ASSESSMENT OF AUTOMATIC GENERATION CONTROL

IN A DEREGULATED ENVIRONMENT

Thesis submitted towards the partial fulfillment of the requirements of the degree of

Master of Engineering

in

Power System and Electric Drives

submitted by

Aprajita salgotra

(801041004)

Under the supervision of

Ms. Manbir Kaur

Associate Professor, EIED

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DEPARTMENT OF ELECTRICAL AND INSTRUMENTATION ENGINEERING

THAPAR UNIVERSITY

PATIALA – 147 004

CERTIFICATE

I hereby certify that the work which is being presented in the thesis entitled **"Simulation & Assessment of Load Frequency Control under Deregulated Environment Using Linear Quadratic Regulator"** in partial fulfillment of the requirements for the award of degree of Master of Engineering in Power systems and Electric Drives submitted in Electrical & Instrumentation Engineering Department of Thapar University, Patiala, is an authentic record of my own work carried out under the guidance of **Ms. Manbir Kaur**, Associate Professor, EIED.

The matter presented in the thesis has not been submitted for the award of any other degree of this or any other university.

Aprajita

Aprajita Salgotra
(Roll No: 801041004)

It is certified that the above statement made by the student is correct to the best of our knowledge and belief.

Manbir Kaur
9.7.2012

Ms. Manbir Kaur
Associate Professor, EIED
Thapar University
Patiala

Countersigned by:

S. Ghosh

Dr. Samarajit Ghosh
Professor & Head, EIED
Thapar University, Patiala

Dr. S. K. Mohapatra
Dean of Academic Affairs
Thapar University, Patiala

ABSTRACT

Automatic generation control is a significant control process that operates constantly to balance the generation and load in power systems at a minimum cost. The AGC system is responsible for frequency control, power interchange and economic dispatch. This thesis reviews the main structures, configurations, modeling and characteristics of Automatic Generation Control systems in a deregulated environment and addresses the control area concept in restructured Power Systems. The concept of DISCO participation matrix is introduced and reflected in the two-area diagram to make the visualization of contract easier. The modification by superimposition of information flow on the Traditional AGC two-area system is done to take into account the effect of bilateral contracts on the dynamics and the simulations reveal some interesting patterns. Optimization of linear controller gain setting is done using Linear Quadratic Controller (LQR). To validate the effectiveness of LQR robust controller, the simulation has been performed using proposed controller and comparison has been done with conventional Integral type controller.

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CHAPTER 1

INTRODUCTION

1.1 OVERVIEW

Large scale power systems are normally managed by viewing them as being made up of control areas with interconnections between them. Each control area must meet its own demand and its scheduled interchange power. Any mismatch between the generation and load can be observed by means of a deviation in frequency [1]. This balancing between load and generation can be achieved by using Automatic Generation Control (AGC).

The engineering aspects of planning and operation have been reformulated in a restructured power system in recent years although essential ideas remain the same. To improve the efficiency in the operation of the power system some major changes into the structure of electric power utilities have been introduced by means of deregulating the industry and opening it up to private competition. The utilities no longer own generation, transmission, and distribution; instead, there are three different entities, *viz.*, GENCO (Generation Companies), TRANSCOs (Transmission Companies) and DISCOs (Distribution Companies).

As there are several GENCOs and DISCOs in the deregulated structure, a DISCO has the freedom to have a contract with any GENCO for transaction of power. A DISCO may have a contract with a GENCO in another control area. Such transactions are called “bilateral transactions.” All the transactions have to be cleared through an impartial entity called an Independent System Operator (ISO). The ISO has to control a number of so-called “ancillary services,” one of which is AGC. One of the most profitable ancillary services is the load frequency control. The main goal of the LFC is to maintain zero steady state errors for frequency deviation and minimize unscheduled tie-line power flows between neighboring control areas.

1.1.1 **Traditional vs. Restructured Scenario:** The electric power business in vertically integrated utilities (VIUs) owns generation-transmission-distribution systems and supply power to the customer at regulated rates. Such a configuration is shown conceptually in Figure 1.1, in which the large rectangular box denotes a VIU. The VIU is usually interconnected and this interconnection is almost always at the transmission voltage denoted in the figure 1.1 as tie lines. Thus, electric power can be bought and sold between VIUs along these tie lines and moreover, such interconnection provides greater reliability [5].

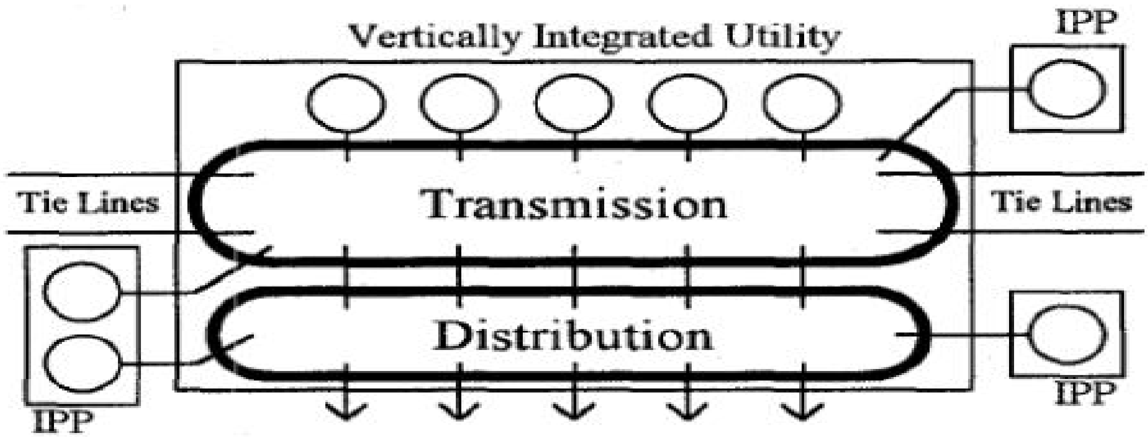


Figure 1.1: Vertically Integrated Utility Structure.

Due to the emergence of independent power producers that can sell power to VIU's, all the square boxes denote the business entities which can buy and/or sell electric power. The first step in deregulation will be to separate the generation of power from the transmission on the same footing as the IPP's. in figure 1.2, the GENCO's will compete in a free market to sell electricity they produce.

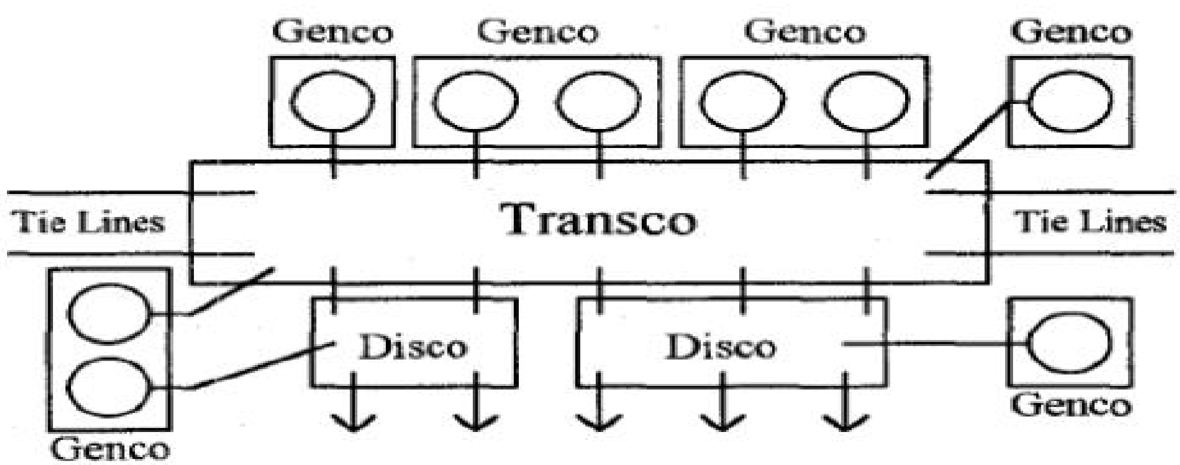


Figure 1.2: Deregulated Utility Structure.

1.1.2 Significance of Automatic Generation Control in Deregulated Environment: The Significance of AGC in deregulated environment is three-fold;

(i) to achieve zero static frequency;

(ii) to distribute generation among areas so that interconnected tie line flows match a prescribed schedule; and

(iii) to balance the total generation against the total load and tie line power exchanges.

In the deregulated environment, control is highly decentralized. Each load matching contract requires a separate control process, yet this process must cooperatively interact to reestablish system frequency and tie-line power interchange. In real-time markets, new organizations, market operators, and supervisors, such as Independent System Operators (ISOs), are responsible for maintaining the real-time balance of generation and load for minimizing frequency deviations and regulating tie-line flows, which would facilitate bilateral contracts spanning over various control areas. In a modern power system, the AGC system should track moment-to moment fluctuations in the system load to meet the specified control area performance criteria.

1.1.3 Technical Issues: In this new deregulated environment, the operation of power system will pose significant problems of purely technical nature. The simple frequency control sometimes becomes challenging when implemented on the premise of price based operation and market driven demand. The basic premise of the regulatory policies is to allow competition among generators and to create market conditions in the sector, seen as necessary conditions for increasing the efficiency of electric energy production and distribution, offering a lower price, higher quality and more secure product.

1.2 LITERATURE SURVEY

Many investigations in the field of automatic generation control of interconnected power system have been reported over the past few decades. These investigations deal with how to select a frequency bias, selection of controller parameters and selection of speed regulator parameter of speed governor. Investigation regarding to the AGC of interconnected system is limited to the selection of controller parameter.

Jayant Kumar *et al* [1, 2] presented AGC simulation model for Price based operation in deregulated power system and suggested the modifications required in the conventional AGC to study the load followings in Price based market operations.

Fosha and Elgerd. [3] provide detailed design of automatic generation and voltage control and proved by the methods of optimum control that better response and wider stability margins can be obtained by lower bias settings and have justified the importance of gain parameter and frequency bias.

Fosha and Elgerd. [4] have used the area controller which operates in response to the integral of the ACE for that area unlike the Classical optimization theory used to find the "best" value of parameters K_I, gain of the area control error (ACE) integrator, and B, frequency bias.

Willems. [7] dealt with the determination of optimum parameter values of conventional load frequency regulation of interconnected power systems and discussed the importance of sensitivity consideration in connection with recommendation made in [2] and [3].

Elgerd and Wood. [8] have provided the detailed design of automatic generation and voltage control for steady the performance of power systems. Their study also includes the effect of coupling between AGC and AVR loops.

Ibraheem e*t al*. [9] have presented AGC schemes based on parameters, such as linear and non linear power system models, classical and optimal control, and centralized, decentralized, and multilevel control.

Kundur. [12] has developed the responses of steam and hydraulic generating units to a small step increase in load demand and effect of addition of integral control on generating units selected for AGC.

Cohn. [13] has discussed the selection of frequency bias setting for large multi area power system. His investigation schemes are based on multilevel control.

Kwatny *et al.* [14] have shown that the load prediction and coordination of area generation in a multi-area interconnection can effectively improve the regulation of inter-area power flows.

Athay. [17] has explained the purpose of area regulation control to determine unit desired generation values, given the nominal ones determined by area tracking control, so as to regulate the area control error (ACE) to zero.

Jaleeli *et al.*[18] have described the way loads and unit governors respond to various upsets of electric power mismatch in the system is presented which is followed by a brief description of types of generating units, constraints on their range and rate of response to AGC signals.

Bevrani *et al.* [19] addresses a new decentralized robust strategy to adapt the well tested classical automatic generation control (AGC) system to the changing environment of power system operation under deregulation based on the bilateral AGC scheme.

Kedjar. [25] presents the design and implementation of the Linear Quadratic Regulator with integral action. The integral action is added so as to cancel the steady state errors for the reference tracking or disturbance rejection, knowing that the standard LQR provides only proportional gains.

Literature survey presents a critical review of AGC of Two Area system in a deregulated environment. It has paid particular attention to categorize various AGC strategies in the literature that highlights its salient features. The authors have made a sincere attempt to present the most comprehensive set of reference for Automatic generation control.

1.3 OBJECTIVES OF THE WORK

(i) Modification of the traditional two area system to take into account the effect of Bilateral Contracts.

(ii) To introduce the concept of DISCO participation matrix that helps the visualization and implementation of contracts.

(iii) To simulate the bilateral contracts and reflect it in the two-area block diagram.

(iv) Formulation and Implementation of Linear Quadratic Regulator robust controller by optimizing the parameters.

1.4 ORGANISATION OF THE THESIS WORK

The work carried out in this thesis is carried out in six chapters:

Chapter 1 deliberates on the overview of the problem, brief literature review, objective of the work.

Chapter 2 discusses the introduction of Automatic Generation Control (AGC), frequency model, AGC characteristics and Simulation Results.

Chapter 3 illustrates the AGC in deregulated environment, and various transaction models of deregulated system.

Chapter 4 explains the optimization of integral control gain setting.

2.1 INTRODUCTION

In an interconnected power system, as the load varies, the frequency and tie-line power interchange also vary. To accomplish the objective of regulating system electrical frequency error and tie-line power flow deviation to zero, a supplementary control action, that adjusts the load reference set points of selected generating units, is utilized. This control process is referred to as Automatic Generation Control (AGC) [16].

The role of AGC is to divide the loads among the system, station and generator to achieve maximum economy and accurate control of the scheduled interchanges of tie-line power while maintaining a reasonability uniform frequency.

An interconnected power system can be considered as being divided into control areas which are connected by tie lines. In each control area, all generator sets are assumed to form a coherent group. The power system is subjected to local variations of random magnitudes and durations [19]. A control signal made up of tie line flow deviation added to frequency deviation weighted by a bias factor would accomplish the desired objective. This control signal is known as area control error (ACE). ACE serves to indicate when total generation must be raised or lowered in a control area [9].

2.2 POWER SYSTEM FREQUENCY CONTROL

Frequency deviation is a direct result of the imbalance between the electrical load and the active power supplied by the connected generators. A permanent off-normal frequency deviation directly affects power system operation, security, reliability, and efficiency by damaging equipment, degrading load performance, overloading transmission lines, and triggering the protection devices.

Since the frequency generated in the electric network is proportional to the rotation speed of the generator, the problem of frequency control may be directly translated into a speed control problem of the turbine generator unit. This is initially overcome by adding a governing mechanism that senses the machine speed, and adjusts the input valve to change the mechanical power output to track the load change and to restore frequency to a nominal value.

Depending on the frequency deviation range, as shown in Figure 2.1, in addition to the natural governor response known as the primary control, the supplementary control (AGC), or secondary control, and emergency control may all be required to maintain power system frequency.1 In Figure 2.1, f_0 is nominal frequency, and Δf_1, Δf_2, and Δf_3 show frequency variation range corresponding to the different operating conditions based on the accepted frequency operating standards.

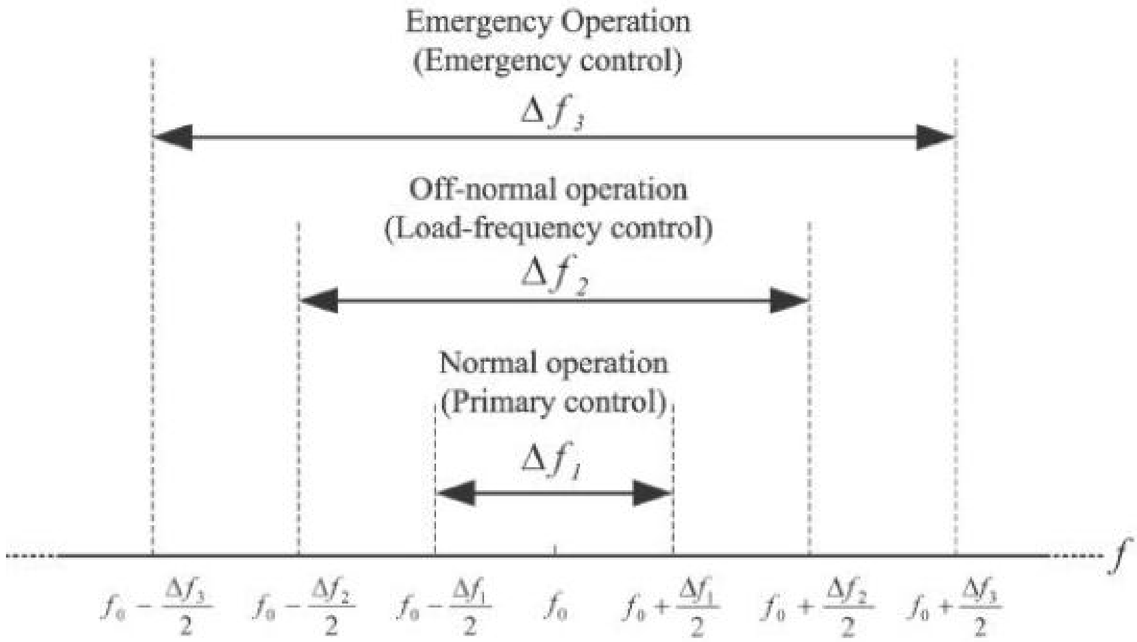


Figure 2.1 Frequency deviations and associated operating controls.

Under normal operation, the small frequency deviations can be attenuated by the primary control. For larger frequency deviation (off-normal operation), according to the available amount of power reserve, the AGC is responsible for restoring system frequency. However, for a serious load-generation imbalance associated with rapid frequency changes following a significant fault, the AGC system may be unable to restore frequency via the supplementary frequency control loop. In this situation, the emergency control and protection schemes, such as under-frequency load shedding (UFLS), must be used to decrease the risk of cascade faults, additional generation events, load/network, and separation events.

Figure 2.2 shows an example of a typical power system response to a power plant trip event, with the responses of primary, supplementary, and emergency controls.

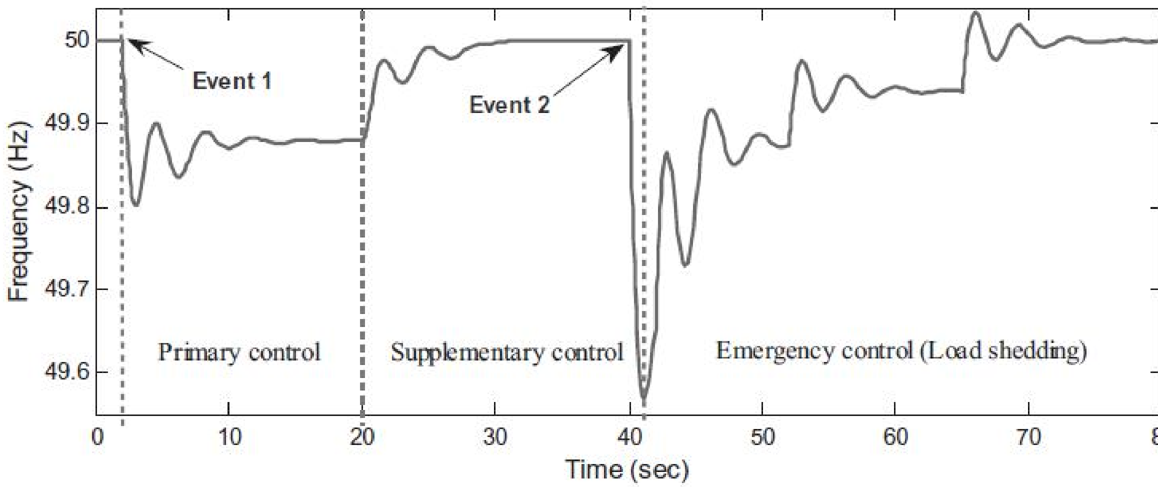


Figure 2.2 Responses Of Primary, Supplementary and Emergency Controls.

Following event 1, the primary control loops of all generating units respond within a few seconds. As soon as the balance is reestablished, the system frequency stabilizes and remains at a fixed value, but differs from the nominal frequency because of the droop of the generators, which provide a proportional type of action that will be explained later. Consequently, the tie-line power flows in a multi-area power system will differ from the scheduled values.

The supplementary control will take over the remaining frequency and power deviation after a few seconds, and can reestablish the nominal frequency and specified power cross-border exchange by allocation of regulating power. Following event 1, the frequency does not fall too quickly, so there is time for the AGC system to use the regulation power and thus recover the load-generation balance. However, it does not happen following event 2, where the frequency is quickly dropped to a critical value. In this case, where the frequency exceeds the permissible limits, an emergency control plan such as UFLS may need to restore frequency and maintain system stability. Otherwise, due to critical under-speed, other generators may trip out, creating a cascade failure, which can cause widespread blackouts.

2.2.1 Primary Control

Depending on the type of generation, the real power delivered by a generator is controlled by the mechanical power output of a prime mover such as a steam turbine, gas turbine, hydro turbine, or diesel engine. In the case of a steam or hydro turbine, mechanical power is controlled by the opening or closing of valves regulating the input of steam or water flow into the turbine. Steam (or water) input to generators must be continuously regulated to match real power demand. Without this regulation, the machine speed will vary with consequent change in frequency. For satisfactory operation of a power system, the frequency should remain nearly constant. The speed governor senses the change in speed (frequency) via the primary control loop. In fact, primary control performs a local automatic control that delivers reserve power in opposition to any frequency change. The necessary mechanical forces to position the main valve against the high steam (or hydro) pressure is provided by the hydraulic amplifier, and the speed changer provides a steady state power output setting for the turbine.

The speed governor on each generating unit provides the primary speed control function, and all generating units contribute to the overall change in generation, irrespective of the location of the load change, using their speed governing. However, as mentioned, the primary control action is not usually sufficient to restore the system frequency, especially in an interconnected power system, and the supplementary control loop is required to adjust the load reference set point through the speed changer motor.

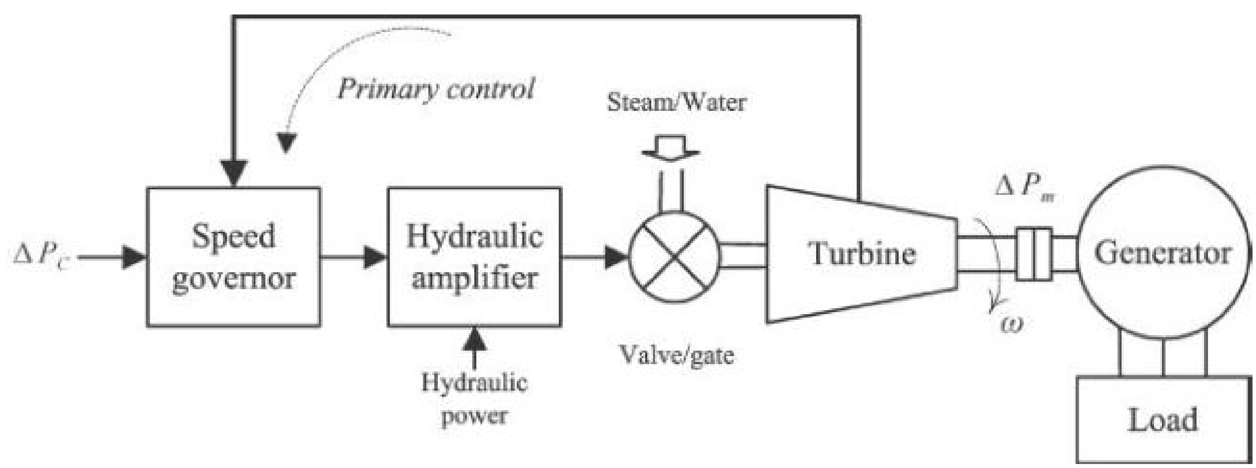


Figure 2.3 Governor-turbine with primary frequency control loop.

2.2.2 Supplementary Control

In addition to primary frequency control, a large synchronous generator may be equipped with a supplementary frequency control loop. A schematic block diagram of a synchronous generator equipped with primary and supplementary frequency control loops is shown in Figure 2.9.

The supplementary loop gives feedback via the frequency deviation and adds it to the primary control loop through a dynamic controller. The resulting signal is used to regulate the system frequency. In real-world power systems, the dynamic controller is usually a simple integral or proportional integral (PI) controller. Following a change in load, the feedback mechanism provides an appropriate signal for the turbine to make generation (ΔP_m) track the load and restore system frequency.

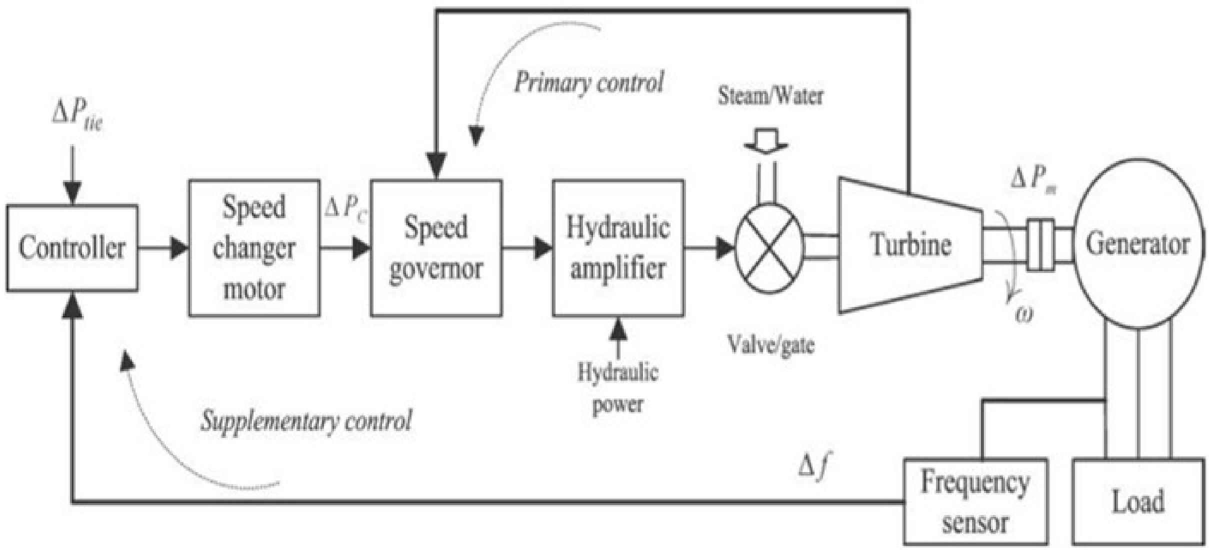


Figure 2.4 Governor-turbine with primary frequency control loop.

2.2.3 Emergency Control

Emergency control, such as load shedding, shall be established in emergency conditions to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown. Load shedding is an emergency control action to ensure system stability, by curtailing system load. The load shedding will only be used if the frequency (or voltage) falls below a specified frequency (voltage) threshold. Typically, the load shedding protects against excessive frequency (or voltage) decline by attempting to balance real (reactive) power supply and demand in the system.

The load shedding curtails the amount of load in the power system until the available generation can supply the remaining loads. If the power system is unable to supply its active (reactive) load demands, the under-frequency (under-voltage) condition will be intense. The number of load shedding steps, the amount of load that should be shed in each step, the delay between the stages, and the location of shed load are the important objects that should be determined in a load shedding algorithm. A load shedding scheme is usually composed of several stages. Each stage is characterized by frequency/ voltage threshold, amount of load, and delay before tripping. The objective of an effective load shedding scheme is to curtail a minimum amount of load, and provide a quick, smooth, and safe transition of the system from an emergency situation to a normal equilibrium state.

2.3 PERFORMANCE OF AGC UNDER NORMAL AND ABNORMAL CONDITIONS

Under normal conditions with each area able to carry out its control obligations, steady state corrective action of AGC is confined to the area where the deficit or excess of generation occurs. Inter area power transfers are maintained at scheduled levels and system frequency is held constant.

Four basic objectives of power system operation during normal operating conditions are associated with automatic generation control (AGC):

i) matching total system generation to total system load;

ii) regulating system electrical frequency error to zero;

iii) distributing system generation among control areas so that net area tie flows match net area tie flow schedules;

iv) distributing area generation among area generation sources so that area operating costs are minimized. [17]

Under abnormal conditions, one or more areas may be able to correct for the generation-load mismatch due to insufficient generation reserve on AGC. In such an event, other areas assist by permitting the inter areas power transfers to deviate from scheduled values and by allowing system frequency to depart from its pre disturbance value. Each area participates in frequency regulation in proportion to its available regulating capacity relative to that of overall system [10].

2.4 FREQUENCY RESPONSE MODEL AND AGC CHARACTERISTICS

To understand the variation of frequency in a power system, we can consider a single machine connected to an isolated load, as shown in the figure 2.5. The turbine mechanical power (P_m) and the electrical load power (Pl) are equal. Whenever there is a change in load, with mechanical power remaining the same the speed (ω) of the turbine generator changes as decided by the rotating inertia (M) of the rotor system, as given by the following differential equation..

$$P_m - P_l = M\,[d\omega/dt]$$

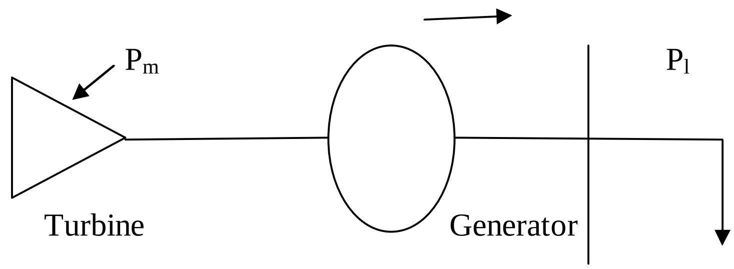


Figure2.5 : Single Turbine Generator with Load

In an interconnected power system the control area concept needs to be used for the sake of synthesis and analysis of the AGC system. The control area is a coherent area consisting of a group of generators and loads, where all the generators respond to changes in load or speed changer settings, in unison.

2.5 DROOP CHARACTERISTIC

The ratio of speed (frequency) change (Δf) to change in output-generated power (ΔP_g) is known as droop or speed regulation, and can be expressed as

$$R\ (\text{Hz/ puMW}) = \Delta f / \Delta P_g \qquad (2.1)$$

For example, a 5% droop means that a 5% deviation in nominal frequency causes a 100% change in output power. The interconnected generating units with different droop characteristics can jointly track the load change to restore the nominal system frequency. This is illustrated in Figure 2.6, representing two units with different droop characteristics connected to a common load.

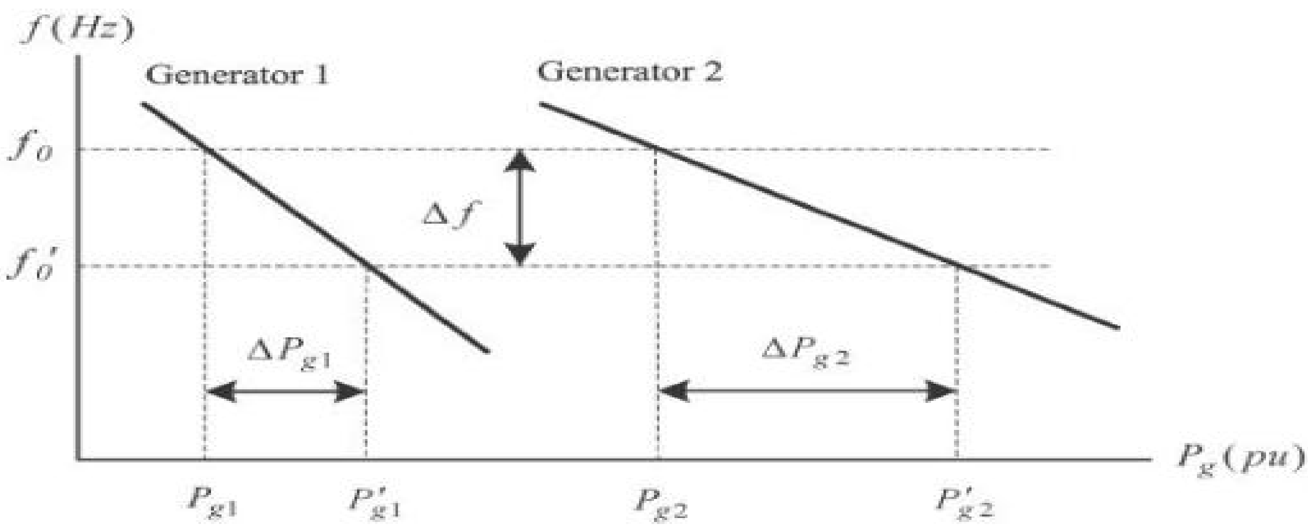


Figure 2.6: Load Tracking by Generators with Different Droops

2.6 LOAD FREQUENCY CONROL

A Load Frequency Control System (LFC) performs the function of controlling small and slow changes in real power load and frequency when a system is operating in the steady state and it maintains the net interchange of power between pool members.

2.6.1 Simulation of the Speed Governing System

The simulation of speed governing system is developed for small signal analysis around a nominal steady state operating condition. The schematic representation of the operating features of a Speed Governing System in Figure 2.7.

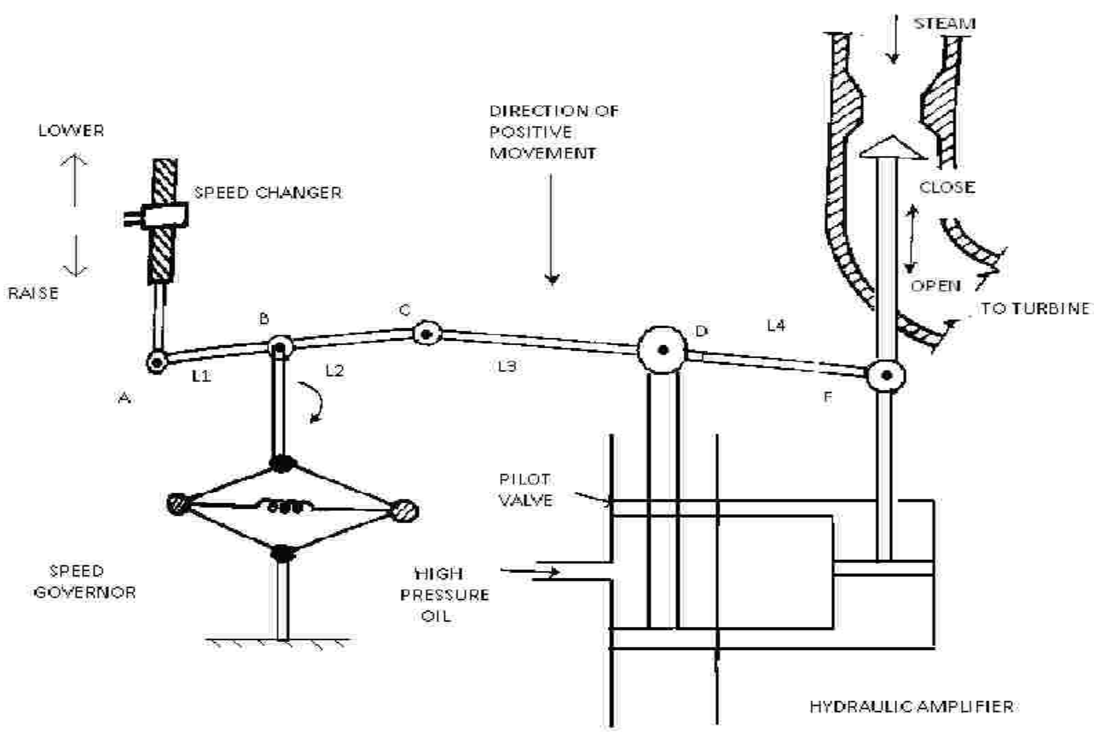


Figure 2.7: Schematic Representation of a Speed Governing System

The System has the following major components.

Speed Governor: It consists of centrifugal fly-balls driven directly or through gears by the turbine shaft and provide up and down vertical movement of linkage point proportional to the change in shaft speed.

Linkage Mechanism: The linkage arms L_1 and L_2 are stiffly coupled, and stiffly coupled, and so are arms L_3 and L_4. All five linkages points A, B, C, D, E are free. This mechanism provides movement to the turbine value through a hydraulic amplifier in proportion to change in shaft speed. Link arm L_4 provides a feedback from the turbine value movement.

Hydraulic Amplifier: Very large mechanical forces are needed to position the main valve against the high steam pressure, and these forces are obtained via several stages of hydraulic amplifiers.

Speed Changer: The speed changer consists of the servo-motor driven rotating vertical screw arrangement to move the linkage point A up and down. By adjusting the linkage point A, scheduled load at nominal frequency can be adjusted.

The change in position ΔY_A of point A corresponds to a change in reference power setting $\Delta P_{ref.}$ Similarly, ΔY_C corresponds to a change in valve position command ΔP_V, which changes the turbine power by $\Delta P_{T.}$

The operating conditions can be characterized by

f= System Frequency

$P°_G$ = Generator Power Output = Turbine Output

$Y°_G$ = Steam Valve Setting

The following sequence of events is assumed to occur.

1. A small downward movement of the speed changer is made, and the linkage point A moves downwards a small distance.
2. At this time no speed change has takes place, hence the point B is fixed. Thus, movement of linkage point A causes small upward movement of linkage points C and D by ΔY_C and $\Delta Y_{D,}$ respectively. This makes high pressure oil to flow through the upper pilot valve of the hydraulic amplifier on to the top of the main piston moving it downward and cause the steam valve to move download by ΔY_C resulting in an increase in the turbine power ΔP_T and consequently the generated power $\Delta P_{G.}$
3. The increased power ΔP_G causes a momentary surplus power in the system, and the frequency will rise slightly by Δf that will cause the linkage point B to move downward by ΔY_B proportional to Δf.

For small linkage movements, the following relationships can be written

$$\Delta Y_C = K_1 \Delta f - K_2 \Delta P_{ref} \quad (2.2)$$

$$\Delta K_3 = K_3 \Delta f - K_4 \Delta Pref \quad (2.3)$$

The constants K_1 and K_2 depend on the length of the linkage arms L_1 and L_2 upon the constants of the speed changer and the speed governor. The constants k_3 and k_4 depend on the lengths of the linkage L_3 and L_4.

The flow of oil into the hydraulic amplifier is proportional to incremental movement ΔY_D of the pilot valve; the volume of oil entering the cylinder is proportional to the time integral of ΔY_D. The movement ΔY_E can be obtained by dividing the oil volume by the cross-sectional area of the piston as follows:

$$\Delta Y_E = K_5 \int (-\Delta Y_D)\, dt \qquad (2.5)$$

Taking the Laplace Transform of Equation 2.2, 2.3 and 2.4, and eliminating ΔY_C and ΔY_D;

$$\Delta Y_E(s) = \frac{[K_2 K_3 \Delta P_{ref}(s) - K_1 K_3 \Delta f(s)]}{\left(K_4 + \frac{s}{K_5}\right)} \qquad (2.6)$$

Where

$\Delta Y_E(s)$, $\Delta P_{ref}(s)$, and $\Delta f(s)$ are Laplace Transforms of ΔY_E, ΔP_{ref}, and Δf, respectively.

Equation 2.5 may be rewritten in the following form

$$\Delta P_{ref}(s) - \frac{1}{R}\Delta F(s) = \Delta Y_E(s) \qquad (2.7)$$

$$\frac{K_{SG}}{1+sT_{SG}}\left[\Delta P_{ref}(s) - \frac{1}{R}\Delta F(s)\right] = \Delta Y_E(s) \qquad (2.8)$$

$$G_{SG}\left[\Delta P_{ref}(s) - \frac{1}{R}\Delta F(s)\right] = \Delta Y_E(s) \qquad (2.9)$$

Where;

$R = (k_2/k_1)$ is the speed regulation due to governor action;

$K_{SG} = k_2 k_3/k_4$ is the static gain of the speed governing mechanism;

$T_{SG} = 1/k_4 k_5$ is the time constant of the speed governing system; and

$G_{SG}(s)$ is the transfer function of the speed governing mechanism.

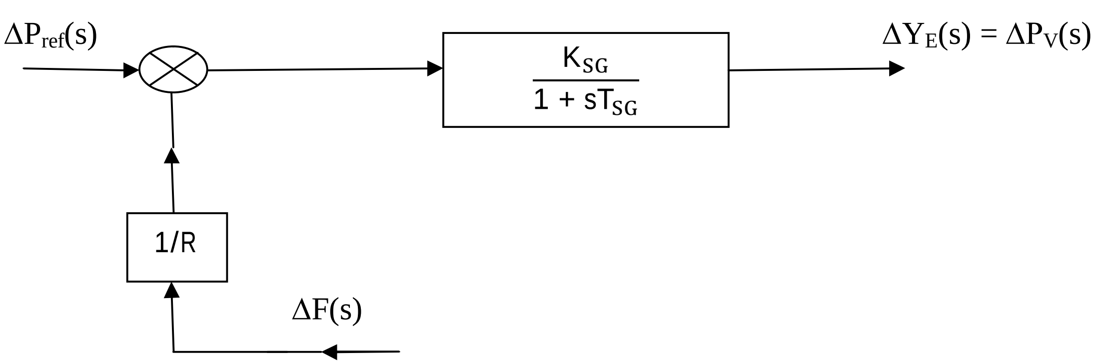


Figure 2.8: Block Diagram Representation of a Speed Governing System

2.6.2 Simulation of the Turbo-generator

When an electrical power system is operating in the steady state, there is an exact balance in the turbine power P_T and the generator electromechanical air gap power P_G. As a result, there is no acceleration and power is delivered at a constant speed or frequency. However, when a disturbance occurs, the balance between P_T and P_G is upset and the machine accelerates if ΔP_T is greater than ΔP_G and the machine will decelerate if ΔP_T is smaller than ΔP_G. The change in turbine power is dependent on the incremental valve power ΔP_V and the response characteristics of the turbine. A steam turbine may be represented by the transfer function of $G_T(s)$ as

$$G_T(s) = \frac{K_T}{1+sT_T} \qquad (2.3)$$

T_T is the time constant of the turbine and has a value in the range of 0.2 to 2s and K_T is the gain constant of the turbine.

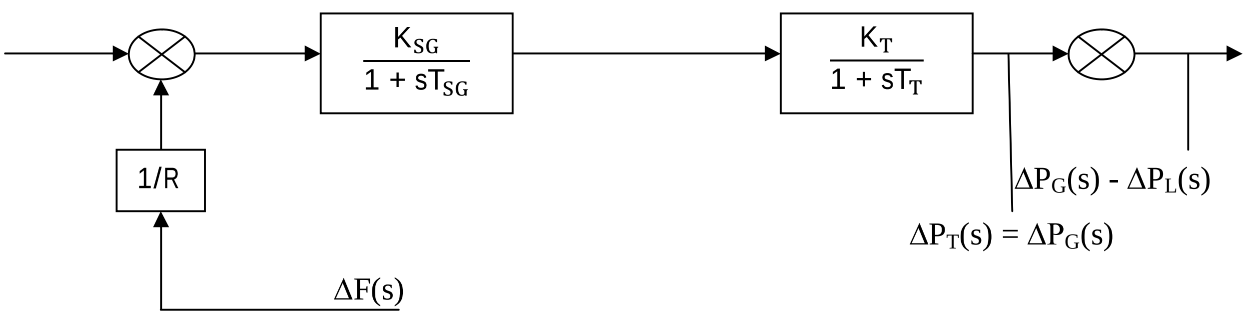


Figure 2.9: Transfer Function Representation of Power Control Mechanism of Generator

Any increase in the load demand ΔP_L on the generator is immediately met by a corresponding increase in the generated power $\Delta P_{G.}$ in comparison to the slow variation in turbine power, the adjustment of the generator output ΔP_G to load changes ΔP_L is considered to be instantaneous.

2.7 PERCEPTION OF CONTROL AREA

The load frequency control loop is considered to represent the whole system, if individual control loops have the same regulation parameter and individual turbine generators have the same response characteristics. Then, the control of the generators in the system is said to be in unison and the entire system is referred to as a control area. For purposes of developing a suitable control strategy, a control area can be reduced to a single speed governor, turbo-generator and load system.

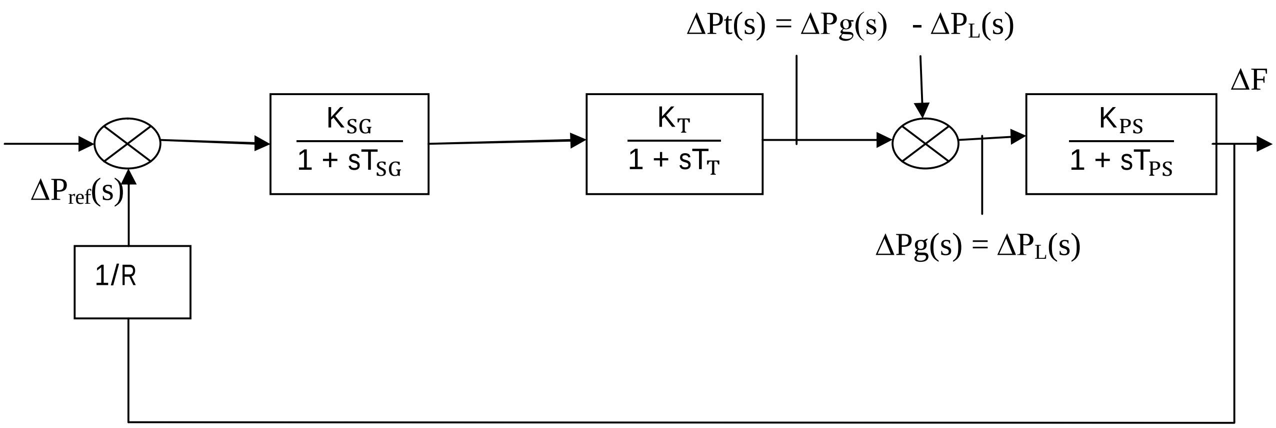


Figure 2.10: Primary Load Frequency Control Loop for Isolated Power System

2.8 INCREMENTAL POWER BALANCE OF CONTROL AREA

Under the domain of generator, a service area is to be supplied with power to feed an assortment of loads. It is assumed that the area experiences a real load change of $\Delta P_{L.}$ [3] Due to the action of a governor controlled mechanism, the generator power increases by $\Delta P_{G.}$ the surplus power will be accounted in three ways:

(i) By increasing the rate of rise of area kinetic energy W_{kin}

$$\frac{d}{dt}W_{kin} = \frac{d}{dt}[W_{kin} * \left(\frac{f}{f}*\right)^2]$$

$$= d/dt \; [W_{kin}*(1+2\,(\Delta f/f*)]$$

$$= 2\frac{W_{kin}*}{f*}\frac{d}{dt}(\Delta f) \qquad (2.8)$$

(ii) By an increased load compensation: all typical loads experience an increase in Load Frequency constant (D) with increase with speed or frequency;

(iii) By increasing the export of power, via tie lines, with the total amount ΔP_{tie} MW defined positive out from the area i:

$$\Delta P_{D\,i} - \Delta P_{G\,i} = 2\frac{W_{kin}*}{f*}\frac{d}{dt}(\Delta f) + Di\Delta f_i + \Delta P_{tie\,i} \qquad (2.9)$$

$$\Delta P_{D\,i} - \Delta P_{G\,i} = 2\frac{Hi}{f*}\frac{d}{dt}(\Delta f) + D_i \Delta f_i + \Delta P_{tie\,i} \qquad (2.10)$$

Where the inertia constant H_i is defined as

$$Hi = \frac{W_{kin\,i}*}{Pr\,i}\ MWs$$

The differential equation 2.10 is linear with constant coefficients and upon Laplace Transformation it takes on the form:

$$[\triangle P_{G\,i}(s) - \triangle P_{D\,i}(s) - \triangle\triangle P_{tie\,i}(s)]\frac{Kpi}{1+sTpi} = \triangle Fi(s) \quad (2.11)$$

And the following new parameters have been introduced:

$$T_{PS} \triangleq \frac{2H_i}{fD_i}$$

$$K_{ps} = 1/D \text{ Hz/pu MW} \quad (2.12)$$

2.9 ADDITION OF SECONDARY LOOP

In order to reduce the frequency deviation to zero, a reset action is achieved by the addition of an integral controller as the secondary control loop. In the secondary control loop, the frequency error signal, after amplification, is integrated with respect to time and is fed to the speed changer to change the speed set point as shown in Figure 2.11.

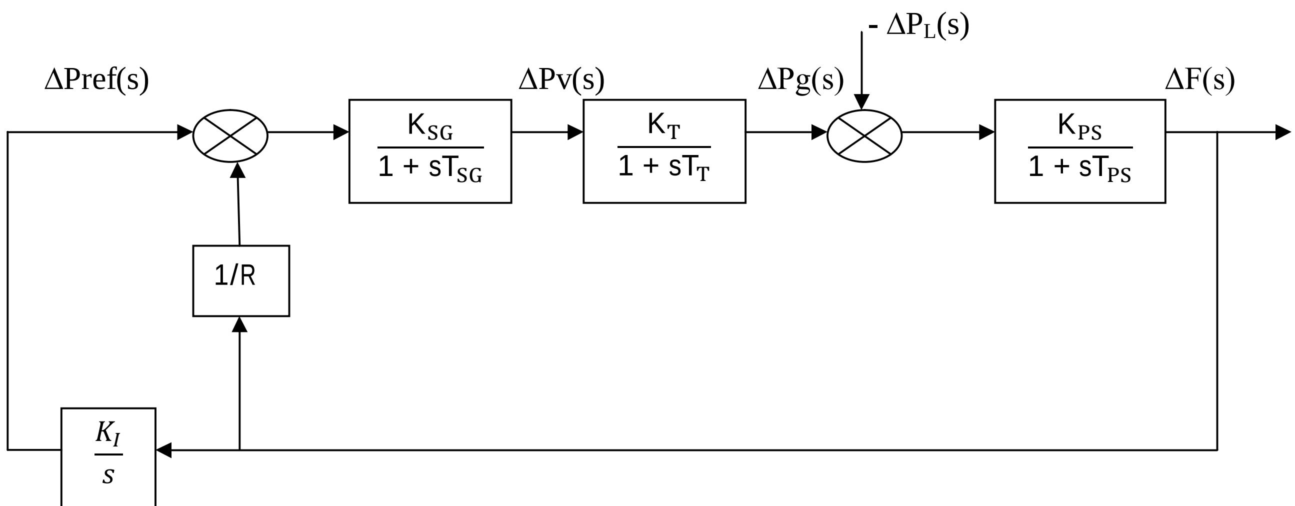


Figure 2.11: Addition of Integral (Secondary) Control Loop

Mathematically, the change in speed changer position due to integral control action may be expressed as

$$\Delta P_{ref} = - K_I \int \Delta f \, dt \quad (2.13)$$

Where K_I is the amplification factor or gain constant measured in puMW/s

2.10 AUTOMATIC GENERATION CONTROL IN A TWO AREA SYSTEM

A power system comprising of two control areas interconnected by a weak lossless tie-line is considered. Each control area is represented by an equivalent generating unit interconnected by a Tie-line with reactance X_{12}. Each area is represented by a voltage source behind an equivalent source reactance. Under steady state operation, the transfer of power over the Tie-line P_{12} can be written as

$$P_{12} = \frac{E_1 E_2}{X_{12}} \sin(\delta_1 - \delta_2) \quad (2.14)$$

Where E1 and E2 are the magnitudes of the end voltages of control areas 1 and 2 respectively, and δ1 and δ2 are the voltage angles of E1 and E2, respectively.

For a small change $\Delta\delta_1$ and $\Delta\delta_2$ in voltage angles, the change in Tie-line power, ΔP_{12} is shown as

$$P_{12} = \frac{E_1 E_2}{X_{12}} \cos(\delta_1 - \delta_2)\,(\Delta\delta_1 - \Delta\delta_2) \quad (2.15)$$

Where T_{12} is defined as the synchronizing coefficient and is given as

$$T_{12} = \frac{E_1 E_2}{X_{12}} \cos(\delta_1 - \delta_2) \quad (2.16)$$

Expressing Equation 2.14 in term of Δf, gives

$$\Delta P_{12}(s) = 2\pi T_{12}\,[\int \Delta f_1 dt - \int \Delta f_2 dt] \quad (2.17)$$

Taking Laplace Transform of Equation 2.17

$$\Delta P_{12}(s) = 2\pi T_{12}\,[\Delta F_1(s) - \Delta F_2(s)\,] \quad (2.18)$$

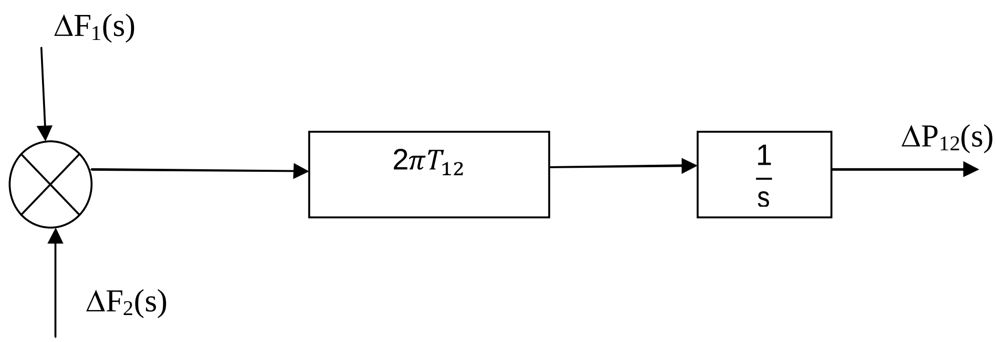


Figure 2.12: Block diagram of a tie line connecting two control areas 1 and 2

The power flow over the tie line from area 1 to area 2 is considered as positive. As the losses in the tie line are neglected, the transfer of power over the Tie-line is expressed as

$$\Delta P_{12} = -\Delta P_{21} \quad (2.19)$$

2.11 BLOCK DIAGRAM MODEL OF A TWO AREA SYSTEM

With the connection of the control area to another control area via a tie-line, the expression for transfer of power, Equation 2.19, is required to be incorporated into the power balance equation.

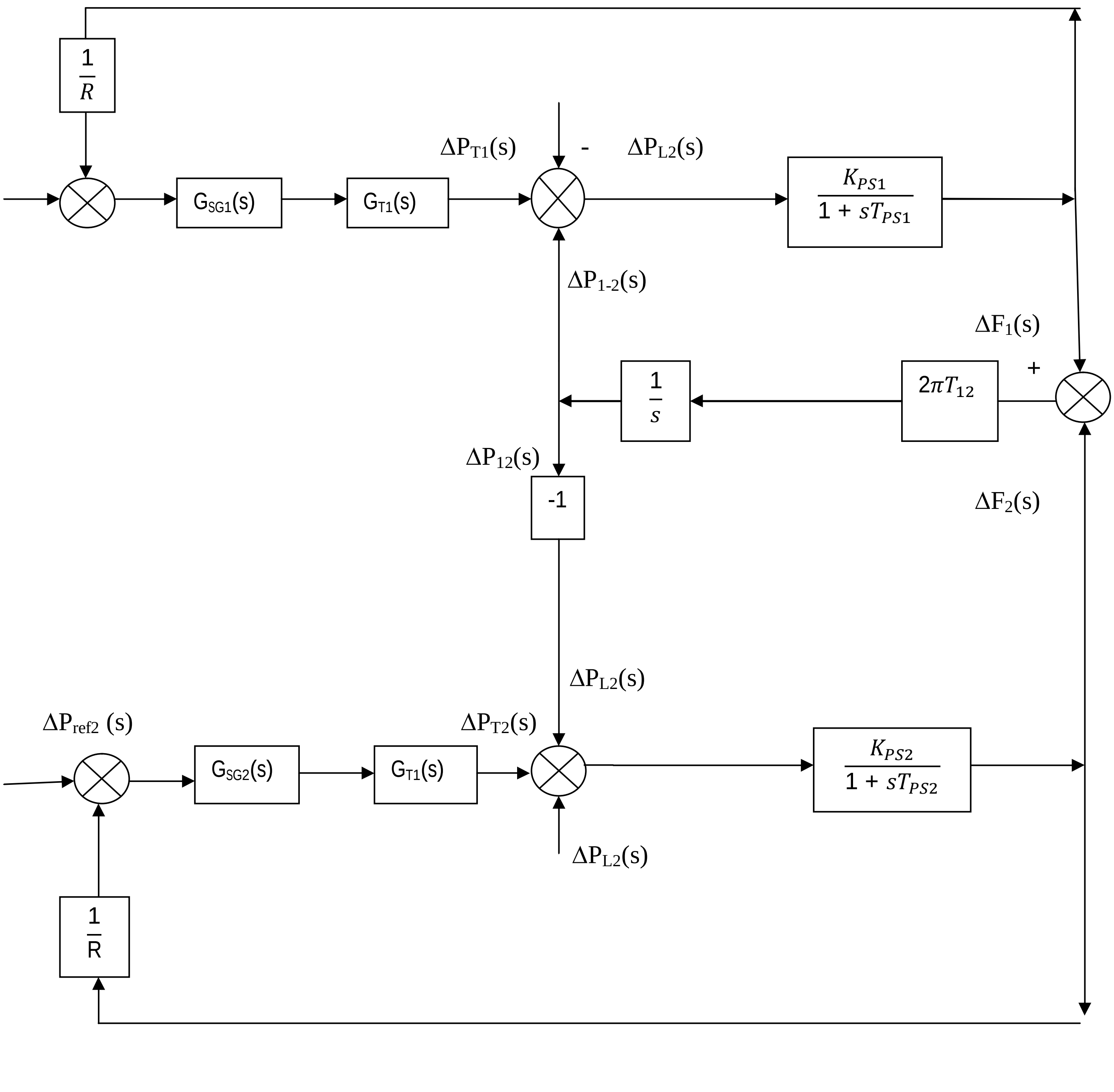


Figure 2.13 Block Diagram Simulation of a Two Area Control System

When two primary Load frequency loops are used to model the two control areas then these can be interconnected by the tie-line as shown in Fig. 2.13

2.12 TIE LINE BIAS CONTROL FOR TWO AREA SYSTEM

The control error for each area is a linear combination of tie-line power and frequency errors and can be expressed as shown

$ACE_1 = \Delta P_{1-2} + B_1\Delta f_1$ (2.13)

$ACE_2 = \Delta P_{2-1} + B_2\Delta f_2$ (2.14)

The signals to the respective speed changers will, therefore, be of the following type

$\Delta P_{ref\ 1} = -K_{I1}\int(\Delta P_{1-2} + B_1\Delta f_1)\, dt$ (2.15)

$\Delta P_{ref\ 1} = -K_{I1}\int(\Delta P_{1-2} + B_1\Delta f_1)\, dt$ (2.16)

Where B_1 and B_2 represent tie line bias parameters; and K_{I1} and K_{I2} are integrator gains.

2.13 TIE LINE BIAS CONTROL OF MULTI AREA SYSTEM

In order to write a mathematical expression for the tie line bias control, consider a control area designated as k and the net interchange f power is equal to the sum of power over all the j interconnecting tie-lines. The area control error (ACE) is indicative of the total interchange of power. Therefore, it is expressed in the following form:

$ACE_k = \Sigma(\Delta P_{ij} + B_k\Delta f_k)$ (2.17)

All the area generators which constitute the secondary LFC receive the ACE and initiate corrective action for restoring the tie-line power to its power interchange and frequency to its normal value.

CHAPTER 3
AGC IN DEREGULATED ENVIRONMENT

3.1 INTRODUCTION

The electricity market has experienced enormous setbacks in delivering on the promise of deregulation. In theory, deregulating the electricity market would increase the efficiency of the industry by producing electricity at lower costs and passing those cost savings on to customers. [22]. For the electric industry, deregulation means the generation portion of electricity service will be open to competition. However, the transmission and distribution of the electricity will remain regulated and our local utility company will continue to distribute electricity to us and provide customer services to us. [23] The generation of electricity is being deregulated, which means we will have the opportunity to shop around for the electricity generation supplier of choice.

3.1.1 Requirements of Deregulation: The requirements of deregulation are:

(i) Good operations, planning and market design engineers.
(ii) Supply and fuel diversity.
(iii) Sufficient transmission infrastructure.
(iv) Efficient demand side responsiveness and management.
(v) Provision of right incentives and good price signals.

3.1.2 Benefits 0f Deregulation: The benefits of Deregulation include

(i) It involves issue of survival of the fittest i.e. efficient units live and others perish.
(ii) Cheaper electricity through competition and innovation.
(iii) Improves generation and planning efficiency and economy.
(iv) Revitalization of the power engineering profession means increased job and challenging opportunities.

3.2 GENERAL CONFIGURATION OF AUTOMATIC CONTROL GENERATION IN A DEREGULATED ENVIRONMENT

General configuration for the Automatic Generation Control (AGC) system in a deregulated environment is shown in Figure 3.1. The Generating Companies

(GENCO's) send the bid regulating reserves to the AGC center through a secure network service. These bids are sorted by a pre-specified time period and price. Then, the sorted regulating reserves with the demanded load from Discos, the tie-line data from Transco, and the area frequency are used to provide control commands to track the area load changes. The bids are checked and re-sorted according to the received congestion information (from Transco) and screening of available capacity (collected from Gencos).

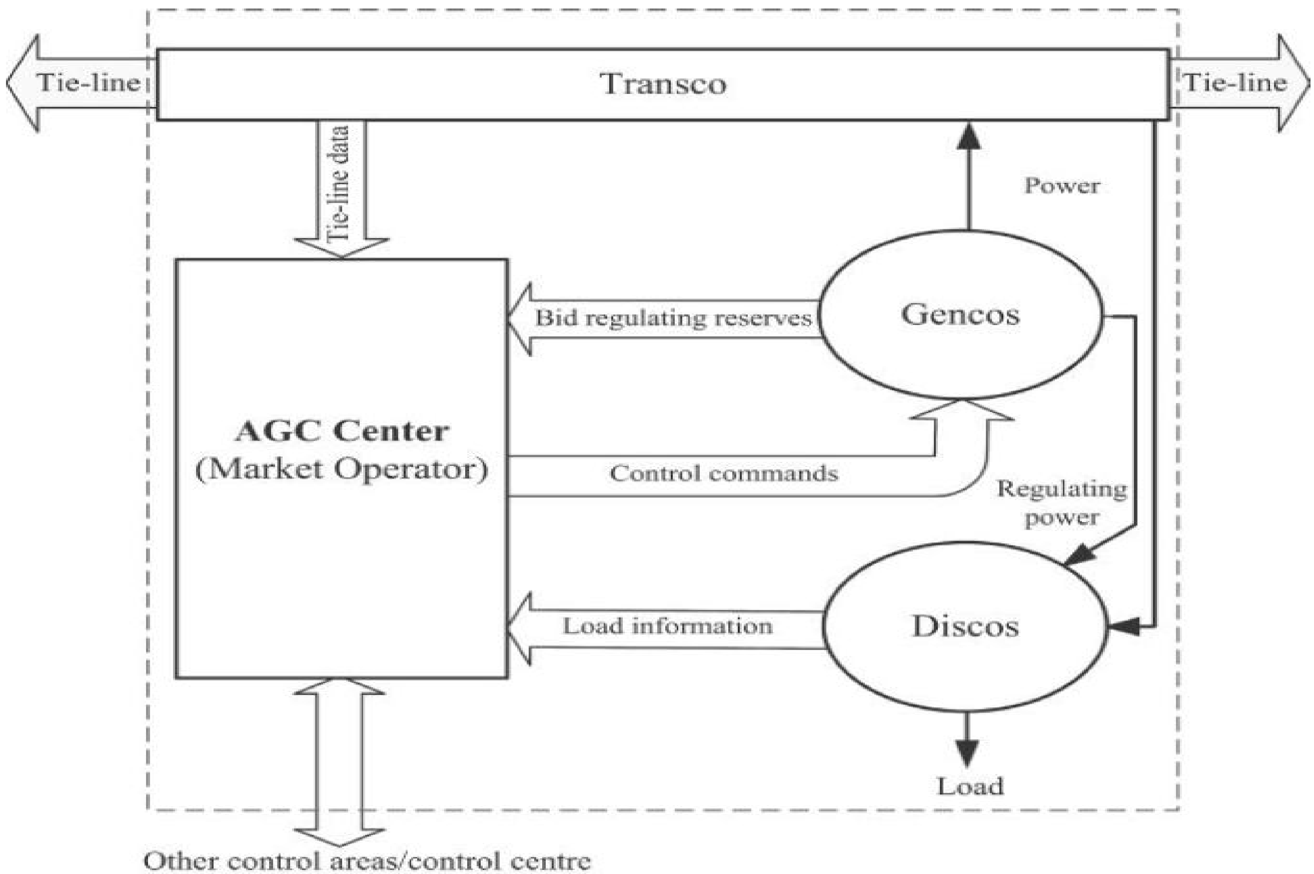


Figure 3.1: AGC configuration in deregulated environment.

3.3 DISCO PARTICIPATION MATRIX

The participation factor indicates the amount of participation of a generator unit in the Automatic Generation Control (AGC) system. Following a load disturbance within the control area, the produced appropriate supplementary control signal is distributed among generator units in proportion to their participation, to make generation follow the load. In a given control area, the sum of participation factors is equal to 1.

In a competitive environment, AGC participation factors are actually time dependent variables and must be computed dynamically by an independent organization based on bid prices, availability, congestion problems, costs, and other related issues.

In the restructured environment, Generating Companies (GENCOs) sell power to various Distributing Companies (DISCOs) at competitive prices. Thus, DISCOs have the liberty to choose the GENCOs for contracts. They may or may not have contracts with the GENCOs in their own area. This makes various combinations of GENCO-DISCO contracts possible in practice. The concept of a “DISCO participation matrix” (DPM) is introduced to make the visualization of contracts easier [9]. DPM is a matrix with the number of rows equal to the number of GENCOs and the number of columns equal to the number of DISCOs in the system. Each entry in this matrix can be thought of as a fraction of a total load contracted by a DISCO (column) toward a GENCO (row). Thus, the entry corresponds to the fraction of the total load power contracted by DISCO from a GENCO. The sum of all the entries in a column in this matrix is unity. DPM shows the participation of a DISCO in a contract with a GENCO; hence the name “DISCO participation matrix.”

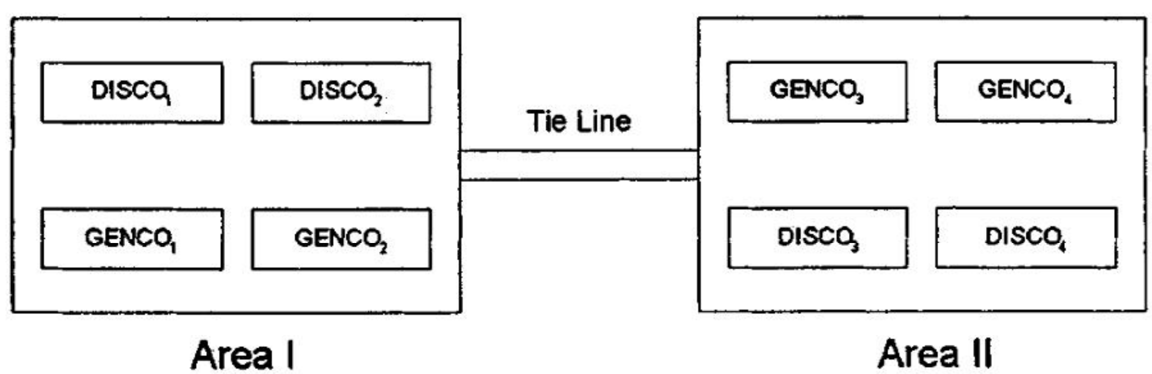


Figure 3.2: Schematic of a Two-Area System in Restructured Environment.

3.4 FORMULATION OF STATE MODEL

The formulation of the block diagram for a two-area AGC system in the deregulated scenario is shown in Figure 3.3. Whenever a load demanded by a DISCO changes, it is reflected as a local load in the area to which this DISCO belongs. This corresponds to the local loads ΔP_{L1} and ΔP_2 and should be reflected in the deregulated AGC system block diagram at the point of input to the power system block. As there are many GENCOs in each area, ACE signal has to be distributed among them in proportion to their participation in the AGC. Coefficients that distribute ACE to several GENCOs are termed as "ACE participation factors" Unlike in the traditional AGC system; a DISCO asks/demands a particular GENCO or GENCOs for load power. These demands must be reflected in the dynamics of the system. Turbine and governor units must respond to this power demand. Thus, as a particular set of GENCOs are supposed to follow the load demanded by a DISCO, information signals must flow from a DISCO to a particular GENCO specifying corresponding demands. Here, we introduce the information signals which were absent in the traditional scenario. The demands are specified by Contract Participation Factor (elements of *DPM*) and the puMW load of a DISCO. These signals carry information as to which GENCO has to follow a load demanded by which DISCO.

The scheduled steady state power flow on the tie line is given as

$\Delta P_{tie1\text{-}2,scheduled}$ = (demand of DISCOs in area II from GENCOs in area I) - (demand of DISCOs in area I from GENCOs in area II)

At any given time, the tie line power error, $\Delta P_{tie1\text{-}2,error}$ is defined as

$$\Delta P_{tie\ 1-2,error} = \Delta P_{tie\ 1-2,actual} - \Delta P_{tie\ 1-2,scheduled} \quad (3.1)$$

$\Delta P_{tie1\text{-}2,error}$ vanishes in the steady state as the actual tie line power flow reaches the scheduled power flow. This error signal is used to generate the respective ACE signals as in the traditional scenario

$$ACE_1 = B_1\Delta f_1 + \Delta P_{tie\ 1-2,error} \quad (3.2)$$

$$ACE_2 = B_2\Delta f_2 + \Delta P_{tie\ 2-1,error} \quad (3.3)$$

Where

$$\Delta P_{tie\ 1-2,error} = -\frac{P_{r1}}{P_{r2}}\Delta P_{tie\ 1-2,error} \quad (3.4)$$

P_{r1} and P_{r2} are the rated powers of areas I and II, respectively.

Therefore

$$ACE_1 = B_1\Delta f_1 + \alpha_{12}\Delta P_{tie\ 1-2,error} \quad (3.5)$$

$$\alpha_{12} = -\frac{P_{r1}}{P_{r2}}$$

The block diagram for AGC in a deregulated system is shown in Fig. 3.3. Structurally it is based upon the idea of [1], [2]. The local loads in areas I and II are denoted by $\Delta P_{L1,Loc}$ and $\Delta P_{L2,Loc}$, respectively.

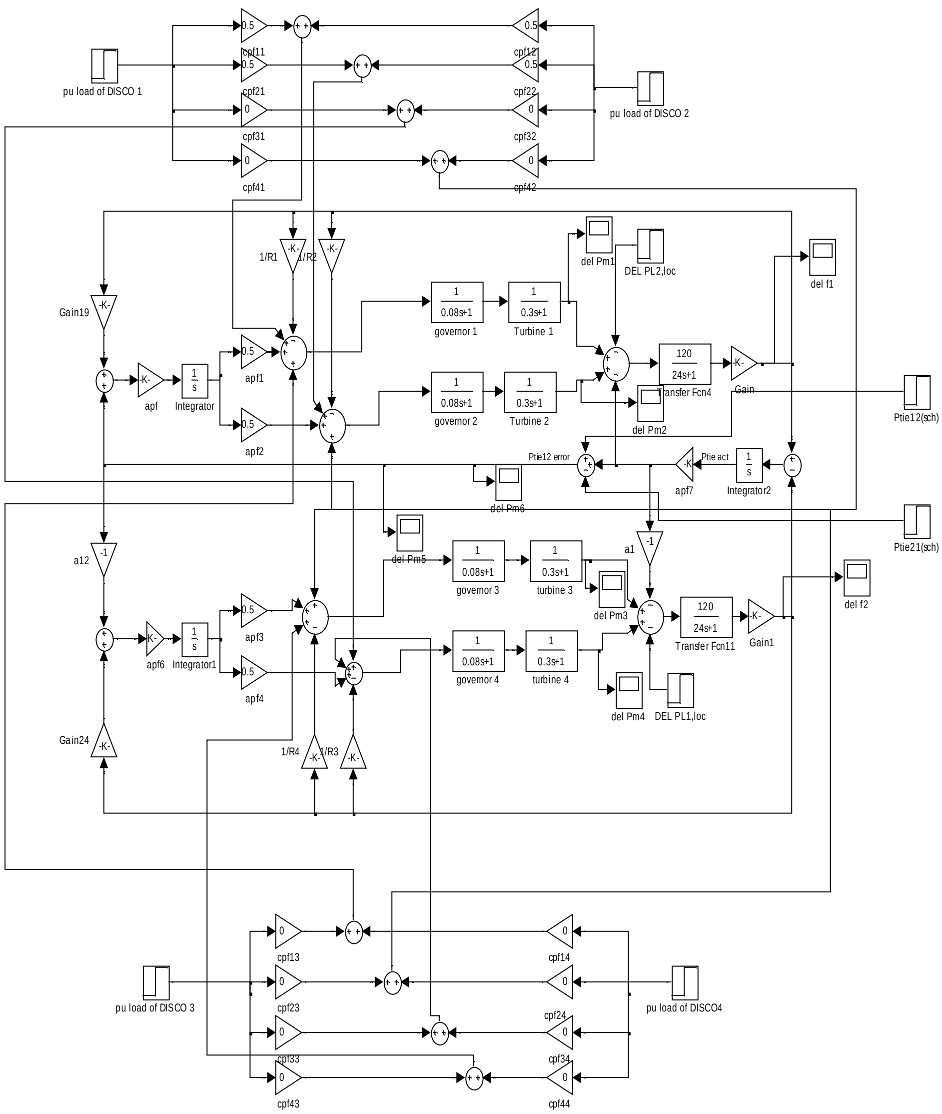


Figure 3.3: Two-Area AGC System Block Diagram in Restructured Scenario.

3.5 STATE SPACE CHARACTERIZATION OF THE TWO-AREA SYSTEM IN DEREGULATED ENVIRONMENT

A two-area system is used to illustrate the behavior of the proposed AGC scheme. The same data as in [3], [4] is used for simulations. Both the areas are assumed to be identical. The governor-turbine units in each area are assumed to be identical. Before presenting the optimal design, the formulation of state model is done. It is achieved by writing the differential equations describing each individual block of Figure 3.3 in terms of state variables. Considering the state space vectors;

$x_1 = \Delta w_1$

$x_2 = \Delta w_2$

$x_3 = \Delta P_{GV1}$

$x_4 = \Delta P_{GV2}$

$x_5 = \Delta P_{GV3}$

$x_6 = \Delta P_{GV4}$

$x_7 = \Delta P_{M1}$

$x_8 = \Delta P_{M2}$

$x_9 = \Delta P_{M3}$

$x_{10} = \Delta P_{M4}$

$x_{11} = \int ACE_1 \, dt$

$x_{12} = \int ACE_2 \, dt$

$x_{13} = \Delta P_{tie\ 1-2}$

$$x_1 = (\Delta P_{L1,Loc} - x_3 + x_4)\frac{K_{P1}}{1 + sT_{P1}}$$

$$\dot{x_1} = \frac{1}{T_{P1}}x_1 - \frac{K_{P1}}{T_{P1}}x_3 + \frac{K_{P1}}{T_{P1}}x_4 - \Delta P_{L1,Loc}\frac{K_{P1}}{T_{P1}} \quad (3.6)$$

$$x_2 = (\Delta P_{L2,Loc} - a_{12}x_3 + x_6)\frac{K_{P2}}{1 + sT_{P2}}$$

$$\dot{x_2} = \frac{1}{T_{P2}}x_1 - a_{12}\frac{K_{P2}}{T_{P2}}x_3 + \frac{K_{P2}}{T_{P2}}x_6 - \Delta P_{L1,Loc}\frac{K_{P2}}{T_{P2}} \quad (3.7)$$

$$x_3 = \frac{1}{1 + sT_{T1}}x_4$$

$$\dot{x_3} = \frac{1}{T_{T1}}(x_4 - x_3) \quad (3.8)$$

$$x_4 = \frac{1}{1 + sT_{T2}} x_5$$

$$\dot{x_4} = \frac{1}{T_{T2}} (x_5 - x_4) \quad (3.9)$$

$$x_5 = \frac{1}{1 + sT_{T3}} x_6$$

$$\dot{x_5} = \frac{1}{T_{T3}} (x_6 - x_5) \quad (3.10)$$

$$x_6 = \frac{1}{1 + sT_{T4}} x_7$$

$$\dot{x_6} = \frac{1}{T_{T4}} (x_7 - x_6) \quad (3.11)$$

$$\dot{x_7} = -\frac{x_1}{T_{G1}R_1} - \frac{x_5}{T_{G1}} + (-K_1 apf_1)\frac{1}{T_{G1}} \quad (3.12)$$

$$\dot{x_8} = -\frac{x_1}{T_{G2}R_2} - \frac{x_6}{T_{G2}} + (-K_1 apf_2)\frac{1}{T_{G2}} \quad (3.13)$$

$$\dot{x_9} = -\frac{x_2}{T_{G3}R_2} - \frac{x_7}{T_{G3}} + (-K_2 apf_3)\frac{1}{T_{G3}} \quad (3.14)$$

$$\dot{x_{10}} = -\frac{x_2}{T_{G4}R_2} - \frac{x_8}{T_{G4}} + (-K_2 apf_4)\frac{1}{T_{G4}} \quad (3.15)$$

$$\dot{x_{11}} = B_1 x_1 + x_{13} \quad (3.16)$$

$$\dot{x_{12}} = B_2 x_2 + a_{12} x_{13} \quad (3.17)$$

$$\dot{x_{13}} = \frac{T_{12}}{2\pi} (x_1 - x_2) \quad (3.18)$$

The thirteen equations from (3.6) to (3.18) can be organized in the following vector matrix form. The closed loop system in Fig. 3.3 is characterized in state space form as

$$\frac{dx}{dy} = A^{cl} + B^{cl} \quad (3.19)$$

where 'x' is the state vector and u is the vector of power demands of the Disco's. 'A^{cl}' and 'B^{cl}' matrices are constructed from Fig. 3.3.

A^{cl}	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
1	$-1/T_{P1}$	0	K_{P1}/T_{P1}	K_{P1}/T_{P1}	0	0	0	0	0	0	0	0	K_{P1}/T_{P1}
2	0	$-1/T_{P2}$	0	0	K_{P2}/T_{P2}	K_{P2}/T_{P2}	0	0	0	0	0	0	K_{P2}/T_{P2}
3	0	0	$-1/T_{T1}$	0	0	0	$1/T_{T1}$	0	0	0	0	0	0
4	0	0	0	-	0	0	0	$1/T_{T2}$	0	0	0	0	0

				$1/T_{T2}$									
5	0	0	0	0	$-1/T_{T3}$	0	0	0	$1/T_{T3}$	0	0	0	0
6	0	0	0	0	0	$-1/T_{T4}$	0	0	0	$1/T_{P4}$	0	0	0
7	$-1/2\pi R_1 T_{G1}$	0	0	0	0	0	$1/T_{G1}$	0	0	0	$-K_1 apf_1/T_{G1}$	0	0
8	$-1/2\pi R_1 T_{G1}$	0	0	0	0	0	0	$-1/T_{G2}$	0	0	$-K_1 apf_1/T_{G1}$	0	0
9	0	$-1/2\pi R_1 T_{G1}$	0	0	0	0	0	0	$-1/T_{G3}$	0	0	$-K_1 apf_1/T_{G1}$	0
10	0	$1/2\pi R_1 T_{G1}$	0	0	0	0	0	0	0	$-1/T_{G4}$	0	$-K_1 apf_1/T_{G1}$	0
11	$B_1/2\pi$	0	0	0	0	0	0	0	0	0	0	0	1
12	0	$B_2/2\pi$	0	0	0	0	0	0	0	0	0	0	-1
13	$T_{12}/2\pi$	$-T_{12}/2\pi$	0	0	0	0	0	0	0	0	0	0	0

B^{cl}	1	2	3	4
1	$-K_{P1}/T_{P1}$	$-K_{P1}/T_{P1}$	0	0
2	0	0	K_{P2}/T_{P2}	K_{P2}/T_{P2}
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	Cpf_{11}/T_{G1}	Cpf_{12}/T_{G1}	Cpf_{13}/T_{G1}	Cpf_{14}/T_{G1}
8	Cpf_{21}/T_{G2}	Cpf_{22}/T_{G2}	Cpf_{23}/T_{G2}	Cpf_{24}/T_{G2}
9	Cpf_{31}/T_{G3}	Cpf_{32}/T_{G3}	Cpf_{33}/T_{G3}	Cpf_{34}/T_{G3}
10	Cpf_{41}/T_{G4}	Cpf_{42}/T_{G4}	Cpf_{43}/T_{G4}	Cpf_{44}/T_{G4}
11	$Cpf_{31}+cpf_{41}$	$Cpf_{32}+cpf_{42}$	$-(Cpf_{13}+cpf_{23})$	$-(Cpf_{14}+cpf_{24})$
12	$-(Cpf_{31}+cpf_{41})$	$-(Cpf_{32}+cpf_{42})$	$Cpf_{13}+cpf_{23}$	$Cpf_{14}+cpf_{24}$
13	0	0	0	0

$U = [\Delta P_{L1}\ \Delta P_{L2}\ \Delta P_{L3}\ \Delta P_{L4}]^T$

$X = [\Delta w_1\ \Delta w_2\ \Delta P_{GV1}\ \Delta P_{GV2}\ \Delta P_{GV3}\ \Delta P_{GV4}\ \Delta P_{M1}\ \Delta P_{M2}\ \Delta P_{M3}\ \Delta P_{M4}\ \int ACE_1\ \int ACE_2\ \Delta P_{tie1\text{-}2}]^T$

For this study the following system data is used:

TABLE I

SYSTEM DATA

$P_{r1} = P_{r2}$	2000 MW
$H_1 = H_2$	5 seconds
$D_1=D_2$	$8.33 * 10^{-3}$pu MW/Hz
$T_{T1}=T_{T2}$	0.3 seconds
$T_{G1}=T_{G2}$	0.08 seconds
R_1	2.4 Hz/ pu MW
$P_{tie\ max}$	200 MW
$\delta_1^* - \delta_2^*$	30 Degrees
T_{12}^*	0.545 pu MW/Hz
ΔP_{d1}	0.01 pu MW

Substituting the nominal values from Table I, we get the matrices A^{cl} & B^{cl} and vector of power demands of the DISCO's.

A^{cl}	1	2	3	4	5	6	7	8	9	10	11	12	13
1	-0.008	0	0.167	0.167	0	0	0	0	0	0	0	0	-0.167
2	0	-0.008	0	0	0.1667	0.1677	0	0	0	0	0	0	0.167
3	0	0	-3.33	0	0	0	3.33	0	0	0	0	0	0
4	0	0	0	-3.33	0	0	0	3.33	0	0	0	0	0
5	0	0	0	0	-3.33	0	0	0	3.33	0	0	0	0
6	0	0	0	0	0	-3.33	0	0	0	3.33	0	0	0
7	-0.829	0	0	0	0	0	-12.5	0	0	0	-4.115	0	0
8	-0.829	0	0	0	0	0	0	-12.5	0	0	-4.115	0	0
9	0	-0.829	0	0	0	0	0	0	-12.5	0	0	-4.115	0

10	0	0.829	0	0	0	0	0	0	0	-12.5	0	-4.115	0
11	0.069	0	0	0	0	0	0	0	0	0	0	0	1
12	0	0.069	0	0	0	0	0	0	0	0	0	0	-1
13	0.0136	-0.013	0	0	0	0	0	0	0	0	0	0	0

B^{cl}	**1**	**2**	**3**	**4**
1	-0.1667	-0.1667	0	0
2	0	0	-0.1667	-0.1667
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	6.25	3.125	0	3.75
8	2.5	3.125	0	0
9	0	3.125	12.5	0
10	0	3.125	0	17.857
11	0.3	0.5	0	-0.3
12	-0.3	-0.5	0	0.3
13	0	0	0	0

U = [0.1 0.1 0.1 0.1 0 0 0 0]

3.6 SIMULATION RESULTS OF A TWO- AREA SYSTEM IN A DEREGULATED ENVIRONMENT

3.6.1 Scenario I

Consider a case where the GENCOs in each area participate equally in AGC; i.e., ACE participation factors are

apf_1=0.5,

apf_2=1-apf_1= 0.5,

apf_3= 0.5,

apf_4=1-apf_3=0.5.

it is assumed that the load change occurs only in area I. Thus, the load is demanded only by $DISCO_1$ and $DISCO_2$. Let the value of this load demand be 0.1 pu MW for each of them.

$$DPM = \begin{matrix} cpf_{11} & cpf_{12} & cpf_{13} & cpf_{14} \\ cpf_{21} & cpf_{22} & cpf_{23} & cpf_{24} \\ cpf_{31} & cpf_{32} & cpf_{33} & cpf_{34} \\ cpf_{41} & cpf_{42} & cpf_{43} & cpf_{44} \end{matrix} \qquad (3.20)$$

The corresponding Disco Participation Matrix will become

$$DPM = \begin{bmatrix} 0.5 & 0.5 & 0 & 0 \\ 0.5 & 0.5 & 0 & 0 \\ 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 \end{bmatrix}$$

Note that $DISCO_3$ and $DISCO_4$ do not demand power from any GENCOs, and hence the corresponding participation factors (columns 3 and 4) are zero.

Fig. 3.4 shows the results of this load change: area frequency deviations, actual power flow on the tie line (in a direction from area I to area II), and the generated powers of various GENCOs, following a step change in the load demands of $DISCO_1$ and $DISCO_2$. The frequency deviation in each area goes to zero in the steady state. As only the DISCOs in area I, *viz.* $DISCO_1$ and $DISCO_2$, have nonzero load demands, the transient dip in frequency of area I is larger than that of area II.

Since the off diagonal blocks of DPM are zero, i.e., there are no contracts of power between a GENCO in one area and a DISCO in another area, the scheduled steady state power flow over the tie line is zero. The actual power on the tie line goes to zero. In the steady state, generation of a GENCO must match the demand of the DISCOs in contract with it. This desired generation of a GENCO in pu MW can be expressed in terms of Contract Participation Factor (cpf's) and the total demand of DISCOs as

$$\Delta P_{Mi} = \sum_j cpf_{ij} \Delta P_{Lj} \qquad (3.21)$$

where ΔP_{Lj} is the total demand of DISCO j and cpfs are given by DPM. In the two area case,

$$\Delta P_{Mi} = cpf_{i1}\Delta P_{L1} + cpf_{i2}\Delta P_{L2} + cpf_{i3}\Delta P_{L3} + cpf_{i4}\Delta P_{L4} \qquad (3.22)$$

For the case under consideration, we have

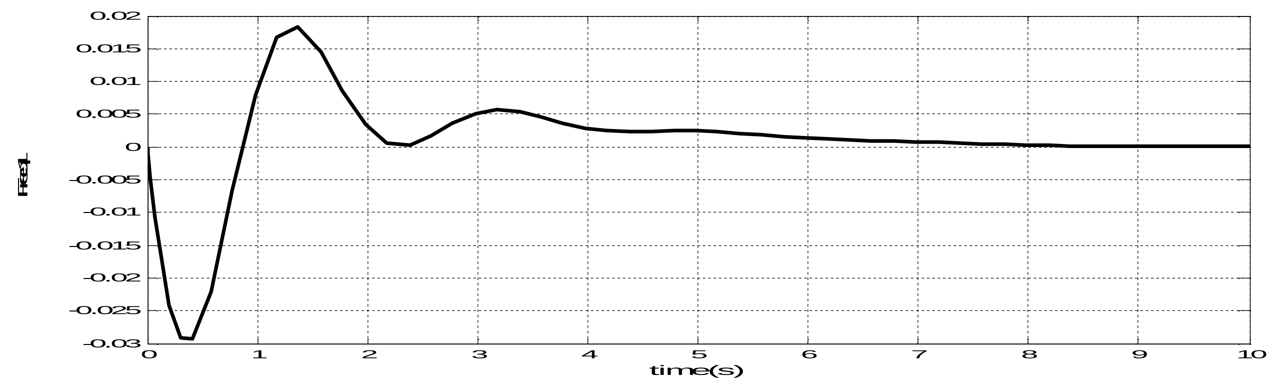
$\Delta P_{M1} = 0.5 * \Delta P_{L1} + 0.5 * \Delta P_{L2}$

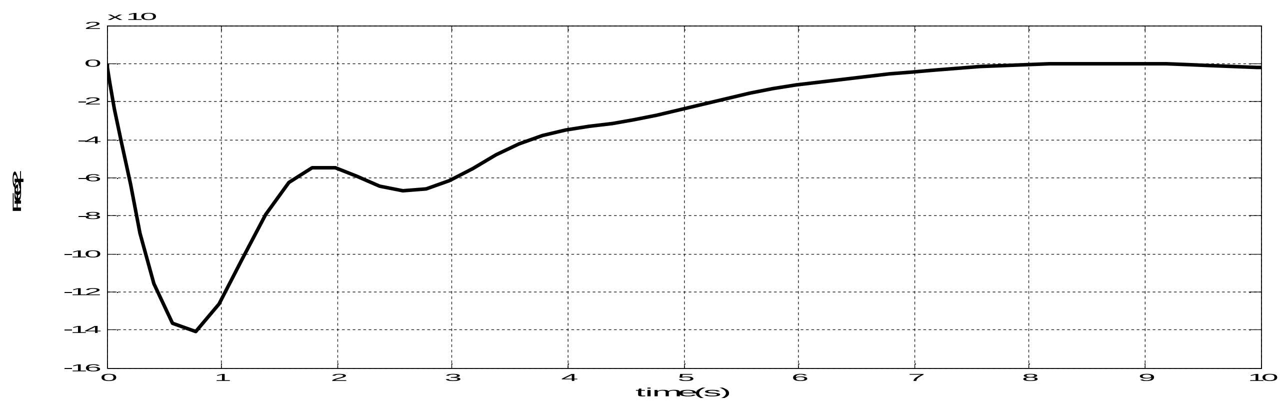
$= 0.1$puMW

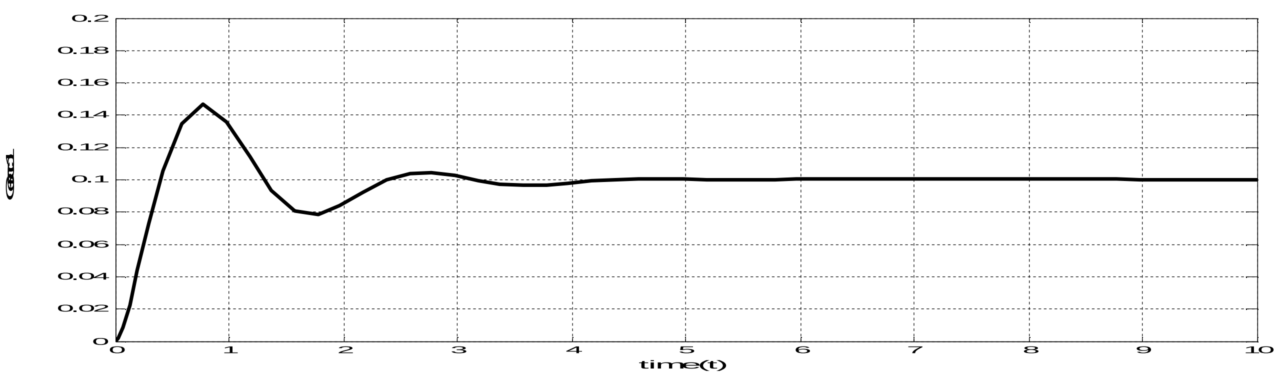
And Similarly,

$\Delta P_{M2} = 0.1$ pu MW; $\Delta P_{M3} = 0$ pu MW; $\Delta P_{M4} = 0$ pu MW

$GENCO_3$ and $GENCO_4$ are not contracted by any DISCO for a transaction of power; hence, their change in generated power is zero in the steady state.







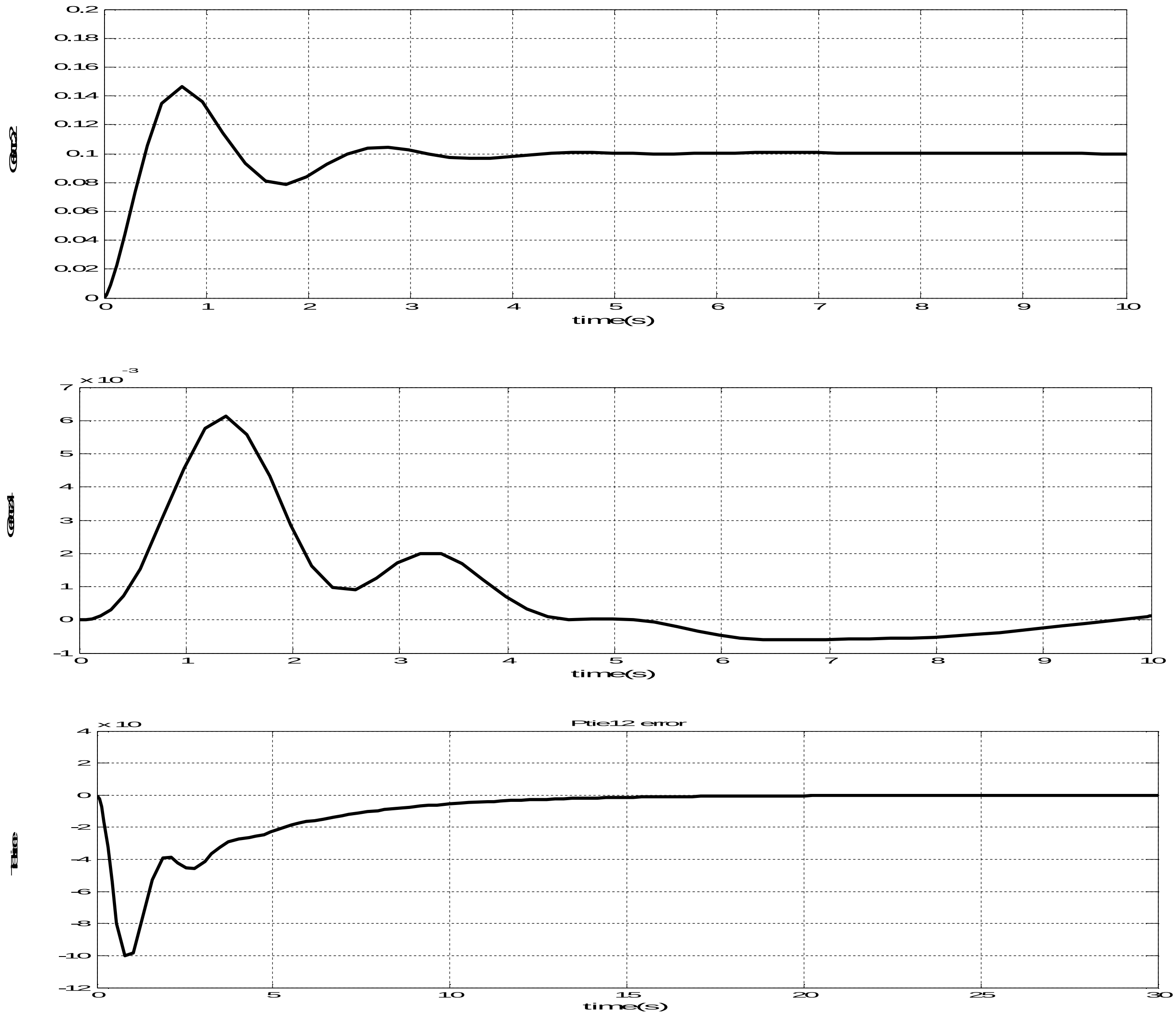


Figure 3.4: Frequency Deviations (rad/s) and Generated Power (pu MW)

3.6.2 Scenario II

Consider a case where all the DISCOs contract with the GENCOs for power as per the following DPM:

$$DPM = \begin{matrix} 0.5 & 0.25 & 0 & 0.3 \\ 0.2 & 0.25 & 0 & 0 \\ 0 & 0.25 & 1 & 0.7 \\ 0.3 & 0.25 & 0 & 0 \end{matrix}$$

It is assumed that each DISCO demands 0.1 pu MW power from GENCOs as defined by Contract Participation Factor in DPM matrix and each GENCO participates in AGC as defined by following ACE Participation Factors (apfs) are

apf_1=0.75;

apf_2=1-apf_1= 0.25;

apf_3= 0.5;

apf_4=1-apf_3=0.5

ACE participation factors affect only the transient behavior of the system and not the steady state behavior when subcontracted loads are absent.

The system in Fig. 3.3 is simulated using the data shown in Table I and the results are depicted in Fig. 3.5. The off diagonal blocks of the DPM correspond to the contract of a DISCO in one area with a GENCO in another area. From Eq. (3.20), the scheduled power on the tie line in the direction from area I to area II is

$$\Delta P_{tie\ 1-2,scheduled} = \sum_{i=1}^{2} \sum_{j=3}^{4} cpf_{ij}\, \Delta P_{Lj} - \sum_{i=3}^{4} \sum_{j=1}^{2} cpf_{ij}\, \Delta P_{Lj}$$

Hence, $\Delta P_{tie\ 1-2,scheduled}$ = -0.05pu MW

Fig. 3.5 shows the actual power on the tie line. It is to be observed that it settles to 0.05 pu MW, which is the scheduled power on the tie line in the steady state.

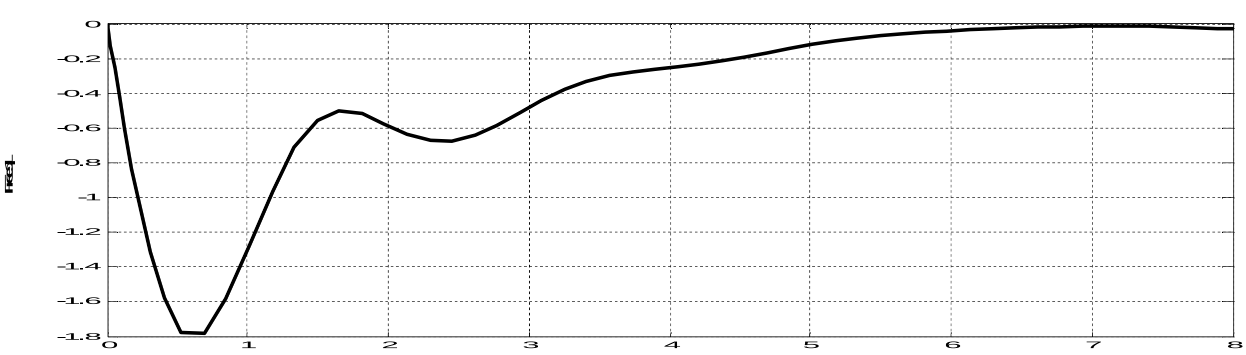
As given by (3.22), in the steady state, the GENCOs must Generate

ΔP_{M1} = 0.5 (0.1) + 0.25(0.1) + 0 + 0.3(0.1) = 0.105 pu MW

ΔP_{M2} = 0.045 pu MW;

ΔP_{M3} = 0.195 pu MW;

ΔP_{M4} = 0.055 pu MW



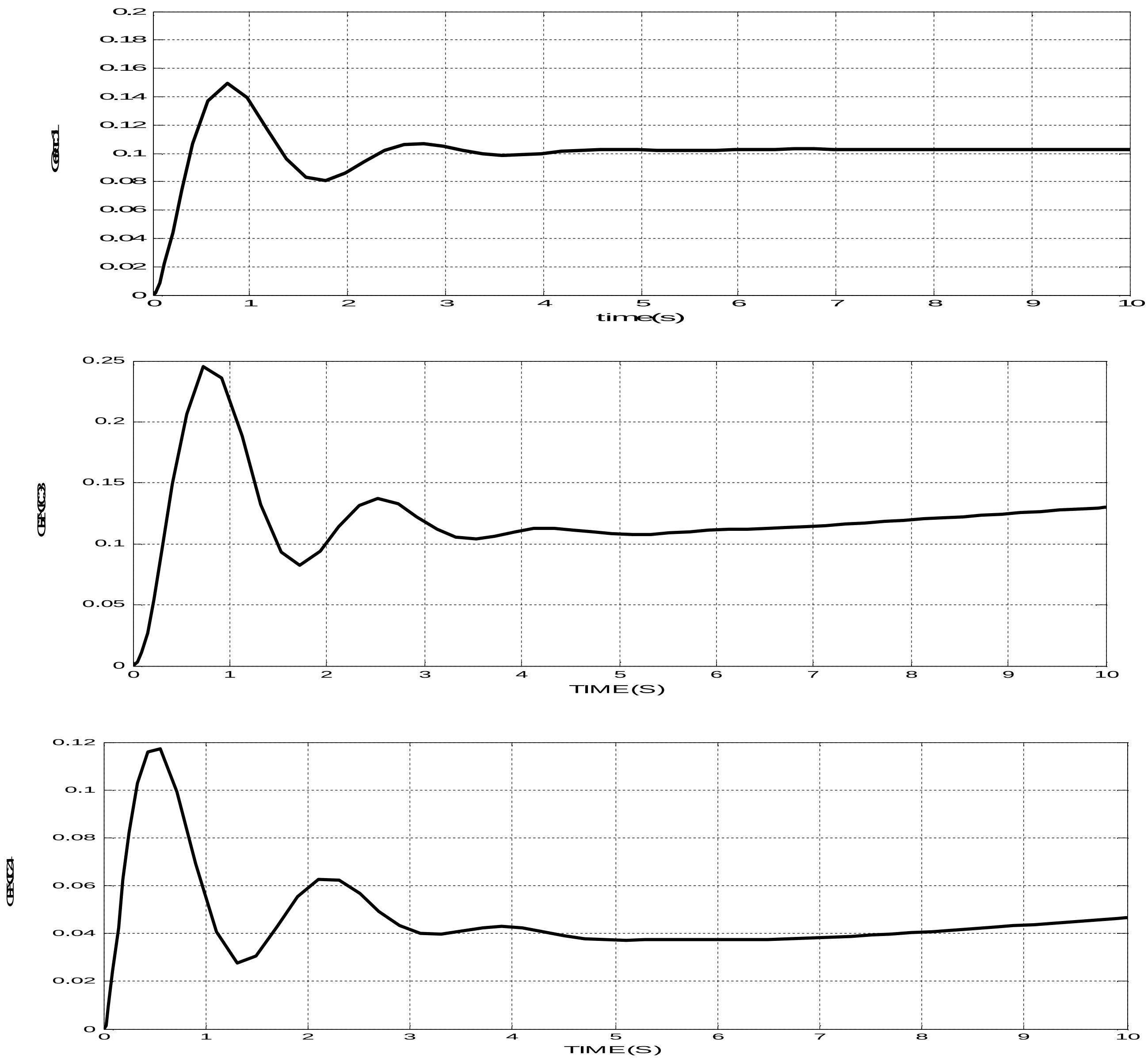


Figure 3.5: Frequency Deviations (rad/s) and Generated Power (pu MW)

3.6.3 Scenario III (Contract Violation)

It may happen that a DISCO violates a contract by demanding more power than that specified in the contract. This excess power is not contracted out to any GENCO. This subcontracted power must be supplied by the GENCOs in the same area as the DISCO. It must be reflected as a local load of the area but not as the contract demand. Consider scenario II again with a modification that DISCO demands 0.1 pu MW of excess power.

The total local load in area I $\Delta P_{L1,Loc}$ = Load of $DISCO_1$ + Load of $DISCO_2$

= (0.1 + 0.1) + 0.1 pu MW

= 0.3 pu MW

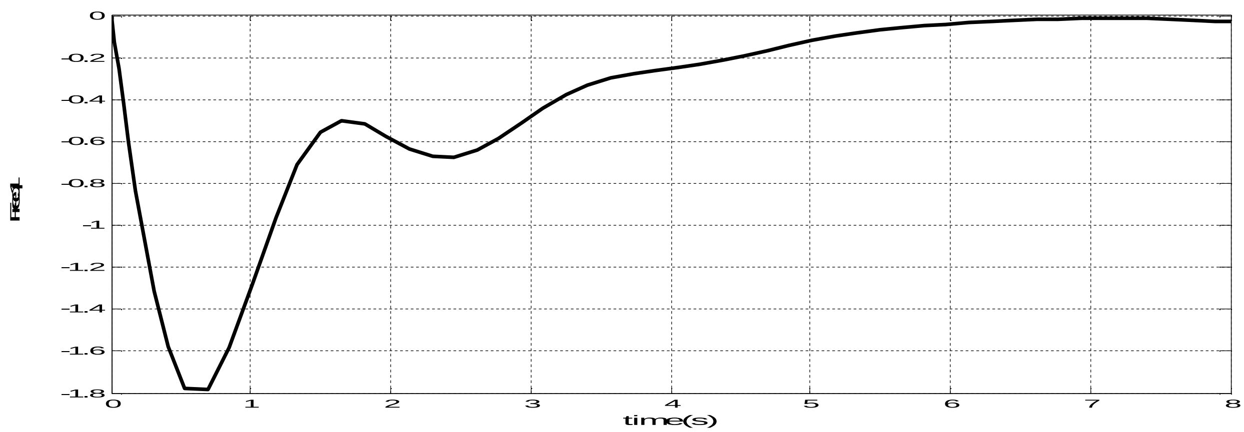
Similarly,

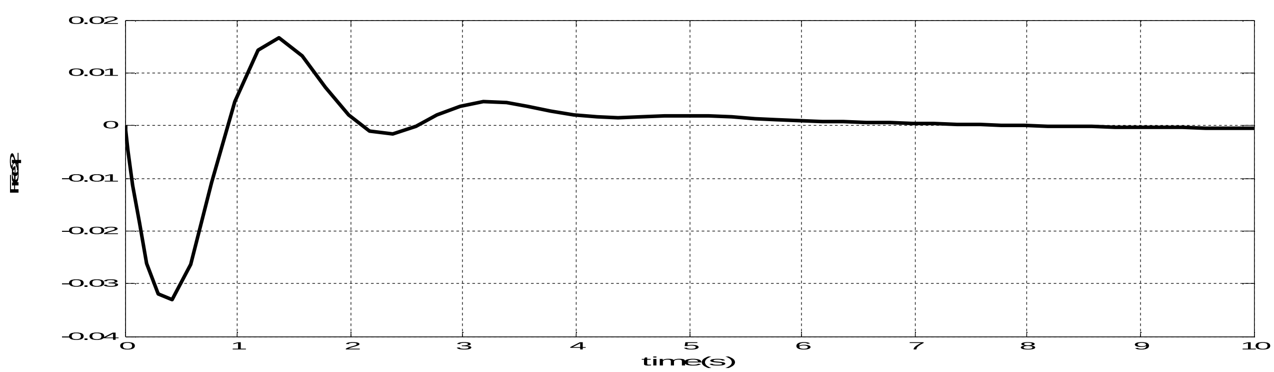
The total local load in area II $\Delta P_{L2,Loc}$ = Load of $DISCO_3$ + Load of $DISCO_4$

= 0.2 pu MW

The frequency deviations vanish in the steady state [Fig. 3.6]. As DPM is the same as in case 2 and the excess load is taken up by GENCOs in the same area, the tie line power is the same as in case 2 in steady state. The generation of GENCOs 3 and 4 is not affected by the excess load of DISCO (refer Scenario II).

The subcontracted load of DISCO is reflected in the generations of GENCO and GENCO. ACE participation factors decide the distribution of subcontracted load in the steady state. Thus, this excess load is taken up by the GENCOs in the same area as that of the DISCO making the subcontracted demand.





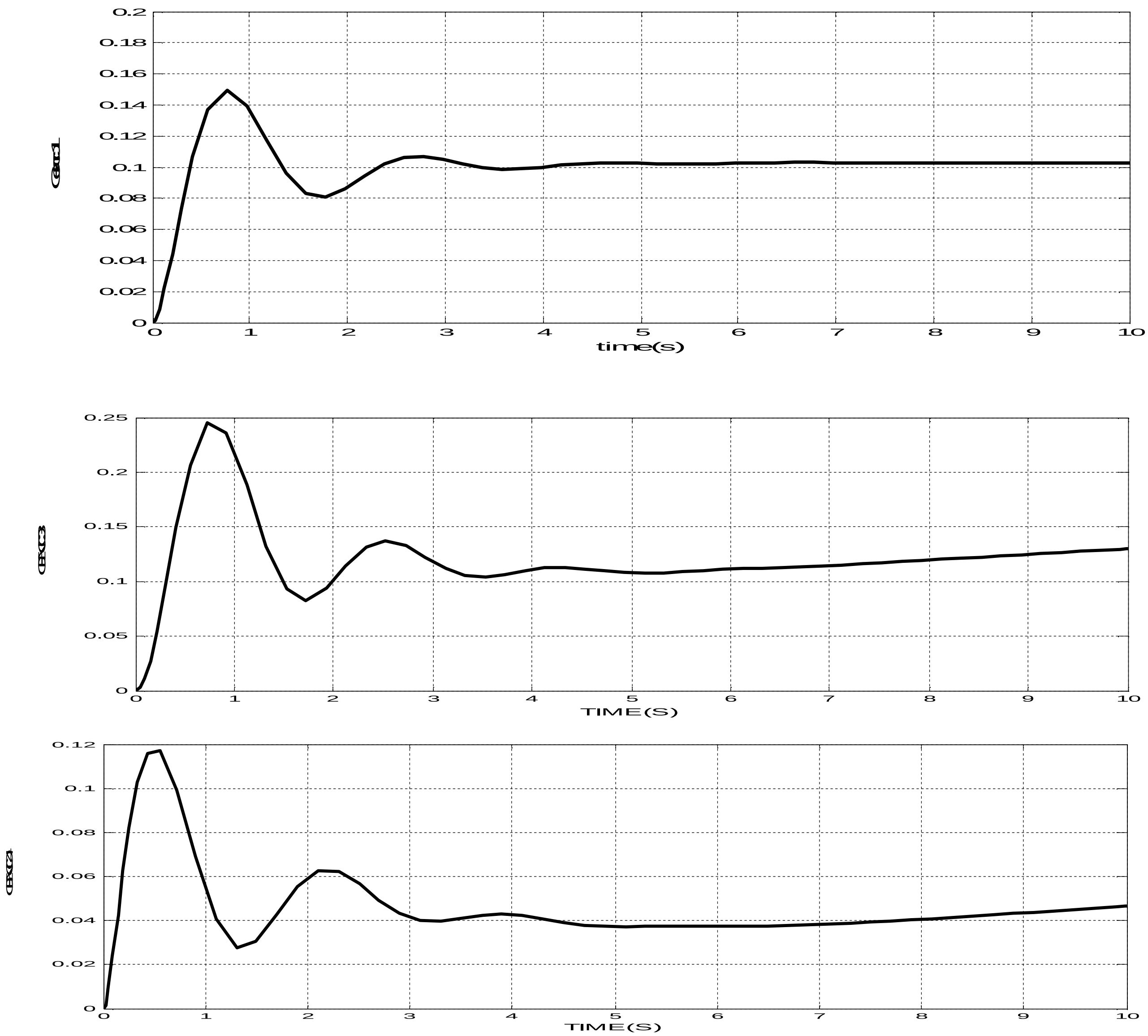


Figure 6.3: Frequency Deviations (rad/s) and Generated Power (pu MW)

CHAPTER 4

OPTIMIZATION OF INTEGRAL CONTROLLER GAIN SETTING

4.1 LINEAR QUADRATIC REGULATORS

Classical optimal control theory has evolved over decades for the design of Linear Quadratic Regulators which minimizes the deviation in state trajectories while requiring minimum controller effort. For the design of an optimal quadratic regulator the Algebraic Riccati Equations (ARE) are conventionally used to calculate the state feedback gains for a chosen set of weighting matrices. These weighting matrices regulate the penalties on the deviation in the trajectories of the state variables (x) and control signal (u). Indeed, with an arbitrary choice of weighting matrices, the classical state feedback optimal regulators seldom show good set-point tracking performance due to the absence of integral term. Thus, combining the tuning philosophy of PI controllers with the concept of LQR allows the designer to enjoy both optimal set-point tracking and optimal cost of control within the same design framework. [25]

The closed loop system is characterized in state space form as:

$\frac{d}{dt}(x) = A^{cl} + B^{cl}$

Where 'x' is the state vector and 'u' is the vector of power demands of the DISCOs. A^{cl} and B^{cl} matrices are constructed.

In order to have a LQR formulation with the system, the following Quadratic cost function (J) is minimized-

$$J = \int_0^{inf} [x^T (t) Q x(t) + u^T (t) R u(t)] dt \qquad (4.1)$$

Where 'Q' and 'R' are the state and control weighting matrices, respectively which are square and symmetric.

For full state feedback, the control vector u is constructed by a linear combination of all the ststes, i.e

$$u = -Kx \qquad (4.2)$$

Where k is the feedback matrix and it is to be determined so that a certain performance index (PI) is minimized in transferring the system from an arbitrary initial state x(0) to origin in infinite time. A convenient PI has the quadratic form

$$PI = \frac{1}{2} \int_0^{inf} [x'^T Q x' + u'^T R u'] dt$$

(4.3)The matrices Q and R are defined for the problem in hand through the following design considerations:

(i) Excursions of ACEs about the steady values are minimized. The steady values of $ACEs\ are\ of\ course\ zero.$

(ii) Excursions of ∫ACE dt about the steady values are minimized. The steady values of ∫ACE dt are, of course, constant.

(iii) Excursions of the control vector about the steady value are minimized. The steady value of the control vector is, ofcouse, a constant. This minimization is intended to indirectly limit the control effort within the physical capability of components. For example, the steam valve cannot be opened more than a certain value without causing the boiler pressure to rop severely.

Determination of the feedback matrix K which minimizes the performance index is the standard optimal regulator problem. K is obtained from solution of the reduced matrix Riccati equation given below

$$A^T S + SA - SBR^{-1}B^T S + Q = 0 \tag{4.4}$$

$$K = R^{-1}B^T S \tag{4.5}$$

The acceptable solution of K is that for which the system remains stable. Considering the system parameters shown in Table I, the computer solution using MATLAB R2009a for the feedback matrix is presented below.

K =

0.33	-0.17	0.004	0.004	-0.008	v	0.001	0.001	-0.002	-0.002	-0.38	-0.24	2.01	-0.38
0.48	-0.12	0.026	0.026	-0.005	0.005	-0.007	-0.007	-0.001	-0.001	-0.7	-0.34	0.716	0.104
- 0.008	0.009	0.0007	0.0007	0.0004	0.0004	0.0002	0.0002	0.0001	0.0001	0.018	0.017	- 0.034	0.029
-0.55	-0.45	-0.056	-0.056	- 0.0225	-0.022	-0.014	-0.014	-0.006	-0.006	0.664	0.331	0.621	- 0.932

Performance index = 6.7306

Matrix k obtained is [4*14] and then divided into two parts Kp[4*13] which represents proportional matrix and Ki[4*1] is the integral action.[26]

4.2 LOAD FREQUENCY CONTROLLER DESIGN PROCEDURE:

For the design of robust controller, four blocks are considered from Figure [3.3] which are integral control block, governor, turbine and generator block and their transfer functions are:

$\frac{d}{dt}(x_1)$ = -$\frac{1}{T_P}x_1 + \frac{K_P}{T_P}x_2$ +-$\frac{K_P}{T_P}$ΔP$_d$

$\frac{d}{dt}$ (x_2) = -$\frac{1}{T_P}x_2 + \frac{K_T}{T_T}x_3$

$\frac{d}{dt}$ (x_3) = -$\frac{1}{T_G}. x_3$ +-$\frac{K_G}{T_G}. x_4$ +$\frac{K_G}{T_G}u(t) - \frac{K_G}{T_G}R\, x_1$

$\frac{d}{dt}$ (x_4) =$K_1\ x_1$

A =

-1/T_P	K_P/T_P	0	0
0	-1/T_T	1/T_T	0
-1/RT_g	0	-1/T_g	-1/T_g
K	0	0	0

B =

0	0	1/T_g	0

C =

-K_P/T_P	0	0	0

The nominal parameters are taken from original model shown in Figure [3.3] and the matrix formed by substituting the parameter values from Table I is obtained as

A =

-2.551	6	0	0
0	-3.33	3.33	0
-5.208	0	-12.5	-12.5

0.6584	0	0	0

B=

0	0	12.5	0

C=

-6	0	0	0

For the implementation of the LQR, the built-in lqr function of MATLAB is used. [K, S, e] = lqr(A,B,Q,R) calculates the state feedback law that minimizes the cost function.

J = Integral {x'Qx + u'Ru} dt

subject to the continuous constraint equation:

$\frac{d}{dt}$(x) = Ax + Bu;

'K' is the optimal feedback gain matrix, 'S' is the Riccati solution and 'e' is the closed loop eigen values; e = EIG(Ad-Bd*K). The matrices A and B specify the continuous plant dynamics. The values thus obtained are:

K =

K1	0.1386
K2	0.7936
K3	2.3798
K4	0.4142

S=

0.0038	0.0044	0.0001	0.0082
0.0044	0.0085	0.0006	0.0114
0.0001	0.0006	0.0019	0.0003
0.0082	0.0114	0.0003	0.0373

e=

-41.4706
-3.0660 + 1.1278j
-3.0660 - 1.1278j
-0.5254

4.3 OUTPUT FREQUENCY RESPONSE WITH INTEGRAL CONTROLLER WITHOUT CONSIDERING FEEDBACK GAIN:

By using MATLAB version R2009a, the simulation model without considering the feedback gain is shown in Figure 4.1 (a) and the frequency response is shown in Figure 4.1(b).

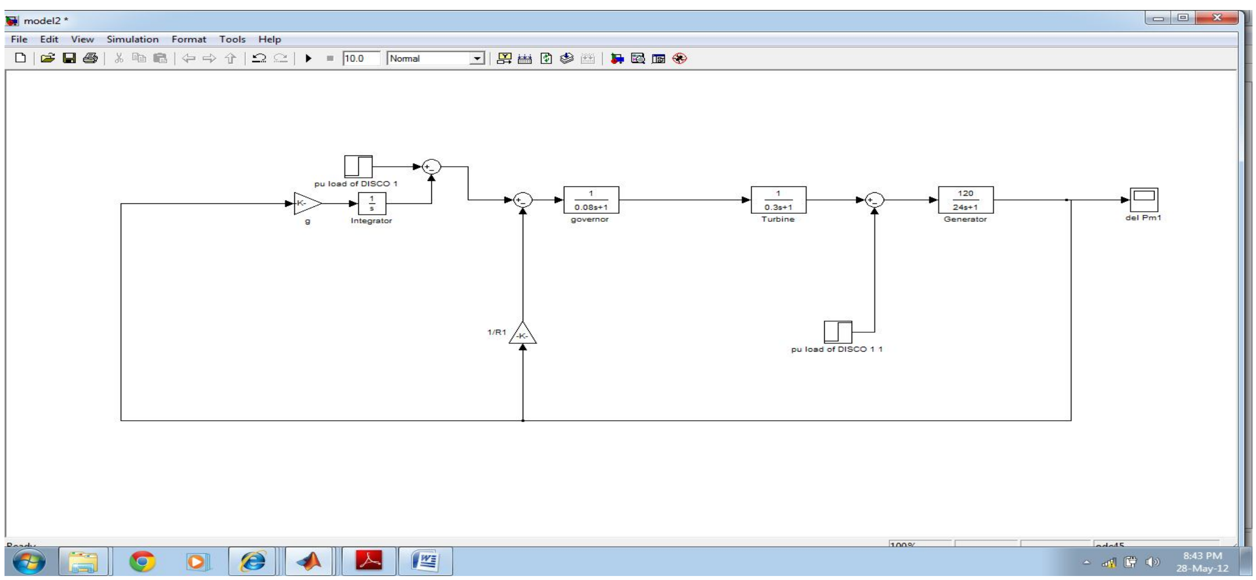


Figure 4.1(a): Simulation model without feedback gain

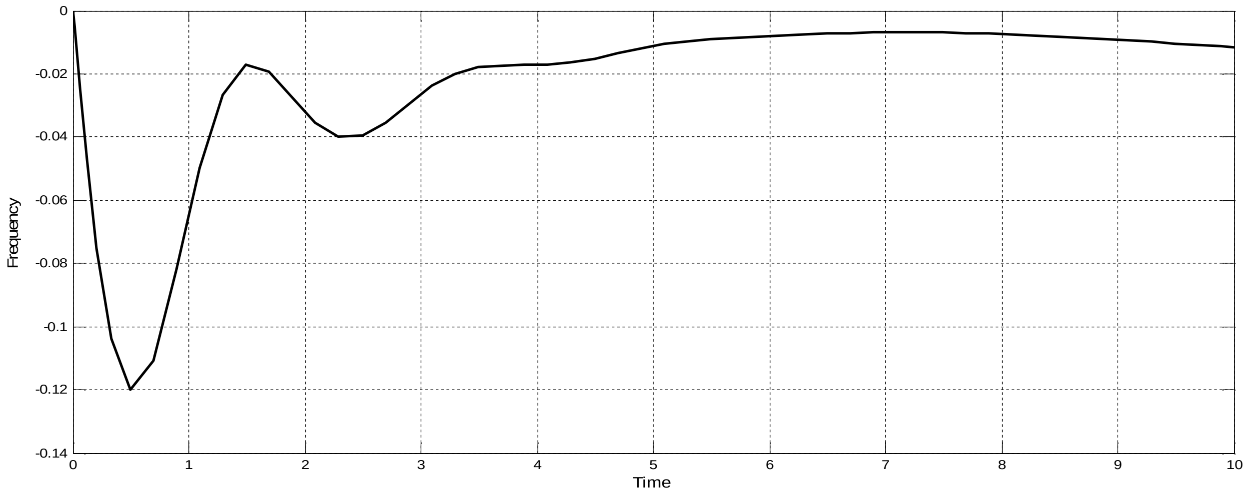


Figure 4.1 (b): Output Frequency response drawn without considering feedback gains.

4.4 OUTPUT FREQUENCY RESPONSE WITH INTEGRAL CONTROLLER CONSIDERING THE OPTIMAL FEEDBACK GAIN:

The optimal feedback gains (K_1, K_2, K_3, K_4) obtained from the Algebraic Riccati Equation are incorporated in the simulation model as shown in Figure 4.2 (a) and the output Frequency response obtained is shown in figure 4.2 (b).

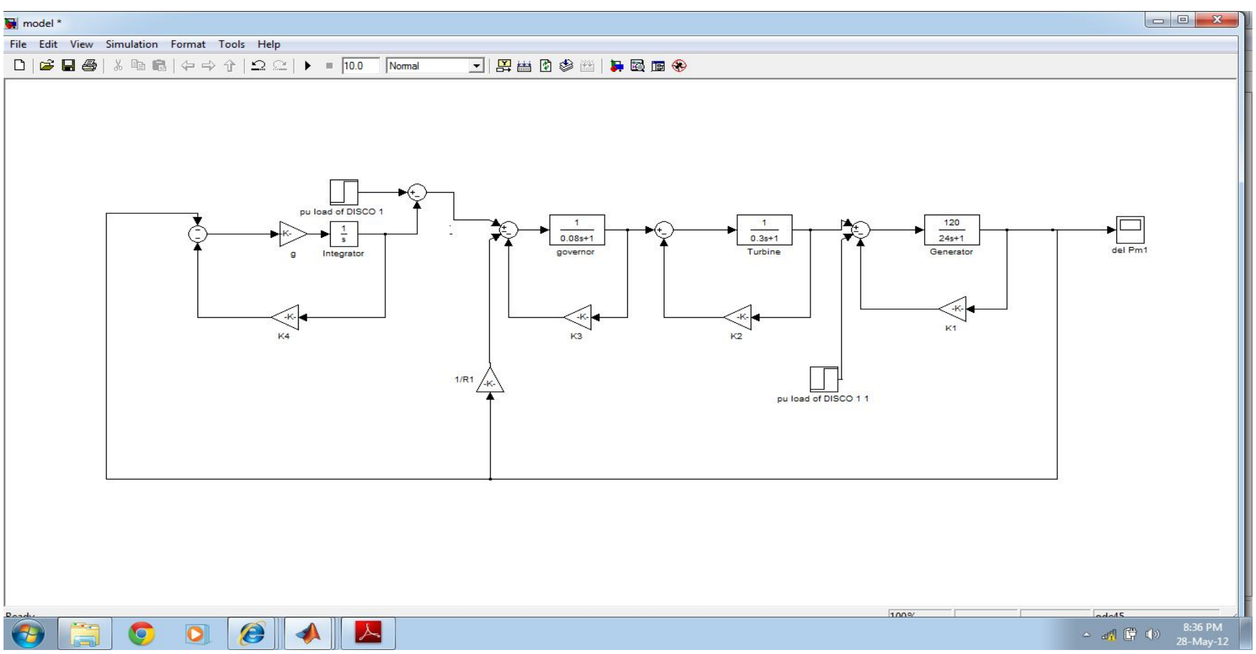


Figure 4.2 (a): Simulation model considering feedback gain

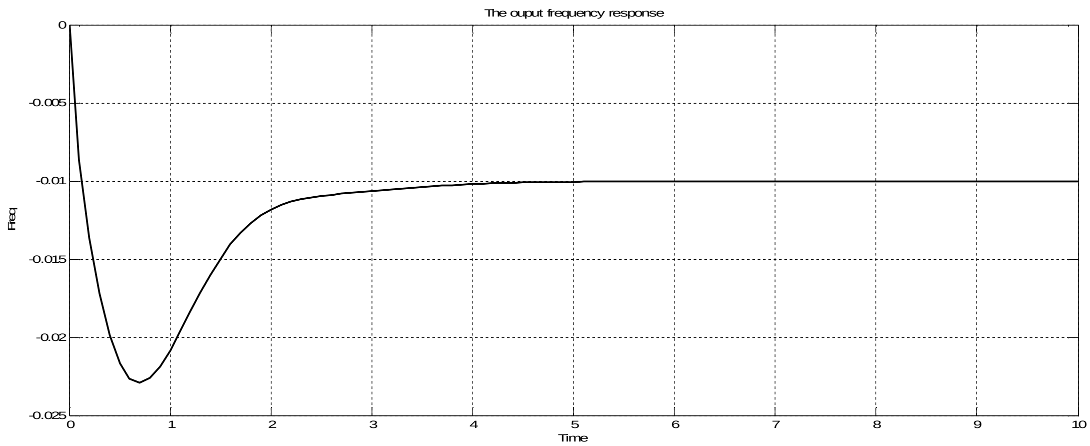


Figure 4.2 (b): Output Frequency response drawn considering feedback gains.

Comparing figure 4.1 (b) and 4.2 (b), the transient dip of the output frequency response is larger when optimal feedback gains are not considered. The proposed robust controller is simple, effective and can ensure that the overall system is asymptotically stable for all admissible uncertainties.

CHAPTER 5
CONCLUSION AND FUTURE SCOPE

5.1 CONCLUSION

This thesis work gives an overview of AGC in deregulated environment which acquires a fundamental role to enable power exchanges and to provide better conditions for the electricity trading. The AGC is treated as an ancillary service essential for maintaining the electrical system reliability at an adequate level. The important role of AGC will continue in restructured electricity markets, but with modifications. Bilateral contracts can exist between DISCOs in one control area and GENCOs in other control areas. The use of a "DISCO Participation Matrix" facilitates the simulation of bilateral contracts. It is emphasized that the new challenges will require some adaptations of the current AGC strategies to satisfy the general needs of the different market organizations and the specific characteristics of each power system. The existing market-based AGC configurations and new concepts are briefly discussed, and an updated frequency response model for decentralized AGC markets was introduced.

5.2 FUTURE SCOPE

In this research, a scheme for automatic generation control indulges the effect of voltages and market structure has been developed. This approach is the real solution for power system problem. This research will make a power system economically efficient and more reliable. It is expected that the research will add the world of AGC structure on demand side management.

The new framework will be required for AGC scheme based on market structure with intelligence controller to solve complex problem and need another technical issues to be solved. In general, a variety of technical scrutiny will be needed to ensure secure system operation and a fair market place. Optimization of linear controller gain setting can be done by using Genetic Algorithm technique

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