ACKNOWLEDGEMENT

I write this acknowledgement with great honor, pride and pleasure to pay my respects to all who enabled me either directly or indirectly in reaching this stage.

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P.S.Bhargava

ABSTRACT

This research project deals with the application of Artificial Neural Network (ANN) based Adaptive Neuro-Fuzzy Inference System (ANFIS) approach to Decentralized Automatic Generation Control (DAGC) Scheme for interconnected multi-area Power System. The proposed ANFIS Controller combines the advantages of Fuzzy Controller as well as quick response and adaptability nature of ANN. The design controller for Decentralized Automatic Generation Control has three major objectives i.e., To maintain the system Frequency at nominal value (50Hz), To maintain the net Tie-line power interchange from different areas at their scheduled values and To incorporated various types of possible transactions such as PoolCo-based transactions, Bilateral transactions or a combination of these two.

Conventionally, for issues related to Automatic Generation Control (AGC), the frequency deviation is minimized by the flywheel type of governor of synchronous machine. However, the significant control is not achieved for the Load Frequency Control (LFC) objective. In this context, the supplementary control is introduced to the governor via signal directly proportional to the frequency deviation plus its integral action. The proposed approach with non-interaction between frequency and tie-line power control and each control area responsible for its own load variations. The technique based on coordinated system-wide correction of time error and inadvertent interchange is incorporated for AGC (generally referred to as Area Control Error (ACE)).

In a Practical power system, there may be more than two areas, and each of the areas may have different ratings. Contrary to the centralized control for a large scale power system, Decentralized control is preferable, because it reduces the computational burden with pass of the communication between different systems and make the control more feasible and simple. In order to overcome the problem arising out of the centralized control, the decentralized control approach has been addressed. The basic objective of later technique is to make the composite system divided into subsystem, each of which control separately. The advantage of a decentralized controller is to reduce complexity and therefore, make its implementation more practical.

The prominent feature of fuzzy and neural network based schemes is that they provide a model-free description of control systems and do not require model identification. In this research a control scheme based on ANFIS, which is trained by the results of off-line studies, obtained using genetic algorithm has been proposed. ANFIS is considered to be an adaptive

network, which is very similar to neural networks. Adaptive network has synaptic weights, but has so called adaptive and non-adaptive nodes. It must be said that adaptive network can be easily transformed to neural networks architecture with classical feed no forward topology. This adaptive network is functionally equivalent to a fuzzy inference system (FIS). Using a given input/output data set, ANFIS adjusts all the parameters using back propagation gradient descent and least squares type of method for non-linear and linear parameters respectively.

The proposed Decentralized Automatic Generation Control (DAGC) based on ANFIS Controller scheme has been simulated on a practical 39-bus New England system and a 75-bus Indian power system. The performance of the Decentralized Automatic Generation Control (DAGC) ANFIS controller is compared with the results of Decentralized Automatic Generation Control (DAGC) based integral controller. Simulation results indicates that the controllers exhibit better performance.

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LIST OF ACRONYMS AND ABBREVIATIONS

LFC	Load Frequency Control
CA	Control Area
AVR	Automatic Voltage Regulation
AGC	Automatic Generation Control
ACE	Area Control Error
DAGC	Decentralized Automatic Generation Control
GENCO	Generation Company
DISCO	Distribution Company
TRANSCO	Transmission Company
SO	System Operator
ISO	Independent System Operator
DPM	Disco Participation Matrix
AGPM	Augmented Generation Participation Matrix
EPF	Economic Participation Factor
CPF	Contract Participation Factor
FERC	Federal Energy Regulatory Commission
NOPR	Notice Proposed Rulemaking
TP	Transmission Provider
EMS	Energy Management System
ICA	Independent Contract Administrator
ANN	Artificial Neural Network
ANFIS	Adaptive Neuro-Fuzzy Inference System
GUI	Graphical User Interface
FIS	Fuzzy Inference System
MATLAB	Matrix Laboratory

1. LOAD FREQUENCY CONTROL

1.1 DEFINITION :

Any power system that has the fundamental control problem of matching real power generation to load including losses is called Load Frequency Control. The frequency is dependent upon active power which comes from the load generation mismatch.

1.2 INTRODUCTION :

The main objective of an interconnected power system control is generating, transmitting and distributing electric power as economically and reliably as possible while maintaining the quality of power, voltage magnitude and frequency within the acceptable limits. Large-scale power systems comprise interconnected subsystems (control areas) forming coherent groups of generators, whereas connection between the areas is made using tie-lines. Each control area has its own generation and it is responsible for its own load and scheduled interchanges with neighbouring areas. The load in a given power system is continuously changing and consequently the system frequency and tie-line flows deviate from the desired nominal values. Therefore, to ensure the quality of power supply, a load frequency controller (LFC) is needed to maintain the system frequency and inter-area flows at the desired nominal values. The objective of the LFC in an interconnected power system is to maintain the frequency of each area within limits and to keep tie-line power flows within some pre-specified tolerances by adjusting the MW outputs of the generators so as to accommodate fluctuating load demands. A well designed and operated power system must cope with changes in the load and with system disturbances and it should provide acceptable high level of power quality while maintaining both voltage and frequency within tolerance limits. The nominal operating point of a power system changes from its pre-specified value when subjected to any disturbance. As a result the deviation occurs about the operating point such as nominal system frequency, scheduled power exchange to the other areas which is undesirable.

1.3 GENERATOR CONTROL LOOPS

In modern large interconnected systems, manual regulation is not feasible and therefore automatic generation and voltage equipment is installed on each generator *(LFC: controls frequency and real power, AVR: controls voltage magnitude and reactive power)*. Figure 1.1 gives the schematic diagram of load frequency and excitation voltage regulators of a turbo-generator. The controllers are set for a particular operating condition and they take care of small changes in load demand without frequency and voltage exceeding the prescribed limits.

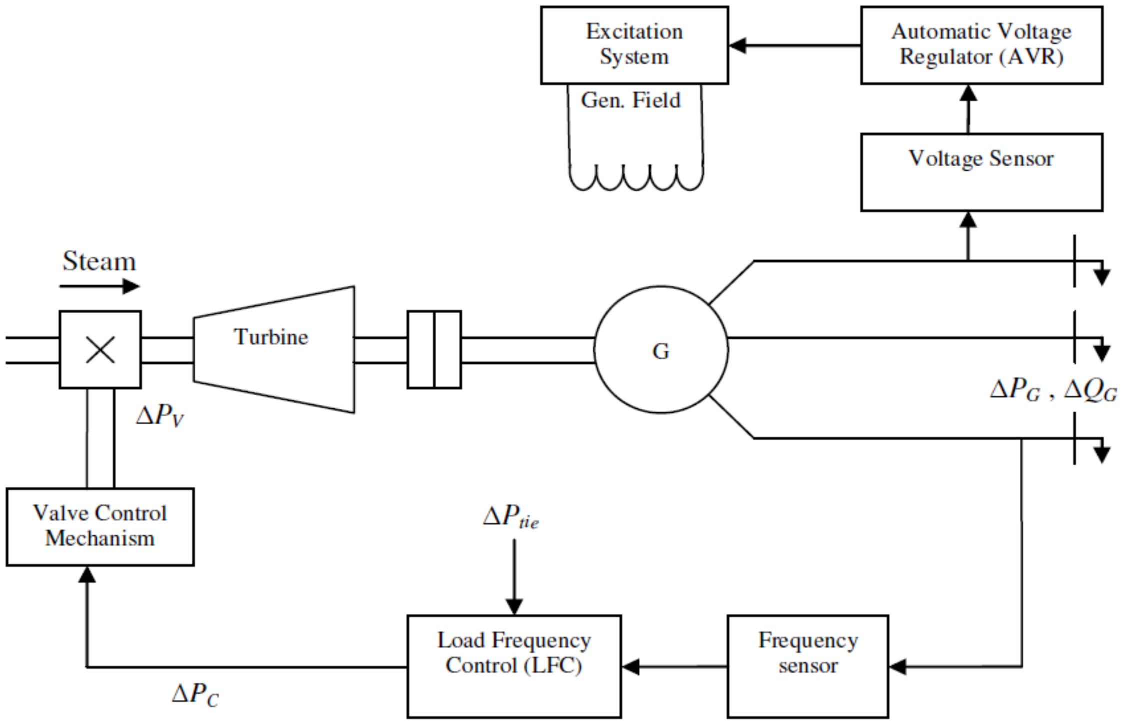

Fig .1.1 the schematic diagram of LFC and AVR of a turbo-generator

Small changes in load depend upon the change in rotor angle and is independent of the bus voltage whereas the bus voltage is dependent on machine excitation (i.e., on the reactive generation, and is independent of rotor angle).Therefore, the two controls, i.e., load frequency and excitation voltage controls are non-interactive for small changes and can be modelled and analyzed independently. Besides, the load frequency controller is slow acting because of the large time constant contributed by the turbine and generator moment of inertia, and excitation voltage control is fast acting as the time constant of field winding is relatively smaller, thus the transients in excitation voltage control vanish much faster and do not affect the dynamics of load frequency control.

1.4 MODELS AND BLOCK DIAGRAMS

1.4.1 SPEED GOVERNOR MODEL :

The governor is a device used to sense a turbine speed changes when the load of the generator is suddenly increased. In that case, the electrical power exceeds the input mechanical power. The shortage of this power is supplied by kinetic energy stored in the rotating system, reducing the mechanical power of the turbine. This reduction in energy causes the turbine speed to fall and thus the generator frequency to fall. Any change in speed is sensed by the turbine governor, which will act to adjust the input valves of the turbine to change the output mechanical power to bring the speed to a new steady state.

Speed governor is the **HEART OF THE LOAD FREQUENCY CONTROL**

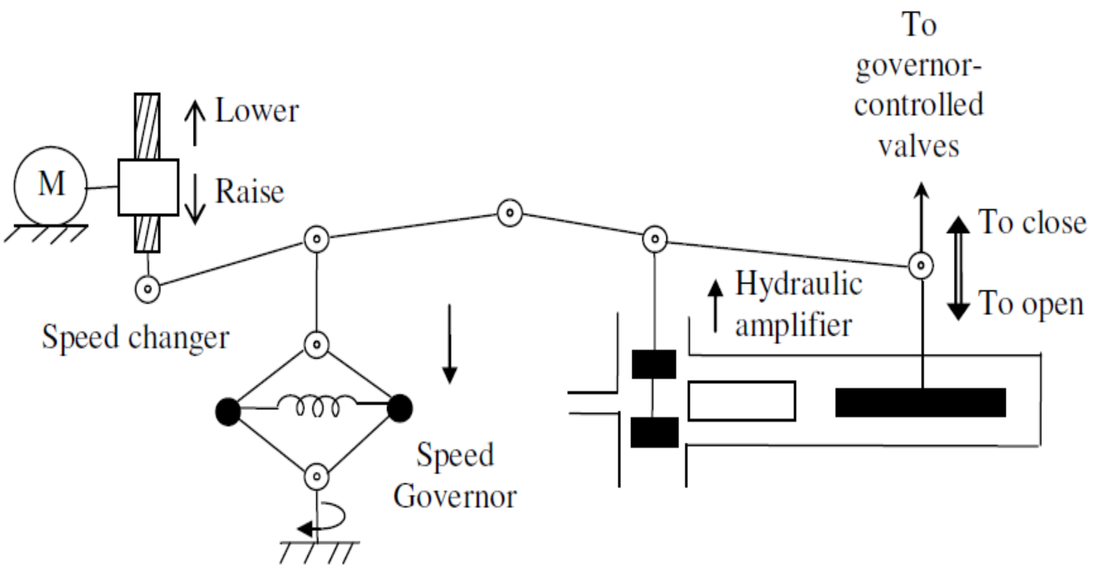

Fig. 1.2 a Schematic of Fly-Ball Type Speed Governor

The speed governor acts as a comparator whose output ΔP_g is the difference between the reference set power ΔP_{ref} and the power $\frac{\Delta\omega}{R}$

$$\Delta P_g = \Delta P_{ref} - \frac{\Delta\omega}{R}$$

In s-domain,

$$\Delta P_g(s) = \Delta P_{ref}(s) - \frac{\Delta\omega(s)}{R}$$

Where,

R = speed – regulation due to governor action

$\Delta\omega$ = change in the frequency

Governors typically have speed regulation of 5 to 6 percent from no load to full load.

Consider a simple time constant (Tg) and assume linear relationship, we have the equation,

$$\Delta P_v(s) = \frac{\Delta \mathrm{Pg(s)}}{1+Tg(s)}$$

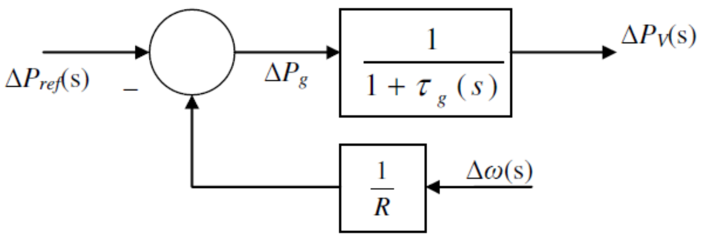

Fig. 1.3 Speed – Governor Block Diagram

1.4.2 TURBINE – GENERATOR MODEL :

It is the source of mechanical power; it may be a hydraulic turbine at waterfalls, steam turbine whose energy comes from burning of gas, coal, and gas turbine. Its model relates changes in mechanical power output ΔP_m to changes in steam valve position ΔP_v, then the transfer function of the turbine – generator model is given by fig .1.4

$$G(s) = \frac{\Delta \mathrm{Pm(s)}}{\Delta \mathrm{Pv(s)}} = \frac{1}{1+Tt(s)}$$

Where,

G(s) = Transfer – Function of the Turbine – Generator Model

$T_t(s)$ = Time Constant of the Turbine – Generator Model

The time – constant of the turbine – generator model varies from 0.2 to 2msec.

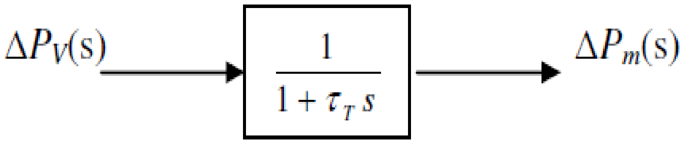

Fig. 1.4 Turbine – Generator Block Diagram

1.4.3 GENERATOR – LOAD MODEL :

The swing equation of the synchronous machine is given by the equation,

$$\Delta\omega(s) = \frac{1}{2HS}[\Delta Pm(s) - \Delta Pe(s)]$$

Where,

ΔP_m = Change in Input Mechanical Power

$\Delta \omega$ = Frequency Deviation

H = Inertia Constant (in p.u) = $\frac{Kinetic\ energy\ at\ synchronous\ speed}{machine\ rating}$

ΔP_e=Change in Electrical Power

Inertia constant having a unit of seconds and ranging from 1 to 10 seconds depending on the type and size of the machine .The equivalent circuit for generator-load model is represented by fig. 1.5

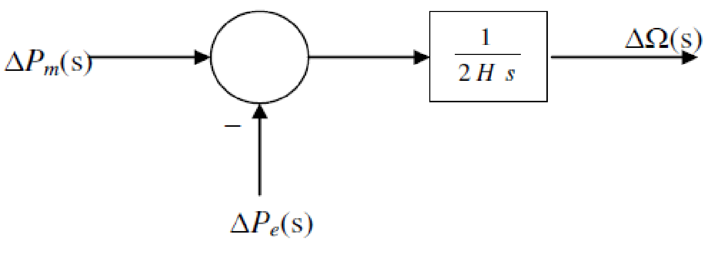

Fig. 1.5 Generator Block Diagram

In power systems, the loads are mainly resistive loads, and this is independent of frequency. And the other type of loads is Motor loads (mainly inductive), which is sensitive to change in frequency, depending on the composite of the speed-load characteristic of all driven devices. Speed load characteristic of composite load is:

$$\Delta P_e = \Delta P_L + \mathrm{D}\,(\Delta\omega)$$

Where,

ΔP_L= Independent frequency loads.

D = ratio of percentage change in load to percentage change in frequency (Damping Factor).

D $(\Delta\omega)$ = frequency sensitive loads.

When the block diagram of the load- model is added to the generator- model the generator-load model is represented by fig 1.6

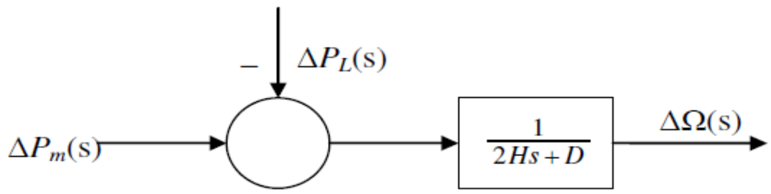

Fig. 1.6 Generator – Load Block Diagram

Combining block diagrams of the preceding models we can find ***the block diagram of the LFC of an isolated power station***, providing the primary level of LFC.

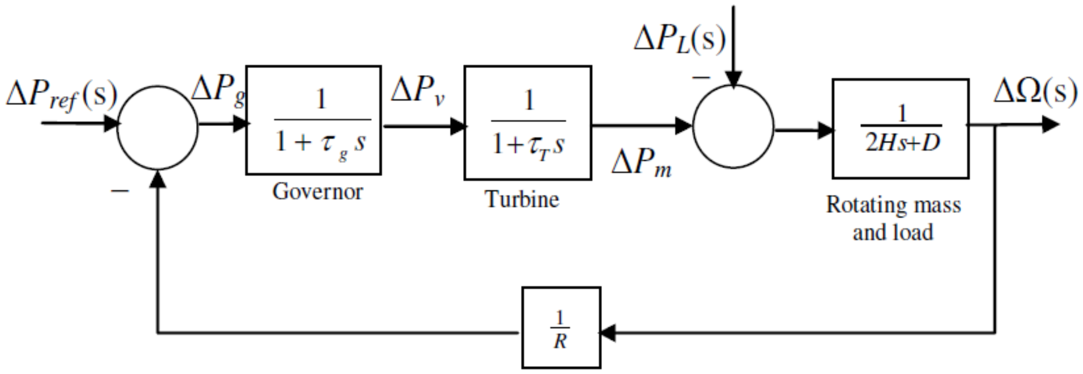

Fig. 1.7 LFC Block Diagram of an Isolated Power System (or) single – area system

1.5 STEADY – STATE ERROR ANALYSIS OF AN ISOLATED POWER SYSTEM

With the load change $-\Delta P_L(s)$ as an input, and the frequency deviation $\Delta\omega(s)$ as an output, the resultant block diagram of an isolated power system is given by fig .1.8

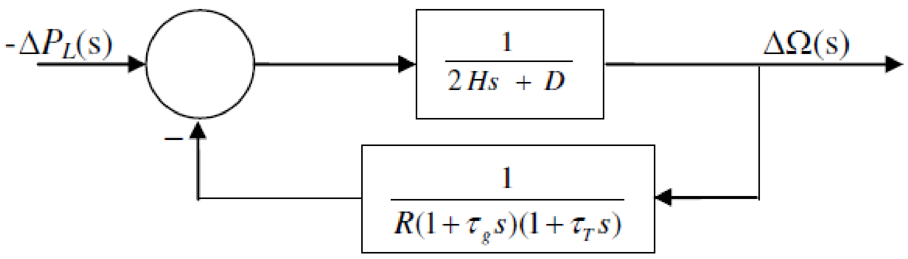

Fig.1.8 LFC with input $-\Delta P_L(s)$ **and output** $\Delta\omega(s)$

The open – loop transfer function for the system is given by,

$$G(s)H(s) = \frac{1}{(2HS+D)(1+TgS)(1+TtS)R}$$

The closed loop transfer function is given by the equation,

$$\frac{\Delta\omega(s)}{-\Delta PL(s)} = \frac{(1+TgS)(1+TtS)}{(2HS+D)(1+TgS)(1+TtS)+1/R} = T\ (S)$$

(OR)

$$\Delta\omega_s = -\Delta P_L(s)\ T\ (S)$$

The load change is a step input (i.e. ΔP_L = ΔP_L/s) then the steady state value of $\Delta\omega_{ss}$ is known by using the **Final Value Theorem**

$$\Delta\omega_{ss} = \lim_{s\to 0} s\Delta\omega(s)$$

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{(D+\frac{1}{R})}$$

We can find that for the case of no frequency sensitive load (i.e. with D=0) then the steady-state value of the frequency deviation is

$$\Delta\omega_{ss} = (-\Delta P_L)\ R$$

If we have a case of multiple generators with governor speed regulations $R_1, R_2 \ldots\ldots R_n$ then

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{(D+\frac{1}{R_1}+\frac{1}{R_2}+\cdots\ldots\ldots+\frac{1}{R_n})}$$

2. AUTOMATIC GENERATION CONTROL

2.1 DEFINITION :

Any supplementary control that automatically adjusts the power output levels of electric generators within a control area is AGC. Automatic Generation Control (AGC) schemes can include one or more control subsystem(s) such as load frequency control, economic dispatch control, environmental dispatch control, security dispatch control etc.

2.2 INTRODUCTION :

In an electric power system, Automatic Generation Control (AGC) 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 and 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; if it is increasing, more power is being generated than used, and all the machines in the system are accelerating. If the system frequency is decreasing, more load is on the system than the instantaneous generation can provide, and all generators are slowing down. Before the use of automatic generation control, one generating unit in a system would be designated as the regulating unit and would be manually adjusted to control the balance between generation and load to maintain system frequency at the desired value. The remaining units would be controlled with speed droop in proportion to their share of the load according to their ratings. With automatic systems, many units in a system can participate in regulation, reducing wear on a single unit's controls and improving overall system efficiency, stability, and economy. Where the grid has tie interconnections to adjacent control areas, automatic generation control helps maintain the power interchanges over the tie lines at the scheduled levels. With computer-based control systems and multiple inputs, an automatic generation control system can take into account such matters as the most economical units to adjust, the coordination of thermal, hydroelectric, and other generation types, and even constraints related to the stability of the system and capacity of interconnections to other power grids.

Each generator which has a governor can be represented by fig 2.1. Note that the value of the load reference P_{m0} is adjusted by AGC.

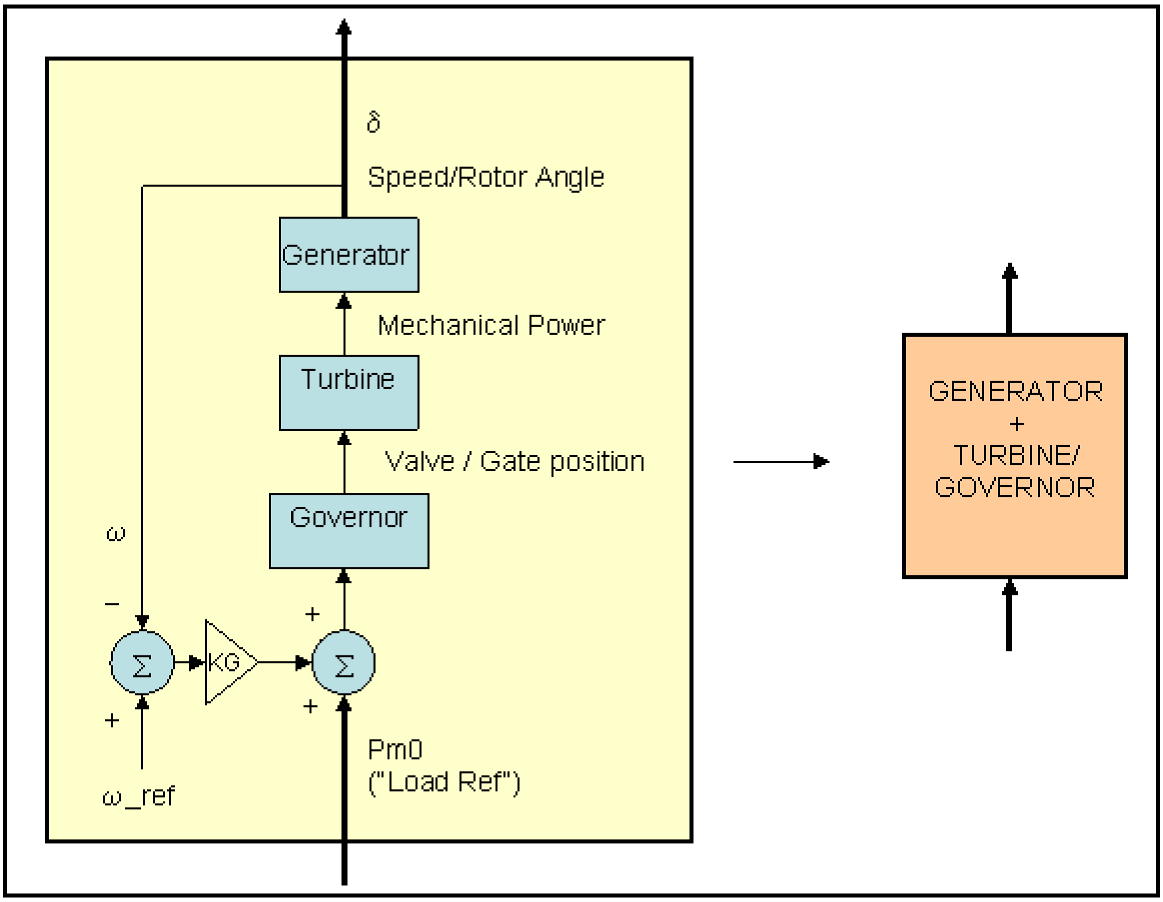

Fig. 2.1 Automatic Generation Control (AGC) Block Diagram

2.3 ACG IN SINGLE AREA SYSTEM :

In order to reduce frequency deviation to zero, we must provide a reset action; there set action can be achieved by adding integral controller. The LFC system with addition of integral controller is shown in the figure 2.2

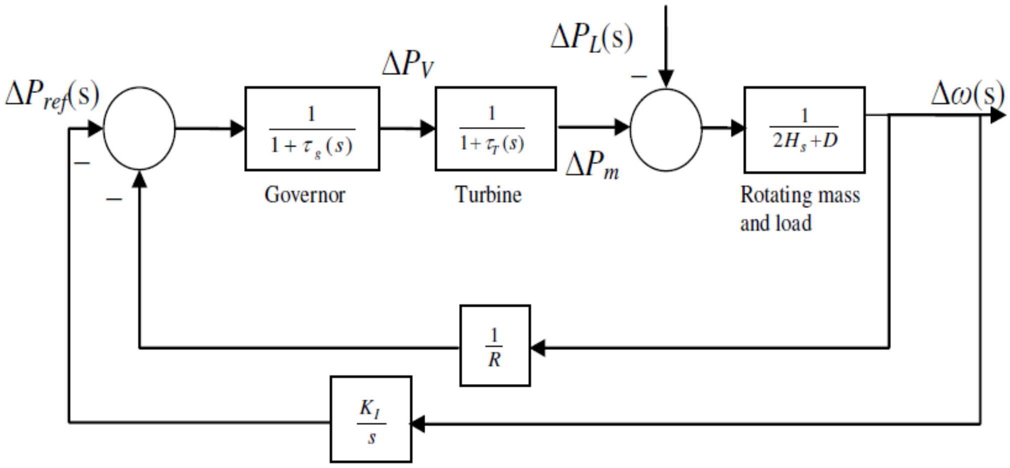

Fig. 2.2 AGC for an isolated power system

2.3.1 STEADY – STATE ERROR ANALYSIS OF A SINGLE AREA CONTROL SYSTEM

Combining the parallel branch results, the following block diagram is obtained,

The transfer function is given by the equation,

$$\frac{\Delta\omega(s)}{-\Delta PL(s)} = \frac{s(1+TgS)(1+TtS)}{S(2HS+D)(1+TgS)+Ki+\frac{S}{R}} = T1(S)$$

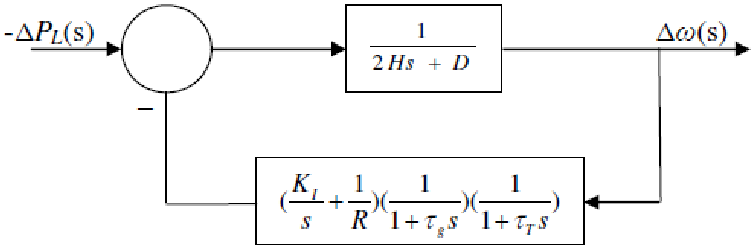

Fig.2.3 Equivalent Diagram of single area control system

The load change is a step input (i.e. ΔP_L = ΔP_L/s) then the steady state value of $\Delta\omega_{ss}$ is known by using the **Final Value Theorem**

$$\Delta\omega_{ss} = \lim_{s\to 0} s\Delta\omega(s)$$

$$\Delta\omega_{ss} = \frac{-\Delta P_L}{Ki}$$

2.4 AGC IN A TWO-AREA SYSTEM :

One of the objectives of the load frequency control is to correct value of interchange of power between the control areas. In two area system the areas are connected by means of tie –line, thus the design of tie-line is necessary in order to analyze AGC in a two area system.

Consider these two areas represented by an equivalent generating units interconnected by a lossless tie line with reactanceX_{tie} in fig 2.4. Each area is represented by voltage source behind an equivalent reactance as shown in figure 2.5

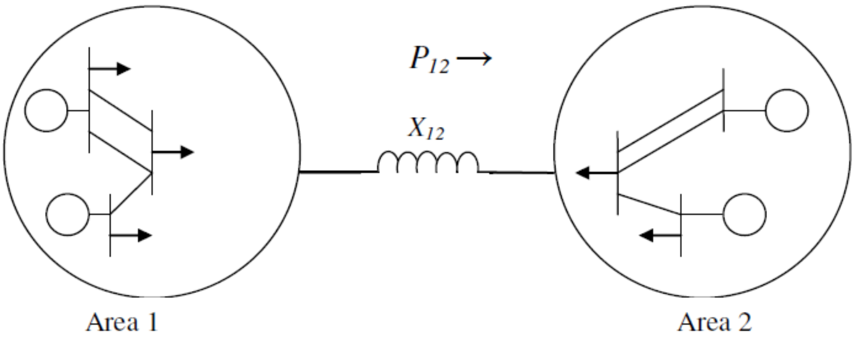

Fig .2.4 Schematic of two area system

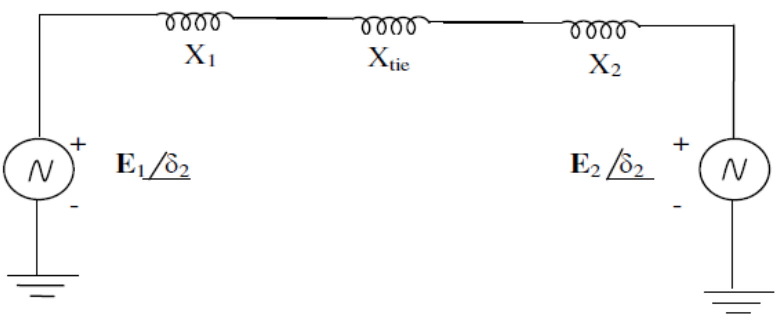

Fig.2.5 Equivalent network of two area system

During normal operation the real power transferred over the tie line is given by:

$$P_{12} = \frac{E1\ E2}{X12} sin\ \delta_{12}$$

Where,

$X_{12} = X_1 + X_2 + X_{tie}$

$\delta_{12} = \delta_1 - \delta_2$

The above equation can be linearized for a small deviation in the flow ΔP_{12} from the nominal value i.e.

$$\Delta P_{12} = \frac{dP12}{d\delta 12} * \delta_{12} = P_s \delta_{12}$$

Where,

P_s = slope of the power angle curve at the initial operating angle $\Delta\delta_{12} = \Delta\delta_1 - \Delta\delta_2$

Thus,

$$P_s = \frac{dP12}{d\delta 12} = \frac{E1\ E2}{X12}\ cos\Delta\delta_{12}$$

Then,

$$\Delta P_{12} = P_s\ (\Delta\delta_1 - \Delta\delta_2)$$

$$\Delta\omega = 2\Pi\ \Delta f$$

$$\frac{d\Delta\delta}{dt} = 2\Pi\Delta f$$

$$\int d\Delta\delta = \int 2\Pi\Delta f\ \mathrm{dt}$$

$$\Delta\delta = 2\Pi \int \Delta f\ \mathrm{dt}$$

$$\Delta\delta = \frac{2\Pi\ T_{12}}{s}$$

Hence the tie-line power flow equation is given by

$$\Delta P_{12}\ (\mathrm{s}) = \frac{2\Pi\ T_{12}}{s} [\Delta f_1(s) - \Delta f_2(s)]$$

And $\Delta P_{12} = a_{12} * \Delta P_{21}$

Where,

$$P_{r1} * P_{tie1} = -\ P_{tie2} * P_{r2}$$

i.e. $a_{12} = \frac{-Pr1}{Pr2}$

P_{r1}, P_{r2} are ratings of generators in the respective control areas. If ratings of both the generators are equal then a_{12} = -1 (i.e. ΔP_{12} = -ΔP_{21})

T_{12} = synchronizing torque coefficient = $\dfrac{\Delta P_{12}}{\Delta \delta_{12}}$

The direction of the power flow depends upon the phase angle difference: if $\delta_1 > \delta_2$ then power flows from area-1 to area-2 and vice-versa. The equivalent network for a two area uncontrolled system is shown in the fig 2.6

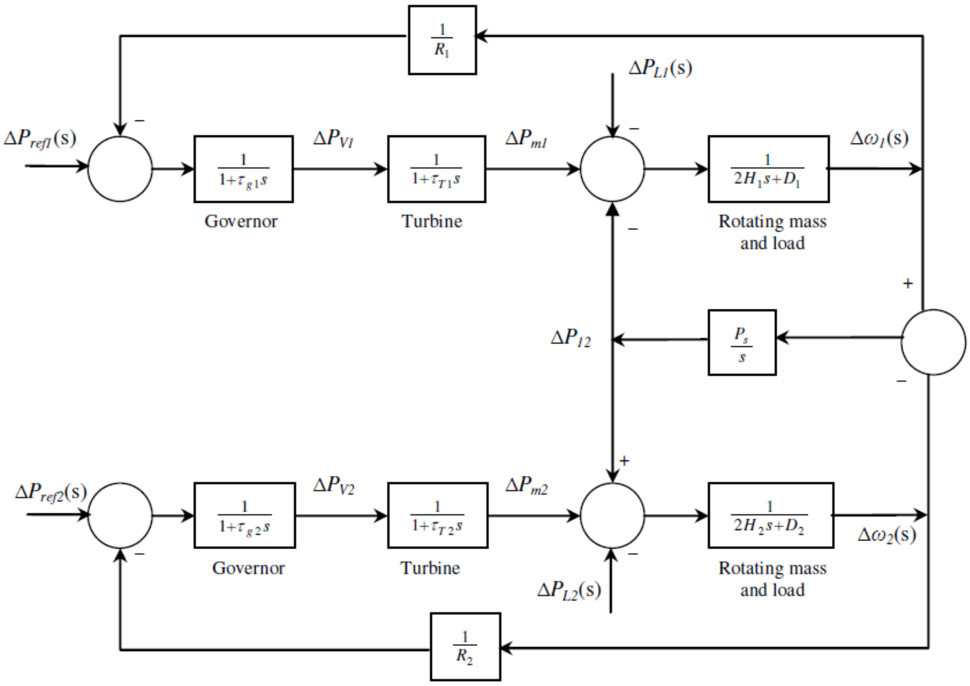

Fig.2.6 Block diagram of a two- area uncontrolled system

Consider load change in area 1 isΔP_{L1}, in the steady-state; both areas will have the same steady-state frequency deviation;

$$\Delta\omega = \Delta\omega_1 = \Delta\omega_2$$

Now,

$$\Delta P_{m1} - \Delta P_{12} - \Delta P_{L1} = \Delta\omega\, D_1 \quad \text{and} \quad \Delta P_{m2} + \Delta P_{12} = \Delta\omega\, D_2$$

The change in mechanical power is determined by the governor speed characteristic, given by:

$$\Delta P_{m1} = \frac{-\Delta\omega}{R1} \text{and } \Delta P_{m2} = \frac{-\Delta\omega}{R2}$$

Solving for $\Delta\omega$,

$$\Delta\omega = \frac{-\Delta P_{L1}}{\left(D1+\frac{1}{R1}\right)+(D2+\frac{1}{R2})} = \frac{-\Delta P_{L1}}{B1+B2}$$

Where B1 and B2 are known as the frequency bias factors. The change in the tie line power is given by,

$$\Delta P_{12} = \frac{-\left(D_2+\frac{1}{R_2}\right)\Delta P_{L1}}{\left(D_1+\frac{1}{R_1}\right)+(D_2+\frac{1}{R_2})} = \frac{B_2\,(-\Delta P_{L1})}{B_1+B_2}$$

We can easily extend the tie line bias control to an n-area system

2.4.1 TIE – LINE BIAS CONTROL :

LFC was equipped with only the primary control loop, a change of power in area 1 was met by the increase in generation in both areas associated with a change in the tie-line power, and a reduction in frequency. In the normal operating state, the power system is operated so that the demands of areas are satisfied at the normal frequency. A simple control strategy for the normal mode is:

- To keep frequency approximately at the nominal value (50 or 60 Hz).
- To maintain the tie-line flow at about scheduled value.
- Each area should absorb its own load changes.

Conventional LFC is based upon tie-line bias control, where each area tends to reduce the ***Area Control Error*** (**ACE**) to zero. The control error for each area consists of a linear combination of frequency and tie-line errors.

$$ACE_i = \sum_{j=1}^{n} \Delta\mathrm{Pij} + \mathrm{Ki}\ \Delta\omega$$

The area bias Ki determines the amount of interaction during a disturbance in the neighboring areas. An overall satisfactory performance is achieved when Ki is selected equal to the frequency bias factor of that area, i.e.

$$B_1 = D_1 + 1/R_i$$

Thus the ACG of the two areas are given by,

$$ACE_1 = B_1\ \Delta\omega_1 + \Delta P_{12}$$
$$ACE_2 = B_2\ \Delta\omega_2 + \Delta P_{12}$$

ACEs are used as actuating signals to achieve changes in the reference power set points, and when steady-state is reached, ΔP_{12} and $\Delta\omega$ will be zero. The block diagram of a simple AGC for a two-area system with ACE loops is shown in figure 2.7.

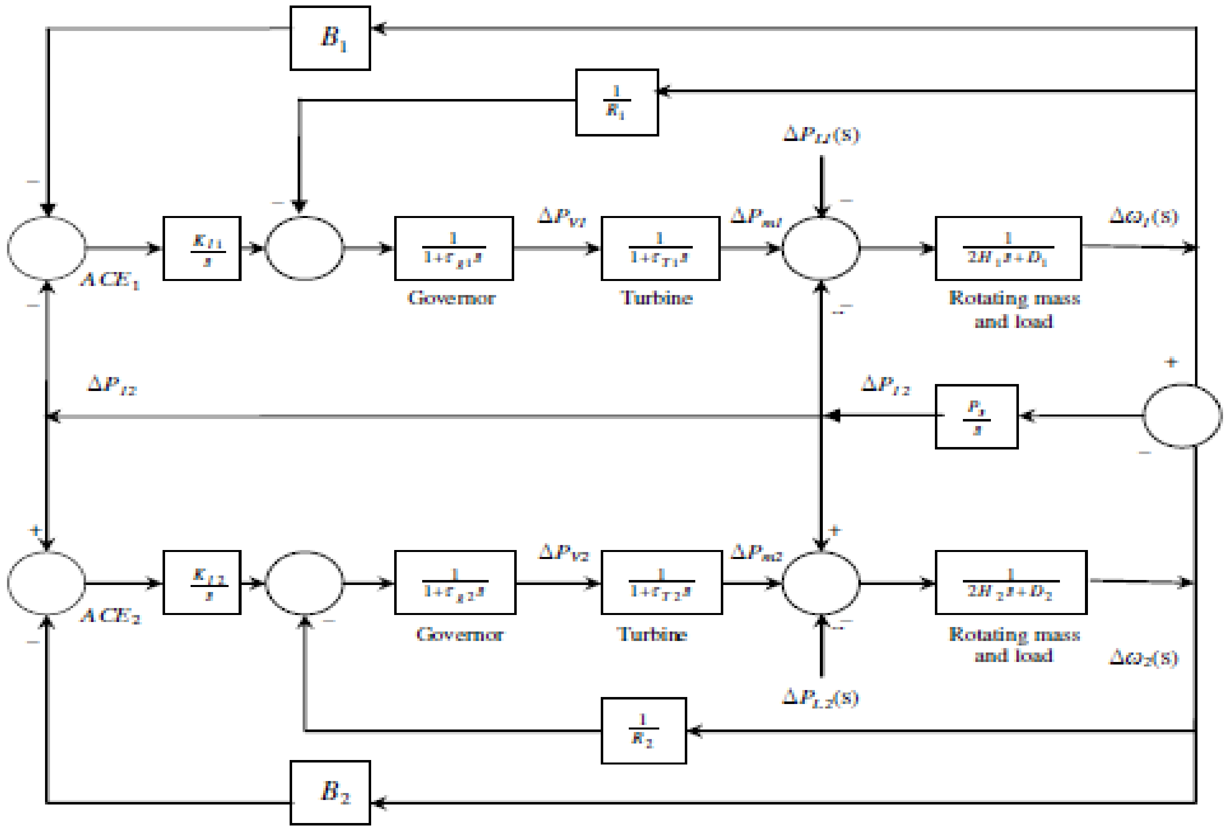

Fig .2.7 Block diagram of two area AGC with ACE loops

2.5 SIMULATION RESULTS OF 39 BUS POWER SYSTEM :

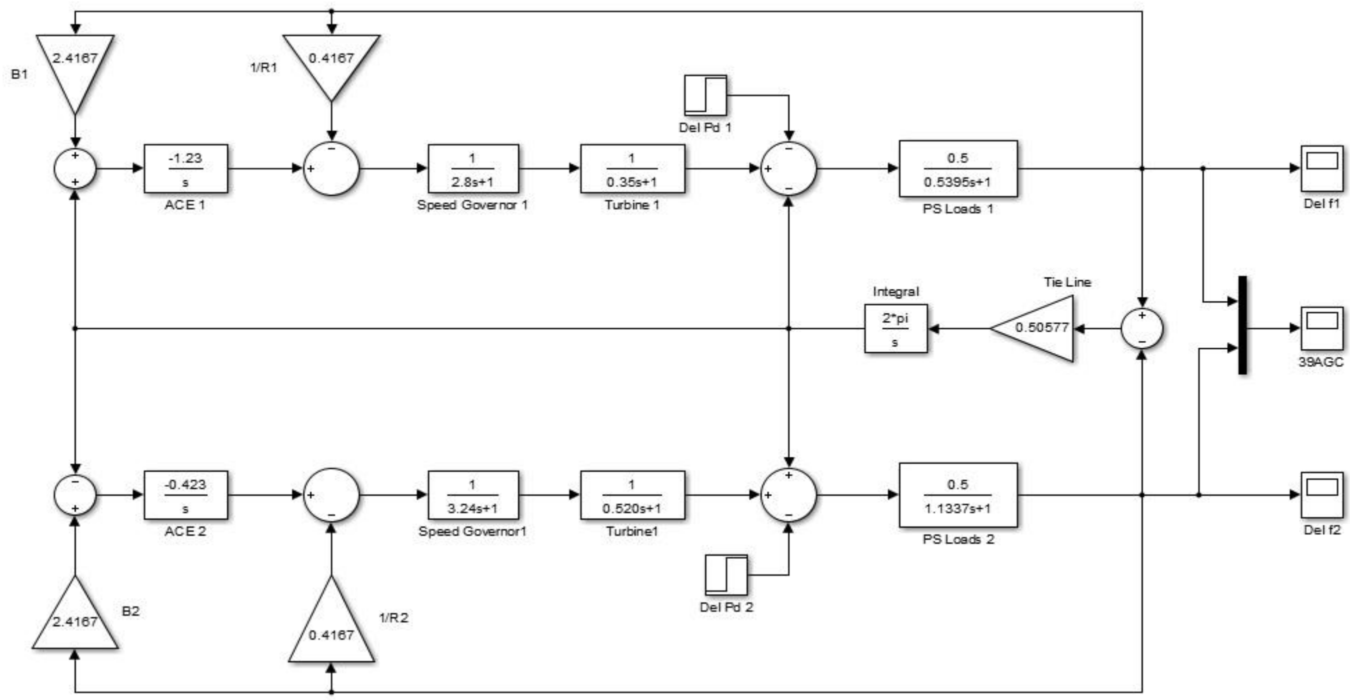

Fig .2.8 Simulink diagram of 39 bus system AGC with ACE loops

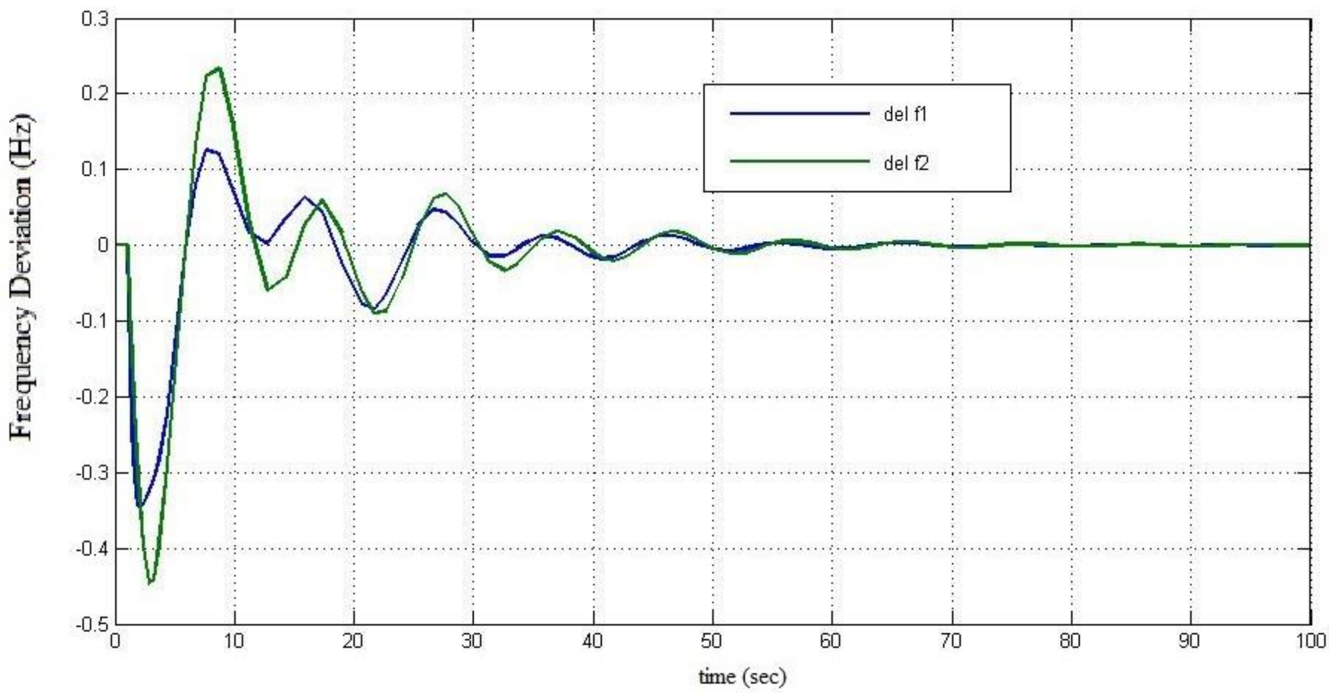

Fig .2.9 Frequency Deviation of 39 Bus System

3. DECENTRALIZED AUTOMATIC GENERATION CONTROL (DAGC)

3.1 DEFINITION :

Deregulation in power industry is restructuring of the rules and economic incentives that government set up to control and drive the electric power industry. In other words Deregulation is the process of restructuring or reforming state regulations. It is therefore opposite of regulation, which refers to the process of the government regulating certain activities.

3.2 INTRODUCTION :

The power industry across the globe is experiencing a radical change in its business as well as in an operational model where, the vertically integrated utilities are being unbundled and opened up for competition with private players. This enables an end to the era of monopoly. Right from its inception, running the power system was supposed to be a task of esoteric quality. The electric power was then looked upon as a service. Control consisting of planning and operational tasks was administered by a single entity or utility. The vertical integration of all tasks gave rise to the term – vertically integrated utility. The arrangement of the earlier setup of the power sector was characterized by operation of a single utility generating, transmitting and distributing electrical energy in its area of operation. Thus, these utilities enjoyed monopoly in their area of operation. They were often termed as monopoly utilities.

In a competitive electricity market, there will be many market players, such as generating companies (Gencos), distribution companies (Discos), transmission company (Transco), and system operator (SO). For stable and secure operation of a power system, the SO has to provide a number of ancillary services. One of the ancillary services is the "frequency regulation "based on the concept of the load frequency control. The load frequency control in a deregulated electricity market should be designed to consider different types of possible transactions such as Poolco-based transactions, bilateral transactions, and a combination of these two. An AGC scheme required for Poolco-based transactions, utilizing an integral controller.

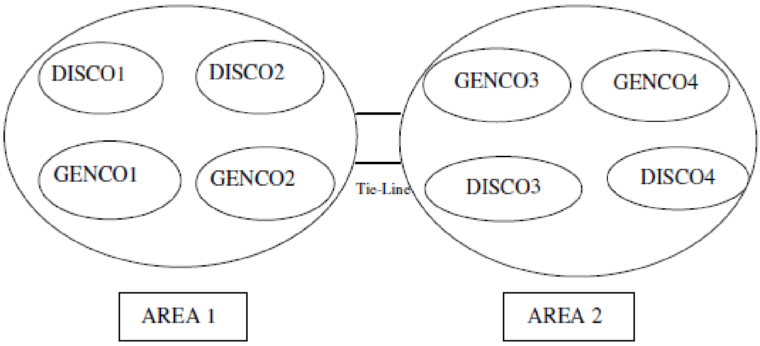

Fig.3.1 Schematic of a two area system in restructured environment

In the restructured environment, GENCOs sell power to various DISCOs at competitive prices. Thus, DISCOs have the liberty to choose the GENCOs for contracts. They may or may not have contracts with GENCOs with their own area. This makes various combinations of GENCO – DISCO contracts possible in practice. Hence the concept of "DISCO Participation Matrix (DPM) (or) Augmented Generation Participation Matrix (AGPM) "is introduced to make the visualization of the contracts easier. DPM is a matrix with the number of rows equal to the number of GENCOSs in the system and the number of columns equal to number of DISCOs in the system. Each entity in this matrix can be thought of as a fraction of the total load contracted by the DISCO (column) towards the GENCO (row). Thus, the ij-th entry corresponds to the fraction of the total load power contracted by the DISCO-j from a GENCO-i. The sum of all the entries in a column in this matrix is unity. DPM shows the participation of a DISCO in contract with a GENCO; hence the name "DISCO Participation Matrix ". Consider a two area system in which each area has two GENCOs and two DISCOs in it. Let GENCO 1 ,GENCO 2, DISCO 1 ,DISCO 2 be in area one and GENCO 3 ,GENCO 4 ,DISCO 3 and DISCO 4 be in area 2 .The corresponding DPM will become,

$$\text{DPM} = \begin{bmatrix} cpf_{11} & cpf_{12} & cpf_{13} & cpf_{14} \\ cpf_{21} & cpf_{22} & cpf_{23} & cpf_{24} \\ cpf_{31} & cpf_{32} & cpf_{33} & cpf_{34} \\ cpf_{41} & cpf_{42} & cpf_{43} & cpf_{44} \end{bmatrix}$$

Where,

cpf refers to "contract participation factor " .

In case of an interconnected power system having two or more areas connected through tie lines, each area supplies its control area and tie lines allow electric power to flow among the areas. However, a load perturbation in any of the areas affects output frequencies of all the areas as well as the power flow on tie lines. Hence the control system of each area needs information about transient situation in all the other areas to restore the nominal values of area frequencies and tie line powers. The information about each area is found in its output frequency and the information about other areas is in the deviation of tie line powers. We use load frequency control to maintain voltage and frequency within permissible limits, minimize frequency fluctuations, to regulate tie- line power in case of interconnected systems. The concept of decentralization is that the controller of each subsystem operates independently of the other subsystems. The main objective is to find a decentralized feedback law for an interconnected system in order to attain a sufficiently small performance index.

A decentralized scheme is proposed for the design of automatic generation control (AGC) for interconnected power systems. This scheme uses the natural structural properties of interconnected power systems and gives a new method for decentralized AGC regulator design, using the existing theory of proportional-plus-integral linear regulators applied to each individual power area. It is shown that a decentralized design, based upon the expansion-contraction theory of large-scale systems with overlapping and modified linear regulators with incomplete subsystem feedback, is suitable to handle the design of AGC regulators for present-day interconnected power systems. The resulting AGC retains the autonomous area control concept and load distribution property of conventional AGC regulators, while at the same time allows for improved transients and stability margins for interconnected areas.

3.3 CALCULATION OF AREA CONTROL ERROR (ACE) :

In a practical multi area power system, a control area is interconnected to its neighbouring areas with tie lines, all forming part of the overall power pool. If P_{ij} is the tie line real power flow from an area-i to another area-j and m is the total number of areas, the net tie line power flow from area-i will be

$$P_{ij} = \sum_{\substack{j=1 \\ j \neq i}}^{m} P_{ij}$$

In a conventional AGC formulation, P_{tie-i} is generally maintained at a fixed value. However, in a deregulated electricity market, a Disco may have contracts with the Gencos in the same area as well as with the Gencos in other areas, too. Hence, the scheduled tie-line power of any area will change as the demand of the Disco changes. Thus, the net scheduled steady-state power flow on the tie line from an area-i can be expressed as

$$P_{t-new-i} = P_{tie-i} + \sum_{\substack{j=1 \\ j\neq i}}^{m} D_{ij} - \sum_{\substack{j=1 \\ j\neq i}}^{m} D_{ji}$$

Where D_{ij} is the demand of Discos in area-i from Gencos in area-j, and D_{ji} is the demand of Discos in area-j from Gencos in area-i. During the transient period, at any given time, the tie-line power error is given as

$$P_{t-i-error} = P_{t-i-actual} - P_{t-i-new}$$

This error can be used to generate the ACE signal as

$$ACE_i = \ B_i \Delta f + P_{t-i-error}$$

Where $B_i$the frequency is bias factor, and Δf is the frequency deviation in area-i. If BC_{ii} and BC_{ij} are the bilateral transaction signals from the Discos in the same area-i and other area-j , respectively, then the overall block diagram of the proposed AGC for an i-th area of m-area power system may be represented as shown in figure 4.1.

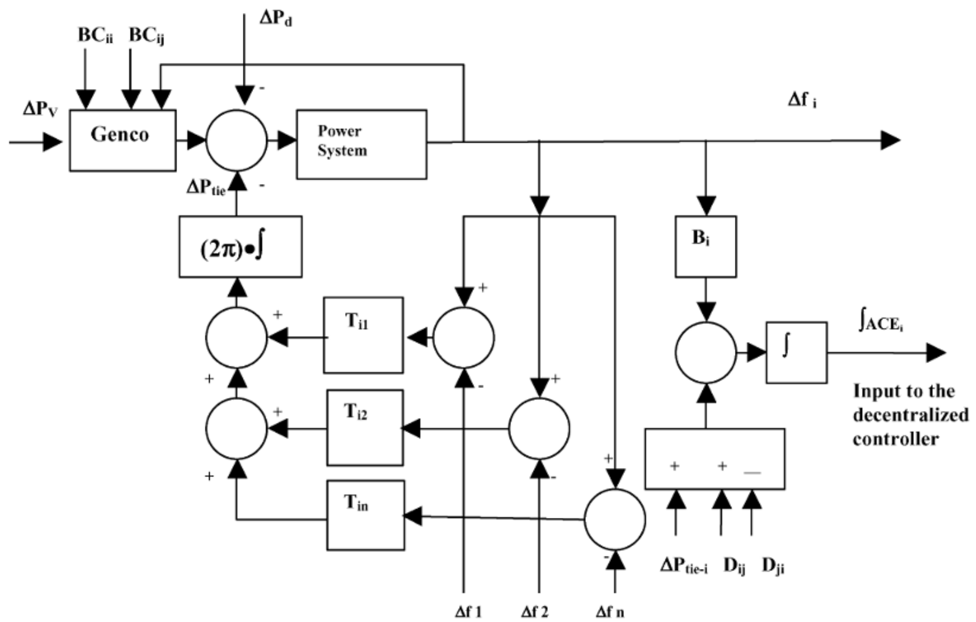

Fig.3.2 AGC block diagram of an area-i

The transfer function of the model of the power system is given as $\frac{K_i}{1+sT_{pi}}$, where K_i is the system gain, and T_{pi} is the time constant. $T_{p1}, T_{p2,}T_{p3 ....}T_{pn}$ are the synchronizing power coefficients of the tie lines connecting to area, used to model the net tie line power error. This model of the tie line has been utilized for simulation purposes to test the effectiveness of the proposed AGC scheme. In practice, this signal will be derived from actual tie-line power flow measurements and will utilize ACE for its calculation.

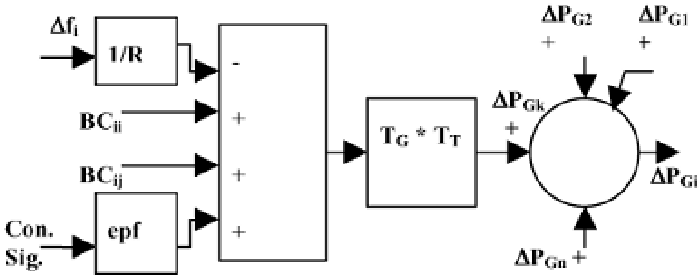

Fig.3.3 Block Diagram of GENCO-k of area-i

There may be a number of Gencos in the ith area. Figure represents the block diagram of the kth Genco in area-i. The epf is the Gencos' economic participation factor, R is the droop, and Governor+Turbine representa the transfer function model of governor and turbine. $\Delta P_{G1}, \Delta P_{G2}, \Delta P_{G3} \dots \dots . \Delta P_{Gn}$ Represent the change in the output of area-i Gencos. The net change in area-i generation is$\Delta P_{Gi} = \Delta P_{G1} + \Delta P_{G2} + \Delta P_{G3} + \cdots + \Delta P_{Gn}$, where n is the total number of Gencos in area-i. The participation factor of the Genco-k depends on its bid price and capacity in the frequency regulation market. The output of the controller (Con. Sig.) is the input to epf block of Genco-k. There may be number of Discos in the ith area.

If $\Delta P_{D1}, \Delta P_{D2}, \Delta P_{D3} \dots \dots . \Delta P_{Dn}$ represent the change in the load of Discos in the area. The net load change in the i-th area is given as $\Delta P_{Di} = \Delta P_{D1} + \Delta P_{D2} + \Delta P_{D3} + \cdots + \Delta P_{DL}$, where L is the total number of Discos in area-i. Let DC_{ii} be the demand of a Disco in area-i to the Gencos in same area and DC_{ij} be the demand of same Disco to the Gencos in other area. These signals flow directly from a Disco to a Genco. The Poolco-based transaction signals do not flow directly but appear in the system as a part of the deviation in total area load demand (ΔP_{DL}), which is left after the bilateral transactions. The part of area demand is fulfilled by bilateral transactions, and the rest of the demands are arranged by the SO through Poolco-based contracts.

3.4 SIMULATION OF DECENTRALIZED AUTOMATIC GENERATION CONTROL FOR 39 BUS SYSTEM :

The 39-bus system has been divided into two control areas. For the systems, three Discos and at least one Genco, having the Poolco based contract, have been considered in each area. The number of Gencos and Discos in the 39-bus system is given in Tables 4.1. To simulate the 39-bus system, it is assumed that the Discos are also participating in the market along with the generators. If the frequency of the grid falls due to increase in the load in any area, the Discos of the same area are supposed to curtail their loads and the Gencos to increase their generation and vice versa, if frequency of the grid increases. To simulate the decentralized controller for the Poolco and bilateral transactions, the change in demand of area-2 was assumed to be 0.1 p.u. The results of area frequency deviations and tie-line power flow are shown in Fig.4.8 & Fig 4.9 respectively.

Control Area	Area Rating (in MW)	Market Participants
Area-1	400	Genco 1,2,3,4,5 Disco 1,2,3
Area-2	500	Genco 6,7,8,9,10 Disco 4,5,6

Table 3.1 Control Areas in 39 Bus Power System

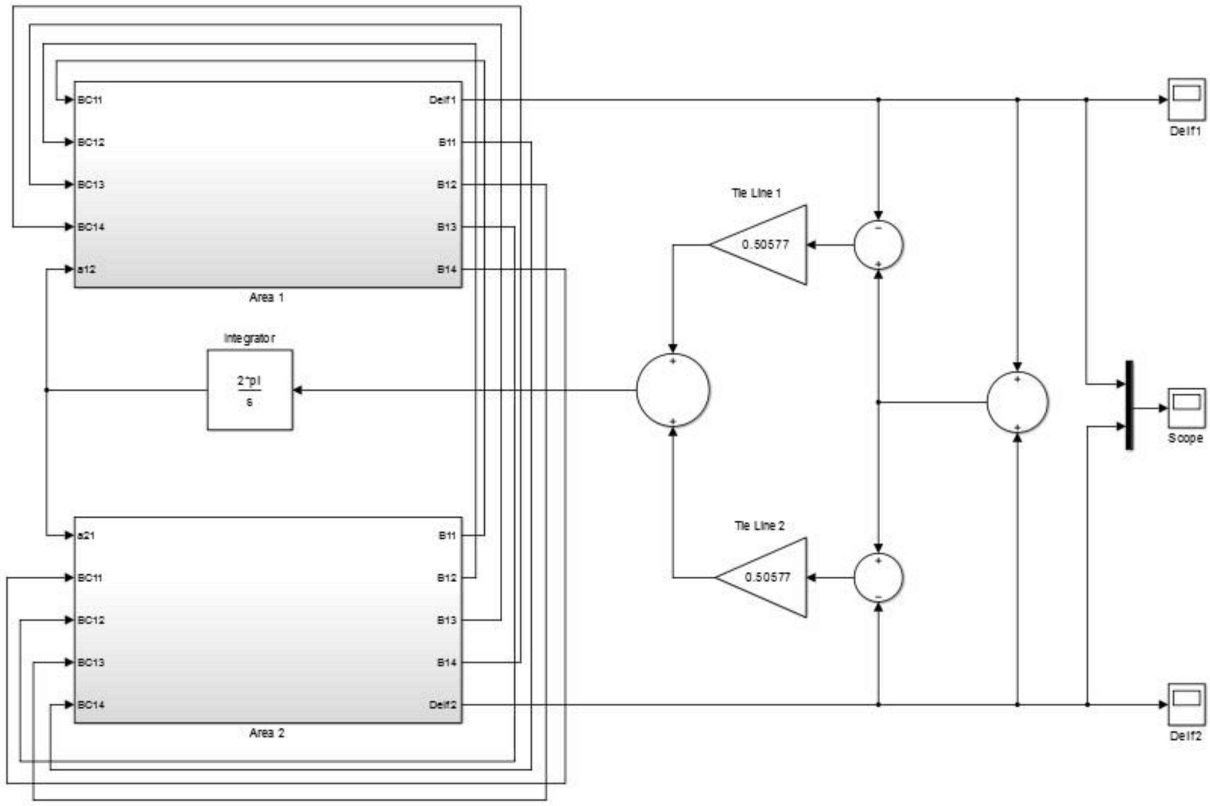

Fig.3.4 Decentralized AGC for 39 Bus System divided into two control areas

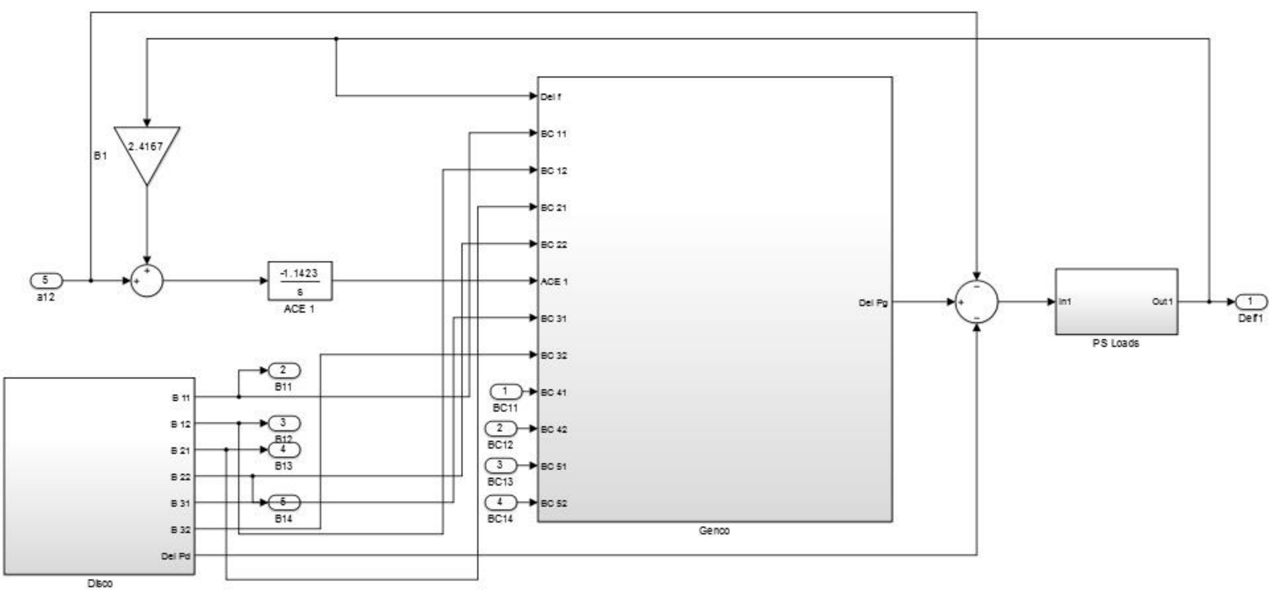

Fig.3.5 Simulink Diagram of Genco, Disco & power System Loads of area-1

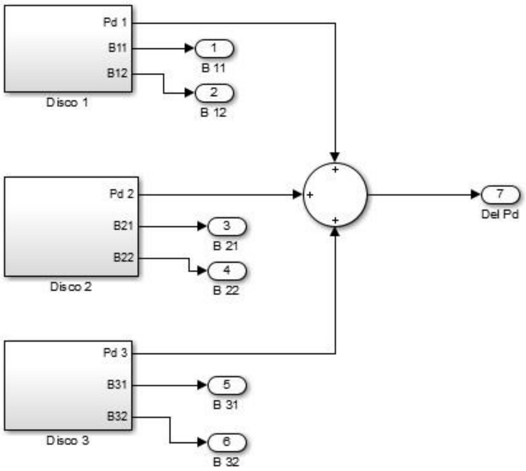

Fig.3.6 Simulink Diagram of Discos of area-1

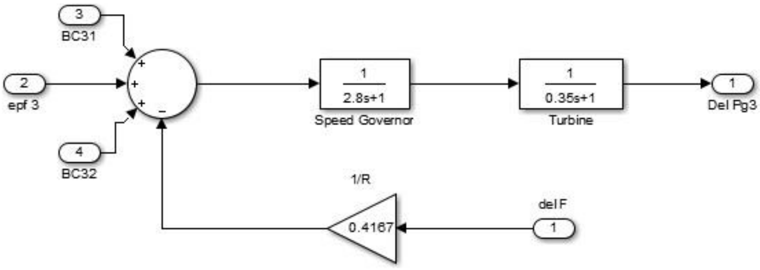

Fig.3.7 Simulink Diagram of Speed Governor & Turbine of area-1

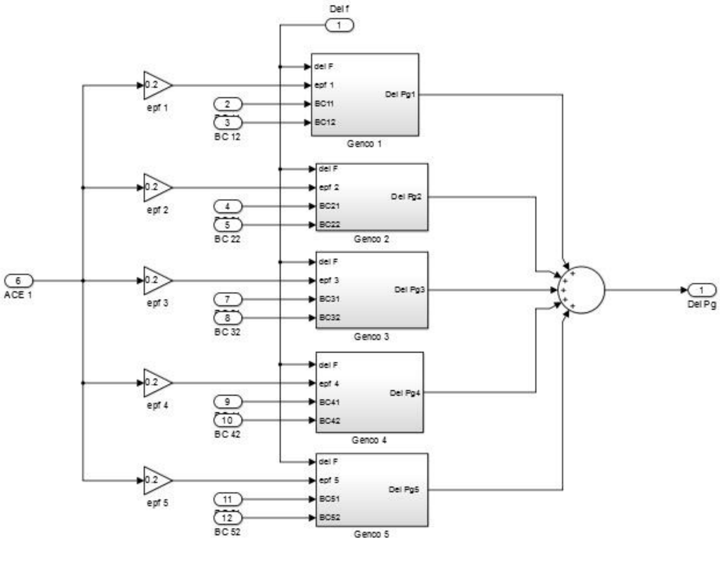

Fig.3.8 Simulink Diagram of Gencos of area-1

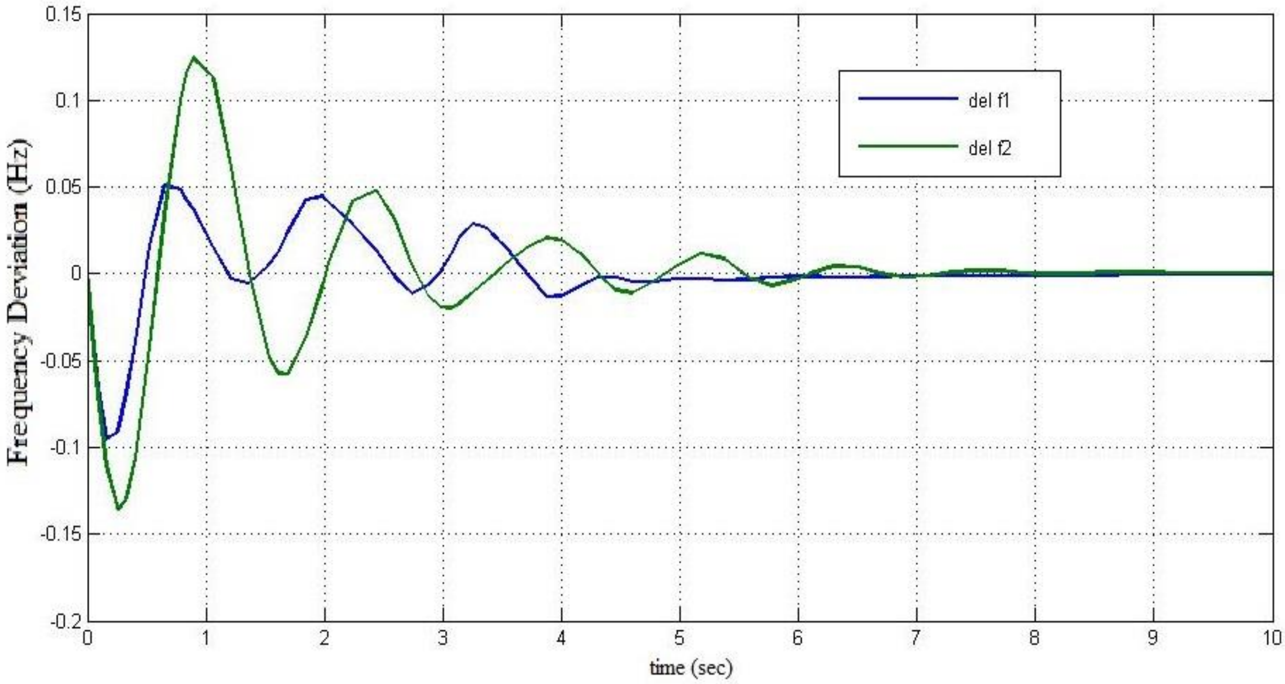

Fig.3.9 Frequency Deviation of Decentralized AGC for 39 Bus System divided into two control areas

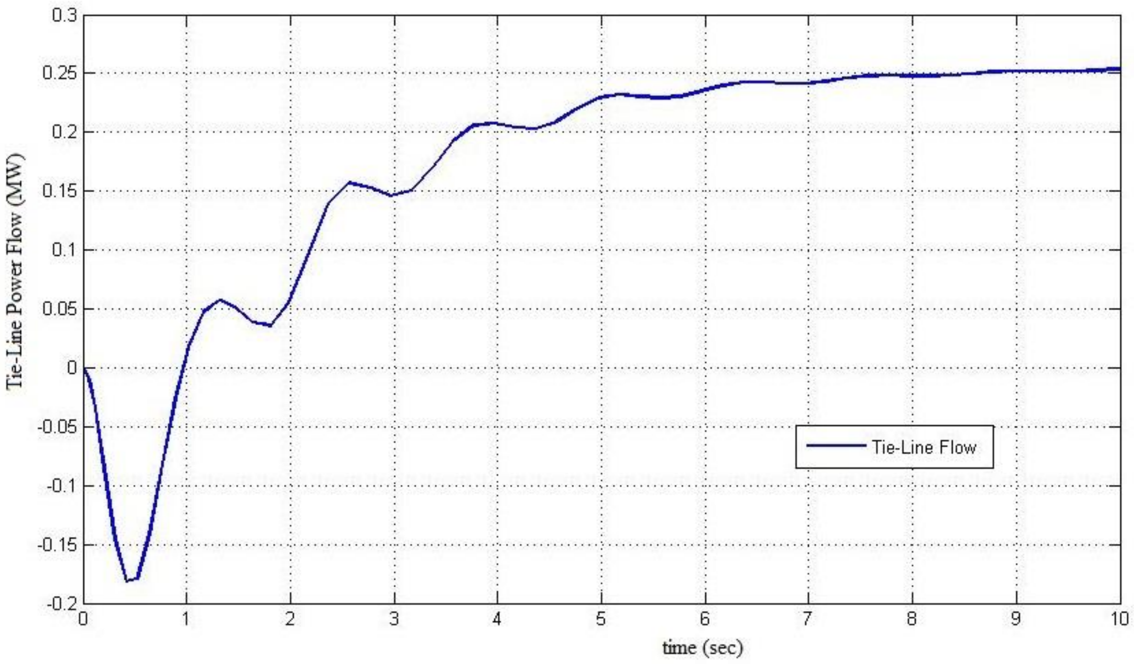

Fig.3.10 Tie-Line Power Flow of 39 Bus Interconnected Areas

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4. AGC IN CENTRALIZED AND DECENTRALIZED MARKETS

4.1 INTRODUCTION :

The Structure of electric utilities have changed dramatically since the Federal Energy Regulatory Commission (FERC) issued, in 1995, its Notice Proposed Rulemaking (NOPR) on Open Access seeking comments on proposals to encourage a more fully competitive wholesale electric power market. In order 888, FERC identified a set of ancillary services "necessary to support the transmission of energy and capacity from resources to load while maintaining reliable operation of the Transmission Provider's (TP) transmission system in accordance with good utility practice."

4.2 AGC IN CENTRALIZED MARKETS :

Before deregulation the activities of a control area such as: generation control (manual or automatic), assessment of transmission capabilities are monitored from a single location called Energy Management System (EMS). One of the functions of EMS is Load Frequency Control (LFC) or AGC. AGC has been used in electric utilities for almost seven decades. Due to continuous and unpredictable changes in the load AGC is designed to follow short-term (minute to minute) fluctuations of the load. Some of the control area's generating units have the capability of working under the command of AGC. The AGC system uses an indicator called the Area Control Error (ACE) and other economic indicators to send control signals (Raise/Lower) to appropriate units under its control. A unit will react to a raise/lower signal by raising/lowering its generation output.

The ACE equation has the following form:

$$ACE = (T_a - T_s) - 10\, B\, (F_a - F_s)$$

Where

ACE: Area control error (in MW)

T_{as}: Actual (measured) and scheduled interchange (in MW)

F_a: Actual (measured) frequency (in Hz)

F_s: Scheduled (fixed) frequency (in Hz). Could be 60.02, 60.00, or 59.98 Hz

B: ACE frequency bias (in MW/0.lHz, negative number)

A positive ACE indicates an excess area generation and a negative ACE indicates an area generation deficiency. Equation is sometimes referred to as tie-line bias control. In this equation ACE is not explicitly expressed in terms of generation and demand but in terms of two components:

1. (T_a -T_s) scheduled net interchange that reflects contractual flows
2. A bias of 10 B (F_a -F_s) representing the area's share of agreement between the control area and others. When the ACE equation for interconnected operation was formulated, it was assumed that each control should take care of its internal load and losses. The form chosen for (1) enabled different control areas to help each other during normal or abnormal conditions by taking advantage of the presence of the tie-lines and to ensure reliability throughout the interconnection by supporting the system frequency. The only setback of this approach is that some companies may take advantage of this automatic support. NERC developed some means of accountability by developing rules and policies that have been in place for almost four decades. It should be noted that it is impossible to exactly and continuously achieve a zero ACE or a generation load balance. This balance is only possible in a time average manner.

4.3 AGC IN DECENTRALIZED MARKETS :

The framework of the electric utilities before FERC's order 888 did not allow for competitive marketing of electricity and for this main reason deregulation was born. The new structure of the electric industry is shown in Figure

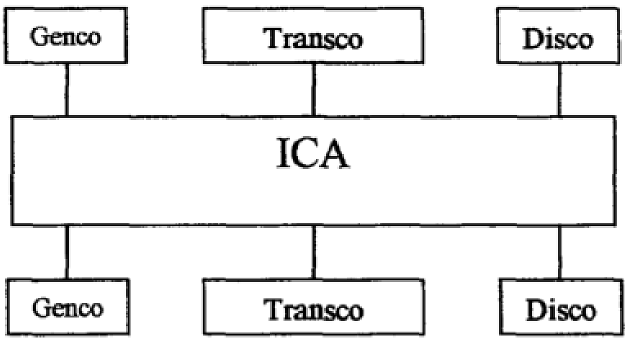

Fig.4.1 Electric Utility in a Decentralized Framework

To provide AGC in a deregulated framework at least three companies have to be involved. An agreement between Disco and Genco should be established to supply regulation. If the two companies are not adjacent to each other than a path must be arranged between the two companies through Transco. To resolve any difference between different companies, a fourth player is needed. This player is referred to as the Independent Contract Administrator (ICA). In NERC policy 10, ICA is referred to as the operating authority and is defined as an entity that:

1. Has ultimate accountability for a defined portion of the power system to meet one or more of the three reliability objectives-generation load balance, transmission security, and/or emergency preparedness; and
2. Is accountable to NERC and its Regional Reliability Councils for complying with NERC and Regional Policies; and
3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these policies.

4.4 COMPARISON OF AGC IN CENTRALIZED AND DECENTRALIZED MARKETS :

Item	AGC IN CENTRALIZED MARKETS	AGC IN DECENTRALIZED MARKETS
ISO	Centralized	Hierarchical
MARKETS	Monopolized market	Competitive market
AGC Form	Tie-line bias	Tie-line bias + bidding prices
AGC Requirements	Estimation and allocation **as** needed	Estimation and commitment
AGC Compensation	Unknown and part of overall cost	Energy based Trajectory based (total up and down) Just commitment without provision Discos or ICA pays Gencos
Losses	Responsibility of CA	Responsibility of Gencos
Operating Reserve	Provided by a single CA and through reserve sharing with other CAS	Provided by Gencos with coordination with ICA

Transmission Capabilities	Provided by a single CA. No congested problem.	Provided by Transcos with coordination with ICA. Congested area should be considered.

4.5 SIMULATION COMPARISON OF AGC IN CENTRALIZED AND DECENTRALIZED MARKETS :

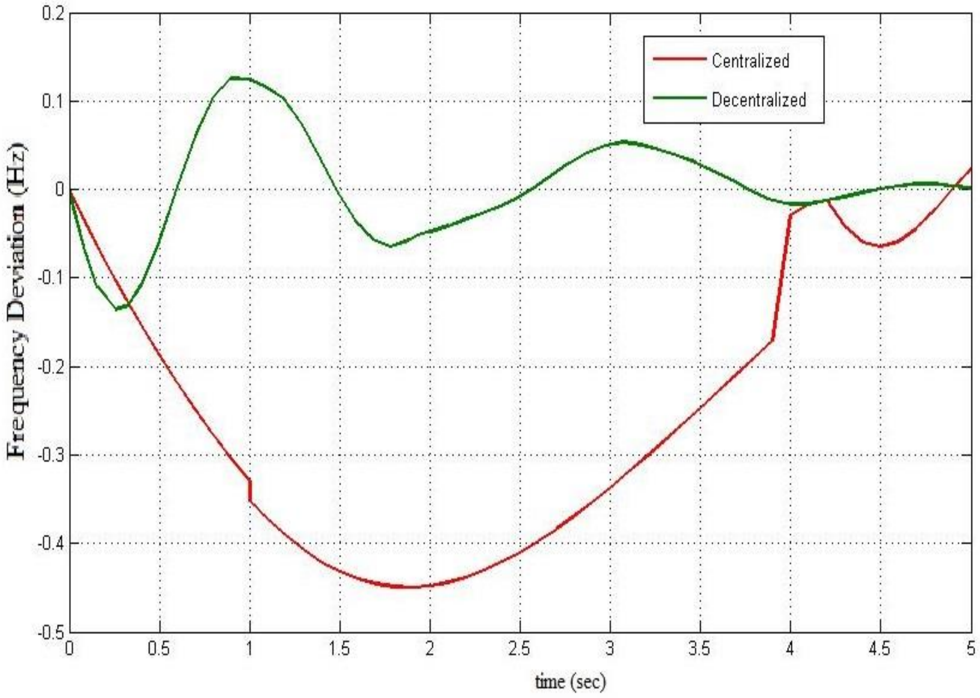

Fig.4.2 Frequency Deviations in area-1 for 39 Bus System divided into two control areas

It is observed from these results that a properly designed decentralized controller works quite effectively. Frequency deviations in all the interconnected areas finally settle to zero, and the change in the output of the Gencos of different areas are as per their bilateral and Poolco-based transactions

5. ADAPTIVE NEURO-FUZZY INFERENCE SYSTEM (ANFIS)

5.1 FUZZY LOGIC :

Fuzzy logic was developed for representing uncertain and imprecise knowledge. It provides an approximate but effective means of describing the behavior of systems that are too complex, ill-defined, or not easily analyzed mathematically. "Inferencing" is the key to any fuzzy system. A typical fuzzy inference system consists of membership functions, a rule base and an inference procedure.

5.2 FUZZY SETS :

A classical set is a set with crisp boundary. In contrast, a fuzzy set is a set with smooth boundary. Let X be a space of objects and x be a generic element of X. In classical set theory, a subset A of the universe X is defined by its binary (0 or 1) characteristic function $\mu_A(x)$: X —> [0, 1] such that $\mu_A(x) = 1$ if x∈A and $\mu_A(x) = 0$ if x∈A. Unlike conventional sets, the characteristic function of a fuzzy set is allowed to have values between 0 and 1, where A is called a fuzzy set and μ_A is called the membership function of A. Fuzzy sets can either be discrete or continuous. The construction of a fuzzy set depends on two things: the identification of a suitable universe and the specification of an appropriate membership function.
A fuzzy set is uniquely characterized by its membership function.

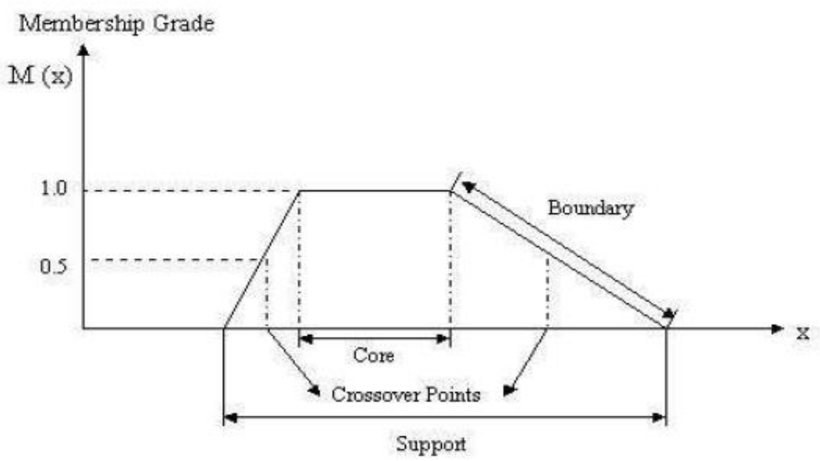

Fig. 5.1 Cores, supports, boundaries, crossover points of membership function

Classical sets have three basic operations: union, intersection, and complement. Likewise, fuzzy sets have similar operations. Suppose A and B are fuzzy sets of the universe X with membership functions μ_A and μ_B. The union AUB, intersection A∩B and complement A' are also fuzzy sets whose membership functions are related to those of A and B. They are defined as:

Union μ_{AUB} (x) = max (μ_A (x), μ_B (x)) = μ_A (x) V μ_B (x)

Intersection $\mu_{A\cap B}$ (x) = min (μ_A (x), μ_B (x)) = μ_A (x) Λ μ_B (x)

Complément $\mu_{A'}$ (x) = 1 – μ_A (x)

Also, other operators have been introduced to extend the classical set theoretic operations. These operators are referred to as T-norm for the intersection, T-co-norm or S-norm for the union, and negation for the complement. The fuzzy extension of the classical modus ponens principle allows for the construction of fuzzy inference systems.

5.3 FUZZY MEMBERS :

A fuzzy set can be defined by enumerating membership values of the Elements in the set if it is discrete or by defining the membership function mathematically if it is continuous. Although there are exist numerous types of membership functions, the most commonly used in practice are triangles, trapezoids, Gaussian, and bell curves.

Triangular MFs and trapezoidal MFs have been widely used due to their simplicity and computational efficiency. However, since they are composed of straight line segments, these MFs are not smooth at the corner points specified by the parameters. In some cases, the derivatives of membership functions with respect to their inputs and parameters are very important for fine-tuning a fuzzy inference system to achieve a desired input/output mapping, thus a smooth and nonlinear membership function is needed. On the other hand, most membership functions are determined subjectively; the human-determined membership functions, however, may not be precise enough in certain applications. Therefore, it is always advisable to apply optimization techniques to fine-tune parameterized membership functions for better performance. Because of these reasons, Gaussian and bell curve MFs are becoming more popular for specifying fuzzy sets.

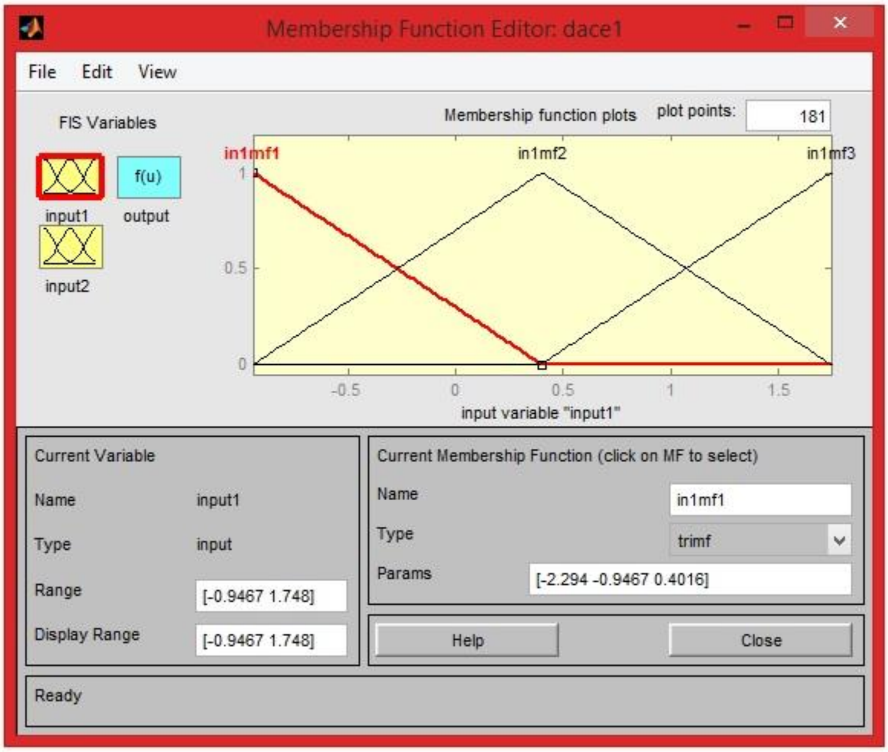

Fig. 5.2 Fuzzy Membership Function

5.4 FUZZY IF-THEN RULES :

Fuzzy if-then rules are a knowledge representation scheme for capturing knowledge (typically human knowledge) that is imprecise and inexact by nature. Generally, this is achieved by using linguistic variables to describe elastic conditions (i.e., conditions that can be satisfied to a degree) in the "if part" of fuzzy rules and to perform inference under partial matching.

A fuzzy if-then rule takes the form:

IF x is A_k THEN y is B_k (x)

Where A_k and B_k are linguistic values defined by fuzzy sets on universes X and Y respectively. Often, the "if part" is called antecedent or premise, while the "then part" is called consequence or conclusion. The fuzzy sets in a rule's antecedent define a fuzzy region of the input space covered by the rule (i.e., the input situations that fit the rule's condition completely or partially), whereas the fuzzy sets in a rule's consequent describe the vagueness of the rule's conclusion.

The consequent of fuzzy rules can be classified into three categories

(i) Crisp Consequent: IF… THEN y = a.

Where a is a no fuzzy numeric value or a symbolic value.

(ii) Fuzzy Consequent: IF… THEN y is A.

Where A is a fuzzy set.

(iii) Functional Consequent: IF x_1 is A_1, x_2 is A_2, and x_n is A_n THEN $y = a_0 + \sum a_i * x_i$

Where a_0, a_1 … a_n are constants.

5.5 FUZZY REASONING :

Fuzzy reasoning, also called approximate reasoning, is an inference procedure that derives conclusions from a set of fuzzy if-then rules and known facts.

Definition**:** Fuzzy reasoning (Approximate reasoning)

Let A, A', and B be fuzzy sets of X, X, and Y, respectively. Assume that the fuzzy implication A —> B is expressed as a fuzzy relation R between X and Y, then the fuzzy set B' induced by "x is A' " and the fuzzy rule "if x is A then y is B" is defined by

$$\mu_{B'}(y) = \max \min[\mu_{A'}(x), \mu_R(x, y)]$$

The process of fuzzy reasoning can be divided into four steps

(i) Degrees of compatibility: Compare the known facts with the antecedents of fuzzy rules to find the degrees of compatibility with respect to each antecedent MF.

(ii) Firing strength: Combine degrees of compatibility with respect to antecedent MFs in a rule using fuzzy AND OR operators to form a firing strength that indicates the degree to which the antecedent part of the rule is satisfied.

(iii) Qualified (induced) consequent MFs: Apply the firing strength to the consequent MF of a rule to generate a qualified consequent MF.

(iv) Overall output MF: Aggregate all the qualified consequent MFs to obtain an overall output MF.

5.6 FUZZY INFENERCE SYSTEMS :

Fuzzy inference systems are the most important modeling tool based on fuzzy set theory, whereas fuzzy rules and fuzzy reasoning are the backbone of fuzzy inference systems. The basic structure of a fuzzy inference system consists of three conceptual components:

(i) A rule base, which contains a selection of fuzzy rules;

(ii) A database, which defines the membership functions used in the fuzzy rules.

(iii) A reasoning mechanism, which performs the inference procedure upon the rules and given facts to derive a reasonable output or conclusion.

The inputs of fuzzy inference system can either be fuzzy sets or crisp values (which are viewed as fuzzy singletons). If the system produces fuzzy sets as output, while a crisp output is needed, then a method of de-fuzzification is required to extract a crisp value that best represents the fuzzy set. In general, there are several different methods for de-fuzzifying a fuzzy set. They are: centroid of area, bisector of area, and mean of maximum, smallest of maximum, largest of maximum, and height methods with crisp inputs and outputs, a fuzzy inference system implements a nonlinear mapping from its input space to output space.

Depending on the types of fuzzy reasoning and fuzzy if-then rules employed, most fuzzy inference systems can be classified into three types:

(i) Mamdani fuzzy model

Mamdani fuzzy model was proposed to control a steam engine and boiler combination by a set of linguistic control rules (Mamdani and Assillian, 1975). The fuzzy rule in this model is in the form of:

$$\text{IF } x_1 \text{ is } A_{i1} \ldots \text{and } x_n \text{ is } A_{in} \text{ THEN } y \text{ is } C_i.$$

Where xj (j=1, 2… n) are the input variables, y is the output variable, Aij and Ci are fuzzy sets for xj and y respectively.

(ii) Takagi–Sugeno's fuzzy model

Sugeno fuzzy model (also known as TSK model) was proposed to develop a systematic approach to generating fuzzy rules from a given input-output data set (Takagi and Sugeno, 1985; Sugeno and Kang, 1988). For a two-input system, the fuzzy rule in this model is in the form of:

IF x_1 is A and x_2 is B THEN y = f (x_1, x_2), where A and B are fuzzy sets in the antecedent, y = f (x_1, x_2) is a crisp function in the consequent. Usually, f (x_1, x_2) is a polynomial function of the input variables x_1 and x_2, but it can be any function as long as it can appropriately describe the output of the model within the fuzzy region specified by the antecedent of the rule. When f (x_1, x_2) is a first-order polynomial function, the resulting fuzzy inference system is called a first-order Sugeno fuzzy model. When f (x_1, x_2) is a constant, the system is referred as a zero-order Sugeno fuzzy model.

Without the time consuming and mathematically intractable defuzzification operation, the Sugeno model is by far the most popular candidate for sample-based fuzzy modeling.

(iii) Tsukamoto fuzzy model

Tsukamoto fuzzy model (Tsukamoto, 1979) was proposed as another approach to fuzzy reasoning method. The fuzzy rule in this model is in the form of:

$$\text{IF } x \text{ is } A_i \text{ THEN } y \text{ is } Ci.$$

Where x is the input variable, y is the output variable, A_i is a fuzzy set with a monotonical MF, Ci is a crisp value induced by rule's firing strength.

5.7 FUZZY MODELLING :

In general, the process to construct a fuzzy inference system is called fuzzy modeling. Theoretically, fuzzy modeling can be accomplished in two stages. The first stage is identification of surface structure, which includes the following tasks (Jang, Sun and Mizutani, 1997):

(i) Select relevant input and output variables.

(ii) Choose a specific type of fuzzy inference system.

(iii) Determine the number of linguistic terms associated with each input and output variable. For Sugeno model, determine the order of consequent equations.

(iv) Design a collection of fuzzy rules.

The second stage is the identification of deep structure, which means:

(i) Choose appropriate parameters of membership functions.

(ii) Refine the parameters of the MFs using regression and optimization techniques

5.8 DESIGN OF A FLC :

The idea behind the FLC is to fuzzify the controller inputs, and then infer the proper fuzzy control decisions based on defined rules. The FLC output is then produced by defuzzifying this inferred control decision. Thus main FLC processes are fuzzification, rules definition, inference and defuzzification.

5.9 FUZZIFICATION AND MEMBERSHIP FUNCTION:

Fuzzification is the process of transferring the crisp control variables to corresponding fuzzy variables. Each of the FLC input and output signals are interpreted into a number of linguistic variables. The number of linguistic variables varies according to the application. Usually an odd number is used. A reasonable number is seven. Each linguistic variable has its fuzzy membership function. The membership function maps the crisp values into fuzzy variables. A set of membership defined for seven linguistic variables NB, NM, NS, Z, PS, PM, PB which stand for negative big, negative medium, negative small, zero, positive small, positive medium, positive big

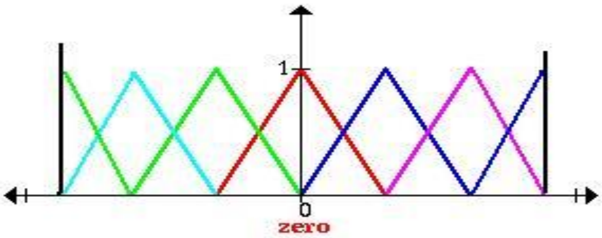

Fig. 5.3 Membership functions for seven linguistic variables

5.10 RULES CREATION :

In general, fuzzy systems map input fuzzy sets to output fuzzy sets. Fuzzy rules are the relations between input/output fuzzy sets. They usually are in the form if A, then B, where A is rule antecedent and B is rule consequence. Each rule defines a fuzzy patch in the Cartesian product AxB (system state space). For a system of two control variables with seven linguistic variables in each range leads to a 7x7 decision table.

The Fuzzy logic power system stabilizer is developed using MATLAB's fuzzy logic toolbox. The Fuzzy Logic Toolbox is a collection of functions built on the MATLAB numeric computing environment. It provides tools to create and edit fuzzy inference systems within the framework of MATLAB, or we can integrate the fuzzy systems into simulations with Simulink. The Fuzzy Logic Toolbox allows us to do several things, but the most important thing is to create and edit fuzzy inference systems. We can create these systems using graphical tools or command-line functions, or can generate them automatically using either clustering or adaptive neuro-fuzzy techniques. If we have access to Simulink, we can easily test the fuzzy system in a block diagram simulation environment.

We can build the system using graphical user interface (GUI) tools provided by the Fuzzy Logic Toolbox. Although it is possible to use the Fuzzy Logic Toolbox by working strictly from the command line, in general it is much easier to build a system graphically. There are five primary GUI tools for building, editing, and observing fuzzy inference systems in the Fuzzy Logic Toolbox: the Fuzzy Inference System or FIS Editor, the Membership Function Editor, the Rule Editor, the Rule Viewer, and the Surface Viewer. These GUIs are dynamically linked, in that changes made to the FIS using one of them, can affect the other GUIs.

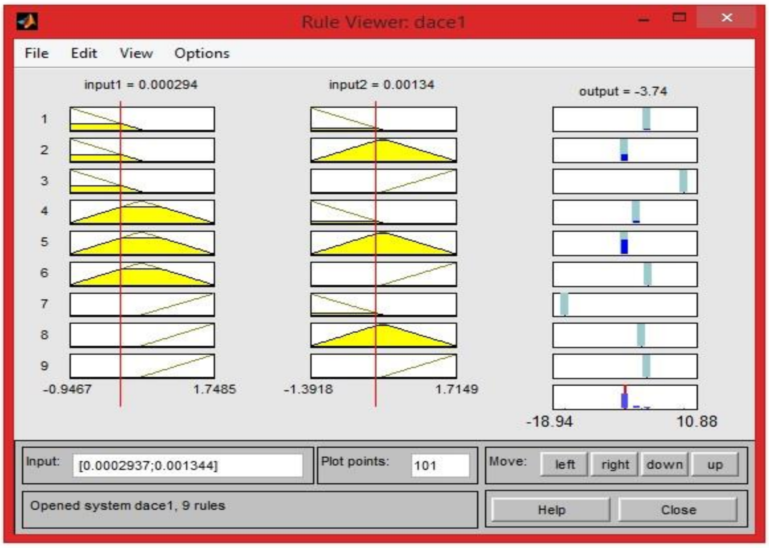

Fig. 5.4 the Rule Viewer

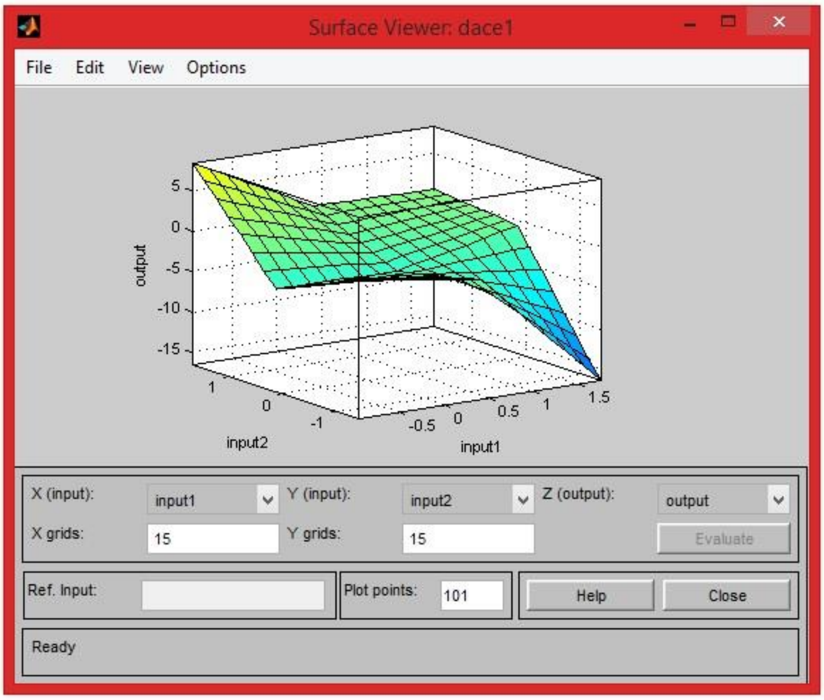

Fig. 5.5 the Surface Viewer

The FIS Editor handles the high-level issues for the system: like How many input and output variables are required their name. The Fuzzy Logic Toolbox doesn't limit the number of inputs. The Membership Function Editor is used to define the shapes of all the membership functions associated with each variable. The Rule Editor is for editing the list of rules that defines the behavior of the system. The Rule Viewer and the Surface Viewer are used for looking at, as opposed to editing, the FIS. They are strictly read-only tools. The Rule Viewer is a MATLAB based display of the fuzzy inference diagram shown at the end of the last section. Used as a diagnostic, it can show (for example) which rules are active, or how individual membership function shapes are influencing the results. The Surface Viewer is used to display the dependency of one of the outputs on any one or two of the inputs — that is, it generates and plots an output surface map for the system.

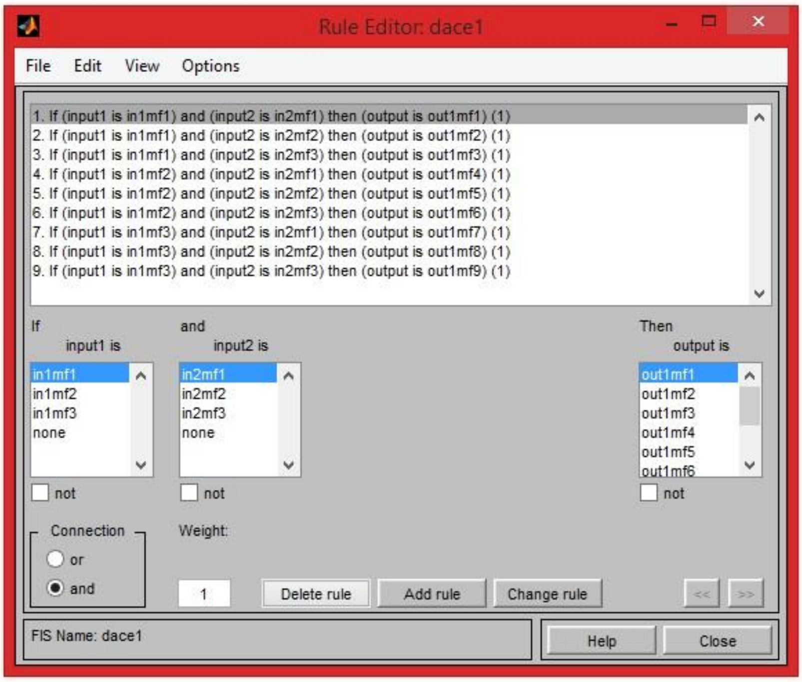

Fig. 5.6 Fuzzy Rules Creations

5.11 SUGENO FUZZY MODEL :

Unlike Mamdani model, Sugeno output membership functions are either linear or constant. If a fuzzy system has two inputs *x* and *y* and one output *f*, then for a first order Sugeno fuzzy model, a common rule set with two fuzzy if then rules is as follows:

Rule 1: If x is A_1 and y is B_1, then $f_1 = p_1x + q_1y + r_1$

Rule 1: If x is A_2 and y is B_2, then $f_2 = p_2x + q_2y + r_2$

For a zero-order Sugeno model, the output level is a constant ($p_i = q_i = 0$)

The output level f_i of each rule is weighted by the firing strength w_i of the rule. For example, for an AND rule with Input 1 = *x* and Input 2 = *y*, the firing strength is

w_i = *AND method* $(A_1(x), B_1(y))$ Where A_1 and B_1 are the membership functions for *Input 1* and *Input 2* respectively. The final output of the system is the

Weighted average of all rule outputs, computed as

Final output = $\sum W_i f_I / \sum W_I$ from i= 1 to n

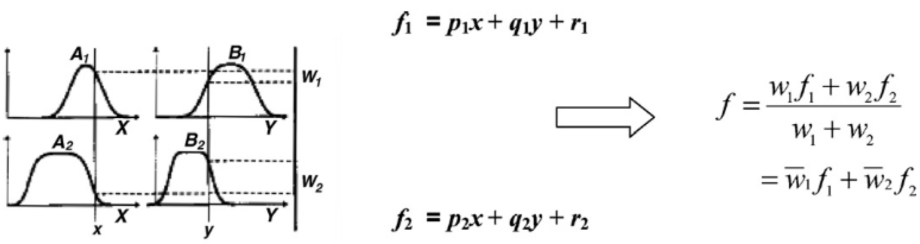

Fig. 5.7 Multi-Layer Perceptron (MLP) functioning Reasoning

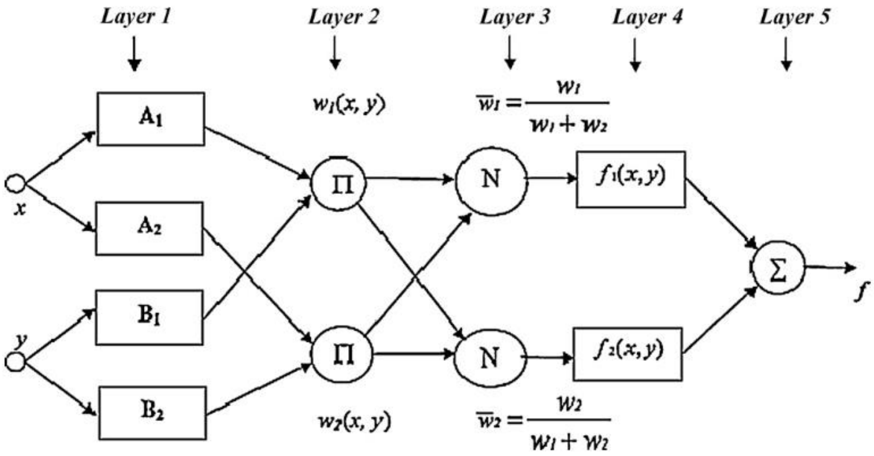

Fig. 5.8 Equivalent ANFIS architecture

5.12 ANFIS ARCHITECTURE :

Fig.6.7 illustrates the reasoning mechanism for the Sugeno model discussed above while the corresponding Adaptive Neuro-fuzzy Inference System (ANFIS) architecture is as shown in Fig 6.8, where nodes of the same layer have similar functions. The output of i^{th} node in layer l is denoted as $O_{l,i}$.

Layer 1: Every node *i* in this layer is an adaptive node with a node function**.**

$$O_{1,i} = \mu_{A\,i}(x) \text{ , for i-1,2 or}$$

$$O_{1,i} = \mu_{B\,i\text{-}2}(y) \text{ , for i=3,4,}$$

Where *x* (or *y*) is the input to node *i* and A_i (or B_{i-2}) is a linguistic label (“small” or “large”) associated with the node. Here the membership function for *A* (or *B*) can be any parameterized membership function.

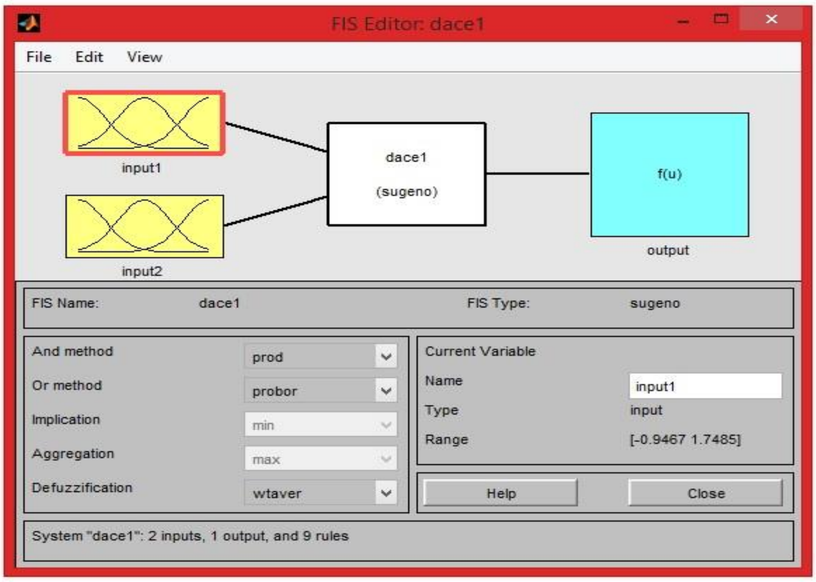

Fig. 5.9 Takagi–Sugeno’s fuzzy model

In this work, generalized Gaussian membership function is taken as follows

$$\mu_A(x) = \exp\left[-\left(\frac{x - c_i}{a_i}\right)^2 \right] \tag{1}$$

Where $\{c_i, a_i\}$ is the parameter set. These are called premise parameters.

Layer 2: Every node in this layer is a fixed node labeled Π, whose output is the product of all the incoming signals.

$$O_{2,i} = w_i = \mu_{A_i}(x)\mu_{B_i}(y),\ i=1,2. \tag{2}$$

Layer 3: Here, the i^{th} node calculates the ratio of the i^{th} rule's firing strength to the sum of all rule's firing strength.

$$O_{3,i} = \overline{w_i} = \frac{w_i}{w_1 + w_2},\ i=1,2. \tag{3}$$

Layer 4: Every node *i* in this layer is an adaptive node with a node function.

$$O_{4,i} = \overline{w_i} f_i = \overline{w_i}(p_i x + q_i + r_i) \tag{4}$$

Where w_i is a normalized firing strength from layer 3 and $\{p_i, q_i, r_i\}$ is the parameter set of the node. These parameters are referred to as consequent parameters.

Layer 5: The single node in this layer is a fixed node labeled Σ, which computes the overall output as the summation of all incoming signals:

$$O_{5,i} = \sum_i \overline{w_i} f_i = \frac{\sum_i w_i f_i}{\sum_i w_i}$$

5.13 HYBRID LEARNING ALGORITHM :

The Hybrid Learning Algorithm is a combination of least square and back-propagation method. In the least square method, the output of a model *y* is given by the parameterized expression.

$$Y = \theta_1 * f_1(u) + \theta_2 * f_2(u) + \ldots\ldots\ldots\ldots\ldots\ldots\ldots + \theta_n * f_n(u) \tag{6}$$

Where $u_1, u_2, \ldots u_n$ is the model's input vector, $f_1, \ldots\ldots, f_n$ are known functions of u, and $\theta_1, \theta_2, \ldots \theta_n$ are unknown parameters to be optimized. To identify these unknown parameters θ_i , usually a training data set of data pairs$\{(u_i , y_i), i=1,\ldots.,m \}$ is taken; substituting each data pair in equation (6) a set of linear equations is obtained, which can be written as

$$A * \theta = y \tag{7}$$

in matrix form. Where A is an m×n matrix, θ is an n×1 unknown parameter vector and *y* is an m×1 output vector. Since generally *m>n,* instead of exact solution of the equation (7) an error vector e is introduced to account for the modeling error, as

$$A^*\theta+e=y \tag{8}$$

and searched for θ =θˆ which minimizes sum of squared error.

$$\mathrm{E}(\theta)=\sum_{i=1}^{m}\left(y_i-a_i^T\theta\right)^2=e^Te \tag{9}$$

E(θ)is called the objective function. The squared error in equation (9) is minimized when θ =θˆ, called Least Squares Estimator (LSE) that satisfies the normal equation

$$A^TA\theta = A^Ty \tag{10}$$

If A^TA is nonsingular, θ is unique and is given by

$$\theta= (A^TA)^{-1}A^Ty \tag{11}$$

In case of Back-propagation learning rule the central part concerns how to recursively obtain a gradient vector in which each element is defined as the derivative of an error measure with respect to a parameter. Assuming that a given feed-forward adaptive network has *L* layers and layer *l* has N(*l*) nodes, then the output function of node *i* in layer *l* can be represented as $x_{l,i}$ and $f_{l,i}$ respectively.

Node function $f_{l,i}$:

$$X_{l,i} = f_{l,i}(x_{l-1,1}, \ldots\ldots\ldots x_{l-1,N(l-1)}, \alpha, \beta, \gamma, \ldots..) \tag{12}$$

Where α,β,γ ,etc. are the parameters of this node. Assuming that the given training data set has P entries, an error measure can be defined for the p^{th} ($1 \le p \le P$) entry of the training data set as the sum of squared errors:

$$E_p = \sum_{k=1}^{N(L)}\left(d_k - x_{l,k}\right)^2$$

(13)

Where d_k is the k^{th} component of the p^{th} desired output vector and $x_{L,k}$ is the k^{th} component of the actual output vector produced by presenting the p^{th} input vector to the network. The task here is to minimize an overall error measure, which is defined as

$$E=\sum_{P=1}^{P}E_p \tag{14}$$

To use steepest descent to minimize the error measure, first the gradient vector is to be obtained. The basic concept in calculating the gradient vector is to pass a form of derivative information starting from the output layer and going backward layer by layer until the input layer is reached. That is why the process is called 'back-propagation'.

The Error Signal $\epsilon_{l,I}$ is defined as

$$\in_{l,i} = \partial E_p / \partial X_{l,i} \tag{15}$$

For i^{th} output node (at layer L)

$$\in_p = \partial E_p / \partial X_{l,i} \tag{16}$$

$$\therefore \in_{l,i} = -2\left(d_i - X_{l,i}\right) \tag{17}$$

For the internal node at the i^{th} position of layer l, the error signal can be derived iteratively by the chain rule:

$$\in_{l,i} = \partial E_p / \partial X_{l,i} = \sum_{m=1}^{N(l+1)} \left(\partial E_p / \partial X_{l+1,m} * \partial f_{l+1,m} / \partial X_{l,i}\right) = \sum_{m=1}^{N(l+1)} \in_{l+1,m} \partial f_{l+1,m} / \partial X_{l,i} \tag{18}$$

The gradient vector is defined as the derivative of the error measure with respect to each parameter. If α is a parameter of the i^{th} node at layer l, we have

$$\partial E_p / \partial \alpha = \partial E_p / \partial X_{l,i} * \partial f_{l,i} / \partial \alpha = \in_{l,i} * \partial f_{l,i} / \partial \alpha \tag{19}$$

The derivative of the overall error measure E with respect to α is

$$\partial E / \partial \alpha = \sum_{p=1}^{p} \partial E_p / \partial \alpha \tag{20}$$

Accordingly, for simplest steepest descent without line minimization, the update formula for generic parameter α is

$$\Delta \alpha = -\eta * \partial E / \partial \alpha \tag{21}$$

in which η is the learning rate. So, for parameter α it may be written that

$$\alpha_{new} = \alpha_{old} + \Delta \alpha = \alpha_{old} - \eta * \partial E / \partial \alpha \tag{22}$$

In this type of learning, the update formula for parameter α is based on the above equations and the update action occurs only after the whole set of training data pair is presented. This process of presentation of whole set of training data pair is called epoch. That is, after each epoch the update takes place Now, It is assumed that *'S'* is the total set of parameters and *'S_1'* and *'S_2'* are the sets of input and output parameters respectively. For hybrid learning algorithm, each epoch consists of a forward pass and a backward pass. In the *forward pass*, when a vector of input data pair is presented, the node outputs of the system are calculated layer by layer. This process continues till the corresponding row in the matrices *A* and *y* of equation (7) are obtained. The process is repeated for all the training data pair to form the matrices *A* and *y* completely. Then the output parameters of set S_2 are calculated according to the equation (11) of least square method. After the identification of output parameters the error measure for each training data pair is to be calculated. The derivative of those error measures with respect to each node output are calculated following the equations (15) and (18). Thus the error signal is obtained. In the *backward pass*, these error signals propagate from the output end towards the input end. The gradient vector is found for each training data entry. At the end of the backward pass for all training data pairs, the input parameters in set S_1 are updated by steepest descent method as described earlier.

5.14 DECENTRALIZED AUTOMATIC GENERATION CONTROL USING ANFIS:

The fuzzy controller uses 49 rules and 7 membership functions in each variable to compute output and exhibits good performance. Now main aim is to extract a smaller set of rules using neuro-fuzzy learning and to do the same the following steps are followed:

1. Data generation: to design the ANFIS controller, some data is needed, i.e., a set of two dimensional input vectors and the associated set of one-dimensional output vectors are required. Here, the training data has been generated by sampling input variables ACE and its derivative (d (ACE)/dt) uniformly and computing the value of stabilized signal for each sampled point.
2. Rule extraction and membership functions: after generating the data, the next step is to estimate the initial rules. Then applying subtractive clustering algorithm, rules are extracted. These rules are not so close to the identified system. Hence, there is a need of optimization of these rules. Hybrid learning algorithm is used for training to modify the above parameter after obtaining the fuzzy inference system from subtracting clustering. This algorithm iteratively learns the parameter of the premise membership functions via back propagation and optimizes the parameters of the consequent equations via linear least-squares estimation. The training is continued until the error Measure becomes constant.

5.15 SIMULATION OF DECENTRALIZED AUTOMATIC GENERATION CONTROL USING ANFIS:

The basic steps followed for designing the ANFIS controller in MATLAB/Simulink is outlined:

1. Draw the Simulink model with fuzzy controller and present the given rule base.
2. The first step for designing the ANFIS controller is collecting the training data while simulating the model with fuzzy controller.
3. The two inputs, i.e., ACE and d (ACE)/dt and the simulate output signal gives the training data.
4. Use anfisedit to create the ANFIS .fis file.
5. Load the training data collected in Step 2 and generate the FIS with gbell MF's.
6. Train the collected data with generated FIS up to a particular no. of Epochs.
7. Save the FIS. This FIS file is the neuro-fuzzy enhanced ANFIS file.

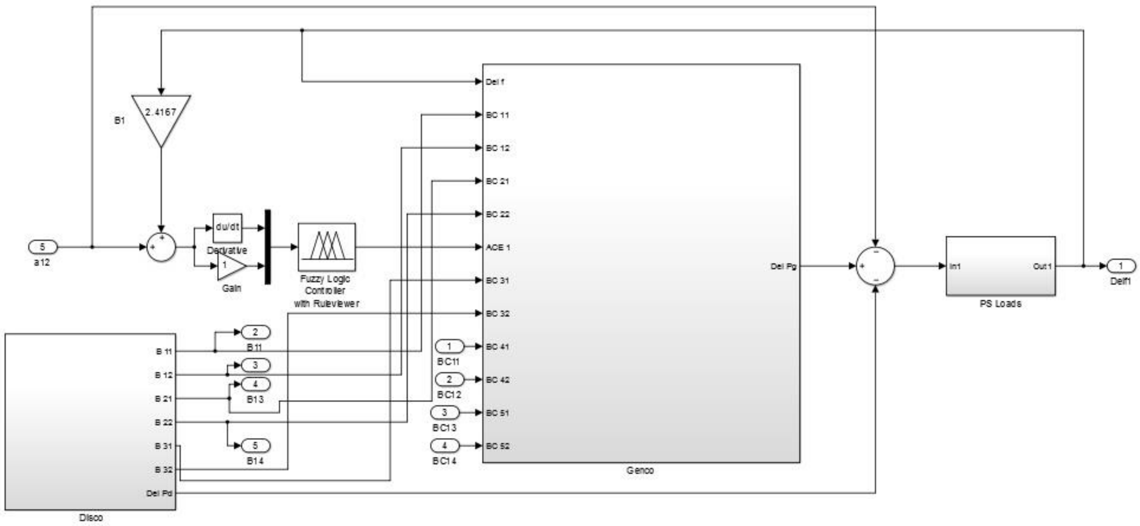

Fig.5.10 Simulink Diagram of ANFIS Controller in Decentralized AGC for 39 Bus System divided into two control areas

The results of area frequency deviations and tie-line power flow are shown in Fig.6.11 & Fig.6.12 respectively.

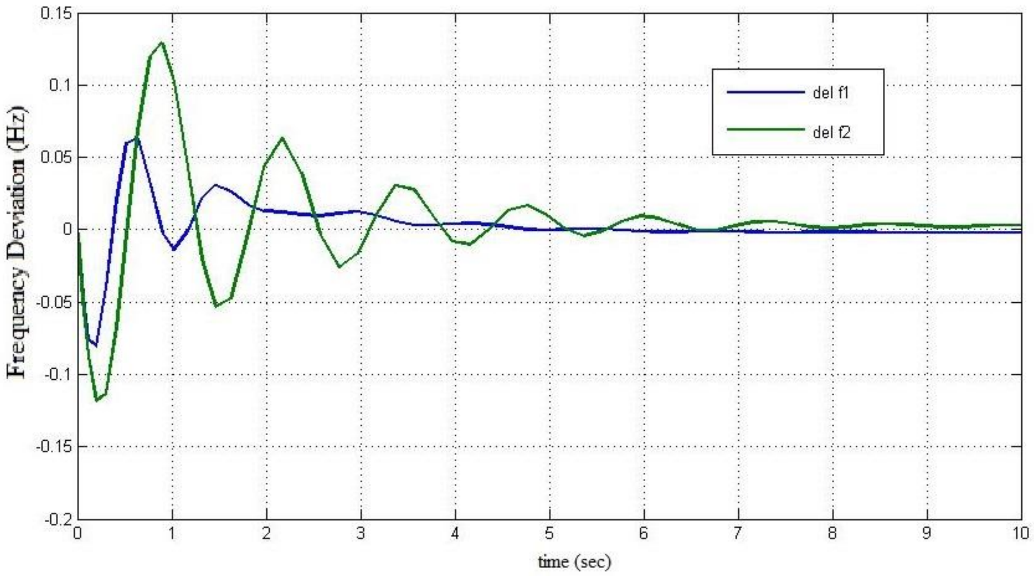

Fig.5.11 Frequency Deviation of Decentralized AGC Using ANFIS Controller for 39 Bus System divided into two control areas

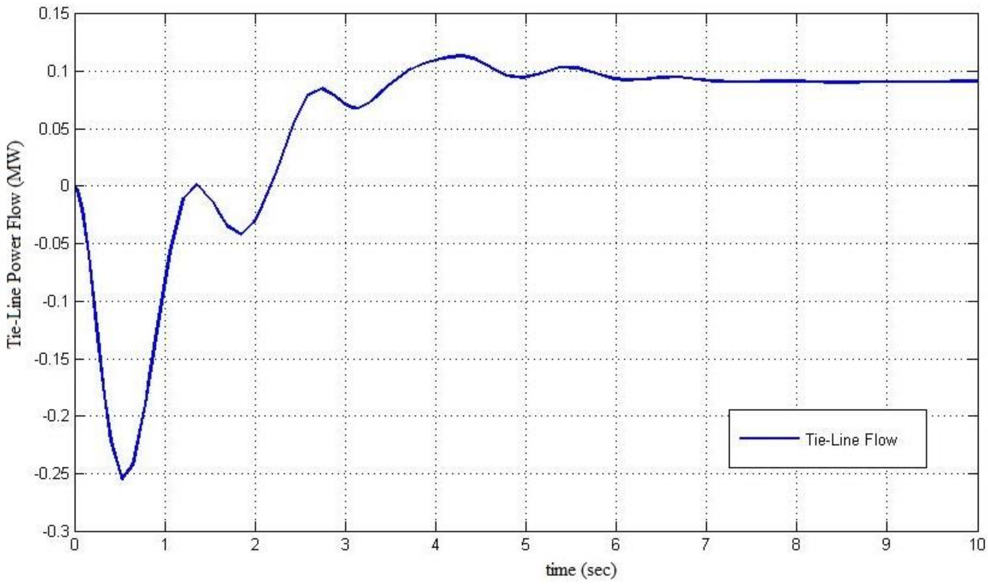

Fig.5.12 Tie-Line Power Flow of 39 Bus Interconnected Areas

It can be seen from the frequency and the tie-line power deviations that the settling time with integral controller is large compared to ANFIS controller. While the system settles after a large sustained oscillations and the overshoot is also large in case of integral controller, but in contrast, the ANFIS controller results are found to be satisfactory, having a small overshoot and also the system settles very early in each area irrespective of the disturbance location.

6. SIMULATION RESULTS AND DISCUSSION

6.1 SIMULATION OF DECENTRALIZED AGC FOR 39 BUS SYSTEM DIVIDED INTO THREE CONTROL AREAS :

The 39-bus system has been divided into three control areas. For the systems, three Discos and at least one Genco, having the Poolco based contract, have been considered in each area.

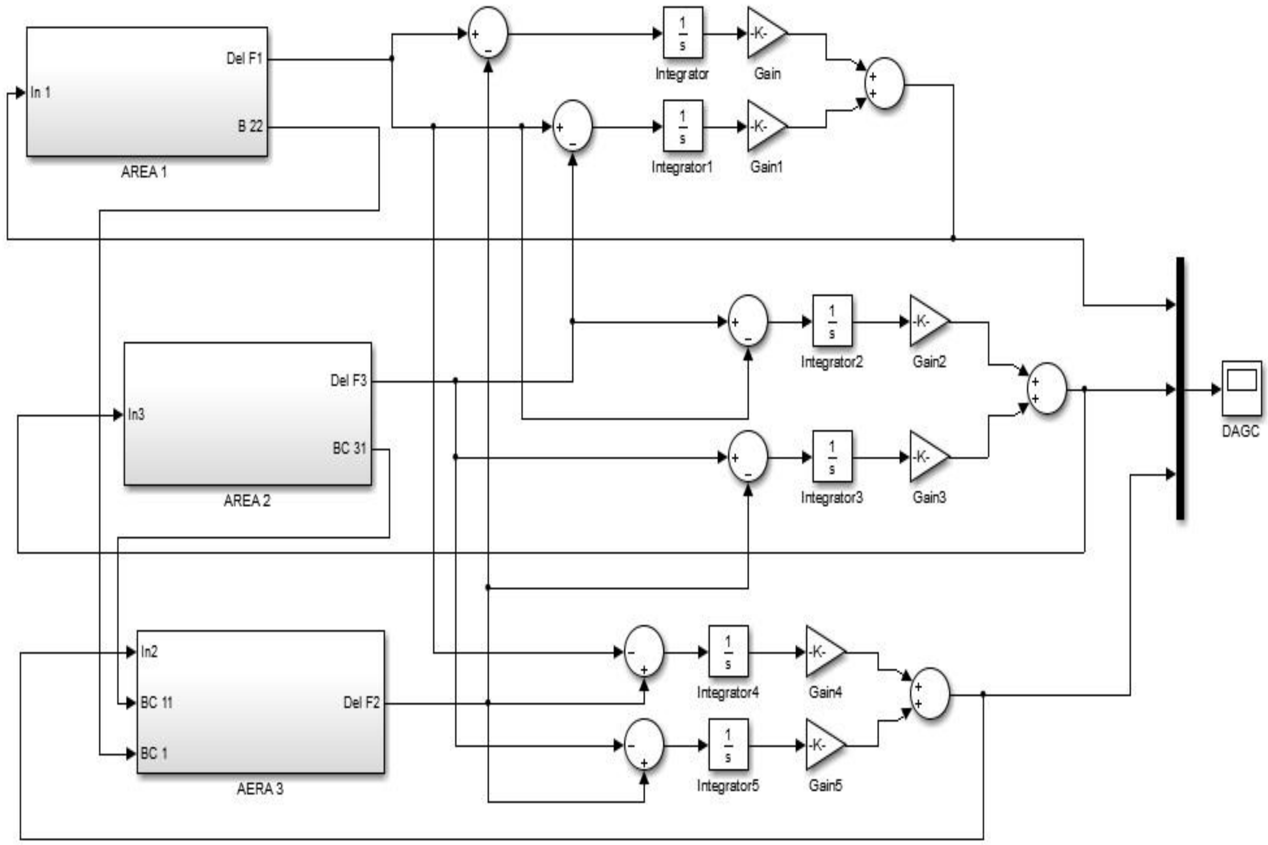

Fig.6.1 Simulink Diagram of Decentralized AGC for 39 Bus System divided into three control areas

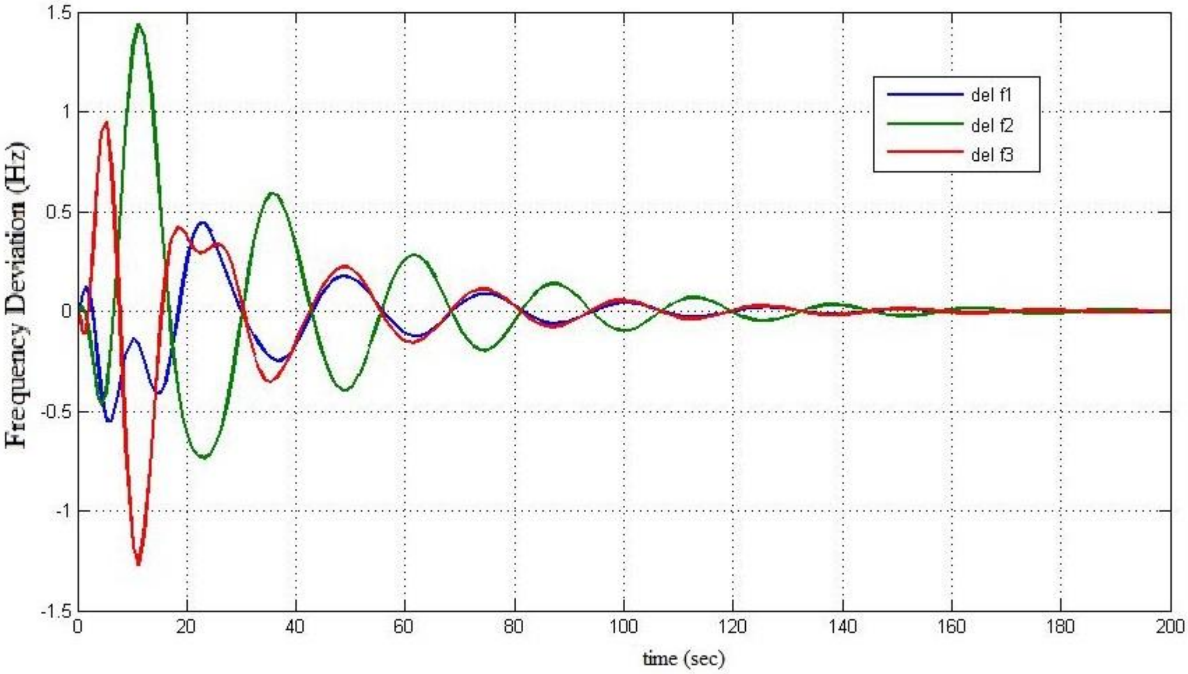

Fig.6.2 Frequency Deviation of Decentralized AGC for 39 Bus System divided into three control areas

6.2 SIMULATION OF DECENTRALIZED AGC USING ANFIS FOR 39 BUS SYSTEM DIVIDED INTO THREE CONTROL AREAS :

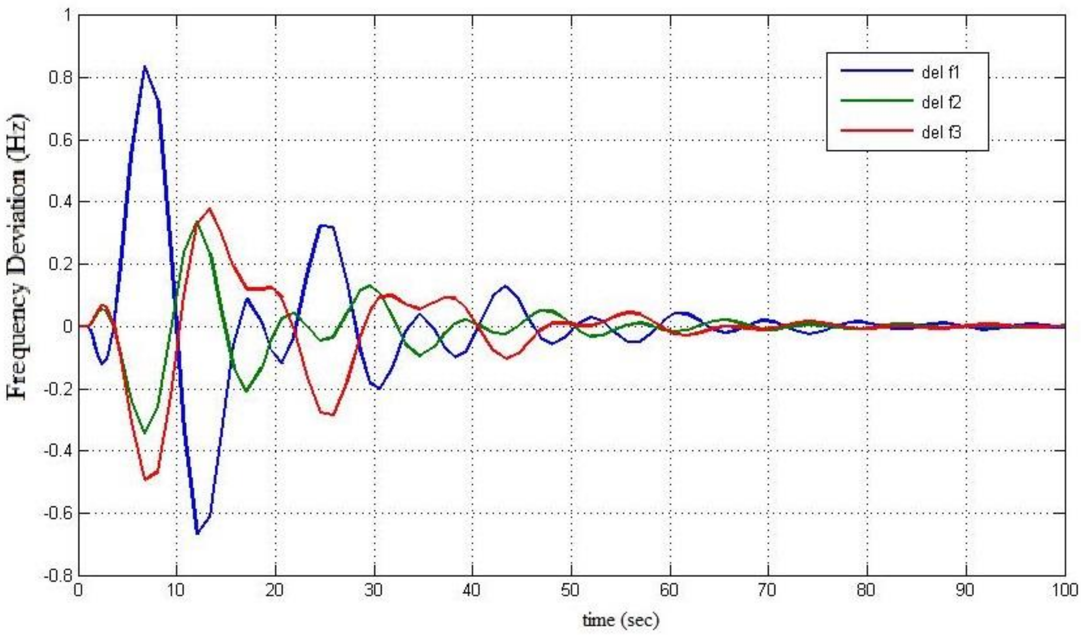

Fig.6.3 Frequency Deviation of Decentralized AGC Using ANFIS for 39 Bus System divided into three control areas

6.3 SIMULATION OF DECENTRALIZED AGC FOR 75 BUS SYSTEM DIVIDED INTO FOUR CONTROL AREAS :

The 75-bus system into four control areas for the systems, three Discos and at least one Genco, having the Poolco based contract, have been considered in each area. The number of Gencos and Discos in the 75-bus system is given in Table7.1. To simulate the 75-bus system, it is assumed that the generators and the loads are participating in the frequency regulation market, and both Poolco and bilateral transactions are taking place simultaneously. To simulate the results, the change in the load demand of area-2 and area-4 were assumed to be 0.0503 p.u. (50 MW) and 0.0112 p.u. (50 MW), respectively. Different bilateral contracts for area-2 have also been considered.

Control Area	Area Rating (in MW)	Market Participants
Area-1	460	Genco 1,2,3 Disco 1,2,3
Area-2	994	Genco 4,5,6,7,8 Disco 4,5,6
Area-3	400	Genco 9,10 Disco 7,8,9
Area-4	4470	Genco 11,12,13,14,15 Disco 10,11,12

Table 6.1 Control Areas in 75 Bus Power Systm

The results of area frequency deviations are shown in Fig.7.5.

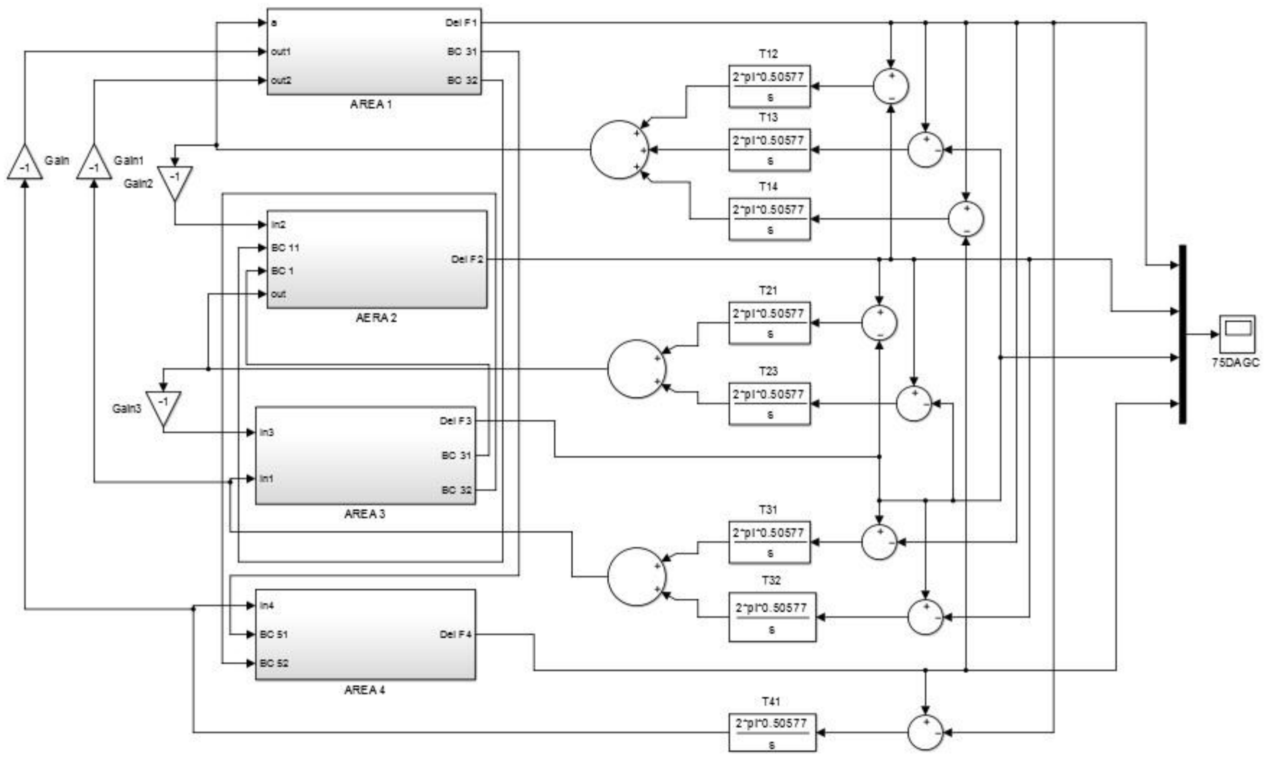

Fig.6.4 Simulink Diagram of Decentralized AGC for 75 Bus System divided into four control areas

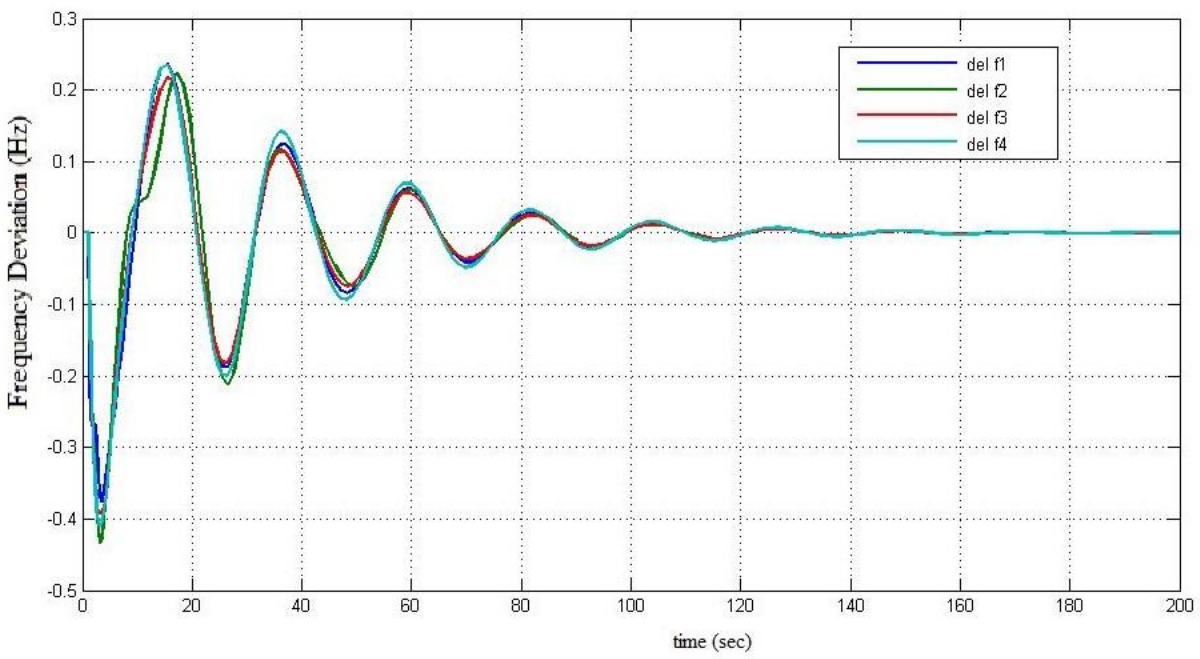

Fig.6.5 Frequency Deviation of Decentralized AGC for 75 Bus System divided into four control area

6.4 SIMULATION OF DECENTRALIZED AGC USING ANFIS FOR 75 BUS SYSTEM DIVIDED INTO FOUR CONTROL AREAS :

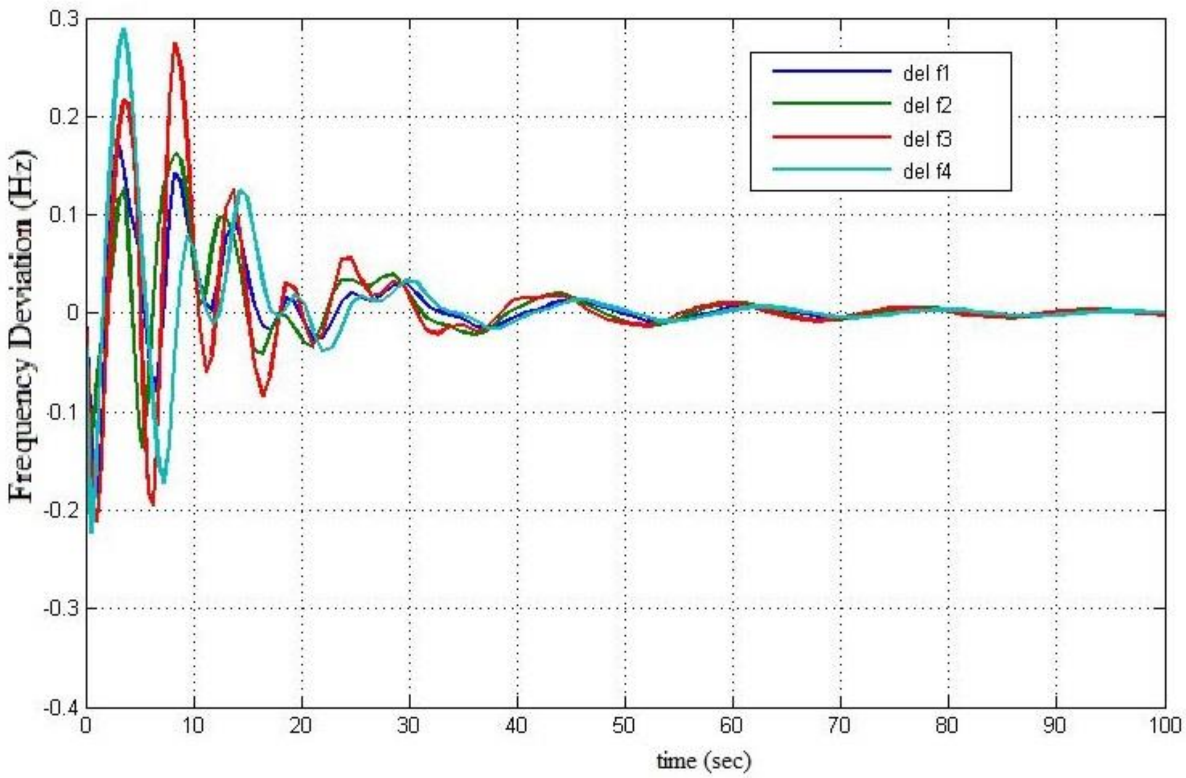

Fig.6.6 Frequency Deviation of Decentralized AGC Using ANFIS for 75 Bus System divided into four control areas

6.5 SIMULATION COMPARISON OF DECENTRALIZED AGC USING INTEGRAL CONTROL Vs. DECENTRALIZED AGC USING ANFIS CONTROLLER:

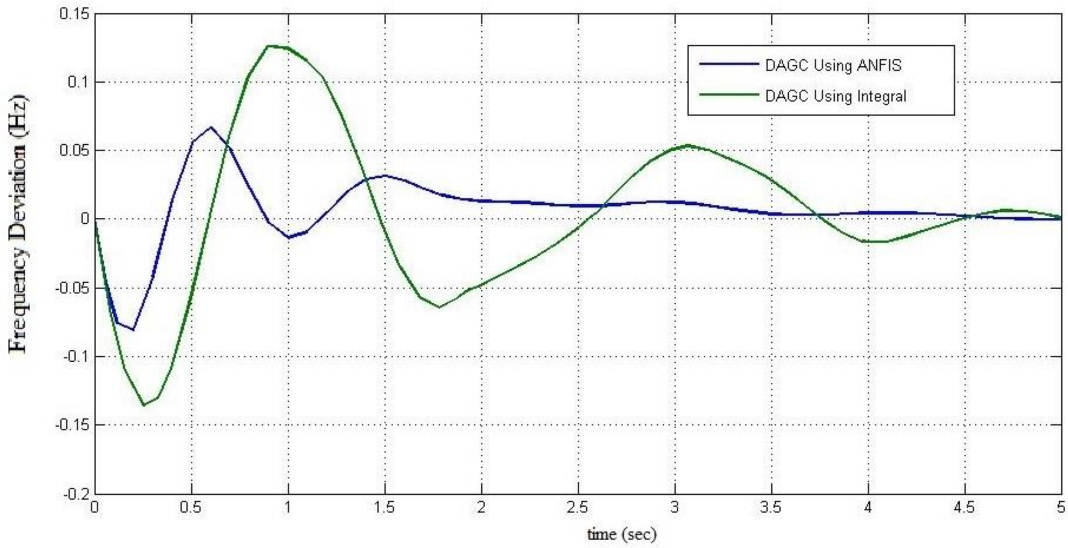

Fig.6.7 Frequency Deviation Comparison of 39 Bus System

It can be seen from the frequency that the settling time with integral controller is large compared to ANFIS controller. While the system settles after a large sustained oscillations and the overshoot is also large in case of integral controller, but in contrast, the ANFIS controller results are found to be satisfactory, having a small overshoot and also the system settles very early in each area irrespective of the disturbance location.

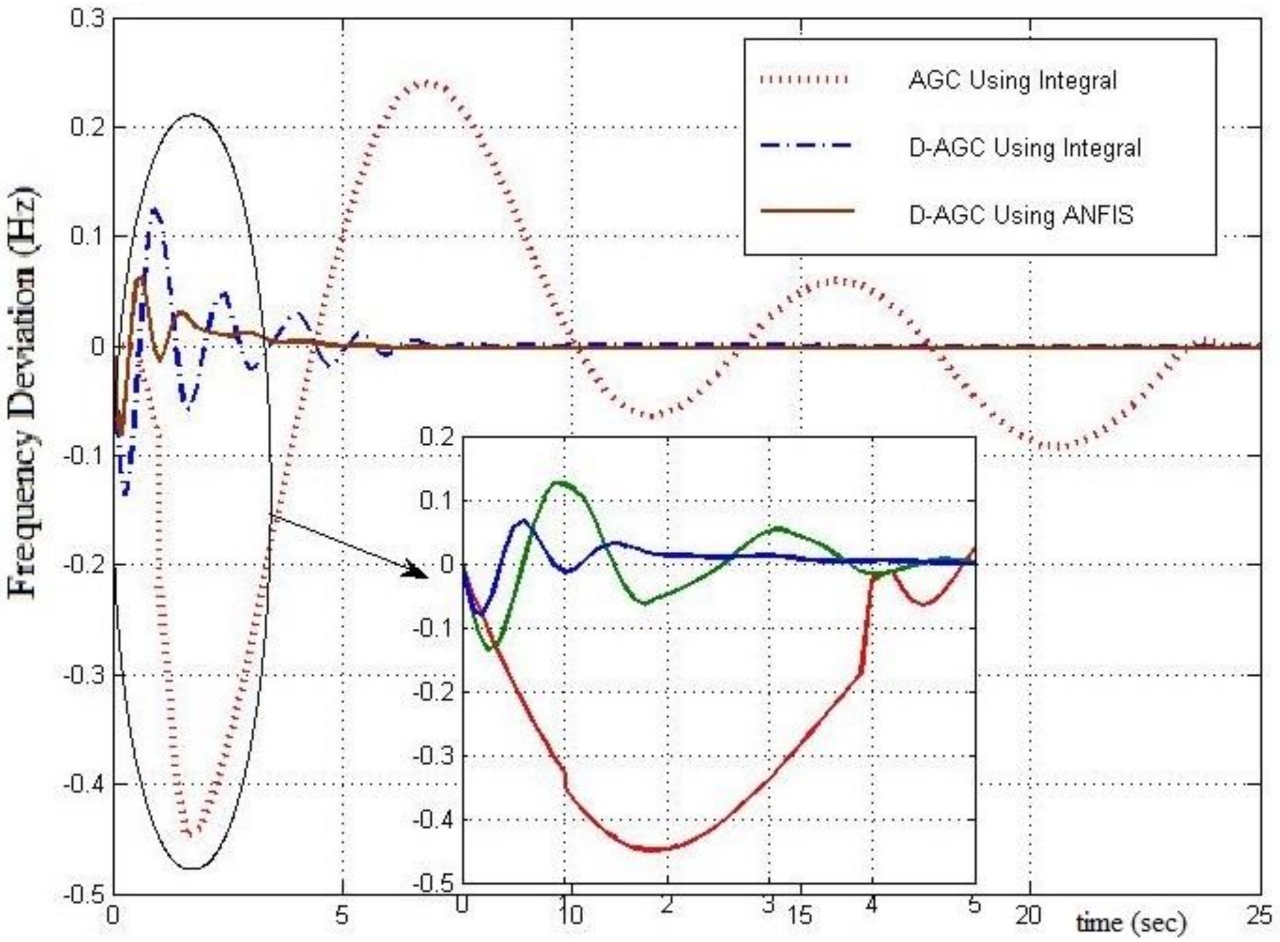

Fig.6.8 Frequency Deviation Comparison of 39 Bus System

The performance of the Decentralized Automatic Generation Control (DAGC) ANFIS controller is compared with the results of Decentralized Automatic Generation Control (DAGC) based integral controller. Simulation results indicates that the controllers exhibit better performance.

7. SUMMARY AND CONCLUSION

A decentralized controller for multi-area automatic generation control suitable for the restructured competitive electricity market, has been proposed in this research work to meet the Poolco-based as well as bilateral transactions. The developed decentralized controller places the controllable modes of the closed-loop system at the desired locations. The proposed decentralized controller has been successfully tested on a 39-bus New England system and a 75-bus Indian power system for all types of load following contracts. In all the cases simulated, the area frequency error got eliminated in the steady state and Gencos and Discos shared the increase in demand of the area, as per their participation in the frequency regulation market. Results of the decentralized controller were compared with those obtained with a centralized.

This research work also intended to find the most suitable configurations of the ANFIS controller for automatic generation control of a multi-area power system. The superiority of ANFIS is evident from the simulation results for all types of perturbation location. Moreover, it is observed that ANFIS controller is found to be more suitable in present day power system where complexity is gradually increasing day by day. The controller fast controller design method is illustrated in a very simple systematic manner and the efficiency of proposed method is demonstrated on a 39-bus New England system and a 75-bus Indian power system. It is observed that the Decentralized Automatic Generation Control (DAGC) based on ANFIS Controller scheme exhibit better performance when compared with the results of Decentralized Automatic Generation Control (DAGC) based Integral Controller.

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9. APPENDIX

Transaction / Player (i)	Load demand (MW)	S(j,k)	B(i)
1	4184.8	(30→90.0), (31→600.0), (32→460.0), (33→650.0), (34→608.0), (35→357.95), (36→279), (37→297.85), (38→387), (39→455)	3,4,7,8,12,15,16, 18,20,21,23,24,27
2	1965.7	(30→90.0), (31→249.0), (32→170.0), (33→307.8), (34→232.9), (35→170), (36→152), (37→148), (38→206), (39→240)	25,26,28,29,31,39

Table 9.1 Transaction data of New England 39 Bus Power System

Transaction / Player (i)	Load demand (MW)	S(j,k)	B(i)
1	5199.26	(1 → 847.74), (2 → 331.63), (3 → 258.77), (4 → 25.91), (5 → 93.98), (6 → 205.75), (7 → 90.60), (8 → 68.56), (9 → 296.25), (10 → 62.00), (11 → 19.52), (12 → 1704.82), (13 → 806.88), (14 → 216.66), (15 → 170.17)	16, 20, 24, 25, 27, 28, 30, 32, 34, 37, 39, 42, 46, 47, 48, 49, 50, 51, 52, 53, 54, 55, 56, 60, 61, 62, 63, 64, 65, 66, 67, 68, 69, 70, 71, 72, 73, 74, 75
2	368.86	(1 → 15), (2 → 15), (3 →15), (4 → 15), (5 → 15), (6 → 15), (7 → 15), (8 → 15), (9 → 15), (10 → 15), (11 → 15), (12 →15), (13 → 15), (14 → 158.86), (15 → 15)	57,58,59

Table 9.2 Transaction Data of Indian 75 Bus Power System

Bus No.	LMPs' at all buses ($/MWh)											
	Without loss model CASE 1				Concentrated loss model CASE 2				Distributed loss model CASE 3			
	LP approach Fixed bids	GA approach		Bat linear bids	LP approach Fixed bids	GA approach		Bat linear bids	LP approach Fixed bids	GA approach		Bat linear bids
		Fixed bids	Linear bids			Fixed bids	Linear bids			Fixed bids	Linear bids	
1	14.09	11.16	11.3	8.65	14.09	11.14	11.46	8.92	14.09	11.14	11.28	8.79
2	14.09	11.16	11.3	8.65	14.09	11.08	11.39	8.82	14.09	11.08	11.22	8.70
3	14.09	11.16	11.3	8.65	14.09	11.22	11.54	8.93	14.09	11.21	11.36	8.81
4	14.09	11.16	11.3	8.65	14.09	11.24	11.57	8.95	14.09	11.24	11.39	8.83
5	14.09	11.16	11.3	8.65	14.09	11.18	11.51	8.89	14.09	11.18	11.33	8.76
6	14.09	11.16	11.3	8.65	14.09	11.16	11.48	8.86	14.09	11.16	11.30	8.73
7	14.09	11.16	11.3	8.65	14.09	11.24	11.56	8.95	14.09	11.24	11.38	8.82
8	14.09	11.16	11.3	8.65	14.09	11.26	11.58	8.97	14.09	11.26	11.40	8.85
9	14.09	11.16	11.3	8.65	14.09	11.21	11.53	8.98	14.09	11.21	11.35	8.85
10	14.09	11.16	11.3	8.65	14.09	11.07	11.39	8.76	14.09	11.06	11.21	8.62
11	14.09	11.16	11.3	8.65	14.09	11.1	11.42	8.80	14.09	11.09	11.24	8.66
12	14.09	11.16	11.3	8.65	14.09	11.1	11.42	8.80	14.09	11.1	11.24	8.66
13	14.09	11.16	11.3	8.65	14.09	11.1	11.42	8.80	14.09	11.1	11.24	8.66
14	14.09	11.16	11.3	8.65	14.09	11.18	11.5	8.87	14.09	11.17	11.32	8.75
15	14.09	11.16	11.3	8.65	14.09	11.23	11.55	8.90	14.09	11.22	11.36	8.79
16	14.09	11.16	11.3	8.65	14.09	11.19	11.51	8.84	14.09	11.17	11.32	8.74
17	14.09	11.16	11.3	8.65	14.09	11.21	11.53	8.88	14.09	11.19	11.34	8.78
18	14.09	11.16	11.3	8.65	14.09	11.23	11.55	8.91	14.09	11.22	11.36	8.81
19	14.09	11.16	11.3	8.65	14.09	10.96	11.27	8.59	14.09	10.99	11.13	8.52
20	14.09	11.16	11.3	8.65	14.09	10.96	11.27	8.59	14.09	10.99	11.13	8.52
21	14.09	11.16	11.3	8.65	14.09	11.13	11.45	8.75	14.09	11.09	11.23	8.66
22	14.09	11.16	11.3	8.65	14.09	10.98	11.30	8.57	14.09	10.92	11.06	8.49
23	14.09	11.16	11.3	8.65	14.09	11.00	11.32	8.60	14.09	10.95	11.09	8.48
24	14.09	11.16	11.3	8.65	14.09	11.19	11.52	8.84	14.09	11.17	11.32	8.74
25	14.09	11.16	11.3	8.65	14.09	11.04	11.36	8.75	14.09	11.03	11.17	8.68
26	14.09	11.16	11.3	8.65	14.09	11.11	11.43	8.77	14.09	11.08	11.23	8.69
27	14.09	11.16	11.3	8.65	14.09	11.20	11.53	8.87	14.09	11.18	11.33	8.78
28	14.09	11.16	11.3	8.65	14.09	10.96	11.28	8.56	14.09	10.92	11.06	8.50
29	14.09	11.16	11.3	8.65	14.09	10.85	11.16	8.43	14.09	10.8	10.94	8.37
30	14.09	11.16	11.3	8.65	14.09	11.08	11.39	8.82	14.09	11.08	11.22	8.70
31	11.16	11.16	11.3	11.55	11.16	11.16	11.48	11.76	11.16	11.16	11.3	11.63
32	14.09	11.16	11.3	8.65	14.09	11.07	11.39	8.76	14.09	11.06	11.21	8.62
33	11.24	14.06	14.2	8.65	11.24	13.86	14.17	8.59	11.24	13.89	14.03	8.52
34	14.09	11.16	11.3	8.65	14.09	10.96	11.27	8.59	14.09	10.99	11.13	8.52
35	14.09	11.16	11.3	8.65	14.09	10.98	11.3	8.57	14.09	10.92	11.06	8.49
36	14.09	11.16	11.3	8.65	14.09	11.00	11.32	8.6	14.09	10.95	11.09	8.48
37	14.09	11.16	11.3	8.65	14.09	11.04	11.36	8.75	14.09	11.03	11.17	8.68
38	14.09	11.16	11.3	8.65	14.09	10.85	11.16	8.43	14.09	10.8	10.94	8.37
39	14.09	11.16	11.3	8.65	14.09	11.17	11.49	8.98	14.09	11.17	11.32	8.85

Table 9.3 Bus LMP's For New England 39 Bus Power System

Bus No.	LMPs' at all buses ($/MWh)											
	Without loss model CASE 1				Concentrated loss model CASE 2				Distributed loss model CASE 3			
	LP approach Fixed bids	GA approach		Bat linear bids	LP approach Fixed bids	GA approach		Bat linear bids	LP approach Fixed bids	GA approach		Bat linear bids
		Fixed bids	Linear bids			Fixed bids	Linear bids			Fixed bids	Linear bids	
1	10.93	11.25	10.97	11.47	11.25	11.25	11.348	11.993	11.25	11.25	11.303	11.378
2	10.93	11.25	10.97	11.47	11.25	11.249	11.348	11.981	11.25	11.25	11.303	11.393
3	10.93	11.25	10.97	11.47	11.25	11.576	11.677	12.466	11.25	11.575	11.63	11.878
4	7.58	14.6	14.32	14.82	7.58	15.568	15.672	16.593	7.58	15.597	15.653	16.115
5	10.93	11.25	10.97	11.47	11.25	11.739	11.842	12.815	11.25	11.738	11.793	12.442
6	10.93	11.25	10.97	11.47	11.25	11.743	11.846	12.819	11.25	11.742	11.798	12.444
7	10.93	11.25	10.97	11.47	11.25	11.669	11.771	12.782	11.25	11.668	11.723	12.331
8	10.93	11.25	10.97	11.47	11.25	11.706	11.809	12.753	11.25	11.705	11.76	12.242
9	10.93	11.25	10.97	11.47	11.25	11.247	11.345	11.994	11.25	11.245	11.298	11.339
10	10.93	11.25	10.97	11.47	11.25	11.685	11.787	12.603	11.25	11.684	11.739	11.987
11	10.93	11.25	10.97	11.47	11.25	11.524	11.625	12.421	11.25	11.524	11.578	11.754
12	10.93	11.25	10.97	11.47	11.25	11.241	11.339	11.986	11.25	11.239	11.292	11.324
13	10.93	11.25	10.97	11.47	11.25	11.255	11.353	12.009	11.25	11.253	11.306	11.346
14	10.93	11.25	10.97	11.47	11.25	11.885	11.989	12.913	11.25	11.884	11.94	12.419
15	10.93	11.25	10.97	11.47	11.25	11.747	11.85	12.854	11.25	11.746	11.801	12.221
16	10.93	11.25	10.97	11.47	11.25	11.249	11.348	11.981	11.25	11.25	11.303	11.393
17	10.93	11.25	10.97	11.47	11.25	11.25	11.348	11.993	11.25	11.25	11.303	11.378
18	10.93	11.25	10.97	11.47	11.25	11.576	11.677	12.466	11.25	11.575	11.63	11.878
19	10.93	11.25	10.97	11.47	11.25	11.572	11.673	12.419	11.25	11.572	11.626	11.786
20	10.93	11.25	10.97	11.47	11.25	11.572	11.673	12.419	11.25	11.572	11.626	11.786
21	10.93	11.25	10.97	11.47	11.25	11.97	12.074	12.999	11.25	11.969	12.025	12.502
22	10.93	11.25	10.97	11.47	11.25	11.949	12.054	12.972	11.25	11.949	12.005	12.468
23	10.93	11.25	10.97	11.47	11.25	11.672	11.775	12.581	11.25	11.672	11.727	11.971
24	10.93	11.25	10.97	11.47	11.25	11.685	11.787	12.603	11.25	11.684	11.739	11.987
25	10.93	11.25	10.97	11.47	11.25	11.957	12.061	12.976	11.25	11.956	12.012	12.468
26	10.93	11.25	10.97	11.47	11.25	11.721	11.823	12.616	11.25	11.72	11.775	12.011
27	10.93	11.25	10.97	11.47	11.25	11.73	11.833	12.628	11.25	11.729	11.785	12.015
28	10.93	11.25	10.97	11.47	11.25	11.898	12.002	12.923	11.25	11.897	11.953	12.415
29	10.93	11.25	10.97	11.47	11.25	11.915	12.019	12.945	11.25	11.914	11.97	12.453
30	10.93	11.25	10.97	11.47	11.25	11.942	12.047	12.97	11.25	11.941	11.998	12.474
31	10.93	11.25	10.97	11.47	11.25	11.739	11.842	12.815	11.25	11.738	11.793	12.442
32	10.93	11.25	10.97	11.47	11.25	11.743	11.846	12.819	11.25	11.742	11.798	12.444
33	10.93	11.25	10.97	11.47	11.25	11.669	11.771	12.782	11.25	11.668	11.723	12.331
34	10.93	11.25	10.97	11.47	11.25	11.706	11.809	12.753	11.25	11.705	11.76	12.242
35	10.93	11.25	10.97	11.47	11.25	11.247	11.345	11.994	11.25	11.245	11.298	11.339
36	10.93	11.25	10.97	11.47	11.25	11.519	11.619	12.327	11.25	11.518	11.572	11.69
37	10.93	11.25	10.97	11.47	11.25	11.513	11.614	12.323	11.25	11.513	11.567	11.675
38	10.93	11.25	10.97	11.47	11.25	11.876	11.98	12.931	11.25	11.875	11.931	12.465
39	10.93	11.25	10.97	11.47	11.25	11.799	11.902	12.866	11.25	11.798	11.853	12.418
40	10.93	11.25	10.97	11.47	11.25	11.524	11.625	12.421	11.25	11.524	11.578	11.754
41	10.93	11.25	10.97	11.47	11.25	11.241	11.339	11.986	11.25	11.239	11.292	11.324
42	10.93	11.25	10.97	11.47	11.25	11.255	11.353	12.009	11.25	11.253	11.306	11.346
43	10.93	11.25	10.97	11.47	11.25	11.885	11.989	12.913	11.25	11.884	11.94	12.419
44	10.93	11.25	10.97	11.47	11.25	11.747	11.85	12.854	11.25	11.746	11.801	12.221
45	10.93	11.25	10.97	11.47	11.25	11.77	11.873	12.876	11.25	11.769	11.825	12.244
46	10.93	11.25	10.97	11.47	11.25	11.425	11.525	12.187	11.25	11.425	11.479	11.576
47	10.93	11.25	10.97	11.47	11.25	11.626	11.728	12.509	11.25	11.625	11.68	11.909

Table 9.4 Bus LMP's For Indian 75 Bus Power System

Bus No.	LMPs' at all buses ($/MWh)											
	Without loss model CASE 1				Concentrated loss model CASE 2				Distributed loss model CASE 3			
	LP approach Fixed bids	GA approach		Bat linear bids	LP approach Fixed bids	GA approach		Bat linear bids	LP approach Fixed bids	GA approach		Bat linear bids
		Fixed bids	Linear bids			Fixed bids	Linear bids			Fixed bids	Linear bids	
48	10.93	11.25	10.97	11.47	11.25	11.594	11.696	12.496	11.25	11.594	11.648	11.825
49	10.93	11.25	10.97	11.47	11.25	11.619	11.72	12.522	11.25	11.618	11.673	11.85
50	10.93	11.25	10.97	11.47	11.25	11.542	11.643	12.353	11.25	11.542	11.596	11.757
51	10.93	11.25	10.97	11.47	11.25	12.015	12.12	12.931	11.25	12.014	12.07	12.306
52	10.93	11.25	10.97	11.47	11.25	12.19	12.297	13.118	11.25	12.189	12.247	12.484
53	10.93	11.25	10.97	11.47	11.25	12	12.105	13.04	11.25	11.999	12.056	12.556
54	10.93	11.25	10.97	11.47	11.25	11.894	11.998	12.911	11.25	11.893	11.949	12.35
55	10.93	11.25	10.97	11.47	11.25	12.014	12.12	13.105	11.25	12.014	12.07	12.485
56	10.93	11.25	10.97	11.47	11.25	11.93	12.034	12.958	11.25	11.929	11.985	12.457
57	10.93	11.25	10.97	11.47	11.25	12.034	12.14	13.082	11.25	12.033	12.09	12.606
58	10.93	11.25	10.97	11.47	11.25	12.032	12.137	13.076	11.25	12.031	12.088	12.591
59	10.93	11.25	10.97	11.47	11.25	12.006	12.111	13.065	11.25	12.005	12.061	12.616
60	10.93	11.25	10.97	11.47	11.25	12.098	12.203	13.126	11.25	12.097	12.154	12.611
61	10.93	11.25	10.97	11.47	11.25	11.995	12.099	13.042	11.25	11.994	12.05	12.574
62	10.93	11.25	10.97	11.47	11.25	11.887	11.991	12.955	11.25	11.886	11.942	12.543
63	10.93	11.25	10.97	11.47	11.25	11.991	12.096	13.051	11.25	11.99	12.046	12.455
64	10.93	11.25	10.97	11.47	11.25	11.691	11.793	12.546	11.25	11.69	11.745	11.906
65	10.93	11.25	10.97	11.47	11.25	11.973	12.077	13.002	11.25	11.972	12.028	12.505
66	10.93	11.25	10.97	11.47	11.25	11.62	11.721	12.47	11.25	11.619	11.674	11.834
67	10.93	11.25	10.97	11.47	11.25	11.686	11.789	12.6	11.25	11.686	11.741	11.985
68	10.93	11.25	10.97	11.47	11.25	11.622	11.724	12.514	11.25	11.621	11.676	11.92
69	10.93	11.25	10.97	11.47	11.25	11.59	11.692	12.405	11.25	11.589	11.644	11.753
70	10.93	11.25	10.97	11.47	11.25	12.119	12.225	13.149	11.25	12.118	12.175	12.632
71	10.93	11.25	10.97	11.47	11.25	11.732	11.834	12.63	11.25	11.731	11.786	12.02
72	10.93	11.25	10.97	11.47	11.25	12.095	12.201	13.124	11.25	12.094	12.151	12.608
73	10.93	11.25	10.97	11.47	11.25	11.846	11.95	12.926	11.25	11.845	11.901	12.293
74	10.93	11.25	10.97	11.47	11.25	11.666	11.768	12.572	11.25	11.665	11.72	11.959
75	10.93	11.25	10.97	11.47	11.25	11.863	11.967	12.89	11.25	11.862	11.918	12.401

Table 9.5 (Contd...) Bus LMP's For Indian 75 Bus Power System

GENERATOR		
Unit no.		Arbitrary reference number
Rated MVA		Machine-rated MVA; base MVA for impedances
Rated kV		Machine-rated terminal voltage in kV; base kV for impedances
Rated PF		Machine-rated power factor
SCR	(1)	Machine short circuit ratio
x''_d	pu	Unsaturated d axis subtransient reactance
x'_d	pu	Unsaturated d axis transient reactance
x_d	pu	Unsaturated d axis synchronous reactance
x''_q	pu	Unsaturated q axis subtransient reactance
x'_q	pu	Unsaturated q axis transient reactance
x_q	pu	Unsaturated q axis synchronous reactance
r_a	pu	Armature resistance
x_ℓ or x_p	pu	Leakage or Potier reactance
r_2	pu	Negative-sequence resistance
x_2	pu	Negative-sequence reactance
x_0	pu	Zero-sequence reactance
τ''_d	s	d axis subtransient short circuit time constant
τ'_d	s	d axis transient short circuit time constant
τ''_{d0}	s	d axis subtransient open circuit time constant
τ'_{d0}	s	d axis transient open circuit time constant
τ''_q	s	q axis subtransient short circuit time constant
τ'_q	s	q axis transient short circuit time constant
τ''_{q0}	s	q axis subtransient open circuit time constant
τ'_{q0}	s	q axis transient open circuit time constant
τ_a	s	Armature time constant
W_R	MW·s	Kinetic energy of turbine + generator at rated speed in MJ or MW·s
r_F	Ω	Machine field resistance in Ω
$S_{G1.0}$	(2)	Machine saturation at 1.0 pu voltage in pu

EXCITER (*continued*)		
$V_{R\max}$	pu (4)	Maximum regulator output, starting at full load field voltage
$V_{R\min}$	pu (4)	Minimum regulator output, starting at full load field voltage
K_E	pu	Exciter self-excitation at full load field voltage
τ_E	s	Exciter time constant
$S_{E.75\max}$	(5)	Rotating exciter saturation at 0.75 ceiling voltage, or K_I for SCPT exciter
$S_{E\max}$	(5)	Rotating exciter saturation at ceiling voltage, or K_p for SCPT exciter
A_{EX}	(5)	Derived saturation constant for rotating exciters
B_{EX}	(5)	Derived saturation constant for rotating exciters
$E_{FD\max}$	pu (5)	Maximum field voltage or ceiling voltage, pu
$E_{FD\min}$	pu	Minimum field voltage
K_F	pu	Regulator stabilizing circuit gain
τ_F or τ_{F1}	s	Regulator stabilizing circuit time constant (#1)
τ_{F2}	s	Regulator stabilizing circuit time constant (#2)

TURBINE-GOVERNOR		
GOV	(6)	Governor type: G = general, C = cross-compound, H = hydraulic
R	(6)	Turbine steady-state regulation setting or droop
$P_{\max}$	MW	Maximum turbine output in MW
τ_1	s	Control time constant (governor delay) or governor response time (type H)
τ_2	s	Hydro reset time constant (type G) or pilot valve time (type H)
τ_3	s	Servo time constant (type G or C), or hydro gate time constant (type G) or dashpot time constant (type H)
τ_4	s	Steam valve bowl time constant (zero for type G hydrogovernor) or ($\tau_W/2$ for type H)
τ_5	s	Steam reheat time constant or 1/2 hydro water starting time constant (type C or G) or minimum gate velocity in MW/s (type H)
F	(6)	pu shaft output ahead of reheater or

Table 9.6 Definitions of Tabulated Generator Unit Data

GENERATOR										
Unit no.		*H1*	*H2*	*H3*	*H4*	*H5*	*H6*	*H7*	*H8*	*H9*
Rated MVA		9.00	17.50	25.00	35.00	40.00	54.00	65.79	75.00	86.00
Rated kV		6.90	7.33	13.20	13.80	13.80	13.80	13.80	13.80	13.80
Rated PF		0.90	0.80	0.95	0.90	0.90	0.90	0.95	0.95	0.90
SCR	(1)	1.250	. . .	2.280	1.167	1.180	1.18	1.175	2.36	1.18
x''_d	pu	0.329	0.330	0.310	0.235	0.288	0.340	0.240	0.140	0.258
x'_d	pu	0.408	. . .	. . .	0.260	0.318	0.380	0.260	0.174	0.320
x_d	pu	0.911	1.070	1.020	1.000	0.990	1.130	0.900	0.495	1.050
x''_q	pu	. . .	. . .	. . .	0.264	0.306	0.340	. . .	0.135	0.306
x'_q	pu	0.580	0.660	0.650	0.620	0.615	0.680	0.540	. . .	0.670
x_q	pu	0.580	0.660	0.650	0.620	0.615	0.680	0.540	0.331	0.670
r_a	pu	. . .	0.003	0.0032	0.004	0.0029	0.0049	0.0022	0.0041	0.0062
x_ℓ or x_p	pu	. . .	0.310	0.924	0.170	0.224	0.2100	. . .	0.120	0.140
r_2	pu	. . .	0.030	0.030	0.040	. . .	. . .	0.014	. . .	0.060
x_2	pu	. . .	0.490	0.460	0.270	0.297	0.340	0.260	0.130	0.312
x_0	pu	. . .	0.200	0.150	0.090	0.125	0.180	0.130	0.074	0.130
τ''_d	s	. . .	0.035	0.035	0.035	. . .	. . .	. . .	. . .	0.044
τ'_d	s	. . .	1.670	2.190	2.300	1.700	3.000	1.600	1.850	2.020
τ''_{d0}	s	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	0.051
τ'_{d0}	s	4.200	5.400	7.200	7.100	5.300	8.500	5.500	8.400	4.000
τ''_q	s	. . .	0.035	0.035	0.035	. . .	. . .	. . .	. . .	0.017
τ'_q	s	. . .	0.835	1.100	1.150	. . .	. . .	. . .	. . .	. . .
τ''_{q0}	s	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	0.033
τ'_{q0}	s	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .	. . .
τ_a	s	0.1800	. . .	. . .	. . .	. . .	. . .	. . .	. . .	0.286
W_R	MW·s	23.50	117.00	183.00	254.00	107.90	168.00	176.00	524.00	233.00
r_F	Ω	. . .	. . .	. . .	. . .	0.269	0.301	0.199	0.155	0.332
$S_{G1.0}$	(2)	0.160	0.064	0.064	0.064	0.194	0.3127	0.1827	0.170	0.245
$S_{G1.2}$	(2)	0.446	1.018	1.018	1.018	0.685	0.7375	0.507	0.440	0.770
E_{FDFL}	(2)	2.080	2.130	2.130	2.130	2.030	2.320	1.904	1.460	2.320
D	(3)	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000

Table 9.7 Typical Data for Hydro (H) Units

TURBINE-GOVERNOR										
GOV	(6)	*G*	*G*	*G*	*G*	*G*	*G*	*G*	*G*	*G*
R	(6)	0.050	0.050	0.050	0.050	0.056	0.050	0.050	0.050	0.050
P_{max}	MW	8.60	14.00	23.80	40.00	40.00	52.50	65.50	90.00	86.00
τ_1	s	48.440	16.000	16.000	16.000	0.000	0.000	25.600	20.000	12.000
τ_2	s	4.634	2.400	2.400	2.400	0.000	0.000	2.800	4.000	3.000
τ_3	s	0.000	0.920	0.920	0.920	0.500	0.000	0.500	0.500	0.500
τ_4	s	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
τ_5	s	0.579	0.300	0.300	0.300	0.430	0.785	0.350	0.850	1.545
F	(6)	−2.000	−2.000	−2.000	−2.000	−2.000	−2.000	−2.000	−2.000	−2.000

Table 9.8 (Contd...) Typical Data for Hydro (H) Units

GENERATOR										
Unit no.		$H10$	$H11$	$H12$	$H13$	$H14$	$H15$	$H16$	$H17$	$H18$
Rated MVA		100.10	115.00	125.00	131.00	145.00	158.00	231.60	250.00	615.00
Rated kV		13.80	12.50	13.80	13.80	14.40	13.80	13.80	18.00	15.00
Rated PF		0.90	0.85	0.90	0.90	0.90	0.90	0.95	0.85	0.975
SCR	(1)	1.20	1.05	1.155	1.12	1.20	...	1.175	1.050	...
x''_d	pu	0.280	0.250	0.205	0.330	0.273	0.220	0.245	0.155	0.230
x'_d	pu	0.314	0.315	0.300	0.360	0.312	0.300	0.302	0.195	0.2995
x_d	pu	1.014	1.060	1.050	1.010	0.953	0.920	0.930	0.995	0.8979
x''_q	pu	0.375	0.287	0.221	0.330	0.402	0.290	0.270	0.143	0.2847
x'_q	pu	0.770	0.610	0.686	0.570	0.573	0.510	...	0.568	0.646
x_q	pu	0.770	0.610	0.686	0.570	0.573	0.510	0.690	0.568	0.646
r_a	pu	0.0049	0.0024	0.0023	0.004	...	0.002	0.0021	0.0014	...
x_ℓ or x_p	pu	0.163	0.147	0.218	0.170	0.280	0.130	0.340	0.160	0.2396
r_2	pu	...	0.027	0.008	...	...	0.045	...	...	...
x_2	pu	0.326	0.269	0.211	0.330	...	0.255	0.258	...	...
x_0	pu	...	0.161	0.150	0.150	...	0.120	0.135	...	...
τ''_d	s	0.035	...	...	0.030	...	0.024	0.020	...	...
τ'_d	s	1.810	2.260	1.940	2.700	...	1.600	3.300	...	...
τ''_{d0}	s	0.039	0.040	...	0.030	0.041	0.029	0.030	...	...
τ'_{d0}	s	6.550	8.680	6.170	7.600	7.070	5.200	8.000	9.200	7.400
τ''_q	s	...	...	...	0.030	...	0.028	0.020	...	...
τ'_q	s	...	...	...	...	...	...	...	...	...
τ''_{q0}	s	0.071	0.080	...	0.040	0.071	0.034	0.060	...	...
τ'_{q0}	s	...	...	...	...	...	...	...	...	...
τ_a	s	0.278	0.330	...	0.180	...	0.360	0.200	...	...
W_R	MW·s	312.00	439.00	392.09	458.40	469.00	502.00	786.00	1603.00	3166.00
r_F	Ω	0.332	0.156	0.379	0.182	...	0.206	0.181	...	...
$S_{G1.0}$	(2)	0.219	0.178	0.200	0.113	0.220	0.1642	0.120	0.0769	0.180
$S_{G1.2}$	(2)	0.734	0.592	0.612	0.478	0.725	0.438	0.400	0.282	0.330
E_{FDFL}	(2)	2.229	2.200	2.220	1.950	2.230	1.990	1.850	1.88	...
D	(3)	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000	2.000

Table 9.9 (Contd...) Typical Data for Hydro (H) Units

TURBINE-GOVERNOR										
GOV	(6)	G	G	G	G	G	G	G	G	G
R	(6)	0.030	0.051	0.050	0.050	0.038	0.050	0.050	0.050	0.050
P_{max}	MW	133.00	115.00	171.00	120.00	160.00	155.00	267.00	250.00	603.30
τ_1	s	52.100	...	31.00	27.500	65.300	...	124.470	30.000	36.000
τ_2	s	4.800	...	4.120	3.240	6.200	...	8.590	3.500	6.000
τ_3	s	0.500	...	0.393	0.500	0.500	...	0.250	0.520	0.000
τ_4	s	0.000	...	0.000	0.000	0.000	...	0.000	0.000	0.000
τ_5	s	0.498	...	0.515	0.520	0.650	...	0.740	0.415	0.900
F	(6)	−2.000	−2.000	−2.000	−2.000	−2.000	−2.000	−2.000	−2.000	−2.000

Table 9.10 (Contd...) Typical Data for Hydro (H) Units