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

$$
\Delta P_{m1} = -\frac{\Delta \omega_{ss}}{R_1} \quad \Delta P_{m2} = -\frac{\Delta \omega_{ss}}{R_2}
$$

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

Adjusting $R_1$ and $R_2$ may change generation dispatch between Units 1 and 2.
Composite Frequency Response Characteristic (FRC)

- 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.

\[ M_{eq} = 2H_{eq} = 2 \times (H_1 + \ldots + H_n) \]

\[ R_{eq} = \frac{1}{1/R_1 + \ldots + 1/R_n} \]

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

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

- 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 4-27. Eastern Interconnection

Figure 4-28. Western Interconnection

Figure 4-29. ERCOT 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

\[
P_{12} = \frac{|E_1| |E_2|}{X_T} \sin \delta_{12} \quad X_T = X_1 + X_{tie} + X_2
\]

\[
\delta_{12} = \delta_1 - \delta_2
\]

\[
\Delta P_{12} \approx \frac{dP_{12}}{d\delta_{12}} \bigg|_{\delta_{120}} \Delta \delta_{12} = P_s \Delta \delta_{12} = P_s (\Delta \delta_1 - \Delta \delta_2)
\]

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

\[
P_s = \frac{dP_{12}}{d\delta_{12}} \bigg|_{\delta_{120}} = \frac{|E_1| |E_2|}{X_T} \cos \Delta \delta_{120}
\]

\(P_s\) is the synchronizing power coefficient

(a) Two-area system

(b) Electrical equivalent

\(P_{12,\text{max}}\)

Slope = \(P_s\)
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 $\Delta P_{L1}$ 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:
  \[ \Delta P_{m1} = -\Delta \omega / R_1 \quad \Delta P_{m2} = -\Delta \omega / R_2 \]
- Solve $\Delta \omega$ and $\Delta P_{12}$
  \[ \Delta \omega = \frac{-\Delta P_{L1}}{\left(\frac{1}{R_1} + D_1\right) + \left(\frac{1}{R_2} + D_2\right) / (\beta_1 + \beta_2)} = \frac{-\Delta P_{L1}}{\beta_1 + \beta_2} \]
  \[ \Delta P_{12} = \Delta \omega D_2 - \Delta P_{m2} = \Delta \omega (D_2 + 1 / R_2) = \Delta \omega \cdot \beta_2 \]
  \[ = \frac{\beta_2}{\beta_1 + \beta_2} (-\Delta P_{L1}) \]
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:

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

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

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

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

$$\Delta P_{t2} = \Delta \omega \left(\frac{1}{R_2} + D_2\right) = -0.005(16.9) = 0.0845 \text{ pu}$$

$$= -84.5 \text{ MW}$$

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.
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 (see Sec. 4.3 in EPRI Tutorial)
  – Spinning Reserve is not considered
  – Governors have dead-bands (not functioning in $60\pm0.03$ to $0.04$Hz)
  – Depends on the type of Unit ($Hydro$: very responsive; $Combustion$ $turbine$: may or may not be responsive; $Steam$: varies depending on the type)
  – Governors may be blocked: a generator operator can intentionally prevent the 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)
Impact of Governor Dead-band on Frequency Response


Fig. 19. Case A locations.

Fig. 20. Case A—measurement in North Carolina.

Fig. 27. Case B locations.

Fig. 28. Case B—measurement in Ohio.

1GW generator trip

Improved model accuracy
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**
  - i.e. 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**
  - i.e. 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 $K_i$

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

- Applied to the system in Example 12.1 (Example 12.3) 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

\[ \text{ACE}_i = \sum_{j=1}^{n} \Delta P_{ij} + B_i \Delta \omega \]

– \( B_i \): frequency bias factor (may or may not equal \( \beta_i \))
– Any combination of ACEs containing \( \Delta P_{ij} \) and \( \Delta \omega \) will result in steady-state restoration of the tie line flow and frequency deviation (the integral control action reduces each \( \text{ACE}_i \) to 0)
– What composition of ACE signals should be selected is more important from dynamic performance considerations.
Comparing different $B_i$’s in ACE signals

• Consider a sudden load increase $\Delta P_{L1}$ in Area 1:

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

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

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

Load change is taken care of locally

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

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

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

What does $k \neq 1$ mean? ($k > 1$: both generators are dynamically more active in regulating frequency)

<table>
<thead>
<tr>
<th>Coefficient of $-\Delta P_{L1}$</th>
<th>$k=2$</th>
<th>$k=1$</th>
<th>$k=1/2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>($\beta_1 = \beta_2 = 20$)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$1.5$</td>
<td>$1$</td>
<td>$0.75$</td>
<td></td>
</tr>
<tr>
<td>$0.5$</td>
<td>$0$</td>
<td>$-0.5$</td>
<td></td>
</tr>
</tbody>
</table>
In practice, only selected units participate in AGC, i.e. receiving supplementary control signals (ACE).
\[ B_i = 2\beta_i \]

\[ B_i = \beta_i = D + 1/R_i \]

\[ B_i = \beta_i / 2 \]

\[ \Delta \omega_1 \sim 0 \]
\[ \Delta \omega_2 \sim 0 \]

\[ \Delta P_{m1} > 0 \]
\[ \Delta P_{m2} \sim 0 \]
\[ \Delta P_{12} \sim 0 \]
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.

![Diagram of power flows between areas](image)

*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 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 \((P_{\text{ref,max}} - P_{\text{ref}})\), 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.*
Notes on AGC

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

• For a sudden load increase or generation loss, only generators with spinning reserves may quickly increase their outputs up to their maximum output limits (by either governors or AGC)
  – EPRI tutorial Sec. 4.4.2: “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.”

• For 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

\[ B_1 = 250 \text{MW}/0.1 \text{Hz} \]

Spinning reserve: 1,000 of 10,000MW

\[ B_2 = 500 \text{MW}/0.1 \text{Hz} \]

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 (losing some spinning reserve)

(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
Spinning reserve: 1,000 of 4,000MW
\( B_1 = 250 \text{MW/0.1Hz} \)

Spinning reserve: 1,000 of 10,000MW
\( B_2 = 500 \text{MW/0.1Hz} \)

\[ \text{ACE}_i = B_i \Delta f + \Delta P_{i - \text{others}} \]

\[ = 0 \text{ with sufficient reserve} \]

\[ \text{or } \neq 0 \text{, otherwise} \]

\[ \Delta P_{mi} - \Delta P_{Li} = D_i \Delta f + \Delta P_{i - \text{others}} \]

\[ - \sum_i \Delta P_{L,i} = (\sum_i 1/R_i + \sum_i D_i) \Delta f \]

\[ = (1/R + D) \Delta f \]

**FIGURE 12.25**
AGC block diagram for a two-area system.
Loss of 1,000MW load

Solution

(a) *With no supplementary control.*

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

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

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

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

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

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

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

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

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

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

Total effective load damping of the two areas is

\[
D = D_1 + D_2 = 983.33 \text{ MW/Hz}
\]
Loss of 1,000MW load

Spinning reserve: 1,000 of 4,000MW

\[ B_1 = 250\text{MW/0.1Hz} \]

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

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

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

\[
\Delta P_{D1} = D_1 \Delta f = 316.67 \times 0.04619 = 14.63 \text{ MW}
\]

\[
\Delta P_{D2} = D_2 \Delta f = 666.67 \times 0.04619 = 30.79 \text{ MW}
\]

Generation changes in the two areas due to speed regulation are

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

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

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

<table>
<thead>
<tr>
<th>Area 1</th>
<th>Area 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load</td>
<td>Load</td>
</tr>
<tr>
<td>= 20,000.00 - 1,000.00 + 14.63</td>
<td>= 40,000.00 + 30.79</td>
</tr>
<tr>
<td>= 19,014.63 MW</td>
<td>= 40,030.79 MW</td>
</tr>
<tr>
<td>Generation</td>
<td>Generation</td>
</tr>
<tr>
<td>= 19,000.00 - 307.93</td>
<td>= 41,000.00 - 646.65</td>
</tr>
<tr>
<td>= 18,692.07 MW</td>
<td>= 40,353.35 MW</td>
</tr>
</tbody>
</table>

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

$$ACE_1 = B_1 \Delta f + \Delta P_{12} = 0$$
$$ACE_2 = B_2 \Delta f - \Delta P_{12} = 0$$

Hence,

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

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.
Loss of 500MW generation carrying part of spinning reserve

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

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

\[
\frac{500}{3,000} \times 1,000 = 166.67 \text{ MW}
\]

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 = 333.33 MW

Spinning reserve:
- Area 1: 1,000 of 4,000MW
- Area 2: 1,000 of 10,000MW

\[B_1 = 250\text{MW}/0.1\text{Hz}\]

\[B_2 = 500\text{MW}/0.1\text{Hz}\]
(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,
\[
\Delta P_{12} = B_2 \Delta f = 5,000 \Delta f
\]
There is thus a net reduction in system frequency. This causes a reduction in loads due to frequency sensitivity.

Area 1 load damping is
\[
D_1 = \frac{1 \times 20,000 \times 100}{100 \times 60} = 333.33 \text{ MW/Hz}
\]
The balance of generation loss in area 1 is made up by a reduction in load and tie flow from area 2. Hence,
\[
-1,000 = D_1 \Delta f + \Delta P_{12} = 333.33 \Delta f + 5,000 \Delta f
\]
\[
\Delta f = \frac{-1,000}{5,000 + 333.33} = -0.1875 \text{ Hz}
\]

Change in area 1 load is
\[
\Delta P_{D_1} = D_1 \Delta f = 333.33 \times (-0.1875) = -62.5 \text{ MW}
\]
The tie flow change is
\[
\Delta P_{12} = 5,000 \times (-0.1875) = -937.5 \text{ MW}
\]
Change in area 2 load is
\[
\Delta P_{D_2} = D_2 \Delta f = 666.67 \times (-0.1875) = -125.0 \text{ MW}
\]

<table>
<thead>
<tr>
<th>Area 1</th>
<th>Area 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load</td>
<td>20,000.0 – 62.5</td>
</tr>
<tr>
<td></td>
<td>19,937.5 MW</td>
</tr>
<tr>
<td>Generation</td>
<td>19,000.0 – 1,000.0</td>
</tr>
<tr>
<td></td>
<td>18,000.0 MW</td>
</tr>
<tr>
<td>Load</td>
<td>40,000.0 – 125.0</td>
</tr>
<tr>
<td></td>
<td>39,875.0 MW</td>
</tr>
<tr>
<td>Generation</td>
<td>41,000.0 – 125.0 + 937.5</td>
</tr>
<tr>
<td></td>
<td>41,812.5 MW</td>
</tr>
</tbody>
</table>

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.
(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,

\[ \text{ACE}_1 = \Delta P_{12} + B_1 \Delta f_1 = 1,000 + 2,500 \Delta f = 0 \]

Solving, we find

\[ \Delta f_1 = \frac{-1000}{2500} = -0.4 \text{ Hz} \]

Change in area 1 load is

\[ \Delta P_{D1} = D_1 \Delta f_1 = 333.33 \times (-0.4) = -133.33 \text{ MW} \]

Similarly for area 2, we have

\[ \Delta f_2 = \frac{1,000}{5,000} = 0.2 \text{ Hz} \]

\[ \Delta P_{D2} = 666.67 \times 0.2 = 133.33 \text{ MW} \]

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

<table>
<thead>
<tr>
<th>Area 1</th>
<th>Area 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load</td>
<td>Load</td>
</tr>
<tr>
<td>20,000.00</td>
<td>40,000.00</td>
</tr>
<tr>
<td>-133.33</td>
<td>+133.33</td>
</tr>
<tr>
<td>= 19,866.67 MW</td>
<td>= 40,133.33 MW</td>
</tr>
<tr>
<td>Generation</td>
<td>Generation</td>
</tr>
<tr>
<td>19,866.67 MW</td>
<td>40,133.33 MW</td>
</tr>
<tr>
<td>( f_1 )</td>
<td>( f_2 )</td>
</tr>
<tr>
<td>59.6 Hz</td>
<td>60.2 Hz</td>
</tr>
</tbody>
</table>
(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
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.,

- shedding 10% load at 59.3 Hz
- shedding 10% additional load at 59.0 Hz, and
- shedding 10% more at 58.7 Hz
Industry Practices

References

• “Balancing and Frequency Control,” NERC resources Subcommittee, January 26, 2011

• Bob Green, “Governor and AGC Control of System Frequency” at TRE Technical Workshop, 3/31/2009
  www.ercot.com/content/meetings/.../TRE_Workshop_Gov_and_AGC_20090331.ppt

• “Generation Control” Interconnection Training Program, 2010
  http://www.pjm.com/~media/training/nerc-certifications/gc-gencontrol.ashx
Steady-state speed characteristic with speed changer

Materials of this and the following slides are from Bob Green’s presentation entitled “Governor and AGC Control of System Frequency” at TRE Technical Workshop, 3/31/2009
Three generators serving 360MW

<table>
<thead>
<tr>
<th>Generator</th>
<th>Gen (MW)</th>
<th>60hz setpt (MW)</th>
<th>Rating (MW)</th>
<th>Droop (%)</th>
<th>Slope (MW/Hz)</th>
</tr>
</thead>
<tbody>
<tr>
<td>#1</td>
<td>80.0000</td>
<td>80</td>
<td>300</td>
<td>10.0%</td>
<td>50</td>
</tr>
<tr>
<td>#2</td>
<td>120.0000</td>
<td>120</td>
<td>450</td>
<td>7.5%</td>
<td>100</td>
</tr>
<tr>
<td>#3</td>
<td>160.0000</td>
<td>160</td>
<td>600</td>
<td>5.0%</td>
<td>200</td>
</tr>
</tbody>
</table>

LOAD-FREQUENCY CHARACTERISTIC

No governor deadband modeled.

\[
\text{Slope (MW/Hz)} = -\frac{1}{R} \times \frac{\text{Rating (MW)}}{60 (Hz)}
\]
Three generators serving 367MW

<table>
<thead>
<tr>
<th>Generator</th>
<th>Gen (MW)</th>
<th>60hz setpt (MW)</th>
<th>Rating (MW)</th>
<th>Droop (%)</th>
<th>Slope (MW/Hz)</th>
</tr>
</thead>
<tbody>
<tr>
<td>#1</td>
<td>81.00</td>
<td>80</td>
<td>300</td>
<td>10.0%</td>
<td>50</td>
</tr>
<tr>
<td>#2</td>
<td>122.00</td>
<td>120</td>
<td>450</td>
<td>7.5%</td>
<td>100</td>
</tr>
<tr>
<td>#3</td>
<td>164.00</td>
<td>160</td>
<td>600</td>
<td>5.0%</td>
<td>200</td>
</tr>
</tbody>
</table>

LOAD-FREQUENCY CHARACTERISTIC

No governor deadband modeled.
Three generators serving 374MW

LOAD-FREQUENCY CHARACTERISTIC

No governor deadband modeled.
Three generators serving 381MW

**LOAD-FREQUENCY CHARACTERISTIC**

No governor deadband modeled.

**GENERATOR #1**
- **Gen (MW)**: 83.00
- **60hz setpt (MW)**: 80
- **Rating (MW)**: 300
- **Droop (%)**: 10.0%
- **Slope(MW/Hz)**: 50

**GENERATOR #2**
- **Gen (MW)**: 126.00
- **60hz setpt (MW)**: 120
- **Rating (MW)**: 450
- **Droop (%)**: 7.5%
- **Slope(MW/Hz)**: 100

**GENERATOR #3**
- **Gen (MW)**: 172.00
- **60hz setpt (MW)**: 160
- **Rating (MW)**: 600
- **Droop (%)**: 5.0%
- **Slope(MW/Hz)**: 200
Load of 367MW and 60HZ SPs increased by 7 MW

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
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</thead>
<tbody>
<tr>
<td><strong>Freq (hz)</strong></td>
<td>60.0000</td>
</tr>
<tr>
<td><strong>60hz load (MW)</strong></td>
<td>367</td>
</tr>
</tbody>
</table>

**GENERATOR #1**

<p>| | |</p>
<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>Gen (MW)</td>
<td>81.00</td>
</tr>
<tr>
<td>60hz setpt (MW)</td>
<td>81</td>
</tr>
<tr>
<td>Rating (MW)</td>
<td>300</td>
</tr>
<tr>
<td>Droop (%)</td>
<td>10.0%</td>
</tr>
<tr>
<td>Slope(MW/Hz)</td>
<td>50</td>
</tr>
</tbody>
</table>

**GENERATOR #2**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen (MW)</td>
<td>122.00</td>
</tr>
<tr>
<td>60hz setpt (MW)</td>
<td>122</td>
</tr>
<tr>
<td>Rating (MW)</td>
<td>450</td>
</tr>
<tr>
<td>Droop (%)</td>
<td>7.5%</td>
</tr>
<tr>
<td>Slope(MW/Hz)</td>
<td>100</td>
</tr>
</tbody>
</table>

**GENERATOR #3**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Gen (MW)</td>
<td>164.00</td>
</tr>
<tr>
<td>60hz setpt (MW)</td>
<td>164</td>
</tr>
<tr>
<td>Rating (MW)</td>
<td>600</td>
</tr>
<tr>
<td>Droop (%)</td>
<td>5.0%</td>
</tr>
<tr>
<td>Slope(MW/Hz)</td>
<td>200</td>
</tr>
</tbody>
</table>

LOAD-FREQUENCY CHARACTERISTIC

No governor deadband modeled.
Illustration of typical governor dead band

Gen#1 and Gen#2 have a "typical" governor dead band equal to +/- 0.036 Hz. Governors "jump" at dead band limit [the increased load causes higher frequency].
Generation oscillations at the dead band frequency
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.

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

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 1.2 seconds in a 10 hour interval (i.e., 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).