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A Review on Genetic Algorithm Based Automatic Generation Control in Muti Area Power System

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Abstract— This paper describes genetic algorithm (GA) based automatic generation control (AGC) in multi-area power system considering generation rate constraints and governor dead band. The objective of AGC is to regulate the power output of the electric generator within an area in response to changes in system frequency and tie line loading. Paper deals with GA tuned PID controller so that the transient deviation in frequency & tie-line loading can be minimized. MATLAB based software program is developed for optimizing PID gains using genetic algorithm. Simulink software based model is developed to verify the performance of the AGC in singe area power systems using gains obtained by genetic algorithm optimization technique.

Index Terms— Automatic Generation Control, PID Controller, ACE, Genetic Algorithms.

I. INTRODUCTION

In electric power system, Automatic generation control is a system for adjusting the power output of multiple generators at different power plants in response to changes in the load. Since a power grid requires that generation & load closely balance moment by moment, frequent adjustments to the output of generators are necessary. The balance can be judged by measuring the system frequency. Where the grid has tie interconnections to adjacent control areas, automatic generation control helps to maintain the power interchanges over the tie lines at the scheduled levels. The two most important issue in power system for their normal operation are Frequency and net power interchange over tie lines in an interconnected system To maintain the above two factors at their scheduled level, a control scheme known as “Automatic generation control” is employed [6]. The main objectives of AGC include: Match total system generation to total system load. Adjust system electrical frequency deviation to zero. Maintain tie-line interchange [1-7] power at their scheduled value and allocate generation in an economical manner.

II. OVERVIEW OF GENERATION CONTROL STRUCTURE

The automatic control system consists of two main parts:

- Primary control (Load frequency control or speed governor control)
- Secondary control (or supplementary control)

In primary control, the control task of priority is to bring the frequency back to acceptable values. However there remains an avoidable frequency error. The control task is shared by all generators participating in primary frequency control irrespective of the location of the disturbance [7].

In secondary control, the power set points of the generators are adjusted in order to compensate for the remaining frequency error and also adjust the power exchange among the control areas at their scheduled values. In secondary control, the location of disturbance is considered when the control action is determined; only disturbances within its own control zone (area) are seen by secondary controller. The AGC block diagram is shown in fig. 2.1

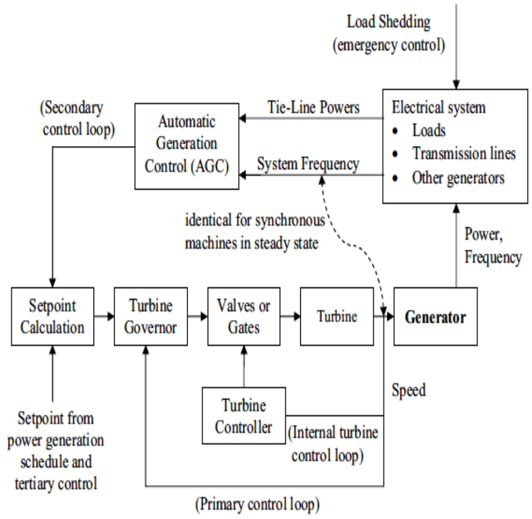

Figure 2.1: AGC block diagram

III. MATHEMATICAL MODELING OF AGC IN SINGLE AREA POWER SYSTEM

For an isolated power system, we need to model following components for load frequency controls (LFC) are: -

i) Speed Governor Model
ii) Turbine Model
iii) Generator and System Load Model.

In the Speed Governor Model, Governors are the units that are used in power systems to sense the frequency deviation caused by load change & cancel it by varying the input of the turbines. Shown in fig. 3.1

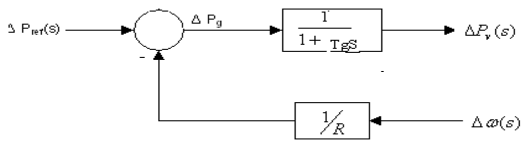

Figure3.1: Governor Model

In Speed regulation, the term speed regulation refers to the amount of speed or frequency change that is necessary to cause the output of the synchronous generator to change from zero output to full output.
The ratio of speed deviation (Δω) or frequency deviation (Δf) to change in power output of generator is equal R. The unit of R is Hz/MW. Shown in fig. 3.2

$$percenR = \frac{\text{Percent speed or frequency change}}{\text{Percent power output change}} \times 100$$

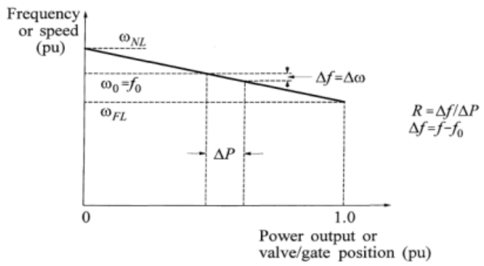

Figure 3.2: Frequency v/s power output characteristics

If two or more generators with drooping governor characteristics are connected to a power system, there will be a unique frequency (but not the scheduled frequency) at which they will share a load change by equation:

$$\frac{\Delta p1}{\Delta p2} = \frac{R2}{R1}$$

In Turbine model Prime mover is commonly known as source of mechanical power. It may be hydraulic turbines whose energy comes from the water potential, steam turbines whose energy comes from the burning of coal, gas, nuclear fuel, and gas turbines.

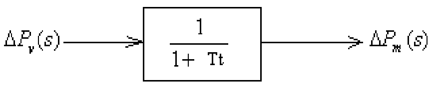

Figure 3.3: Turbine model

Where, T_t is the time constant of turbine which represents steam/water flow- valve/gate position relationship. The time constant T_t is in the range of 0.2 to 2.0 seconds.
Generator Model shows in fig.3.4

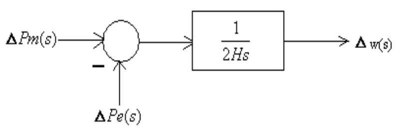

Figure 3.4: Generator Model

Given by equation:

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

Where,
H is inertia constant in MW-Sec/MVA.
ΔP_m is change in mechanical power output of turbine.
ΔP_e is change in electrical load.
Δw is deviation in rotor speed.

In System Load Model, The speed load characteristics of composite load are given by equation:

$$\Delta p_e = \Delta p_L + D\Delta w$$

Where, ΔP_L is the non-frequency sensitive load change, and DΔω is the frequency sensitive load change, D is expressed as percent change in load divided by percent change in frequency. A value of D=1.2 means a change in frequency by 1 % causes the load to change by 1.2%
The load model and the generator model are combined as shown

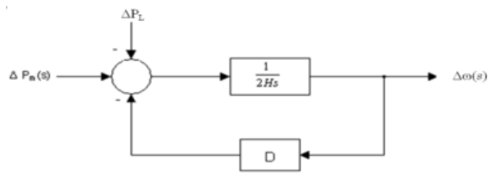

Figure 3.5: Load Model

Finally, LFC in single area Power system as primary control is given by fig. 3.6 and fig 3.7

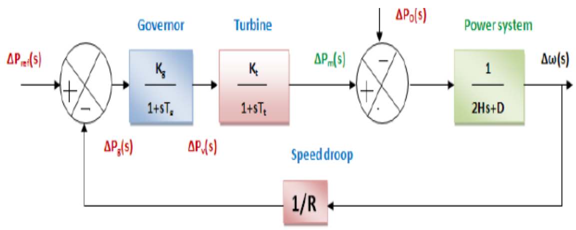

Figure 3.6: Block diagram of primary control

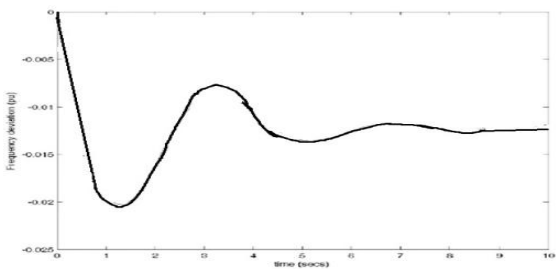

Figure 3.7: Primary load frequency control

This figure shows the frequency deviation as function of time with primary load frequency control.
Steady state frequency deviation is given by

$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R} + D}$$

Where, R is regulation of governor & D is load damping constant

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If several generators (each having its own governor and prime mover) were connected to the system, the frequency change would be given by

$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R_1}+\frac{1}{R_2}+......+\frac{1}{R_n}+D}$$

$$\Delta\omega = \frac{-\Delta P_L}{\frac{1}{R_{eq}}+D}$$

Thus, the composite frequency response characteristics of the system is

$$\beta = \frac{-\Delta P_L}{\Delta\varpi(s)} = \frac{1}{R_{eq}} + D$$

The composite frequency characteristics β is normally expressed in MW/Hz. It is also sometimes referred to as the stiffness of the system or frequency bias factor and is indicative of the change in frequency which would occur for a change in load.

Primary load frequency control (or speed governor control) of an isolated power system which achieves the primary goal of real power balance by adjusting the turbine output to match the change in load demand & all the participating generating units contribute to the change in generation, irrespective of the location of load change but a change in load results in steady state frequency deviation. The restoration of frequency to nominal value requires an additional control loop known as supplementary loop. The LFC with supplementary control loop is generally called as AGC (Automatic generation control). Block diagram of AGC in single area system as supplementary control shown in fig. 3.8

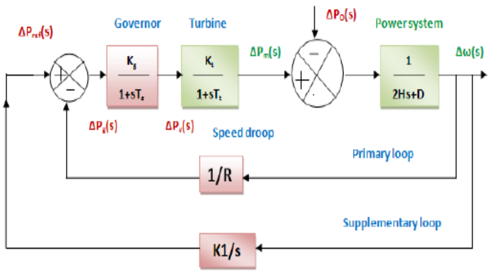

Figure 3.8: Block diagram of AGC in single area system

An important feature of supplementary control is the adjustment of speed reference input by which the main prime mover control mechanism & hence the generator power output can be changed without requiring a change in system speed. The effect of the speed reference input is to produce a family of parallel speed-load characteristic curves.

Unit governing characteristics before, during & after supplementary regulation is shown in fig. 3.9

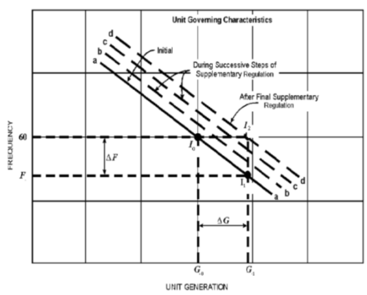

Figure 3.9: Unit governing characteristics

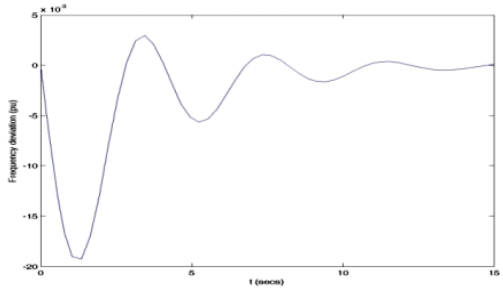

Figure 3.10: Frequency deviation as function of time

Fig. 3.10 shows the frequency deviation as function of time with supplementary control (AGC).

IV. PHYSICAL CONSTRAINTS IN POWER SYSTEM

The important physical constraints in power system are:

i) Generation rate constraint (GRC)

ii) Speed governor dead band.

In GRC Most of the reheat units have a generation rate around 3%/min. some have a generation rate between 5 to 10%/min.

In Speed governor dead band The dead band associated with speed governor is defined as " the total magnitude of change in steady state speed within which there is no resulting measurable change in the position of the governor controlled valves or gates". Dead band is expressed in percent of rated speed.

The current IEEE standards specify a maximum dead band of 0.06% (+/-0.036Hz) for the governors of large steam turbines. The speed droop characteristic appears as a band rather than a line. The effect of dead band on the governor speed droop characteristics is shown in fig. 4.1

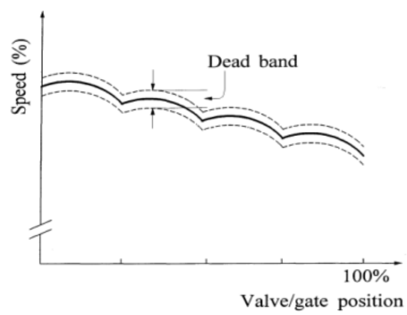

Figure 4.1: Speeds droop characteristic

V. GC IN TWO AREA POWER SYSTEM

The block diagram of AGC in two Area System is shown below. Consider a change in load ΔP_{L1} in area1. The steady state frequency deviation Δf is the same for both the areas. That is $\Delta f = \Delta f_1 = \Delta f_2$.

$$\Delta f = \Delta\omega_1 = \Delta\omega_2 = \frac{-\Delta P_L}{\beta_1 + \beta_2}$$

Where,

$\beta_1 = (D_1+1/R_1)$; and $\beta_2 = (D_2+1/R_2)$.

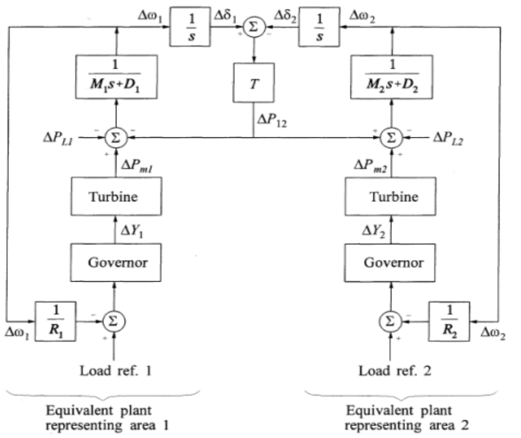

Figure5.1: Two area system with primary control

An increase of load in area1 by P_{L1} results in a frequency reduction in both areas and a tie-line flow of P_{12}. A positive P_{12} is indicative of flow from Area1 to Area 2 while a negative P_{12} means flow from Area 2 to Area1

$$\Delta P_{12} = \frac{-\Delta P_{L1}\beta_2}{\beta_1 + \beta_2}$$

Similarly, for a change in Area 2 load by P_{L2}, we have

$$\Delta P_{12} = -\Delta P_{21} = \frac{-\Delta P_{L2}\beta_1}{\beta_1 + \beta_2}$$

VI. AREA CONTROL ERROR

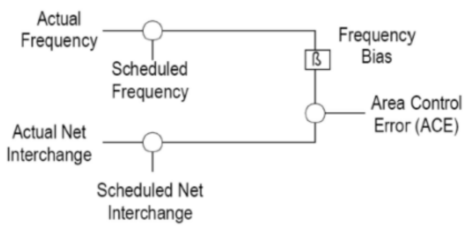

Figure6.1 Area Control Error

ACE = Δ Net Interchange + β Δ f
Δ Net Interchange = Interchange error = Scheduled – Actual
Δ f = Δ ω = frequency deviation
β = frequency bias (pu MW/ pu frequency) or frequency response characteristics and is indicative of the change in frequency which would occur for a change in the load.
Basic Idea
When ACE> 0 decrease generation
When ACE<0 increase generation
Assume load increases in one area only, then

- Frequency drops everywhere $\Delta f<0$
- Interchange from affected area decreases
  Δ Net Interchange <0
- Interchange from other areas increases
  Δ Net Interchange >0
- Affected area has negative ACE
- In other areas ACE is small or zero
- Affected area increases generation

Others stay unchanged
If all areas have ACE=0; Δω = 0
& all Δ Net Interchange =0

Driving ACE to zero restores frequency and interchange
In a two area system
$ACE_1 = \Delta P_{12} + B_1\,\Delta f\,;\ B_1 = \beta_1$
$ACE_2 = \Delta P_{21} + B_2\,\Delta f\,;\ B_2 = \beta_2$
ACEs are used as control signals to activate changes in the reference set points. Under steady state ΔP_{12} and Δf will be zero.

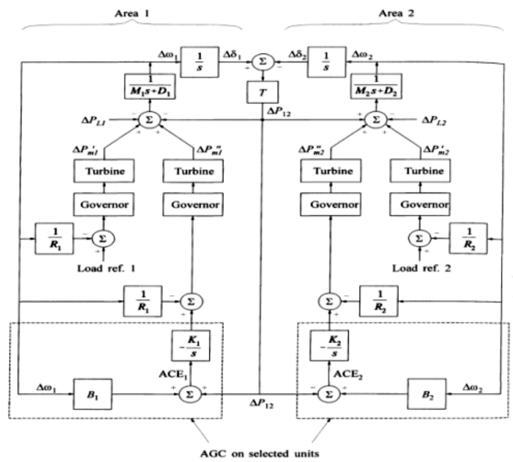

Figure 6.2: the secondary control in two area power system

Consider an increase in load of area 1, which leads to a decrease in system frequency. The primary ALFC loop limits the frequency deviation to the tie–line power has a deviation

$$\Delta P_{12} = \beta_2 \Delta f.$$

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

The slower acting supplementary control, starts responding now. If there is a change in Area 1 load, there should be supplementary control only in Area1 and not in Area 2.

$$ACE_1 = \Delta P_{12} + B_1\Delta f = \frac{-\Delta P_{L1}}{\beta_1+\beta_2}(\beta_2+\beta_1) = (-\Delta P_{L1})$$

$$ACE_2 = -\Delta P_{12} + B_2\Delta f = \frac{-\Delta P_{L1}}{\beta_1+\beta_2}(-\beta_2+\beta_2) = 0$$

Only supplementary control of area 1 responds to ΔP_{L1} and the generation changed so that ACE_1 becomes zero. [4][5][6].

VII. ROBLEM FORMULATION

In this work, the error signal is area control error (ACE) of each area. This ACE must be reduced close to zero to achieve scheduled frequency and tie line transfer.

To minimize the error signal, PID controller is used. In this work, Genetic algorithm is used for optimizing the gains of PID controller with ISE as performance index. Cost function can be assumed as minimization of “integral of square error” (ISE)

$$ISE = \int e^2(t)dt$$

We consider this as our cost function

$$Fcost = \int ACE\,i^2\ dt$$

For i=1, 2…..

The fitness function is given by equation

$$Fcost = \frac{1}{1 + Fcost}$$

VIII. METHODOLOGY: GENETIC ALGORITHMS

Genetic algorithms are the main paradigm of evolutionary computing. GAs is inspired by Darwin's theory about evolution-the "survival of the fittest". In nature, competition among individuals for scanty resources results in fittest individuals dominating over the weaker ones. GAs are the ways of solving problems by mimicking processes nature uses; i.e., selection, Crossover, mutation and accepting, to evolve a solution to a problem [7].

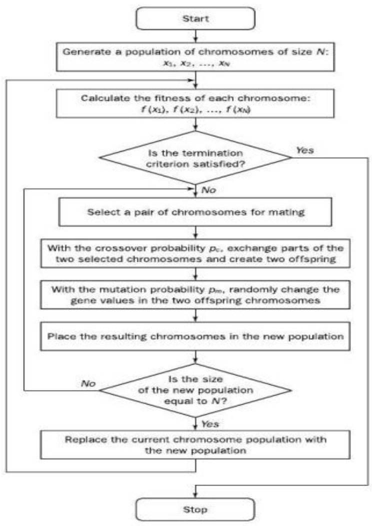

Figure8.1: Block diagram of GA

IX. CONCLUSION

After the alteration of power system management structure, also known as deregulation, Several AGC schemes will be required for generation control purpose to ensure stable, economic & reliable operation. High renewable energy penetration in power systems may increase uncertainties during abnormal operation, introduce several technical implications. AGC can be one of the automatic control techniques to withstand certain abnormal condition of power systems having REs units to ensure reliable operation.
An attempt will have made for finding the optimum PID controller gains of Automatic generation control using Genetic algorithm considering nonlinearities of power system.

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