxed{\frac{R^{B1}}{S_{B1}} = \frac{R^{B2}}{S_{B2}}}$$

$$P = \overline{P}^{B1} \times S_{B1} = \overline{P}^{B2} \times S_{B2}$$

$$R_1 = \frac{1000}{600}(0.06) = 0.1 \text{ pu} \qquad R_2 = \frac{1000}{500}(0.04) = 0.08 \text{ pu} \qquad \Delta P_L = \frac{90}{1000} = 0.09 \text{ pu}$$

(a) D=0

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{\frac{1}{R_1}+\frac{1}{R_2}} = \frac{-0.09}{10+12.5} = -0.004 \text{ pu}$$

$$\Delta f = -0.004 \times 60 = -0.24 \text{ Hz}$$

$$f = f_0 + \Delta f = 60 - 0.24 = 59.76 \text{ Hz}$$

$$\Delta P_{m1} = -\frac{\Delta\omega_{ss}}{R_1} = -\frac{-0.004}{0.1} = 0.04 \text{ pu } = 40 \text{ MW}$$

$$\Delta P_{m2} = -\frac{\Delta\omega_{ss}}{R_2} = -\frac{-0.004}{0.08} = 0.05 \text{ pu } = 50 \text{ MW}$$

Unit 1 supplies 540MW and unit 2 supplies 450MW at the new operating frequency of 59.76Hz.

(b) D=1.5 (ignoring its change due to load increase)

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{\frac{1}{R_1}+\frac{1}{R_2}+D} = \frac{-0.09}{10+12.5+1.5} = -0.00375 \text{ pu}$$

$$\Delta f = -0.00375 \times 60 = -0.225 \text{ Hz}$$

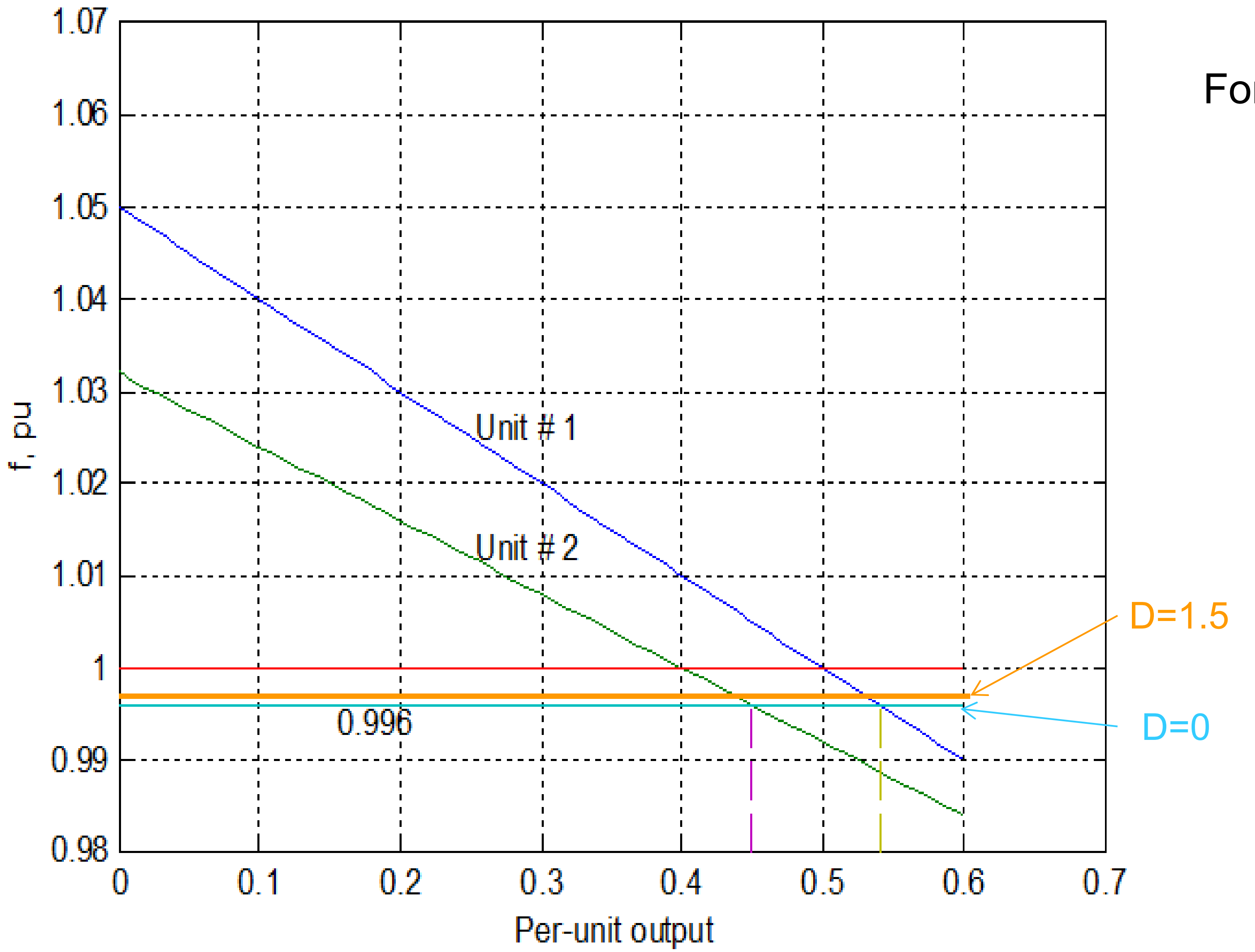
$$f = f_0 + \Delta f = 60 - 0.225 = 59.775 \text{ Hz}$$

$$\Delta P_{m1} = -\frac{\Delta\omega_{ss}}{R_1} = -\frac{-0.00375}{0.1} = 0.0375 \text{ pu=37.5MW}$$

$$\Delta P_{m2} = -\frac{\Delta\omega_{ss}}{R_2} = -\frac{-0.00375}{0.08} = 0.0469 \text{ pu=46.9MW}$$

Unit supplies 537.5MW and unit 2 supplies 446.9MW at the new operating frequency of 59.775Hz. The total change in generation is 84.4MW, i.e. 5.6MW less than 90MW load change, because of the change in load due to frequency drop.

$$\Delta\omega_{ss} \cdot D = -0.00375 \times 1.5 = -0.005625 \text{ pu = -5.625MW}$$



For D=0 (frequency-sensitive load is ignored):

$$\Delta P_{m1} = -\frac{\Delta\omega_{ss}}{R_1}$$

$$\Delta P_{m2} = -\frac{\Delta\omega_{ss}}{R_2}$$

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

Adjusting R_1 and R_2 may change generation dispatch between Units 1 and 2

Composite Frequency Response Characteristic (FRC)

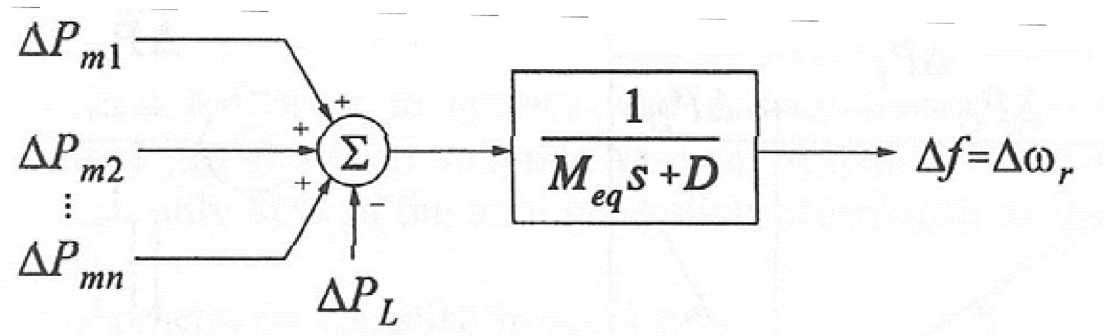


Figure 11.16 System equivalent for LFC analysis

- LFC analysis for a multi-generator system:
  - Assume coherent response of all generators to changes in system load
  - Consider an equivalent generator representing all generators

$$M_{eq}=2H_{eq}=2\times(H_1+\ \dots\ +H_n) \qquad R_{eq}=\frac{1}{1/R_1+\cdots+1/R_n}$$

$$\Delta\omega_{ss}=\frac{-\Delta P_L}{D+1/R_{eq}}$$

- Frequency response characteristic (FRC), also called Frequency bias factor β

  $\beta=D+1/R_{eq}\ =|\Delta P_L/\Delta f|$ (Unit: MW/0.1 Hz)

- FRC tells how much MW change may cause a 0.1Hz frequency derivation, and it can be developed for either the whole system or any section of the system.
- FRC depends on:
  - The governor droop settings (R_{eq}) of all on-line units in the system.
  - The frequency response (D) of the connected load in the system.
  - The condition of the system (includes current generator output levels, transmission line outages, voltage levels, etc.) when the frequency deviation occurs.

FRCs of Different Interconnections

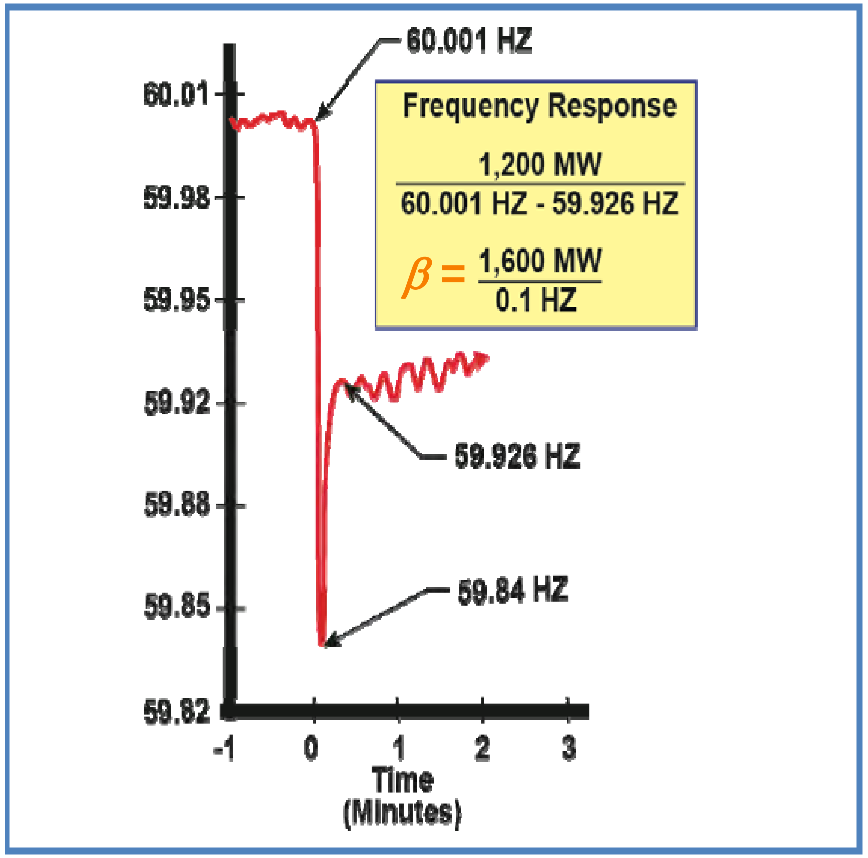


Figure 4-28. Western Interconnection

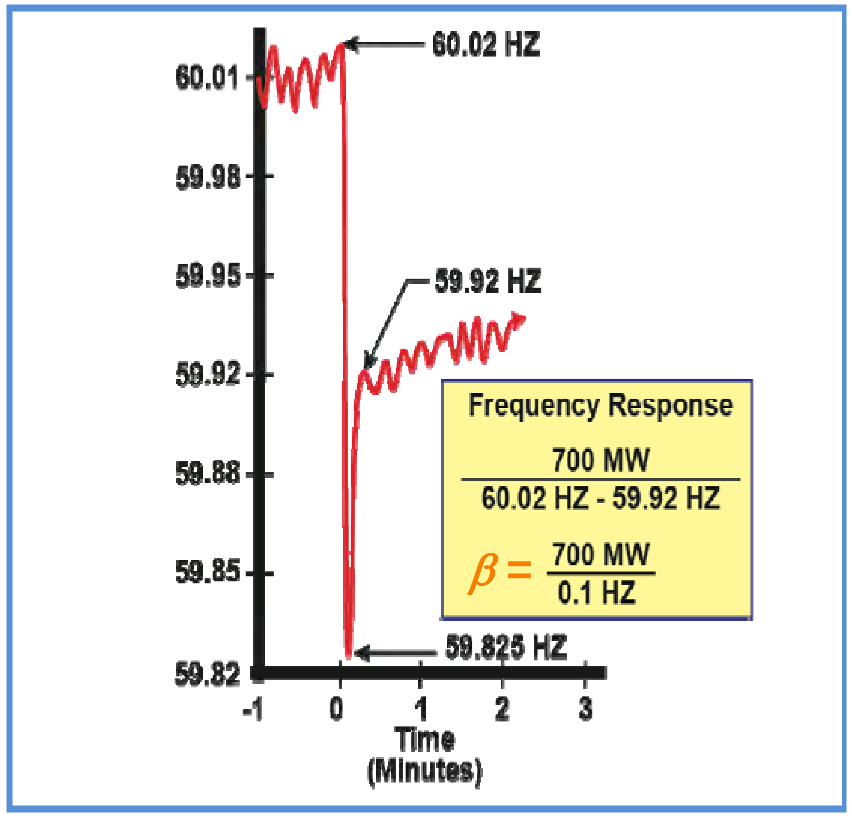


Figure 4-29. ERCOT Interconnection

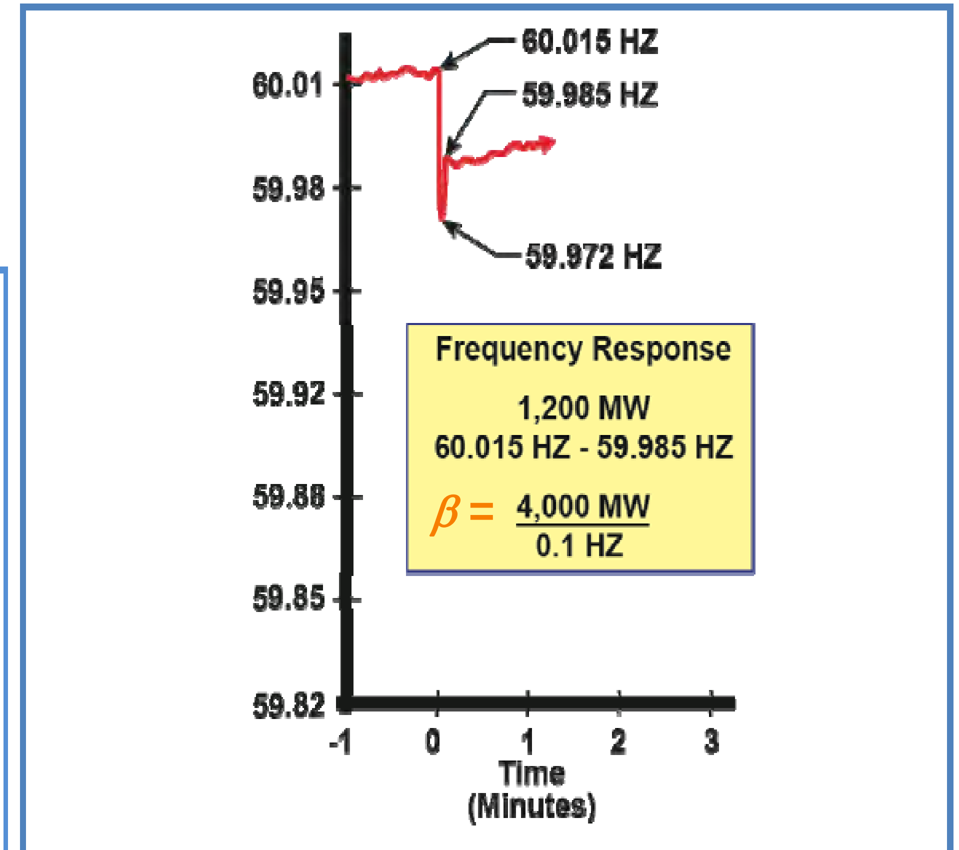
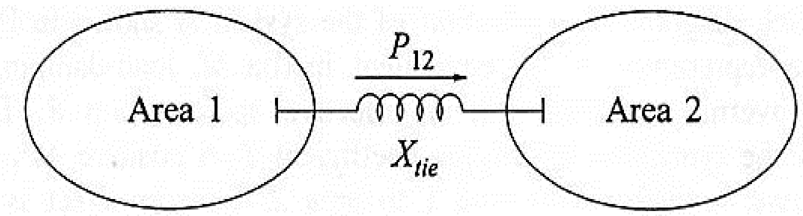


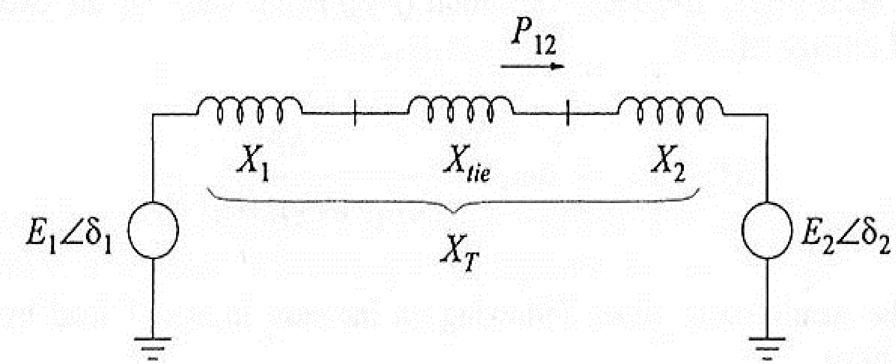
Figure 4-27. Eastern Interconnection

LFC for a Two-Area System

- Generators in each area are coherent, i.e. closely coupled internally
- Two areas are represented by two equivalent generators (modeled by a voltage source behind an equivalent reactance) interconnected by a lossless tie line



(a) Two-area system



(b) Electrical equivalent

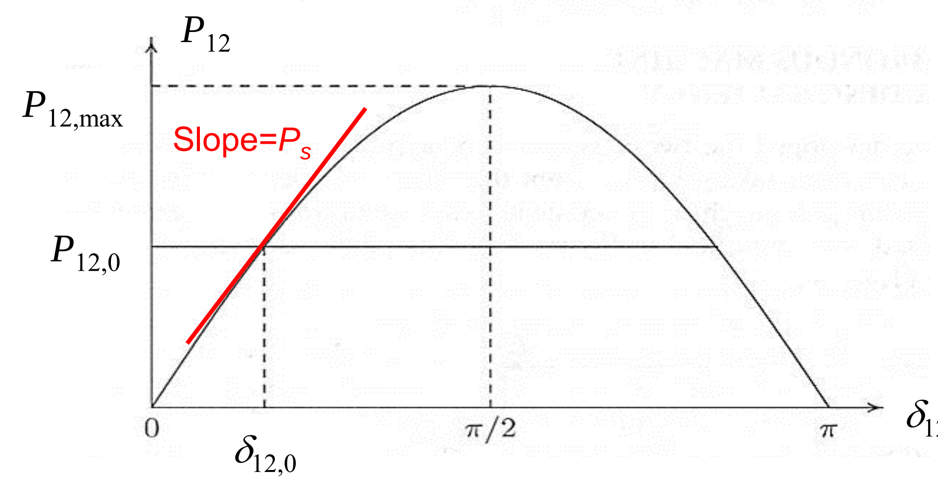
$$P_{12} = \frac{|E_1||E_2|}{X_T}\sin\delta_{12} \qquad X_T = X_1 + X_{tie} + X_2$$

$$\delta_{12} = \delta_1 - \delta_2$$

$$\Delta P_{12} \approx \left.\frac{dP_{12}}{d\delta_{12}}\right|_{\delta_{12_0}} \Delta\delta_{12} = P_s\Delta\delta_{12} = P_s(\Delta\delta_1 - \Delta\delta_2)$$

$$= \frac{P_s}{s}(\Delta\omega_{r1} - \Delta\omega_{r2})$$

$$P_s = \left.\frac{dP_{12}}{d\delta_{12}}\right|_{\delta_{12_0}} = \frac{|E_1||E_2|}{X_T}\cos\Delta\delta_{12_0}$$



P_s is the synchronizing power coefficient

LFC for a Two-Area System: with only the Primary Loop

- Generators in each area are coherent and represented by one equivalent generator
- Consider a load change ΔP_{L1} in area 1.
- Both areas have the same steady-state frequency deviation

$$\Delta\omega = \Delta\omega_1 = \Delta\omega_2$$

$$\Delta P_{m1} - \Delta P_{12} - \Delta P_{L1} = \Delta\omega D_1$$

$$\Delta P_{m2} + \Delta P_{12} - 0 = \Delta\omega D_2$$

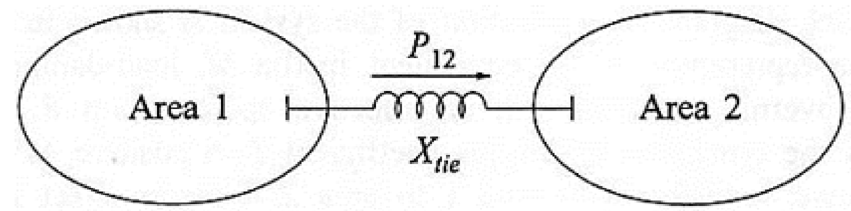
$$\Delta P_{12} = \Delta\omega D_2 - \Delta P_{m2}$$

- Changes in mechanical powers determined by governor speed characteristics:

$$\Delta P_{m1} = -\Delta\omega / R_1 \qquad \Delta P_{m2} = -\Delta\omega / R_2$$

- Solve $\Delta\omega$ and ΔP_{12}

$$\Delta\omega = \frac{-\Delta P_{L1}}{(\frac{1}{R_1} + D_1) + (\frac{1}{R_2} + D_2)} = \frac{-\Delta P_{L1}}{\beta_1 + \beta_2}$$



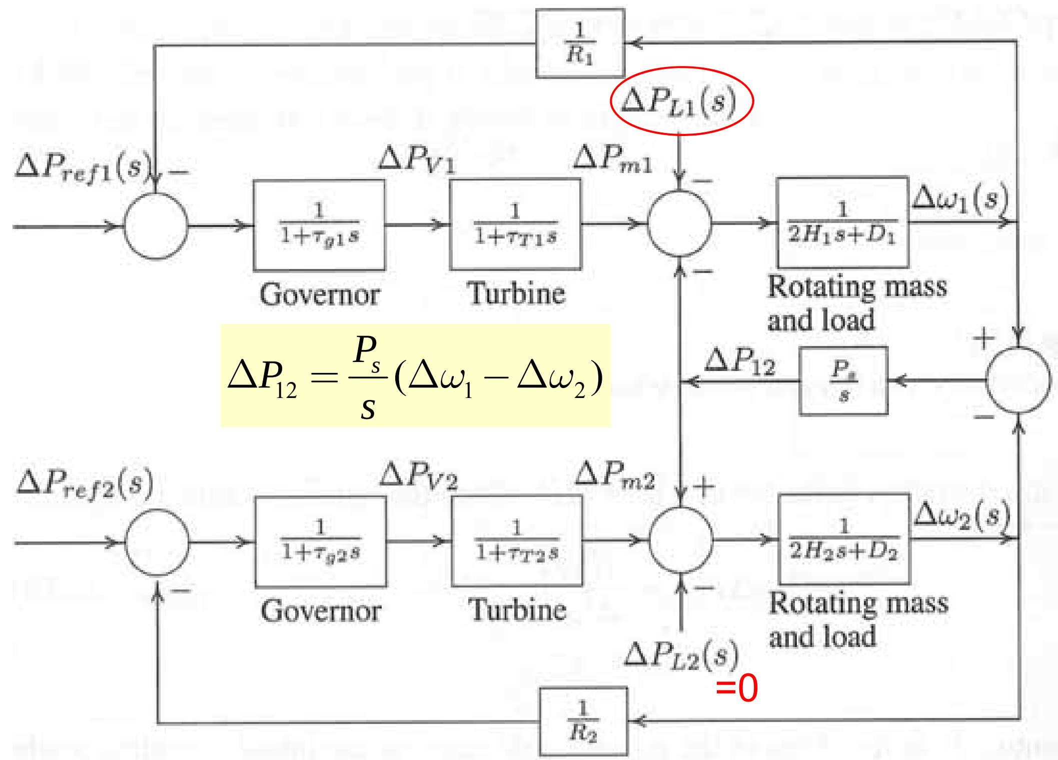


FIGURE 12.21
Two-area system with only primary LFC loop.

$$\Delta P_{12} = \Delta\omega D_2 - \Delta P_{m2} = \Delta\omega(D_2 + 1/R_2) = \Delta\omega\cdot\beta_2$$

$$= \frac{\beta_2}{\beta_1 + \beta_2}(-\Delta P_{L1})$$

Example 12.4 (chp12ex4), (sim12ex4.mdl)

A two-area system connected by a tie line has the following parameters on a 1000-MVA common base

Area	1	2
Speed regulation	$R_1 = 0.05$	$R_2 = 0.0625$
Frequency-sens. load coeff.	$D_1 = 0.6$	$D_2 = 0.9$
Inertia constant	$H_1 = 5$	$H_2 = 4$
Base power	1000 MVA	1000 MVA
Governor time constant	$\tau_{g1} = 0.2$ sec	$\tau_{g2} = 0.3$ sec
Turbine time constant	$\tau_{T1} = 0.5$ sec	$\tau_{T2} = 0.6$ sec

The units are operating in parallel at the nominal frequency of 60 Hz. The synchronizing power coefficient is computed from the initial operating condition and is given to be $P_s = 2.0$ per unit. A load change of 187.5 MW occurs in area 1.
(a) Determine the new steady-state frequency and the change in the tie-line flow.
(b) Construct the *SIMULINK* block diagram and obtain the frequency deviation response for the condition in part (a).

(a) The per unit load change in area 1 is

$$\Delta P_{L1} = \frac{187.5}{1000} = 0.1875 \text{ pu}$$

The per unit steady-state frequency deviation is

$$\Delta\omega_{ss} = \frac{-\Delta P_{L1}}{(\frac{1}{R_1} + D_1) + (\frac{1}{R_2} + D_2)} = \frac{-0.1875}{(20 + 0.6) + (16 + 0.9)} = -0.005 \text{ pu}$$

Thus, the steady-state frequency deviation in Hz is

$$\Delta f = (-0.005)(60) = -0.3 \text{ Hz}$$

and the new frequency is

$$f = f_0 + \Delta f = 60 - 0.3 = 59.7 \text{ Hz}$$

The change in mechanical power in each area is

$$\Delta P_{m1} = -\frac{\Delta\omega}{R_1} = -\frac{-0.005}{0.05} = 0.10 \text{ pu}$$
$$= 100 \text{ MW}$$

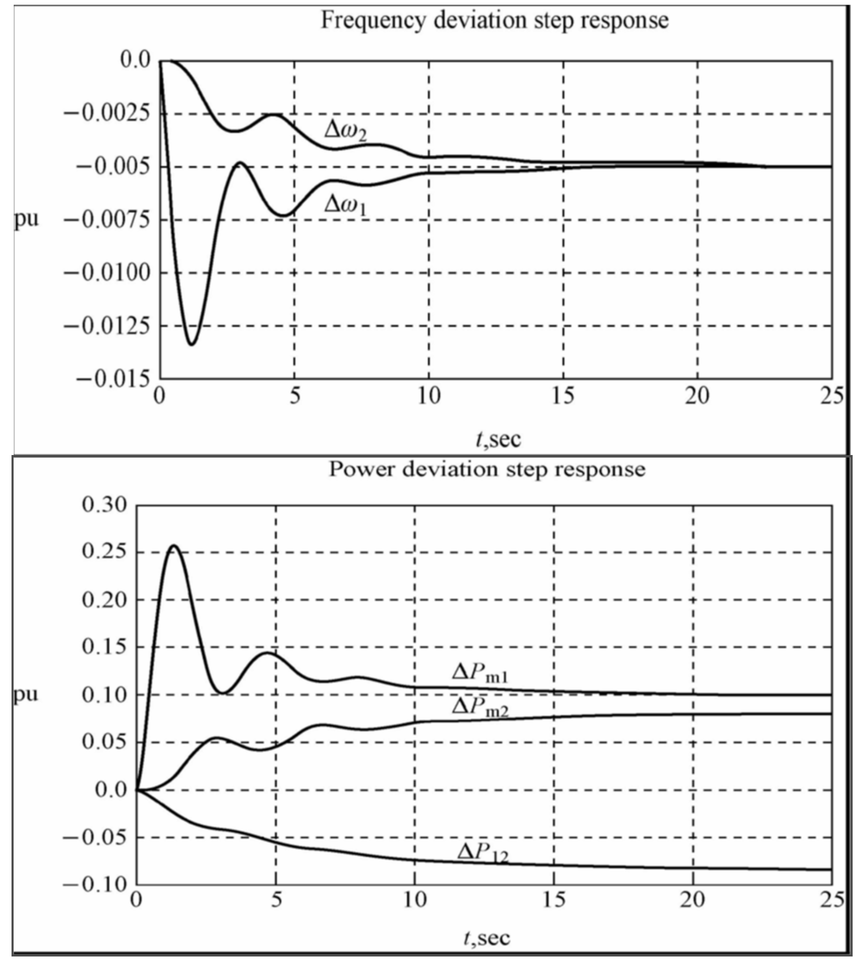
$$\Delta P_{m2} = -\frac{\Delta\omega}{R_2} = -\frac{-0.005}{0.0625} = 0.080 \text{ pu}$$
$$= 80 \text{ MW}$$

Thus, area 1 increases the generation by 100 MW and area 2 by 80 MW at the new operating frequency of 59.7 Hz. The total change in generation is 180 MW, which is 7.5 MW less than the 187.5 MW load change because of the change in the area loads due to frequency drop.

The change in the area 1 load is $\Delta\omega D_1 = (-0.005)(0.6) = -0.003$ per unit (-3.0 MW), and the change in the area 2 load is $\Delta\omega D_2 = (-0.005)(0.9) = -0.0045$ per unit (-4.5 MW). Thus, the change in the total area load is -7.5 MW. The tie-line power flow is

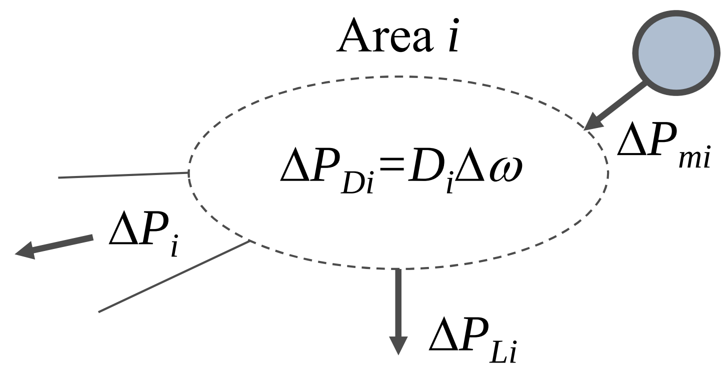
$$\Delta P_{12} = \Delta\omega\left(\frac{1}{R_2} + D2\right) = -0.005(16.9) = 0.0845 \text{ pu}$$
$$= -84.5 \text{ MW}$$

That is, 84.5 MW flows from area 2 to area 1. 80 MW comes from the increased generation in area 2, and 4.5 MW comes from the reduction in area 2 load due to frequency drop.



LFC for more than two areas

- Given load change ΔP_{Li}, find the net export change ΔP_i



$$\Delta P_{mi} = \Delta P_i + \Delta P_{Li} + \Delta P_{Di}$$

$$\Delta P_{mi} = -\Delta\omega / R_i \qquad \Delta P_{Di} = D_i \Delta\omega$$

$$\Delta P_i = -\Delta P_{Li} - \left(D_i + \frac{1}{R_i} \right) \Delta\omega \quad = -\Delta P_{Li} - \beta_i \Delta\omega$$

$$\Delta P_i = -\Delta P_{Li} - \beta_i \Delta\omega = -\Delta P_{Li} - \beta_i \frac{-\sum_j \Delta P_{Lj}}{\sum_j \beta_j}$$

From the balance in active power:

$$0 = \sum_i \Delta P_i = -\sum_i \Delta P_{Li} - \left(\sum_i \beta_i \right) \Delta\omega$$

$$\Delta\omega = \frac{-\sum_i \Delta P_{Li}}{\sum_i \beta_i} = \frac{-\sum_i \Delta P_{Li}}{\sum_i \left(D_i + \frac{1}{R_i} \right)}$$

$$\Delta P_i = \frac{-\Delta P_{Li} \sum_j \beta_j + \beta_i \sum_j \Delta P_{Lj}}{\sum_j \beta_j}$$

Example 12.4: $\Delta P_{L1} \neq 0$ and $\Delta P_{L2} = 0$

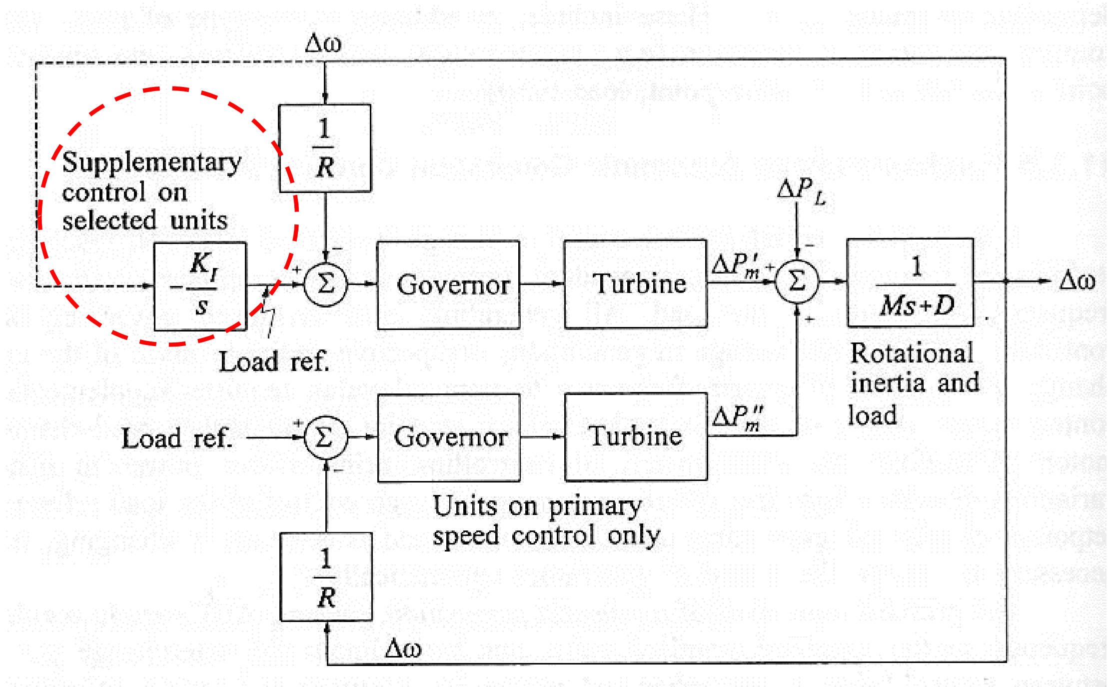
$$\Delta P_{12} = \Delta P_1 = \frac{-\Delta P_{L1}(\beta_1 + \beta_2) + \beta_1(\Delta P_{L1} + 0)}{\beta_1 + \beta_2}$$

$$= \frac{\beta_2}{\beta_1 + \beta_2} (-\Delta P_{L1})$$

Limitations of Governor Frequency Control

- Governors do not recover frequency back to the scheduled value (60Hz) due to the required % droop characteristic.
- Governor control does not adequately consider the cost of power production so control with governors alone is usually not the most economical alternative.
- Governor control is intended as a primary means of frequency control and is not suited to fine adjustment of the interconnected system frequency.
- Other limitations of a governor (see Sec. 4.3 in EPRI Tutorial)
  - Spinning Reserve is not considered;
  - Has a dead-band, typically 60Hz ± 0.03-0.04 Hz , in which it stops functioning;
  - Depends on the type of generation unit (*Hydro*: very responsive; *Combustion turbine*: may or may not be responsive; *Steam*: varies depending on the type);
  - May be blocked: a generator operator can intentionally prevent a unit from responding to a frequency disturbance.
- From studies on EI and WECC in 2011-2013, 70-80% units are modeled with governors but only 30-50% of units actually have governor responses (governors of the others are either turned off or inactive due to dead-bands).

Automatic Generation Control (AGC)



- Adding supplementary control on load reference set-points of selected generators
  - Controlling prime-mover power to match load variations
  - As system load is continually changing, it is necessary to change the output of generators automatically
- Primary objective: LFC
  - Regulating frequency to the specified nominal value, e.g. 60Hz, and maintaining the interchange power between control areas at the scheduled values by adjusting the output of selected generators
- Secondary objective: Generation Dispatch
  - Distributing the required change in generation among generators to minimize operation costs.

- During large disturbances and emergencies, AGC is bypassed and other emergency controls are applied.

AGC for an Isolated Power System

- An integral controller is added with gain K_I

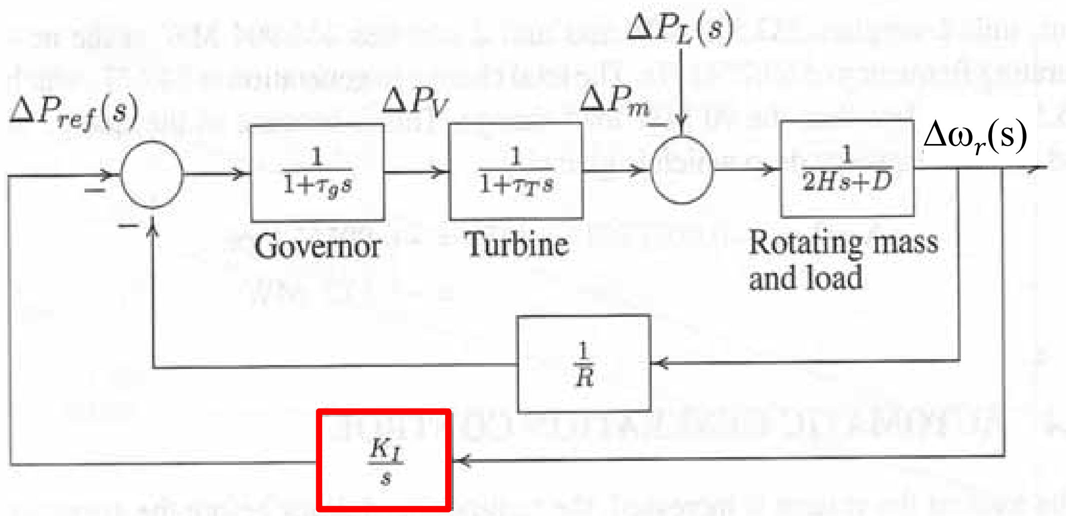


FIGURE 12.16
AGC for an isolated power system.

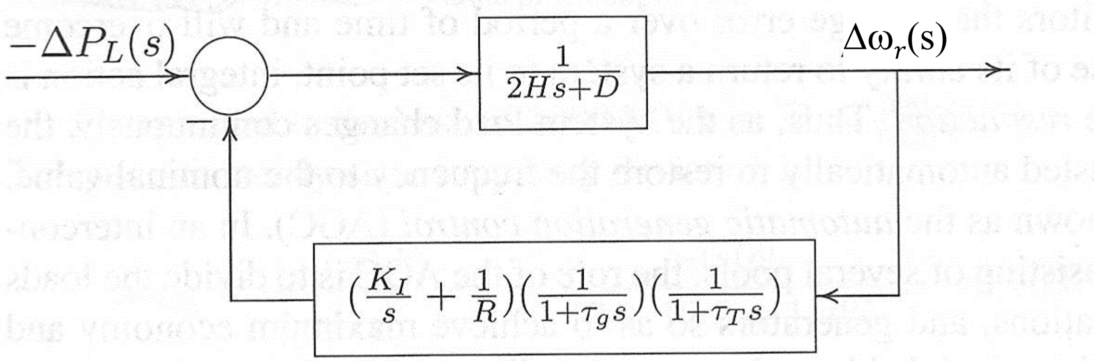
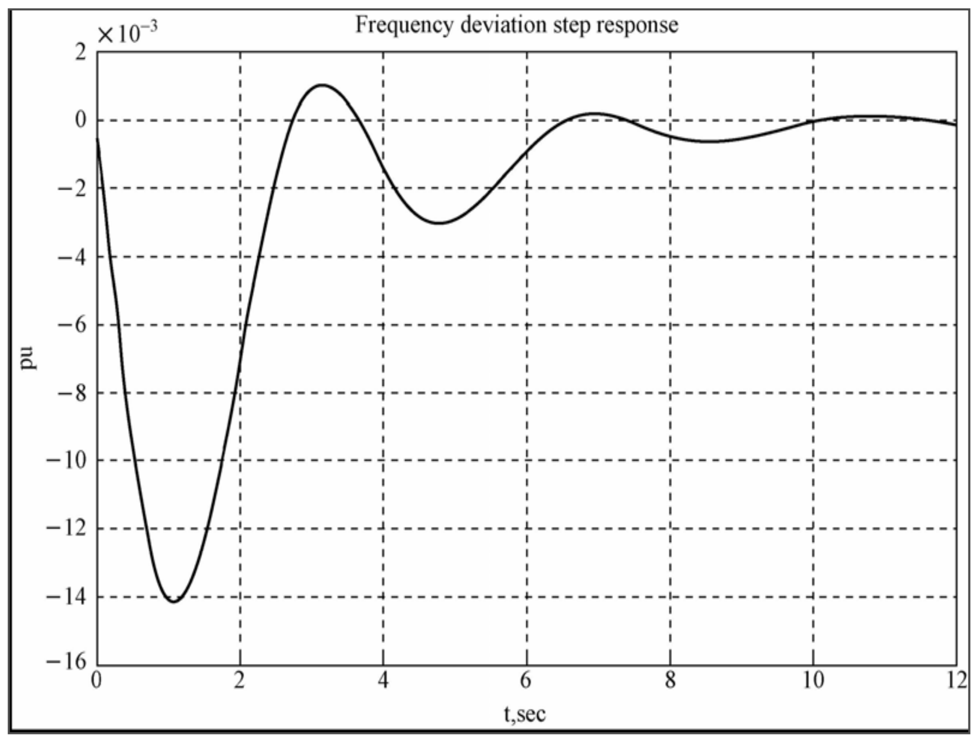


FIGURE 12.17
The equivalent block diagram of AGC for an isolated power system.

$$\frac{\Delta\omega_r(s)}{-\Delta P_L(s)} = \frac{s(1+\tau_g s)(1+\tau_T s)}{s(2Hs+D)(1+\tau_g s)(1+\tau_T s)+K_I+s/R}$$

- Example 12.3: Applied to the system in Example 12.1 with K_I=7



AGC with Frequency Bias Tie-Line Control

- The objective is to restore generation-load balance in each area
- A simple control strategy:
  - Keep frequency approximately at the nominal value (60Hz)
  - Maintain the tie-line flow at about schedule
  - Each area should absorb its own load changes
- Area Control Error (ACE): supplementary control signal added to the primary LFC through an integral controller

$$\mathrm{ACE}_i = \sum_{j=1}^{n} \Delta P_{ij} + B_i \Delta\omega$$

  - B_i: frequency bias factor (may or may not equal β_i)
  - Any combination of ACEs containing ΔP_{ij} and $\Delta\omega$ will result in steady-state restoration of the tie line flow and frequency deviation (the integral control action reduces each ACE_i to 0)
  - What composition of ACE signals should be selected is more important from dynamic performance considerations.
  - In practice, only the selected units participating in AGC receive and respond to ACE signals

Comparing different B_i's in ACE signals

- Consider a sudden load increase ΔP_{L1} in Area 1:

1) $B_i = k\beta_i = \beta_i = D + 1/R_i$

$$ACE_1 = \Delta P_{12} + \beta_1 \Delta\omega = \frac{\beta_2}{\beta_1+\beta_2}(-\Delta P_{L1}) + \beta_1 \frac{-\Delta P_{L1}}{\beta_1+\beta_2} = -\Delta P_{L1}$$

$$ACE_2 = -\Delta P_{12} + \beta_2 \Delta\omega = -\frac{\beta_2}{\beta_1+\beta_2}(-\Delta P_{L1}) + \beta_2 \frac{-\Delta P_{L1}}{\beta_1+\beta_2} = 0$$

k=1: load change is taken care of locally

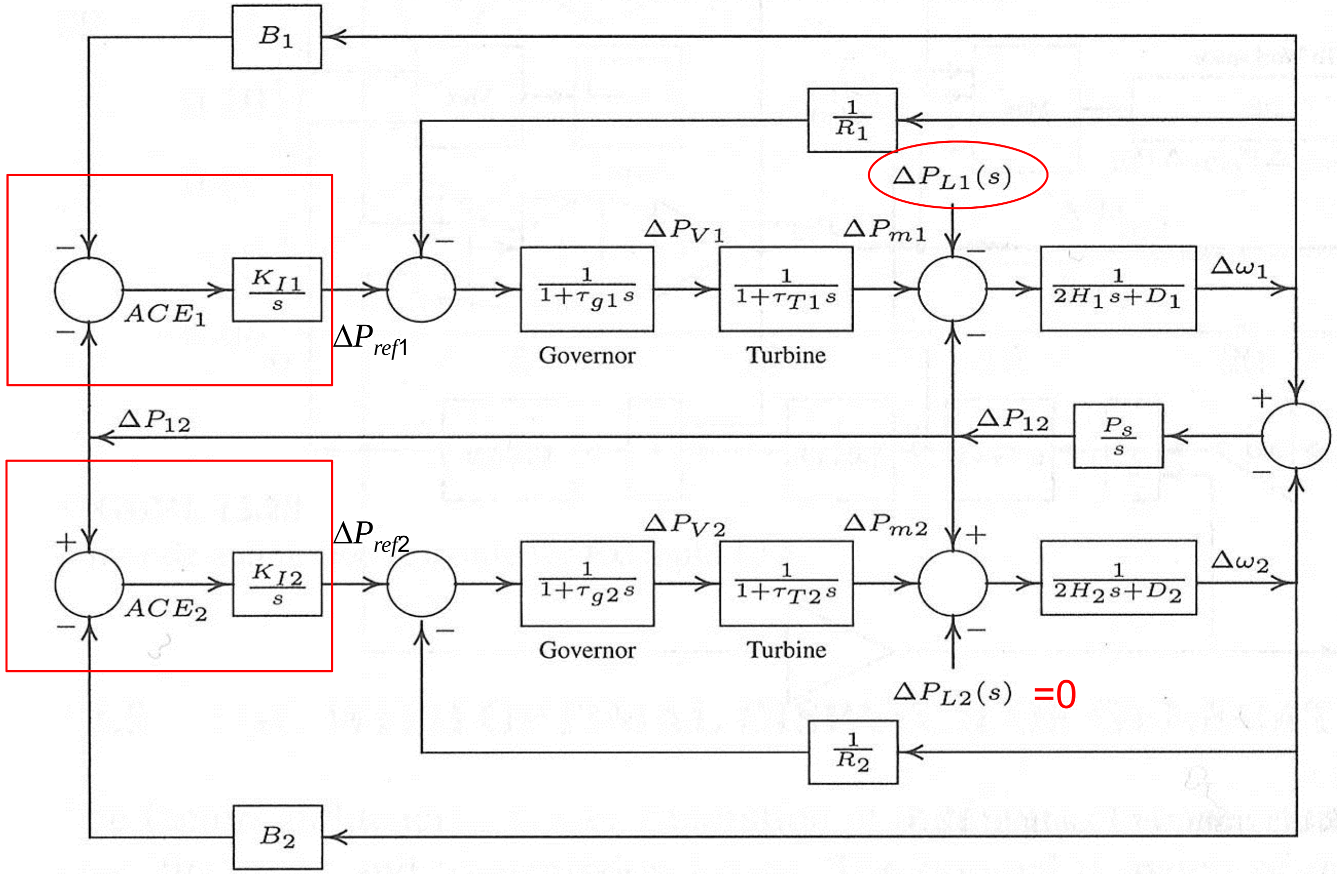


FIGURE 12.25
AGC block diagram for a two-area system.

2) $B_1 = k\beta_1$, $B_2 = k\beta_2$

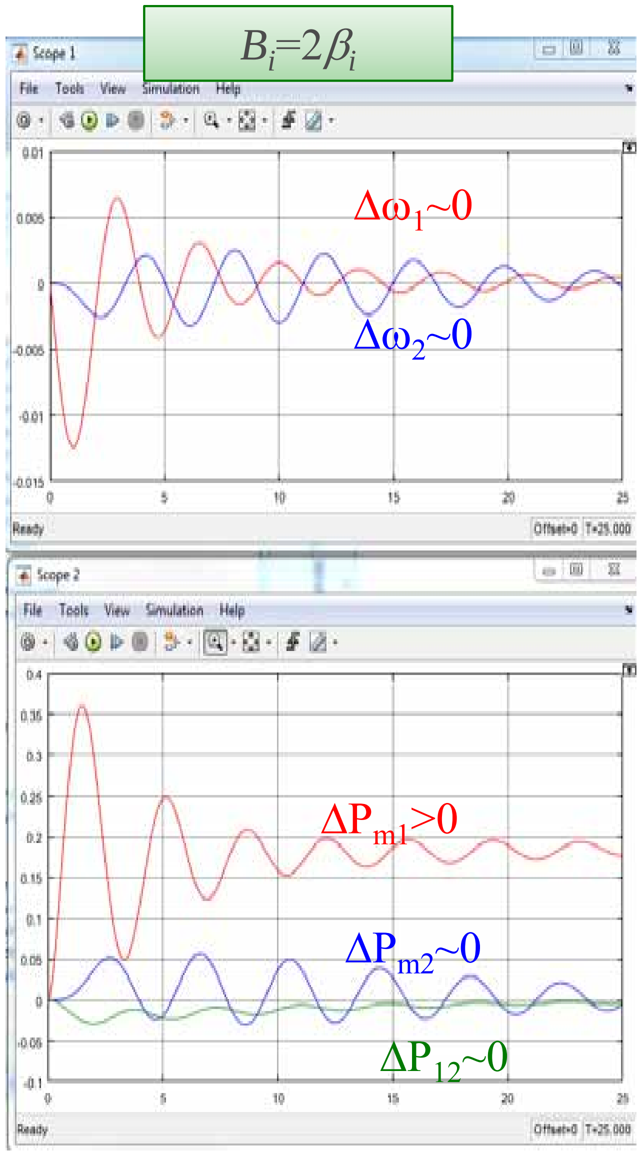
$$ACE_1 = \Delta P_{12} + k\beta_1 \Delta\omega = \frac{\beta_2}{\beta_1+\beta_2}(-\Delta P_{L1}) + k\beta_1 \frac{-\Delta P_{L1}}{\beta_1+\beta_2} = -\Delta P_{L1}\frac{k\beta_1+\beta_2}{\beta_1+\beta_2}$$

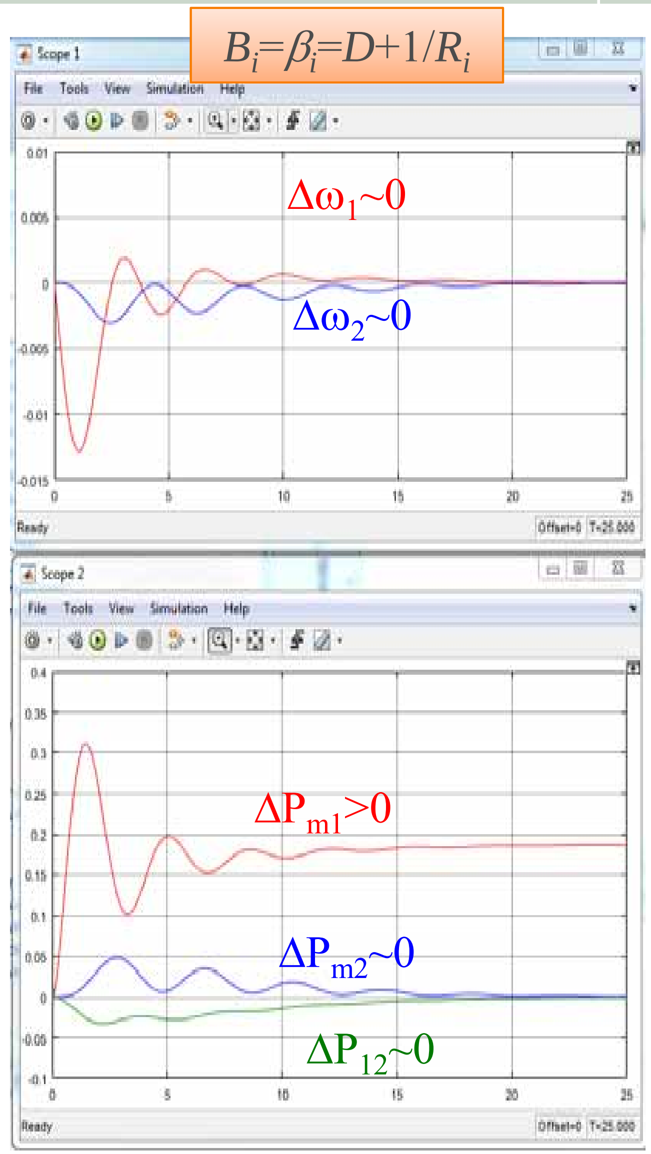
$$ACE_2 = -\Delta P_{12} + k\beta_2 \Delta\omega = -\frac{\beta_2}{\beta_1+\beta_2}(-\Delta P_{L1}) + k\beta_2 \frac{-\Delta P_{L1}}{\beta_1+\beta_2} = -\Delta P_{L1}\frac{(k-1)\beta_2}{\beta_1+\beta_2}$$

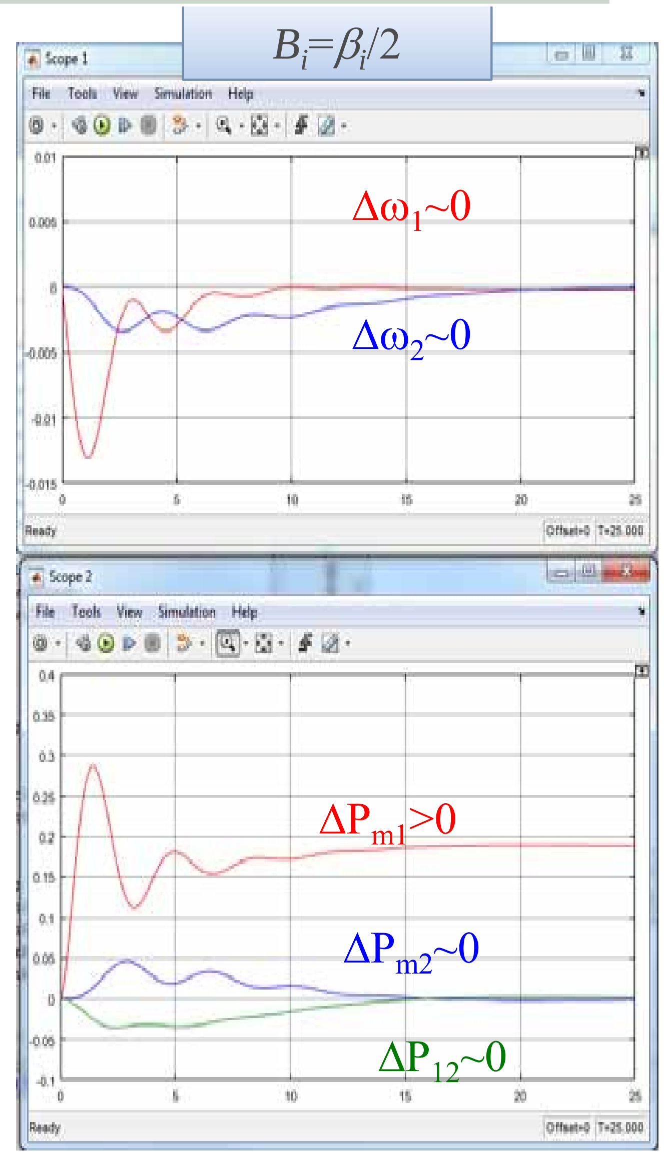
Coefficient of $-\Delta P_{L1}$ ($\beta_1=\beta_2=20$)		
k=2	k=1	k=1/2
1.5	1	0.75
0.5	0	-0.5

k>1: both generators are more active in regulating frequency

Coefficient of $-\Delta P_{L1}$ ($\beta_1=\beta_2=20$)		
$k=2$	$k=1$	$k=1/2$
1.5	1	0.75
0.5	0	-0.5







AGC for more than two areas

- By means of ACEs, the frequency bias tie-line control scheme schedules the net import/export for each area, i.e. the algebraic sum of power flows on all the tie lines from that area to the others

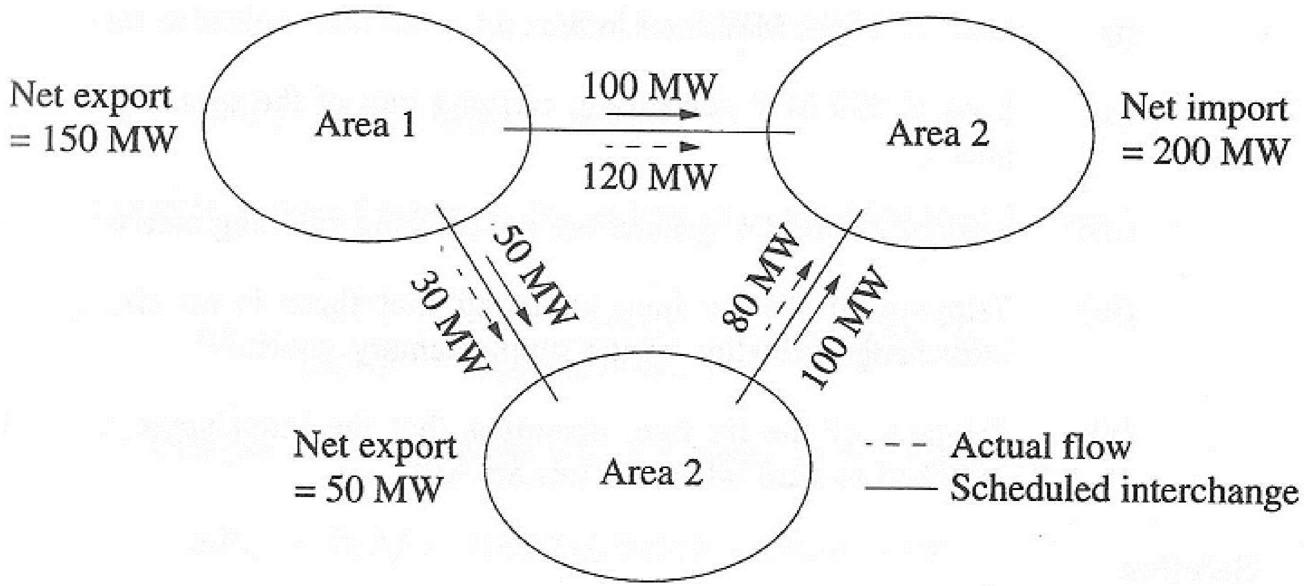
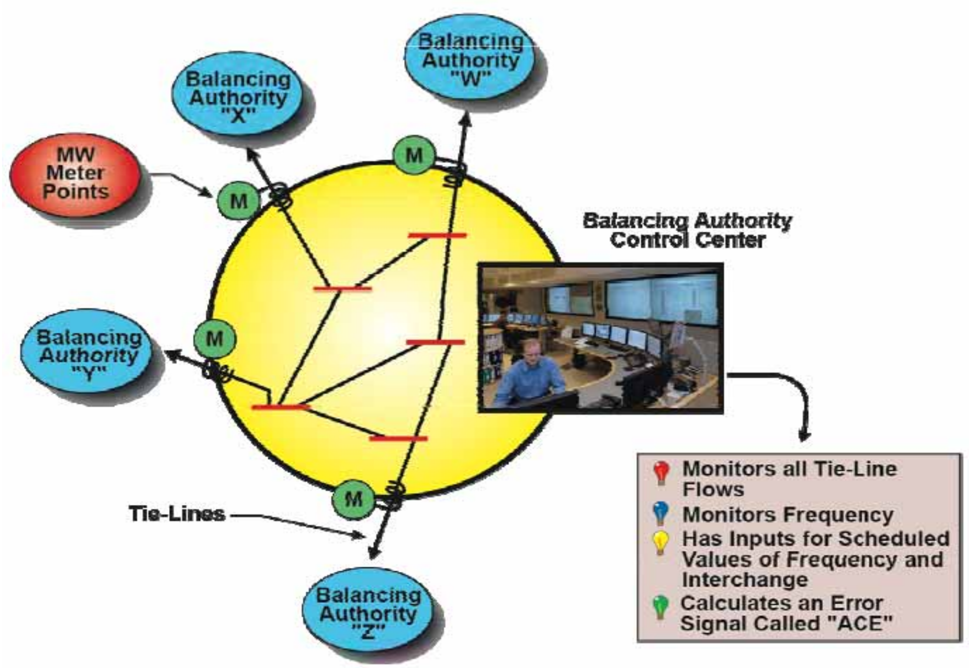
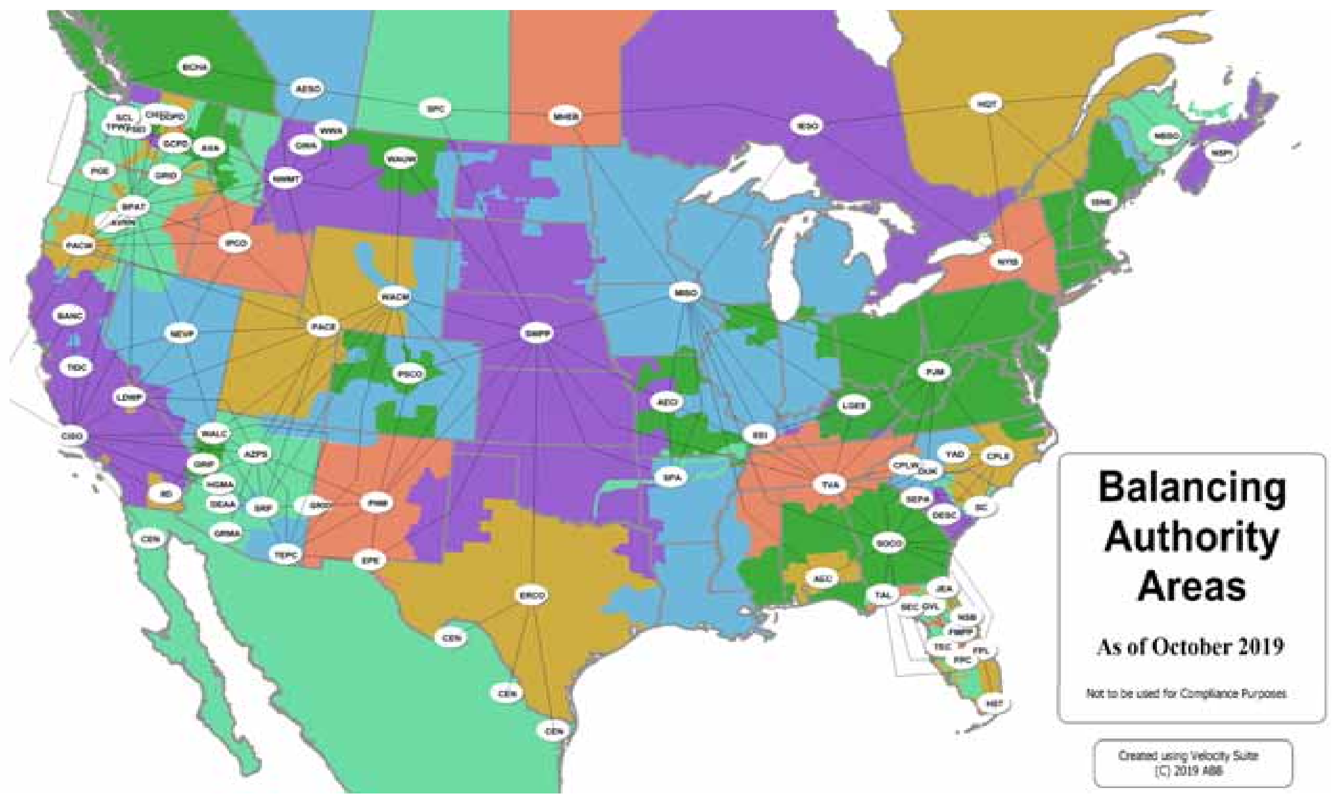


Figure 11.26 Three areas connected by tie lines

NERC Balancing Authority

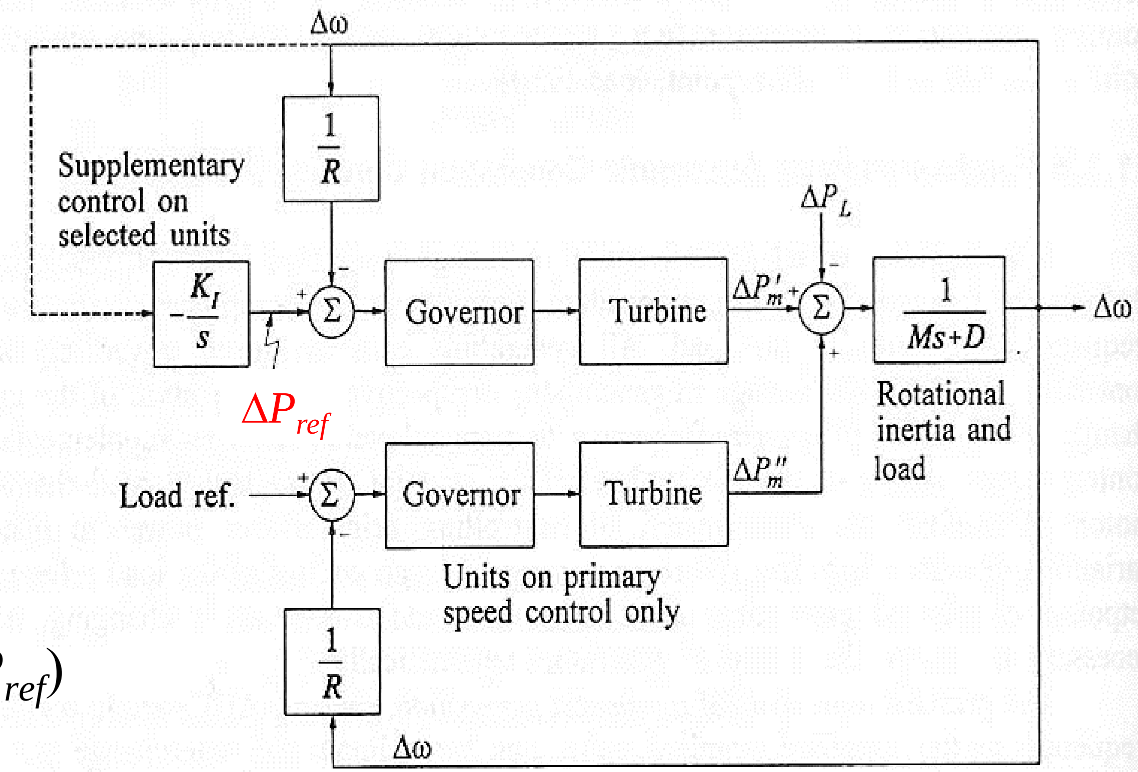
- The control center is the headquarters of the BA, where the AGC computer system is typically located and all the data collected by the AGC system are processed.
- Based on the gathered data, the AGC signals are transmitted from the control center to the various generators currently involved in supplementary control to tell the generators what generation levels (set-points) to hold.
- It is unnecessary for the AGC system to regulate outputs of all generators in a BA. Most BAs have policies requiring that as many units as needed are under control and able to respond to the BA's continual load changes. Those units that receive and respond to AGC signals are called regulating units. Their number vary from a few for a small BA to 40-50 for the largest BA





Influences from generation reserves

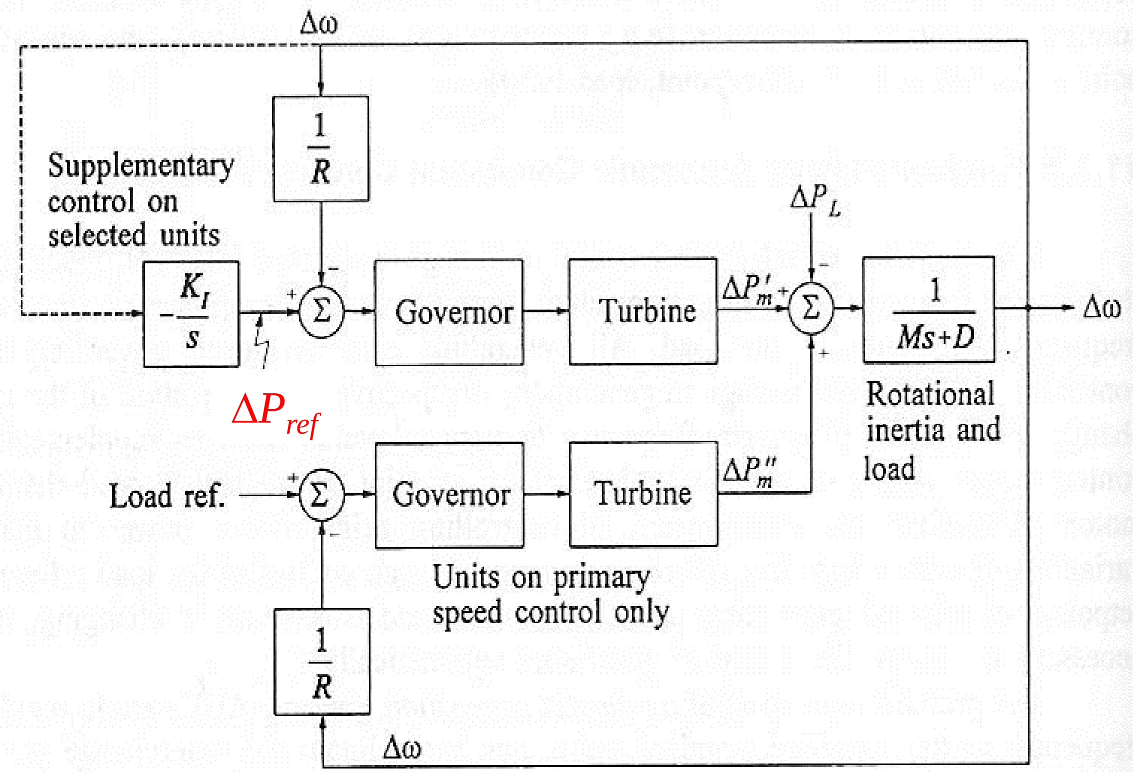
- Sufficient or insufficient spinning reserve
  - Normal conditions: each area has sufficient generation reserve to carry out its supplementary control (AGC) obligations to eliminate the ACE
  - Abnormal conditions: one or more areas cannot fully eliminate the ACE due to insufficient generation reserve; thus, there will be changes in frequency and tie-line flows (under both supplementary control and primary control)
- Operating reserve resources
  - Spinning reserve: unloaded generating capacity ($P_{ref,max}-P_{ref}$) or some interruptible load controlled automatically
  - Non-spinning reserve: not currently connected to the system but can be available within a specific time period, e.g. 15 minutes. Examples are such as combustion turbines while cold standby and some interruptible load.
- Each BA shall carry enough operating reserves.



Influences from generation reserves (cont'd)

- In an interconnect system, all generators with governors may respond to a generation/load change due to $\Delta f/R \neq 0$ or $\Delta P_{ref} \neq 0$

- **Under a sudden load increase or generation loss**, only the generators with spinning reserves can quickly increase their outputs up to their maximum output limits (by either AGC or governors)
  - "Spinning reserves consist of unloaded generating capacity that is synchronized to the power system. A governor cannot increase generation in a unit unless that unit is carrying spinning reserves. An AGC system cannot increase a unit's MW output unless that unit is carrying spinning reserves." from EPRI tutorial Sec. 4.4.2.

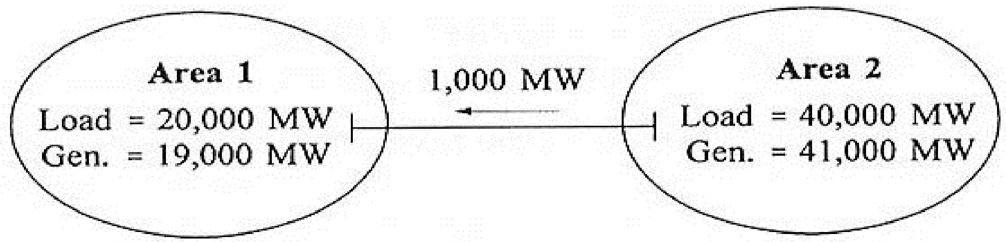


- **Under a load decrease**, all generators may reduce their outputs as long as higher than their minimum output limits.

Kundur's Example 11.3

Spinning reserve:
1,000 of 4,000MW

B_1=250MW/0.1Hz



D = 1.0
R = 5%

Spinning reserve:
1,000 of 10,000MW

B_2=500MW/0.1Hz

The connected load at 60 Hz is 20,000 MW in area 1 and 40,000 MW in area 2. The load in each area varies 1% for every 1% change in frequency. Area 1 is importing 1,000 MW from area 2. The speed regulation, R, is 5% for all units.

Area 1 is operating with a spinning reserve of 1,000 MW spread uniformly over a generation of 4,000 MW capacity, and area 2 is operating with a spinning reserve of 1,000 MW spread uniformly over a generation of 10,000 MW.

Determine the steady-state frequency, generation and load of each area, and tie line power for the following cases.

(a) Loss of 1,000 MW load in area 1, assuming that there are no supplementary controls.

(b) Each of the following contingencies, when the generation carrying spinning reserve in each area is on supplementary control with frequency bias factor settings of 250 MW/0.1 Hz for area 1 and 500 MW/0.1 Hz for area 2.

- (i) Loss of 1,000 MW load in area 1
- (ii) Loss of 500 MW generation, carrying part of the spinning reserve, in area 1
- (iii) Loss of 2,000 MW generation, not carrying spinning reserve, in area 1
- (iv) Tripping of the tie line, assuming that there is no change to the interchange schedule of the supplementary control
- (v) Tripping of the tie line, assuming that the interchange schedule is switched to zero when the ties are lost

$$\mathrm{ACE}_i = B_i\Delta f + \Delta P_{i-others} \begin{cases} = 0 & \text{with AGC and sufficient reserve} \\ \neq 0 & \text{otherwise} \end{cases}$$

Without AGC (supplementary control) or reserve:

$$-\sum_i \Delta P_{L,i} = (\sum_i \frac{1}{R_i} + \sum_i D_i) \times \Delta f \quad = (\frac{1}{R} + D) \times \Delta f$$

$$\Delta P_{Gi} - \Delta P_{Li} = D_i \Delta f + \Delta P_{i-others}$$

$$\Delta P_{Gi} = -\frac{\Delta f}{R_i}$$

Capacity of all online generators (including spinning reserve)

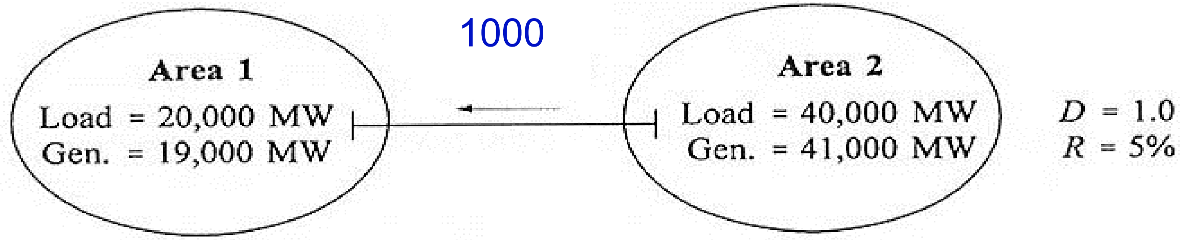
$$\frac{1}{R_i}(\text{MW/Hz}) = \frac{1}{R_i}(\text{p.u.}) \times \frac{P_{\text{gen capacity}}(\text{MW})}{60(\text{Hz})}$$

$$D_i(\text{MW/Hz}) = D_i(\text{p.u.}) \times \frac{P_{L,i}(\text{MW})}{60(\text{Hz})}$$

Spinning reserve:
1,000 of 4,000MW

B_1=250MW/0.1Hz

Loss of 1,000MW load



Spinning reserve:
1,000 of 10,000MW

B_2=500MW/0.1Hz

Solution

(a) *With no supplementary control.*

$$\frac{1}{R_i}(\text{MW/Hz}) = \frac{1}{R_i}(\text{p.u.}) \times \frac{P_{\text{gen capacity}}(\text{MW})}{60(\text{Hz})}$$

$$D_i(\text{MW/Hz}) = D_i(\text{p.u.}) \times \frac{P_{L,i}(\text{MW})}{60(\text{Hz})}$$

Assuming that none of the governors are blocked, all generating units in the two areas respond to the loss of load.

A 5% regulation on 20,000 MW generating capacity (including spinning reserve of 1,000 MW) in area 1 corresponds to

Online generators with active governor control

$$\frac{1}{R_1} = \frac{1}{0.05} \times \frac{20{,}000}{60} = 6{,}666.67 \quad \text{MW/Hz}$$

Similarly, a 5% regulation on 42,000 MW generating capacity in area 2 corresponds to

$$\frac{1}{R_2} = \frac{1}{0.05} \times \frac{42{,}000}{60} = 14{,}000.00 \quad \text{MW/Hz}$$

Total regulation due to 62,000 MW generating capacity in the two areas is

$$\frac{1}{R} = \frac{1}{R_1} + \frac{1}{R_2} = 20{,}666.67 \quad \text{MW/Hz}$$

Load damping due to 19,000 MW load (remaining after loss of 1,000 MW load) in area 1 is

$$D_1 = 1 \times \frac{19{,}000}{100} \times \frac{100}{60} = 316.67 \quad \text{MW/Hz}$$

Load damping due to 40,000 MW load in area 2 is

$$D_2 = 1 \times \frac{40{,}000}{100} \times \frac{100}{60} = 666.67 \quad \text{MW/Hz}$$

Total effective load damping of the two areas is

$$D = D_1 + D_2 = 983.33 \quad \text{MW/Hz}$$

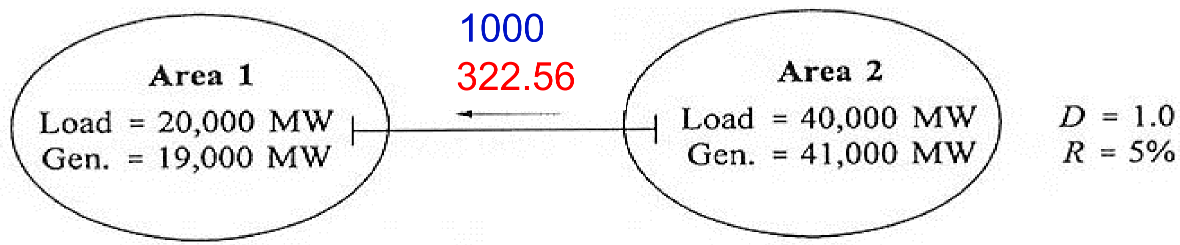
Change in system frequency due to loss of 1,000 MW load in area 1 is

$$\Delta f = \frac{-\Delta P_L}{1/R + D} = \frac{-(-1000)}{20{,}666.67 + 983.33} = 0.04619 \quad \text{Hz}$$

Spinning reserve:
1,000 of 4,000MW

B_1=250MW/0.1Hz

Loss of 1,000MW load



Spinning reserve:
1,000 of 10,000MW

B_2=500MW/0.1Hz

Load changes in the two areas due to increase in frequency are

$$\Delta P_{D1} = D_1 \Delta f = 316.67 \times 0.04619 = 14.63 \quad \text{MW}$$

$$\Delta P_{D2} = D_2 \Delta f = 666.67 \times 0.04619 = 30.79 \quad \text{MW}$$

Generation changes in the two areas due to speed regulation are

$$\Delta P_{G1} = -\frac{1}{R_1}\Delta f = 6{,}666.67 \times 0.04619 = -307.93 \quad \text{MW}$$

$$\Delta P_{G2} = -\frac{1}{R_2}\Delta f = 14{,}000.00 \times 0.04619 = -646.65 \quad \text{MW}$$

The new load, generation and tie line power flows are as follows.

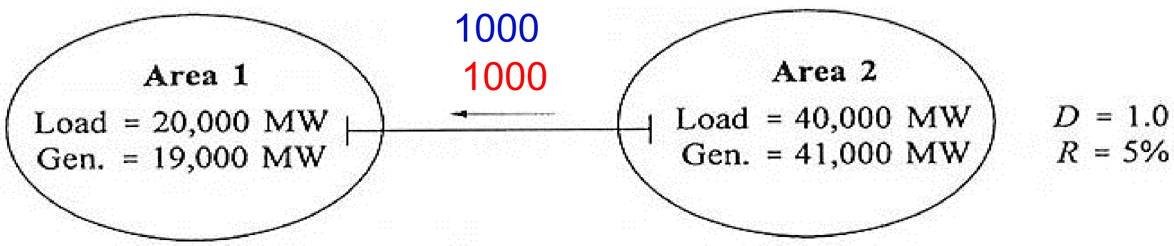
Area 1		Area 2	
Load	$= 20{,}000.00 - 1{,}000.00 + 14.63$ $= 19{,}014.63$ MW	Load	$= 40{,}000.00 + 30.79$ $= 40{,}030.79$ MW
Generation	$= 19{,}000.00 - 307.93$ $= 18{,}692.07$ MW	Generation	$= 41{,}000.00 - 646.65$ $= 40{,}353.35$ MW

Tie line power flow from area 2 to area 1 is 322.56 MW. Steady-state frequency is 60.04619 Hz.

Spinning reserve:
1,000 of 4,000MW

B_1=250MW/0.1Hz

Loss of 1,000MW load



Spinning reserve:
1,000 of 10,000MW

B_2=500MW/0.1Hz

$$\mathrm{ACE}_i = B_i \Delta f + \Delta P_{i-others} \begin{cases} = 0 & \text{with AGC and sufficient reserve} \\ \neq 0 & \text{otherwise} \end{cases}$$

(b) *With supplementary control.*

(i) Loss of 1,000 MW load in area 1:

Area 1 has a generating capacity of 4,000 MW on supplementary control, and this will reduce generation so as to bring ACE_1 to zero. Similarly, area 2 generation on supplementary control will keep ACE_2 at zero:

$$\mathrm{ACE}_1 = B_1 \Delta f + \Delta P_{12} = 0$$
$$\mathrm{ACE}_2 = B_2 \Delta f - \Delta P_{12} = 0$$

Hence,

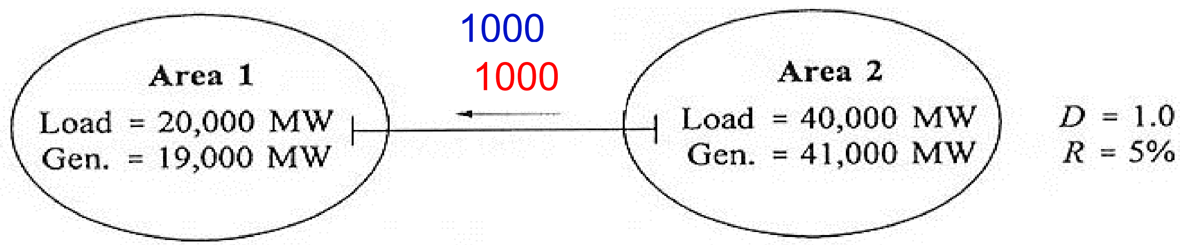
$$\Delta f = 0 \qquad \Delta P_{12} = 0$$

Area 1 generation and load are reduced by 1,000 MW. There is no steady-state change in area 2 generation and load, or the tie flow.

Spinning reserve:
1,000 of 4,000MW

B_1=250MW/0.1Hz

Loss of 500MW generation that carry part of spinning reserve



Spinning reserve:
1,000 of 10,000MW

B_2=500MW/0.1Hz

$$\mathrm{ACE}_i = B_i \Delta f + \Delta P_{i-others} \begin{cases} = 0 & \text{with AGC and sufficient reserve} \\ \neq 0 & \text{otherwise} \end{cases}$$

(ii) Loss of 500 MW generation carrying part of spinning reserve in area 1:

(Some spinning reserve is lost.)

Prior to loss of generation, area 1 had a spinning reserve of 1,000 MW spread uniformly over a generation of 4,000 MW capacity (3,000 MW generation plus 1,000 MW reserve). Spinning reserve lost with generation loss is

$$\Delta P_{Rsrv1} = \frac{500}{3{,}000} \times 1{,}000 = 166.67 \quad \text{MW}$$

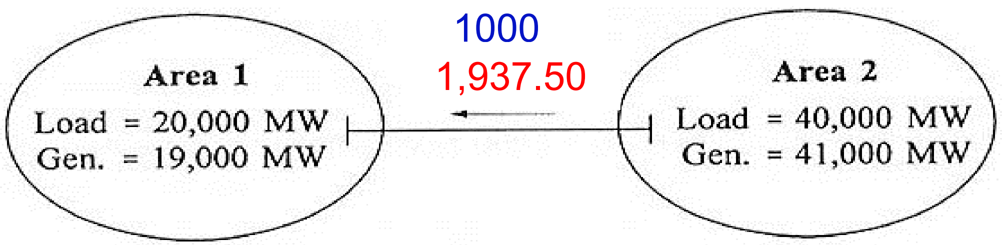
$$\frac{\Delta P_{Rsrv,i}}{\Delta P_{G,i}} = \frac{P_{Rsrv,i}}{P_{G,i}}$$

Spinning reserve remaining is 1,000.00−166.67=833.33 MW. This is sufficient to make up for 500 MW generation loss. Hence, the generation and load in the two areas are restored to their pre-disturbance values. There are no changes in tie line flow or system frequency. However, area 1 spinning reserve is reduced from 1,000 MW to 833.33−500=333.33MW

Spinning reserve:
1,000 of 4,000MW

B_1=250MW/0.1Hz

Loss of 2,000MW generation that do not carry spinning reserve



D = 1.0
R = 5%

Spinning reserve:
1,000 of 10,000MW

B_2=500MW/0.1Hz

$$\mathrm{ACE}_i = B_i\Delta f + \Delta P_{i-others} \begin{cases} = 0 & \text{with AGC and sufficient reserve} \\ \neq 0 & \text{otherwise} \end{cases}$$

(iii) Loss of 2,000 MW generation in area 1, not carrying spinning reserve:

Half of the generation loss will be made up by the 1,000 MW spinning reserve on supplementary control in area 1. When this limit is reached, area 1 is no longer able to control ACE. Supplementary control in area 2, however, is able to control its ACE. Hence,

$$\mathrm{ACE}_2 = B_2\Delta f - \Delta P_{12} = 0$$

$$\Delta P_{12} = B_2\Delta f = 5{,}000\Delta f \quad \neq 0$$

There is thus a net reduction in system frequency. This causes a reduction in loads due to frequency sensitivity.

Area 1 load damping is

$$D_1 = 1\times\frac{20{,}000}{100}\times\frac{100}{60} = 333.33 \quad \text{MW/Hz}$$

The balance of generation loss in area 1 is made up by a reduction in load and tie flow from area 2. Hence,

$$-\Delta P_{Li} = D_i\Delta f + \cancel{\frac{\Delta f}{R_i}} + \Delta P_{i-others}$$

$$-1{,}000 = D_1\Delta f + \Delta P_{12} = 333.33\Delta f + 5{,}000\Delta f$$

$$\Delta f = \frac{-1{,}000}{5{,}000+333.33} = -0.1875 \quad \text{Hz}$$

Change in area 1 load is

$$\Delta P_{D1} = D_1\Delta f = 333.33\times(-0.1875)$$
$$= -62.5 \quad \text{MW}$$

The tie flow change is

$$\Delta P_{12} = 5{,}000\times(-0.1875) = -937.5 \quad \text{MW}$$

Change in area 2 load is

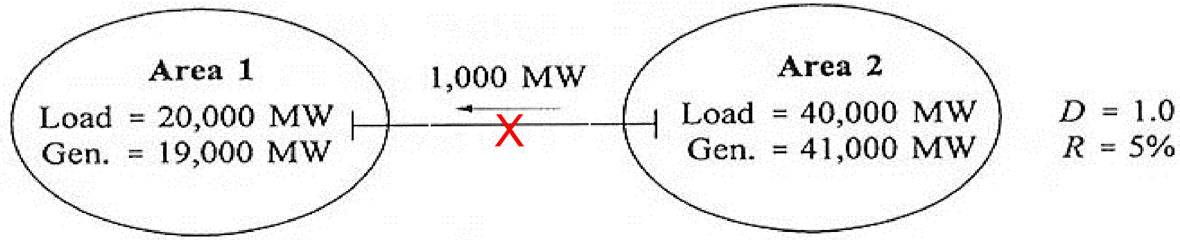
$$\Delta P_{D2} = D_2\Delta f = 666.67\times(-0.1875)$$
$$= -125.00 \quad \text{MW}$$

Area 1		Area 2	
Load	= 20,000.0 − 62.5 = 19,937.5 MW	Load	= 40,000.0 − 125.0 = 39,875.0 MW
Generation	= 19,000.0 − 1,000.0 = 18,000.0 MW	Generation	= 41,000.0 − 125.0 + 937.5 = 41,812.5 MW

The steady-state tie line power flow from area 2 to area 1 is 1,937.50 MW, and the system frequency is 60.0 − 0.1875 = 59.8125 Hz.

Spinning reserve:
1,000 of 4,000MW

B_1=250MW/0.1Hz



Spinning reserve:
1,000 of 10,000MW

B_2=500MW/0.1Hz

(iv) Tripping of the tie line, assuming no change in interchange schedule:

The supplementary control of area 1 attempts to maintain interchange schedule at 1,000 MW. Hence,

$$\mathrm{ACE}_1 = \Delta P_{12} + B_1 \Delta f_1 = 1{,}000 + 2{,}500 \Delta f = 0$$

$$\mathrm{ACE}_i = B_i \Delta f + \Delta P_{i-others} \begin{cases} = 0 & \text{with AGC and sufficient reserve} \\ \neq 0 & \text{otherwise} \end{cases}$$

Solving, we find

$$\Delta f_1 = -\frac{1000}{2500} = -0.4 \quad \mathrm{Hz}$$

Change in area 1 load is

$$\Delta P_{D1} = D_1 \Delta f_1 = 333.33 \times (-0.4) = -133.33 \quad \mathrm{MW}$$

Similarly for area 2, we have

$$\Delta f_2 = \frac{1{,}000}{5{,}000} = 0.2 \quad \mathrm{Hz}$$

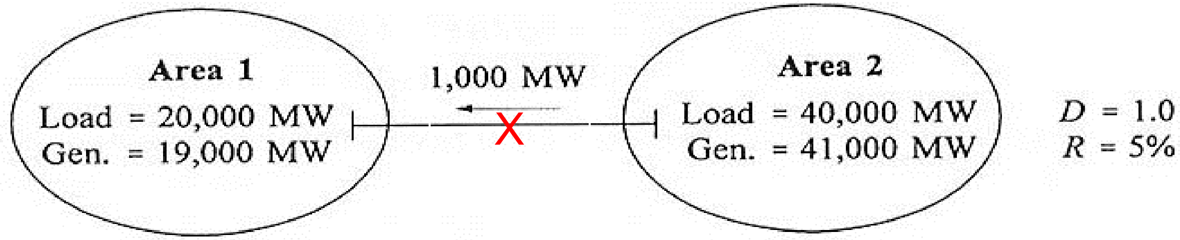
$$\Delta P_{D2} = 666.67 \times 0.2 = 133.33 \quad \mathrm{MW}$$

The area load, generation, and frequencies are as follows:

Area 1		Area 2	
Load	= 20,000.00 − 133.33 = 19,866.67 MW	Load	= 40,000.00 + 133.33 = 40,133.33 MW
Generation	= 19,866.67 MW	Generation	= 40,133.33 MW
f_1	= 59.6 Hz	f_2	= 60.2 Hz

Spinning reserve:
1,000 of 4,000MW

B_1=250MW/0.1Hz



Spinning reserve:
1,000 of 10,000MW

B_2=500MW/0.1Hz

(v) Tripping of the tie line, with interchange schedule switched to zero:

With interchange schedule switched to zero, area 1 supplementary control will pick up 1,000 MW generation to make up for loss of import power. Similarly, area 2 supplementary control reduces generation by 1,000 MW to compensate for loss of export. The generation in each area is equal to the respective loads and the area frequencies are equal to 60 Hz.

Frequency response following the loss of a generator

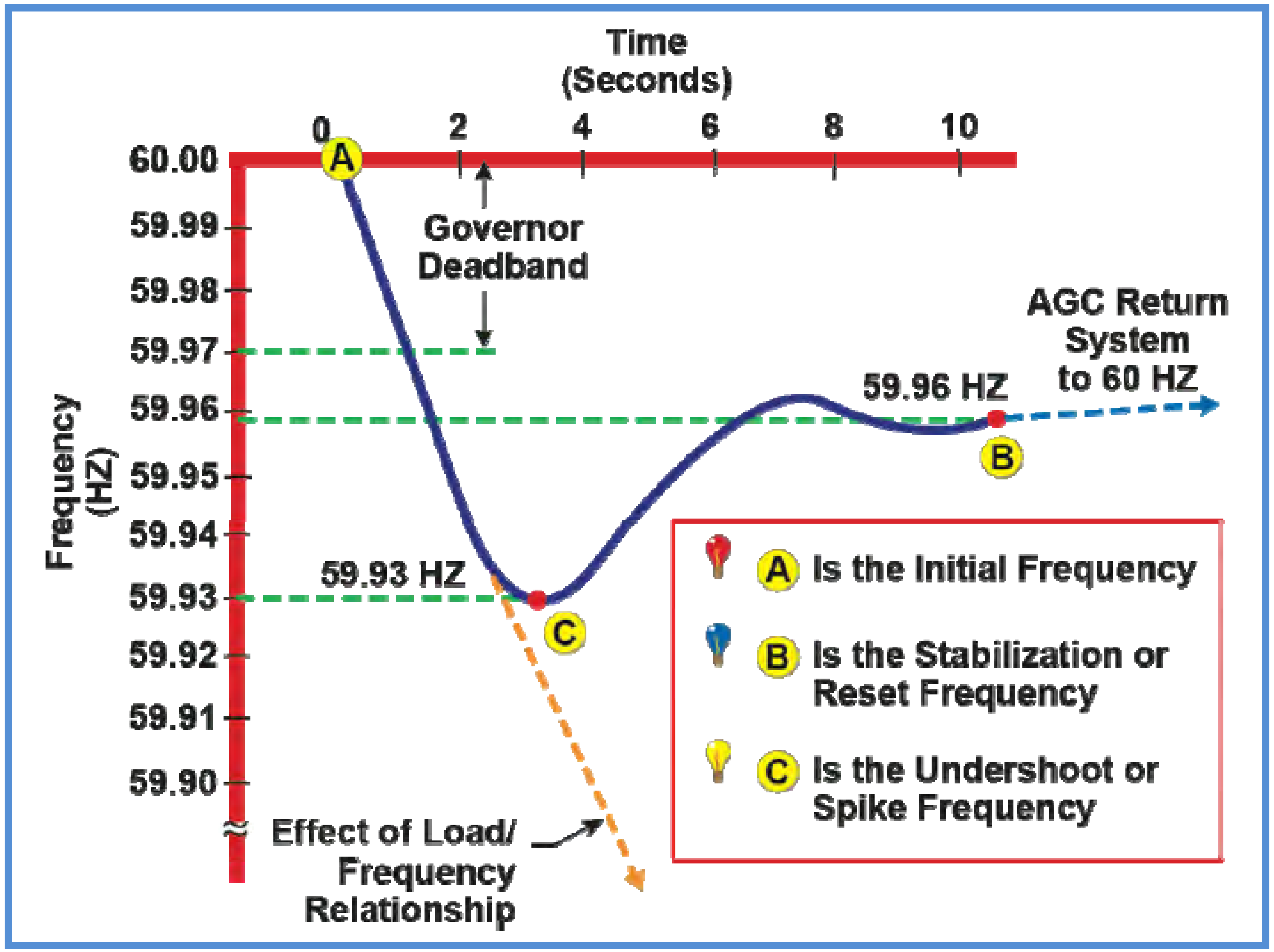
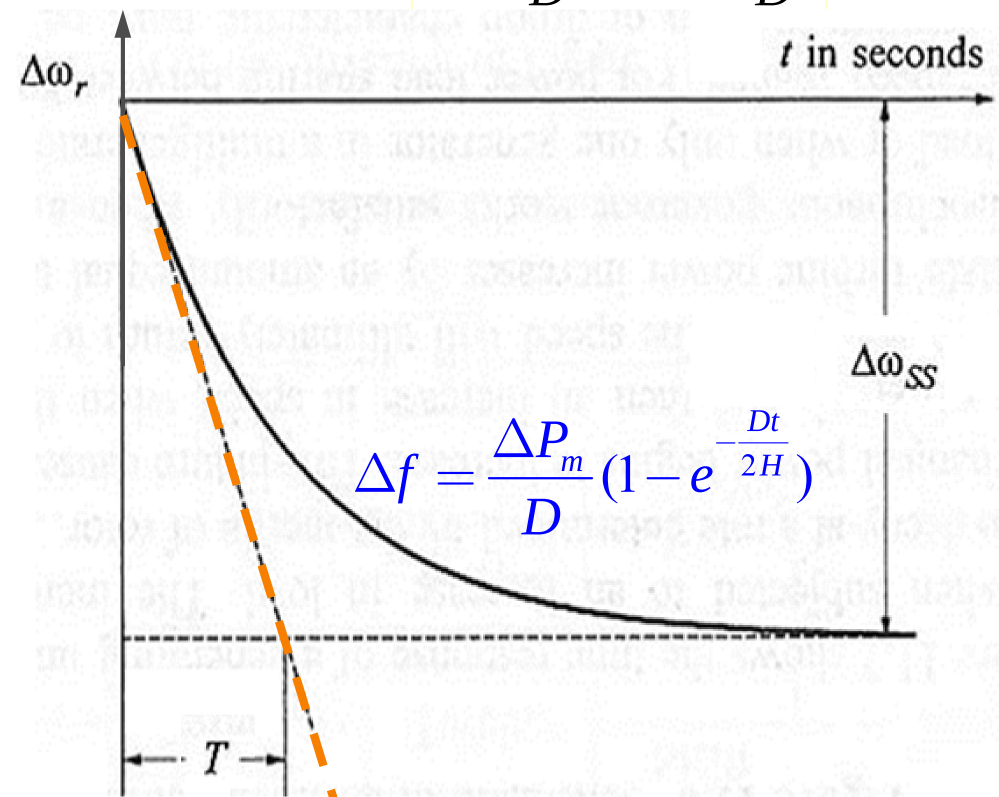


Figure 4-54. Plot of a Simulated Frequency Disturbance

$$\Delta P_m \text{ or } -\Delta P_L \longrightarrow \boxed{\frac{K}{1+sT}} \longrightarrow \Delta\omega_r$$

$$K = \frac{1}{D}, \quad T = \frac{2H}{D}$$



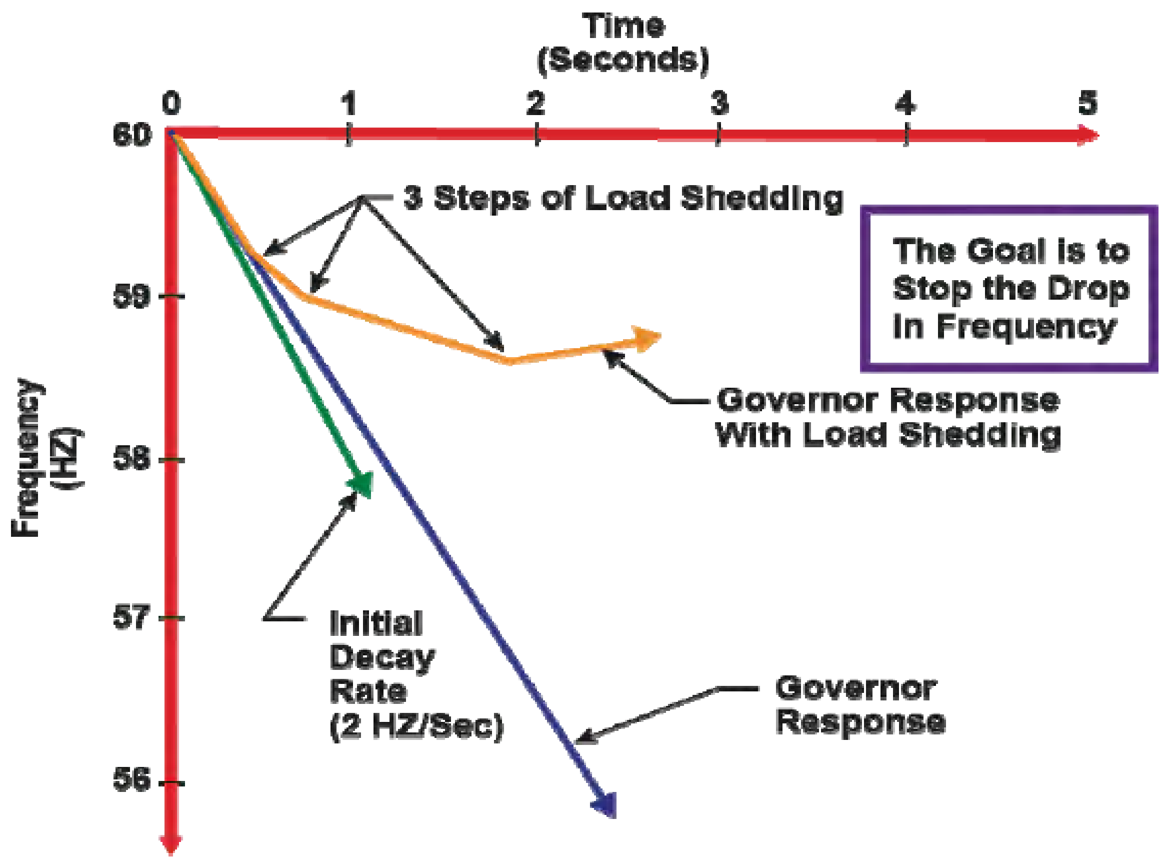
$$\Delta f = \frac{\Delta P_m}{D}\left(1 - e^{-\frac{Dt}{2H}}\right)$$

$$\left.\frac{df}{dt}\right|_{t=0} (\text{Hz/sec}) = \left.\frac{\Delta P_m}{2H} e^{-\frac{Dt}{2H}}\right|_{t=0} \times 60$$

$$= \frac{\Delta P_m}{2H} \times 60 \ (\text{Hz / sec})$$

Underfrequency Load Shedding (UFLS)

- In many situations, a frequency decline may lead to tripping of steam turbine generators by underfrequency protective relays, thus aggravating the situation further.
- UFLS is a protection program that automatically trips selected customer loads once frequency falls below a specific value.
- The intent of UFLS is not to recover the frequency to 60 Hz but rather to arrest or stop the frequency decline. Once UFLS has operated, manual intervention by the system operators is likely required to restore the system frequency to a healthy state.



- A typical UFLS setting for a North American utility may include three steps conducted by under-frequency relays, e.g.,
  1. shedding 10% load at 59.3 HZ
  2. shedding 10% additional load at 59.0 HZ
  3. shedding 10% more at 58.7Hz

North American Industry Practices in Frequency Control

References

- "Balancing and Frequency Control," NERC resources Subcommittee, January 26, 2011

http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

- "Generation Control" Interconnection Training Program, 2010

http://www.pjm.com/~/media/training/nerc-certifications/gc-gencontrol.ashx

Hierarchical Load balancing and Frequency control

Control Continuum

Summary Table 1 summarizes the discussion on the control continuum and identifies the service[5] that provides the control and the NERC standard that addresses the adequacy of the service.

Control	Ancillary Service/IOS	Timeframe	NERC Standard
Primary Control	Frequency Response	10-60 Seconds	FRS-CPS1
Secondary Control	Regulation	1-10 Minutes	CPS1– CPS2 – DCS - BAAL
Tertiary Control	Imbalance/Reserves	10 Minutes - Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	TEC

Source: "Balancing and Frequency Control," NERC resources Subcommittee, Jan 26, 2011

Time Control and Time Error Correction

- Even with AGC, the average frequency over time of one interconnection usually is not exactly 60 Hz because of occasional errors in tie-line meters caused by transducer inaccuracy, hardware/software problems with SCADA, or communications errors.
- Each Interconnection designates one Reliability Coordinator to monitor and calculate frequency/time error and request time error corrections so as to maintain the long-term average frequency at 60Hz. For example, MISO (Midcontinent Independent System Operator) is the Time Monitor for EI.
- The Time Monitor compares a clock using Interconnection frequency as a reference against "official time" provided by the NIST (National Institute of Standards and Technology).
- For example, if frequency=60.002Hz,
  - The clock using Interconnection frequency will gain a Time Error of 1.2 seconds in a 10 hour interval: (60.002 Hz-60.000 Hz)/60 Hz × 10 hrs × 3600 s/hr = 1.2 s
  - If the Time Error accumulates to a pre-determined value (e.g., +10 seconds in the EI), the Time Monitor will send notices for all BAs to offset their scheduled frequency by -0.02Hz (i.e. 59.98Hz).
  - This offset, known as Time Error Correction, will be maintained until Time Error has decreased below the termination threshold (i.e. +6 s in the EI).