AGC 3

1.0 Introduction

The primary controller response to a load/generation imbalance results in generation adjustment so as to maintain load/generation balance. However, due to droop, it also results in a non-zero steady-state frequency deviation. This frequency deviation must be corrected.

Also, the net scheduled export must be maintained according to the purchase agreements.

Primary control does nothing to correct the steady-state frequency error or the net scheduled export. These two problems are handled by providing a supplementary signal from the control center to each generation unit on automatic generation control (AGC).

The signal is derived from the Area Control Error (ACE) and, when received at a generation plant, activates the "speed changer motor" to adjust the energy supply set point to the generator.

In these notes, we will learn how the ACE is computed, and we will see how it is used in correcting steady-state frequency error.

2.0 Review

From our notes AGC1, we defined the following terms:

- Net Actual Interchange: AP_{ij}
- Net Scheduled Interchange: SP_{ij}
- Interchange Deviation (defined pg 396 of text):

$$\Delta P_{ij}=AP_{ij}-SP_{ij} \qquad (1)$$

Note that the above terms are each defined with respect to two distinct areas.

We also defined, in AGC1, the following terms:

- Actual Export: $AP_i = \sum_{j=1}^{n} AP_{ij}$ (2)
- Scheduled Export: $SP_i = \sum_{j=1}^{n} SP_{ij}$ (3)
- Net Deviation: $\Delta P_i = \sum_{j=1}^{n} \Delta P_{ij}$ (4)

Note that the above three terms are each defined with respect to a single area.

We also saw that the net deviation is related to the net actual and scheduled interchanges, and to the actual and scheduled exports, by:

$$\Delta P_i = \sum_{j=1}^{n} \Delta P_{ij} = \sum_{j=1}^{n} (AP_{ij} - SP_{ij})$$

$$= \sum_{j=1}^{n} AP_{ij} - \sum_{j=1}^{n} SP_{ij} = AP_i - SP_i \quad (5)$$

Although your text does not define net deviation, it does use it as the first term in the ACE expression of eq. (11.30).

Finally, we saw in our notes AGC2, when discussing the multi-machine case, that

$$\frac{\Delta f}{60} = \frac{-\Delta P}{\left[\frac{S_{R1}}{R_{1pu}} + \ldots + \frac{S_{RK}}{R_{Kpu}}\right]} \tag{6}$$

$$\Delta P_{Mi} = \frac{-S_{Ri}}{R_{pui}}\frac{\Delta f}{60} = \frac{S_{Ri}}{R_{pui}}\frac{\Delta P}{\left[\frac{S_{R1}}{R_{1pu}} + \ldots + \frac{S_{RK}}{R_{Kpu}}\right]} \tag{7}$$

If all units have the same per-unit droop constant, i.e., if $R_{1pu}=R_{2pu}=\ldots=R_{Kpu}$, then eqs. (6) and (7) become

$$\frac{\Delta f}{60} = \frac{-R_{pu}\Delta P}{\left[S_{R1} + \ldots + S_{RK}\right]} \tag{8}$$

$$\Delta P_{Mi} = \frac{-S_{Ri}}{R_{pu}}\frac{\Delta f}{60} = \frac{S_{Ri}\Delta P}{\left[S_{R1} + \ldots + S_{RK}\right]} \tag{9}$$

In eqs. (8) and (9), ΔP represents the change in total load so that it is

- positive if load increases, negative if load decreases;
- positive if gen decreases, negative if gen increases.

3.0 Area Control Error

The Area Control Error (ACE) is composed of

- Net Deviation ΔP_i, from eq. (5), written more compactly below:

$$\Delta P_i = AP_i - SP_i \tag{5}$$

When $\Delta P_i > 0$, it means that the actual export exceeds the scheduled export, and so the generation in area i should be reduced.

- Steady-state frequency deviation

$$\Delta f = f - 60 \tag{10}$$

When $\Delta f > 0$, it means the generation in the system exceeds the load and therefore we should reduce generation in the area.

From the above, our first impulse may be to immediately write down the ACE for area i as:

$$ACE_i = \Delta P_i + \Delta f \tag{11a}$$

Alternatively (and consistent with the text)

$$ACE_i = \Delta P_i + \Delta \omega \tag{11b}$$

But we note 2 problems with eq. (11). First, we are adding 2 quantities that have different units.

Anytime you come across a relation that adds 2 or more units having different units, beware.

The second problem is that the magnitudes of the two terms in eq. (11) may differ dramatically. If we are working in MW and Hz (or rad/sec), then we may see ΔP_i in the 100's of MW whereas we will see Δf (or $\Delta\omega$) in the hundredths or at most tenths of a Hz. The implication is that the control signal, per eq. (11), will greatly favor the export deviations over the frequency deviations.

Therefore we need to scale one of them. To do so, we define area i frequency characteristic as β_i. It has units of MW/Hz. Your text shows (pg. 393) that

$$\beta_{fi} = D_{fi} + D_{Lfi} + \frac{1}{R_{fi}} \quad (12a)$$

$$\beta_{\omega i} = D_{\omega i} + D_{L\omega i} + \frac{1}{R_{\omega i}} \quad (12b)$$

where

- D_i is the damping coefficient from the swing equation (and represents the effect of synchronous generator windage and friction);
- D_{Li} is the load damping coefficient and represents the tendency of the load to decrease as frequency decreases (an effect mainly attributed to induction motors).
- The f or ω subscripts indicate whether we will compute ACE using f or ω (text uses ω).

EPRI [1] provides an interesting figure which compares frequency sensitivity for motor loads with non-motor loads, shown below in Fig. 0.

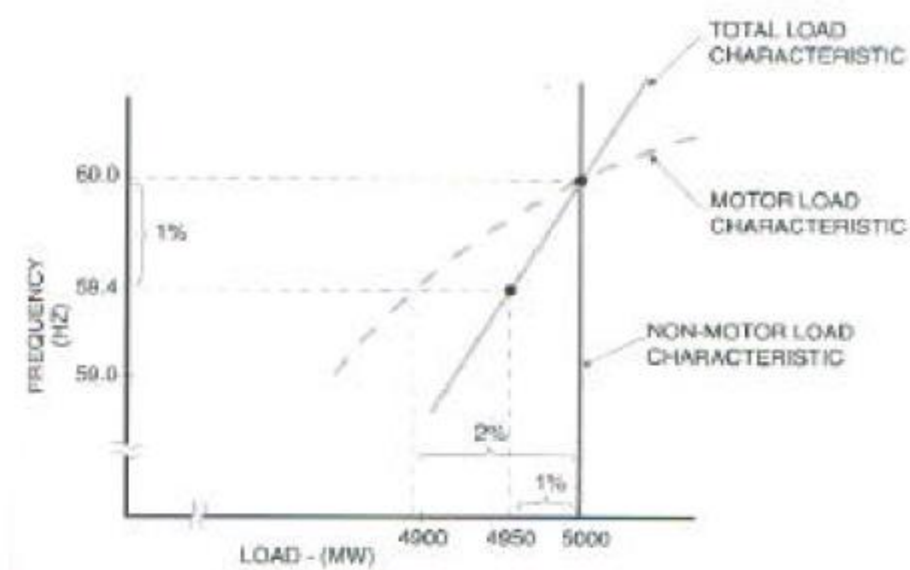

Fig. 0

Figure 0 shows that motor loads reduce about 2% for every 1% drop in frequency. If we assume that non-motor loads are unaffected by frequency, a reasonable composite characteristic might be that total load reduces by 1% for every 1% drop in frequency, as indicated by the "total load characteristic" in Fig. 0.

To account for load sensitivity to frequency deviations, we will use parameter D_{Li} according to

$$\boldsymbol{D_{Li}} = \frac{\text{pu change in load}}{\text{pu change in frequency}} \tag{0a}$$

from which we may write:

$$\text{pu change in load} = \boldsymbol{D_{Li}\Delta\omega} \tag{0b}$$

If our system has a 1% decrease in power for every 1% decrease in frequency, then D_{Li} =1.

The damping terms of eq. (12) are usually significantly smaller than the regulation term, so that a reasonable approximation is that

$$\beta_{fi} = \frac{1}{R_{fi}} \tag{12c}$$

$$\beta_{\omega i} = \frac{1}{R_{\omega i}} \tag{12d}$$

Then the ACE equation becomes:

$$\boldsymbol{ACE_i = \Delta P_i + B_{fi}\Delta f} \tag{12e}$$

$$\boldsymbol{ACE_i = \Delta P_i + B_{\omega i}\Delta \omega} \tag{12f}$$

where B_{fi} (or $B_{\omega i}$) is the frequency bias characteristic for area i; it is generally set equal to the area i frequency characteristic, β_{fi} (or $\beta_{\omega i}$), as shown in your text on p. 396.

4.0 Example (similar to Ex 11.5 in text)

Consider the two-area interconnection shown in Fig. 1 with data given as below.

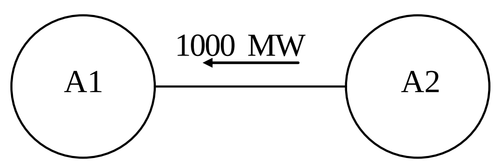

Fig. 1

Area 1	Area 2
Load=20,000 MW	Load=40,000 MW
Capacity=20,000 MW	Capacity=42,000 MW
Gen=19,000 MW	Gen=41,000 MW
R_{1pu}=0.05	R_{1pu}=0.05

The scheduled interchange is 1000 MW flowing from A2 to A1, so that scheduled exports are:

- SP_1=-1000 MW
- SP_2=1000 MW

There are two parts to this problem:

1. Determine frequency and generation of each area and the tie line flow after a 1000 MW loss of load in A1, but before secondary control has taken effect (this means we will determine only the effect of primary control).
2. Repeat (1) after secondary control action has taken effect.

Solution:

We assume that area capacities are the ratings:

S_{R1}=20000

S_{R2}=42000

We also note that the load decreases, therefore ΔP=-1000 MW.

1. From eq. (8),

$$\frac{\Delta f}{60} = \frac{-R_{pu}\Delta P}{\left[S_{R1} + ... + S_{RK}\right]} = \frac{-0.05(-1000)}{[20000 + 42000]} = 0.000806\,pu$$

Therefore

$$\Delta f = 0.000806 * 60 = 0.0484 Hz$$

so that f=60.0484 Hz.

Then we can compute the increase in generation in each area per eq. (9). For Area 1:

$$\Delta P_{M1} = \frac{S_{R1}\Delta P}{[S_{R1} + S_{R1}]} = \frac{(20000)(-1000)}{20000 + 42000} = -322.6MW$$

Therefore

$$P_{M1} = 19000 - 322.6 = 18,677.4MW$$

For Area 2:

$$\Delta P_{M2} = \frac{S_{R2}\Delta P}{[S_{R1} + S_{R1}]} = \frac{(42000)(-1000)}{20000 + 42000} = -677.4MW$$

Therefore

$$P_{M2} = 41000 - 677.4 = 40,322.6MW$$

It is of interest now to obtain the actual exports, and we can do this for each area by taking the difference between load and generation. The loads in areas 1 and 2 were 20000 and 40000, but remember that we lost 1000 MW of load in area 1, so that its value is now 19000. Generation levels were computed above. Therefore

$$AP_1=18,677-19,000=-322.6 \text{ MW}$$

$$AP_2=40,322.6-40,000=322.6 \text{ MW}$$

So clearly the new tie-line flow is 322.6 MW from A2 to A1.

Note: For multiple areas, calculating tie-line flows requires a power flow solution (DC power flow is suitable to use here).

From eq. (5), net deviation is:

$$\Delta P_1 = AP_1 - SP_1 = -322.6 - (-1000) = 677.4$$

$$\Delta P_2 = AP_2 - SP_2 = 322.6 - (1000) = -677.4$$

2. To find the effect of supplementary control, we first need to compute the frequency bias parameters. We neglect effects of damping terms, so that we use eq. (12c) or (12d):

$$\beta_{fi} = \frac{1}{R_{fi}} \qquad (12c)$$

$$\beta_{\omega i} = \frac{1}{R_{\omega i}} \qquad (12d)$$

But note that the droop constant in (12c) or (12d) is not in per-unit. To convert to per-unit, recall eqs. (13) and (14) from AGC2 notes:

$$R_f = -\frac{\Delta f}{\Delta P_M} \quad (13a)$$

$$R_\omega = -\frac{\Delta \omega}{\Delta P_M} \quad (13b)$$

$$R_{pu} = -\frac{\Delta f \,/\, f_0}{\Delta P_M \,/\, S_r} = -\frac{\Delta \omega / \omega_0}{\Delta P_M \,/\, S_r} = -\frac{\Delta f_{pu}}{\Delta P_{Mpu}} = -\frac{\Delta \omega_{pu}}{\Delta P_{Mpu}} \quad (14)$$

Substituting eq. (13a) or (13b) into (14) gives:

$$R_{pu} = -\frac{\Delta f \,/\, f_0}{\Delta P_M \,/\, S_r} = -\frac{\Delta f}{\Delta P_M}\frac{S_r}{f_0} = R_f \frac{S_r}{f_0} \quad (15a)$$

$$R_{pu} = -\frac{\Delta \omega / \omega_0}{\Delta P_M \,/\, S_r} = -\frac{\Delta \omega}{\Delta P_M}\frac{S_r}{\omega_0} = R_\omega \frac{S_r}{\omega_0} \quad (15b)$$

Therefore

$$R_f = R_{pu} \frac{f_0}{S_r} \quad (16a)$$

$$R_\omega = R_{pu} \frac{\omega_0}{S_r} \quad (16b)$$

We can use (16a) to calculate the frequency bias term of (12c), which is used in the ACE equation of (12d):

$$\boldsymbol{ACE_i = \Delta P_i + B_{fi} \Delta f} \quad (12d)$$

Alternatively, we can use (16b) to calculate the frequency bias terms of (12d), which is used in the ACE equation of (12e):

$$\boldsymbol{ACE_i = \Delta P_i + B_{\omega i}\Delta\omega} \qquad (12e)$$

In the rest of this example, we will use (16a), (12c), and (12d).

Applying eq. (16a) to obtain R_{f1} and R_{f2}, we get

$$R_{f1} = R_{pu}\frac{f_0}{S_{r1}} = 0.05\frac{60}{20000} = 0.00015 Hz/MW$$

$$R_{f2} = R_{pu}\frac{f_0}{S_{r2}} = 0.05\frac{60}{42000} = 0.000071429 Hz/MW$$

Then the frequency bias terms are obtained as

$$\boldsymbol{B_{f1} = \frac{1}{R_{f1}} = \frac{1}{0.00015} = 6666.7\ MW\ /\ Hz}$$

$$\boldsymbol{B_{f2} = \frac{1}{Rf_2} = \frac{1}{0.000071429} = 14000\ MW\ /\ Hz}$$

Now we can compute the ACE in each area:

$$\boldsymbol{ACE_1 = \Delta P_1 + B_{f1}\Delta f = (AP_1 - SP_1) + B_{f1}\Delta f}$$

$$= (\text{-}322.6 - \text{-}1000) + 6666.7(0.0484)$$

$$\boldsymbol{= 677.4 + 322.68 = 1000\ MW}$$

$$ACE_2 = \Delta P_2 + \beta_{f2}\Delta f = (AP_2 - SP_2) + \beta_{f2}\Delta f$$
$$= (322.6 - 1000) + 14000(0.0484)$$
$$= -677.4 + 677.6 = 0MW$$

So what does this mean?

- ACE_1 indicates that the generators in A1 receive a signal to decrease generation by 1000 MW. Recall from page 9 that after primary control action, P_{M1}=18,677.4 MW. With a 1000 MW decrease, then P_{M1}=17,677.4 MW.
- ACE_2 indicates that the generators in A2 do not change, so P_{M2}=40,322.6 MW.

But now consider that previous to the secondary control action, we were at a steady state (with steady-state frequency deviation of 0.0484 so that f=60.0484 Hz). Now the ACE signal has caused a decrease in A1 generation by 1000 MW. This action creates a load-generation imbalance of ΔP=+1000 MW that will cause unit primary controllers to act in both areas. From eq. (8):

$$\frac{\Delta f}{60} = \frac{-R_{pu}\Delta P}{[S_{R1} + ... + S_{RK}]} = \frac{-0.05(+1000)}{[20000 + 42000]} = -0.000806\,pu$$

Therefore

$$\Delta f = -0.000806 * 60 = -0.0484 Hz$$

so that f=60.0484 - 0.0484 = 60Hz.

Then we compute the increase in generation in each area per eq. (9). For Area 1:

$$\Delta P_{M1} = \frac{S_{R1}\Delta P}{[S_{R1} + S_{R1}]} = \frac{(20000)(+1000)}{20000 + 42000} = +322.6MW$$

Therefore

$$P_{M1} = 17677.4 + 322.6 = 18{,}000MW$$

For Area 2:

$$\Delta P_{M2} = \frac{S_{R2}\Delta P}{[S_{R1} + S_{R1}]} = \frac{(42000)(+1000)}{20000 + 42000} = +677.4MW$$

Therefore

$$P_{M2} = 40{,}322.6 + 677.4 = 41{,}000MW$$

The exports for the two areas will then be:

AP_1=18,000-19,000=-1000 MW

AP_2=41,000-40,000=+1000 MW

A summary of the situation is given below, where we see that the final control action has resulted in A1 generation entirely compensating for the A1 load decrease of 1000 MW (with area exports unchanged).

Area 1	Area 2
Load=19,000 MW	Load=40,000 MW
Gen=18,000 MW	Gen=41,000 MW

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[1] "Interconnected Power System Dynamics Tutorial," Electric Power Research Institute EPRI TR-107726, March 1997.