Real Power and Frequency Control of Large Electric Power Systems under Open Access

by

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B.S., Mechanical Engineering (1992)
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Submitted to the Department of Mechanical Engineering
in partial fulfillment of the requirements for the degree of

Master of Science in Mechanical Engineering

at the

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

June 1996

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Abstract

This thesis represents a continuing effort toward developing a new framework for dynamic system regulation in a competitive electric power industry environment. It is a follow-up to two earlier PhD theses done on this topic at M.I.T. The emphasis here, relative to the earlier work, is on (1) model development for large power electric power systems, and extensive simulation studies, and (2) the notion of minimal regulation. (2) is proposed in this thesis for the first time.

A particular modeling approach introduced in the earlier work is used. It simplifies the dynamics of a very complex system by extracting only relevant information at each level of hierarchy. This modeling approach is shown to be particularly useful for modeling large horizontally structured electric power systems under competition.

The newly proposed control technique consists of fringe control and minimal regulation. The fringe control is decentralized and used to preserve the frequency quality within a certain administrative area. Minimal regulation is coordinated. It is implemented on a slower time scale than the fringe control. Minimal regulation reschedules the entire system generation and minimizes generation cost relevant to system-wide performance. This control design is subject to the constraints on both generator power and tie-line flows for security and reliability purposes.

The simulations carried out on the standard IEEE 39-bus system show that minimal regulation leads to improved dynamic performance and economic efficiency when compared to the presently used control. The results are interpreted as a function of the industry structure for which they may be used.

Thesis Supervisor: Marija D. Ilić
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Acknowledgments

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Chapter 1

Introduction

1.1 Introduction

The work in this thesis is motivated by the need to revisit automatic generation control principles of large electric power systems. These systems have traditionally been horizontally structured into administratively separate areas of an, otherwise, large interconnected system. Each (control) area is at present equipped with an automatic generation control (AGC) scheme that is used to regulate net generation-demand imbalance and maintain average frequency in the area within technical specifications. This is done so that the net tie-line power flow exchanges with the neighboring subsystems are also stabilized to their scheduled values.

Scheduling of tie-line flows among the areas is not automated, nor coordinated from the interconnected system level. Instead, these schedules are established through bilateral negotiations among the areas, and are primarily done for economic reasons. Any deviations from scheduled flows are made up on daily basis by means of compensating the so-called inadvertent energy exchange (IEE). The IEE reflects the fact that there exists an unavoidable cumulative deviation of tie-line flows from their desired (scheduled) values. The compensation of IEE is done in such a manner that each area observes its own IEE and adjusts schedules accordingly the following day. This process is based on a voluntary cooperation among the control areas. It results in a relatively high quality frequency regulation of the entire interconnected system.

The use of generation at the interconnected level is generally sub-optimal. One could observe, however, non-uniform values of IEE as a result of non-uniform ACE's over a daily deviation. Consequences of this non-uniform regulation are economic since particular areas use more of their own resources, and others use less[1].

Recent studies have shown that it is difficult to meet the performance criteria in a changing industry when only the current ACE-like control signals, which combine both frequency and net tie-line flow deviations, are used. As the United States utility industry undergoes rapid restructuring, a new control technique that makes market trading feasible is more urgently needed and should be developed as quickly as possible.

This thesis addresses the modeling and control design aspects of the future operation framework. An earlier developed hierarchical modeling approach is used to develop the models for large scale electric power systems. It eliminates the traditional modeling assumptions with respect to system decomposition and the strength of interconnections among different areas. While the structure of the electrical power industry is gradually transforming from a vertical structure into a "nested" structure, the new modeling technique is sufficiently general for an arbitrary industry structure. Furthermore, because this approach allows unbundling of information within a control area, the control design can include generation costs.

The suggested control scheme for future industry is called minimal regulation. It consists of fringe control for frequency regulation and minimal regulation for optimal generation dispatch at different hierarchies. By including economic dispatch concepts, the proposed control technique can achieve economic efficiency and maintain high power quality at the same time. In addition, minimal regulation can guarantee system reliability and security. Simulation results illustrate that this control technique can meet the performance criteria in the changing industry and can adapt to the future operating structure.

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[1]This is often referred to "riding" on the neighbors for frequency regulation.

1.2 Thesis Format

This thesis is organized in the following format:

- Before discussing the details of control design, Chapter 2 reviews our general modeling approach. This chapter also reviews the hierarchical modeling concepts as well as succinct derivations of new structure-based models relevant for frequency and tie-line power flow control. This is done for completeness.

- Chapter 3 reviews the Automatic Generation Control (AGC) presently used in industry for system regulation in a normal operating environment[2]. It addresses two different kinds of AGC approach, ACE-based AGC and the proposed advanced AGC. The first one is used in the current utility industry for average frequency and net tie-line flow stabilization at each control area level. The newly developed control technique separates AGC into two subtasks, frequency regulation and tie-line flow control. Advanced AGC combines the two subtasks individually at different control levels. Simulation results show that the system performance improves greatly with the use of advanced AGC. In particular, one could guarantee a prespecified frequency response at each subsystem level, independently from the activities in other subsystems.

- Chapter 4 briefly reviews the ongoing regulation changes in the utility industry that lead to the restructuring of utility. Two often discussed proposed industry structures are described. This chapter also discusses the role of independent system operator (ISO) for coordinating activities at the interconnected system level.

  Next, Chapter 4 also introduces the new notion of minimal regulation. It is the minimal coordination needed to maintain system integrity and provide the essential system regulation at the same time. Model development, control laws, and detailed algorithms are presented.

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[2] "Normal" stands here to imply no unexpected equipment failures. [16]

- Chapter 5 presents simulation studies of the proposed minimal regulation. The results are compared to those of conventional AGC. It also illustrates the possible ways for using the minimal regulation while observing physical constraints on generator outputs and tie-line flows.

- Chapter 6 studies some cases of system operation in a bilateral industry environment. Since the US utility industry restructuring could be partially based on a bilateral model, it is important to prove that our method can be implemented successfully in a bilateral environment.

- Chapter 7 offers conclusions and future research.

Chapter 2

Review of the Modeling Approach Adopted

A new modeling approach to large scale electric power networks was recently introduced in [1-3]. This approach was further developed in [4-6]. This general approach eliminates the need for the modeling assumption with respect to system interconnection strength. Conventional models were based on an assumption that the interconnections within a particular area of a horizontally structured electric power system are tighter then those among the areas. Therefore, no specific restrictions on the decomposition of the interconnected system are needed. Furthermore, this approach also makes it easier to associate system dynamics evolving over different time scales with the specific levels of system hierarchy. As such, it provides a potentially powerful tool for control designs of complex multi-functional large scale electric power systems.

2.1 Hierarchies in Large Scale Power Systems

Because of their complex structures and large sizes, electric power networks are typically monitored and controlled according to their hierarchical structures. Instead of modeling the intricate dynamics of the entire system, the system dynamics is modeled by deriving submodels relevant for each particular sub-process. This is based on observing different time scales over which sub-processes evolve under certain as-

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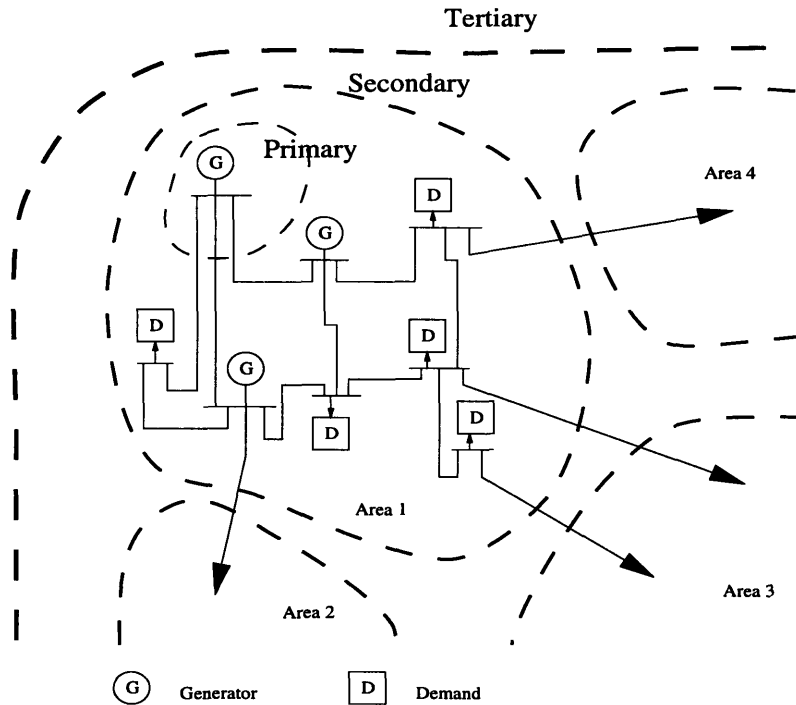
Figure 2-1: An example of different hierarchies in large scale power systems

sumptions. The overall system behavior can be fully portrayed by piecing together those simpler, yet essential, elements. The theoretical basis for this type of modeling in large electric power systems was introduced in [8]. The basic submodels are the (i) primary (local) model at a device level, (ii) secondary (area-wide) level for each administrative area, and (iii) tertiary (global) level representing the interconnected system, Figure 2-1.

The primary control level is entirely decentralized at present. Within this level, controllers respond to the small but fast local disturbances appearing at the terminals of each generator. The speed governor units in electric machines maintain the control of this level. Primary controllers stabilize system dynamics within a very short time constant, T_p, i.e., on the second scale, with the performance specification of a minute, or so.

The secondary control level is decentralized and is particularly useful in analyzing

and controlling the dynamic performance within an administrative area (subsystem level). This model represents all generators and large number of loads connected by transmission lines in each administrative area. The secondary control is implemented at a slower time scale, T_s, than that of the primary control (i.e., T_s is typically on the several-second scale, with the performance objective over 10 minutes, or so). The secondary control is intended to stabilize system outputs within the administrative area that are disturbed by changes within the area as well as by the changes in neighboring areas. Presently implemented AGC is based on this control structure. Seen from the interconnected system level, each subsystem uses AGC using decentralized measurements at its own level only.

The theoretical tertiary control level is coordinated. The aggregate tertiary-level models describe the inter-area dynamics among administrative areas and are useful for regulating inter-area variables such as tie-line power flows. These models evolve on an even slower time constant, T_t, than the secondary level rate, T_s, i.e., on the minute scale. This higher level structure is not currently used in the utility industry. However, its importance is increasing as the electric power market is changing and becoming more competitive. It is plausible that in the future, decentralized regulation at the secondary-level would not be sufficient to respond to intense interactions among the areas under an open access environment. The later parts of this thesis provide examples illustrating potential problems of this sort.

Hierarchical level models higher than the tertiary control level described in this thesis can also be developed. For example, in present utility industry, the control centers reset the scheduled values of transmission power among the areas and the phase angle of the slack generator at a much slower rate for economic reasons. The unit commitment procedures such as turning on- and off- the available generators in anticipation of demand on a daily basis, is yet another process of interest. These processes, at least in concepts, could be regarded as evolving at hierarchies beyond the tertiary level. However, these models are beyond the scope of this thesis.
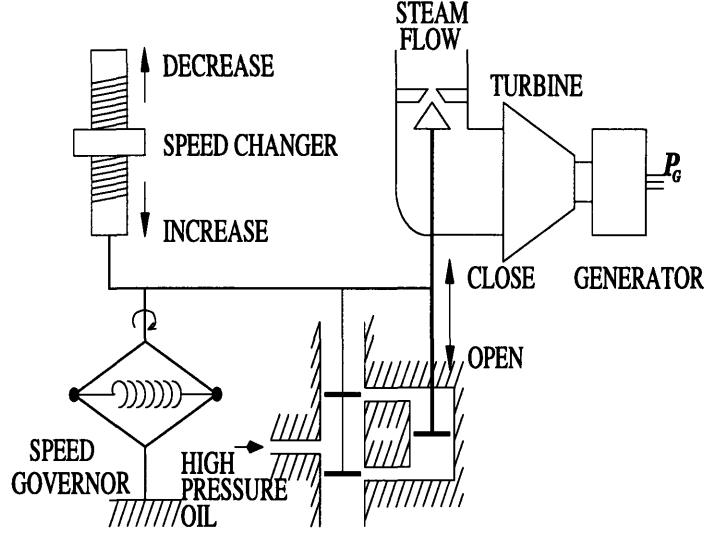
Figure 2-2: A simple scheme of the primary control unit
Source: [7]

2.2 Modeling

In this section a brief summary of the modeling done in [1] is reviewed for completeness.

2.2.1 Individual Control Unit

The governor systems are the main controllers responsible for frequency regulation of local generation units. An illustration of a typical turbine controlled by a governor is shown in Figure 2-2. Neglecting the effects of transmission networks, a completely decoupled dynamics of generation unit can be modeled by using its local state variables. Under the assumption of real power/frequency and reactive power/voltage decoupling[1], linearized state space model of a single generator can be written as [1]

---

[1]This assumption has generally been used in many Automatic Generation Control studies, for example, reference [9].

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$$\begin{bmatrix} \dot{\omega}_G \\ \dot{P}_{ta} \\ \dot{a} \end{bmatrix} = \begin{bmatrix} -\frac{D}{\mathcal{M}} & \frac{1}{\mathcal{M}} & \frac{e_T}{\mathcal{M}} \\ 0 & -\frac{1}{T_a} & \frac{K_t}{T_a} \\ -\frac{1}{T_g} & 0 & -\frac{r}{T_g} \end{bmatrix} \begin{bmatrix} \omega_G \\ P_{ta} \\ a \end{bmatrix} + \begin{bmatrix} -\frac{1}{\mathcal{M}} \\ 0 \\ 0 \end{bmatrix} P_G + \begin{bmatrix} 0 \\ 0 \\ \frac{1}{T_a} \end{bmatrix} \omega_G^{ref}[k] \qquad (2.1)$$

The variables in the Equation (2.1) are

- ω_G, the generator frequency;

- P_{ta}, the turbine mechanical power;

- a, the governor-controlled valve[2] opening;

- $\mathcal{M}$, the moment of inertia of the generator;

- D, the generator's damping coefficient;

- T_g, the governor time constant;

- T_a, the turbine time constant;

- e_T, K_t, and r, linearizations of governor characteristics.

The two variables in Equation (2.1) to which local dynamics of each generation unit responds, are P_G and ω_G^{ref}. P_G is the real electric power output of a generator and ω_G^{ref} is the governor reference frequency set point. If the generation unit were completely disconnected from the electric power network then these two variables can be treated as two independent inputs to the local dynamics. However, when the single generation units are connected by transmission lines, generator power outputs will be constrained by network power balance and are no longer independent. Therefore, the key control signal of generator frequency control is the reference frequency set point, ω_g^{ref} for a governor unit. For e.g., by updating the ω_G^{ref} every T_s seconds, the speed governor can drive the generator frequency deviation to zero.

---

[2]This is used to control turbine power.

$$\underline{S}_G = \underline{P}_G + j\,\underline{Q}_G \qquad \hat{\underline{S}}^N = \mathrm{diag}(\hat{\underline{V}})\,\hat{\underline{Y}}_{bus}^*\,\hat{\underline{V}}^* \qquad \underline{S}_L = \underline{P}_L + j\,\underline{Q}_L$$
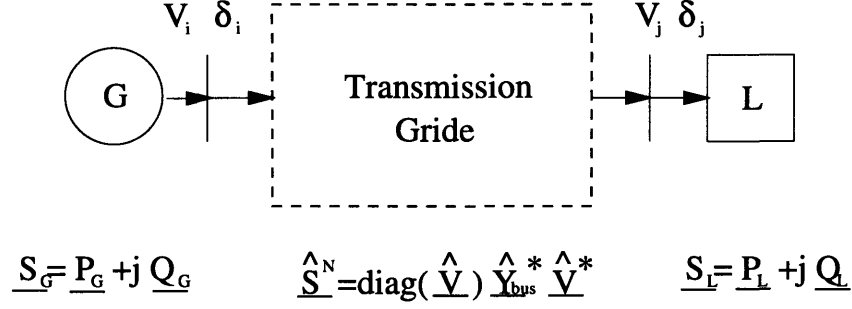
Figure 2-3: Network power balance

2.2.2 Network Constraints of Interconnected Systems

Every administrative area consists of a set of generation buses and load buses, and transmission lines that connect those generation and load buses. As each generation unit is connected to the electric power system network, P_G, the real power output of a generator is no longer an independent input in Equation (2.1). The transmission network which connects all generators and loads, constrains the variables of individual units by imposing power balance conditions on some related variables. The complex-valued power injections into all nodes, a combination of real power P and reactive power Q, can be expressed as

$$\hat{\underline{S}} = \underline{P} + j\underline{Q} \qquad (2.2)$$

Complex-valued power injected into network can also be found by computing the following equation:

$$\hat{\underline{S}}^N = diag(\hat{\underline{V}})\hat{Y}_{bus}^*\hat{\underline{V}}^* \qquad (2.3)$$

where $\hat{\underline{S}}^N = \underline{P}^N + j\underline{Q}^N$; $\hat{Y}_{bus}$ is the admittance matrix of the sub-network; and $\hat{\underline{V}} = [V_1 e^{j\delta_1}, V_2 e^{j\delta_2}, \cdots]$ is the vector of all nodal voltage phasers, with magnitude V_i and phase δ_i of each bus.

The power into a network should balance automatically so the complex-valued power into all nodes will be equal to that injected into the network, namely,

$$\hat{\underline{S}}^N = \hat{\underline{S}} \qquad (2.4)$$

Partitioning only the real part of this equation under decoupling assumption of real power from voltage, network constraints of real power take on the form

$$\underline{P}^N = \left[\begin{array}{c} \underline{P}_G + \underline{F}_G \\ -\underline{P}_L + \underline{F}_L \end{array} \right] \tag{2.5}$$

where $\underline{P}_G$ represents real power injections into the network from generator buses, $\underline{P}_L$ represents real power sinked from load buses, and $\underline{F}_G$ and $\underline{F}_L$ represent tie-line power flows from adjacent area into the network at generator and load buses, respectively. Equation (2.5) is further linearized around a typical nominal operating point[3] as

$$\left[\begin{array}{c} \underline{P}_G + \underline{F}_G \\ -\underline{P}_L + \underline{F}_L \end{array} \right] = \left[\begin{array}{cc} J_{GG} & J_{GL} \\ J_{LG} & J_{LL} \end{array} \right] \left[\begin{array}{c} \underline{\delta}_G \\ \underline{\delta}_L \end{array} \right] \tag{2.6}$$

where

$$J_{ij} = \frac{\partial P_i^N}{\partial \delta_j} \tag{2.7}$$

$$i, j, \in 1, \cdots, (N_G + N_L) \tag{2.8}$$

J_{ij} is a Jacobian matrix of real power injections for each bus. N_G and N_L represent the number of generator and load buses respectively. In practice, the Jacobian matrix elements, J_{ij}, are obtained easily by load flow calculations. Solving Equation (2.6), which is a very important expression for real power, P_G is

$$\underline{P}_G = K_p \underline{\delta}_G - (\underline{F} - D_p \underline{P}_L) \tag{2.9}$$

where

$$D_p = -J_{GL} J_{LL}^{-1} \tag{2.10}$$

$$K_p = J_{GG} + D_p J_{LG} \tag{2.11}$$

$$\underline{F} = \underline{F}_G + D_p \underline{F}_L \tag{2.12}$$

---

[3]This linearization point can be repeated as new information about the operating conditions is available.

In Equation (2.9), F stands for "mapped" tie-line power flows; they represent tie-line flows into generating units, F_G, while "mapping" the tie-line flows into loads F_L. Via computing $\underline{F} = \underline{F}_G + D_p\underline{F}_L$, tie-line flows are projected back onto the generator buses[4] . In area-wide level models, these mapped tie-line flows will be treated as disturbances coming from adjoining areas.

2.2.3 Secondary Level Model

In the secondary control level, the fast transient responses of generators are no longer of direct interest to control design engineers. Assuming that primary level controllers are designed to stabilize individual generators, while observing the system on the secondary time scale, only the steady state values will be present[5]. This assumption allows one to simplify the system complexity when deriving the secondary and tertiary level models.

Let us start the derivation using a linearized model of a single generator [1]

$$
\begin{bmatrix} \dot{\omega}_G \\ \dot{P}_{ta} \\ \dot{a} \end{bmatrix} = \begin{bmatrix} -\frac{D}{M} & \frac{1}{M} & \frac{e_T}{M} \\ 0 & -\frac{1}{T_a} & \frac{K_t}{T_a} \\ -\frac{1}{T_g} & 0 & -\frac{r}{T_g} \end{bmatrix} \begin{bmatrix} \omega_G \\ P_{ta} \\ a \end{bmatrix} + \begin{bmatrix} -\frac{1}{M} \\ 0 \\ 0 \end{bmatrix} P_G + \begin{bmatrix} 0 \\ 0 \\ \frac{1}{T_a} \end{bmatrix} \omega_G^{ref}[k] \quad (2.13)
$$

In order to find the steady state solution of Equation (2.13), set all terms on the left-hand side equal to zero. Therefore, the generator frequency can be solved,

$$
\omega_G[k] = (1 - \sigma D)\omega_G^{ref}[k] - \sigma P_G[k] \quad (2.14)
$$

where σ is the droop characteristic constant of the generator:

$$
\sigma = \frac{r}{e_T + rD + K_t} \quad (2.15)
$$

---

[4]Use of this mapping technique to design controllers was shown in [5], [4], and [6]. For further developments reported in this thesis it is relevant to observe that the actual tie-line flows may still become unstable even though the mapped tie-line flows are regulated.

[5]This is a strong assumption since it has been documented that at present many governors are not tuned adequately [1].

The droop characteristic equations of all generators within a certain area are stacked to obtain a multigenerator area-wide expression:

$$\omega_G[k] = (1 - \Sigma D)\omega_G^{ref}[k] - \Sigma P_G[k] \tag{2.16}$$

where

$$D = diag[D_1 D_2 \cdots D_m] \tag{2.17}$$

$$\Sigma = diag[\sigma_1 \sigma_2 \cdots \sigma_m] \tag{2.18}$$

The generator power can be expressed in the following way so as to satisfy the network constraints:

$$\underline{P}_G = K_p \delta_G - \underline{F} + D_P \underline{P}_L \tag{2.19}$$

By replacing P_G in Equation (2.16) with Equation (2.19) the droop characteristic equations and network constraints are combined to form a complete secondary frequency model:

$$\omega_G[k] = (I - \Sigma D)\omega_G^{ref}[k] - \Sigma(K_P \delta_G[k] - F[k] + D_p P_L[k]) \tag{2.20}$$

$$\omega_G[k+1] - \omega_G[k] = (I - \Sigma D)(\omega_G^{ref}[k+1] - \omega_G^{ref}[k]) - \Sigma\{K_P(\delta_G[k+1] - \delta_G[k])$$
$$-(F[k+1] - F[k]) + D_p(P_L[k+1] - P_L[k])\}$$

Using the backward difference approximation,

$$\omega_G[k+1] \approx \frac{\delta_G[k+1] - \delta_G[k]}{T_s} \tag{2.21}$$

or

$$\omega_G[k+1]T_s \approx \delta_G[k+1] - \delta_G[k], \tag{2.22}$$

the load bus phase angles, δ_L, are eliminated and a frequency model is found:

$$\omega_G[k+1] = (I + \Sigma K_P T_s)^{-1} \{\omega_G[k] + (I - \Sigma D)u[k] - \Sigma(f[k] + D_p d[k])\} \quad (2.23)$$

where

$$u[k] \;=\; \omega_G^{ref}[k+1] - \omega_G^{ref}[k] \tag{2.24}$$

$$f[k] \;=\; F[k+1] - F[k] \tag{2.25}$$

$$d[k] \;=\; P_L[k+1] - P_L[k] \tag{2.26}$$

In this model, generator frequencies are the only state variables for an administrative area. Another generator real power model[6] for secondary level control can also be obtained by eliminating ω_G in Equation (2.16) and Equation (2.19). However, these two models are duals of each other. If one tried to use both models in secondary level simultaneously, controllability problems will emerge. The controls, $u[k]$, are the difference of governor reference frequencies. From Equation (2.13), the reference frequencies for primary level control is simply $\omega_G^{ref}[k+1] = \omega_G^{ref}[k] + u[k]$. The reference frequencies are the only control signal for real power and frequency control[7].

2.2.4 Tertiary Level Aggregate Model

An entire electric power system network is formed by several administrative areas interconnected through the transmission lines between areas. The area-wide dynamics is coupled through tie-line power flows. In this section, we derive the relationship between tie-line power flows and generator frequencies on the tertiary time scale by using the new hierarchical structural modeling approach.

At first, considering the real power transmission in tie-lines, one can directly write

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[6]The generator real power model may be used for other purposes. In this thesis, however only the generator frequency model will be used.

[7]This idea is very important and no matter what signals are sent from tertiary level control to secondary level or from secondary level control to primary level, only ω_G^{ref}'s are acting as real control signals.

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down the expressions of a certain tie-line flow in terms of voltage phasors at the end of its two terminal nodes and the line impedance of that line. According to the decoupling assumption, the voltage will not be affected by the frequency deviations. Therefore, the power flows depends solely on phase angle. The sensitivity matrix defining change in tie-line power flows with respect to voltage phase angles is

$$J_{fG} = \frac{\partial \underline{P}_f^N}{\partial \underline{\delta}_G} \tag{2.27}$$

$$J_{fL} = \frac{\partial \underline{P}_f^N}{\partial \underline{\delta}_L} \tag{2.28}$$

The dependence of real power flows on voltage phase angles is

$$\underline{P}_f = \begin{bmatrix} J_{fG} & J_{fL} \end{bmatrix} \begin{bmatrix} \delta_G \\ \delta_L \end{bmatrix} \tag{2.29}$$

Secondly, recall that when looking at the overall Jacobian expression of generator real power output, Equation (2.6), the tie-line flow terms F_G and F_L are not present in the equation. Consequently, the phase angles on load buses can be expressed in terms of the phase angles on generator buses and loads on load buses:

$$\delta_L = -J_{LL}^{-1}(J_{LG}\delta_G + \underline{P}_L) \tag{2.30}$$

Substituting Equation (2.30) into Equation (2.29) eliminates the load phase angles in Equation (2.29):

$$\underline{P}_f[K] = K_f \delta_G[K] + D_f \underline{P}_L[K] \tag{2.31}$$

where

$$K_f = J_{fG} - J_{fL}J_{LL}^{-1}J_{LG} \tag{2.32}$$

$$D_f = -J_{fL}J_{LL}^{-1} \tag{2.33}$$

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Hence

$$\underline{P}_f[K+1] = \underline{P}_f[K] + K_f(\underline{\delta}_G[K+1] - \underline{\delta}_G[K]) + D_f(\underline{P}_L[K+1] - \underline{P}_L[K]) \quad (2.34)$$

One can easily obtain the relationship between phase angle differences and generator frequencies.

$$\omega_G[K]T_t \approx \delta_G[K+1] - \delta_G[K] \quad (2.35)$$

Thus, the tertiary level tie-line power flow model is found:

$$\underline{P}_f[K+1] = \underline{P}_f[K] + K_fT_t\underline{\omega}_G^{set}[K] + D_f\underline{d}[K] \quad (2.36)$$

where $\underline{d}[K]$ is the load difference, $(P_L[K+1] - P_L[K])$. This is the disturbance to the system. $\underline{\omega}_G^{set}[K]$ signal will be sent to the secondary level controller as a reference input. The details of controller implementation will be presented in the next chapter. Note that some tie-line flows might be sums or linear combinations of other tie-line flows. The independence of tie-line flows is determined by network topologies but can also be detected by checking eigenvalues of matrix K_f. Namely, model (2.36) may have some controllability problems if one tried to control every single tie-line, including independent tie-lines and dependent tie-lines. Only the subgroup of independent tie-lines are fully controllable. The subgroup of dependent tie-line flows are linearly dependent on the independent ones. Therefore, the tie-line flow deviations of those dependent tie-lines will be driven to zero as well once all independent tie-line flows are regulated.

2.3 Simulation Setup

The standard IEEE 39-bus system was chosen to illustrate theoretical ideas introduced in this thesis. The system data were created by the New England Electric System (NEES) several years ago. This system is a simplification of the 345 kV transmission system in the New England region, with 10 generators and 29 loads, as
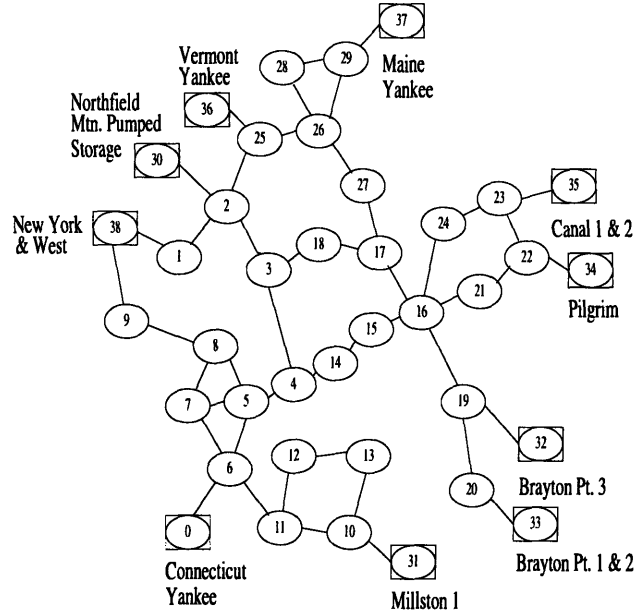
Figure 2-4: A illustration of 39-bus New England transmission network
Source: [10]

shown in Figure 2-4. In the figure, individual generation nodes are identified with individual plants rather than aggregations of many units.

For purposes of this study, this system is partitioned into four administrative areas. As shown in Figure 2-3, generator bus 30 and bus 38 and load buses 1 through 9 with the exception of bus 6 are in area 1; generator bus 31 and slack bus 0 as well as load bus 6 and buses 10 through 15 are in area 2; generator buses 32 through 35 and load bus 16 and bus 19 through 24 are in area 3; all others are in area 4. The areas are interconnected through seven tie-lines. The tie-lines are connecting buses 2 and 25, 3 and 18, 4 and 14, 5 and 6, 6 and 7, 15 and 16, and buses 16 and 17. This is an arbitrary decomposition and it is not based on the strength of interconnections among the subsystems. Areas 1 and 3, and areas 2 and 4 are not directly connected.

The generator and line parameters[8] are shown in Tables 2.1 and 2.2, respectively[9]. For the system inputs (generation and demand) shown in Table 2.3, the load flow solution for system voltages and angles is shown in Table 2.4.

---

[8]Repeated connections mean that there are more than one line between two buses; for example, two lines exist between bus 1 and bus 38.

[9]All data are in a per unit system.

AREA 1   G

I

30

1

38

9

8

7   5   4

2

POWER SELLER

3

TIE-LINE

TIE-LINE

AREA 4   I   I

36

25

37

29

26   28

27

18   17

TIE-LINE

TIE-LINE

TIE-LINE

TIE-LINE

14

13

12

11

6

0

G

15

10

G

31

AREA 2

G

TIE-LINE

16

G

33

20

G

19

32

I

34

22

21

24

G

35

23

POWER BUYER

AREA 3
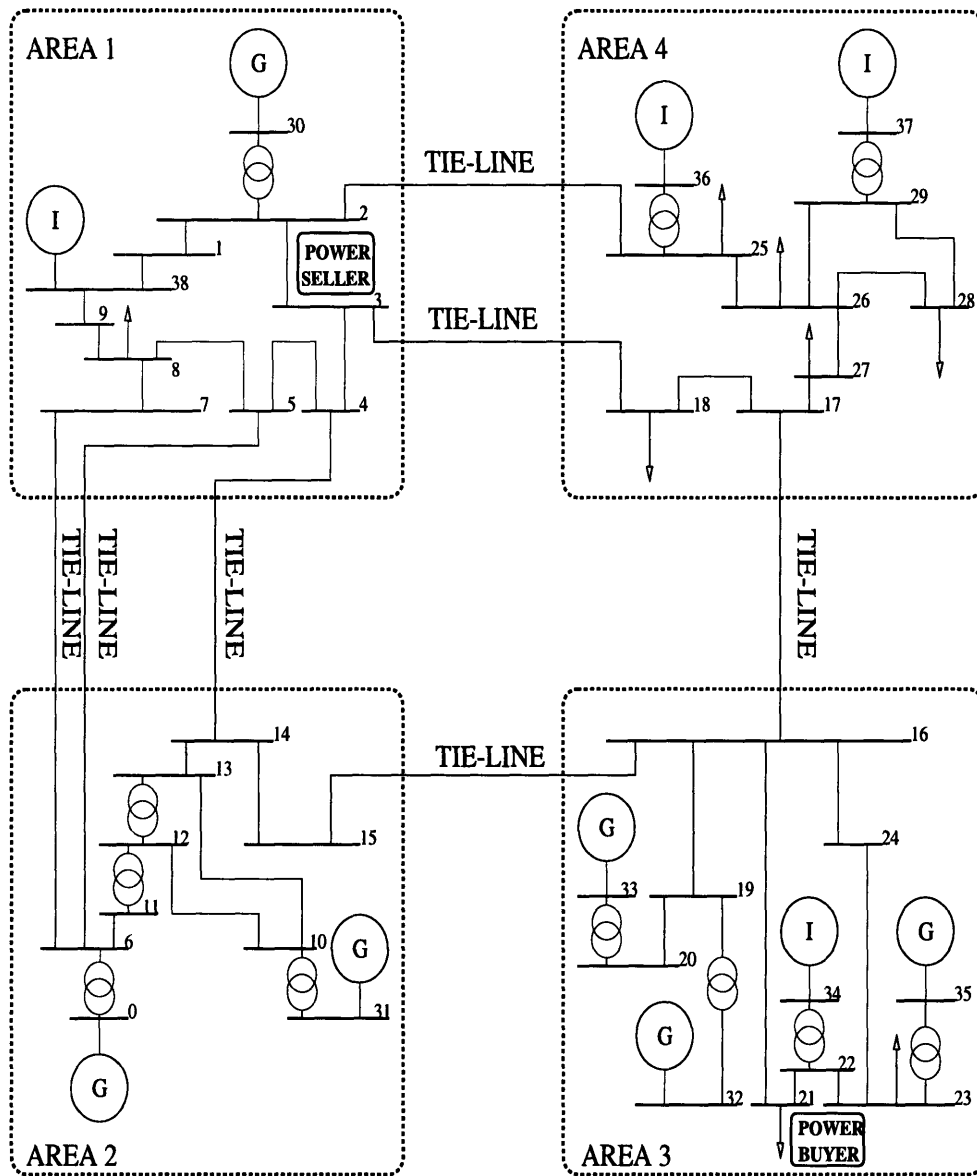
G: UTILITY-OWNED GENERATORS
I: INDEPENDENT POWER PRODUCERS

Figure 2-5: Rearranged IEEE 39-bus system (4 Areas)

Table 2.1: Generator parameters for 39-bus example (per unit)

Generator	$\mathcal{M}$	D	e_T	T_a	K_t	r	T_g
30	4.0	5.0	39.4	0.2	250	19	0.25
31	2.5	4.0	39.4	0.2	250	19	0.25
32	4.0	6.0	39.4	0.2	250	19	0.25
33	2.0	3.5	39.4	0.2	250	19	0.25
34	3.5	3.0	39.4	0.2	250	19	0.25
35	3.0	7.5	39.4	0.2	250	19	0.25
36	2.5	4.0	39.4	0.2	250	19	0.25
37	2.0	6.5	39.4	0.2	250	19	0.25
38	6.0	5.0	39.4	0.2	250	19	0.25
0	3.0	4.0	39.4	0.2	250	19	0.25

Table 2.2: Line parameters for 39-bus example (per unit)

line	1–2	1–38	1–38	2–3	2–25	3–4	3–18
r	0.003500	0.002000	0.002000	0.001300	0.007000	0.001300	0.001100
x	0.041100	0.050000	0.050000	0.015100	0.008600	0.021300	0.013300

line	4–5	4–14	5–6	5–8	6–7	6–11	7–8
r	0.000800	0.000800	0.000200	0.000800	0.000600	0.000700	0.000400
x	0.012800	0.012900	0.002600	0.011200	0.009200	0.008200	0.004600

line	8–9	9–38	10–11	10–13	13–14	14–15	15–16
r	0.002300	0.001000	0.000400	0.000400	0.000900	0.001800	0.000900
x	0.036300	0.025000	0.004300	0.004300	0.010100	0.021700	0.009400

line	16–17	16–19	16–21	16–24	17–18	17–27	21–22
r	0.000700	0.001600	0.000800	0.000300	0.000700	0.001300	0.000800
x	0.008900	0.019500	0.013500	0.005900	0.008200	0.017300	0.014000

line	22–23	23–24	25–26	26–27	26–28	26–29	28–29
r	0.000600	0.002200	0.003200	0.001400	0.004300	0.005700	0.001400
x	0.009600	0.035000	0.032300	0.014700	0.047400	0.062500	0.015100

line	2–30	6–0	6–0	10–31	12–11	12–13	19–20
r	0.000000	0.000000	0.000000	0.000000	0.001600	0.001600	0.000700
x	0.018100	0.050000	0.050000	0.020000	0.043500	0.043500	0.013800

line	19–32	20–33	22–34	23–35	25–36	29–37	
r	0.000700	0.000900	0.000000	0.000500	0.000600	0.000800	
x	0.014200	0.018000	0.014300	0.027200	0.023200	0.015600	

Table 2.3: Generation and demand data for 39-bus example (per unit)

bus	1	2	3	4	5	6	7	8	9
P_L	0.0000	0.0000	3.2200	5.0000	0.0000	0.0000	2.3380	5.2200	0.0000
Q_L	0.0000	0.0000	0.0240	1.8400	0.0000	0.0000	0.8400	1.7600	0.0000
P_G	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Q_G	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
bus	10	11	12	13	14	15	16	17	18
P_L	0.0000	0.0000	0.0850	0.0000	0.0000	3.2000	3.2940	0.0000	1.5800
Q_L	0.0000	0.0000	0.8800	0.0000	0.0000	1.5300	0.3230	0.0000	0.3000
P_G	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Q_G	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
bus	19	20	21	22	23	24	25	26	27
P_L	0.0000	6.8000	2.7400	0.0000	2.4750	3.0860	2.2400	1.3900	2.8100
Q_L	0.0000	1.0300	1.1500	0.0000	0.8460	-0.9200	0.4720	0.1700	0.7550
P_G	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Q_G	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
bus	28	29	30	31	32	33	34	35	36
P_L	2.0600	2.8350	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Q_L	0.2760	1.2690	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
P_G	0.0000	0.0000	2.5000	6.5000	6.3200	5.0800	6.5000	5.6000	5.4000
Q_G	0.0000	1.0000	1.3620	1.7590	1.0334	1.6439	2.0483	0.9688	-0.0443
bus	37	38	0						
P_L	0.0000	11.0400	0.0920						
Q_L	0.0000	2.5000	0.0460						
P_G	8.3000	10.0000	5.7286						
Q_G	0.1938	0.6845	1.7034						

Table 2.4: Load flow data for 39-bus example (per unit)

bus	1	2	3	4	5	6	7	8	9
V	1.0163	0.9979	0.9616	0.9267	0.9299	0.9327	0.9223	0.9223	0.9861
δ	-0.1779	-0.1269	-0.1811	-0.1959	-0.1709	-0.1565	-0.2015	-0.2119	-0.2097
bus	10	11	12	13	14	15	16	17	18
V	0.9421	0.9372	0.9165	0.9377	0.9334	0.9393	0.9606	0.9584	0.9572
δ	-0.1083	-0.1247	-0.1251	-0.1229	-0.1572	-0.1668	-0.1390	-0.1590	-0.1760
bus	19	20	21	22	23	24	25	26	27
V	0.9795	0.9808	0.9721	1.0075	1.0052	0.9697	1.0059	0.9725	0.9571
δ	-0.0461	-0.0713	-0.0921	-0.0073	-0.0114	-0.1368	-0.0997	-0.1213	-0.1620
bus	28	29	30	31	32	33	34	35	36
V	0.9817	0.9940	1.0475	0.9831	0.9972	1.0123	1.0493	1.0635	1.0278
δ	-0.0517	0.0015	-0.0836	0.0325	0.0451	0.0194	0.0807	0.1304	0.0211
bus	37	38	0						
V	1.0265	1.0300	0.9820						
δ	0.1270	-0.2074	0						

2.4 Summary

In this chapter, present hierarchies, the primary, secondary, and tertiary levels, in electric power systems are briefly reviewed first. This is followed by the review of new hierarchical models originally conceived in [1].

Two models which are frequently used in this thesis are (i) the secondary-level frequency model given in Equation (2.23) that describes the local frequency dynamics in each administrative area, and (ii) the tertiary level tie-line flow model given in Equation (2.36) that establishes the relation between tie-line flows and generator frequencies at the interconnected system level.

In order to avoid repeats and for convenience, the expression $\omega_G[k + 1] = (I + \Sigma K_P T_s)^{-1}\{\omega_G[k]+(I-\Sigma D)u[k]-\Sigma(f[k]+D_p d[k])\}$ in the secondary frequency model is simplified to

$$\omega_G[k + 1] = A_\omega \omega_G[k] + B_\omega u[k] + L_\omega(f[k] + D_p d[k]) \qquad (2.37)$$

Similarly, for the tertiary tie-line flow model, $\underline{P}_f[K+1] = \underline{P}_f[K] + K_f T_t \underline{\omega}_G^{set}[K] + D_f \underline{d}[K]$ is simply expressed as

$$\underline{P}_f[K+1] = A_f \underline{P}_f[K] + B_f \underline{\omega}_G^{set}[K] + L_f \underline{d}[K] \tag{2.38}$$

in the rest of this thesis.

Finally, the IEEE 39-bus system is used as an example system to approximate the real electric network. All simulations in this thesis are based on this system.

Chapter 3

Conventional AGC and Advanced AGC

This chapter reviews two approaches to the automatic generation control at the secondary (subsystem) level of an interconnected system. The first one is the conventional AGC [11], [12], which is the control technique currently used for generator frequency and tie-line flow regulation in electric power industry. It automatically responds to the deviations in Area Control Error (ACE) signals that, in steady state, represent the mismatch between load and generation within a certain administrative area. By using bundled and decentralized ACE signals, conventional AGC ingeniously simplifies the two major control tasks, frequency regulation and tie-line flow control, into ACE signal regulation.

The second approach is referred to as an advanced AGC[1], and it represents a recently developed method for automatic generation control. This new technique separates and realizes two tasks of AGC at different control levels. The control models of advanced AGC are the hierarchical models which have been addressed in the previous chapter. These structure-based models allow for unbundling of information at each administrative area level. In addition, by using centralized control, advanced generation control can globally coordinate and actually stabilize tie-line flows.

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[1]This notation was first used in [5] and [6].
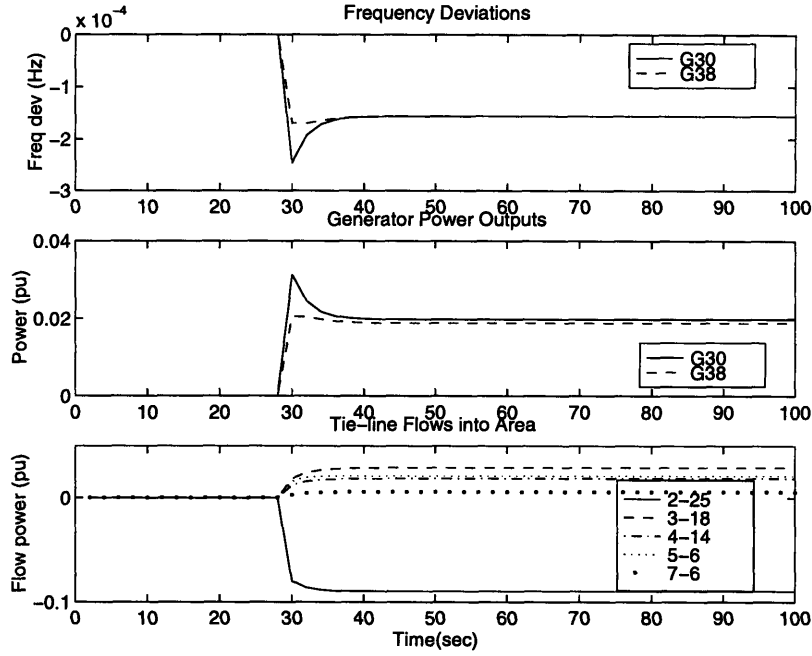
Figure 3-1: System response to 0.2 p.u. disturbance without any coordination (Area 1)

3.1 Conventional AGC

Before discussing the advanced automatic generation control, a very simple example is provided to demonstrate the basic role of AGC in electric power systems. Assume that the standard IEEE 39 bus system is operating under its nominal conditions defined in Chapter 2. At $t = 30$ seconds, a 0.2 per unit load disturbance occurs at bus 25 causing deviations from the system equilibrium. Figures 3-1 to 3-4 show system response to this disturbance when only primary control is active, i.e., without AGC. Every generation unit increases power generation to meet the increased load so as to balance the real power in the network. Frequencies of all generators settle to non-60 Hz steady-state values. It is shown, by simulations, that the frequency deviations are not truly regulated when only primary control is used. If these deviated values are sufficiently large and kept over long-term horizons, the system may become unstable. Some system equipment may also be sensitive to these deviations and damaged.

Figures 3-1 to 3-4 illustrate that in order to guarantee the quality of system response over long-term horizons, it is necessary to provide an area-wide coordination
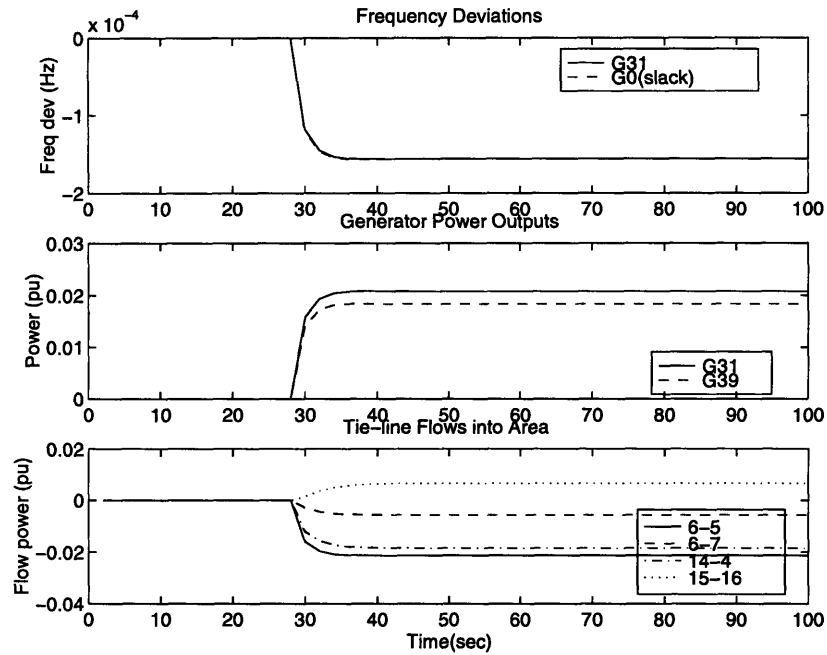
Figure 3-2: System response to 0.2 p.u. disturbance without any coordination (Area 2)
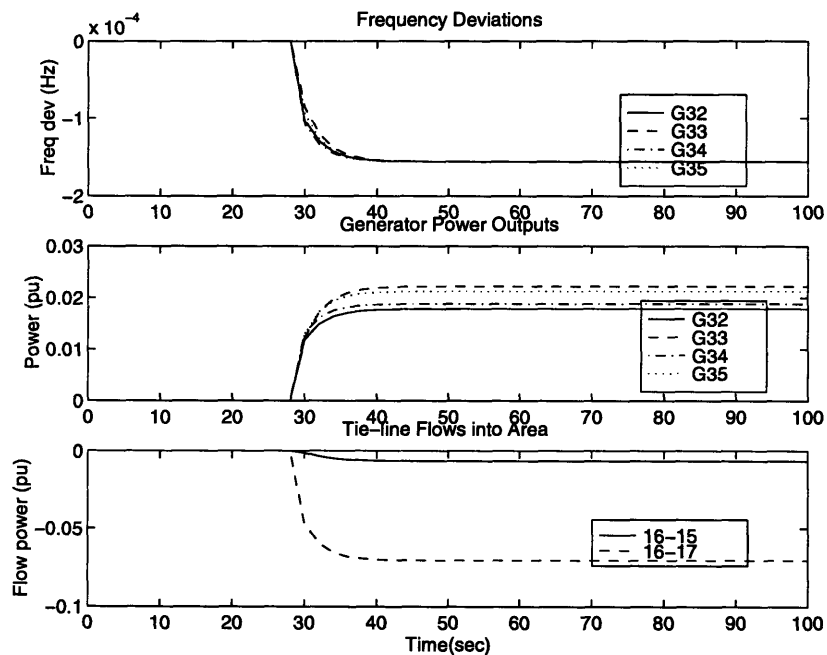
Figure 3-3: System response to 0.2 p.u. disturbance without any coordination (Area 3)

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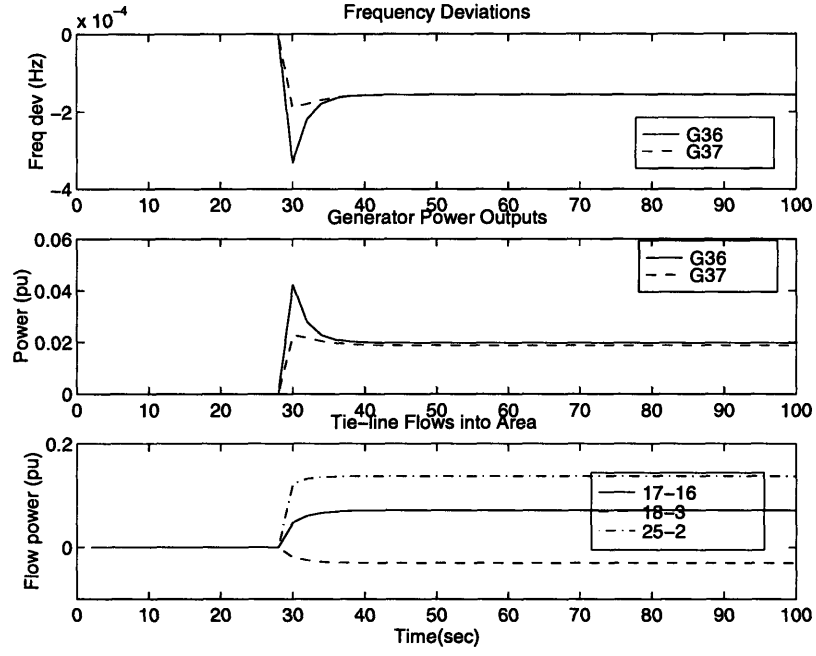
Figure 3-4: System response to 0.2 p.u. disturbance without any coordination (Area 4)

for frequency regulation. The conventional AGC has a very simple but surprisingly efficient control algorithm. The conventional AGC approach is based on the Area Control Error (ACE) measurement. In the next section, the functions and ways to compute ACE are discussed.

3.1.1 ACE Signal and Participation Factor

When a load in a particular subsystem (control area) increases, generator frequencies tend to decrease and tie-line flows from adjacent areas increase. The ACE signal reflects the power mismatch causing by load change and it is defined as

The ACE is defined as:

$$ACE_i(t) = -\frac{10}{2\pi}b_i\omega_i^{ave}(t) + F_i^{net}(t) \qquad (3.1)$$

$$i = 1, \cdots, R \qquad (3.2)$$

where

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- ω_i^{ave} denotes the average frequency offset from 60 Hz in area i.

- F_i^{net} denotes the net tie-line flow deviation, the algebraic sum of all tie-lines flows, into area i.

- b_i is the frequency bias[2], which is a scaling factor that represents the sensitivity of $ACE_i(t)$ to the average frequency ω_i^{ave}.

- R stands for the number of areas.

Several issues arise and need to be discussed. First, the $ACE_i(t)$ signal is a scalar, bundled measure of average frequency deviations from nominal and the net deviations of tie-line flows associated with a certain area. This measure is based on an implicit assumption that the frequency deviations within an administrative area change by the same amounts. In other words, it is based on the assumption that the interconnections within an administrative area are tighter than the interconnections among different areas. Once the topology of a network violates this assumption, ACE signals no longer represent the true situation on the system. Second, the frequency bias, b_i, is used as a scaling factor to map the average frequency offset into an equivalent power deviation. Some guidelines on how to choose better b_i are provided by the North American Electric Reliability Council (NERC). It is generally suggested that the frequency bias should not be less than 1% of the total peak load in the area, and the larger the values the better. Even though some recommendations about how to choose the frequency bias, b_i, exist, they are not based on explicit calculations that could be used to guarantee a prespecified performance of each control area. Typical industry standard, referred to as A1, recommends that ACE cross zero at least once each 10 minutes. The choice of b_i is not directly related to this present standard.

The ACE signals represent the total power generation needed for each area. How much power should be generated by each electric machine is determined by the so called participation factors, α_n. The power which generator n should provide is simply

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[2]The units of b_i usually are MW/0.1 Hz, or p.u./0.1 Hz

computed from

$$P_{Gn}(t) = \alpha_n ACE_i(t) \tag{3.3}$$

$$n = 1, \cdots, N_{Gi} \tag{3.4}$$

N_{Gi} indicates the number of generators in area i. Obviously, the sum of all participation factors for a certain area should be one.

$$\sum_{n=1}^{N_{Gi}} \alpha_n = 1 \tag{3.5}$$

A general rule for assigning participation factors is based on both dynamic response characteristics of machines participating in AGC and possibly their cost characteristics. In the ideal case, if the generation costs of some generators are less than others (for example: hydroelectric power plants are cheaper than fossil-fueled plants), then cheaper generators should be assigned larger participation factors as long as they have the capacity to generate the required amount of power. It is relevant to observe that at present most of the regulating machines are not optimized for cost [13]. The economic use of generation is basically attempted only through the economic dispatch, a function that schedules generation for the anticipated (known) demand. System regulation, such as AGC, in response to demand deviations from their scheduled quantities is not necessarily decided on economics as the major criterion; dynamic response, such as using flexible units that are capable of meeting standards such as A1 is the prime concern. This fact should be kept in mind when attempting to understand costs associated with dynamic regulation of present electric power systems.

3.1.2   Simulation Example for Conventional AGC

This section presents a simple example of conventional AGC in response to the same 0.2 per unit disturbance on bus 25 with $b_i = 20$ pu/0.1 Hz; all generators are given the same participation factor within an area, i.e., $\alpha_i = 0.5$ for all i in area 1, 2, and 4, and $\alpha_i = 0.25$ for all i in area 3. In the simulation, ACE signals are reset every 20 seconds.
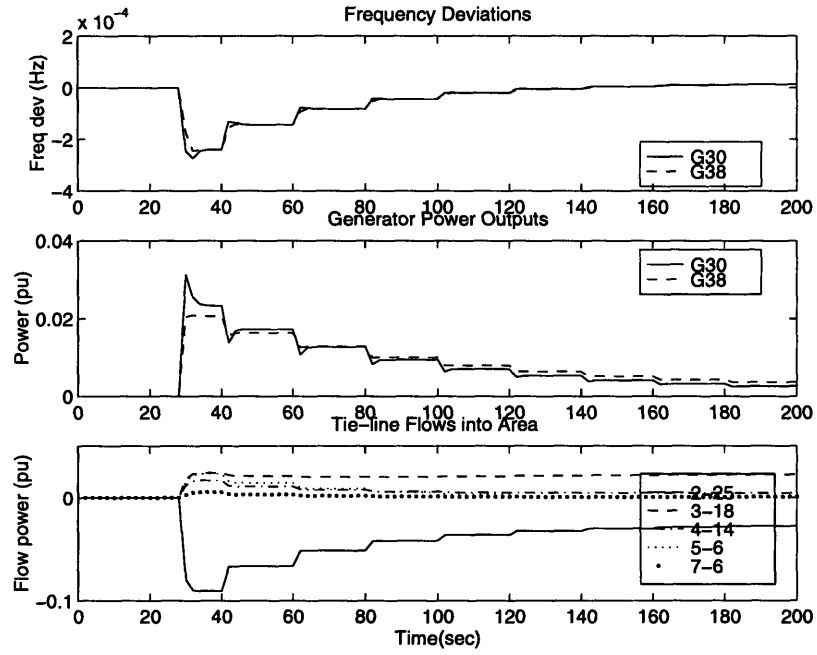
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Figure 3-5: System response to 0.2 p.u disturbance with ACE-based AGC (Area 1)

Figure 3-6: System response to 0.2 p.u disturbance with ACE-based AGC (Area 2)
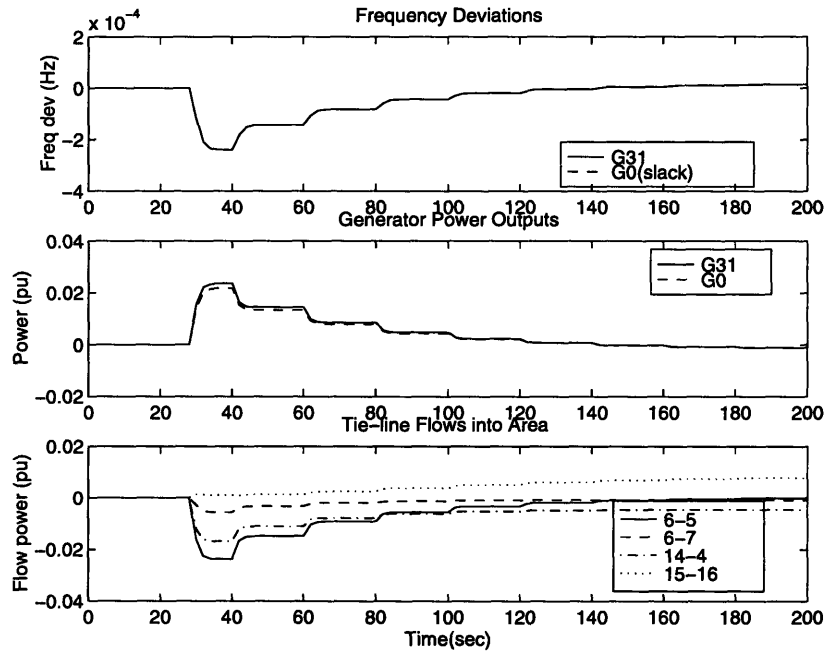
41
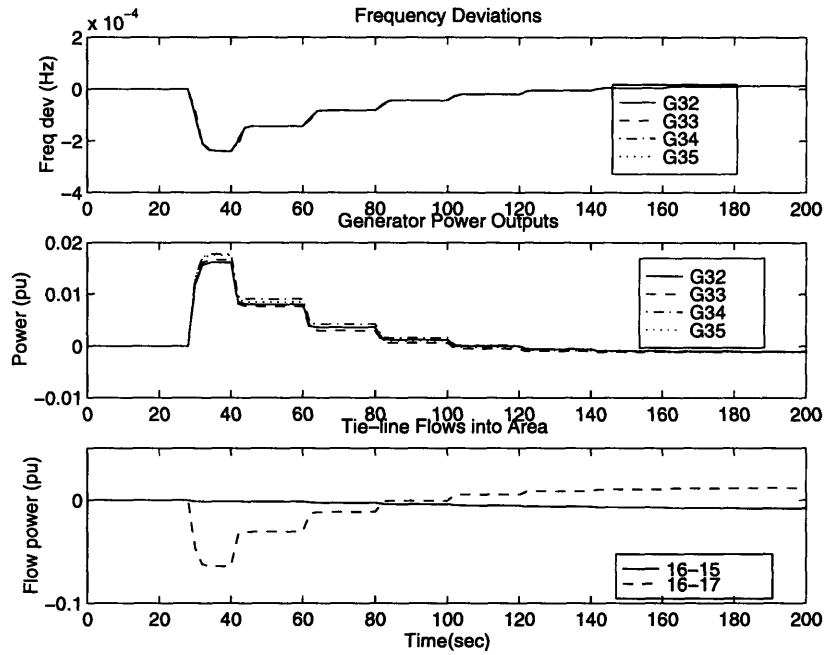
Figure 3-7: System response to 0.2 p.u disturbance with ACE-based AGC (Area 3)
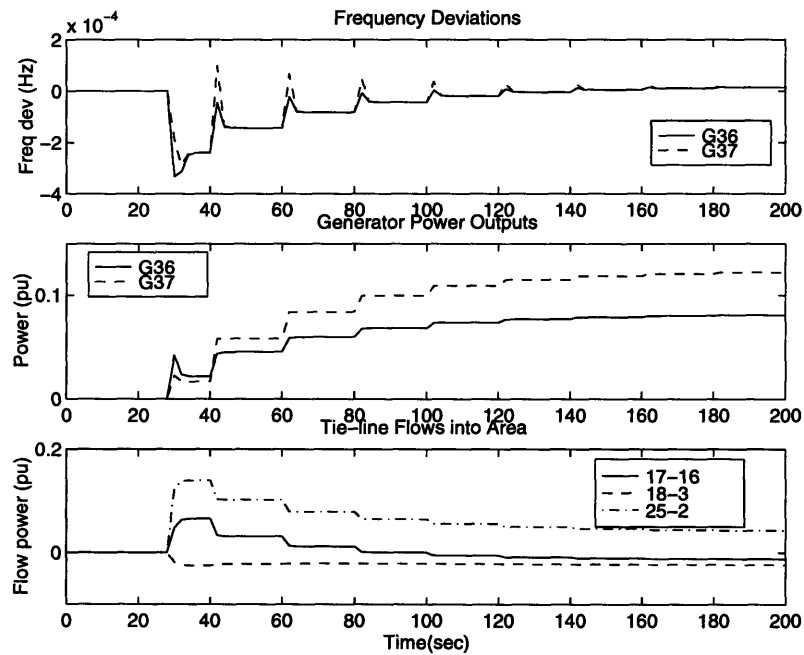
Figure 3-8: System response to 0.2 p.u disturbance with ACE-based AGC (Area 4)

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Figures 3-5 to 3-8 show the system response within 200 seconds. A comparison of this to the system response without AGC as shown in Figure 3-1 to Figure 3-4 shows that the conventional AGC successfully reduces the frequency deviations from the scheduled values as well as inadvertent tie-line power flows from adjoining areas. The generator frequencies and tie-line flows settle to some values which are close to the predisturbance conditions.

However, because of using bundled ACE-based signals, AGC cannot actually make frequencies or tie-line flows return to the initial values. Since the definition of Area Control Error is $ACE_i(t) = -\frac{10}{2\pi} b_i \omega_i^{ave}(t) + F_i^{net}(t)$, even though ACE signals are regulated to zeros, neither average frequency nor net tie-line flow offsets are necessarily zero. Furthermore, even if average frequency deviation is decreased to a smaller value, this does not necessarily apply to individual frequency. Similarly, Figure 3-5 to Figure 3-8 show that in order to limit $F_i^{net}(t)$ to small values, some individual tie-line flows deviate to positive values and others to negative values.

3.2   Advanced AGC

Recently an advanced approach to modeling and control of real power and frequency for large scale electric power systems was conceived [1-3]. This work was carried further in [4-6].

Revisiting present state-of-the-art of AGC and system-wide frequency/real power regulation was motivated by several factors.

- At present ACE-based AGC is prone to difficulties with choosing frequency bias, b_i, for the recommended industry standards, such as A1, to be met.

- Furthermore, the impact of generation/demand imbalances in the area on changes in ACE is bundled with the impact of deviations in tie-line flows coming from the neighboring areas.

- Meeting an industry standard, such as A1, does not guarantee that the specifications on frequency deviations (neither average, nor at the specific locations)

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would be met.

- Generally, the sensitivity of frequency with respect to real power generation, P_G, is very small. This fact directly follows from the droop characteristic of each generator, given in Chapter 2, Equation (2.14); this is simply because coefficient σ is typically small.

  Implication of this is that even though particular generating units do not respond to the ACE signal, the effect of this is small, and it will not be seen much in the ω^{ave} of the control area. This further means that certain units can "ride" on the others for frequency regulation in response to ACE deviations.

- The same problem of "riding" for frequency regulation is seen at the interconnected system level, since meeting A1 criteria for ACE does not imply that areas would actually regulate tie-line flow exchanges.

All of these facts are easily supported by the simulations in the previous section.

An overall relevant conclusion is that the presently implemented frequency regulation is not capable of meeting the end-user needs by whom the quality of power delivered can be thought of in terms of allowable thresholds of frequency deviations from 60 Hz[3].

At advanced notion of frequency and real power regulation discussed in this thesis is intended to

- Allow each subsystem (area end-user) to prespecify the quality of frequency response desired.

- Not require regulation of tie-line flow deviations at a subsystem level.

- Develop a slower, minimal order, scheme for regulating tie-line flow deviations at the interconnected system level. This regulation scheme is described and supported by simulations in the remainder of the thesis.

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[3]Here the thinking is only for very small, order of 10^{-3}Hz, yet nonuniform.

3.2.1 Secondary Control Only

The goal of the secondary control is to regulate generator frequencies, $\omega_G[k]$, within an area in order to reach the desired values. The secondary control alone will regulate generation frequencies at the location of interest to 60 Hz, and allow for fast deviations in net tie-line flows. Recall the secondary level model that was reviewed in Chapter 2,

$$\omega_G[k+1] = A_\omega \omega_G[k] + B_\omega u[k] + L_\omega(f[k] + D_p d[k]) \qquad (3.6)$$

This model lends itself in a straightforward way to the standard Optimal Linear Quadratic Regulator (LQR) theory [14], [15]. In [1], [16], a LQR problem formulation for the secondary level frequency regulation was introduced. The objective cost functional used is of the form

$$J = \sum_{k=0}^{\infty} \{\underline{\omega}_G^T[k+1]Q\underline{\omega}_G[k+1] + \underline{u}^T[k]R\underline{u}[k]\} \qquad (3.7)$$

In the cost functional, Q and R are state and control weighting matrices, respectively. These matrices should be chosen to reflect the relative quality of frequency regulation and the cost of regulation. For example, at the locations where higher quality of frequency response is required, the corresponding diagonal element in the matrix Q should be relatively high. Based on LQR method, the control law is

$$\underline{u}[k] = -K_s \underline{\omega}_G[k] \qquad (3.8)$$

where control gain, K_s, is

$$K_s = (R + B_\omega^T S B_\omega)^{-1} B_\omega^T S A_\omega, \qquad (3.9)$$

and S is the solution of

$$0 = A_\omega^T S A_\omega - S + Q - A_\omega^T S B_\omega (R + B_\omega^T S B_\omega)^{-1} B_\omega^T S A_\omega. \qquad (3.10)$$

Table 3.1: Generator parameters for 39-bus system (per unit)

Generator	30	31	32	33	34	35	36	37	38	0
Σ	4.94%	5.19%	4.71%	5.33%	5.48%	4.39%	5.19%	4.60%	4.94%	5.19%
D	5.0	4.0	6.0	3.5	3.0	7.0	4.0	6.5	5.0	4.0
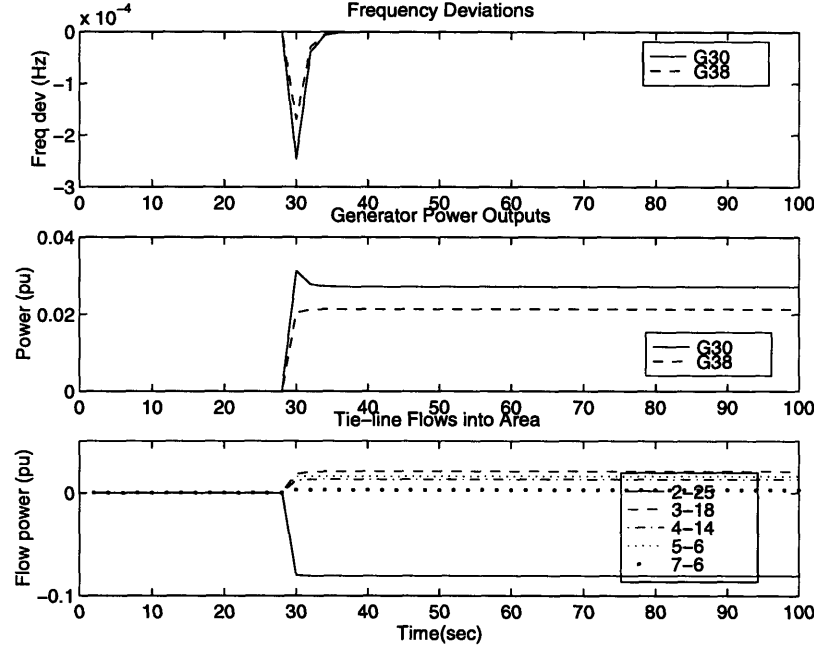
Figure 3-9: System response to 0.2 p.u disturbance with secondary control (Area 1)

Equation (3.10) is the discrete version of algebraic Riccati equation. If the system is controllable, the solution to the Riccati equation is also symmetric and at least positive semidefinite.

The LQR control of this type will guarantee stability; in this model the tie-line flows are treated as disturbances. For robustness with respect to these disturbances, the gain margin should range from 0.5 to infinity and the phase margin from negative 60 degrees to positive 60 degrees [14], [15].

3.2.2 Simulation Examples for Secondary Control

Table 3.1 shows all generator parameters for secondary control simulations. Time period for applying secondary control, T_s, is 2 seconds in the simulations. The ma-

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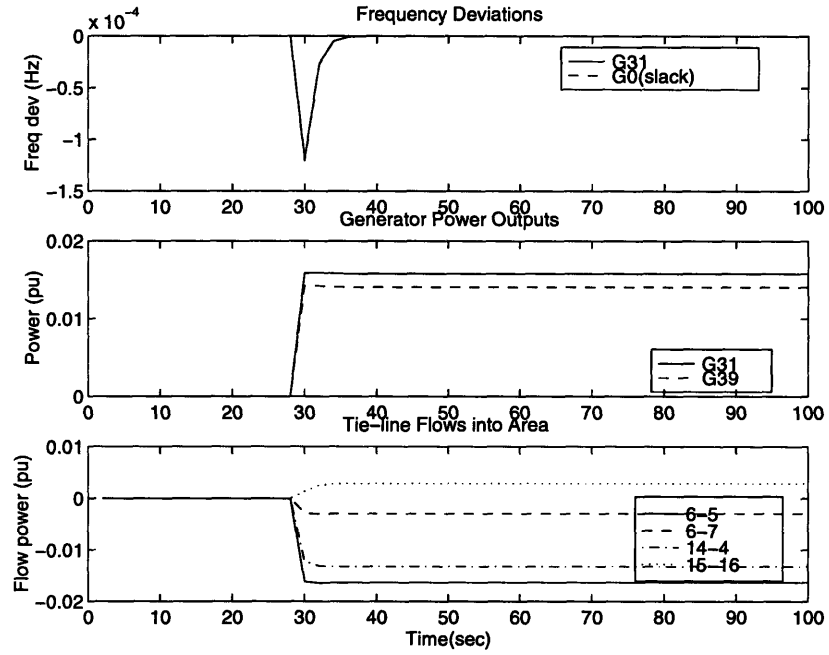
Figure 3-10: System response to 0.2 p.u disturbance with secondary control (Area 2)
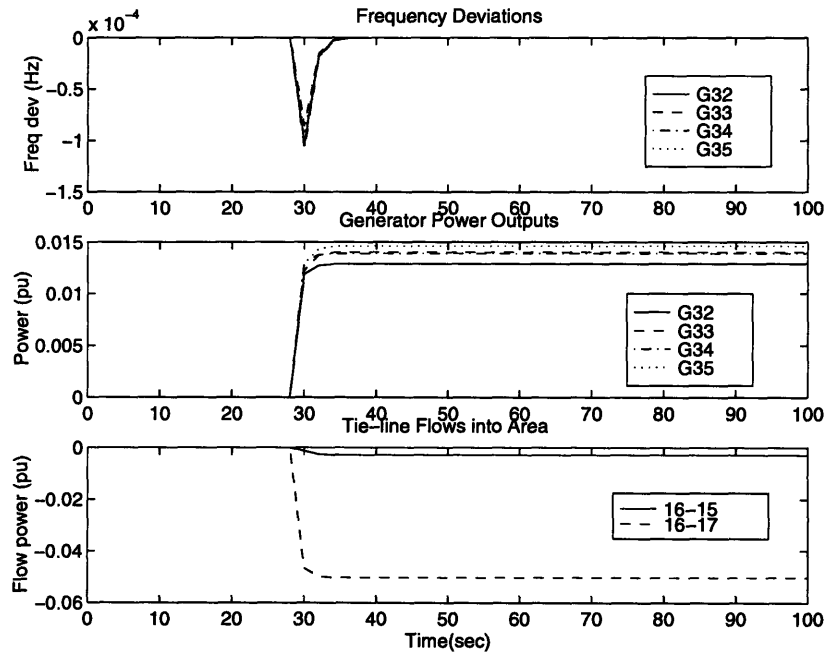
Figure 3-11: System response to 0.2 p.u disturbance with secondary control (Area 3)
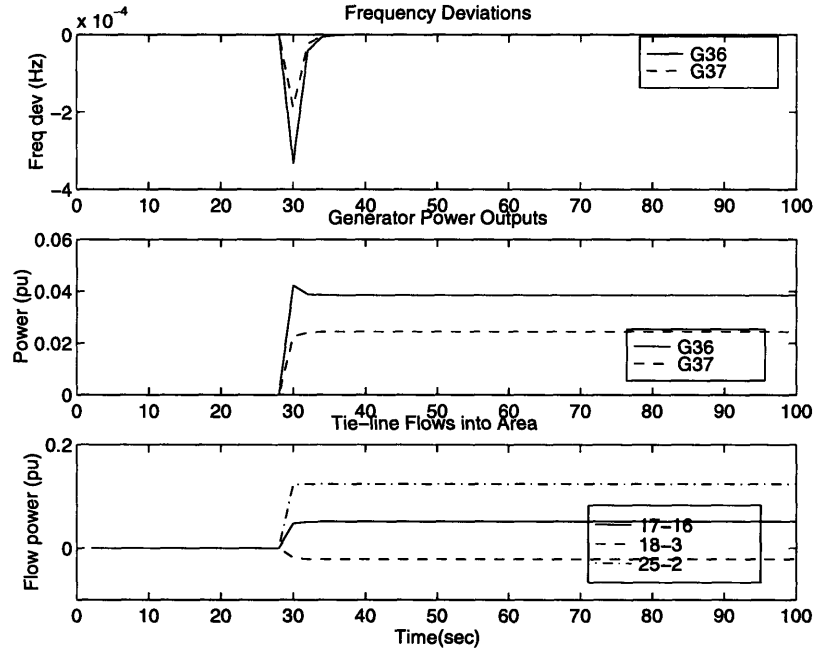
Figure 3-12: System response to 0.2 p.u disturbance with secondary control (Area 4)

trices Q and R for Riccati equation are equal to $100I$ and I, respectively. Where I is the identity matrix. By increasing the same amount of load disturbance on bus 25, readers can compare the results of ACE-based AGC case with the secondary control case.

The simulation results show that the secondary control is not only able to actually regulate the undesired frequency offsets but is also much faster than the conventional way. In addition, secondary control also could be designed to meet different frequency quality requirement. Figure 3-13 shows that by putting heavier weight, the frequency deviation of generator 33 is regulated faster than other three generators in area 3.

However, the secondary control is only in charge of regulating the frequency deviations from 60 Hz so it does not try to regulate any tie-line flows. It will let them flow and balance freely. In this case, the tie-line flow deviations are larger than that with conventional AGC.
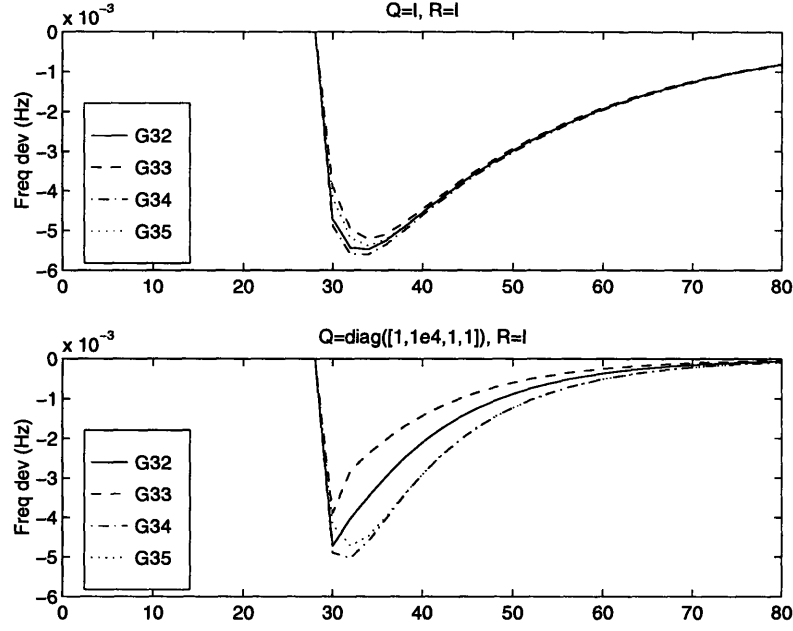
Figure 3-13: Frequency performances in area 3 with putting different weights on G33

3.2.3 Combining Tertiary and Secondary Level Control

The secondary control is designed to take care of the frequency regulation only, so a centralized coordination for tie-line flow control is needed. Even though the tie-line flow control has been discussed in the earlier AGC literature [18], [19], due to the usage of hierarchical control method, our approach is simpler and more straightforward. The derivations of the tertiary control from the tie-line flow model are presented below:

$$\underline{P}_f[K+1] = A_f\underline{P}_f[K] + B_f\underline{\omega}_G^{set}[K] + L_f\underline{d}[K] \tag{3.11}$$

The object performance functional which needs to be minimized in LQR method is

$$J = \sum_{K=0}^{\infty} \{\underline{P}_f^T[K+1]Q\underline{P}_f[K+1] + \underline{\omega}_G^{set^T}[K]R\underline{\omega}_G^{set}[K]\} \tag{3.12}$$

The feedback gain in tertiary level can be computed by solving the Riccati equation:

$$\underline{\omega}_G^{set}[K] = -K_t(\underline{P}_f[K]) \tag{3.13}$$

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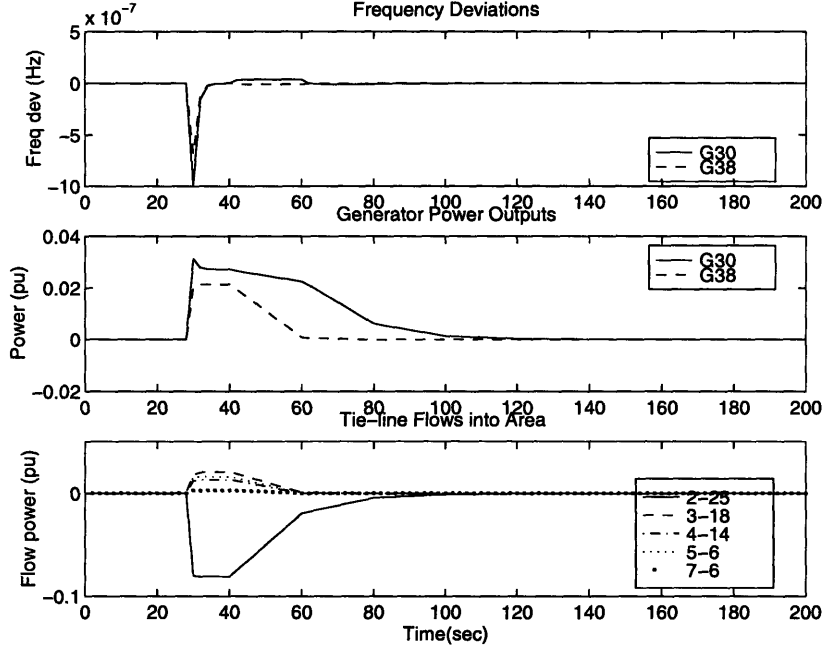
Figure 3-14: System response to 0.2 p.u. disturbance with advanced AGC (Area 1)

where K_t is defined as

$$K_t = (R + B_f^T S B_f)^{-1} B_f^T S A_f, \qquad (3.14)$$

and S is the solution of

$$0 = A_f^T S A_f - S + Q - A_f^T S B_f (R + B_f^T S B_f)^{-1} B_f^T S A_f \qquad (3.15)$$

The signals computed by tertiary control $\underline{\omega}_G^{set}[k]$ are sent to secondary control as reference inputs. Therefore, the control law in secondary level should be slightly changed to adapt to the reference input. For discrete time state feedback control with reference input [17], [4], secondary control law should be modified to

$$\underline{u}[k] = -K_s(\underline{\omega}_G[k] - \underline{\omega}_G^{set}[K]) + B_\omega^{-1}(\underline{I} - A_\omega)\underline{\omega}_G^{set}[K] \qquad (3.16)$$

The secondary control gain K_s is still the same.

3.2.4 Simulation Examples for Advanced AGC
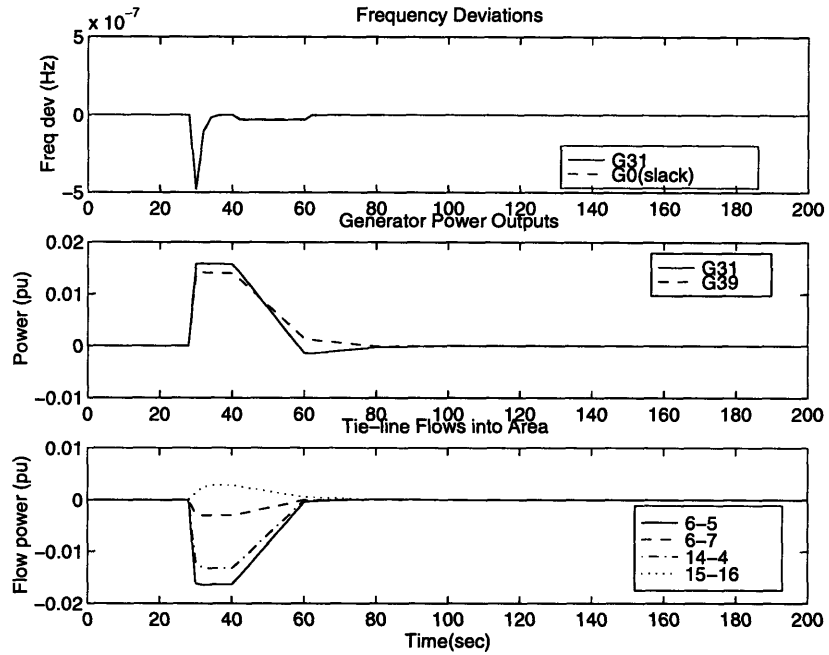
Figure 3-15: System response to 0.2 p.u. disturbance with advanced AGC (Area 2)
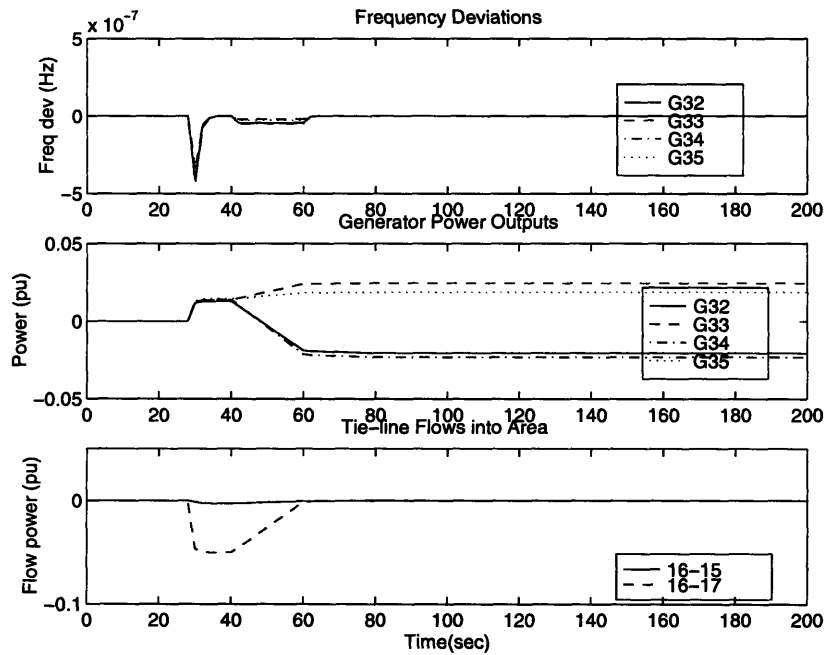
Figure 3-16: System response to 0.2 p.u. disturbance with advanced AGC (Area 3)
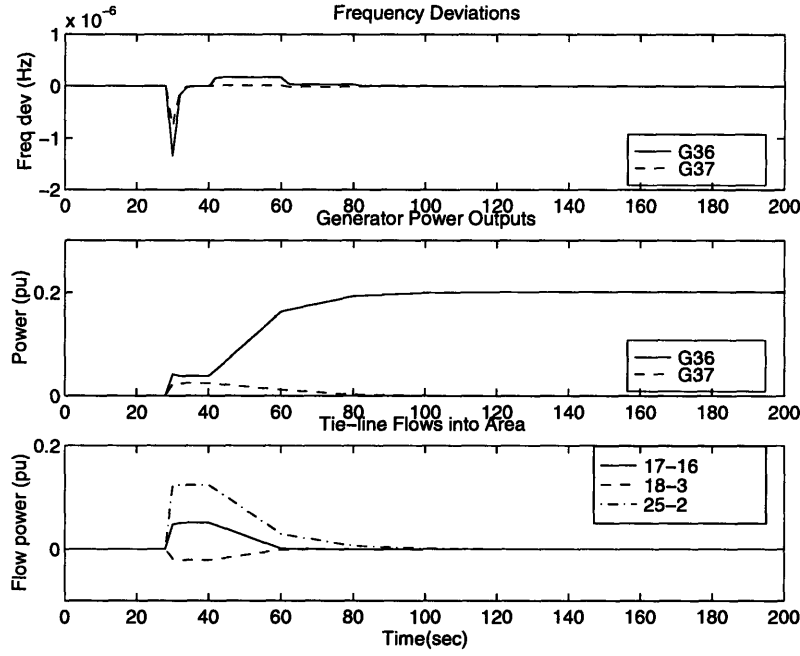
Figure 3-17: System response to 0.2 p.u. disturbance with advanced AGC (Area 4)

In the simulations where secondary level and tertiary level control are applied simultaneously. T_t is ten times[4] larger than T_s. In other words, secondary control runs every 2 seconds and tertiary control runs every 20 seconds. Both tertiary-level weighting matrices Q and R are I.

Figures 3-14 to 3-17 show that both frequency and tie-line flow deviations are completely eliminated by the advanced AGC. There are some interesting properties. First, compared to the frequency response in the secondary control, frequencies are regulated more slowly if both tertiary and secondary controls are applied. This is a trade-off between frequency and tie-line flow regulations. Theoretically, frequency control is done right after that of tie-line flows, because the sensitivities of tie-line flows to generation frequencies are large, namely,

$$\frac{\partial \omega_{Gi}}{\partial P_{fj}} \ll 1 \tag{3.17}$$

---

[4]In typical control design, the time constant of outer loop, tertiary control, is chosen larger than the inner loop control, secondary control, to make sure that inner loop can be stabilized within the time period so that the basic assumption in hierarchical modeling is not violated. 10 times larger is generally considered an appropriate value.

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$$i \in 1, \cdots, N_G \qquad\qquad (3.18)$$

$$j \in 1, \cdots, N_{line} \qquad\qquad (3.19)$$

where N_G and N_{line} represent the number of generator participating in the tertiary control and tie-line respectively. In other words, tiny frequency deviations result in sufficient tie-line flow changes.

Regarding the behavior of tie-line flows, there are two kind of responses in non-disturbed areas. The first kind is like that of area 1 and area 2. Due to the tie-line flow control, the disturbance in area 4 only effects area 1 and area 2 in a very short time. All generators in area 1 and 2 return to their original settling points after the system has reached the steady state. The second kind of response is like that in area 3. All generators in area 3 are adjusted to help the system achieve the regulation. It is impossible for area 4 alone to make tie-line flow deviations between area 3 and 4 return to zero, so area 3 rearranges the generation to create counterflows and cancel the tie-line flow effects from area 4.

3.3 Summary

Two Automatic Generation Control (AGC) methods are introduced in this chapter. The conventional AGC is the current technique widely used in electric power system industry. The advanced AGC is the newly developed control technique for generator frequency and tie-line power flow control.

The conventional AGC functions by responding to the bundled control signals called Area Control Errors (ACEs). However, because of the inherent nature of ACE signals, conventional AGC cannot regulate separately both frequencies and tie-line flows. In addition, even though some suggested solutions are made, the uncertainty of choosing frequency bias, b_i, still exists as an open question.

The general idea of advanced AGC control is that by using a hierarchical structure-based models, the complex control tasks are shared by different hierarchical levels. Therefore, its development is totally based on the significant progress in modeling

technique. The conventional AGC includes unbundled information into control design. It is seen, from the representative simulation results, that the advanced AGC is not only faster and more effective than ACE-based AGC, but it can also allow all frequencies as well as tie-line flows to be regulated to their initial scheduled values.

Chapter 4

Automatic Generation Control Under Open Access

4.1 Changing Electric Power Industry

The traditional structure of the electric power industry consists of a number of strict, mandatory pools owned by utility industry investors. These investors own all generation and transmission resources, which provide customers with most of their electric energy. Under this structure, customers have few choices for services or billing and pricing. However, recently, there has been a strong movement toward deregulating this industry [28].

Over the past several years, most of the new sources of electrical generation in the United States were built by independent power producers (IPPs). Usually IPPs sold power to their local investor-owned utility services. In 1992, the Energy Policy Act (EPAct) required utility investors to open wholesale access to the transmission systems. In other words, independent power producers could use the transmission services provided by investor utilities in order to sell wholesale electricity to any qualified wholesale buyer. Obviously, as competition among different producers of electricity increased, the electricity market in the United States became more and more competitive.

As the environment of the power industry shifts and varying system inputs change

their patterns (i.e., more and more profit-driven energy exchanges or independent injections of demand or generation), the performance criteria for system functions should also change. In order to propose future system regulation, it is essential to study the basic "rules of the game" and to re-examine the criteria in this coming competitive environment. A standardized performance criterion for system operations needs to be found. There are some general rules that have been outlined in recent economic studies and that provide guidelines for the competitive electric power industry in the future [28]:

- Competition should be allowed in generation with open access to transmission and distribution systems.

- Transmission and distribution systems will continue to be well regulated monopolies.

- An independent system operator (ISO) should be established to provide network coordination.

- Ancillary services, such as frequency control, voltage support, and transmission services, are needed to guarantee system reliability as well as power quality.

Some emerging proposals on new industry structures are discussed in the next section.

4.2 Future Operating Framework in a Competitive Environment

The new operating structure in a competitive industry must be able to coordinate the system and preserve overall reliability and security. It should also allow the competitive generation to participate in system-wide regulation, if desired. In this situation, it is essential to make a distinction between (i) technical functions for system-wide performance, and (ii) commercial functions of purchasing and selling.

At present the two most discussed proposals for industry restructuring are so called Pool-Co model and Bilateral model [28], [29], [30]. The Pool-Co model is
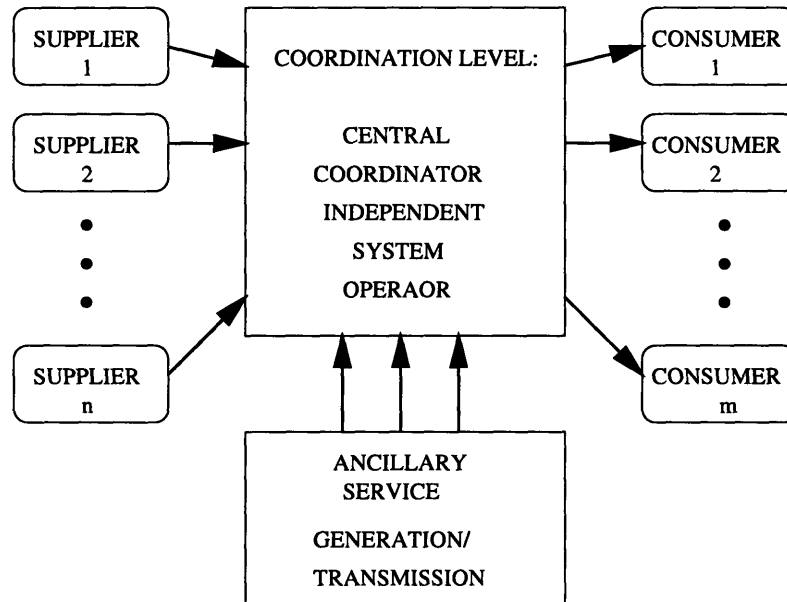
Figure 4-1: The competitive market

based on having a pool in charge of dealing with the energy distribution among sellers and buyers of electricity. The Pool-Co model would allow all customers to buy the electricity at a spot price. On the contrary, in the Bilateral environment, the decentralized bilateral contracts among sellers and buyers determine the price of electricity. The competition of generation is expected to lead to the economic equilibrium.

A latest example of the Pool-Co model is the restructuring of the United Kingdom (UK) power system[31]. UK experience shows that using the Pool-Co structure achieves only partially competitive market. However, it is feasible to create a fully competitive environment that is totally different from the traditional vertically integrated structure in the United States.

Figure 4-1 indicates a possible structure of the future US utility industry under open access to transmission and distribution systems. In fact, the restructuring is

already in progress. In this structure, ISO provides network coordination and other ancillary services. Unlike the UK's approach of a common pool, the restructuring of the electric supply industry in the US is totally based on bilateral contracts. This model provides each customer chances to seek his own supplier. These bilateral transactions are potentially more efficient and could lead to greater customer choices and lower costs.

In fact, both models provide a centralized pool and bilateral contracts, which, however, are given different priority, in the different models. The ultimate goal of these different models is to create a free market-like utility environment, but these models use different ways to approach it.

Once the competitive utility market is established, a lot of "profit-driven" energy may be transferred across the different areas which are physically apart so the origination weakly connected administrative areas will become more strongly connected. In this sense, the vertical hierarchy structure changes into "nested hierarchy" [16]. Within this nested hierarchy structure, new performance objective for system operation should be defined so that the utility industry can build the new market model directly onto the present market structure by providing open access for increased number of players.

Obviously, it will be extremely complex to meet the performance objectives in the real-time operations of a very large nested hierarchical system. It is essential to assign performance objectives relevant to different levels of hierarchy with minimal-order models and minimal coordination for both security and efficiency purposes.

4.2.1 Interconnected Operations Services: The Role of Systems Control

The independent system operator (ISO) will provide the basic coordination in future competitive power markets. The ISO not only needs to have authority to act in emergencies but also has to provide sufficient system control services[1] that can

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[1]In this thesis, the NERC term interconnected operations services is used interchangeably with the FERC introduced term ancillary services and, furthermore, with the term systems control services

preserve the operation reliability of the system and facilitate trades. These services are fundamental and important for keeping the system's integrity under competition [20].

Systems control services include compensation of transmission line losses, maintaining of the system within the operating constraints, frequency regulation, etc. Without them, the system would break down. As the electric power market becomes more and more competitive, the load and flow changes will become more difficult to predict. Therefore, it is impossible for the system manager to know precisely where the violation of the constraints will happen, and a higher burden may be placed on automated systems control services.

This thesis introduces a possible approach to system regulation under competition. This approach separates and simplifies the control objective into two subobjectives, i.e., its secondary and tertiary levels. The secondary level is a regulating level in which fringe control is in charge of frequency regulation. The tertiary level is an economic level. The main objective of this level control is cost optimization.

4.3 Minimal System Regulation under Competition

At present, the set values of tie-line flows are established through arrangement among specific companies. Any deviations from the original set values will very likely violate the optimal dispatch. They are usually treated as "Inadvertent Energy Exchange." As the utility market undergoes severe structural changes, the main objectives of AGC diverge from the traditional ones. Since price and cost will dominate most energy exchanges, the interconnection between the administratively separated areas will become more intensive. Any flow regulation that fails to consider of those economic issues will decrease the economic efficiency. Because making supply and demand competitive achieves the economic efficiency, the performance objectives should induce

in [16].

economic tie-line power flows so that the system can continue to provide a competitive environment for all suppliers and buyers. The use of cost-based control structure will keep the system together in response to the strictly profit-driven system disturbances under open access. The main idea of minimal regulation is to use system-wide resources with the least amount of total generation cost while preserving the system security [32].

4.3.1 Cost

As mentioned earlier in this thesis, at present performance objectives for system regulation in response to unscheduled deviations are mainly technical. However, it is likely that the performance objectives under competition may account for the economics of system regulation. Depending on how the systems control services are charged for, the economics may reflect either cost or profit associated with providing these services. In any event, the cost associated with AGC will take on a new importance. Typically, the generation cost is directly dependent on the power generated. The hierarchical models described in this thesis can provide the unbundled generation cost information to the individual users of systems control services such as AGC. The fuel cost of a generator is a nonlinear function of generation produced.

$$C(\hat{P}_G) = h(\hat{P}_G) \tag{4.1}$$

where $h()$ is a nonlinear cost function, and $\hat{P}_G$ is the actual real generator power rather than the incremental one, $P_G{}^2$. In other words,

$$\hat{P}_G = P_{G0} + P_G \tag{4.2}$$

where P_{G0} is the nominal, scheduled, value of the generator real power output.

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[2]In the previous part of this thesis we considered only the deviations, increment, of real power, P_G.
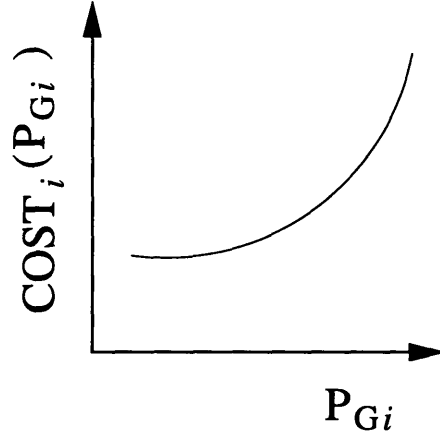
Figure 4-2: Generation cost curve

The nonlinear fuel cost curves are usually approximated by quadratic functions

$$C(\hat{P}_G) = a_0 + a_1\hat{P}_G + a_2\hat{P}_G^2 \qquad (4.3)$$

In addition,

$$
\begin{aligned}
C(\hat{P})G) &= a_0 + a_1\hat{P}_G + a_2\hat{P}_G^2 \\
&= a_0 + a_1(P_{G0} + P_G) + a_2(P_{G0} + P_G)^2 \\
&= (a_0 + a_1P_{G0} + a_2P_{G0}^2) + (a_1P_G + 2a_2P_{G0}P_G) + a_2P_G^2 \\
&= cost_0 + \left.\frac{\partial C(\hat{P}_G)}{\partial P_G}\right|_{P_G^0} P_G + a_2P_G^2 \\
C(P_G) &= \lambda P_G + a_2P_G^2
\end{aligned}
$$

Therefore, the cost deviation can be expressed as

$$C_i(P_{G_i}[k]) = \lambda_i P_{G_i}[k] + a_{2i}(P_{G_i}[k])^2 \qquad (4.4)$$

The λ_i term in the equation is the first order sensitivity of cost at its nominal operating value, P_{G0}. It is also known as a Short Run Marginal Cost (SRMC).

The SRMC is typically used to express optimal economic dispatch conditions for scheduled (known) demand: If the system is operating in the optimal condition that

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minimizes the total cost, λ_i of all participating generation units will be the same as long as the operating constraints are not violated and transmission losses are neglected. Namely, this condition is often referred to being the economic equilibrium.

4.3.2 Economic Dispatch

Some former studies have developed Economic Dispatch (ED) methods and many control centers currently use it routinely for scheduling generation for the anticipated demand [24–27]. ED functions to schedule the real power outputs of the on-line generators so as to meet the net total load with least fuel cost.

Mathematically, the basic ED problem is to find the optimal value of generator power P_G^* that minimizes the total generation cost. Namely,

$$min \sum_{i=1}^{N_G} C_i(\hat{P}_{G_i}) \qquad (4.5)$$

subject to

$$\sum_{i=1}^{N_G} \hat{P}_{G_i} = \sum_{j=1}^{N_L} \hat{P}_{L_j} + \hat{P}_{loss} \qquad (4.6)$$

[3] When the transmission loss, P_{loss}, is neglected, the necessary condition for an optimal solution to this problem is known as

$$\frac{\partial C_1(P_{G_1})}{\partial P_{G_1}} = \frac{\partial C_2(P_{G_2})}{\partial P_{G_2}} = \cdots = \frac{\partial C_{N_G}(P_{G_{N_G}})}{\partial P_{G_{N_G}}} = \lambda^* \qquad (4.7)$$

$$P_{G_i}^{min} \leq P_{G_i}^* \leq P_{G_i}^{max} \qquad (4.8)$$

$$i \in 1, \cdots, N_G \qquad (4.9)$$

where λ is the SRMC. At the optimal operating condition, all generation units have the same value, λ^*. Sometimes, that optimal value of SRMC is called the "system lambda." When all SRMCs approach the system lambda, the system will achieve its maximum technical efficiency in operating an electric power system.

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[3]Symbol $\wedge$ stands here for the actual rather than the incremental values.

For security reasons, the system control should achieve system-wide optimum performance but not violate technical constraints. These constraints must be met for various reasons.

The constrained ED problem that meets constraints on thermal transmission line limits must account for

$$P_{f_j}^{min} \leq P_{f_j}^* \leq P_{f_j}^{max} \tag{4.10}$$

$$j \in 1, \cdots, N_{line} \tag{4.11}$$

4.3.3 Fringe Control

Mr. C. Nichols first proposed the idea of fringe control in 1953 [23], [13]. Before discussing the fringe control, we differentiate between two load components, fringe and sustained loads. The fringe load is the noisy portion of a load signal that changes rapidly. The bandwidth of fringe load is much wider than that of sustained load. Fringe control has an impact on the frequency regulation, since the local generation frequencies are much more sensitive to those small changes than tie-line flows. Ostensibly, the fringe loads do not actually reflect the load fluctuation. Therefore, fringe control may not respond according to cost minimization criteria observed in the economic dispatch. Our control approach separates regulation and economic signals into two different hierarchies. The fringe control is at the secondary level and always in charge of regulating frequency deviations caused by the fringe load components. The control algorithm of the fringe control is the same as that of secondary frequency control addressed in the previous chapter. The objective performance criterion for fringe control control is

$$J = \sum_{k=0}^{\infty} \{\underline{\omega}_G^T[k+1]Q\underline{\omega}_G[k+1] + \underline{u}^T[k]R\underline{u}[k]\}. \tag{4.12}$$

The performance criterion is sufficiently general to reflect the specifications of the output variables at the area-wide level. The elements in the weighting matrices Q and R can be chosen differently to reflect different frequency quality requirements

at individual generators throughout the area. In other words, one can design the secondary control gain, K_s, according to the desired frequency qualities at different locations in the area. This is very easy and straightforward for the unbundled approach but hard for the ACE-based AGC. In an open access environment, this feature is potentially quite important.

4.3.4 Minimal Regulation

Minimal regulation is designed to regulate system-wide response to sustained load deviations from scheduled [32]. The sustained loads are bulks of load changes. These loads change more slowly than fringe loads and some are predictable. Strictly speaking, these sustained loads should be optimally dispatched to every generator participating in the system regulation to minimize total generation cost. To make this idea feasible requires a dynamic controller at the interconnected level. The minimal regulation is placed in the tertiary level and is in effect a dynamic Economic Dispatch control[4].

In order to cause all generation power to approach the optimal dispatch, P_G^*, we need to develop a generation power model. From the Jacobian expression of generation power output in Equation (2.6), for computing the entire Jacobian matrix at the tertiary level, the tie-line flow terms, F_G and F_L, are not present in the equation:

$$\underline{P}_G[K] = K_p \underline{\delta}_G[K] + D_p \underline{P}_L[K] \qquad (4.13)$$

Hence,

$$\underline{P}_G[K+1] = \underline{P}_G[K] + K_p(\underline{\delta}_G[K+1] - \underline{\delta}_G[K]) + D_p(\underline{P}_L[K+1] - \underline{P}_L[K]) \qquad (4.14)$$

---

[4]This term is used to indicated the emphasis on the cost of system-wide regulation. However, one must carefully differentiate between responding scheduled (known) load changes, and the known, yet sustained load deviations from scheduled. The dynamic tertiary control described in this thesis could be applied to both cases.

Again, the approximation of the phase angle is

$$\omega_G[K]T_t \approx \delta[K+1] - \delta[K].$$ (4.15)

Then the model defining deviations in power at the interconnected level take on the form

$$P_G[K+1] = P_G[K] + K_p T_t \omega_G^{set}[K] + D_p d[K]$$ (4.16)

where $\omega_G^{set}[K]$ is the reference value sent to the fringe control. This model can be simply expressed as:

$$\underline{P}_G[K+1] = A_p \underline{P}_G[K+1] + B_p \underline{\omega}_G^{set}[K] + L_p \underline{d}[K]$$ (4.17)

The reference input, $\omega_G^{set}[K]$, for the secondary level control is

$$\underline{\omega}_G^{set}[K] = -K_t(\underline{P}_G[K] - \underline{P}_G^*[K])$$ (4.18)

The Performance criterion for minimal regulation is defined as:

$$J = \sum_{K=0}^{\infty} \{\underline{P}_p^T[K+1]Q\underline{P}_p[K+1] + \underline{\omega}_G^{set^T}[K]R\underline{\omega}_G^{set}[K]\}$$ (4.19)

The matrix K_t that optimizes the performance criterion at the interconnected system level, is, again, obtained from the LQR calculation. The optimal values of real power generation, P_G^*, are obtained from the economic dispatch calculation, which is mentioned earlier. Due to the network power balance[5], the sum of all generator power outputs will be the sum of total demand and transmission losses

$$\sum_{j=1}^{N_L} P_{Lj} + P_{loss} \approx \sum_{i=1}^{N_G} P_{G_i}$$ (4.20)

Therefore, we can update the demand and losses information that are needed for economic dispatch every T_t seconds. Assuming that the sustained load fluctuation

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[5]Of course, we assume that the network power equilibrium can be achieved within T_t seconds.

is relatively small within one T_t interval, we could use the information at KT_t to compute the optimal set point of generator power for $[K + 1]T_t$. Besides, since all generator cost curves are approximated by quadratic functions, the solution, P_G^*, of the economic dispatch problem is already known.

In practice, the frequency set values, ω_G^{set}, are sent to secondary controllers to computer the reference frequencies, ω_G^{ref} of all generators. Finally, the reference frequencies are sent to the primary controllers, speed governors. Remember that, no matter how many hierarchies are adopted in the control design, the only tuning factors, real control signals, for real power and frequency control in electric power systems is ω_G^{ref}.

Intuitively, not all the power from generators are independent variables because they have to satisfy the constraint:

$$\sum_{i=1}^{N_G} P_{Gi} = \sum P_{demand} \tag{4.21}$$

Namely, total generation has to meet total demand. This phenomenon also emerges in a mathematical form. In the tertiary generation model, matrix K_p does not have full rank and the number of the rank always lacks one. The slack generator that is in charge of balancing the electric system is designed to make up the defect. In the interconnected system level, the slack generator is not controlled and only the other $(N_G - 1)$ generators are controlled. However, once other generators approach P_G^*, slack power generation will approach its own value automatically due to the power balance in the network. Mathematically, output power of the slack generator can be expressed as a linear combination of other $(N_G - 1)$ values so it is not an independent state.

4.4 Summary

As more independent power producers participate in electrical power generation, the utility industry of the United States is becoming more competitive. Moreover, the

mandate of open access to transmission and distribution systems made by the Energy Policy Act (EPAct) in 1992 makes restructuring of the utility industry an actively studied problem.

Two possible models for the future utility industry are Pool-Co model and Bilateral model. Both of them need an independent system operator (ISO) to provide essential systems control services that make all market trades feasible and also guarantee the system security and reliability.

As the operating environment changes, the performance criteria for operation should be changed. Market activities will determine the strength of interconnection among areas. Hence, tie-line flows should be regulated in the most economic way rather than forced to return to their original set values. In this sense, using a cost-based performance objective for system control is fairly straightforward.
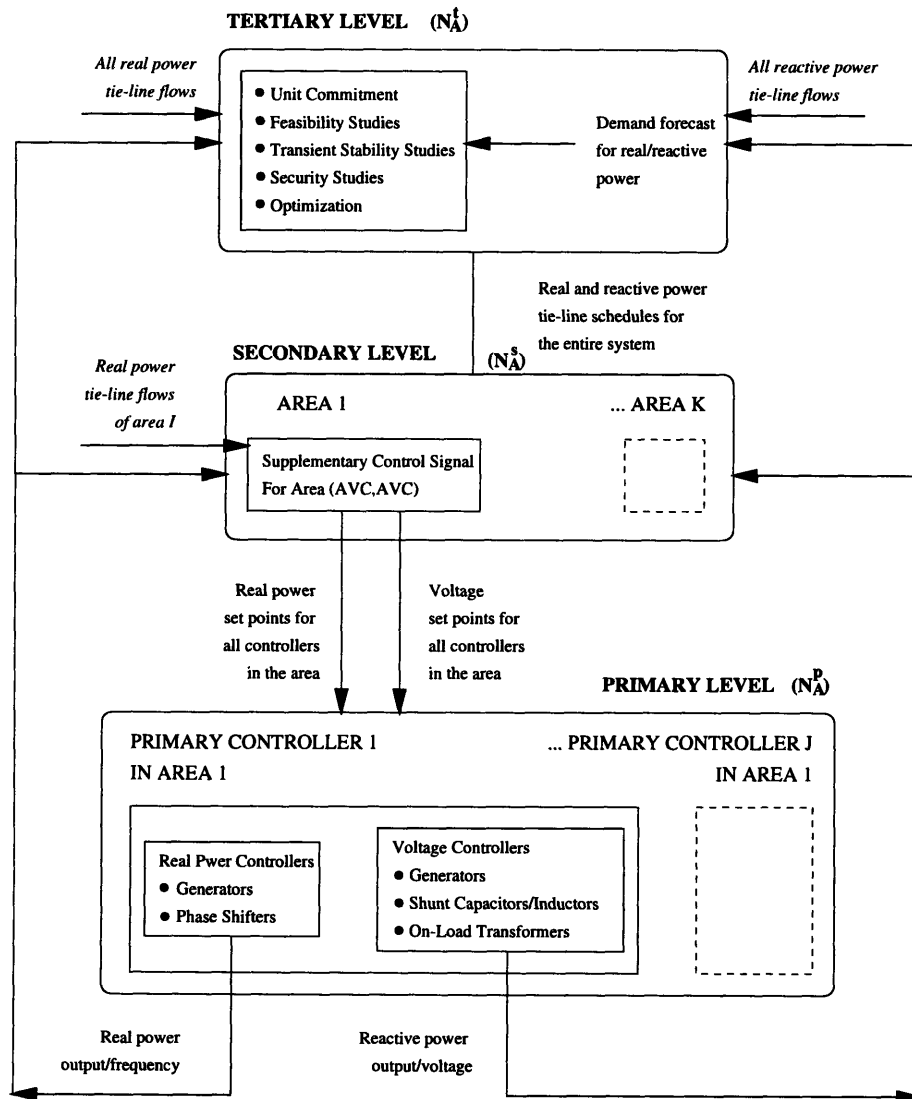
Since the traditional control assumptions on which AGC is based are hard no longer valid due to the increase of market-driven energy exchanges, the conventional control will be inadequate for future operation.

A new control scheme for systems control services is called minimal regulation. Table 4.1 shows the hierarchical structure of the minimal regulation. The minimal regulation is a tertiary level control that minimizes the total generation cost of the entire system by optimally arranging the generation.

The minimal regulation will indirectly cause optimal rescheduling of tie-line flows in response to the load variations, $P_L[K]$, while maintaining the system frequency quality. The optimally rescheduled tie-line flows can also preserve transmission security. In other words, they will not exceed transmission limits.

In an open access and competitive environment, the size and the number of control areas are no longer based on traditional decomposition rules, i.e., the physical topology or the strength of interconnection, because the profit-driven power flows will dominate all energy exchanges. The strength of interconnection is going to fluctuate dynamically with market activities.

Table 4.1: Hierarchical measurement/control structure of systems control services

TERTIARY LEVEL (N_A^t)

All real power   • Unit Commitment
tie-line flows   • Feasibility Studies   Demand forecast   *All reactive power*
                          • Transient Stability Studies   for real/reactive   *tie-line flows*
                          • Security Studies   power
                          • Optimization

                                                    Real and reactive power
                                                    tie-line schedules for
Real power   SECONDARY LEVEL (N_A^s) the entire system
tie-line flows
of area I   AREA 1   ... AREA K

                          Supplementary Control Signal
                          For Area (AVC,AVC)

                    Real power   Voltage
                    set points for   set points for
                    all controllers   all controllers
                    in the area   in the area   PRIMARY LEVEL (N_A^p)

                PRIMARY CONTROLLER 1   ... PRIMARY CONTROLLER J
                IN AREA 1   IN AREA 1

                    Real Pwer Controllers   Voltage Controllers
                    • Generators   • Generators
                    • Phase Shifters   • Shunt Capacitors/Inductors
                                              • On-Load Transformers

            Real power   Reactive power
        output/frequency   output/voltage

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Chapter 5

Minimal Regulation in a Pool-Co Environment

5.1 Pool-Co Market

One proposed model of the operating framework that has been successfully implemented in UK is called Pool-Co model. The Pool-Co is an independent coordinator of buyers and sellers of electricity. It is regulated to provide open access and comparable services so that customers can buy electricity at spot prices. It establishes a competitive market which is accessible to all buyers and sellers.

The entire utility industry in the United Kingdom functions as a single power pool with a uniform energy price across the country. In the Pool-Co model, ISO controls all generation in its own control area and it buys power from all generators and sells power to all customers simultaneously.

5.2 Conventional AGC and Minimal Regulation

Assume that the IEEE 39-bus system is operating in a Pool-Co environment and the power pool includes all 10 generators. In the beginning, the electric market is at the economic equilibrium and the short run marginal costs (SRMCs) of all generation units are equal to the system lambda, λ^*. In the following simulation examples,
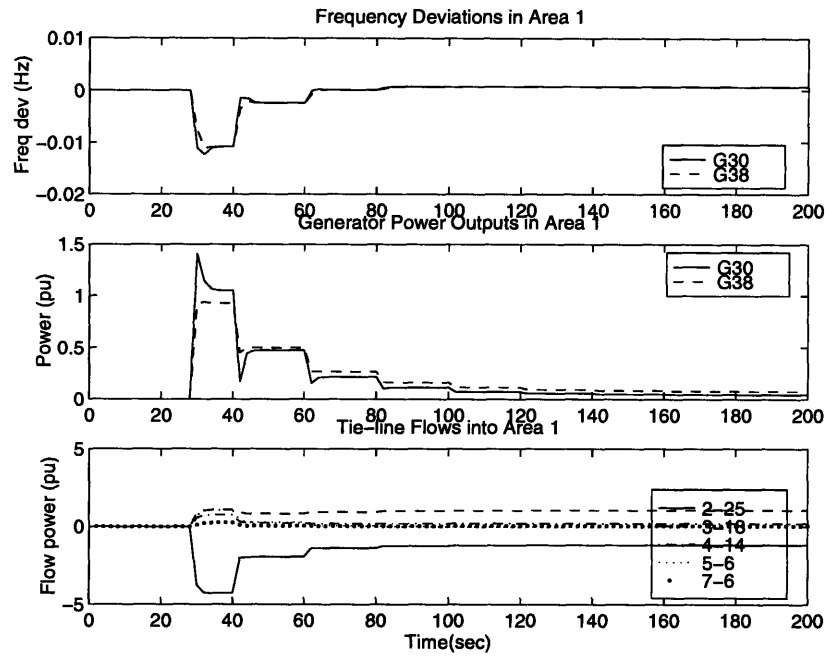
Figure 5-1: Conventional AGC response in the Pool-Co environment (Area 1)

the original value of λ^* is 0.7. The quadratic term coefficients of the cost curve of generator 30, 31, 32, 33, 34, 35, 36, 37, 38, and the slack generator, 0, are 0.002, 0.005, 0.2, 0.25, 0.17, 0.21, 0.1, 0.15, 0.03, and 0.07 respectively. Since the nominal generation costs of all generators are minimized, the fuel costs of those generators that have larger quadratic term coefficients will grow faster than that of the generators having smaller coefficients. In this case, these values are set in such a way to make the generation in area 1 cheapest (in Figure 2.3, Chapter 2) and generation in area 3 the most expensive. Consequently, generation is area 2 is cheaper than that in area 4 but still more expensive than area 1.

At time t=30 seconds, a large load increase 9 p.u. occurs. In the Pool-Co environment, the load requirement is shared by all generators in the pool. The generator frequencies drop at the instant of load changing. Therefore, system control, AGC, immediately acts and starts regulating the system.

Figures 5-1 to 5-4 show how conventional AGC responds to this large load demand increase. In the conventional AGC, ACE combines average frequency and net tie-line flow. As mentioned earlier, sensitivities of the tie-line power flows to the

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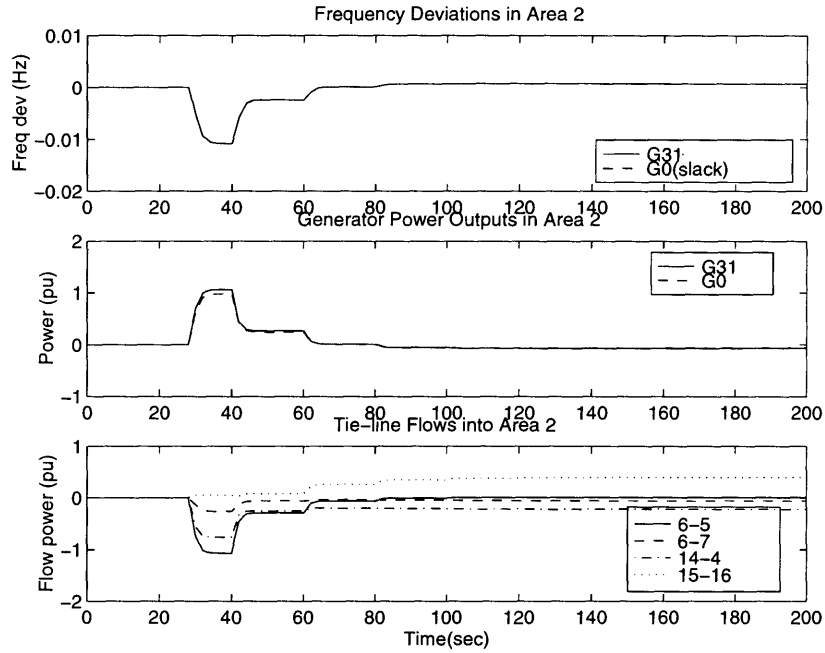
Figure 5-2: Conventional AGC response in the Pool-Co environment (Area 2)
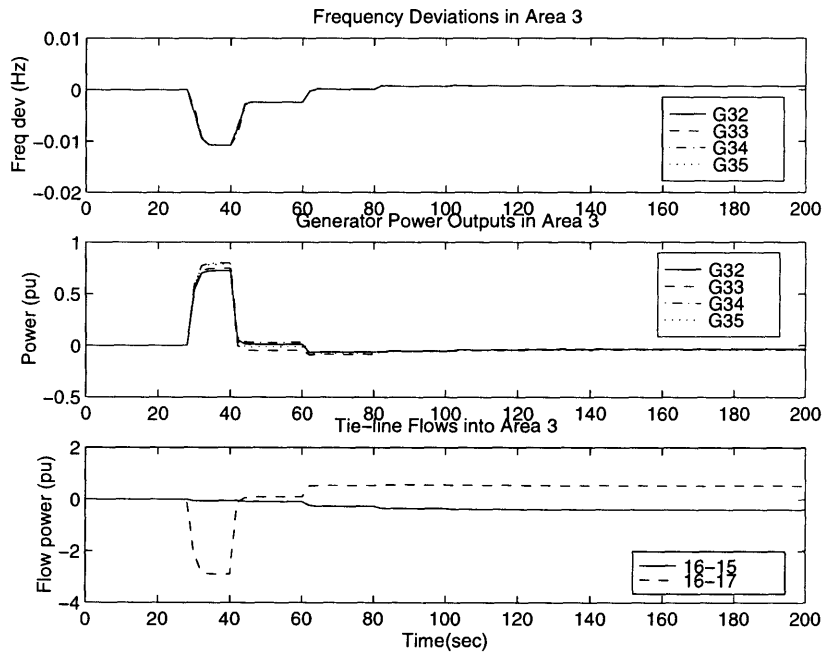
Figure 5-3: Conventional AGC response in the Pool-Co environment (Area 3)

Frequency Deviations in Area 4

Freq dev (Hz)

0.02

0

-0.02

0   20   40   60   80   100   120   140   160   180   200

G36
G37

Generator Power Outputs in Area 4

Power (pu)

6

4

2

0

0   20   40   60   80   100   120   140   160   180   200

G36
G37

Tie-line Flows into Area 4

Flow power (pu)

10

5

0

-5

0   20   40   60   80   100   120   140   160   180   200

Time(sec)

17–16
18–3
25–2
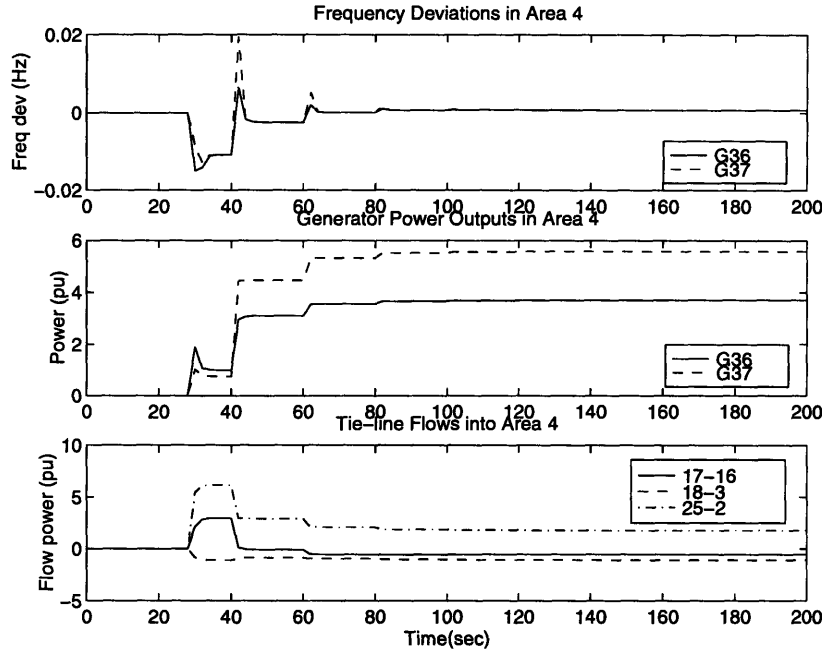
Figure 5-4: Conventional AGC response in the Pool-Co environment (Area 4)

power mismatch caused by this load increase are much larger than the sensitivity of frequency deviations. Therefore, at the beginning of the ACE regulation, net tie-line flow regulation will dominate. For example, in this case, the peak value of frequency deviation is about 0.01 Hz in area 1. Generator frequencies are regulated after the net tie-line flow offsets return to small values.

Figures 5-5 to 5-8 illustrate the system response to the same load change under the minimal regulation. In this case, the maximum value of frequency deviation in area 1 is only 1.8×10^{-3} p.u. Unlike the conventional AGC, the fringe control regulates generator frequencies continuously while minimal regulation control is working simultaneously. Hence, the frequency performance of minimal regulation is much better than that of conventional AGC.

In addition, the load increase occurs on bus 25 in area 4, Figure 2.3, and area 4 is the second most expensive area. Simulations of the minimal regulation show that generators in the cheapest area, area 1, generate more power than the generators in other areas and the power is transfered to area 4 via the transmission line 2–25. Similarly, the generators in area 2 also generate a lot of power and inject it into area

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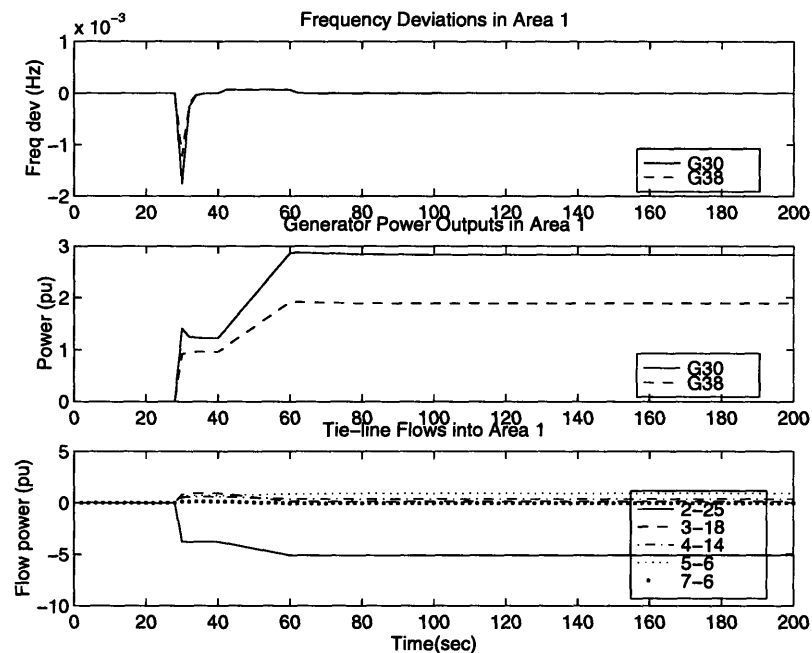
Figure 5-5: Minimal regulation response in the Pool-Co environment (Area 1)
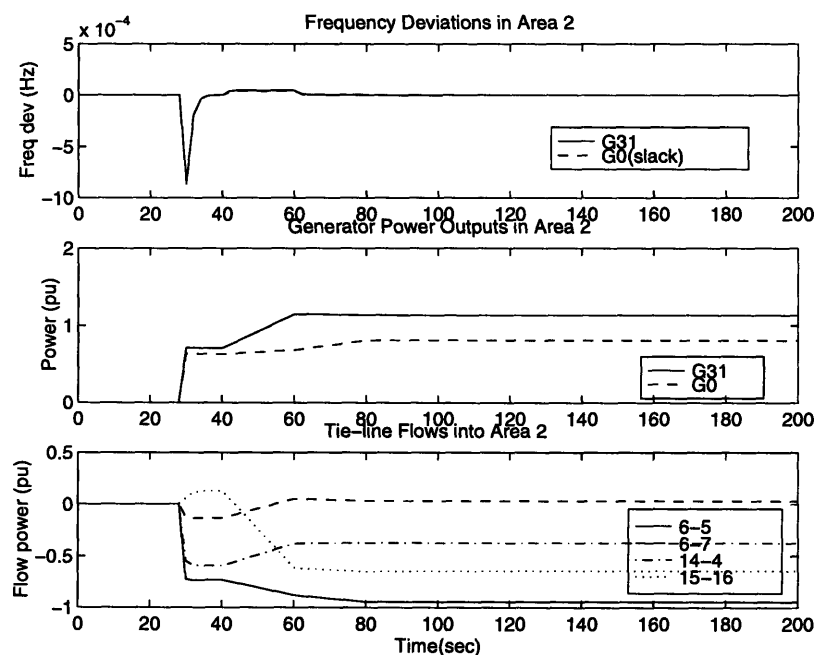
Figure 5-6: Minimal regulation response in the Pool-Co environment (Area 2)

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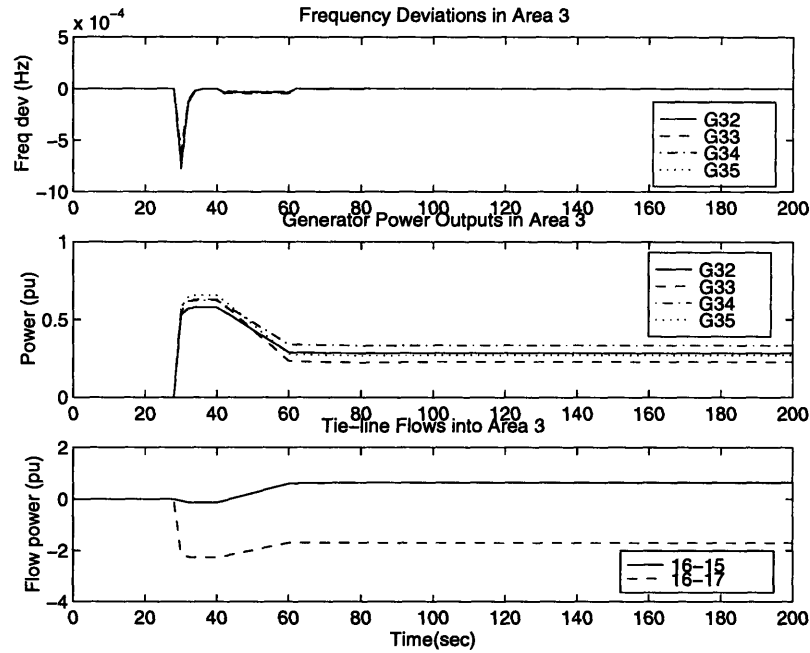
Figure 5-7: Minimal regulation response in the Pool-Co environment (Area 3)
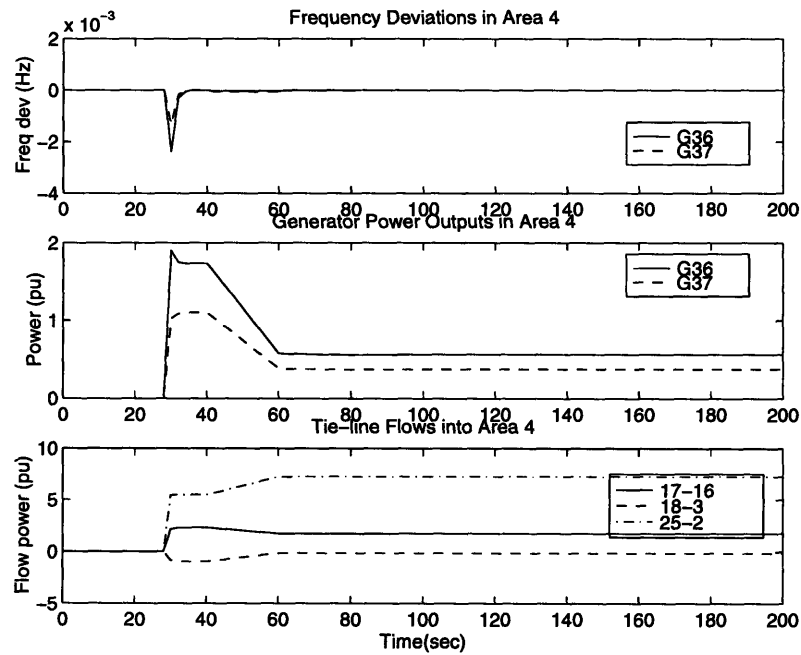
Figure 5-8: Minimal regulation response in the Pool-Co environment (Area 4)
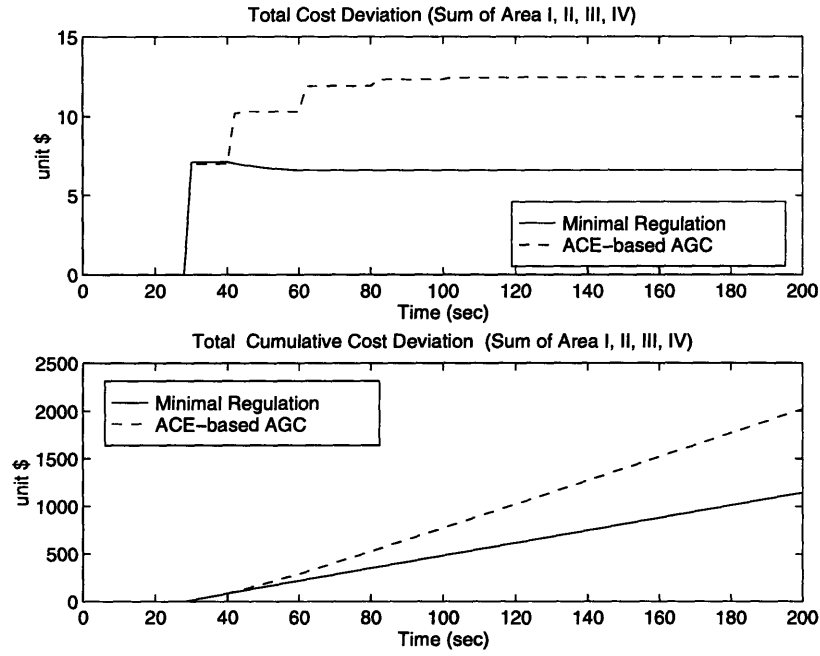
Figure 5-9: Cost allocation analysis

4 via tie lines 15–16 and 16–17.

In contrast, conventional AGC suppresses the tie-line flows and forces the system to use expensive generation to meet the demand. Figure 5-9 illustrates the generation cost needed to regulate the system by ACE-based AGC and minimal regulation. The figure shows that the cost of minimal regulation is much less than that of conventional AGC.

5.3   Minimal Regulation with Constraints

Just like saturation to power amplifiers and maximum speed to DC motors, generation and transmitted power in electric power systems have limits.

5.3.1 Incorporating Generation Constraints

Only the constraints on generator power are included. The Economic Dispatch problem is modified to be

$$min\{\sum_{i=1}^{N_G} C_i\} \qquad (5.1)$$

subject to

$$\sum_{i=1}^{N_G} P_{G_i}^* = \sum_{j=1}^{N_L} P_{Lj} + P_{loss} \qquad (5.2)$$

and

$$P_{G_i}^{min} \le P_{G_i}^* \le P_{G_i}^{max} \qquad (5.3)$$

$$i \in 1, \cdots, N_G \qquad (5.4)$$

$P_{G_i}^*$ is the solution of the constrained Economic Dispatch problem. These values will be used in minimal regulation. Assume that generator 30 in Figure 2.3 in area 1 has smaller-scale and, for security purposes, its extra generation capacity is constrained by 1 p.u.. In the same situation, the real power outputs of generator 31 in area 2, generator 32 in area 3, and generator 36 in area 4 have to be maintained within 1 p.u. limits.

Figures 5-10 to 5-13 show that the real power outputs of generator 30 and 31 hit the 1 p.u. limits and the minimal regulation can constrain them within the safe operation efficiently. This example shows that minimal regulation is able to maintain the generator outputs within the limits while it minimizes total generation cost.

5.3.2 Incorporating Transmission Constraints

One of the AGC objectives is to regulate tie-line flows back to their nominal set points. These set points are obtained from OPF and are within the transmission limits. At present, it is assumed that AGC has sufficient regulation to stabilize system frequencies without violating these tie-line constraints. However, these assumptions are not easily met under the new open access assumptions. This makes the system regulation subject to constraints on transmission lines potentially more complex in a
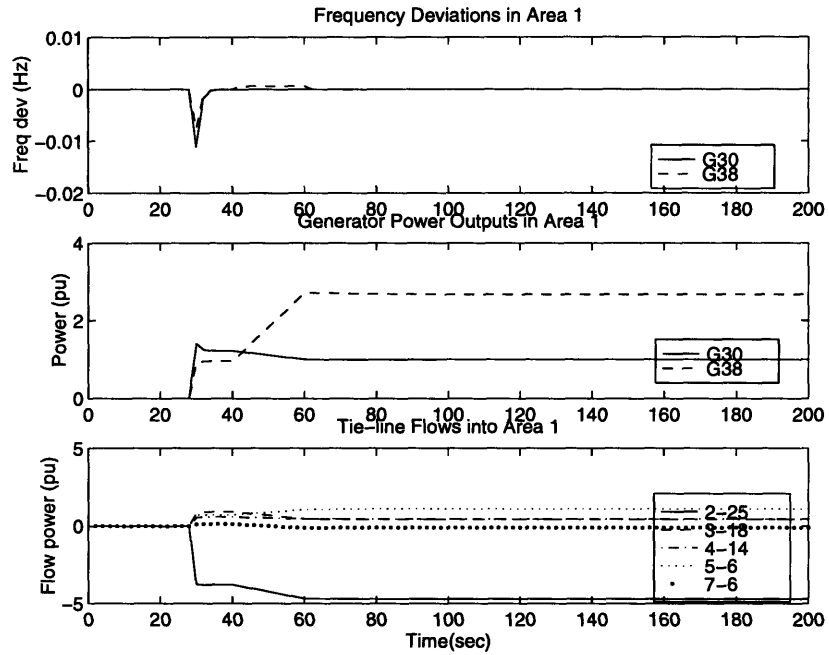
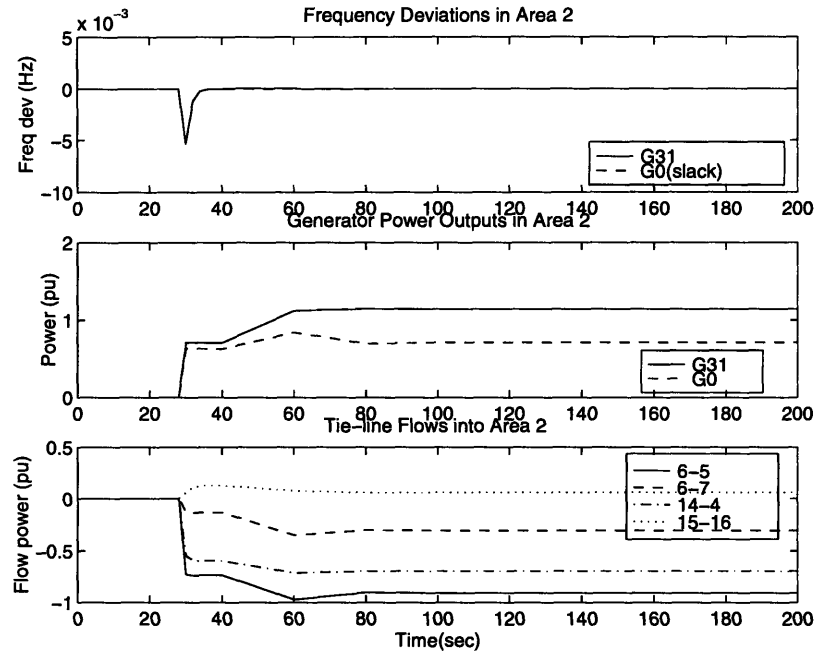Figure 5-10: Minimal regulation with generator power constraints (Area 1)
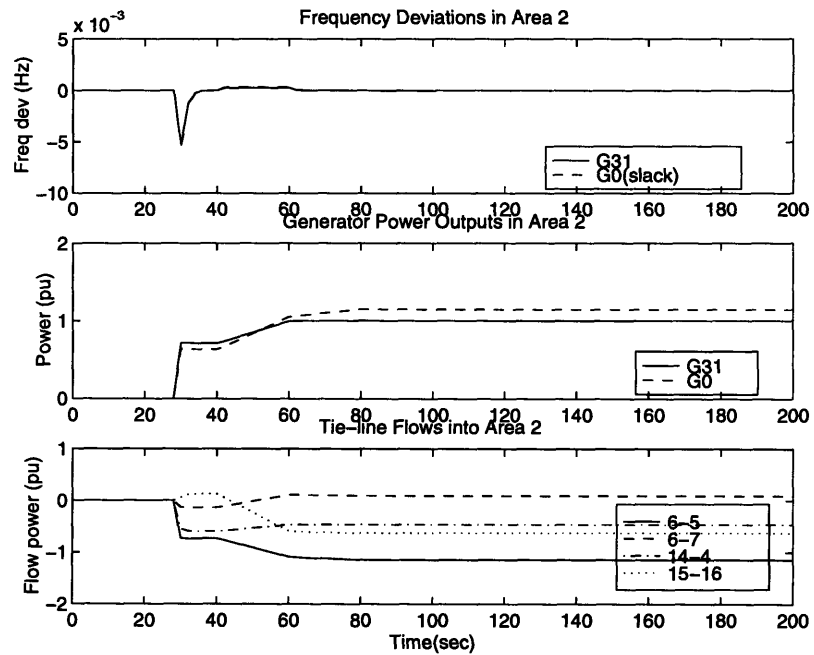
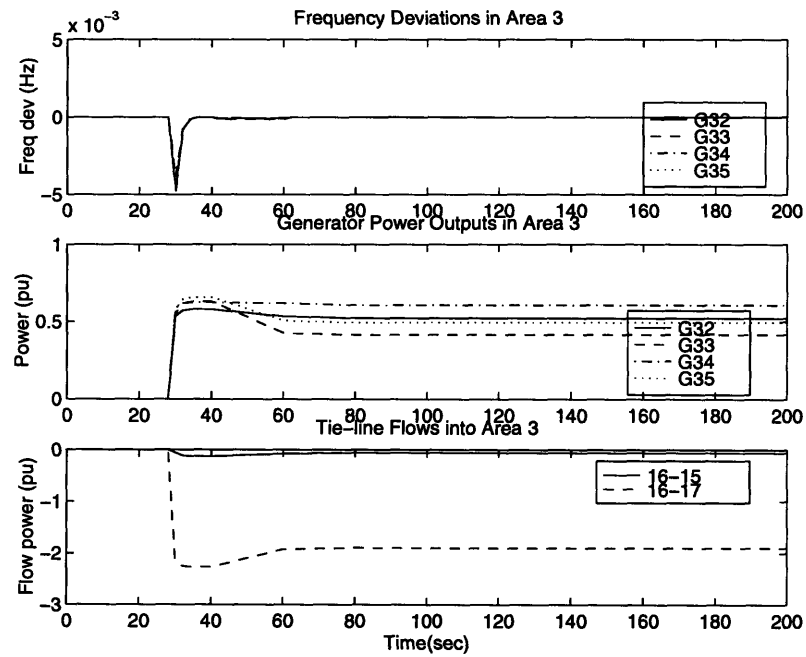Figure 5-11: Minimal regulation with generator power constraints (Area 2)
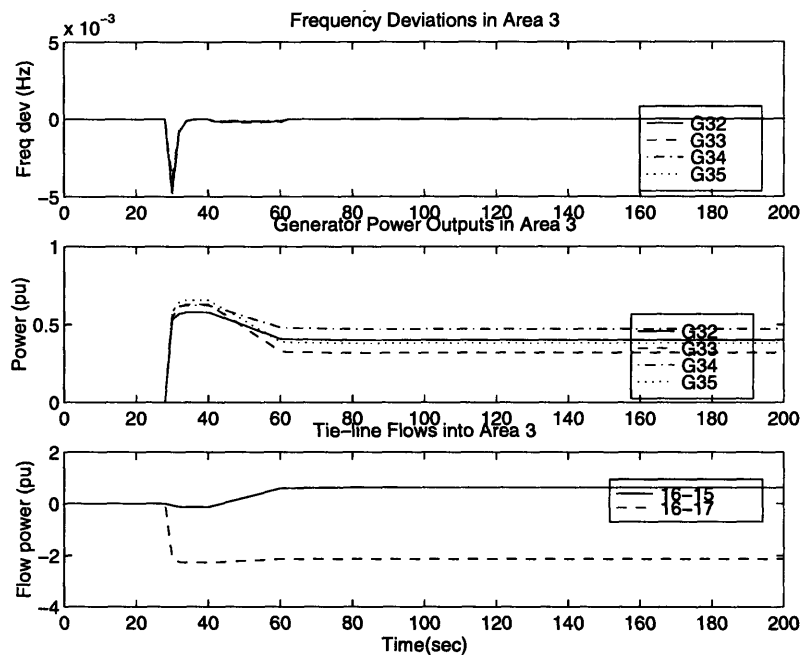
Figure 5-12: Minimal regulation with generator power constraints (Area 3)
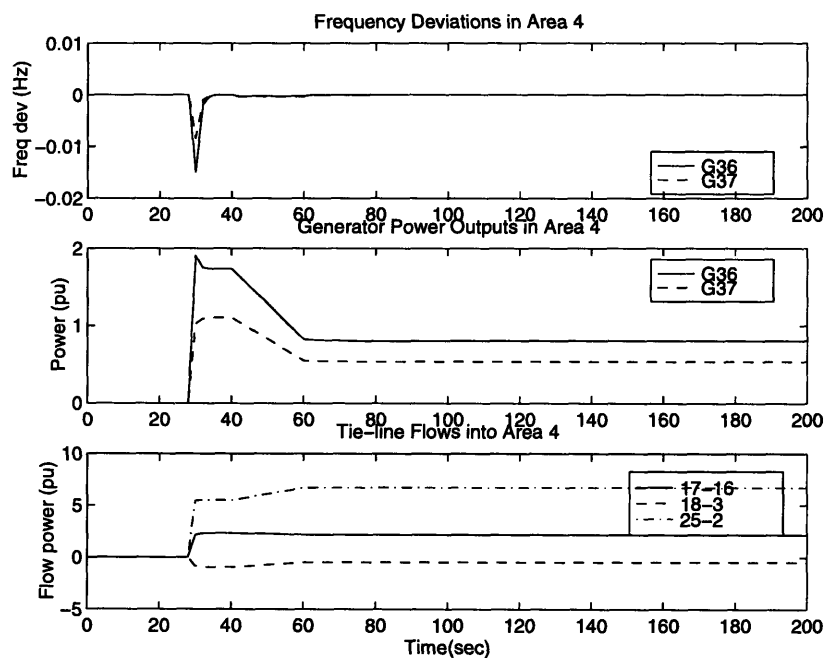
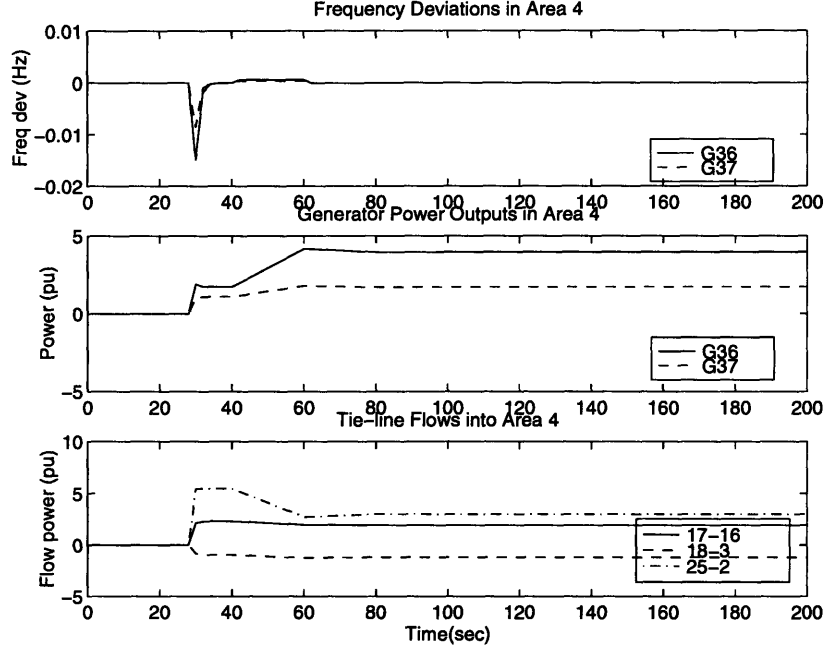Figure 5-13: Minimal regulation with generator power constraints (Area 4)

competitive utility market than in the present industry.

Now, the Economic Dispatch problem with tie-line flow constraints becomes

$$min\{\sum_{i=1}^{N_G} C_i\} \tag{5.5}$$

subject to

$$\sum_{i=1}^{N_G} P_{G_i}^* = \sum_{j=1}^{N_L} P_{L_j} + P_{loss} \tag{5.6}$$

and

$$P_{f_n}^{min} \leq P_{f_n}^* \leq P_{f_n}^{max} \tag{5.7}$$

$$n \in 1, \cdots, N_{line} \tag{5.8}$$

To solve this optimization problem we observe that a direct relation between generation power, P_G, and tie-line power flows, P_f, of the form

$$P_f = f(P_{G1}, P_{G2}, \cdots, \cdots, P_{G_{N_G}}) \tag{5.9}$$

To derive this relation, recall, from Chapters 2 and 4, the linearized expressions for generator and tie-line power

$$\underline{P}_G = K_p \underline{\delta}_G + D_p \underline{P}_L \tag{5.10}$$

$$\underline{P}_f = K_f \underline{\delta}_G + D_f \underline{P}_L \tag{5.11}$$

However, only $P_{G1}, \cdots, P_{GN_G-1}$ are independent variables. The real power of the slack generator, P_{GN_G} is linearly dependent. By solving Equation (5.10) and (5.11) the relation between tie-line flows and these $(N_G - 1)$ generators is found to be

$$\underline{P}_f = \tilde{K}_f \tilde{K}_p^{-1} \underline{P}_{G1-(N_G-1)} + (D_f - \tilde{K}_f \tilde{K}_p^{-1} \tilde{D}_P) \underline{P}_L \tag{5.12}$$

where $\tilde{K}_p$ is an $((N_G - 1) \times (N_G - 1))$ matrix. It is submatrix of the matrix K_P whose elements correspond to the $(N_G - 1)$ generators. Similarly, $\tilde{K}_f$ and $\tilde{D}_p$ are matrices
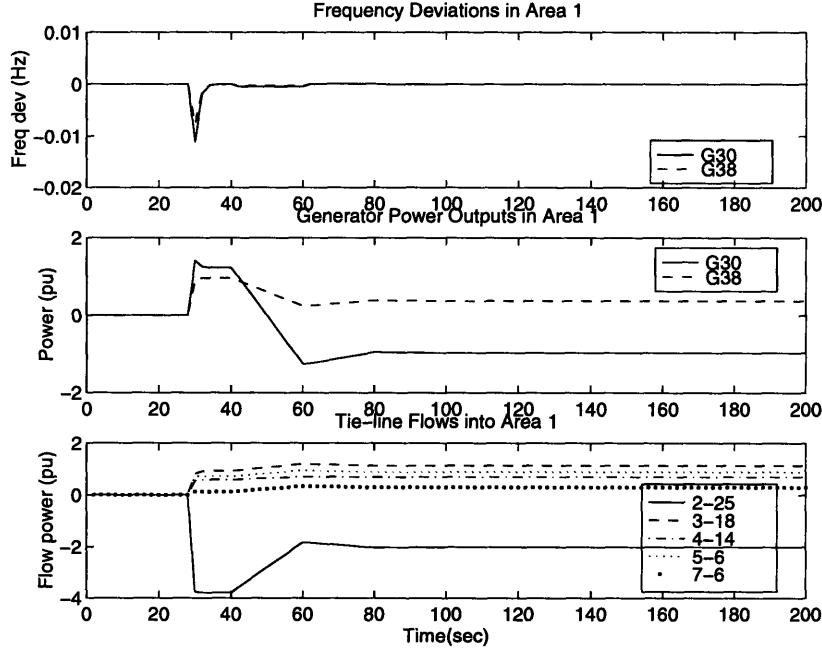
Figure 5-14: Minimal regulation with transmission power constraints (Area 1)

whose dimensions are $(N_{line} \times (N_G - 1))$ and $((N_G - 1) \times N_L)$ matrices, respectively.

The following simulations illustrate the system response to the same system input, 9 p.u., on bus 25, but with $+/-$ 3 p.u. imposed transmission constraints on all tie-lines. Figures 5-14 to 5-17 show that minimal regulation can constrain tie-line power flows within the prespecified constraints. In this case, the tie-line from bus 2 to 25 is constrained. This simulation indicates that the minimal regulation can allow the market to carry on profit-driven energy exchange and monitor tie-line flow automatically and simultaneously.

5.3.3 Incorporating both Generator Power and Tie-Line Flow Constraints

Obviously, both generator power and tie-line flow constraints can be incorporated simultaneously to the minimal regulation by slightly modifying the Economic Dispatch problem as:

$$min\{\sum_{i=1}^{N_G} C_i\} \tag{5.13}$$

Figure 5-15: Minimal regulation with transmission power constraints (Area 2)

Figure 5-16: Minimal regulation with transmission power constraints (Area 3)

Figure 5-17: Minimal regulation with transmission power constraints (Area 4)

subject to

$$\sum_{i=1}^{N_G} P_{G_i}^* = \sum_{j=1}^{N_L} P_{L_j} + P_{loss} \qquad (5.14)$$

and

$$P_{G_i}^{min} \leq P_{G_i}^* \leq P_{G_i}^{max} \qquad (5.15)$$

$$i \in 1, \cdots, N_G \qquad (5.16)$$

$$P_{f_n}^{min} \leq P_{f_n}^* \leq P_{f_n}^{max} \qquad (5.17)$$

$$n \in 1, \cdots, N_{line} \qquad (5.18)$$

Figure 5-18 to 5-21 demonstrate the system response with both generation power and tie-line flow constraints. The output power of generators 31, 32 , and 36 are constrained by 1 p.u. and the three tie-lines, 2-25, 3-18 and 16-17, reach the +/- 3 p.u. transmission constraints. Compared to the case in which only tie-line flow constraints are incorporated, due to binding generation power of generators 30, 31, 32 and 36 at the same time more tie-lines reach the constraint.

Figure 5-22 shows the total generation cost deviation in four scenarios with differ-
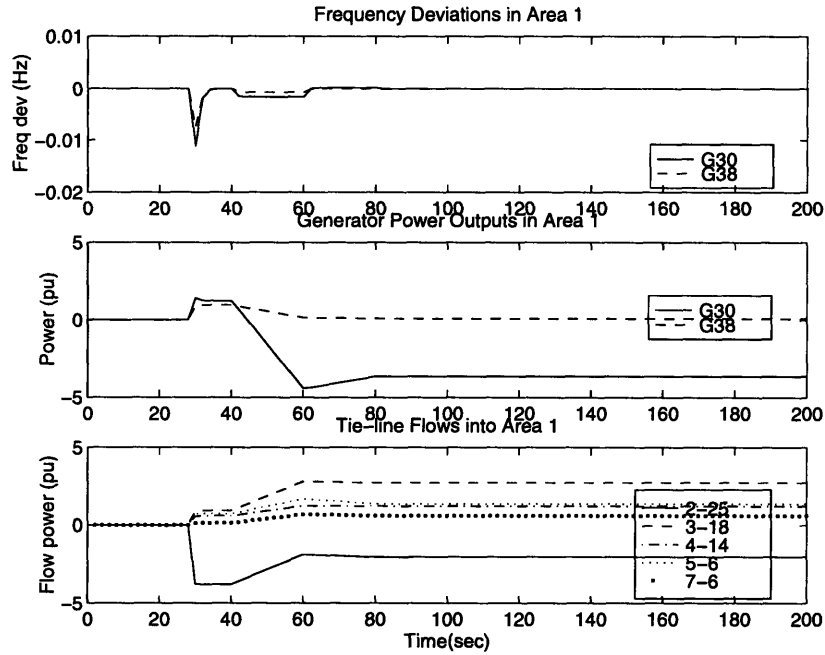
Figure 5-18: Minimal regulation with both generator power and tie-line flow constraints (Area 1)
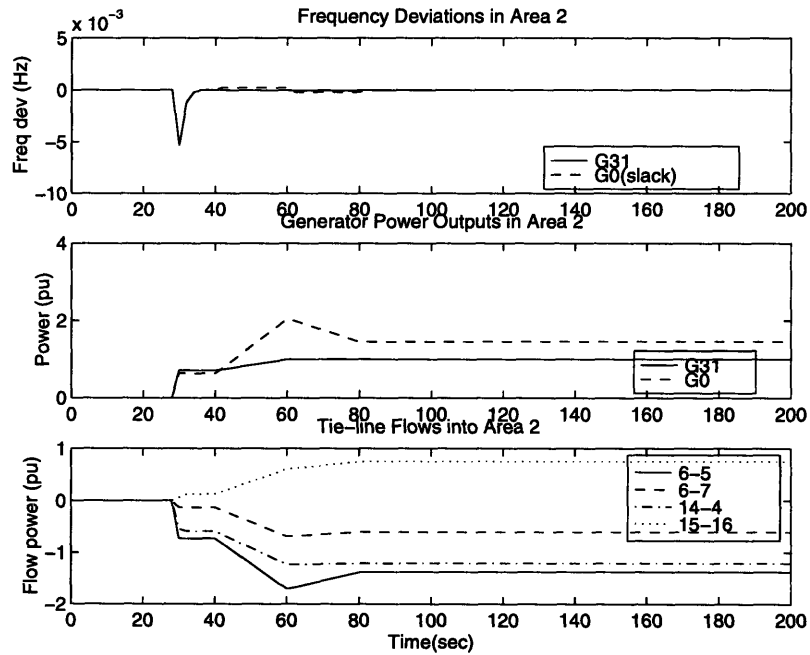
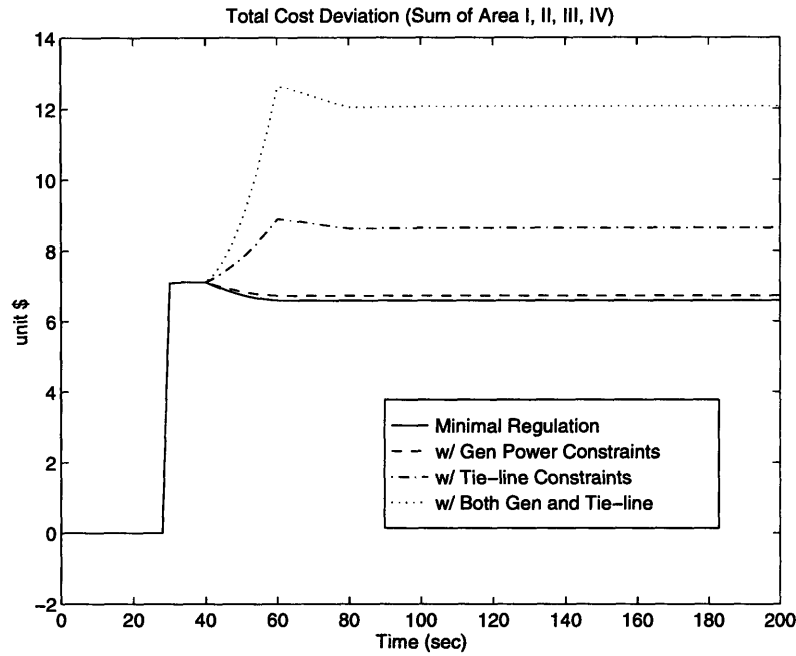Figure 5-19: Minimal regulation with both generator Power and tie-line flow constraints (Area 2)
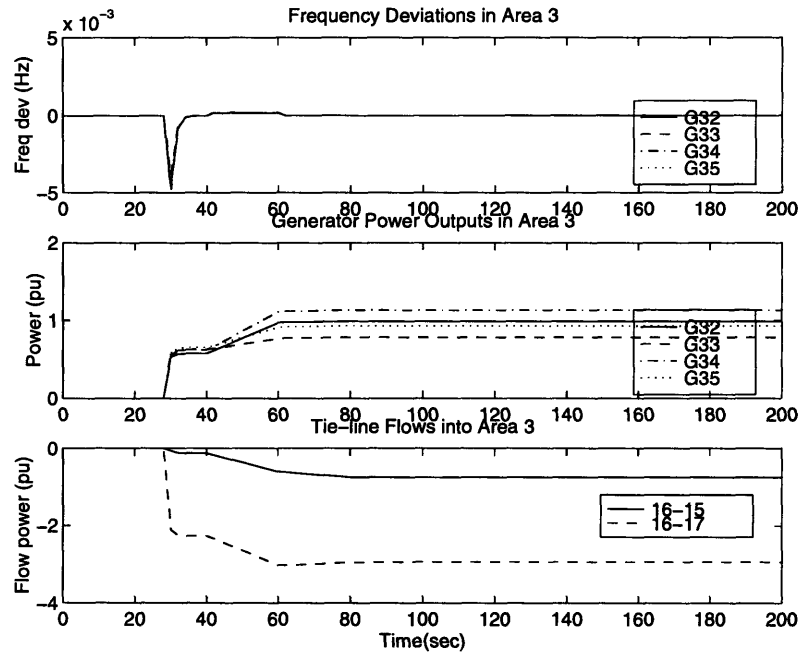
Figure 5-20: Minimal regulation with both generator Power and tie-line flow constraints (Area 3)
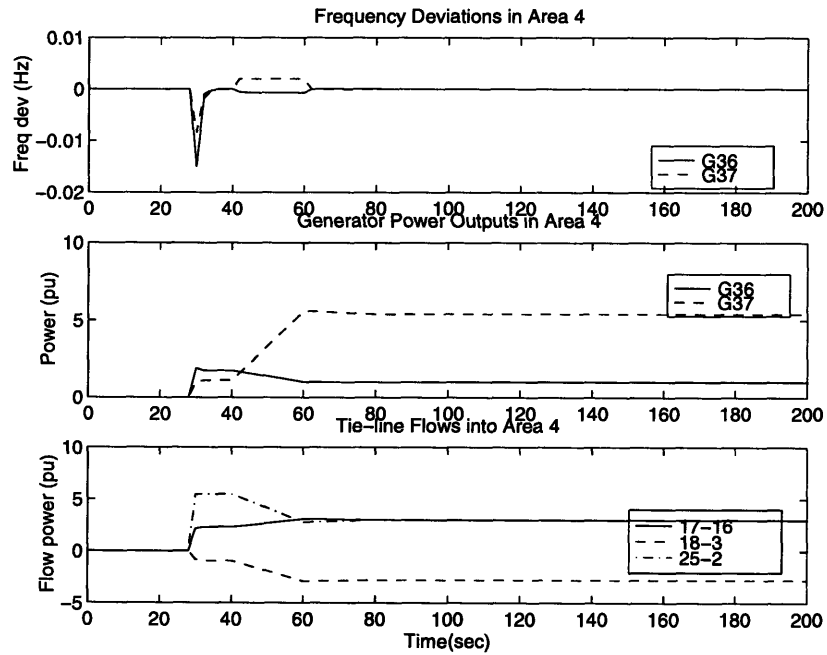
Figure 5-21: Minimal regulation with both generator Power and tie-line flow constraints (Area 4)

Figure 5-22: Total cost deviations of four different constrained situations

ent degrees of constraints: (1) without any constraint, (2) with generation constraints only, (3) with tie-line flow constraints only, and (4) with both generation power and tie-line flow constraints. Figure 5-23 shows the cumulative cost deviations for these four cases. Figures 5-22 and 5-23 show that when tie-line flow constraints are ignored, generation power constraints affect the system cost only slightly because the system is free to choose other cheaper units to generate more power and to compensate the power shortage. However, when some tie-line flows hit the transmission limits, the same generation power constraints lead to a significant cost increase.

5.4 Summary

In this chapter, system regulation in the Pool-Co environment are examined. Pool-Co service is a pool of generators that supply a demand and it makes the utility market more competitive by providing access to transmission and selling electricity at spot prices.

By comparing the system response of conventional AGC to that of minimal regu-

Total Cumulative Cost Deviation (Sum of Area I, II, III, IV)
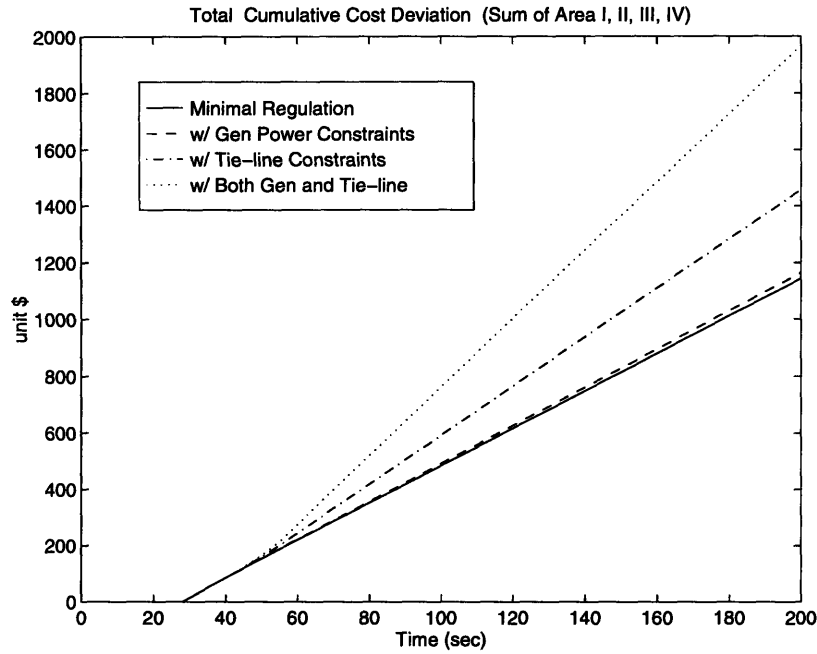
Figure 5-23: Total cumulative cost deviations of four different constrained situations

lation, the regulation cost of the former is much higher than the latter. Furthermore, because the minimal regulation separates two control objectives into different control levels, the frequency performance under the minimal regulation control is much better than that of the conventional AGC. Frequencies only deviate in a very short time period and quickly return to 60 Hz. In other words, the minimal regulation preserves higher service quality of overall at a lower total cost.

Next, the minimal regulation subject to the operating constraints is studied. By solving the constrained economic dispatch problem, minimal regulation can effectively maintain generator power as well as tie-line flows within the limits. Namely, the proposed minimal regulation minimizes the total system generation cost and also preserves system security and reliability.

Chapter 6

Minimal Regulation in a Bilateral Environment

6.1 Bilateral Market

The restructuring based on the model with bilateral transactions is another main alternative to the current industry structure. In the bilateral model, the role of ISO becomes seemingly simpler than that in the Pool-Co model. ISO is only in charge of preserving system reliability but it is responsible for economic dispatch. The importance of ISO emerges when the bilateral trades reach various operating constraints on the system. Otherwise, ISO will only serve to compensate for the transmission losses caused by the bilateral trades of power. Since the ISO does not facilitate the market, in an entirely bilateral environment, each seller has to seek its buyer(s), and vice versa. The ISO will have a major responsibility to preserve system security when system inputs deviate from the agrees upon values. These system imbalances must be compensated for by systems control services of interest in this thesis.

The US utility restructuring is based, at least partially, on the bilateral model so it is important to demonstrate that our approach can function appropriately in the bilateral environment.
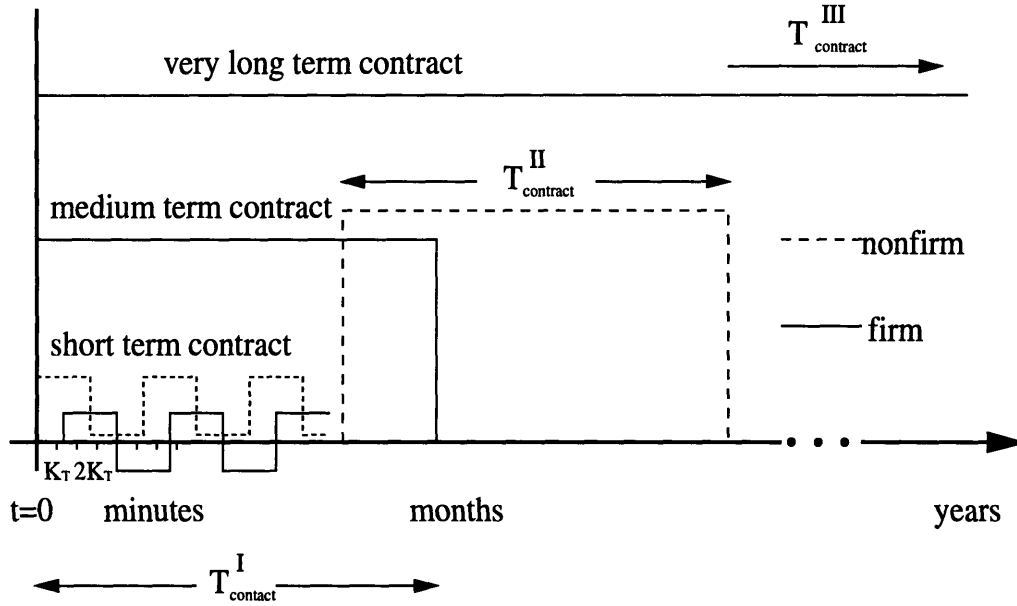
Figure 6-1: A scheme of different types of market transactions

6.2 Firm Contracts

Bilateral transactions in competitive markets could consist in principle of at least three quantatively different components. They are firm and nonfirm contracts and noncompliant inputs that reflect deviations from the firm and nonfirm transactions. Firm contracts are long-term contracts and have impacts on the system-wide efficiency over long-time horizons. In the Pool-Co environment, static optimization tools, such as Optimal Power Flow (OPF) and Economic Dispatch (ED) programs, plan and schedule these long-term transactions in advance. In the entirely bilateral environment, however, these firm contracts are between two specific points i and j on the system; the simplest version[1] is such that a firm contract in established to inject $+X$ MW into point i and take the same amount of $-X$ MW out at point j. The net effect of such firm transaction is only seen through transmission losses created by power flows from i to j.

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[1]The only we considered in this thesis.

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AREA 1 G 30

I 1
38
9
8 7 5 4

POWER SELLER 2 3

TIE-LINE

TIE-LINE

AREA 4 I
I 37
36
25 29
26 28
18 27 17

TIE-LINE TIE-LINE TIE-LINE TIE-LINE

AREA 2
14
13
12
11 6
0
G
10 G
31
15

TIE-LINE

AREA 3 16
G 24
33 19
20
I G
34 35
G 22
32 21 23
POWER BUYER

G: UTILITY-OWNED GENERATORS
I: INDEPENDENT POWER PRODUCERS
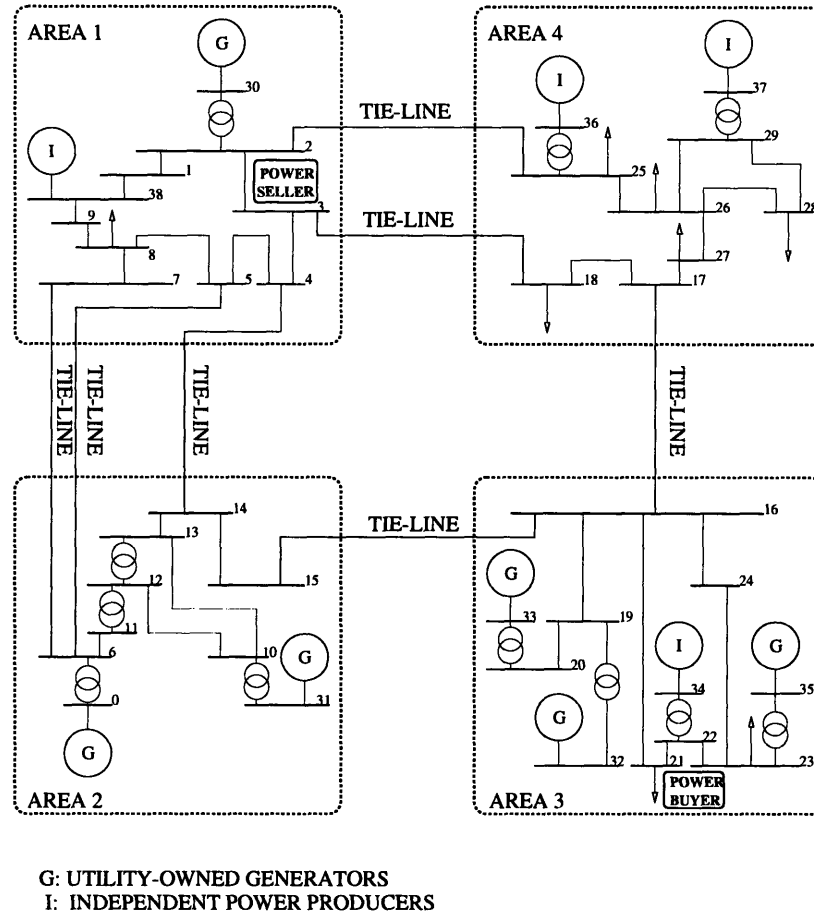
Figure 6-2: A bilateral contract between bus 3 and bus 21

In contrast, nonfirm contracts are short-term contracts and more responsive to the market status. These short-term transactions are usually harder to plan for. Both firm and nonfirm contracts are price-driven inputs to the transmission system.

The noncompliant inputs may display wide ranges of rate and magnitude and they are superposed to the firm and nonfirm signals. The noncompliances are not necessarily price-driven[2]. In addition, the system is always subject to various uncertainties that must be compensated for by system regulation. Figure 6-1 shows a scenario of a typical bilateral transaction.

This section investigates the system responses to the firm transactions under different control methods. In Chapter 5, the assigned cost curves of generators in area

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[2]Except for intentional gaming.

1, 2, 3, and 4 make the generation in area 3 the most expensive and that in area 1 the cheapest. These operation costs make selling power from area 1 to area 3 economically attractive. Assume that bus 3 in area 1 is an independent power producer (IPP) that does not participate in system regulation. In other words, bus 3 is free to sell power to any customer buses. The generator buses 30, 31, 32, 33, 34, 35, 36, 37, 38, and 0 are either utility-owned generators or IPPs participating in the system regulation. These ten generators are controlled by ISO and are in charge of providing system ancillary services. Load bus 21 in area 3 has a bilateral agreement with bus 21 in area 1 to buy 9 p.u. power as shown in Figure 6-2. The transaction starts at time=30 seconds.

Figure 6-2 shows that there is no transmission line directly connecting area 1 and area 3 so the transaction has to be facilitated by the entire transmission network and proper coordination provided by an ISO.

Typically, there are two different ways for conventional AGC to respond to the transaction. If the transaction is not known to the control areas, for example, neither bus 3 nor bus 21 informs the control centers in area 1 and area 3 that the transaction will happen, and then the conventional AGC will treat those inputs as noncompliant type disturbance[3]. On the other hand, if the transaction is made known to the control areas, area 1 and area 3 can reschedule the net tie-line flows and help the transmission[4]. In other words, area 1 redefines its ACE and sets the net tie-line flow deviation to -9 p.u. Similarly, area 3 sets it to +9 p.u.. Since other areas still regulate the net tie-line flow into the area to zero, a very big portion of power flow existing from area 1 is injected into area 3.

Figures 6-3 to 6-6 show the system response to an scheduled bilateral transaction of 0.9 p.u. under the conventional AGC. In this case, no tie-line flow rescheduling takes place, and the conventional AGC responds automatically to suppress the effect of the transaction. The simulations show that the conventional AGC regulates the net tie-line flow in each area. It makes bus 21 withdraw 9 p.u. power only from the

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[3]This could represent for example, a noncompliance with a contract.
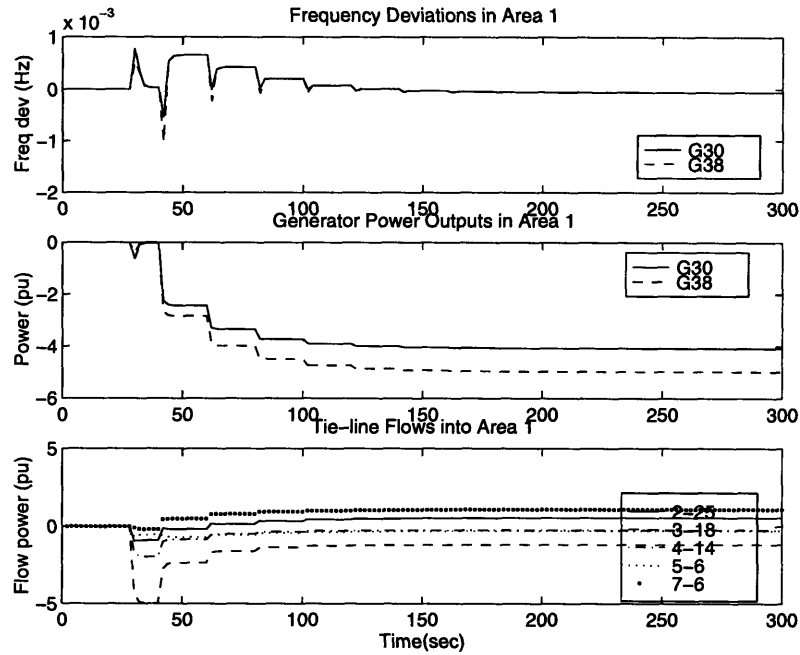[4]This could represent either firm or non-firm scheduled transactions.

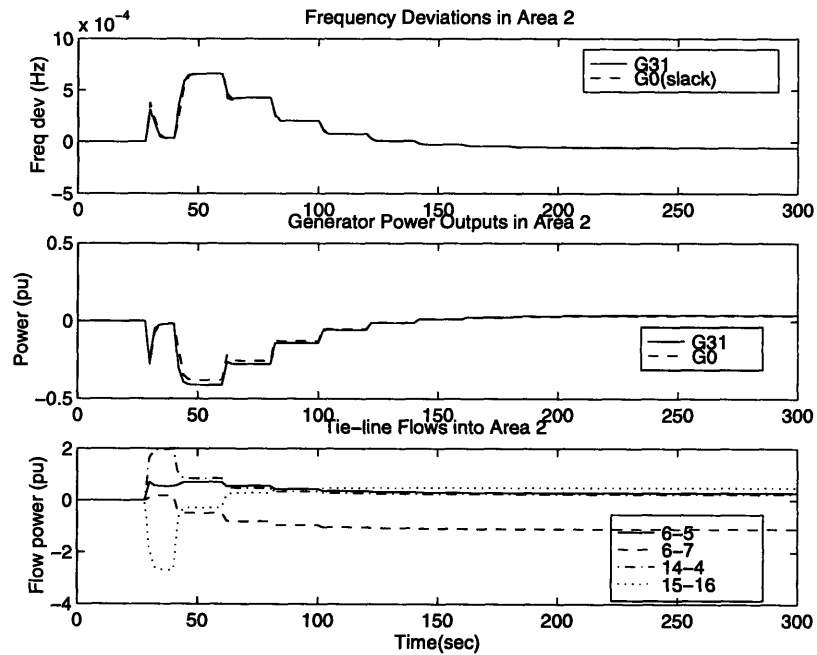Figure 6-3: ACE-based AGC response to a noncomplying bilateral transaction (Area 1)

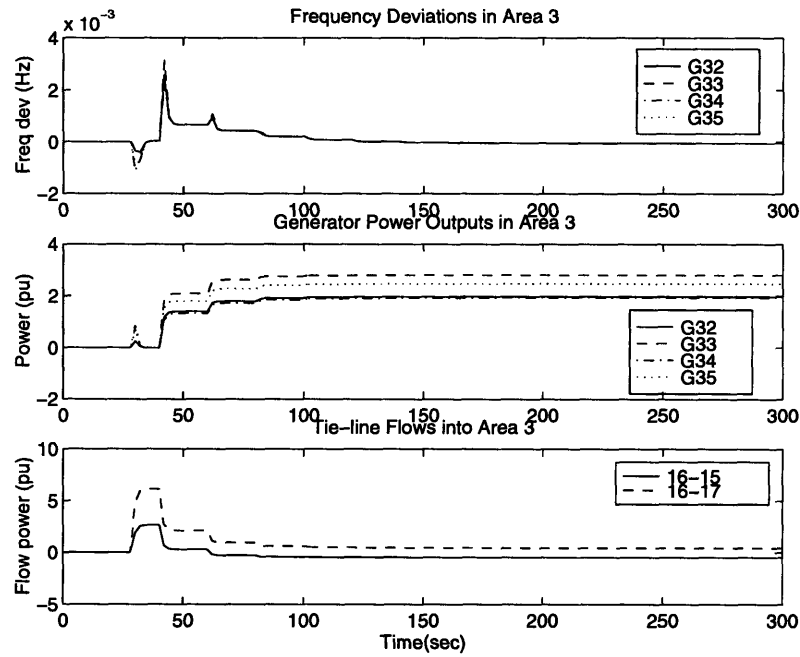Figure 6-4: ACE-based AGC response to a noncomplying bilateral transaction (Area 2)

Figure 6-5: ACE-based AGC response to a noncomplying bilateral transaction (Area 3)
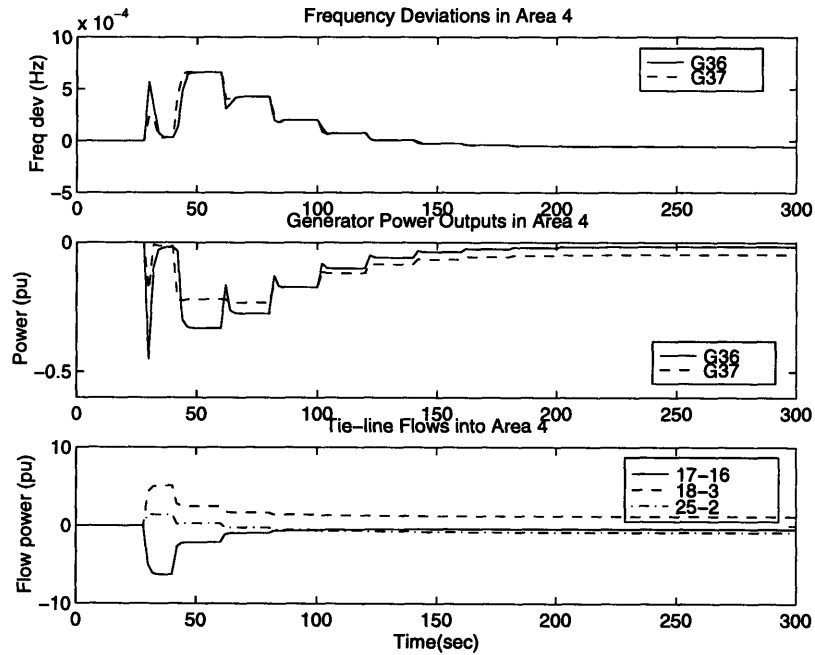

Figure 6-6: ACE-based AGC response to a noncomplying bilateral transaction (Area 4)
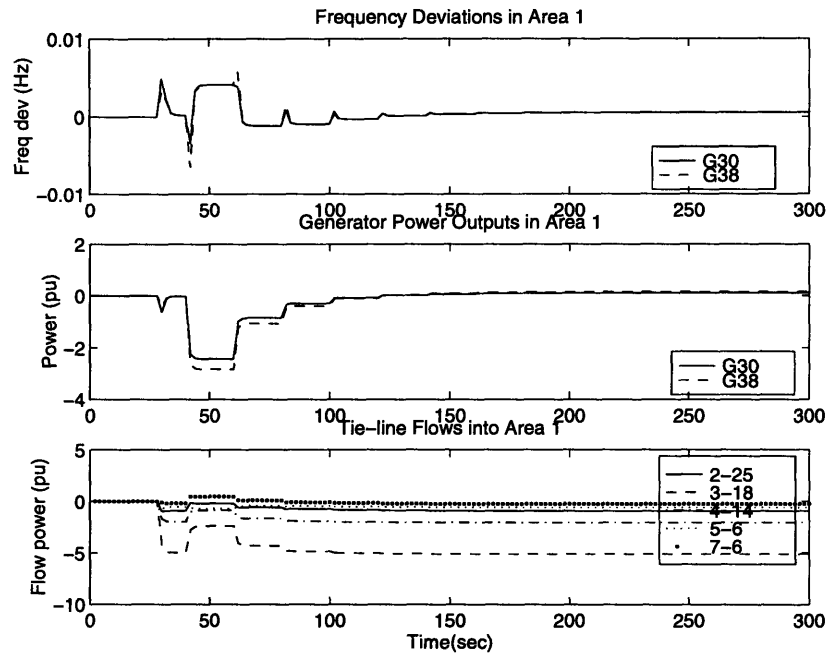
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Figure 6-7: ACE-based AGC response to a known bilateral transaction (Area 1)

generation in area 3 so all other generators in area 3 have to create more power to meet the demand increase. Similarly, all generators in area 1 reduce the generation because of an extra power injection from bus 3. In other words, no physical change of power flows outside of the control area takes place. The agreed upon economic transaction never materializes in the real time operation of the power system.

Figures 6-7 to 6-10 show the second kind of system response to the same transaction. Area 1 and area 3 are informed that the transaction will occur in advance so they reschedule the tie-line flows to allow the transaction. From the simulations, when the system reaches the steady state, the real power of all generators controlled by ISO only deviates a little from the previous schedules. This indicates that the power taken out from bus 21 basically comes from bus 3, and other generators are only needed to compensate for the transmission losses. The power is transfered successfully from bus 3 to bus 21.

Figure 6-11 shows the total generation cost deviation and total cumulative generation cost deviation of these two cases. In the first case, the ACE-based AGC obstructs the transmission among the different areas and forces the system to use
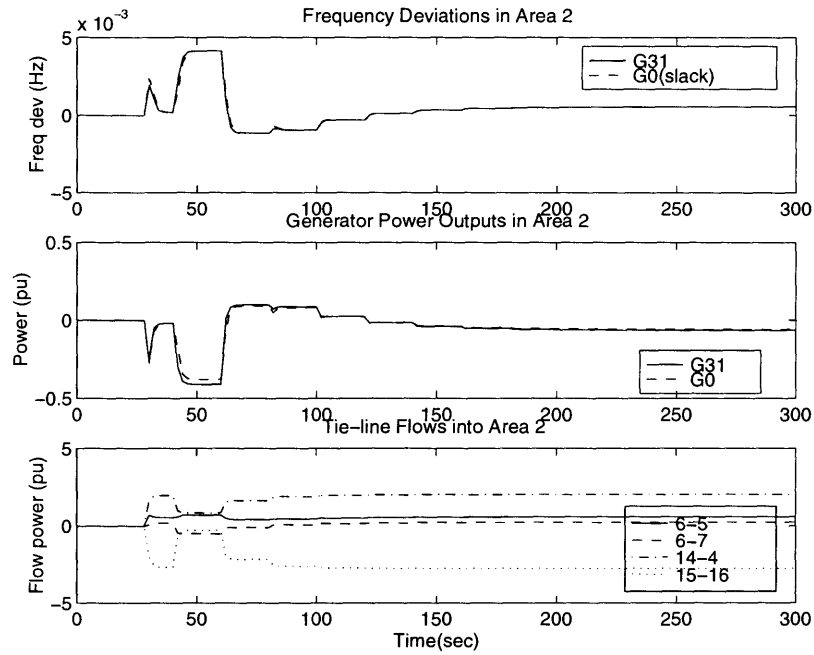
Figure 6-8: ACE-based AGC response to a known bilateral transaction (Area 2)
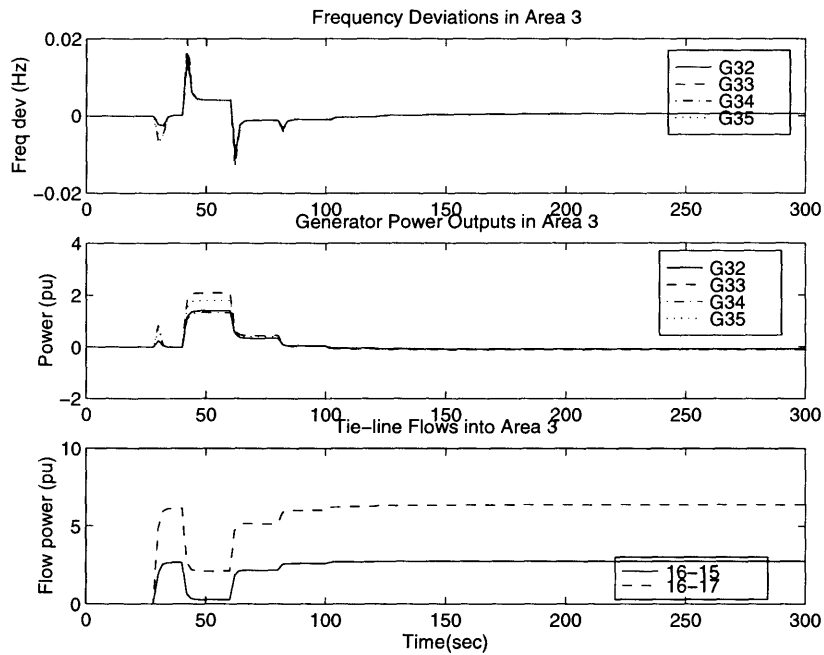
Figure 6-9: ACE-based AGC response to a known bilateral transaction (Area 3)
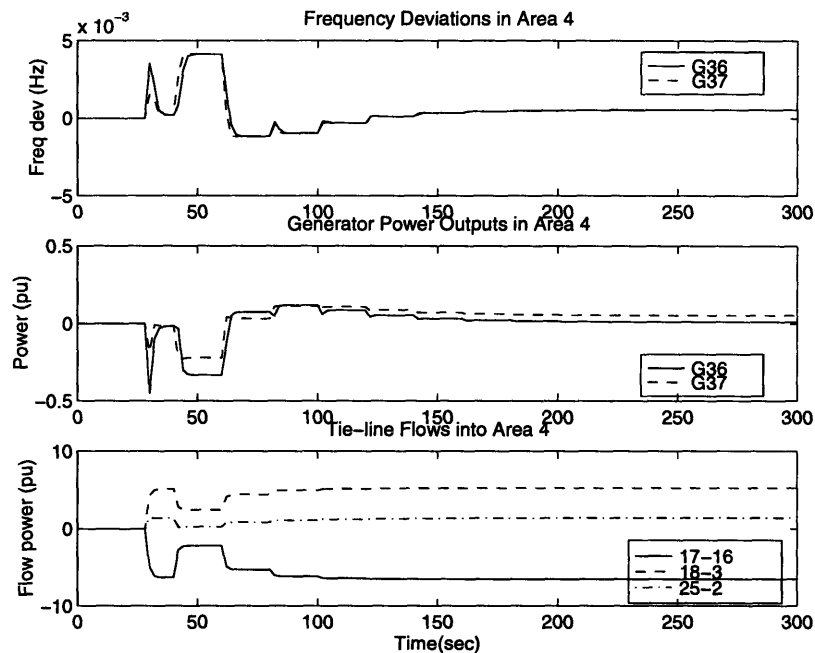
Figure 6-10: ACE-based AGC response to a known bilateral transaction (Area 4)
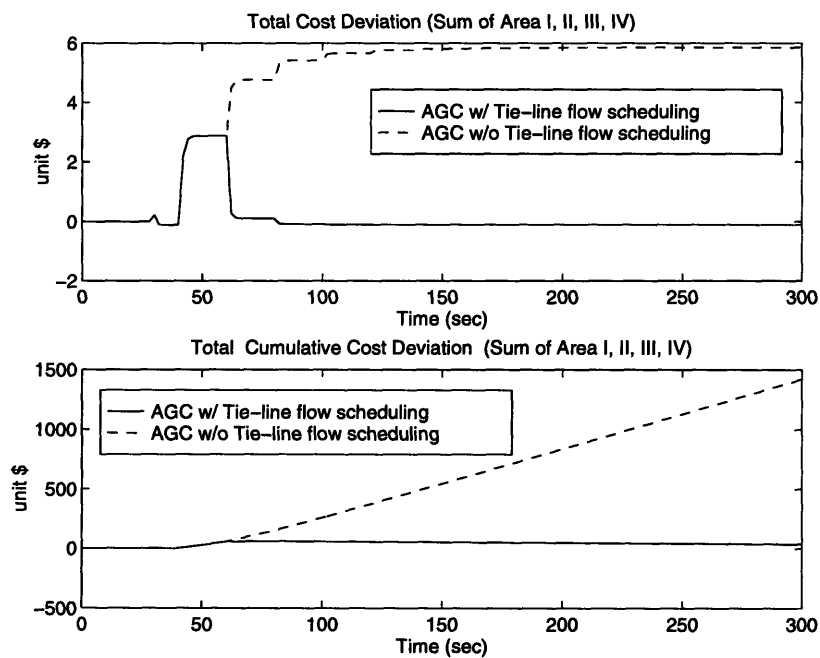

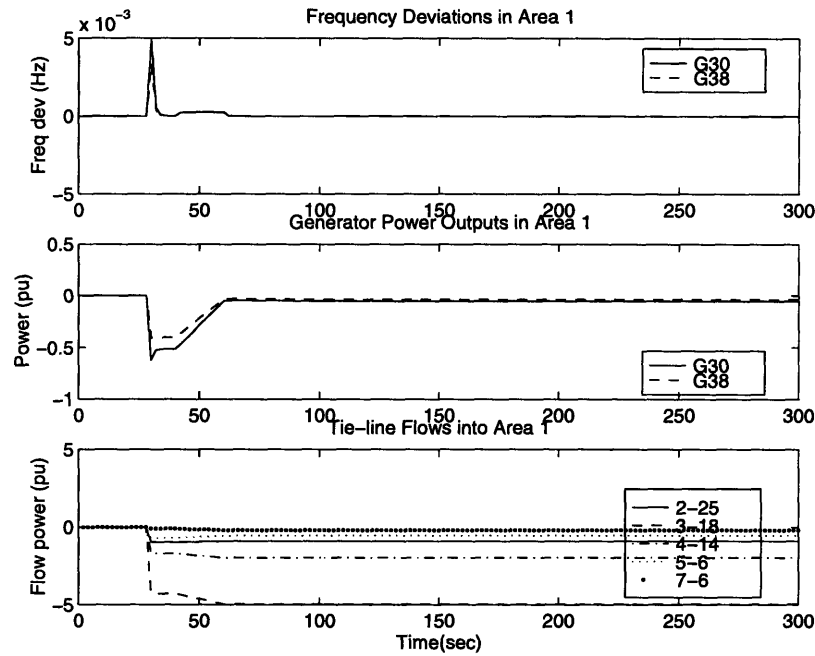Figure 6-11: Cost allocation analysis of two different types of conventional AGC

Figure 6-12: Minimal regulation response to a 9 p.u. firm transaction (Area 1)

some more expensive units to generate the needed power. In the second case, the system is regulated properly and the generators participating in the regulation only need to compensate for the transmission losses. Therefore, the total generation cost of the second case is much less than that of the first case.

Actually, this kind of transmission benefits the entire network because it transports power from a low generation density area to a high generation density area and also from a low generation cost area to a high generation cost area. The steady state value of total cost deviation should be a negative value. Figure 6-11 shows that the final total cost deviation in the second case is indeed negative.

This is an illustration that under present regulation, the control areas in the interconnected system should know each transaction. Otherwise, system regulation will effectively block any power changes outside of the area in which the transactions in located.

Figures 6-12 to 6-15 illustrate system response to the minimal regulation. The system takes 40 seconds (from 30 to 70 seconds) to reach the steady state. In addition, all tie-lines connected to area 1 transmit power out of the area and all tie-lines
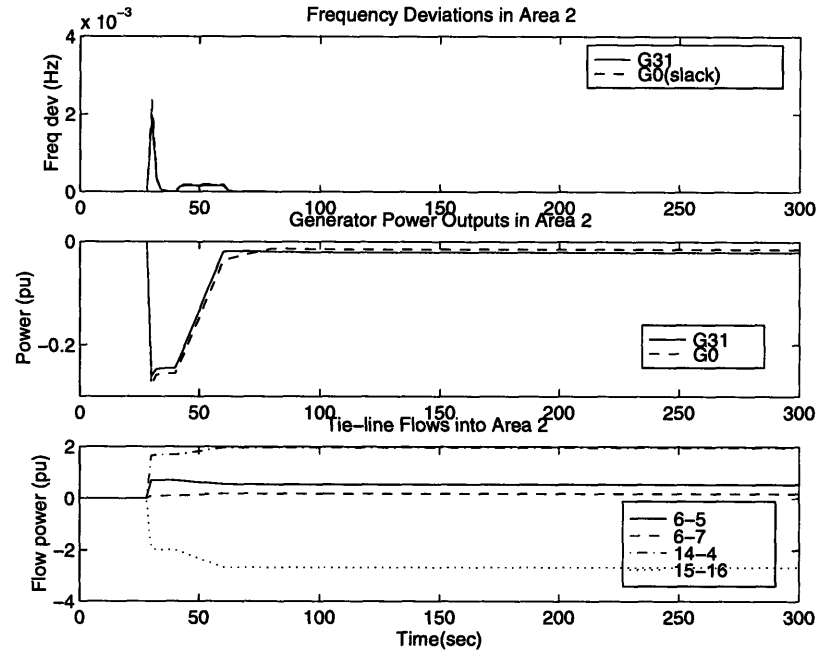
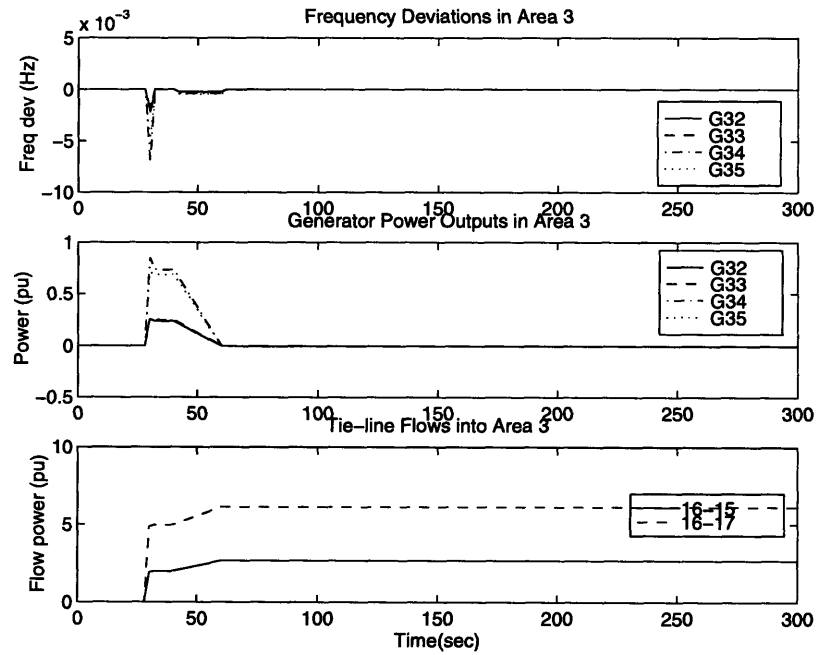Figure 6-13: Minimal regulation response to a 9 p.u. firm transaction (Area 2)

Figure 6-14: Minimal regulation response to a 9 p.u. firm transaction (Area 3)
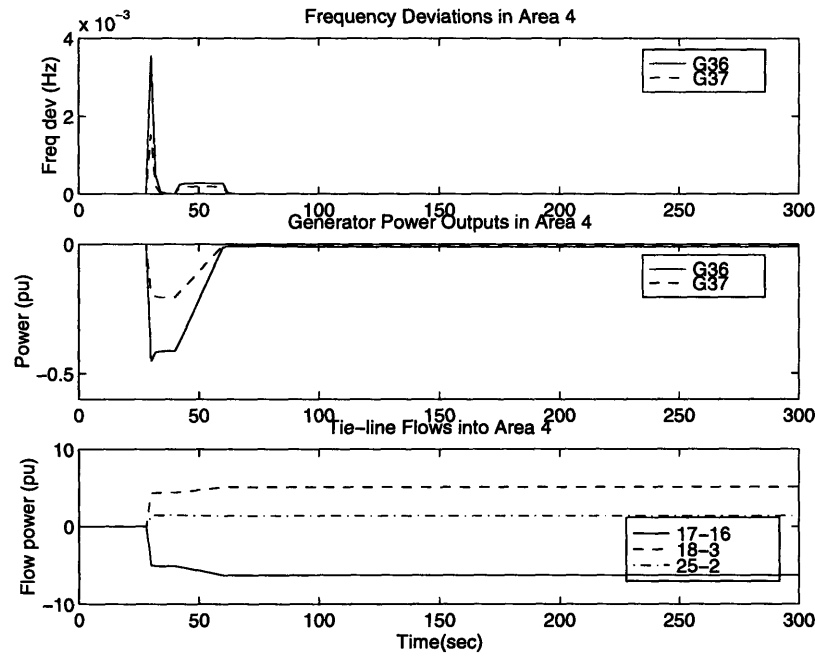
Figure 6-15: Minimal regulation response to a 9 p.u. firm transaction (Area 4)

connected to area 3 transmit power into the area. Area 2 and area 4 merely serve as transmission media. In this case, the generator power and frequencies of the ISO controlled generators are only affected by the transaction over a short period of time, then they return to the original set values.

The costs needed for the regulation of the conventional AGC and the minimal regulation are shown in Figure 6-16. The total generation costs of both controls at the steady state are almost the same, since all generators controlled by ISO are only used to make up the transmission losses. The small cost deviations only reflect the difference in the transmission losses before and after the transaction. However, because the conventional AGC responds rather slowly, a significant amount of extra cost accumulates during the regulation. In contrast, minimal regulation completes its function in a very short time and makes the transaction more economically efficient.
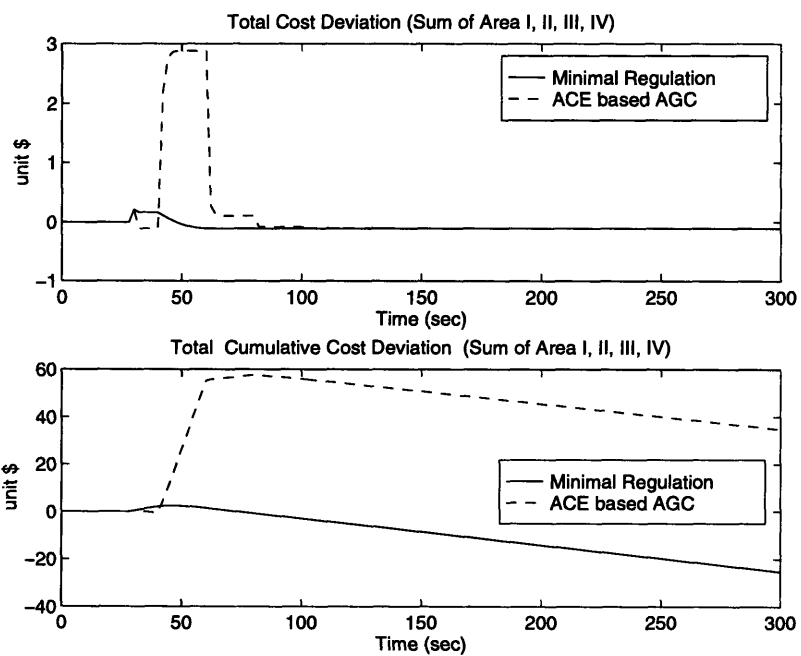
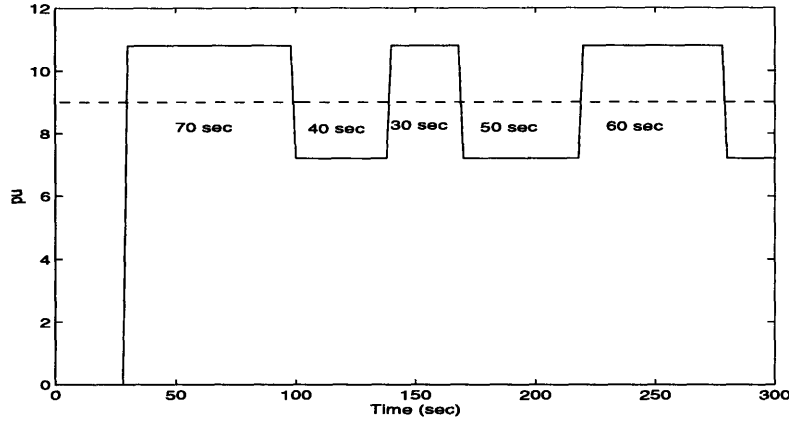Figure 6-16: Cost comparison of the conventional AGC and minimal regulation

Figure 6-17: Power variation of a short-term bilateral transaction

6.3 Nonfirm Contracts

Unlike firm contracts, nonfirm contracts are short-term energy exchanges that reflect the changes of spot prices. Generally, these short-term transactions are fast and not predictable thus they cannot be scheduled in advance. However, these short-term transactions are likely to occur more frequently in the future operation of the utility industry.

An example of nonfirm input is shown in Figure 6-17. It illustrates that when the 9 p.u. long-term power transaction occurs between bus 3 and bus 21, some short-term, nonfirm transactions happen spontaneously. The magnitude of these short-term transaction is 20% that of long term transaction, $+/-$ 1.8 p.u.. In the following, we analyze the system response and cost of regulation associated with this kind of transaction.

Figures 6-18 to 6-21 show the ACE-based AGC response to the nonfirm transaction. Because the conventional AGC responds slowly, the frequency response under the conventional AGC is unsatisfactory. The simulations show that generator frequencies deviate whenever the transactions happen. Furthermore, they deviate even more when AGC begins regulating.

Figures 6-22 to 6-25 show that the minimal regulation reacts automatically to the nonfirm transactions and regulates the generator frequencies quickly and efficiently.
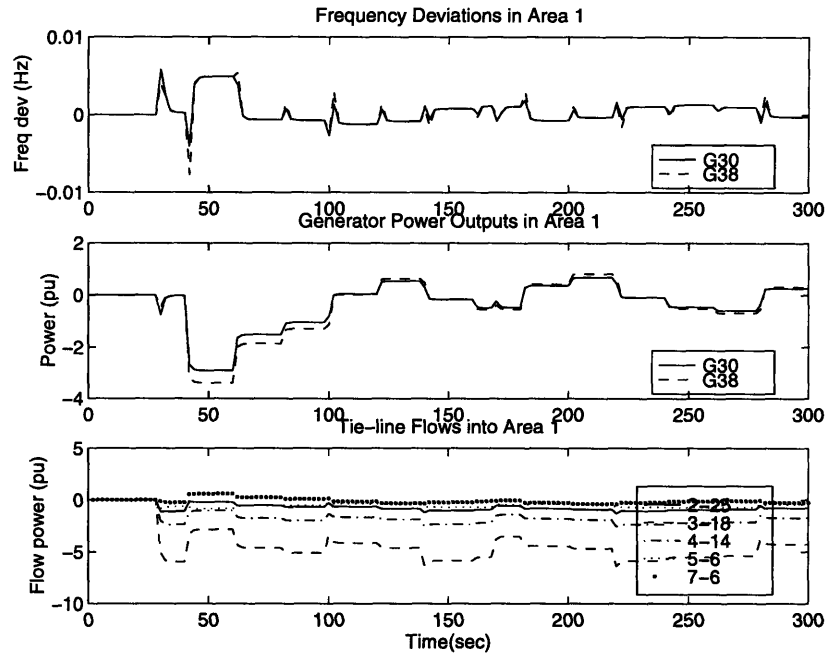
100

Figure 6-18: ACE-based AGC response to the nonfirm transaction (Area 1)
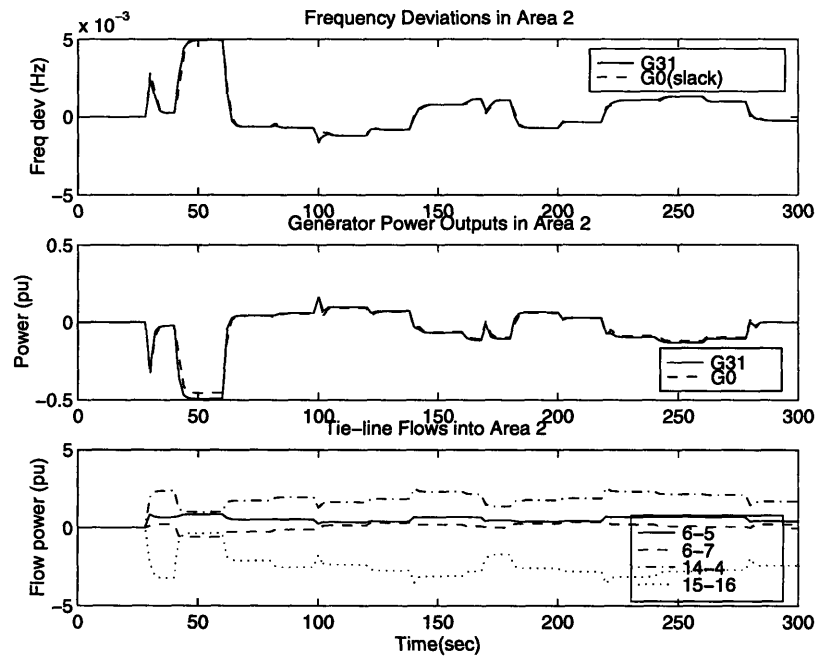

Figure 6-19: ACE-based AGC response to the nonfirm transaction (Area 2)
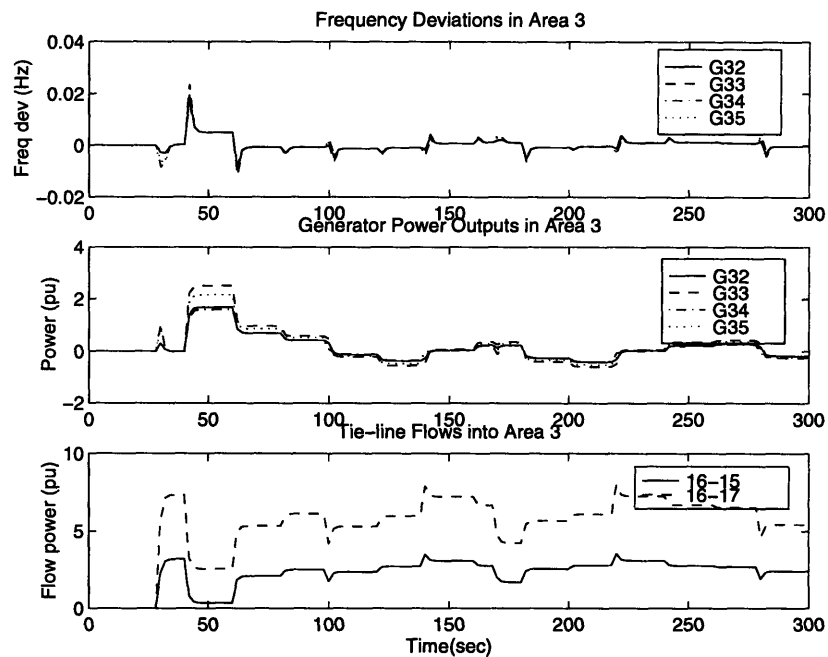
101

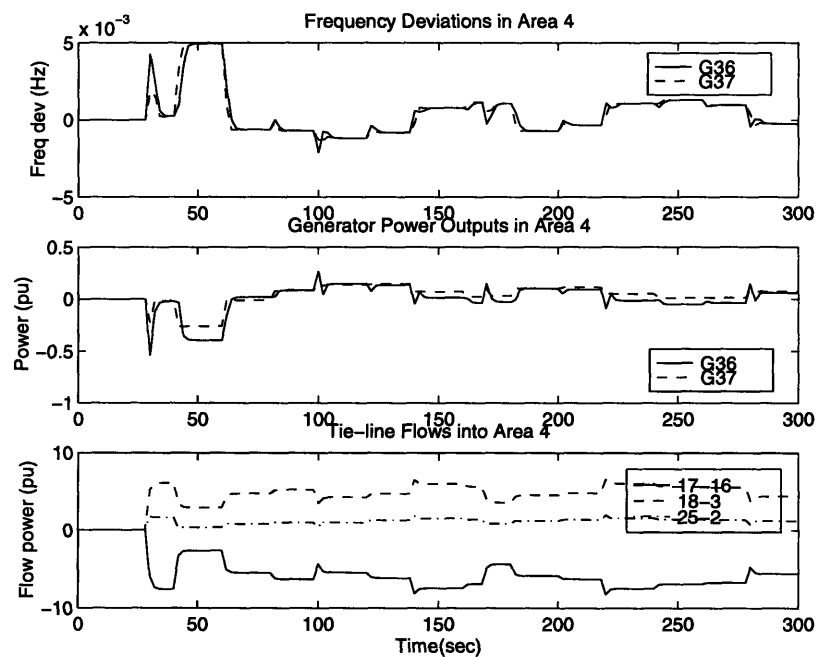Figure 6-20: ACE-based AGC response to the nonfirm transaction (Area 3)

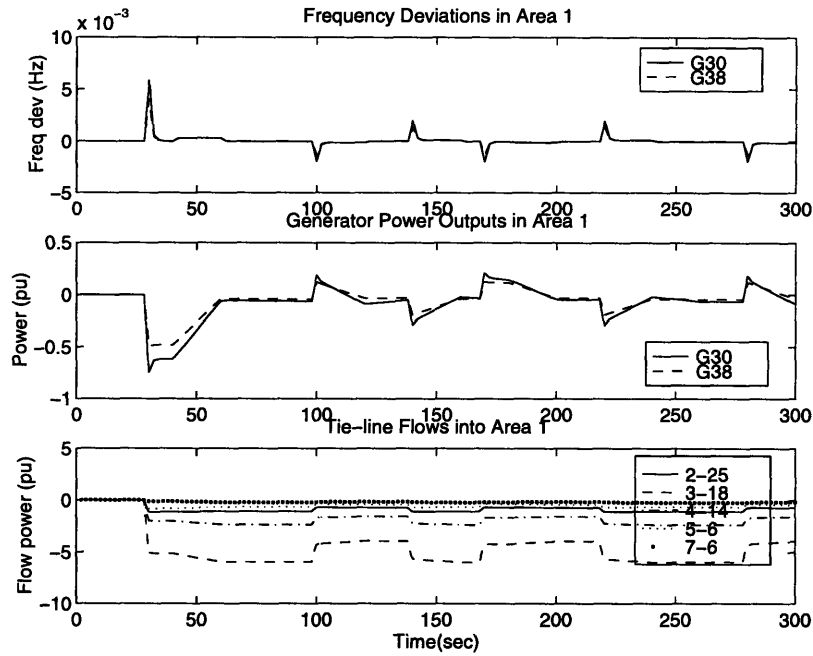Figure 6-21: ACE-based AGC response to the nonfirm transaction (Area 4)

Figure 6-22: Minimal regulation response to the nonfirm transaction (Area 1)

By using fringe control in the secondary control level, our control design is able to guarantee the system frequency quality.

In Figure 6-26, case 1 indicates system response to the 9 p.u firm transaction under the minimal regulation; case 2 indicates system response to the nonfirm transaction under the minimal regulation; case 3 indicates system response to the 9 p.u. firm transaction under the conventional AGC; and case 4 indicates the system's response to the nonfirm transaction under the conventional AGC. Figure 6-26 shows that these smaller but faster nonfirm transactions do not have much effect on the total cumulative cost of the minimal regulation, but the total cumulative cost of the conventional AGC increases significantly. This indicates that the system under the conventional AGC is more sensitive to these short term contracts in the competitive market. Both generator frequencies and the generation costs of the conventional AGC are effected significantly by the small load changes. However, the minimal regulation still performs well.
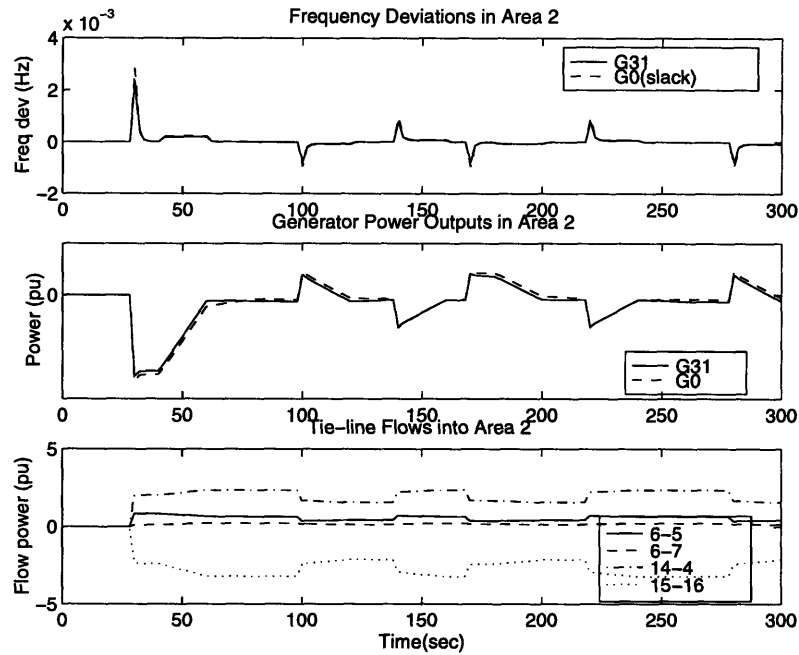
103

Figure 6-23: Minimal regulation response to the nonfirm transaction (Area 2)
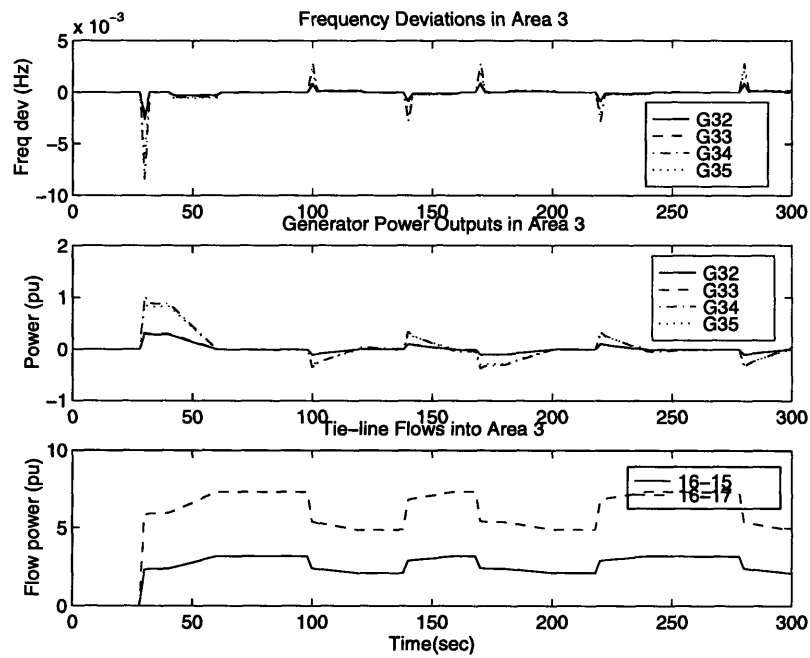

Figure 6-24: Minimal regulation response to the nonfirm transaction (Area 3)
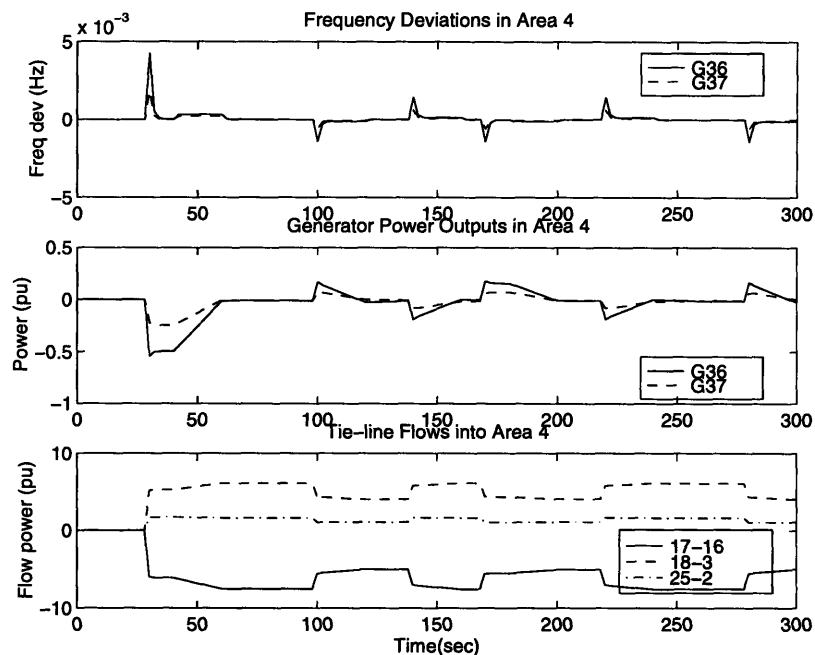
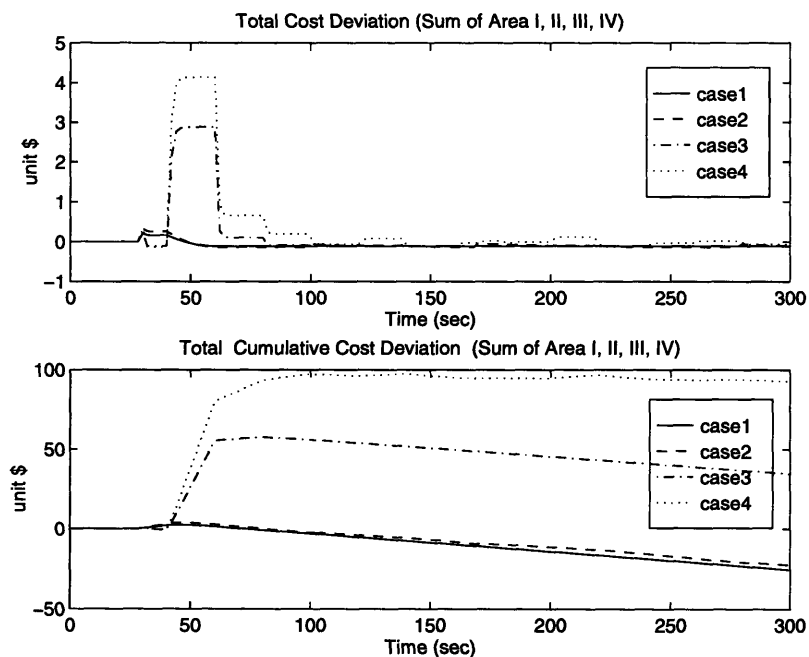Figure 6-25: Minimal regulation response to the nonfirm transaction (Area 4)

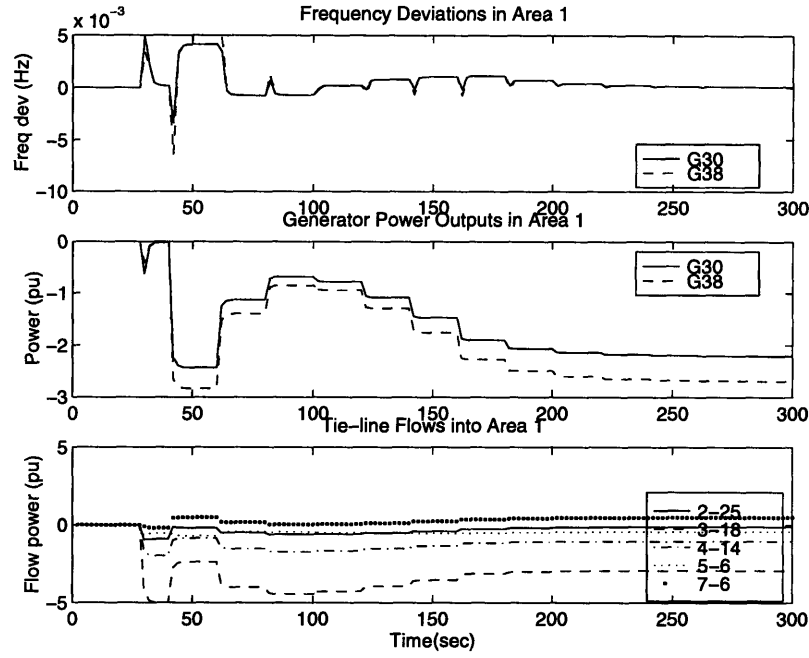Figure 6-26: Cost comparison of conventional AGC and minimal regulation

Frequency Deviations in Area 1

Generator Power Outputs in Area 1

Tie-line Flows into Area 1

Figure 6-27: Constrained ACE-based AGC response to step bilateral transaction (Area 1)

6.4 Constrained Minimal Regulation

In an open access environment, each supplier can transmit power to its buyer(s) freely. It is, therefore, important for the system regulation to have a capability of constraining the transmission power. Since the market-driven power flows are probably large only on certain transmission lines, it is important to have an effective way of eliminating these overloads. The overloaded conditions should be eliminated immediately, otherwise, transmission lines might be damaged because they are over-heated.

To analyze constrained minimal regulation, consider a similar simulation setup as that in the previous section with all tie-lines constrained by the transmission limits of $4p.u.$ and the generator output limits of $-3p.u. \leq P_{Gi} \leq 3p.u..$

At present, when a transmission line is found to violate its thermal limit, the transmission line owner usually has to determine which areas are responsible and have the generation adjusted so that the transmission on that line is reduced. Figures 6-27 to 6-30 show a conventional way of dealing with the transmission constraints. In this
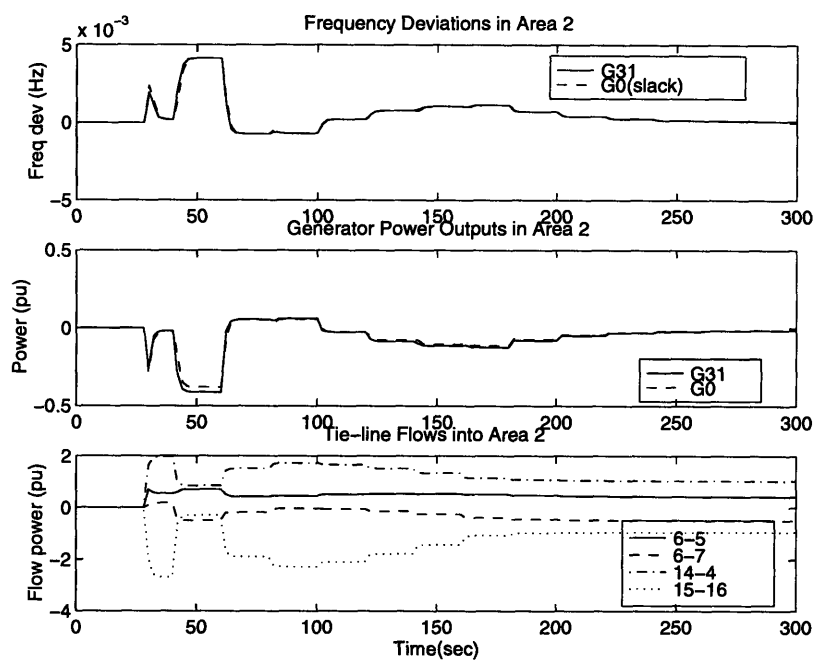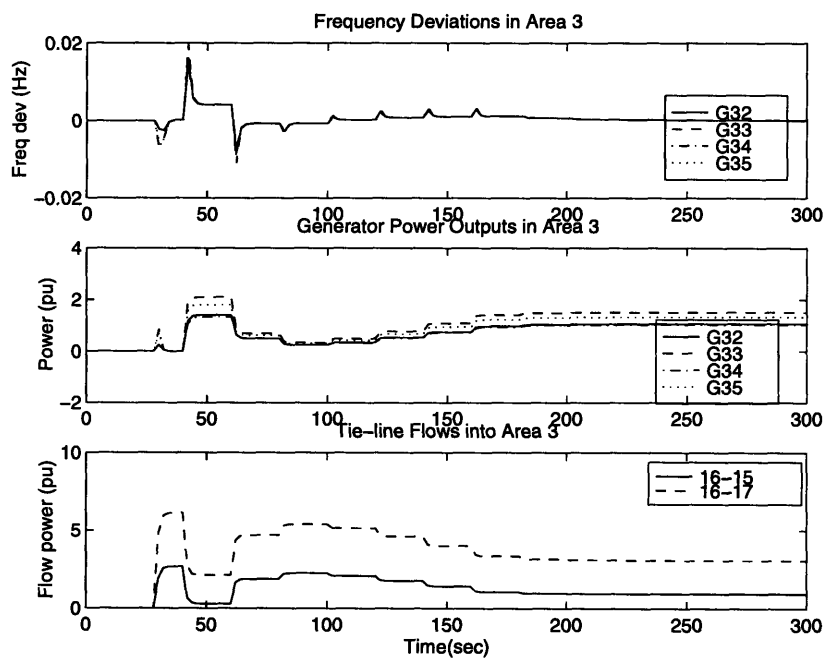
106

Figure 6-28: Constrained ACE-based AGC response to step bilateral transaction (Area 2)

Figure 6-29: Constrained ACE-based AGC response to step bilateral transaction (Area 3)
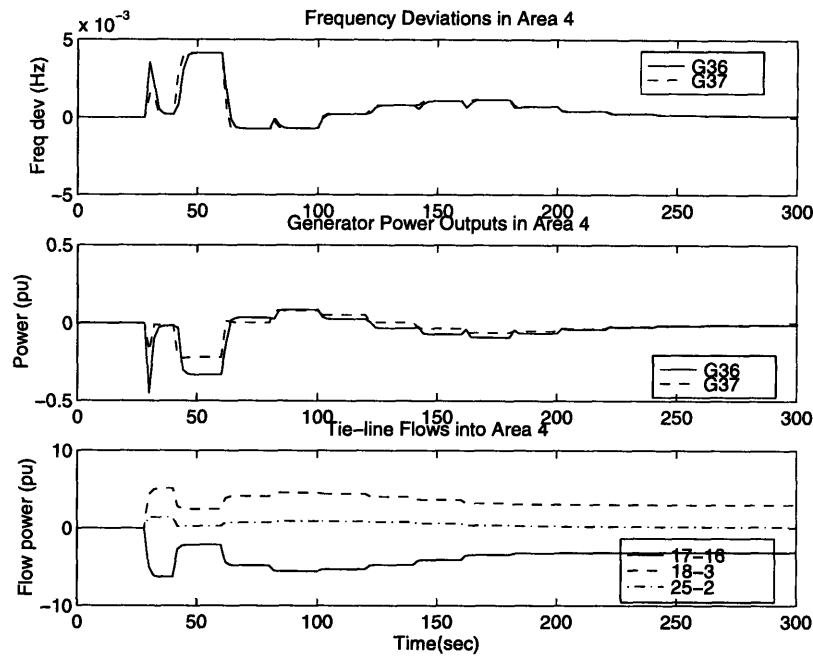
107

Figure 6-30: Constrained ACE-based AGC response to step bilateral transaction (Area 4)

case, real power line flow in 2-25 exceed the transmission limit, and the owner of the line needs to know which transaction causes the problem. Figures 6-27 to 6-30 are the results of the constrained AGC. In these simulations, the transmission power from bus 2 to 25 and from bus 3 to 18 reaches the 4 p.u. constraint. Figures 6-27 to 6-30 also illustrate that the constrained AGC works very slowly. The transmission lines are overloaded for a significant period of time.

It has been demonstrated in the previous chapters that minimal regulation can allow the incorporation of tie-line flow constraints. Figures 6-31 to 6-34 show the constrained minimal regulation response to the 9 p.u. step bilateral transaction. As in the case of the conventional AGC, the transmission is constrained at lines from bus 2 to 25 and from bus 3 to 18, and generator 30 reaches its output limit. Figures 6-31 to 6-34 also show that the minimal regulation responds much faster than the conventional AGC and constrains flows more efficiently.

Since the bilateral transaction does not actually reflect system demand changes, the generation cost needed for system regulation is small even though the conventional

Figure 6-31: Constrained minimal regulation response to step bilateral transaction (Area 1)

Figure 6-32: Constrained minimal regulation response to step bilateral transaction (Area 2)
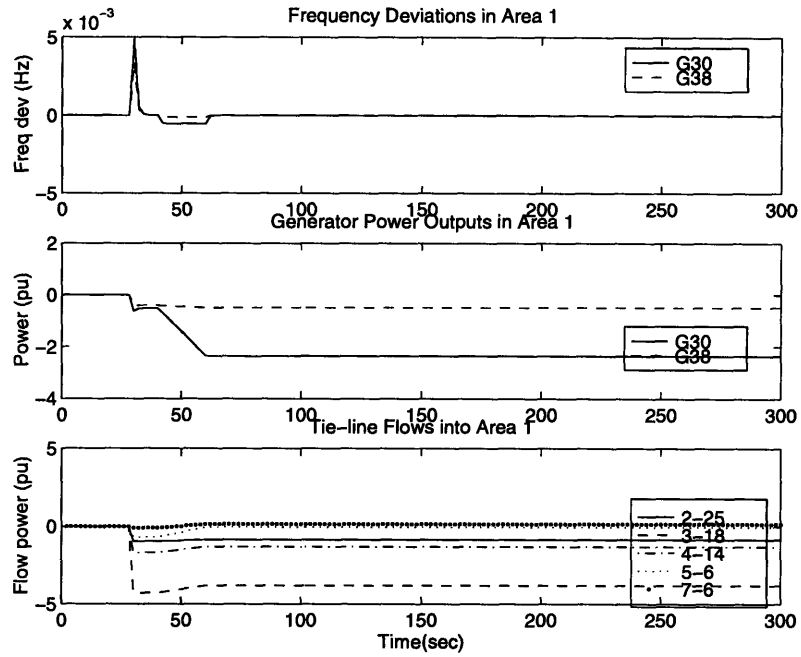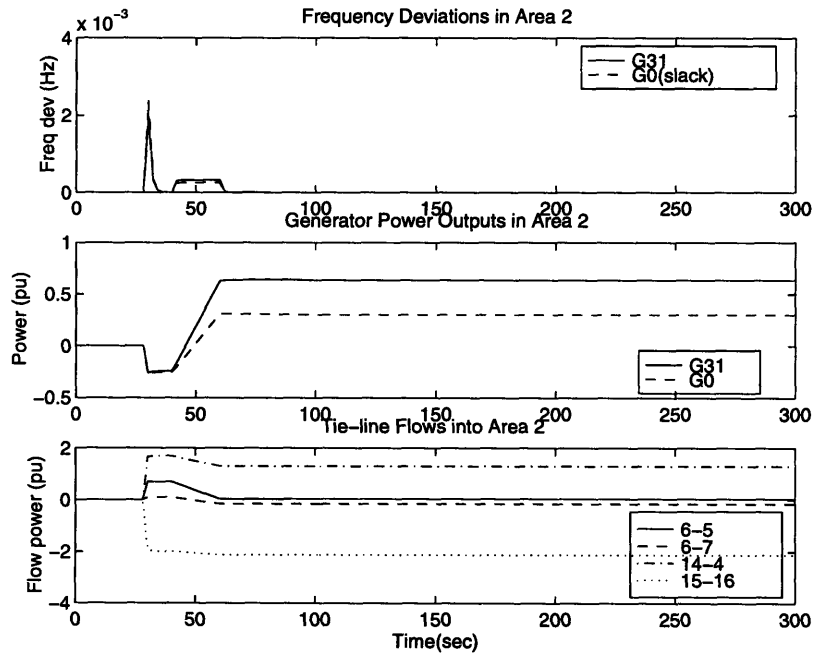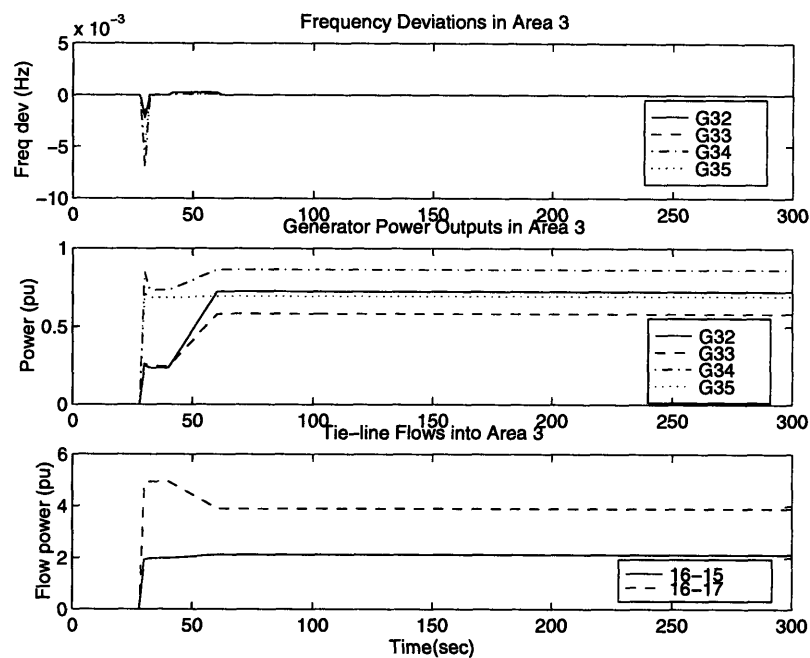
109

Figure 6-33: Constrained minimal regulation response to step bilateral transaction (Area 3)

Figure 6-34: Constrained minimal regulation response to step bilateral transaction (Area 4)
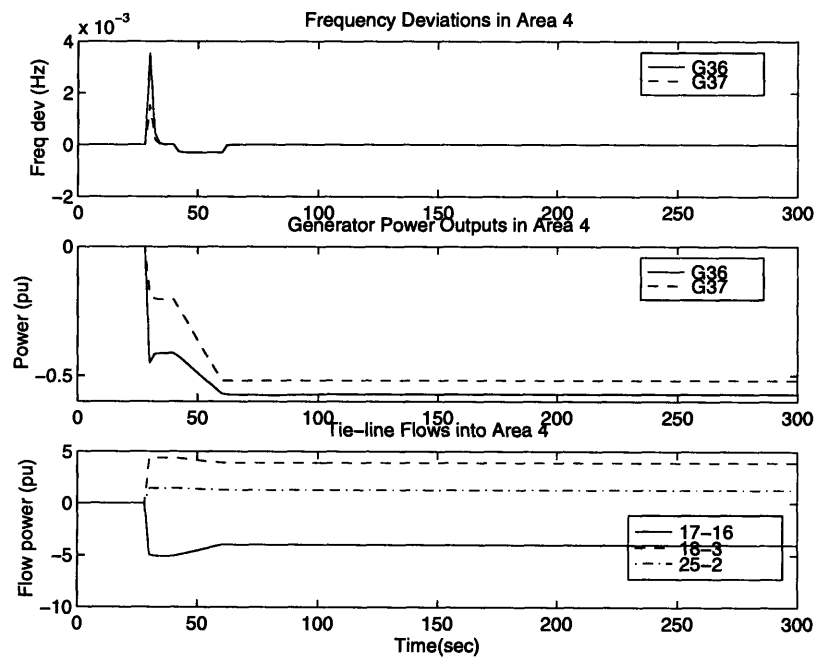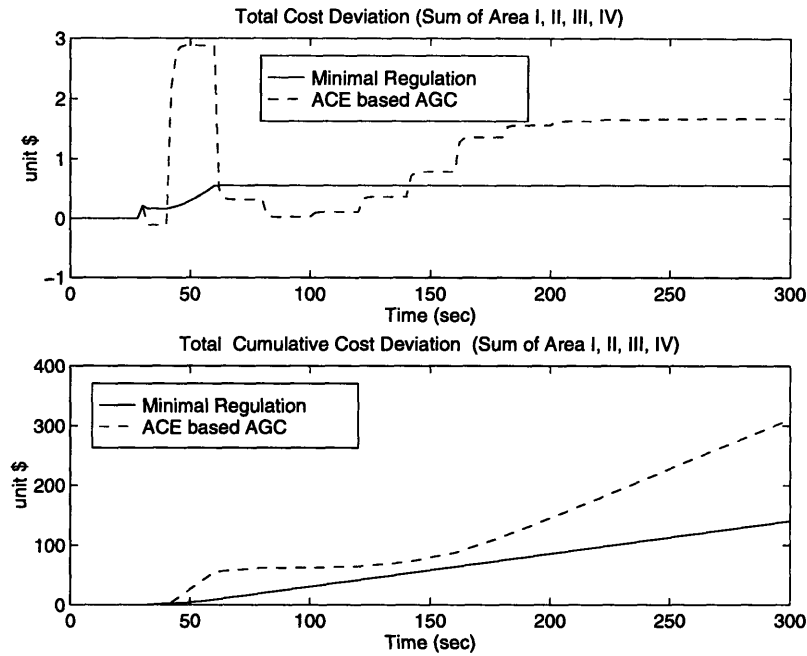
110

Figure 6-35: Cost comparison of conventional AGC and minimal regulation

AGC is used. However, when the transaction is constrained by the transmission limits, the situation is different. Figure 6-35 shows that when some tie-line flows go over their transmission limits, the cost of system regulation is higher if the conventional AGC is used.

Minimal regulation uses the constrained ED program to reschedule all the generation resources involved in the system regulation every T_t seconds[5], but conventional AGC only rearranges the generators in area 1 and in area 3. Therefore, it forces the system to use the more expensive generation (area 3) to maintain the system reliability.

In Figure 6-35, the total generation cost of the conventional AGC is lower than that of the minimal regulation over a short period of time, from about 70 seconds to 140 seconds, during which the conventional AGC is still violating the tie-line flow constraints but the minimal regulation is not. The conventional AGC cannot respond as fast as the minimal regulation, for it needs more time to make tie-line flows return

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[5]Recall that, as discussed in Chapter 4, minimal regulation uses the information monitored in KT_t to compute the optimal values of generation power for $(K+1)T_t$.

to the limits.

In practice, both parties involved in a bilateral agreement would not have the same behavior during the real time operation. Their noncompliances could be different, hence a non-zero net imbalance. In this situation, the cost of system regulation could be much higher. Generally, once the market becomes fully competitive, the market-driven power flows are hard to associate with the specific transactions.

6.5 An Example of a Multilateral Transaction

The system responses to the different types of single bilateral inputs have been demonstrated. System regulation should be capable of responding to more than one transaction simultaneously. Assume that five transactions occur consecutively; at time=30 seconds, bus 3 sells 9 p.u. electric power to bus 21; at time=90 seconds, bus 11 sells 3 p.u. electric power to bus 23; at time=150 seconds, bus 15 sells 5 p.u. electric power to bus 28; at time=210 seconds, bus 8 sells 2 p.u. electric power to bus 25; and at time=270 seconds, bus 1 sells 4 p.u. electric power to bus 10. These bilateral agreements are all economically attractive, since the buyers obtain power from other areas with less expensive generation.

One can observe from Figures 6-36 to 6-39 that with the conventional AGC, every time the system resets the ACE signals, tie-line flows are adjusted. However, because the ACE signals only vary with the net flow changes, the conventional AGC is not able to manage individual tie-line flows. Therefore, the values of tie-line flows will not be their economically optimal values.

In contrast, Figures 6-40 to 6-43 show that the proposed minimal regulation can manage tie-line flows efficiently. Every time a transaction occurs, each tie-line flow is controlled to its optimal value very quickly and efficiently. This is the main reason that why the minimal regulation is more cost-efficient than the conventional AGC.

Figure 6-44 shows the total regulation cost and cumulative cost deviations of both conventional AGC and minimal regulation. Because all the bilateral contracts are based on the economic attraction, transmitting power from an area with cheaper

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Figure 6-36: Conventional AGC response to multilateral transaction (Area 1)

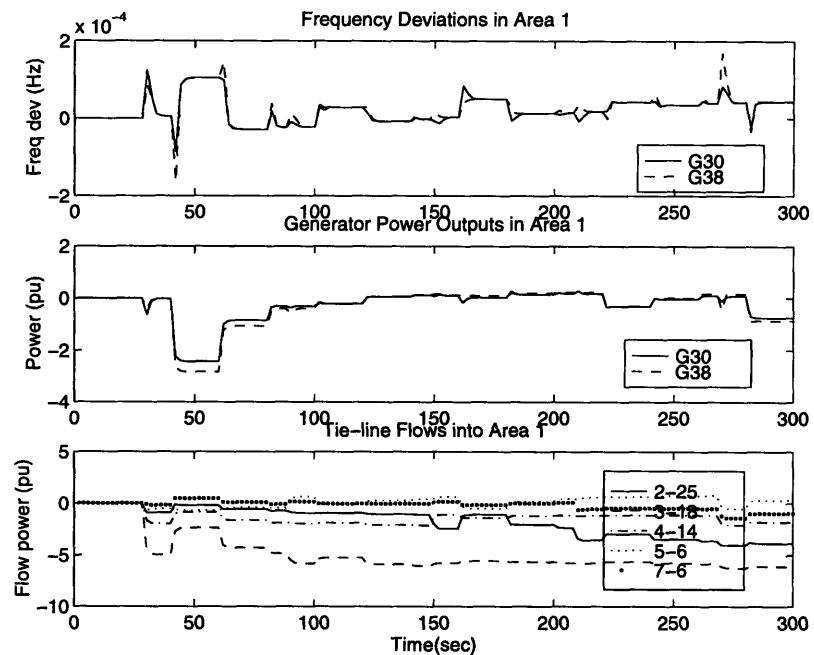Figure 6-37: Conventional AGC response to multilateral transaction (Area 2)

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Figure 6-38: Conventional AGC response to multilateral transaction (Area 3)

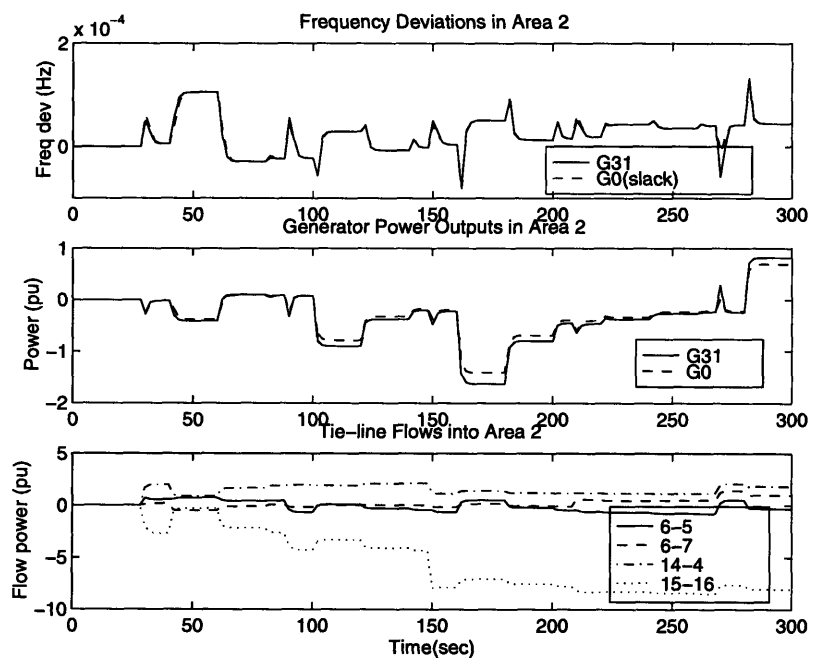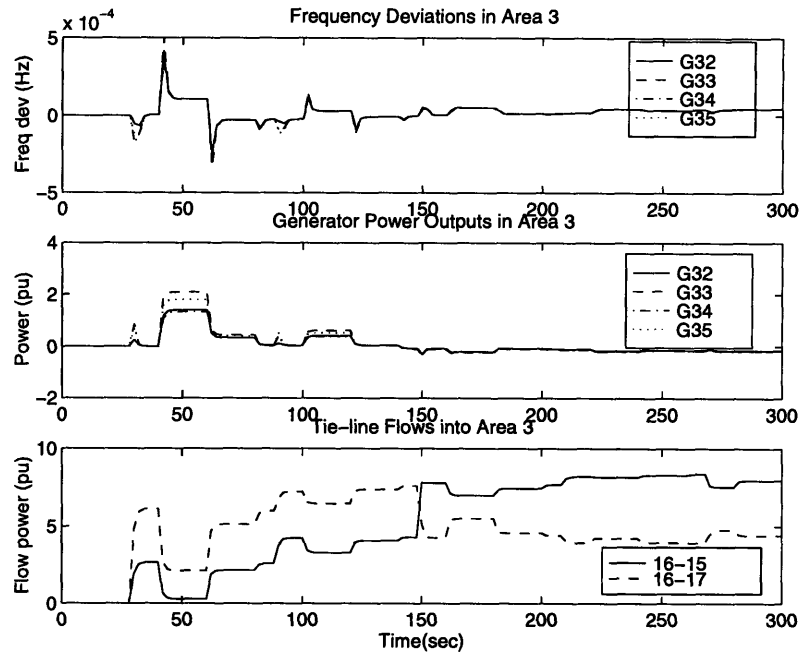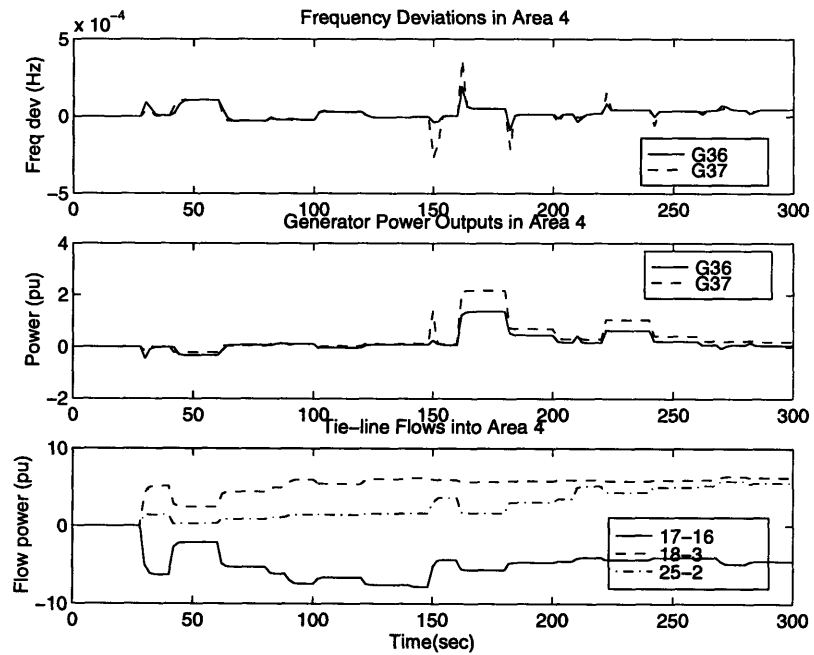

Figure 6-39: Conventional AGC response to multilateral transaction (Area 4)

Figure 6-40: Minimal regulation response to multilateral transaction (Area 1)
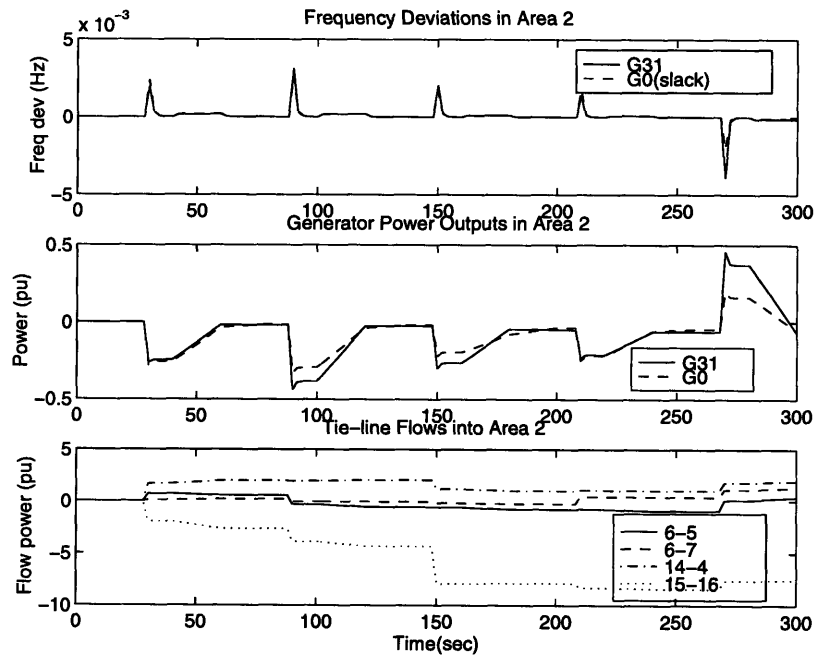
Figure 6-41: Minimal regulation response to multilateral transaction (Area 2)

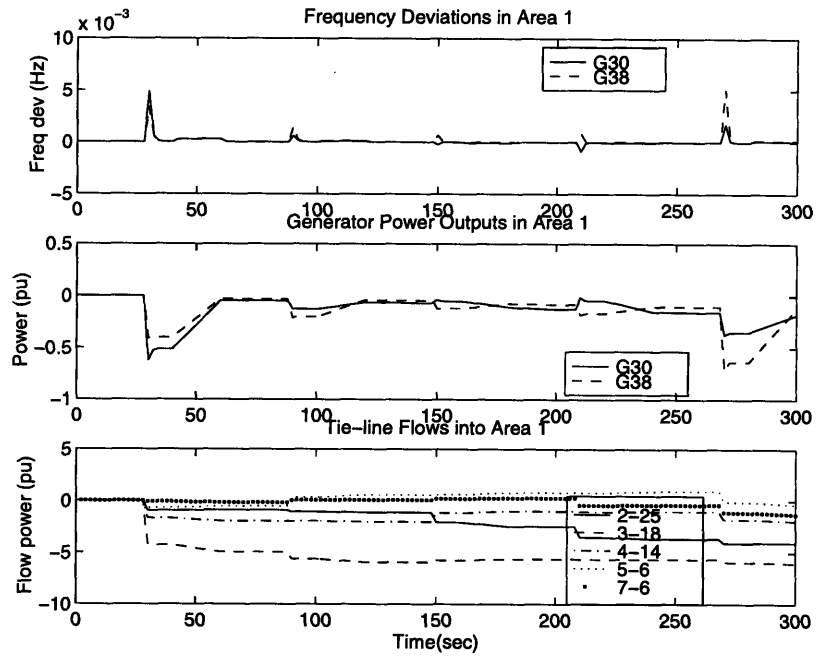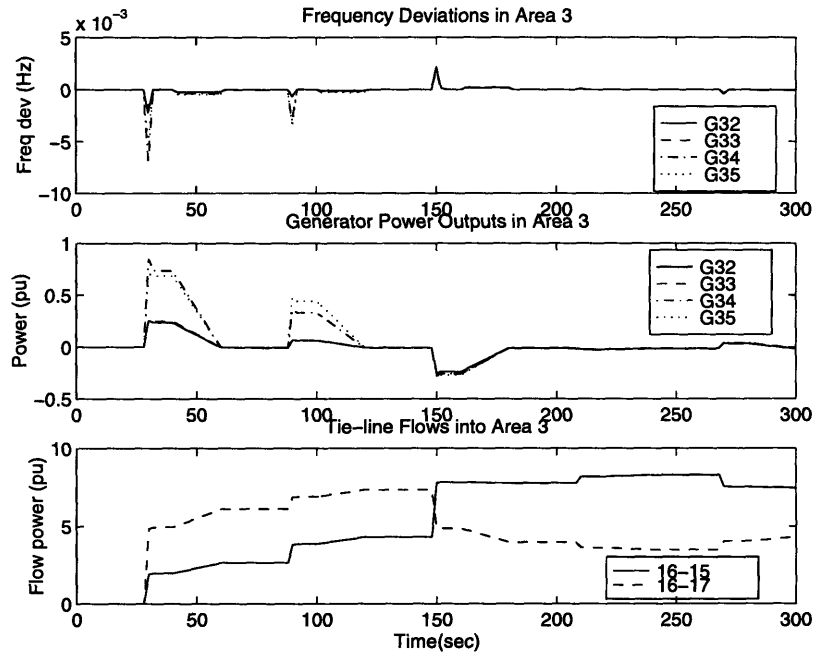Figure 6-42: Minimal regulation response to multilateral transaction (Area 3)
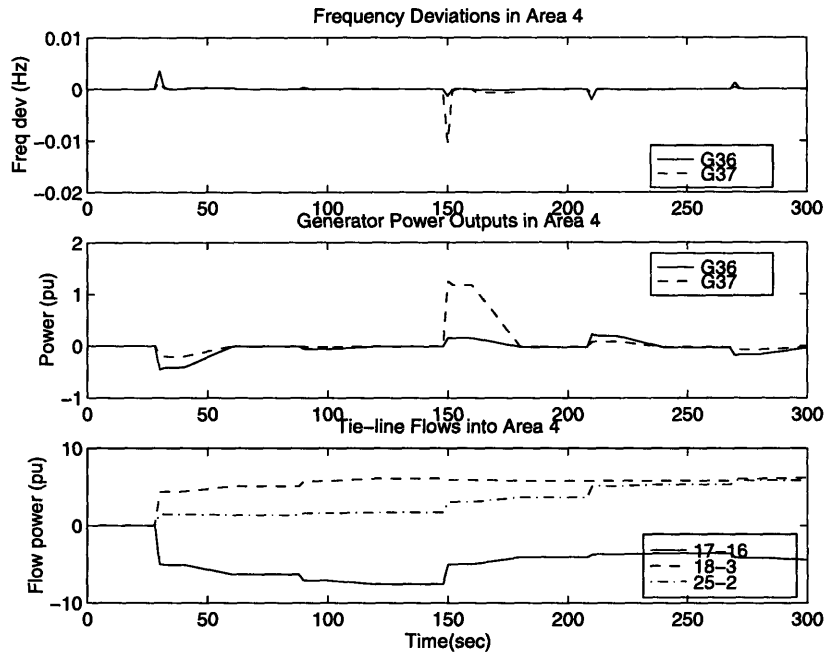
Figure 6-43: Minimal regulation response to multilateral transaction (Area 4)
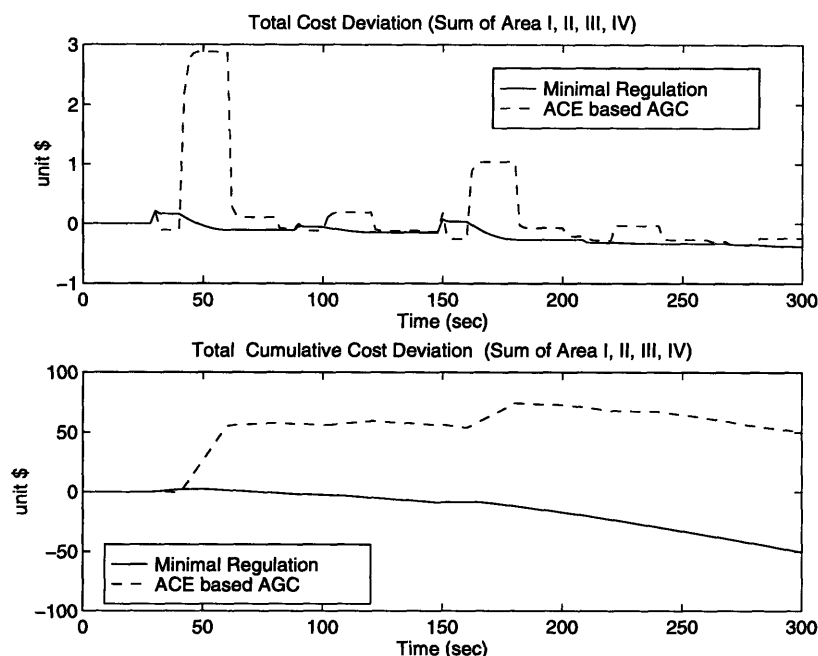
Figure 6-44: Cost comparison of conventional AGC and minimal regulation

generation to an area with expensive generation, minimal regulation realizes this economic efficiency and saves a lot of regulation expense for ISO. However, if the conventional AGC is used, the system does not benefit but has a significant amount of regulation cost.

Similarly in a nonfirm transaction case, these successive transactions result in an extremely bad frequency performance under the conventional AGC. On the other hand, our fringe control always performs well in frequency regulation. Frequency quality is always preserved. In the real world, many deviations from firm and nonfirm agreements are likely to happen simultaneously. In this situation, the transaction signals are extremely complex and the tie-line flows also respond in a complicated way. Therefore, it is hard to maintain frequency quality by using the ACE-based AGC.

6.6 Summary

Since a restructured US utility industry is likely to see many bilateral transactions, this chapter provides a study on the system response to different components and types of bilateral transactions under the minimal regulation, as well as under conventional AGC.

Using the present ACE-based AGC, if a transaction is not made known to all control areas then the actual system-wide response will not correspond to the economic transaction. As the ACE signal is regulated back to zero in an automated way, no change in tie-line flows among the areas will occur. It is best, therefore, for each transaction to be made known. On the contrary, minimal regulation will respond to the transaction automatically. By using the instant information, the proposed minimal regulation updates the optimal power set points P_G^* for next time interval at a tertiary control rate. That is why minimal regulation can function properly and without the need to be informed earlier.

Under a bilateral contract, the power is sold from a supplier bus to a buyer bus, so the same amount of power is injected into and withdrawn from the network simultaneously. No net demand increase takes place, except for the transmission losses. Generators controlled by ISO for system regulation are only in charge of compensating the transmission losses, and balancing the system in response to noncomplying deviations from the contracted power quantities. This results in a small generation regulation cost. However, because the conventional AGC functions sluggishly, a significant amount of cumulative cost is seen while system is regulated. On the other hand, minimal regulation can control the system to the optimal operation points efficiently, so it not only minimizes the total generation cost but also avoids the extra cumulative cost caused by slow frequency regulation.

When some unpredictable and fast nonfirm transactions happen, simulation results show that the short-term transactions affect the performance of conventional AGC significantly. The generator frequencies deviate considerably and the regulation cost increases. In contrast, minimal regulation can still maintain the high level

frequency quality yet it costs much less.

The difference in operation costs between conventional AGC and minimal regulation becomes more pronounced with transmission line constraints accounted for. This leads to a general conclusion that regulation must be done in such a way that the transmission line constraints are met in the most efficient way.

Since the conventional AGC is based on the ACE signals, it cannot manage individual tie-line flows efficiently. Tie-line flows will behave in an unpredictable way when more than one bilateral transaction occurs. On the other hand, our approach can optimally reschedule tie-line flows as soon as a new transaction takes place.

Chapter 7

Conclusions

The electric power market in the US is evolving into a deregulated competitive market for generation. An independent system operator (ISO) will be providing network coordination and systems control services. These generation-based systems control services are needed for frequency regulation, compensation of transmission losses caused by competitive transactions, as well as for keeping the network within the operating limits. They are thought to be a "glue" of the generation and transmission operational systems and are essential to physically foster a competitive electricity market [20].

In this thesis, a particular modeling and control approach is described, that is viewed as basic for system regulation under competition. This approach is capable of responding to the market-driven generation and demand changes, and is referred to as minimal regulation.

Under the open access, customers have many choices in selecting their power suppliers. Typically non-utility owned independent power producers do not participate in system regulation. The traditional horizontally structured industry will be modified into a form of a nested hierarchical structure with these independent producers located inside utilities. Moreover, conventional ways to reschedule coordinated economic dispatch are static and slow so that they cannot respond to the instant market-driven input changes. This may add a significant burden on automated systems control functions.

In this thesis, a newly developed hierarchical modeling approach is used for effective models at different control levels. The main idea of our modeling method is to view system dynamics as evolving over different time scales at different levels of hierarchies, so that one can model the complex system behavior as consisting of simpler submodels. Because these structure-based models allow the unbundling of information to provide for the system coordination, cost signals can be included into the control algorithm to meet "cost-based" performance objectives in the competitive environment.

Traditional performance objectives for system regulations are (i) regulating the ACE signals so that they cross zero every ten minutes (A1 criterion) and (ii) eliminating the inadvertent energy exchange (IEE) among administrative areas. The current control technique, ACE-based AGC, has been used to achieve the first objective. The IEE is basically not regulated in closed-loop; instead, generation is adjusted in each control area to make up for the IEE from the previous day. There are no financial penalties imposed for violations of the A1 criterion, nor for the IEE. However, the rapidly evolving competitive utility market will be qualitatively different from the current system. For power quality control and reliability reasons, frequency deviations should be always regulated. The power flows among the different areas are most probably related to the most economic transfers, and thus cannot be treated as inadvertent energy exchanges. In this sense, the control objectives should be adjusted to optimally benefit the entire industry in a unbiased way. This is achievable by the system coordination of systems control services. The modeling approach adopted in this thesis is important, because only when the objectives of systems control and the type of services that are provided under competition are defined, can the benefits of these services to specific market participants be established. Consequently, the conflicts among different parties will be reduced.

The proposed control which is needed to regulate the system reliably and efficiently under open access consists of two different levels of control, fringe control and minimal regulation. The fringe control has impact on the frequency control which responds to the fast load deviations at a subsystem, secondary control level. The minimal

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regulation is introduced to regulate system economically so that the total cost needed to perform the system regulation is minimized. Our minimal regulation can also allow systems to operate within the safety range without violating the constraints. It is shown how the secondary model, Equation (2.23), can be used for fringe control in order to preserve frequency quality. The tertiary level model, Equation (2.36), is developed for minimal regulation of generation of scheduling in response to sustained demand variations at a slower rate than the fringe control.

To study the system response in the changing industry, several scenarios are used for numerical simulations. The simulation results indicate significant improvements with the newly proposed control over the presently implemented control.

First, the ability of minimal regulation control to regulate the system in a more economic way than the conventional AGC is shown. From the cost analysis, the total generation cost and total cumulative generation cost of minimal regulation are found to be much smaller than those of the ACE-based AGC. In effect, by simply dealing with two major control tasks individually at two different levels of hierarchy, minimal regulation can respond much faster than the conventional AGC so that the new control method can achieve the control targets pre-specified at each control level.

Second, through the simulation examples included in the thesis, the frequency quality of our control method is shown to be much better than that of the conventional one. Because the fringe control can regulate frequency deviations efficiently, the generation frequencies are disturbed by any kind of transaction only over a very short time period. In addition, by using the unbundled secondary model framework and optimal control design method, LQR, the fringe control can assign different level of frequency quality required by specific end users.

Third, the proposed minimal regulation is capable of regulating system-wide response subject to transmission constraints easily and automatically. This enhancement corrects for the major shortcomings of the conventional AGC. The detailed derivations and control algorithms have been presented in Chapter 5. Reliability and efficient system regulation will become increasingly important as the utility market becomes more competitive as reflected in unpredictable short term, nonfirm contracts

and non-compliance with these contracts. Therefore, if the system is operating under a tightly constrained environment, its economic efficiency can only be partially achieved.

In Chapter 6, the system behavior under the bilateral model has been examined. Because the main control objective remains the same, present AGC should inform control center before a bilateral transaction occurs; then, decisions can be made to allow the transaction to take place. However, minimal regulation can respond dynamically to a bilateral transaction even when the ISO is not informed in advance. Furthermore, the conventional AGC regulates system very slowly so it may cause major losses even if transmissions are noticed beforehand. On the other hand, minimal regulation can respond quickly and economically regulate the system so it will save a significant loss of transmission cost.

Finally, since the power injected from a supplier is taken out by a buyer, a bilateral transaction will not actually reflect in a significant net demand increase. Once a transaction is done successfully and regulated adequately, either by ACE-based AGC or using ideas developed in this thesis, the only thing left in the final cost changes will be transmission losses. However, compared to the actual power transfer, the losses are quite small. Namely, when the system reaches its steady state, there is not much difference between the total cost of conventional AGC and the minimal regulation[1]. However, when some tie-line cannot accommodate a specific transaction because of the operating constraints, the transaction has to be constrained; otherwise the system will be forced to reschedule the total generation and utilize some other more expensive generation units. Then, a large difference between total cost of ACE-based AGC and minimal regulation will occur because the conventional AGC cannot dispatch generation efficiently and economically.

In conclusion, the proposed minimal regulation at the interconnected system level is cost effective and would greatly simplify the accounting for the services needed in this changing industry. In addition, it would guarantee technical performance at the interconnected system level.

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[1]However, a significant difference happens on the total cumulative cost deviation.

Appendix A

Reduced Order Tertiary Level Control

In this appendix, we discuss reduced order tertiary level controls: tertiary tie-line flow control and minimal regulation. Since tertiary level control is coordinated, it must be designed for an extremely large region, for example the entire United States or continental Europe. However, based on the concepts which we have developed in previous chapters, a tertiary level controller has to send every generator reference input for secondary level controllers. However, it is impossible for a very large region to communicate between control center and every remote generator.

In the real world, slightly different from the simulation examples, the electric power system is not only physically large but each administrative area is also much larger and more generators are involved. Therefore, there are fewer tie-lines than generators actually participating in regulation. For example, there are hundreds of generators in the electric power network but only twenty or thirty tie-lines connecting the different areas. Obviously, it is not necessary to control hundreds of generators to regulate a few tie-line flows. If the number of generators involved in tertiary level control can be reduced, and the communication between remote generators and the control center can be eliminated, then the tertiary level controllers can be implemented more easily.

A.1 Reduced Order Tie-line Flow Control

The following demonstrates how the number controls participating in tertiary tie-line flow control are reduced. First, assume the number of generators is larger than the number of independent tie-lines in the power system network. For example, in the standard IEEE 39-buses system, there are ten generators but only seven tie-lines, of which six are independent. In Chapter 3, ten control signals are used to control these six variables, but now only six out of ten generators are chosen as the controls. However, the controllability matrix needs to be re-visited. Namely, the generators have to have the capacity to control all tie-lines.

Assume that m generators out of N_G generators are to be controlled

$$N_{line} \le m \le N_G \qquad (A.1)$$

where N_{line} indicates the number of independent tie-line flows, then the model for reduced order tie-line flow control is

$$\underline{P}_f[K+1] = A_f^{red}\underline{P}_f[K] + B_f^{red}\underline{\omega}_{G1-m}^{set}[K] + L_f^{red}\underline{d}[K] \qquad (A.2)$$

where A_f^{red}; B_f^{red}, and L_f^{red} are $(m \times m)$ matrices indicating parts of A_f, B_f, and L_f, respectively, and $\underline{\omega}_{G1-m}^{set}[K]$ is the vector of frequency set points for those m generators that participate in the system regulation. They contain the elements relative to the controlled generators. Using the same algorithm mentioned in Chapter 3, the reference input signal for secondary level control is found to be

$$\underline{\omega}_{G-1-m}^{set}[K] = -K_t^{red}(\underline{P}_f[K]). \qquad (A.3)$$

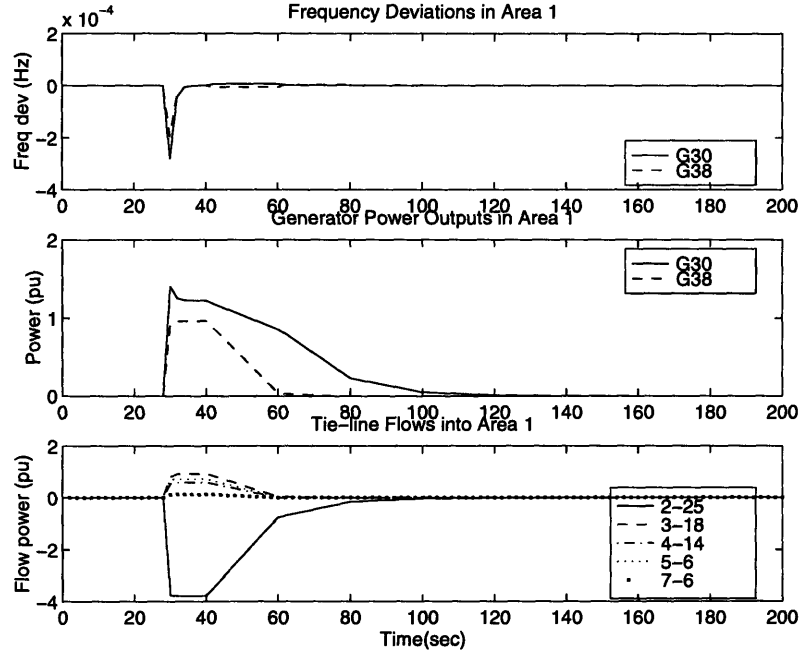The matrix K_t^{red} will be $(m \times N_{line})$ and it is obtained by from LQR calculation.

Frequency Deviations in Area 1

x 10⁻⁴

Freq dev (Hz)

G30
G38

Generator Power Outputs in Area 1

Power (pu)

G30
G38

Tie-line Flows into Area 1

Flow power (pu)

2-25
3-18
4-14
5-6
7-6

Time(sec)

Figure A-1: Reduced order tie-line flow control (Area 1)

A.1.1 Simulation Example of Reduced Order Tertiary Tie-line Flow Control

In the following simulations, only six generators, generators 30, 31, 32, 36, 38 and 0, are controlled. In addition, assuming there is a 9 p.u. load demand increase on load bus 25 at time=30 seconds.

The simulation results show that the reduced order tertiary tie-line flow controller can also regulate tie-line flow back to the original agreement by just controlling the six generators. There is no tertiary level control on generator 33, 34, 35, and 37, so these non-tertiary-level-controlled generators are only in charge of regulating their frequencies.

A.2 Reduced Order Minimal Regulation

As in tertiary tie-line flow control, the same problem is found in proposed minimal regulation which transmits frequency reference input of every secondary level generator. This is impractical for extremely large areas. A reduced order minimal regulation
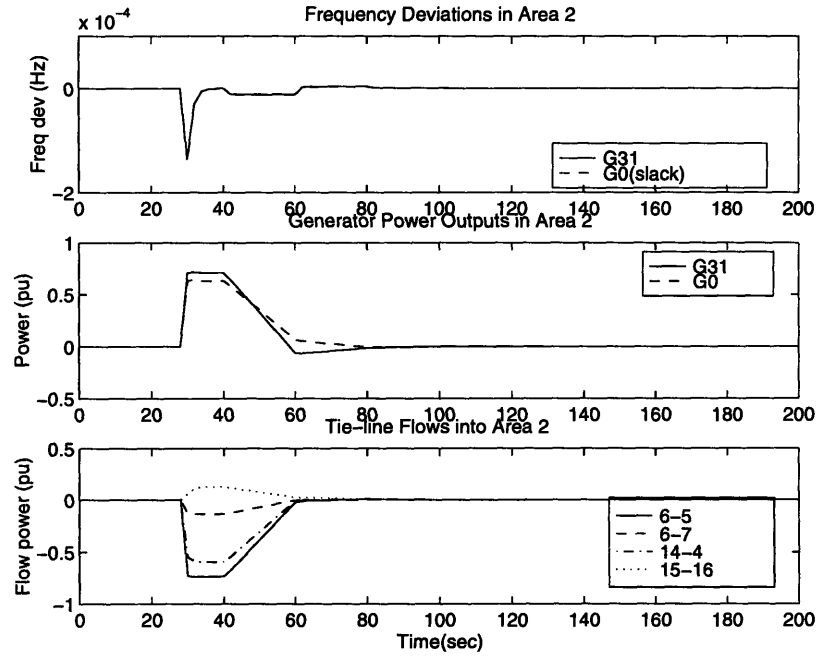
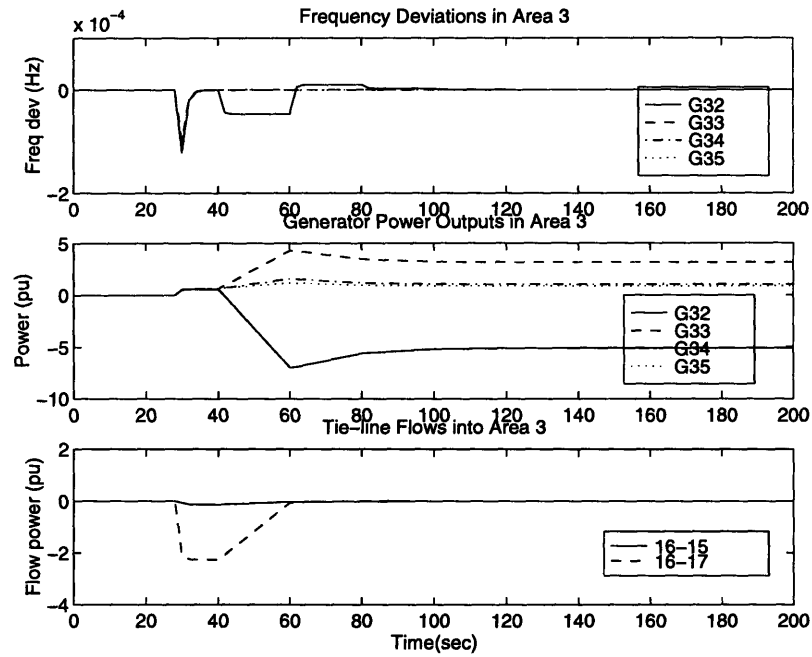Figure A-2: Reduced order tie-line flow control (Area 2)

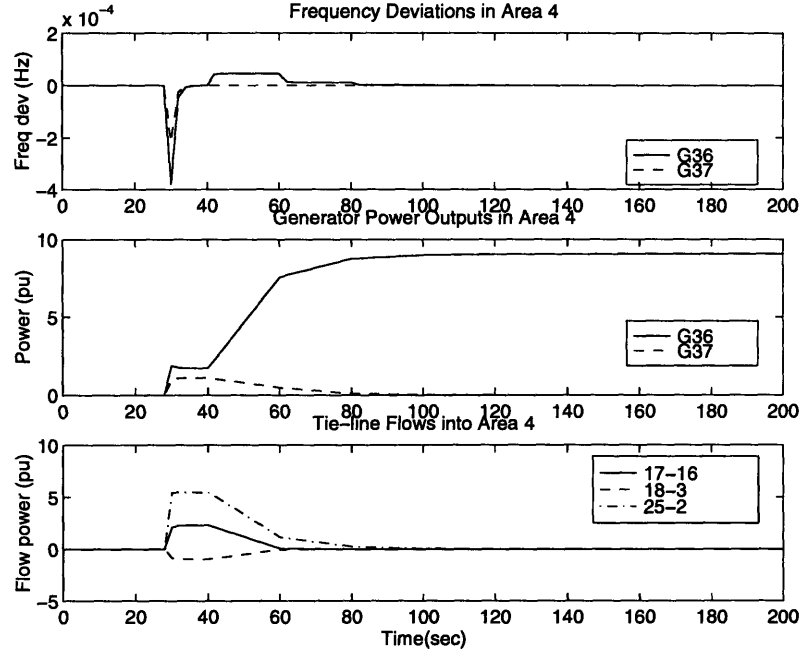Figure A-3: Reduced order tie-line flow control (Area 3)

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Figure A-4: Reduced order tie-line flow control (Area 4)

is formulated by using the same method that applies to tie-line flow control, i.e. the generators not participating in the operation are disregarded. Then, the performance objective of minimal regulation is modified so as to minimize the total cost of the generators involved in the tertiary level control.

Furthermore, the tie-line flows have to be constrained within their limits so at least N_{line} generators have to participate. One suggestion is that the number of generators included in minimal regulation, n has to greater than the number of independent tie-lines, and the larger the better.

$$N_{line} \leq n \leq N_G \qquad (A.4)$$

where n indicates the number of participating generators. Economic dispatch problem differ from former one:

$$min\{\sum_{i=1}^{n} C_i\} \qquad (A.5)$$

subject to

$$\sum_{i=1}^{n} P_{G_i}^* = \sum_{j=1}^{N_L} P_{L_j} + P_{loss} - \sum_{k=n+1}^{N_G} P_{G_k} \qquad (A.6)$$

Similarly, the reduced order model for minimal regulation is

$$\underline{P}_{G_{1-n}}[K+1] = A_p^{red}\underline{P}_{G_{1-n}}[K+1] + B_p^{red}\underline{\omega}_{G_{1-n}}^{set}[K] + L_p^{red}\underline{d}[K] \qquad (A.7)$$

where A_p^{red}; B_p^{red}, and L_p^{red} are n by n matrices and indicating parts of A_p, B_p, and L_p, respectively. They contain the elements relative to the controlled generators. $P_{G_{1-n}}$ and $\omega_{G_{1-n}}^{set}$ represent the vectors of generator power and frequency set points for secondary level control associated with the n generators that is controlled by ISO.

$$\underline{\omega}_{G_{1-n}}^{set}[K] = -K_t^{red}(\underline{P}_{G_{1-n}}[K] - \underline{P}_{G_{1-n}}^*[K]) \qquad (A.8)$$

where K_t^{red} is a $(n \times n)$ matrix and obtained by applying the same method as reduced order tertiary tie-line flow control.

A.2.1   Simulation Example of Reduced Order Minimal Regulation

In the following simulations, the same six generators are controlled. The same amount of load demand increase on bus 25 occurs at time=30 seconds.   Figures A-5 to A-8 show that generators 33, 34, 35, and 37 are not included in minimal regulation so they only respond to the fringe control.

In the end of the appendix, an additional simulation case is included, to show that the reduced order minimal regulation can still maintain the tie-line flows within their limits. As discussed previously, at least six generators is needed to be controlled. In Figures A-9 to A-12, all tie-line transmissions are bounded by $-3pu$ and $3pu$.
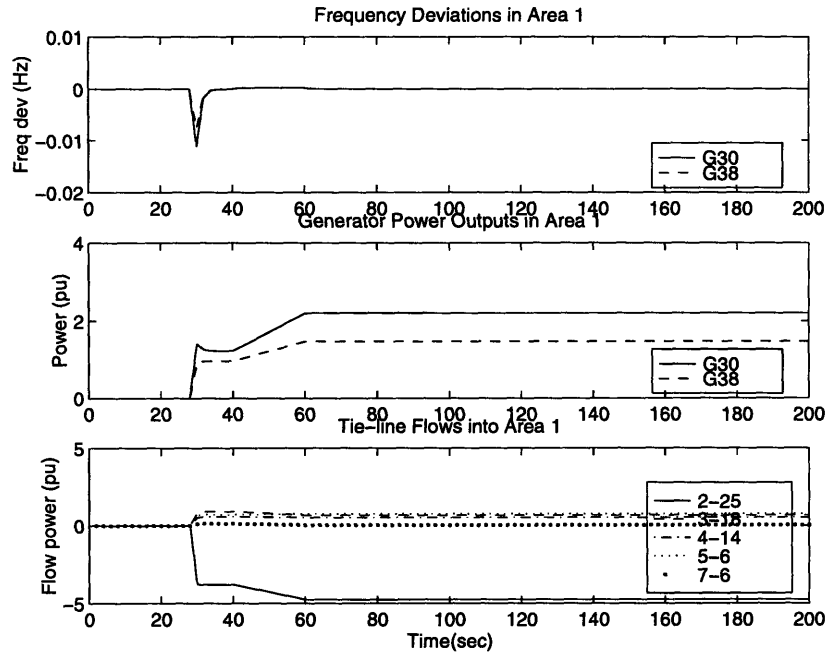
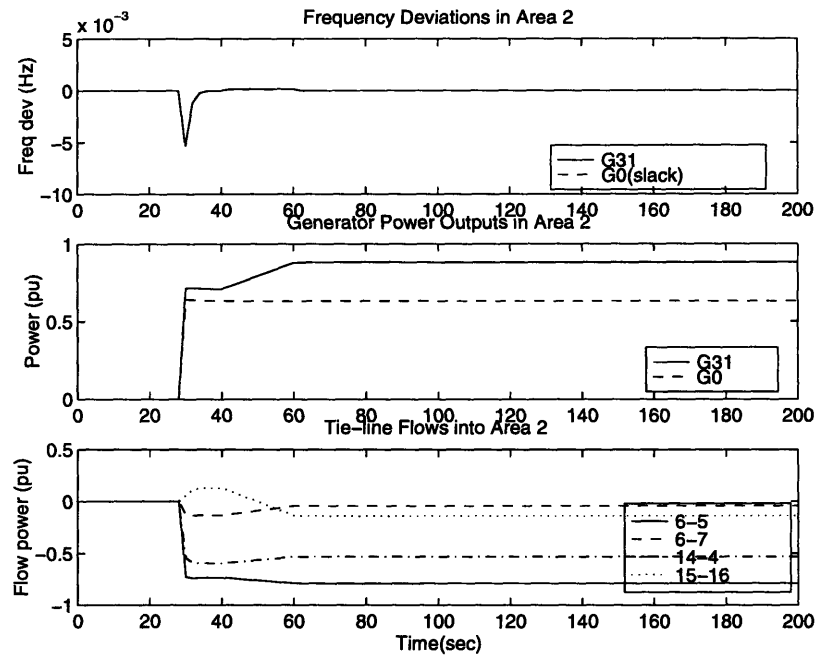Figure A-5: Reduced order minimal regulation (Area 1)

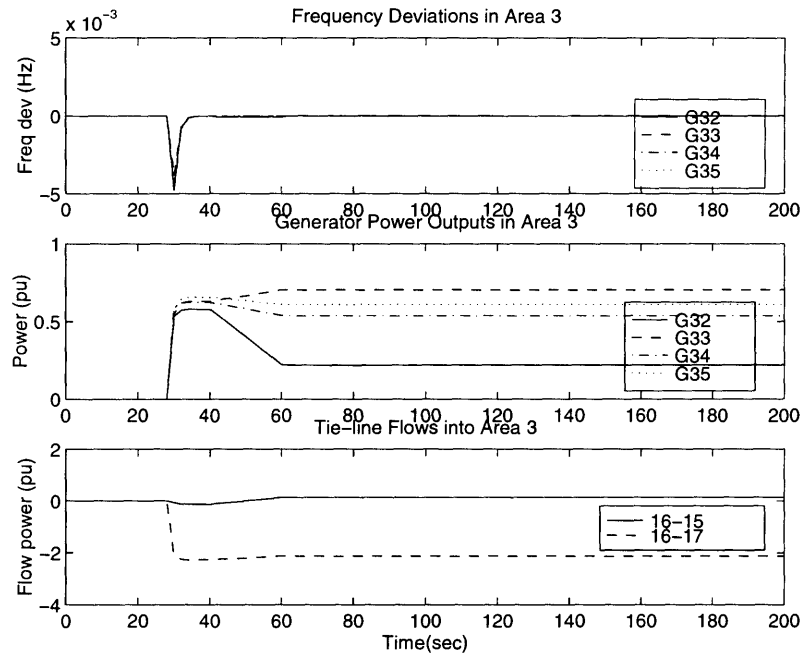Figure A-6: Reduced order minimal regulation (Area 2)

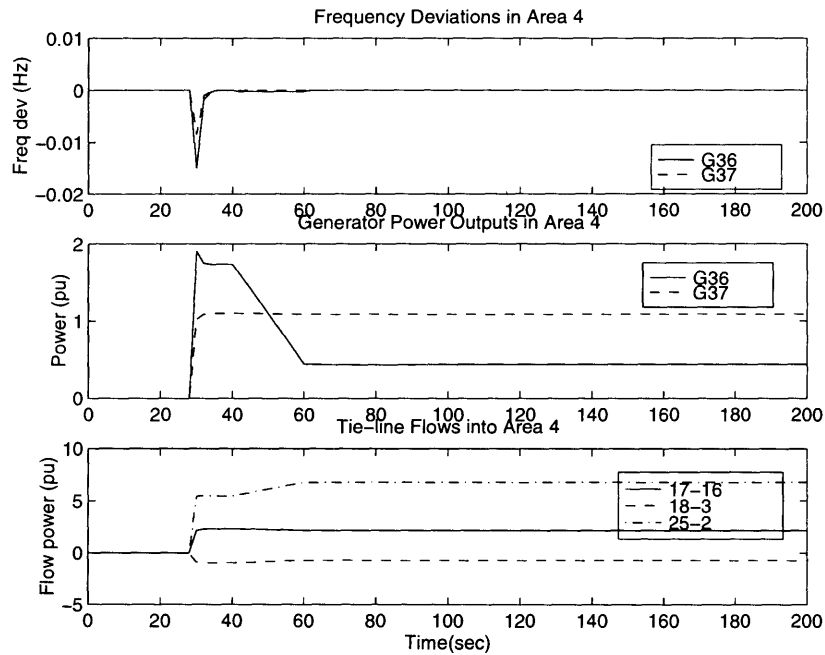Figure A-7: Reduced order minimal regulation (Area 3)

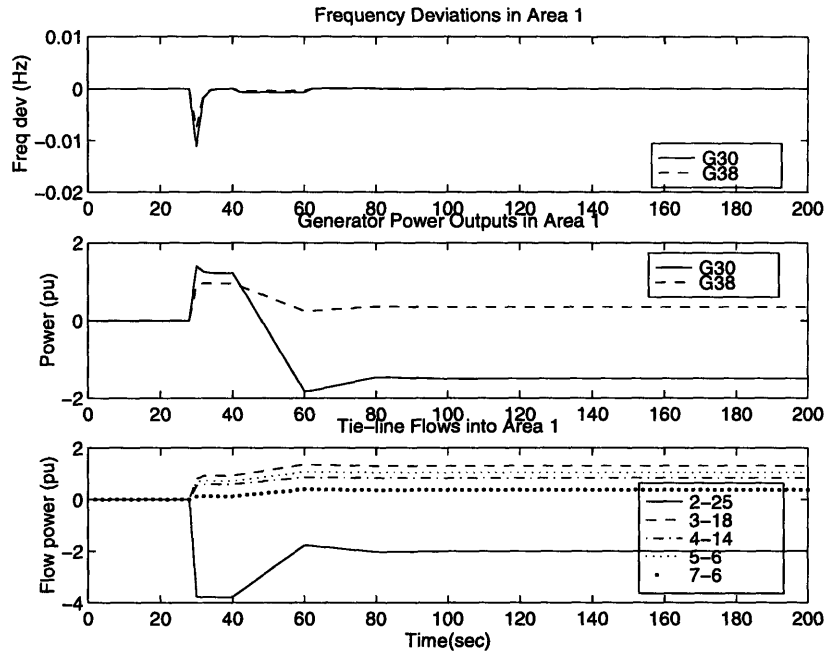Figure A-8: Reduced order minimal regulation (Area 4)

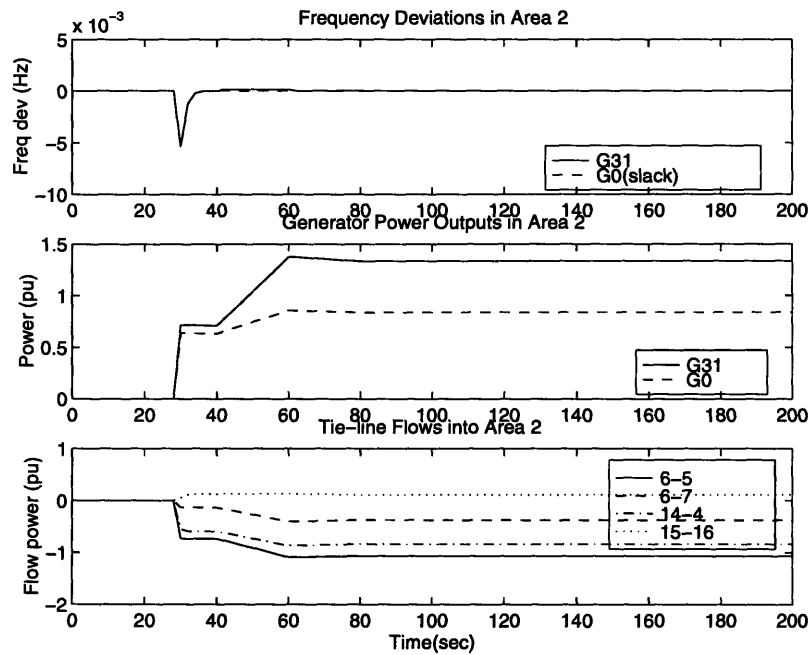Figure A-9: Reduced order minimal regulation with 3 p.u. tie-line flow constraints (Area 1)

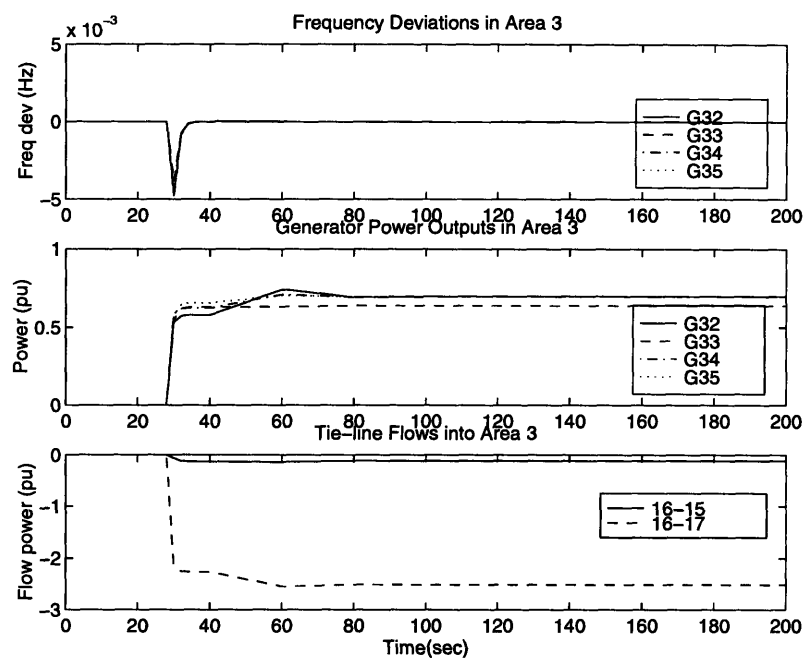Figure A-10: Reduced order minimal regulation with 3 p.u. tie-line flow constraints (Area 2)

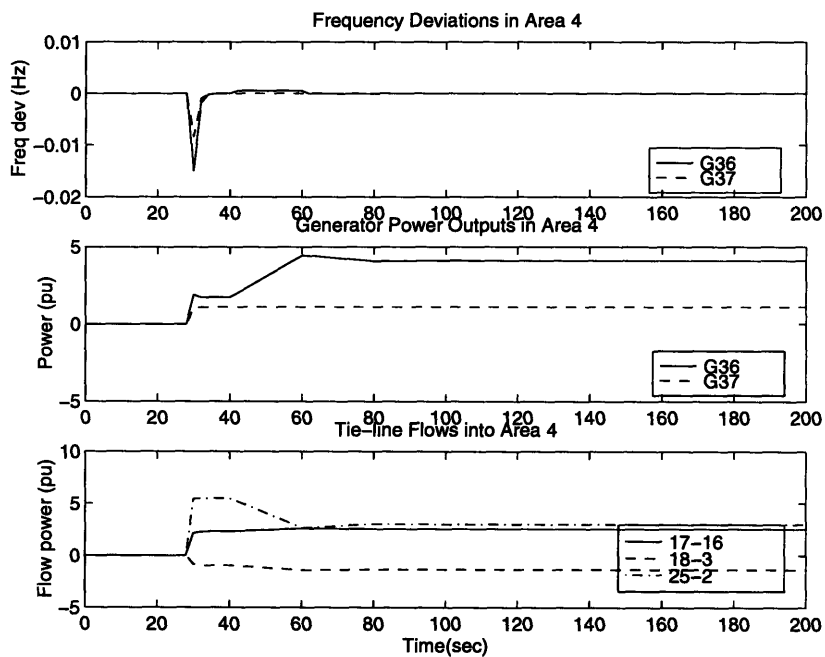Figure A-11: Reduced order minimal regulation with 3 p.u. tie-line flow constraints (Area 3)

Figure A-12: Reduced order minimal regulation with 3 p.u. tie-line flow constraints (Area 4)

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