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PI-BASED LOAD FREQUENCY CONTROLLER DESIGN FOR MULTI MACHINE SYSTEM USING GENETIC ALGORITHM

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Abstract: The paper presents a systematic method of obtaining a detailed model of control area for automatic generation control (AGC) taking into account the effect of power transmission network. The analysis is carried out considering a 6-bus system and genetic algorithm (GA) is used to optimize the gains of Proportional Integral (P-I) controller for improving the dynamic response of the system. The results show that the dynamic response for frequency deviation improves significantly considering P-I controller optimized using GA.

Keywords: Load Frequency Control (LFC); Proportional-Integral (P-I) Controller; Genetic Algorithm (GA).

1. INTRODUCTION

Electrical power systems consist of many number of generating units and loads and their power demand vary continuously. The immediate changes of loads cause the change in frequency and as a result cause change in net power interchanges with the connected control area [1-2].

Load frequency control is very important for designing electrical power system and various control strategies have been proposed [3-7]. Tripathy et al. [4] have designed load frequency controller for power system with reheat steam turbines and governor deadband nonlinearity. Hiyama [5] has designed load frequency controller for decentralized interconnected power system. Lim et al. [6] have designed decentralized load frequency controller for multi-area power system. Yang et al. [7] have designed decentralized load frequency controller based on structured singular values.

And the design of the controller are mostly based on fixed plant model which represents the sum of generating units by equivalent one turbine generator system and effect of transmission of power through Transmission Line is ignored and the loads on distributed load buses are summed up and are considered to be applied on a particular generator. The weak tie-lines between different control areas are separately incorporated for design and analysis of Load Frequency Control [1, 4-7].

This reduced order model works efficiently when the traditional vertically integrated utilities have been considered to control but recent development is the electricity market transaction results in utilities that electricity market transaction results in utilities that all power station have no direct control in their control area. This new development which is known as restructured power system requires new control schemes and strategies [8-10]. Iracleous et al. [11] have designed the controller for multi-task automatic generation control for power regulation.

In the present condition, the conventional control area model for AGC is not so technically suitable and individual power station must be considered separately for designing the controller. Additionally concept of individual power station as specific control area is misleading aspect because interconnection between generators and load buses cannot be considered as a single electrical net. As a result a new model description of a control area is a very important to design Load frequency controller.

2. DEVELOPMENT OF THE SYSTEM MODEL

In order to develop a power system model, it is assumed that each individual power station is represented by an equivalent generator driven by turbine and speed governor. Fig.1 shows the block diagram of speed governing system of a single power system and the state space representation for each power station is given by the following model [12].

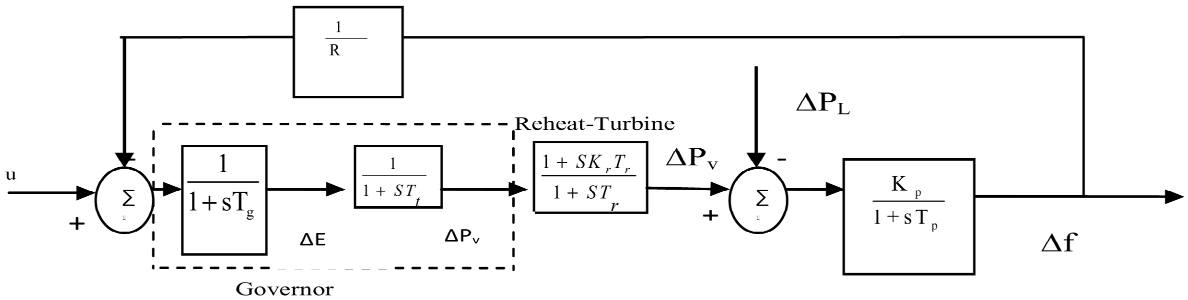


Fig.1: The block diagram of single area AGC

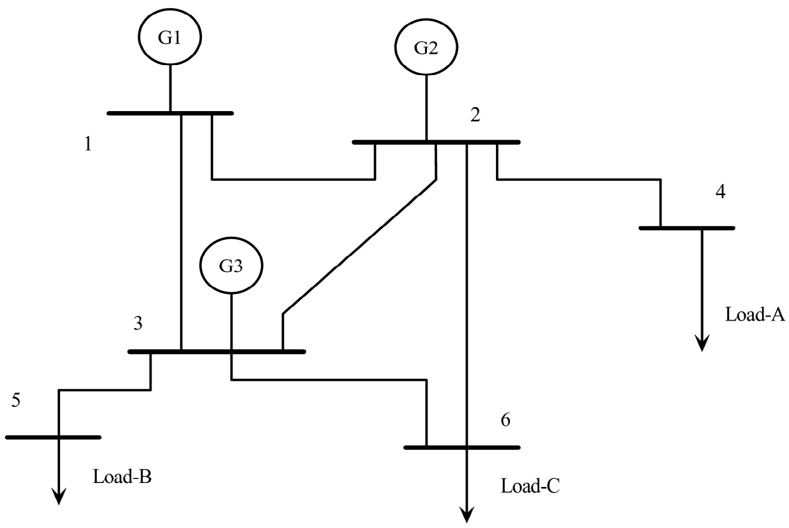


Fig.2: The 6-bus Power System

$$\dot{s}_i = \begin{bmatrix} -\frac{1}{T_{p_i}} & \frac{K_{p_i}}{T_{p_i}} & 0 & 0 \\ 0 & -\frac{1}{T_{r_i}} & \left(\frac{1}{T_{r_i}} - \frac{K_{r_i}}{T_{t_i}}\right) & \frac{K_{r_i}}{T_{t_i}} \\ 0 & 0 & -\frac{1}{T_{t_i}} & \frac{1}{T_{t_i}} \\ -\frac{1}{R_i T_{g_i}} & 0 & 0 & -\frac{1}{T_{g_i}} \end{bmatrix} s_i + \begin{bmatrix} 0 \\ 0 \\ 0 \\ \frac{1}{T_{g_i}} \end{bmatrix} u_i - \begin{bmatrix} \frac{K_{p_i}}{T_{p_i}} \\ 0 \\ 0 \\ 0 \end{bmatrix} \Delta P_{G_i} \qquad \text{.........(1)}$$

Where s_i is the state vector: $\begin{bmatrix} \Delta f_{G_i} \\ \Delta P_{g_i} \\ \Delta P_{v_i} \\ \Delta E_i \end{bmatrix}$ of the *ith* generating unit; $\Delta f_G(t)$ the incremental frequency deviation; $\Delta P_G(t)$ the incremental change in generator output; $\Delta P_v(t)$ the incremental change in turbine power output; $\Delta E(t)$ incremental change in governor valve position; T_p is generator time constant; T_t is turbine time constant; T_g is governor time constant; R is feedback regulation constant; K_p is generator gain constant; K_r is turbine gain constant.

For convenience one can rewrite Eq(1) as follows:

$$\dot{s}_i = A_i s_i + B_i u_i - G_i \Delta P_{G_i} \qquad (2)$$

Where A_i is the plant and B_i is the input matrix. Also G_i is the electrical power-coupling matrix of each generating unit of the system.

Therefore, for a system with *m* individual power stations the generating system is represented by the following equation [11]:

$$\dot{s} = As + Bu - G\Delta P_G \qquad (3)$$

Where,

$A = \mathrm{diag}(A_i)$, $B = \mathrm{diag}(B_i)$, $G = \mathrm{diag}(G_i)$,

$s = [\, s_1 \; s_2, ... \, s_m]^T$, $\quad u = [u_1 \; u_2, ..., u_m]^T$,

$\Delta P_G = [\Delta P_{G1} \; \Delta P_{G2}, ..., \Delta P_{Gm}]$.

For a N-bus electrical network of the system the real and reactive power P_k and Q_k injected at each bus of the system (k=1,2,…..,N) are given by following equations, respectively:

$$P_k = |V_k| \sum_{j=1}^{N} ((G_{kj}\cos\delta_{kj} + B_{kj}\sin\delta_{kj})|V_k|) \qquad (4)$$

$$Q_k = |V_k| \sum_{j=1}^{N} ((G_{kj}\sin\delta_{kj} - B_{kj}\cos\delta_{kj})|V_k|) \qquad (5)$$

Where $|V_k|$ is the voltage amplitude at the node k, δ_{kj} the phase difference between node k and j, G_{kj} and B_{kj} is the real and imaginary part of the admittance between k and j node, respectively.

Since the real and reactive power injection at each node of the system network is a non-linear function of $|V_j|$ and one can express the change of the real and reactive power injection at all the system nodes as follows[11]:

$$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} H & N \\ M & L \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \dfrac{\Delta|V|}{|V|} \end{bmatrix} \qquad (6)$$

Where under the decoupling assumption between the changes of the real and reactive power and the assumption that is small enough, the non-diagonal elements of H and L are given by [2]:

$$H_{kj} = L_{kj} = |V_k||V_j|(G_{kj}\sin\delta_{kj} - B_{kj}\cos\delta_{kj})$$

$$= |V_k||V_j|(G_{kj}\delta_{kj} - B_{kj}) \qquad (7)$$

And the diagonal elements are

$$H_{kk} = -Q_k - B_{kk}V_k^2 \quad \text{and} \quad L_{kk} = Q_k - B_{kk}V_k^2 \qquad (8)$$

Where N and M are considered to be zero, i.e. N=M=0.

Therefore, from Eq(6) one can arrive at

$$\Delta P = \bar{H}\,\Delta\bar{\delta} \qquad (9)$$

Then, the power change in any row of Eq (9) can be expressed as

The matrix H is singular as the sum of the elements s each of its rows zero:

$$\sum_{j=1}^{N} H_{kj} = 0 \tag{10}$$

Then, the power change in any row of Eq (9) can be expressed as

$$\Delta P_k = \sum_{j=1}^{N} H_{kj}\Delta\delta_j + H_{kj}\Delta\delta_1$$
$$= \sum_{j=2}^{N} H_{kj}\Delta\delta_j - \sum_{j=2}^{N} H_{kj}\Delta\delta_1 = \sum_{j=2}^{N} H_{kj}(\Delta\delta_j - \Delta\delta_1) \tag{11}$$

Therefore, Eq(9) can now be expressed as a function of the relative angles by removing the first column of H, that is

$$\Delta P = \bar{H}\Delta\bar{\delta} \tag{12}$$

Where $\bar{H}$ is the $N\times(N\text{-}1)$ part of H and $\Delta\bar{\delta}$ is the (N-1) order vector of the relative angles with reference to $\Delta\delta_1$. Now, Eq(12) can be further portioned into real power injection at the generator and load buses as follows[11]

$$\Delta P = \begin{bmatrix} \Delta P_G \\ \Delta P_L \end{bmatrix} = \begin{bmatrix} \bar{H}_{GG} & \bar{H}_{GL} \\ \bar{H}_{LG} & \bar{H}_{LL} \end{bmatrix} \begin{bmatrix} \Delta\bar{\delta}_G \\ \Delta\bar{\delta}_L \end{bmatrix} \tag{13}$$

Where $\Delta\bar{\delta}_G$ and $\Delta\delta_L$ are the vectors of the relative angle difference at the generating and load buses, respectively with reference to angle deviation of the generator bus labeled as 1.

Solving the second row of Eq(13) for $\Delta\bar{\delta}_L$ one has

$$\Delta\bar{\delta}_L = -\bar{H}_{LL}^{-1}\bar{H}_{LG}\Delta\bar{\delta}_G + \bar{H}_{LL}^{-1}\Delta P_L \tag{14}$$

Substituting Eq(14) in the first row of Eq(13) one obtains

$$\Delta P_G = M_1\Delta\bar{\delta}_G + M_2\Delta P_L \tag{15}$$

Where $M_1 = \bar{H}_{GG} - \bar{H}_{GL}\bar{H}_{LL}^{-1}\bar{H}_{LG}$ and

$$M_2 = \bar{H}_{GL}\bar{H}_{LL}^{-1} \tag{16}$$

Substituting Eq(15) in Eq(3), one obtains the augmented system[11]

$$\begin{bmatrix} \dot{s} \\ \Delta\dot{\delta}_G \end{bmatrix} = \begin{bmatrix} A & -GM_1 \\ E & 0 \end{bmatrix} \begin{bmatrix} s \\ \Delta\delta_G \end{bmatrix} + \begin{bmatrix} B \\ 0 \end{bmatrix} u - \begin{bmatrix} GM_2 \\ 0 \end{bmatrix} \Delta P_L \tag{17}$$

Where E= [Z,diag(E_{i+1})], $E_i = [0\ 0\ 2\pi]$, Z is the $(m\text{-}1)\times 3$ matrix: $Z = [-E_1^T, ..., -E_1^T]^T$. Also, system (17) is a (4m-1)-order system with *m* independent inputs (where *m* is the number of the generating units).

Eq (17) represents a suitable model for AGC strategies, which clearly recognizes individual power stations inside a control area. Therefore, the dynamic operation of the several generating units can be successfully determined in accordance with preselected power and control requirements. Furthermore, it is obvious from the previous analysis that the proposed model is easily obtained for any power system and it can be used for single or multi-area control.

3. OBJECTIVE FUNCTION

Penalizing the frequency excursions, an objective function based on the integral of time-multiplied square error (ITSE) criterion is considered in this study and is given by [13,14]:

$$J = \int_0^{\infty} t(\Delta f)^2 dt \tag{18}$$

To compute the optimum parameter values, a step disturbance in reference input (ΔP_L = 0.2 pu) was used to perturb the system from its operating point.

4. GENETIC ALGORITHM

Genetic algorithms (GAs), is an way to randomly search for the best answer to tough problems and this was first suggested by John Holland in his book in Natural and Artificial systems [15]. The present problem is nonlinear multivariable function with respect to tune the gains of P-I controller. So in the present problem, genetic algorithm is used to minimize the objective function as given by eqn. (18) and hence to design the gains and parameters of P-I controller. The detailed optimization algorithm of GA is given below [16].

The complete optimization procedure using GA is given below:

STEP-1: To form initial binary strings (chromosomes) equal to population size.

STEP-2: To evaluation of the fitness for each string is as follows:

Convert each binary substring (genes) in a string into a decimal number and compute the physical value of design variables using eqn. as follows:

$$y_i = y_i^{min} + I_i \frac{(y_i^{max} - y_i^{min})}{2^{\beta_i} - 1} \tag{19}$$

Where y_i is the design variable, ε = the resolution, β = bit string

To evaluate the objective function J using eqn. (18) by calling the "4-th order Runge-kutta" Subroutine.

To calculate the fitness, $F = \frac{K}{J}$ using eqn. (18).

STEP-3: i) To find out the cumulative fitness of each string by adding its fitness to the fitness of the proceeding population members.

ii) To sum the fitness of all population members.

iii) To find the best fitness string and send it to the solution vector.

STEP-4: To set generation number = 1;

STEP-5: For i =1 to i = "population size * Crossover rate".

i) To select two parents from population (based on roulette wheeling method).

ii) To perform crossover and hence generate two offspring.

iii) To mutate these two offspring based on mutation probability.

STEP-6: To calculate fitness of each offspring (as in STEP-2 and STEP-3).

STEP-7: To repeat STEPS 5 and 6 till maximum number of generation is reached.

In the present algorithm, different combination of mutation probabilities (0.0001, 0.001, 0.005 & 0.01) and the crossover probabilities (0.6, 0.8, 0.9 & 1.0) have been tested and it is found that P_c =1.0 and P_m = 0.005 give the best performance for all the gains of controller.

5. RESULTS

In the present work, a 6 bus system is considered as shown in Fig. 1. The data for the system are given in appendix. The proportional-Integral controller is designed for the generators by minimizing the objection function as given by eqn.(18) using genetic algorithm and the range for optimizing the gains of Proportion and Integral Controller have been considered K_{Pmax} = 30, K_{pmin} = -30 and K_{Imax} = 15, K_{Imin} = -15 respectively. The optimum values gains of PI controllers are given as K_{P1} = 14.9089, K_{P2} = 17.9738 & K_{I1} = -5.1461, K_{I2} = 9.9224. Here as the optimization problem is non-linear in nature, the optimum value of KI1 has been found negative. Dynamic responses have been observed by changing loads of the load buses 4, 5, and 6 respectively for the considered power system as shown in Fig. 2. Fig.-3 & 4 shows the dynamic response of frequency deviation for Generator-2 and Generator-3 respectively with and without considering P-I

Controller for 20% load change at Bus 4. Similarly, dynamic response of frequency deviation for Generator-2 and Generator-3 respectively with and without considering P-I Controller for 20% load change at Bus 5 and Bus 6 have been shown in Fig. 5 & 6 and Fig. 7 & 8 respectively. From these figures, it is seen that the dynamic responses are much better in terms of peak deviation and settling time with P-I controller as compared to without P-I controller. Fig. 9 & 10 show the dynamic responses of frequency for machine 2 and 3 considering 20% load change in bus 4, 5 and 6 separately. It is observed from the Fig. 9 & 10 that dynamic responses change for any particular generator if the load disturbance point changes. So, it is very important to consider whole network of the power system while designing the controller of each individual generator for improving the frequency deviation.

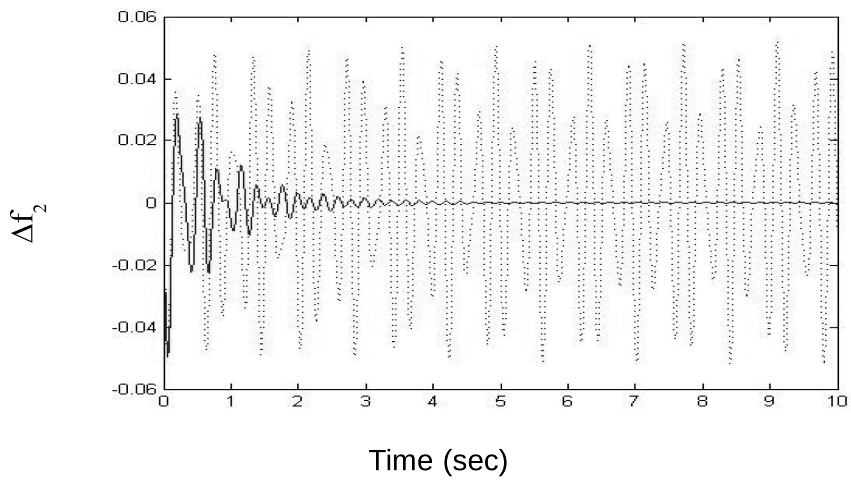


Fig.3: Dynamic response of frequency for Generator 2 considering with and without PI controller for 20% load change at Bus 4.
(——— With PI Control, ----------Without PI Control)

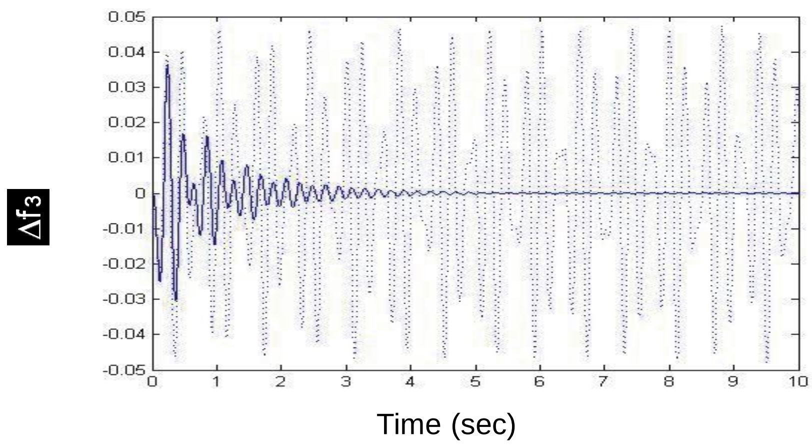


Fig.4: Dynamic response of frequency for Generator 3 considering with and without PI controller for 20% load change at Bus 4
(——— With PI Control,-----------Without PI Control)

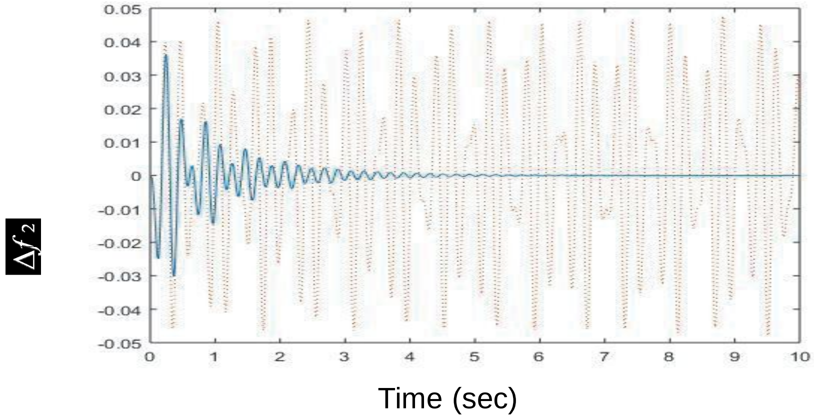


Fig.5: Dynamic response of frequency for Generator 2 considering with and without PI controller for 20% load change at Bus 5.
(——— With PI Control,-----------Without PI Control)

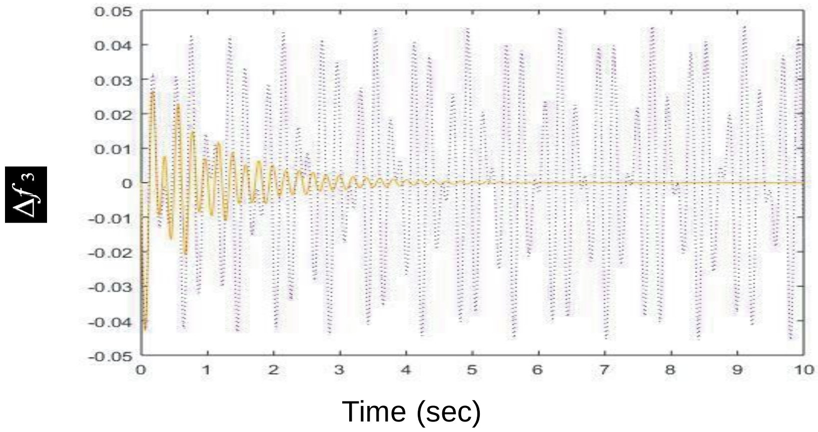


Fig.6: Dynamic response of frequency for Generator 3 considering with and without PI controller for 20% load change at Bus 5.
(——— With PI Control,-----------Without PI Control)

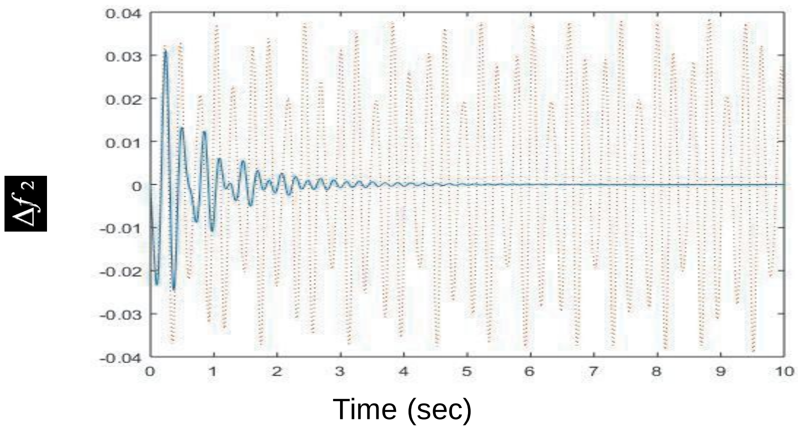
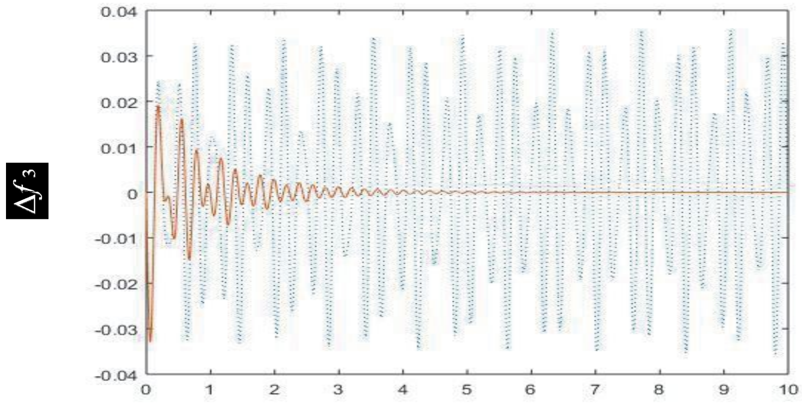
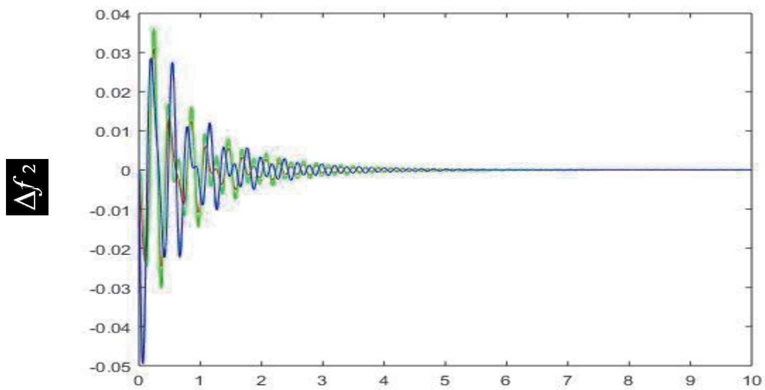


Fig.7: Dynamic response of frequency for Generator 2 considering with and without PI controller for 20% load change at Bus 6.
(——— With PI Control,-----------Without PI Control)



Time (sec)

Fig.8: Dynamic response of frequency for Generator 3 considering with and without PI controller for 20% load change at Bus 6.
(——— With PI Control,------------Without PI Control)



Time (sec)

Fig.9: Dynamic response of frequency for Generator 2 considering with PI controller for 20% load change at Bus 4,5,6 seperately.
(———20% load change at bus 4,———20%load change at bus 5, —— 20% load change at bus 4)

6. CONCLUSION

In this paper, a systematic method of obtaining a detailed model of control area for automatic generation control (AGC) taking into account the effect of power transmission network has been considered. Genetic algorithm (GA) is used to optimize the gains of Proportional Integral (P-I) controller for generators of a 6-bus system for improving the dynamic response of the system. The simulation results show that the dynamic response for frequency deviation improves significantly considering P-I controller optimized using GA. Again, load disturbances at different load buses have been considered separately to observe the variation of frequency responses for each individual generator and it is found that dynamic responses change for any particular generator if the load disturbance point changes.

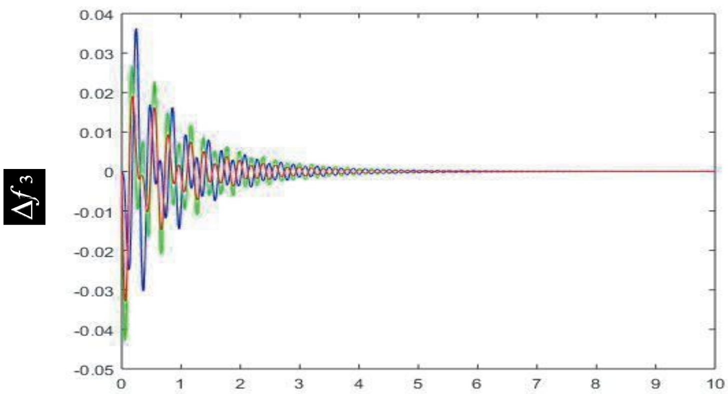


Fig.10: Dynamic response of frequency for Generator 3 considering with PI controller for 20% load change at Bus 4,5,6.
(———20% load change at bus 4,——— 20%load change at bus 5,
———20% load change at bus 4)

Simulation results for dynamic responses shows that it is very important to consider whole network of the power system while designing the controller of each individual generator for improving the frequency deviation.

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APPENDIX

Load Flow data for 6 bus systems are given in Table A1 and A2.

Table A1: Bus Data

Bus Code	Voltage (in p.u.)		Load (in p.u.)		Generation (in p.u.)			
	Magnitude	Phase angle	MW	MVAr	MW	MVAr	Q_{min}	Q_{max}
1	1.06	0.0	0	0	0	0	0	0
2	1.00	0.0	0	0	20	0	-30	30
3	1.00	0.0	0	0	50	0	-40	40
4	1.00	0.0	50	35	0	0	0	0
5	1.00	0.0	50	25	0	0	0	0
6	1.00	0.0	60	25	0	0	0	0

Table A2: Line Data

Bus Code	R (in p.u.)	X (in p.u.)	B/2 (in p.u.)
1-2	0.02	0.08	0.00
1-3	0.02	0.06	0.00
2-3	0.06	0.25	0.00
2-4	0.06	0.25	0.00
2-6	0.06	0.25	0.00
3-5	0.06	0.25	0.00
3-6	0.06	0.08	0.00