Topics for Today:

- Announcements
  - Software: online students - apply for ATP/ATPDraw license, verify licensing when you receive it by e-mail, and we will mail you the install CD.
  - ASPEN software - run off of MTU server via internet, see e-mail instructions.
  - Office: EERC 614. Phone: 906.487.2857
  - Recommended problems & all solutions: Ch.13 solns now posted.

Ongoing topics...

- Chapter 13 - Power system operation, AGC, economic dispatch
  - System Operation Basics
  - Paralleling of Generators, droop characteristics
  - Frequency biasing - $\beta$ and B.
  - Constrained optimization methods - LaGrange multipliers
  - Optimal Dispatch, Generator Scheduling
    - Economics
    - Other constraints - environmental, contractual, availability
    - System load characteristics
  - Application to lossless system
  - System including losses - use $[B]$ loss coefficient matrix
the frequency deviation. Position 4 on the diagram indicates that the frequency bias setting $B_f$, a factor with a negative sign and the units MW/0.1 Hz, is multiplied by $10 \Delta f$ to obtain a value of megawatts called the frequency bias $(10 B_f \Delta f)$.

The frequency bias, which is positive when the actual frequency is less than the scheduled frequency, is subtracted from $(P_{{\text{e}}} - P_{{\text{s}}})$ at position 5 to obtain the ACE, which may be positive or negative. As an equation

$$ACE = (P_{{\text{e}}} - P_{{\text{s}}}) - 10 B_f (f_{{\text{s}}} - f_{{\text{e}}}) \text{ MW} \quad (13.68)$$

A negative ACE means that the area is not generating enough power to send the desired amount out of the area. There is a deficiency in net power output. Without frequency bias, the indicated deficiency would be less because there would be no positive offset ($10 B_f \Delta f$) added to $P_{{\text{e}}}$ (subtracted from $P_{{\text{s}}}$) when actual frequency is less than scheduled frequency and the ACE would be less. The area would produce sufficient generation to supply its own load and the rearranged interchange but would not provide the additional output to assist neighboring interconnected areas to raise the frequency.

Station control error (SCE) is the amount of actual generation of all the area plants minus the desired generation, as indicated at position 6 of the diagram. This SCE is negative when desired generation is greater than existing generation.

The key to the whole control operation is the comparison of ACE and SCE. Their difference is an error signal, as indicated at position 7 of the diagram. If both ACE and SCE are negative and equal, the deficiency in the output from the area equals the excess of the desired generation over the actual generation and no error signal is produced. However, this excess of desired generation will cause a signal, indicated at position 11, to go to the plants to increase their generation and to reduce the magnitude of the SCE; the resulting increase in output from the area will reduce the magnitude of the ACE at the same time.

If ACE is more negative than SCE, there will be an error signal to increase the $\lambda$ of the area, and this increase will in turn cause the desired plant generation to increase (position 9). Each plant will receive a signal to increase its output as determined by the principles of economic dispatch.

This discussion has considered specifically only the case of scheduled net interchange out of the area (positive scheduled net interchange) that is greater than actual net interchange with ACE equal to or more negative than SCE. The reader should be able to extend the discussion to the other possibilities by referring to Fig. 13.8.

Position 10 on the diagram indicates the computation of penalty factors for each plant. Here the $B$-coefficients are used to calculate $B_{{\text{p}}} \Delta P_{{\text{p}}}$, and the penalty factors. The penalty factors are transmitted to the section (position 9), which establishes the individual plant outputs for economic dispatch and the total desired plant generation.
Figure 6.10. Turbine–generator–exciter system

\[ P = \frac{E_f V_f \sin \delta}{X_s} \]

\[ Q = \frac{E_f V_f \cos \delta - V_f^2}{X_s} \]
"Droop Characteristic" of Gen.

Makes possible
- Maintaining 60 Hz.
- Scheduled Gen
- Min System loss ("economic dispatch")

\[ f \]

\[ f_s \]

\[ \Delta P \]

\[ \Delta f \]

"No-Load Set Point"

Operating point

\[ G \rightarrow P_{out} \rightarrow \text{Load} \]

Psched \rightarrow P_{out}
Droop Characteristic (Refer to AGC Notes)

\[ \Delta P_m = - \frac{1}{R} \Delta f \]

(if set-point isn't changed)

"Slope": \[ R = - \frac{\Delta f_{\text{neg}}}{\Delta P_{\text{pos}}} \] \( R \) always positive.

Can track \( f \) either in Hz or p.u.

\( P \) is typically tracked in p.u. (although text examples are in MW).
Two scenarios:

- 1) Controlled change in $P_{scen}$.
   - Change $f_{nodoad}$, let go "do its thing."

- 2) Uncontrolled event: line trip

  Point suddenly decreases, $f \uparrow$

  $\Delta P_m = - \frac{1}{R} \Delta f$

  (See p. 2a, AGC Notes)
"House Diagram"
Typical Speed Drop ≈ 4-5% on Gen Base.

\[
R = - \frac{\Delta f}{\Delta P} = - \frac{f-f_s}{P-P_0}
\]

\[
R = - \frac{(f-f_s)/f_s}{(P-P_0)/P_{\text{Base of Generator}}}
\]
Calculating for 2 or more generators...

Ref. notes: p.4.

- Mult gens.
- β is aggregate freq response of an Area.