Closed-loop Market Dynamics for a Deregulated Electric Power Industry

by

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Submitted to the Department of Electrical Engineering and Computer Science in partial fulfillment of the requirements for the degree of Master of Engineering in Electrical Engineering and Computer Science at the MASSACHUSETTS INSTITUTE OF TECHNOLOGY

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Abstract

The deregulation of the electric power industry in the United States has put pressure on system operators to maintain security and performance levels under increasingly uncertain market conditions. The debate over which market structure is best suited to facilitate provision of power on a competitive basis is still ongoing. In this thesis, a summary is provided first of the effects of deregulation in the U.K. and Scandinavian markets. Based on this summary, a new market structure for trading electrical power is proposed. The trading process is separated into three markets: the long-term, spot and controls markets, distinguished by time frames as well as their functionality. Extensive modeling of the technical behavior of the system as well as the economic decision process of industry participants is introduced. A simulation of the market, driven by stochastic disturbances, shows how entirely profit-based generators adapt themselves to optimize overall social welfare. The second contribution from this thesis is the development of a new concept for market-based frequency controls. By requiring information about load volatility to be included in bilateral contracts, system operators will be able to provide individualized incentives for generators and loads to reduce the overall need for system control. In addition, a modification to the existing criteria for frequency regulation is proposed. It is shown how by relying solely on system frequency as a control variable, an inter-area market for controls can be created. In addition to improving efficiency and taking advantage of inter-area price differentials, the new criterion also eliminates the need for real time coordination of generators participating in frequency control.

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Contents

1 Analysis of Market Structures Under Deregulation ............................ 8
  1.1 Introduction ........................................................................... 8
  1.2 The British System ............................................................... 9
    1.2.1 Market Participants ....................................................... 9
    1.2.2 The Trading Process ..................................................... 10
    1.2.3 Positive Aspects of the British System ........................... 11
    1.2.4 Drawbacks of the British Model .................................... 12
  1.3 The Scandinavian System .................................................... 14
    1.3.1 Market Participants ....................................................... 14
    1.3.2 The Market .................................................................. 14
    1.3.3 Positive Aspects of the Scandinavian Model ................... 16
    1.3.4 Potential Problems with the Scandinavian Market .......... 17
  1.4 Relevance of the European Experience to the American Market .... 17
    1.4.1 Analysis of the Need for New Modeling to Accommodate Deregulation ................................................................... 19

2 A New Market Structure for the American Electric Power Industry 21
  2.1 Problem Statement ............................................................... 21
  2.2 Industry Structure ............................................................... 22
    2.2.1 Description of Industry Participants and Their Respective Responsibilities .......................................................... 23
  2.3 Physical Model .................................................................... 23
6.2 Necessary modeling ................................................. 55
6.2.1 Basic power frequency relations .......................... 55
6.3 Traditional Methods For Controls .......................... 57
6.3.1 Frequency regulation ........................................ 57
6.3.2 Advantages of the present ACE-based decentralized AGC in a regulated industry .............................................. 59
6.3.3 Disadvantages of the ACE-based decentralized AGC in a regulated industry .............................................. 60
6.3.4 ACE-based “trading” of frequency biases between the CAs ................................. 61
6.3.5 Hybrid schemes for partial “trades” of frequency bias .............................................. 62
6.3.6 Possible problems with the $A_1$ criterion when used in competitive industry .............................................. 65
6.4 Moving From $A_1$- to $CPS_1$ and $CPS_2$-based system regulation .................. 68
6.4.1 Problems with the $CPS_1$ Criterion ......................... 70
6.5 Market-based Regulation ........................................ 71
6.5.1 Advantages of the modified $CPS_1$ criterion ............ 73
6.5.2 Who pays for system regulation and how much? ........ 73
6.6 Remaining need for coordination ............................... 75

7 Conclusion ......................................................... 76
# List of Figures

1-1  IPP Bid Curve For Generation ................................................................. 11
1-2  Stacking Generation According to Bid Price .............................................. 12
1-3  Spot Market Price Determination .............................................................. 16

2-1  Natural Frequency Response of an Isolated System .................................... 26

3-1  Structure of Long-Term Contracts .............................................................. 28
3-2  Structure of Contracts Traded on the Controls Market ............................... 30
3-3  Two-Slope Supply Curve .............................................................................. 35
3-4  Effect of Supply Curve Shape on Prive Distribution .................................... 36

4-1  Simulation Results ......................................................................................... 39
4-2  Simulation Results ......................................................................................... 40
4-3  Simulation Results ......................................................................................... 41
4-4  Total System Dynamics ................................................................................ 46
4-5  Matching Disturbance-Bounds with Control Capacity ................................. 48

5-1  Inter-Area Trade of Bulk Power .................................................................... 50
5-2  Effects of Daisy Chaining on Contract Path ................................................. 51

6-1  Market induced instability ............................................................................. 69
Chapter 1

Analysis of Market Structures Under Deregulation

1.1 Introduction

During the next few years the power industry in the United States will go through tremendous changes on its way from a completely regulated industry to a fully competitive market. As of today the key decision makers have not been able to agree on a market structure under which power can be freely traded on the interconnected system. Any legitimate structure will have to include provisions for satisfying the following performance criteria:

1. Meet anticipated demand at the lowest total operating cost while abiding to operating constraints.

2. Compensate for real and reactive transmission losses.

3. Provide real-time balancing control for unexpected deviations in demand.

4. Provide standby generation.

In the regulated industry these criteria were met in a coordinated manner as the utilities used load scheduling to predict demand and set generator outputs accordingly.
Unexpected deviations were dealt with manually, in real time, by designated control generators who were tasked with altering their output to maintain a stable frequency. This was a relatively straightforward procedure since the grid operator had full control over the generators in his area. Under the provisions of deregulation however, the operator of the transmission network is no longer allowed to own any generation. Instead it will be forced to purchase its control power on the open market. This again raises questions about system security and performance. Can the grid operator guarantee the availability of sufficient control and reserve generation on the net? Will the need to purchase control generation from independent producers cause a time delay in the control response, and if so how does this affect system stability? Before attempting to define a possible structure for the American market it is helpful to examine the performance of the market structures already in place abroad. In what follows we provide an analysis of the benefits and shortcomings of the current British and Nordic power markets. While they differ from the United States both in size and availability of resources, they do provide us with useful insights into the behavior of the new market participants.

1.2 The British System

England was the first western country to attempt deregulation of its power generation and transmission system. They opted for a semi-deregulated structure which centers around a power "Pool". The main players in this market together with their responsibilities are described next.

1.2.1 Market Participants

The Independent Power Producers (IPPs) The first step in the deregulation of the power industry was the privatization of all government owned generation, with the exception of nuclear plants. The majority of the plants were absorbed by two newly formed companies, National Power and Power Gen. Together with a growing number of new, privately financed, combined cycle gas generators,
they constitute the independent power producers. The sole purpose of the IPPs is to generate power at the lowest possible cost, and sell at the highest available price. They have no obligation to maintain system stability or balance the overall power on the net.

**The National Grid Company (NGC)** As the utilities were dissolved, the ownership of the entire transmission grid was transferred to a single company, known as the National Grid Company (NGC). The NGC is responsible for maintaining and expanding the physical network, and providing basic services to ensure network security. The NGC recovers its costs by charging an access fee to all IPP’s. Since the grid is a natural monopoly this part of the market is still strictly regulated by the government.

**The Power Pool** The Pool is responsible for scheduling generation so that it meets the predicted demand. As described below, all power transactions on the grid have to be scheduled by the pool (no bilateral contracts are allowed). The Pool is also responsible for compensating for transmission losses as well as for maintaining stable frequency in the presence of unscheduled demand fluctuations. Note that the Pool is a purely administrative entity. It does not own any generators, nor any part of the transmission grid.

**The Distributors** The local networks, which carry power to individual consumers, are owned by the distribution companies. These companies are in charge of providing power for the individual consumers, as well as of metering and billing. Since local networks are also natural monopolies, their price markups are subject to government regulation.

### 1.2.2 The Trading Process

In order to sell power, each IPP must submit a bid to the Pool before 9 am each morning. The bid is in the form of a linearized cost curve with a maximum of three different marginal cost regions (see figure 1-1). Bids also include start up times and
minimum on/off times for generators. The Pool then stacks these bids starting with the lowest price offered (see figure 1-2). It then looks at the predicted demand for the day, and creates a preliminary plan of how much power each generator should be allowed to produce during each hour of the next day. This information is then relayed back to the IPPs. The hourly price of power is determined by the price of the most expensive bid accepted for that specific hour. This price is then paid to all IPPs scheduled to produce in that hour, even if their actual bid was lower. This led to interesting practices such as "zero-bidding", where the IPPs bid very low to ensure their sales. The Pool will send updated signals each hour, telling the IPPs how to set their power output, based on actual demand measurements.

1.2.3 Positive Aspects of the British System

The main attractive features of the British approach to deregulation lies in its security and predictability. The Pool maintains full control over the hourly settings on each generator. Therefore the only major uncertainty comes from the load. Since methods for load forecasting were developed over the years, very little uncertainty is left under
normal operating conditions. The use of a single pool also eliminates much of the market power of the large consumers. Since the pool offers a single price on power both on the supply and demand side, industries can no longer negotiate special deals at the expense of small consumers. The result has been that after deregulation electricity prices actually rose for some industrial buyers while they were reduced for individual consumers.

1.2.4 Drawbacks of the British Model

Despite its benefits, several concerns plague the English power pool. The most serious problems are:

1. The Allocation of Generation: One result of the stacking of bids by the Pool, is that the generators whose bids end up close to the base load of the system will be forced to alter their power output frequently during the course of the day. The emergence of cheap, combined cycle gas turbines, has resulted in moving...
the older, coal fueled, plants upwards in the stack, into the region affected by load fluctuations. Coal plants however, are badly suited for quick turn on/off type operation. This leads to additional operating costs which in turn results in an overall increase in the price of electricity. The coal plants would prefer to supply large industrial consumers directly, without being scheduled by the pool. This would give them a lower sales price, but in return they would be guaranteed a steady demand. The Pool and the Grid Company however, do not allow anyone to use the grid for transactions which have not been processed through the Pool. This is an example where the pool system actually inhibits free competition and drives up energy prices.

2. Peak Load Pricing: The stacking system used for pricing can have disastrous effects during extreme peak load periods. If demand rises far above normal, the Pool is forced to consider bids which were never meant to be implemented (such as turning on and shutting off a coal plant within a short time span). Because the IPP does not really wish for the Pool to use its generation in such a dynamic way, his bidding price may be up to ten times the price when load is nominal. Under the agreement between the Pool and the IPP's, if the Pool is forced to accept such a bid it has to pay each producer the price awarded to the most expensive bid. Thus the overall energy price can multiply within minutes even for customers with long term stable contracts. In order to avert this risk, industrial customers are forced to practice what is know as 'hedging'. Essentially, this means that the companies integrate vertically so that they both sell the power to the pool and buy power from it. In reality this is carried out by special power brokers who are hired by risk averse consumers at a brokers fee.

3. No Market for System Regulation: While IPPs can offer bids for normal power production, there is no such system for submitting competitive bids to participate in real-time frequency regulation. The Pool still relies on the old practice of signing expensive contracts with individual generators over long time spans
to ensure system security.

1.3 The Scandinavian System

The Scandinavian power market became deregulated several years after the British market. This is reflected in a more decentralized model, based on a series of spot markets for trading both regular and control power. The Scandinavian market does not utilize a pool system, but instead allows for bilateral contracts between producers and consumers. The remaining imbalances are compensated through the hourly spot market and a market for regulation. For a more detailed description of the Scandinavian market, see [12].

1.3.1 Market Participants

The main market participants are the IPPs, the System Operator, the Power Brokers, the Distributors and the Consumers. The system operator is responsible for the maintenance and expansion of the network. He is also responsible for compensating any power losses which occur on his lines. As a result, the system operator is by far the largest consumer of power in the Scandinavian system. The other participants contribute to the process of supply/demand balancing. Which participant is responsible for this balance is specified in the contract. Each bilateral contract must specify a balance responsible actor. If this actor does not have access to his own generation (as is the case with a power broker) he must buy or sell power on the spot market in order to balance supply and demand.

1.3.2 The Market

The Scandinavian market is based on bilateral contracts between power producers and consumers. These contracts could take the form of energy contracts, under which the consumer is free to consume power at any rate as long as his total energy consumption over the specified time period does not exceed a given amount. Alternatively
the consumer could sign a power contract. These contracts are usually cheaper, but require the buyer to follow a prespecified contract curve for its power consumption. As mentioned above, each bilateral contract must specify the party is balance responsible for balancing power in the transaction. The party which is designated as balance responsible will be held financially responsible that demand and supply are perfectly matched. Since the balance responsible actor may not be able, or willing, to change its own production to meet the demand in real time, a spot market has been created where balance responsible parties can trade power on an hourly basis. While a bilateral contract specifies which party will be financially responsible for balancing each transaction, the system operator will always be physically responsible for ensuring stable frequency of the entire grid. In order to guarantee the security and stability of the network, the system operator has to assure the availability of sufficient levels of reserve generation for frequency control. In Scandinavia, a separate competitive market has been created for this purpose. The system operator buys control generation in the form of control packages, effective for three months. IPPs compete for these contracts by submitting a packaged bid of the following form:

1. For frequency deviations less than .1 Hz, supply control generation at the rate of 20MW/Hz
2. If frequency deviates beyond .1Hz, supply 2MW control generation.
3. If frequency deviates beyond .5Hz, supply 3MW control generation.

These contracts effectively provide proportional frequency control for deviations up to .1Hz, and a fixed amount of reserve generation for deviations beyond that. The number of these packages which need to be purchased by the system operator depends on the size and natural response of the grid. In Scandinavia the operator is required to purchase 125 packages for each three month period (see [12] for a detailed derivation of this number). In addition to these long term control offers there exists a half-hourly spot market on which an IPP can sell excess generation or offer to decrease its output in return for compensation from the system operator. In this
market the system operator determines its total need, then stacks the offers received and eventually pays all accepted offers the same price, equal to the price of the most expensive offer accepted (see figure 1-3).

This spot market can be used by the system operator to deal with extreme deviations in frequency, or to improve the performance of the primary level controllers by speeding up the frequency recovery. Scandinavia still lacks an automated system of allocating this secondary level control generation in an optimal fashion.

1.3.3 Positive Aspects of the Scandinavian Model

1. Flexible Contracts. One great advantage of the Scandinavian model is that it allows the market participants to form bilateral contracts which optimize the benefits for both producers and consumers. The generators can choose a type of contract which suits their performance potential. A coal fired plant for example would be more likely to offer a low priced contract for a steady supply of power,
while a combined cycle gas plant would be able to track an erratic consumer at a higher price.

2. Competition for System Regulation. By allowing IPPs to offer competitive bids on controls the Scandinavian market has been able to secure a high level of reserve generation at relatively low prices.

1.3.4 Potential Problems with the Scandinavian Market

One issue which remains unresolved in the Scandinavian market is how to allocate the control generation which is purchased through the spot market. The power is purchased with price as the only consideration, ignoring the position of the generator in the network. While this may be a minor issue in a relatively small market like Scandinavia, it could translate into a real problem in the U.S. power system which consists of a large number of control areas.

1.4 Relevance of the European Experience to the American Market

Many of the lessons learned in the UK and Scandinavian markets can be directly applied to the American deregulation process. I will try to argue in this thesis that the US has much to gain by following the Scandinavian market structure and adopting a less rigid market structure centered around bilateral contracts. The experience in Europe has shown that attempting to force the market into optimal operating conditions, mainly by dispatching generator output levels, will backfire in the long run since it does not provide value-based compensation for power producers. This results in suboptimal allocation of capital investment which drives the system away from optimal operating conditions. Using direct contracts between suppliers and load, as in the Scandinavian model, creates a transparent market where services are priced solely based on their financial value to market participants. Given the right incentives, the market will automatically adapt itself, through the reallocation of
generators, to reach a global optimum. The mechanics of this adaptation process will be discussed in depth in a later section. In translating the European deregulation experience to the US, one has to consider a series of characteristics of the American market that clearly sets it apart from its UK and Scandinavian counterparts. The most striking difference is the shear size of the US market. This is not only reflected by the quantitative differences in the amount of power traded, but also in qualitative differences in the structure of the transmission network. I have singled out two key issues which have to be addressed in translating the European models to the United States.

1. Uniform Flow of Power: In both the British and Scandinavian transmission grids, power almost exclusively flows from generators in the north to loads in the southern end of the grid. This characteristic allows system administrators to all but disregard concerns of loop or counter flow in the network. It also greatly simplifies the introduction of high capacity HVDC lines into the system without upsetting the natural settling effect of the AC network. Finally, a north to south flow of power allows for a simple pricing scheme for transmission, as losses are directly proportional to physical distance of generator and load. The power grid in the United States does not process the luxury of a simple north-south trade of power. As isolated markets throughout the country open up to inter area trade, we can expect a drastic increase in the attempts to move power in all directions across the network. This poses a profound challenge for the system administrators who have to find a fair an effective means of compensating for transmission losses, which now includes the prospect of negative losses due to counterflow. Furthermore they need to consider transmission capacity constraints, which is complicated by the fact that physical power transmission is not point to point, but dispersed in accordance with Kirkovs laws. This means that a local transaction of power in one area of the country can affect the availability of transmission capacity on a line hundreds of miles away. Reserving transmission capacity and recovering transmission costs are highly complex tasks which have yet to be fully addressed.
2. The presence of multiple control areas and system operators: Closely tied to the above discussion of transmission constraints and transmission cost recovery is the question of the future roles of control areas and system operators. In the regulated industry each control area represented isolated markets which interacted only through large scale, pre-scheduled, transactions. In the deregulated market however power brokers will seek to take advantage of temporary local price differences by moving power between and across control areas on short notice. In order to accommodate such transactions the system operator must agree on a method for pricing the transmission component of inter-area trades. Currently this is being done by point to point transmission contracts which specify hypothetical contract paths between generators and loads. The network owners located along the contract path are compensated for the transmission service. The physical delivery of the power however will be across a wide variety of control areas many of whom are not specified in the contract and are therefore forced to provide their services for free. This system clearly needs to be replaced by compensation based on actual services rendered, or else we risk driving a large portion of transmission providers out of business.

1.4.1 Analysis of the Need for New Modeling to Accommodate Deregulation

The drive to decentralize the power market in the United States began as a purely economic endeavor. The people in charge of the technical operations of the network have mostly clung to the old axiom ‘the more regulation, the more security’. In this thesis we attempt to take a unified approach to the technical and economical issues involved in shaping a power market. While we recognize that it is not possible to technically outperform a fully coordinated system operation, we intend to show that the increased economic freedom under deregulation provides the system operator with new tools for analyzing and affecting the behavior of other players. The first step in this process is to develop a unified system model which includes the physical
constraints of the transmission grid as well as the economic feedback provided by
dynamic market prices. Such a model will give us a tool necessary to address the
vital questions of system stability and performance under competition. It will also
allow us to simulate the result of economic as well as technical disturbances under the
newly proposed market structures for trading power and control generation. Perhaps
the most important point that we wish to get across in writing this thesis, is that
any party which intends to be a successful participant in the future American power
market will have to shift its focus away from the old paradigm viewing technical and
economical issues as separate entities. Instead, in a fully deregulated market, one
must learn to skillfully utilize complex technical and economic tools made available
by the increase in economic feedback from market participants.
Chapter 2

A New Market Structure for the
American Electric Power Industry

2.1 Problem Statement

In this chapter we propose a new market structure under which industry participants can trade power, as well as any ancillary system service related to generation or transmission of power, in a near-optimal fashion. Before we begin to describe a possible solution, we need to define the criteria under which such a market structure is to be judged. The following is a list of the most important criteria we addressed in creating this proposal:

**System security and performance** Any feasible market structure must provide the tools and incentives for industry participants to ensure system security under normal operating conditions. It must also provide the means to regulate power quality (frequency and voltage) within prespecified margins.

**Optimize social welfare** This includes minimizing the cost of generation, and avoiding situations in which generators can exert market power to increase profits. The market should also provide a means for a system operator to reduce price volatility if it reaches levels that are harmful to consumers.
**Flexibility** The market structure should place as few restrictions as possible on the types, locations and distances involved in the bilateral agreements signed by industry participants.

**Fairness of Compensation** The market should ensure that profits are distributed fairly, prioritizing those who can provide the traded commodity or service at the lowest price.

**Fairness of Cost Recovery** The system operator should recover any cost incurred from system control or maintenance in such a manner as to create incentives for industry participants not to cause additional disturbances on the system.

While the above points do not constitute an exhaustive list of the demands on a successful energy market, they provide us with some criteria under which we can compare our proposed bilateral structure to the pool based solutions already in existence. We will attempt to show that while the technical criteria can be equally well met under a pool formation, a bilateral market will create more competition, and greater freedom for generators in allocating their production capacity. This after all was the purpose of deregulation in the first place.

### 2.2 Industry Structure

In order to best illustrate the impact of the proposed energy market structure, we will use a simplified model of the industry. Participants have been grouped into three categories: Generators, Loads and Independent System Operators. In reality of course there exist actors such as power brokers, who are neither producers nor consumers of power. Since these actors do not have any effect on the net amount of power produced or consumed we will not include them in our model. We do however recognize their impact when addressing the issue of market power in the industry.
2.2.1 Description of Industry Participants and Their Respective Responsibilities

Generators
This group includes all market participants that physically inject power into the network. In a deregulated industry, generators are purely profit-driven entities. They will set their power output levels to maximize their profits without considering overall system security or performance. Clear economic incentives are needed to make generators behave in accordance with system needs.

Load
Loads include all consumers of power. In our setup a distributor serving a number of small customers will be modeled as a simple load. Loads are assumed to be inelastic to fast changes in the price of power, so that spot market demand is constant over price for a given time period.

System Operator
The system operator is physically responsible for the security and performance of the system. This includes maintaining generation reserves in the case of generator fallout, and supplying balancing power when system frequency deviates from 60Hz. Since the system operator is not allowed to own any generating units, he is forced to become a financial actor on the power market to fulfill these obligations. The cost incurred in regulating system performance is recovered through access charges. It is imperative for the system operator to set these charges in a discriminatory manner so as to provide incentives for loads and generators to minimize the disturbance they inflict on the system.

2.3 Physical Model
The model in this section is derived from the structure based model of large electric power systems. We assume the presence of primary frequency control consisting of a governor-turbine-generator set. The primary control responds to differences in the reference frequency setting on the governor form the actual system frequency. The secondary level control which we address in this paper deals with how to set the reference frequency on the generators to maintain a stable system frequency. The
linearized dynamic model for system frequency takes on the form:

\[
\omega_G[k+1] = (I - \sigma K_p T_s) \omega_G[k] + (I - \sigma D) B_s u_s[k] \\
+ \sigma f[k] - \sigma D_p d_s[k]
\]  

(2.1)

where \(\sigma = -\frac{\partial \omega[k]}{\partial X_G[k]}\) is a diagonal matrix representing generator droop constants, \(I\) is an identity matrix, \(D\) stands for a diagonal matrix whose terms are damping coefficients of generators, \(u_s[k] = \omega^\text{ref}_G[k+1] - \omega^\text{ref}_G[k]\) is secondary (AGC) control signal at the discrete instant \(kt_s\), vector \(f[k] = F[k+1] - F[k]\) is a vector of incremental tie-line flows into a control area (for an isolated system this vector is identically zero) and \(d_s[k] = X_L[k+1] - X_L[k]\) is vector of incremental deviations in real power of loads. Matrices \(K_p\) and \(D_p\) are function of electrical characteristics of the transmission grid.

The corresponding linear model for the power output at each generator is of the form:

\[
X_G[k+1] = (I - K_p \sigma T_s) X_G[k] + K_p (I - \sigma D) T_s \omega^\text{ref}_G[k] - \\
- \sigma (f[k] - D_p d_s[k])
\]  

(2.2)

The generators will use equation (2.2) to set the reference frequency on their governors so that their output corresponds to the expected behavior of the load (i.e. the contract curve). If we load at equation(2.1) this means that if \(X_L[k]\) moves along the contract curve, then the effects of \(u_s[k]\) and \(d_s[k]\) will cancel each other out and there will be no net deviation in frequency. However, any unscheduled fluctuation in the load will translate into a proportional offset in system frequency. The magnitude of the frequency deviation will depend on the electrical characteristics of the transmission grid. For an isolated network, we can simplify this relationship to take on the form:

\[
\omega_G[k+1] - \omega_G[k] = D(X^\text{imbalance}[k+1] - X^\text{imbalance}[k])
\]  

(2.3)
where,

\[ X^{\text{imbalance}}[k] = X^{\text{scheduled}}[k] - X_L \] (2.4)

Equation (2.3) assumes that generators set their reference frequencies so that their output level will be equal to the scheduled demand. Note that the actual output of the generator will not necessarily correspond to the scheduled levels. This is because of the so-called quasi-static droop characteristic which relates real power output, system frequency and governor frequency setting.

\[ \omega_G[k] = (1 - \sigma d)\omega_G^{ref}[k] - \sigma P_G[k] \] (2.5)

Equation (2.5) tells us that if the reference frequency is kept constant while system frequency increases, then the real power output of the generator will decrease. This serves as an automatic correction system for the network, guaranteeing that actual load and generation will always match in real time. It is because of this droop characteristic that we are defining the disturbances on the system to be the difference between scheduled generation and actual load. From here on when we address the issue of purchasing balancing power, from the spot market or the controls market, we will be referring to buying scheduled power as reflected by the reference frequency settings.

Returning to equation (2.3), this relationship gives us a direct measure of the amount of balancing generation needed to restore frequency to nominal. Specifically, if frequency has deviated by \( w_o \), the necessary amount of control generation is given by:

\[ X^{\text{control}} = \frac{1}{d}w_o \] (2.6)

Equation (2.6) in fact gives us the form of a simple proportional control law to maintain nominal frequency. This relation translates nicely into the interconnected system, where the constant \( 1/d \) represents the degree of responsibility of the control area towards regulating overall system frequency. We will further discuss the impor-
Figure 2-1: Natural Frequency Response of an Isolated System

tance of this relation when we address the physical implementation of the controls market.
Chapter 3

Temporal and Functional Division of Power Markets

According to the market structure we are proposing, power can be traded in three different contexts: on the long term market, the spot market, and the controls market. The contracts associated with each of these markets differ both in time span and pricing structure. Below is an outline of their most important characteristics.

3.1 Long-Term Market

Trade on the long term market is strictly bilateral. A generator signs a contract directly with a consumer. This contract includes a contract curve, specifying the scheduled rate of production and consumption at any instance during the duration of the contract. Since the consumer cannot be expected to forecast his consumption exactly, and since the generator will be unable to track fast load fluctuations in real time, the contract also specifies a band around the contract curve inside which load and generation are allowed to deviate without being penalized. This produces a bounded contract curve shown in figure 3-1.

The generator will register this contract with the system operator, who uses the magnitude of the allowable generation to determine access fees. The loser the bound, the higher the access fee. This is a technically sound criterion, since the bound repre-
sents the maximum mismatch between load and generation. When such a mismatch occurs, the system operator has to provide balancing generation. He recovers the cost thereby incurred through the access fees. By setting the access fees in an individualized manner, the system operator gives generators an incentive to minimize the width of their contract bounds. Setting the bounds to narrow however could results in significant penalties if the load deviates outside the allowed margins. If access fees and penalties are set accordingly, the width of the bounds specified in the contract should provide an accurate measure of the actual volatility of the load. This information can in turn be used by the system operator to estimate the maximum cumulative disturbance on his system. Using this estimate he can then decide how much control generation to reserve for future time intervals.

3.2 Spot Market

Power on the spot market is traded in one-hour intervals. Before the start of each hour generators enter bids specifying the quantity of power they are offering and the price they are demanding. A generator may divide the power he intends to sell into many smaller bids, so that he can effectively offer a bid curve, as shown in figure 3.
This allows a generator to bid his own marginal cost curve, if he so desires.

The demand from the spot market is generally made up of the system operator, who uses this power to compensate for system losses and generation/load mismatches. However generators may also buy power from the spot market if they cannot cover their long term contracts with their native generation. Once spot market demand has been determined, the generator bids are stacked starting with the lowest price. The point at which the stack of bids intersects the cumulative load specifies the clearing price, defined as the price demanded by the most expensive bid accepted. This price will be awarded to all accepted bids.

### 3.3 Controls Market

This market offers an alternative source of balancing generation for the system operator. Generator bids are in the form of an obligation to alter their power output in response to frequency deviations. For example a bid could take the form:

\[
X_{control} = k\Delta F \quad \text{for} \quad \Delta F < \Delta F_{max} \tag{3.1}
\]

\[
X_{control} = k\Delta F_{max} \quad \text{for} \quad \Delta F > \Delta F_{max} \tag{3.2}
\]

The system operator effectively pays the generator to maintain a control reserve. By deciding how many of these bids to accept, the system operator determines the size of the control reserve for his area. This decision will be closely linked to the maximum anticipated disturbance defined by the sum of the bounds on the long term market. The system operator may choose to accept enough bids to cover his control reserve with the sum of the long term bounds, or he may rely on the spot market to pick up any additional imbalance on his system. The decision on how much control reserve to maintain has a profound effect on the price volatility of the spot market. We will quantify this relationship, and discuss the possible strategies.
of the system operator in a later section.

**3.4 Modeling of Economic Decision Making Process**

Each generator in the network is faced with the decision of how much of his production capacity to allocate for sale on each of the available markets. In order to make an informed decision, the generator needs a means of evaluating expected profits of each scenario. He also needs to account for the risk factor associated with reserving his capacity for sale on the short-term market. In this section we derive the expressions for the expected profits on each of the markets, and show the conditions that must be met for the overall system to be in economic equilibrium. Once we have modeled how generators enter the market, we can proceed to show how physical disturbances translate into deviations in market price.

**3.4.1 Assumptions Related to Generator Behavior**

The following assumptions were made in modeling the behavior of power producers:

1. Generators are purely profit-driven. They will not act in the interest of system security or performance unless they are given clear financial incentives to do so.
2. Generators have no market power. They are price takers on all markets.

3. Demand is inelastic to fast price changes on the spot market.

4. All power producers have smooth quadratic cost curves, and consequently linearly increasing marginal costs. We model these as:

$$TotalCost = aX^2 + b$$  \hspace{1cm} (3.4)

$$MarginalCost = 2aX$$  \hspace{1cm} (3.5)

### 3.4.2 Profits Under Long-term Contracts

When a generator enters into a long-term contract he obligates himself to sell power at a rate given by the contract curve and at a prespecified price. In doing so he eliminates any risk of not being able to sell his power, but also robs himself of the ability to take advantage of short term price peaks on the spot market. Since generators are assumed to be price takers, the profit associated with selling on the long-term market is easy to calculate. Faced with a price $P_L$, the generator will set his total power output so that his marginal cost is equal to $P_L$.

$$P_L = 2aX$$  \hspace{1cm} (3.6)

Using this constraint we can express the total profits of the generator in terms of long-term price.

$$\Pi = P_L^2/4a$$  \hspace{1cm} (3.7)

Since the long term price is known in advance, there is no risk involved in this contract, and we can view (3.7) as a guaranteed profit.
3.4.3 Profits under Short Term Contracts

We will now consider the case of the producer who decides to reserve all his production capacity for sale on the spot market. Again we assume that the generator is a price taker, who at each hour will see a new spot market price ($P_s$). At this price the market will absorb any amount power he can generate. As in the long-term case, the producer will maximize his profits by setting his power output to a level such that the marginal cost of generation is equal to the current spot market price. For each discrete spot market interval the profit of the power producer will then be given by:

$$\Pi[k] = \frac{P_s^2[k]}{4a}$$  \hspace{1cm} (3.8)

If the spot market price was pre-determined, the producer could simply sum the projected profits over each discrete interval, given by (3.8), compare them to the profit on the long term market (3.7), and thus decide where to place his production capacity. In reality however the spot market involves a great deal of uncertainty. Countries who have undergone deregulation have experienced a considerable increase in price volatility on the short-term market. In order to allocate production capacity between the long term and spot market, the producer needs to generate an estimate of his expected profit on each market. To achieve this we will model the spot market price as a random variable $P_s[k]$, with expected value $U_s[k]$, and variance $\sigma_s^2[k]$. Using equation (3.8) we can now express the expected profit in terms of the characteristics of this random variable.

$$E\{\text{Profit} \} = E\{P_s[k]^2/4a\} = U_s[k]^2/4a + \sigma_s^2/4a$$  \hspace{1cm} (3.9)

So what does this expression tell us about the effect of price volatility on the spot market? If we compare equation (3.15) to our expression for profits on the long-term market (3.7), we find that they have a similar form. Indeed if we set the expected price level $U_s[k]$ on the spot market equal to the actual long term market price we find that the expressions for profits on the markets are identical with the exception of the term $\sigma_s^2/4a$ on the spot market. This factor is a direct result of that the profit
is a nonlinear function of price, in this case a simple quadratic function. A marginal increase in spot market price will therefore create a large increase in overall profits, while an equivalent decrease in price will cause a smaller decrease in profits. As a result, an increase in the price volatility (i.e. larger $\sigma^2_S$) will result in greater expected profits on the spot market, as predicted by (3.15). In an industry where participants choose between investing only on the long-term market or only on the spot market, the equilibrium will be reached when expected profits are equal on both markets. Since price variance is always positive, this can only occur if the expected value of the spot market price is below the actual long-term price. This price differential can be expressed directly as a function of spot market price volatility.

$$P^2_L = U^2_S + \sigma^2_S \quad (3.10)$$

The result predicted in (3.10) seems counterintuitive. It is important to realize that the above model does not take into consideration that most generators are likely to be risk adverse. If we would include this behavior in our modeling we would have to add a negative risk correction term to the right hand side of equation (3.10). As it stands, the model simply reflects the effect of passing an uncertain price signal through a nonlinear system.

### 3.4.4 Mixed Strategy Solutions

The above analysis will allow us to find equilibrium prices under the condition that each generator uses a pure strategy of selling only on the long-term market or only on the spot market. In reality there is nothing to prevent a producer from dividing his output between the two markets. In order to specify the long and short term supply curves, we first have to determine under which conditions it is profitable for a producer to be selling on both markets. Consider the following example. A producer with marginal cost $MC = 2aX$ sees a long-term price $P_L$. He therefore commits a capacity of $X_L = P_L/2a$ to the long-term market, setting long term price equal to long term marginal cost. During the course of the long-term contracts, the producer
notices that the short-term price increases above the level of his current marginal cost ($P_L$). He can now increase his profits by selling power on the spot market until the marginal cost of production is equal to the spot market price. The same is true for all generators who sell power on the long-term market.

### 3.5 The Spot Market Supply Curve

We will now proceed to derive the supply curve for the spot market of a simple generic system. Assume our system contains a total of N generators. Each generator has a marginal cost curve of $MC = 2aX$. Further assume that of all producers, a subset of M generators decide to reserve all their capacity for sale on the spot market. The remaining N-M generators will sell power according to the mixed strategy described in the previous section. We derive the shape of the supply curve by considering two separate instances:

1. For $P_s < P_L$, the spot market will be supplied only by the subset of M generators. Under these conditions the supply curve is given by:

   $$P_s = \frac{2aX}{M}$$

   \[ (3.11) \]

2. For $P_s > P_L$, all generators in the system will supply power to the spot market. This will reduce the slope of the supply curve by a factor of $N/(N-M)$. Combining this change of slope with the curve described in (3.11), the total supply curve for the spot market takes on the form:

   $$P_s = \frac{2aX}{M} \quad for \ P_s < P_L$$

   $$P_s = (1 - M/N)P_L + \frac{2aX}{N} \quad for \ P_s > P_L$$

   \[ (3.12) \]

   \[ (3.13) \]

The resulting shape of the supply curve is depicted in figure (3-3).
As seen in the figure, we are dealing with a two-slope supply curve. The breaking point coincides with the price level where generators committed to long-term contract begin to enter the spot market.

### 3.6 Effect of Supply Curve on Price Volatility

The reason we have gone through such length in deriving the structure of the supply curve is that it represents the link between the physical and economic processes modeled above. In the short term, the system is driven by physical disturbances in the form of generator/load mismatches. Such disturbances translate directly into spot market demand. The shape of the supply curve tells us how this demand will cause movements in spot market price. In effect the supply curve is a transfer function between the physical and economic disturbances on the system. Let us use a simple example to illustrate the effects of the supply curve on price volatility and generators profit levels. Assume the supply curve is of the form described in equation (3.14), and the physical disturbance \(X_d\) is a random variable evenly distributed between zero and \((M/a)P_L\). Figure (3-4) shows how the resulting distribution of spot market price is weighted by the supply curve.

Note how the distribution of the disturbance was selected so that it fell symmetrically around the breaking point of the supply curve. When we examine the resulting distribution of the spot market price we find that it no longer displays this symmetry.
While spot price is equally likely to above or below the long-term price level, the range of the deviation is significantly smaller for price levels above $P_L$. On a system-wide level, this means that price is more volatile in the lower price ranges, and that we are less likely to experience extreme price peaks. This illustrates one of the advantages of the proposed market structure. By not restricting balancing generation to a few selected generators, we avoid having high price volatility in the upper price ranges, avoiding unreasonable peaks in spot market price that could be extremely destructive for the end consumer. If we examine these results from the perspective of the individual generator, we find that it has a significant impact on how the producer allocates his resources between the long and short-term markets. In modeling the profits on the spot market, we found that due to the nonlinear relationship between spot market price and producer profits, the expected profits actually increased as the price became more volatile.

$$E\{Profit\} = E\{P_s[k]^2/4a\} = U_s[k]^2/a + \sigma_s^2/4a$$ (3.15)

The shape of the supply curve however is telling us that even if the demand to the spot market is extremely volatile, this will not necessarily translate into high price peaks. The incorporation of long term generators into the spot market therefore has a distinctly negative effect on the projected profits of the purely short term producers.
Reduced profits on the spot market will cause generators to reevaluate their allocation decisions, causing more producers to enter into long term contracts. This will change the shape of the spot market supply curve by moving the breaking point to left, increasing the slope of the primary segment.

Since the price level of the new supply curve is higher than the old for any given demand, the generators which chose to remain with the pure spot market strategy will see an increase in their profits. Market actors will continue to reevaluate their strategies until an equilibrium is reached where expected profit levels for both strategies are equal. This equilibrium will shift as new generators enter the market, or as the characteristics of the load changes. The process by which the market responds to such changing conditions is outlined step by step below.

1. The Power Producers decide how to allocate their generation capacity between the spot market and long term market. Their decisions are based on a known long-term price and an estimate of how the spot market price is going to behave. This in turn determines the shape of the spot market supply curve.

2. Fast fluctuations in load causes power imbalances on the system which translate into demand for short terms balancing power. This power must be purchased by the System Operator on the spot market.

3. The change in demand for spot market power translates into a fluctuation in the spot market price. The magnitude of the price change given a deviation in demand will depend on the shape of the spot market supply curve.

4. Increased volatility in spot market prices will increase the profit incurred by generators investing their capacity in this market. If the volatility remains high during the cause of the long-term contract period, more generators will enter the spot market during the next period, and we are back at stage 1. Thus we have closed the loop, and shown how the system can adjust itself until it reaches a stable equilibrium.
Chapter 4

Simulation

We will now attempt to demonstrate the adaptive behavior of market participants by simulating a small system under realistic conditions. The system consists of five identical generators, and is driven by a single, cumulative, stochastic load.

**Generator Characteristics** Each generator has a total production capacity of 10 units of power. The cost curve is given by $C = X^2 + 4X + 2$, yielding a marginal cost curve of $MC = 2X + 4$.

**Load Characteristics** The load consists of a fixed base portion of 28 units, and a stochastic portion with probability density function evenly distributed between zero and ten for each discrete step. The base portion is covered by long term contracts which are renewed every 50 time steps. The stochastic portion represent unpredicted load variations for which the system operator must compensate by purchasing balancing power on the spot market.
Figure 4-1: Simulation Results
Figure 4-2: Simulation Results
Figure 4-3: Simulation Results
4.1 Analysis of Generator Behavior for each Time Sequence

4.1.1 Sequence A: Time 0-50

We have chosen an arbitrary starting point from which the market can evolve. Generators one through four have committed generation to the long term market, each supplying a load of seven units. The long term market price, given by the marginal cost of generation, is 18. The fifth generator has chosen to participate only in the spot market.

4.1.2 Sequence B: Time 50-100

Long term contracts are allocated as in A. Generators one through four now decide to offer their excess generation for sale on the spot market when spot market price exceeds long term prices. Generator five behaves as in A.

4.1.3 Sequence C: Time 100:150

Faced with diminishing profits, Generator five decides to enter the long term market. This decreases the long term demand seen by each of the other generators. Each now supplies a load of 5.6 units, driving the long term market price down to 15.2. The spot market is now supplied solely through excess capacity not used to fulfill long term obligations.

4.2 Analysis of Simulation Results

If we examine the price plots from the simulated system we find several interesting trends. First if we look at the plot of spot market price, we find that the market adapts itself to reduce price volatility. As we move from sequence A to B, we remove the the price peaks on the spot market. This is because we have moved from a steep single slope supply curve to a two slope supply curve. As we enter sequence C, the
downward volatility off spot market price dissapears. This is a result of all generators participating in the long term market. There will therefore be no one willing to supply the spot market when price is below long term price levels. In addition to reducing price volatility this trend will of course raise the average spot market price. This effect however is overpowered by the simultaneous decrease in the long term price, so that we see a drop in the overall per unit price of power. The trend of the market is towards a decrease in average price and a reduction of price volatility. If we examine the overall cost of production we find a similar trend. The total cost of production for sequence A is 1,873. It drops to 1,8488 for sequence B, and falls further to 1,777for sequence C.

4.3 The Impact of the Controls Market

In the simulation presented in the previous section, we demonstrated how generators adapted their strategies of sale between the spot and long-term markets to minimize overall cost of production, even when faced with a stochastic load. In theory it would be possible for the system operator to rely solely on the spot market for balancing generation. Because of security concerns however it would be advantageous if one could guarantee the presence of balancing power capacity through long term contracts. This is the role of the controls market, which we briefly described earlier and will now revisit in the context of system operator strategies for optimizing production allocation and reducing price volatility.

4.3.1 General Structure of Controls

While the specific implementation of the control process differs from country to country or even from one control area to another, there are three basic temporal steps which are always present.

**Forecasting** The pool operator attempt to predict the cumulative load curve for his control area ahead of time based on historical data and exogenous variables such
as weather forecasts. He then an optimization algorithm to dispatch generators that have bid into the pool for that day. The dispatch will take into account factors such as start up time and minimum running time in addition to bidding price.

**Automatic Generation Control** Since no form of forecasting will ever be perfect, someone needs to compensate for the error between actual and predicted demand in real time. This is traditionally done by setting aside a small number of generators to track frequency based on the Area Control Error (ACE) which we will discuss later.

**Reserve Generation** To insure against unforeseen events such as a generator fallout or transmission line failures the pool will keep one or several generators in idle reserve. These generators are often expensive to run but have quick startup times.

### 4.3.2 Adapting Controls to a Bilateral Market

As the market moves from a pool to a bilateral format, it loses the ability to perform forecasting on a system-wide level. Without a system operator to continue coordinate generator dispatch, forecasting now has to be performed for each individual load rather than the cumulative load of the control area. This, no doubt, will reduce the effectiveness of the forecasting process, forcing the system operator to maintain higher control reserves, thus increasing the cost of controls on the system. While this may seem like a valid reason to retain the pool configuration, I would argue otherwise. Rather than adding cost to the control services, the transformation merely unmasks a hidden cost which has previously been absorbed by market participants. In order to meet demand under the pool configuration, the system operator dispatches generators to turn on and off to meet anticipated swing in demand. The generators which are on the margin (see 1-2) are therefore forced to perform a control function without being offered any additional compensation for their services. This again has an adverse effect on price volatility. Since generators on the margin are not able to
run continuously nor at their optimal output levels, the only way they are able to stay in business is if market price is extremely high during their run time. Since we do not distinguish between balancing and base load power, this price is passed on to all generators, creating a substantial cost increase for the consumer. The purpose of the controls market is to offer the system operator the opportunity to meet the demand for balancing power in a secure way without upsetting the price for base load power. Generators submit their bids to this market in the form of an obligation to track frequency within preset margins:

\[ X_{control} = k \Delta F \quad \text{for} \Delta F < \Delta F_{max} \]  
\[ X_{control} = k \Delta F_{max} \quad \text{for} \Delta F > \Delta F_{max} \]

In purchasing these contracts the system operator ensures himself the availability of reserve capacity, as well as the real time compensation for generation load imbalance. Furthermore, since control contracts are long term, they will not influence the price of power on the spot market. In effect the existence of the controls market allows the system operator to reduce the demand on the spot market, and thus exercise some control on the price volatility on that market. In essence a controls contract can be viewed as an a long term option contract on the spot market, where the use of the option depends on the current state of system frequency. Figure (4-4) shows the complete flow of technical and economic signals through the system.

Here we see how the system operator can reduce the effect of a physical disturbance on price volatility by absorbing part of the power mismatch through controls contract. The strategy employed by the system operator in purchasing controls will also effect the profits incurred by generators on the long term and spot markets. As we saw in the simulated example, these profits in turn determine how generators allocate their available capacity between the long-term and spot markets. The system operator therefore has the ability to impact the balance of generation between the markets, if
Figure 4-4: Total System Dynamics
necessary steering the market back towards optimal operating conditions.

4.3.3 Effective Strategies for Control Cost Recovery

So far we have discussed how the system operator should purchase and implement control resources. The other side of the problem is how to recover the cost of controls in a fair manner while providing incentives for the market participants to reduce the disturbance inflicted on the system. In order to achieve this the system of cost recovery needs to be transparent from both the load and generator viewpoints, and needs to provide individualized fees to avoid free-riding by some participants. The structures of the controls and long-term markets provide an opportunity to satisfy both these criteria. Recall that the long-term contracts specified a contract curve representing the projected use of power, and in edition provided bounds on the maximum deviation of the load from this curve. These bounds represent the maximum potential imbalance induced by the load. By summing the total bounds of all bilateral contracts in his control area, the system operator can establish a conservative bound on the total anticipated disturbance on the system. Now consider the structure of the controls contracts. Each contract represents a band of available control generation, and the sum of the bounds on all contracts purchased determines the total available control reserves for the system. By matching the total bounds on the contracts with the cumulative bounds on the bilateral contracts, the system operator can therefore guarantee the presence of sufficient control resources. Furthermore, by transferring the price paid for the control bands (in MW), to the access fees for long-term contracts based on the width of the of the deviation band (in MW), one creates an transparent, individualized cost recovery scheme. This system will pass the cost of controls directly and fairly on to the loads that cause the imbalance on the system, thus creating an incentive for loads to manage their volatility (if possible), and for generators to find nonvolatile loads. This simple method for control cost recovery is illustrated in figure (4-5) below.
Figure 4-5: Matching Disturbance-Bounds with Control Capacity
5.1 The Current State of Inter-Area Trade

As the entire power industry struggles to come to terms with the new rules and responsibilities under deregulation, the confusion is most apparent in the segment of inter-area trade. Inter-area trades include any transactions in which the producer and consumer are located in different control areas (CAs). More often than not, an inter-area trade is not a bilateral contract between a generator and a load, but a string of contracts, including multiple power marketers or brokers. Here one has to be careful in distinguishing the physical and financial aspects of trading power. The three principal players, the generators, the load, and the system operator, all trade power in a physical sense. The generator and load must match each others production and consumption in terms of real power. Likewise the system operator must schedule the cumulative flow of power to assure that the transmission lines have sufficient capacity, as well as compensating for transmission losses in real time. The power marketers on the other hand own neither a generator, a load, or any part of the transmission network. For them power is a purely financial, liquid asset. They generate revenue by taking advantage of price differences in generation between different areas, and by acting as 'insurance agents', absorbing the risk of future price fluctuations. By exploiting the arbitrage possibilities on the interconnected network, the financial players help to create a truly unified marketplace. In addition, however,
they can also pose a significant problem for the ISOs in charge of the physical network operations.

5.1.1 **Daisy Chaining; the Adverse Effects of Trading Power as a Financial Entity**

Any transaction across multiple control areas must specify a contract path for the power to be traded. This contract path need not represent the physical path which the power takes, since it is often impossible to predict exactly how power will flow once injected into the network. Consider the setup illustrated in figure (5-1). A power marketer sees that there is a significant difference in the price of power between areas A and C. He decides to sign a contract with a generator in area A to supply power. He then signs a separate agreement with a consumer in area C for the same quantity of power. With the source and sink of power defined, it is the responsibility of the marketer to make sure the power is delivered from source to load. To do this the marketer determines a contract path, in this case A-B-C. He then proceeds to negotiate the financial compensation for the system operator in each area, for allowing the power to pass through. At some point during the course of the contract, the price
relations between the areas change. The load in area C finds that it is cheaper to buy local generation, and decides to sell his excess power to a buyer in area D. Shortly thereafter a broker discovers that the price of power has further increased in area B. He buys the power from the load in area D and sets up a contract path to deliver it to a customer in area B. Let us now step back and examine the contrast which has arisen between the physical and financial path of power. Physically, the power is being generated in area A and consumed in area B. The physical path of power is therefore A-B. Financially, the various actors have established contracts to deliver power from A, through B, to C. The next contract delivers power from C to D, and the third contract passes it back to B. The financial contract path is therefore A-B-C-D-B as shown in figure (5-2). Each of the system operators included in the financial contract path will extract a fee for processing the power, although no power passes through areas C and D in a physical sense. Such a case of financial loop flow, also known
as daisy chaining, results in economic losses that have to be absorbed by the end user. Perhaps more severe than the financial loss however, is the technical difficulty this phenomenon causes for the system operators. The ISOs examine the financial contract paths for power, and use them to schedule the actual flow of power on the tie lines. If the contractual flows fail to appear, this can wreak havoc with the operation of the local networks.

5.2 Problems with Dispatching Under Inter-Area Trade

We have previously described how system operators in pool-based markets rely on forecasting the cumulative load for the control area to dispatch optimal output levels for each generator. As we include the effects of aggregators and inter-area trading, this problem becomes far more complex. When aggregators bundle and fragment packages of energy, the system operator looses the real time overview of who is producing the power he is scheduling to meet anticipated demand. This also means he looses information such as startup time, minimum running time and maximum ramping rates of generators supplying his market. In essence the process of dispatching looses its function as the system operator must rely solely on bidding price in deciding which generators to run. While the system operator is still able to produce a forecast of the load in the control area, it is no longer clear if he is in a position to effectively dispatch generators to meet this load. We would argue that under these conditions it is better to loosen the market structure by reducing the role of the system operator and allowing the market to adapt itself to reach optimal generation levels. The introduction of the controls market, described in the previous chapter, plays an important role in moving away from a centrally dispatched market. The controls market absorbs some of the fast fluctuations in load which were previously dealt with by ramping flexible generators in the main market. By separating this marginal generation to a market of its own one is able to award a high price to the
flexible generators, thus compensating them for the additional service provided to the network, without upsetting the price of bulk power. Furthermore this cost can easily be channeled to the loads in proportion to their volatility, so that access fees for controls are based on the magnitude of the disturbance induced on the system. The bilateral/spot/controls market combination satisfies two important market criteria:

1. In the short run, the structure is flexible enough so that market participants adapt themselves to minimize cost and maximize individual profit. We saw in the single-area simulation that under normal market conditions (no market power) this is equivalent to minimizing overall system cost.

2. By recognizing generator flexibility as an asset to the market, we assure that generators are compensated based on value added to the system. This in turn provides the right incentives for long run investments in the industry. The slow adaptive process characterized by investments in new plants will be the crucial factor in determining long term optimality of power generation. A system which reduces costs in the short run but fails to provide value based long term incentives will derail the optimality of the system down the road.
Chapter 6

Technical Criteria for Trading Controls

6.1 Inter-Area Trade of Control Generation

We have already discussed the advantages of a competitive market for trading control generation in the case of an isolated control area. The next logical step is to examine the possibility of a unified controls market for the interconnected system. Such a market would enable the system operator to take advantage of cheaper generators in neighboring areas much in the same way as with the inter-area trade of bulk power. Specifically a control area which lacks flexible or fast ramping generators could contract generation from other areas to fulfill this need. In addition to cost of generation concerns, combining the control area will increase the total control capacity available to each system operator without increasing the cost of maintaining excess capacity. This will serve to further streamline the deregulated market. While the benefits of a unified control market are clear, the technical constraints for operating such a market are harder to define. In this chapter we will provide the necessary technical modeling to establish a unified market for controls. Traditional methods for controls are analyzed and evaluated in the context of technical performance and market efficiency. We then provide a new algorithm for frequency controls, designed specifically to be compatible with an open access market for controls. Finally we
discuss the specific financial implementation of the controls market, including optimal strategies for system operators to recover control induced operating costs.

6.2 Necessary modeling

In this section, we provide a simplified semi-tutorial background on basic power-frequency relations in a control area (CA) interconnected to the rest of the system via DC lines only, and in a typical interconnection. These relations are reviewed first for the case without any automatic regulation; next, relations are stated for a regulated system by means of present AGC. Understanding these relations is essential for a meaningful discussion of interconnection frequency regulation. In summary, several characteristics of AGC are pointed out as relevant for further discussion.

6.2.1 Basic power frequency relations

These relations are stated first for an isolated control area\(^1\), and for the interconnection consisting of two CAs next.

An isolated control area

A CA of interest is characterized by power injections into its buses. Each bus \(j\) in the CA \(i\) is characterized by its net power generation, denoted here as \(P_{Gi j}\). The net generation for the entire CA is given by the sum of the net generation into each bus, and is denoted here by \(P_{Gi}\) for the \(i\)th CA.\(^2\) Mathematically,

\[
P_{Gi} = \sum_{j} P_{ij}
\]

(6.1)

Under normal operating conditions, when \(P_{Gi}\) matches CA losses \(P_{loss}\) and scheduled DC net power exchange \(T_s\) with the neighboring CAs, CA \(i\) operates at the nominal frequency of \(F_0 = 60\) Hz. The frequency deviates from this nominal value in re-

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\(^1\)A more general case would be to consider a CA connected to the rest of the system by DC links.

\(^2\)This derivation assumes that the system remains within the static security limits.
response to the non-zero net generation excess or deficit on the entire subsystem. This “natural” response of a subsystem \( i \) is modeled here as

\[
\Delta F_i = - \frac{1}{10\beta_i} (P_{Gi} - P_{loss,i} - T_s)
\]

(6.2)

For simplicity of notation this is further written as

\[
\Delta F_i = - \frac{1}{10\beta_i} \Delta P_{Gi}
\]

(6.3)

**An interconnection**

Consider next an interconnection consisting of two CAs connected via a tie-line. The basic power-frequency relations for this system, after including the contribution of the tie-line flow deviations from the scheduled \( \Delta T_s \), are

\[
\Delta F_1 = - \frac{1}{10\beta_1} (\Delta P_{G1} - \Delta T)
\]

(6.4)

\[
\Delta F_2 = - \frac{1}{10\beta_2} (\Delta P_{G2} + \Delta T)
\]

(6.5)

Consider next the response of a tie-line flow to power imbalances in the subsystems. The basic premise made here is that in steady state frequency in each area equals the system frequency, i.e.,

\[
\Delta F_1 = \Delta F_2 = \Delta F
\]

(6.6)

Since the two subsystems interact only through the tie-line, the tie-line flow will have to be such as to redistribute power between the subsystems to meet the frequency constraint (6.6).

Assume that initially both subsystems are operating under nominal conditions. This implies \( \Delta P_{G1} = \Delta P_{G2} = 0 \) and \( \Delta F_1 = \Delta F_2 = 0 \) and \( \Delta T = 0 \) simultaneously.

Next, consider an unscheduled increase in the load in the subsystem 2, causing

\[3\]For discussion regarding validity of this assumption, see [6, 7, 11].
power deficit given by
\[ P_{G2} = P_{d2} \leq 0 \] (6.7)

Initially, this mismatch leads to the frequency deviation in area 2 according to its
natural response formula above

\[ \Delta F_2 = -\frac{1}{10\beta_2} P_{d2} \] (6.8)

However, since the steady-state frequency must be equal in both areas, and if no
control actions are taken in area 1, above formulae lead to the following steady-state
tie-line flow:

\[ \Delta T = -\frac{\beta_1}{(\beta_1 + \beta_2)} P_{d2} \] (6.9)

This is an approximate estimate of tie-line flow redistribution needed to maintain a
single stable frequency on the interconnection. This relation is basic to understanding
how the system responds to automated controls, such as AGC.

6.3 Traditional Methods For Controls

6.3.1 Frequency regulation

The above provides some insight into the interaction between power imbalance, fre-
quency and tie-line flows in an unregulated system.

In reality, however, a system operator cannot allow system frequency to deviate
freely in such a manner. In order to keep frequency close to nominal, each subsystem
\( i \) assigns a group of generating units to regulate power imbalance in response to an
output variable, such as the Area Control Error (ACE\(_i\)), which has traditionally been
used by the utilities to manage frequency control and inadvertant flows across control
area boarders. In the notation used in this paper, ACE takes on the form

\[ ACE_i = \Delta T_i - 10B_i \Delta F_i \] (6.10)

It is the responsibility of the regulating units to regulate the ACE according
to the prespecified control performance criteria. Presently in the United States the recommended control criterion is the so-called criterion $A_1$, which states that under normal operating conditions ACE of each CA crosses zero every 10 minutes. The parameter $B_i$ represents a weighting function between the frequency and the tie-line flow deviations from their specified, desired values. In some sense frequency bias $B_i$ is a tradeoff parameter between quality of frequency regulation in the area and the tie-line flow deviations. To better understand the role of this parameter, we use basic formula (6.4) to express power imbalance in area 1 as

$$\Delta P_{G1} = \Delta T - 10\beta_1 \Delta F_1$$  \hspace{1cm} (6.11)$$

This expression is very similar to the expression for the ACE, in fact, if we let $B_1 = \beta_1$ one obtains from (6.11)

$$ACE_1 = \Delta T - 10\beta_1 \Delta F_1 = \Delta P_{G1}$$  \hspace{1cm} (6.12)$$

It directly follows from here that, provided the frequency bias of the area is chosen to correspond to the natural response coefficient $\beta$ of the same area, the $ACE$ provides a measure of the local power imbalance in a specific CA. Consequently if the $ACE_1$ of the area is zero, the area generation and demand are identical. The frequency, however, may still deviate from its nominal value, but such deviations are entirely due to tie line flow deviations, and, as such, are the result of power imbalances in other CAs.

**Decentralized control in response to ACE**

When viewing a single CA, the ACE seems like an unsuitable output variable to regulate frequency since it does not guarantee that frequency returns to its nominal value exactly. However, viewed from the entire interconnected system level, the ACE allows for rather elegant decentralized control scheme. We showed in the previous section that the ACE was a measure of the local (area-wise) power imbalance. This decentralized control scheme is based on the idea of assigning a group of generators
in each CA to the task of regulating the ACE in this CA. The tradeoff parameter in the formula for ACE in each CA is chosen as \( B_i = \beta_i \). We have reviewed that when the parameters are chosen this way, forcing the ACE to zero corresponds to balancing power exactly at each CA level. If the regulating units succeed in driving their ACE to zero, there will be no power imbalance in the interconnected system and, therefore, no unscheduled tie-line flows and no frequency deviations from nominal. For a two area system

\[
ACE_1 = \Delta T - 10\beta_1 \Delta F_1 = 0
\]

(6.13)

and

\[
ACE_2 = -\Delta T - 10\beta_2 \Delta F_2 = 0
\]

(6.14)

Consequently,

\[
ACE_1 + ACE_2 = -10(\beta_1 + \beta_2)\Delta F = 0
\]

(6.15)

### 6.3.2 Advantages of the present ACE-based decentralized AGC in a regulated industry

There are several reasons for using a decentralized control scheme based on the ACE output variable. They are:

1. **Simplicity:** Under ordinary operating conditions there is no need for the system operators in different areas to communicate data for controls in real time. Each operator has a simple criterion for the performance of his own CA based on the data that can be gathered in his CA.

2. **Accounting:**

   The beauty of an ACE-based controller is that when one sets the tradeoff parameter (bias, \( B \)) properly, the control units will compensate only for the
mismatch of load and generation in their own CAs. Thus, there is no need to redistribute costs of controls between the subsystems.\textsuperscript{4} Each area ideally takes care of its own problems.

6.3.3 Disadvantages of the ACE-based decentralized AGC in a regulated industry

1. The decentralized control scheme works well as long as each subsystem is able to maintain its ACE near zero. However, if one CA fails to meet this ACE-based criterion, the net disturbance will propagate throughout the entire system. Furthermore, the regulating units in the neighboring CAs are tuned so as not to respond to disturbances that originate elsewhere on the system. Thus the disturbance will not be compensated by any party which, in turn, may lead to long-term frequency deviations. To compensate for this problem, the so-called time error correction is practiced at present so that the inadvertent is paid back over a long period of time while being consistent with the prevalent time error \cite{5,1}.

2. Although it was shown above that in steady-state with each CA meeting its ACE, system frequency will be nominal, this provides no insight into the dynamic interactions of the independent regulating units. The questions of stability and robustness of this design are briefly addressed later in this section.

3. While each system operator has the freedom to assign control responsibilities in his CA to minimize regulation costs, this does not necessarily lead to a system-wide minimum of frequency regulation cost. It may be possible for a subsystem to reduce its cost by delegating its control responsibility to generators outside the CA. The effect of this process on system performance is discussed next.

\textsuperscript{4}A more refined aspects of this scheme, including the time-error correction cost, require some adjustments to this conceptual statement.
6.3.4 ACE-based “trading” of frequency biases between the CAs

The above discussion dealt with advantages and disadvantages of the ACE criterion assuming that each control area sought to regulate only disturbances originating inside their own boarders. In this thesis however, we have taken on the more ambitious objective of creating a marketplace where the responsibility of regulating frequency in area A can be traded to a set of generators in area B. Any acceptable control criterion must therefore lend itself to this form of trade. In the case of ACE, the item that must be tradeable is the tradeoff parameter B. We will now discuss the feasibility of trading this parameter between control areas.

Start again with the nominal conditions. Next, introduce a disturbance in area 2 \( P_{G2} = P_d \). Since there are no regulating units in area 2, the generation in this area remains at \( P_{G2} = P_d \). The regulating units in area 1, however, will respond to the disturbance \( P_{G1} = P_c \). The regulating generator will set its output level to drive ACE in its region to zero. Thus, in steady state we have a constraint

\[
ACE_1 = \Delta T - 10B_1 \Delta F = 0 \tag{6.16}
\]

We combine this constraint with the general expressions for natural frequency responses in each area and enforce the constraint of uniform frequency in steady state. This allows to specify the level of regulation as a function of the disturbance and the frequency bias as follows:

\[
P_c = \frac{(\beta_1 - B_1)}{\beta_2 + B_1} P_d \tag{6.17}
\]

Chose next \( B_1 = \beta_1 \) which was proven earlier to be optimal in a decentralized control case. With this value, \( P_c = 0 \), which should not come as a surprise. We have argued earlier that a controller is tuned in a decentralized scheme to only respond to a disturbance in its own area.

The real question here is how should one tune the regulating units in area 1 if we
want them to compensate for the disturbances on the entire system. In this case we require that $P_c = -P_d$. Plugging this condition into the constraint above gives us the following relation:

$$\frac{\beta_1 - B_1}{\beta_2 + B_1} = -1$$ (6.18)

Since both $\beta_1$ and $\beta_2$ are positive, the only way of satisfying this constraint is to let $B_1$ go to infinity. This result also should not be surprising. Letting $B_1$ go to infinity corresponds to ignoring the tie-line flows and focusing on regulating the systemwide frequency only. In the case when one has to control the entire system by one regulating unit, the ACE signal is no longer applicable, and one must respond directly to frequency.

This result reflects an important characteristic of ACE in relation to an inter-area market for controls. While the system operator may dispatch generators inside his control area to the area control error, the criterion does not lend itself easily to trade across control area borders. The problem lies in the fact that ACE is local to each control area, and therefore any generator participating in ACE-based frequency controls must monitor the tie-line flows into the area, in addition to system frequency. We will argue in this chapter that by switching to a control algorithm based on a global system variable, namely systemwide frequency, a more effective and transparent market for controls can be created. First however we will continue the analysis of inter-area trade under an ACE-based control model.

### 6.3.5 Hybrid schemes for partial “trades” of frequency bias

Above we have examined the situation where one CA takes over the regulating responsibilities of the entire system. We will now examine the case where the CAs redistribute partial responsibility for their frequency regulation. This is done by altering (“trading”, selling and/or buying) frequency bias between the areas. In order to quantify how one should change frequency bias, one should look beyond the steady-state analysis. Driving the ACE to zero in both CAs will always imply zero
tie-line flow (deviations) in steady state, no matter how one sets frequency bias for individual CAs. Zero tie-line flow deviations imply that each CA balances its own G/D imbalance, and thus there is no way of redistributing regulating responsibilities in the steady state by altering the ACE parameters. In order to appreciate the effect of such changes, one has to examine dynamic interactions of the two regulators. For this, consider the following model\textsuperscript{5}

\[
\Delta F_1[k] = -\frac{1}{10\beta_1} (\Delta P_{G1}[k] - \Delta T[k]) 
\]

\[
\Delta F_2[k] = -\frac{1}{10\beta_2} (\Delta P_{G2}[k] + \Delta T[k]) 
\]

and impose the constraint

\[
\Delta F_1[k] = \Delta F_2[k] = \Delta F[k] 
\]

This leads to the following frequency and tie-line flow dynamics

\[
\Delta F[k] = -\frac{1}{10(\beta_1 + \beta_2)} (\Delta P_{G1}[k] + \Delta P_{G2}[k]) 
\]

\[
\Delta T[k] = \frac{\beta_2}{(\beta_1 + \beta_2)} \Delta P_{G1}[k] - \frac{\beta_1}{(\beta_1 + \beta_2)} \Delta P_{G2}[k] 
\]

Recall the definition of ACE at each step \([k]\)

\[
ACE_1[k] = \Delta T[k] - 10B_1\Delta F[k] 
\]

\[
ACE_2[k] = -\Delta T[k] - 10B_2\Delta F[k] 
\]

\textsuperscript{5}[k] stands for\([kT_s]\) which is sampling time of AGC.
We now tune our regulating units in each CA to compensate for their respective ACE signals as

\[
\Delta P_{G1}^C[k] = -ACE_1[k] \tag{6.26}
\]

\[
\Delta P_{G2}^C[k] = -ACE_2[k] \tag{6.27}
\]

Assume the disturbance on the system originates in area 2, the total generation in each area then becomes

\[
\Delta P_{G1}[k + 1] = \Delta P_{G1}^C[k] \tag{6.28}
\]

and

\[
\Delta P_{G2}[k + 1] = \Delta P_{G2}^C[k] + P_d[k] \tag{6.29}
\]

This leads to a dynamic equation for the evolution of system frequency

\[
\Delta F[k + 1] = -\frac{1}{\beta}(B_1 + B_2)\Delta F[k] - \frac{1}{10\beta}P_d[k] \tag{6.30}
\]

Although very simple in structure, this dynamic equation is the key to understanding the tradeoff involved in altering the parameters in ACEs. The obvious observation is that the dynamic behavior of the frequency depends only on the sum of individual frequency biases. This leads to an easy way of measuring the necessary tradeoffs between \(B_1\) and \(B_2\). One area simply takes over the part of the frequency bias from the other CAs. Since they both react to the same frequency, the increase in the frequency bias for the system is exactly equal to the decrease in the frequency bias of the other area. This can be re-written as

\[
ACE_1[k] = \Delta T[k] - 10(B_1 + b)\Delta F[k] \tag{6.31}
\]

\[
ACE_2[k] = -\Delta T[k] - 10(B_2 - b)\Delta F[k] \tag{6.32}
\]
Pricing for frequency bias

The pricing scheme for frequency bias is relatively straightforward. The additional regulating generation exerted by area is simply given by

\[ P_{G1}^{\text{reallocated}} = \Sigma b \Delta F[k] \]  \hspace{1cm} (6.33)

System stability

The other significant factor to consider when trading bias is system stability. The stability condition depends on the properties of the constant \( \frac{(B_1+B_2)}{\beta} \), as determined from the dynamic model given in (6.30). As long as

\[ \left| \frac{B_1 + B_2}{\beta} \right| \leq 1 \]  \hspace{1cm} (6.34)

(the strict inequality) is met, it follows from the model above that the system will be stable. Otherwise, it could be marginally stable (=1), or unstable when \( \geq 1 \). An interesting observation is that when frequency bias is chosen to correspond to the natural response of each area, the system is only marginally stable! Higher gains would lead to oscillations among the CAs and reducing it would provide for robustly stable response, however somewhat slower regulation of frequency.

In addition to being marginally stable, the ACE-based regulation exhibits some other fundamental problems when attempted to use in a competitive industry. This is described next.

6.3.6 Possible problems with the \( A_1 \) criterion when used in competitive industry

The ACE may seem like a simple, effective measure for controlling frequency. In a regulated industry it served its purpose of maintaining frequency within a tight band more than adequately. It does, however, display some fundamental flaws when applied in a deregulated, competitive market. To understand this, we first have to
specify what we mean by a market for control.

**Market for control**

Assume we have a fully deregulated industry in which an independent system operator (ISO) is responsible for frequency control inside his control area, but is not allowed to own any generation for this purpose. He then needs to contract the regulation service from either utility-owned generators or the independent power producers in order to be able to provide the necessary regulating generation for frequency.

He can go about this task in several ways. The most obvious way is to simply pay the rented generating units to relinquish control of their generators so that the ISO can track the ACE at will. This, however, is likely to be a very expensive option since the regulating units would have to run far below their maximum power output in order to maintain enough power reserve to meet a possible peak in demand, or the loss of another generator, see [4].

An alternative to this brute force approach is to establish a competitive market in which the units participating in regulation are allowed to offer their services at hourly (or even half hourly) bids, see [10]. The regulating units would name the price and the amount of generation willing to provide, and the ISO would then choose the cheapest bids to provide the regulating generation specified by the ACE-based performance criterion $A_1$.

**Potential market induced instabilities**

While this free market approach is likely to lead to a more efficient allocation of generation resources, it also carries with it an inherent problem. In order for the bidding system to function, the ISO will have to decide ahead of time how much control generation he will use in the next period. This in turn will cause a time delay between the point at which the information specifying the ACE is gathered, and the time at which the actual generation is released onto the system. Given the right

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6The discussion is generalizable to an ISO with jurisdiction over several CAs.
combination of disturbances, this time delay can cause the control effort of the ISO to worsen rather than counteract the effect of the disturbance on system frequency.

To demonstrate this point one could simulate a simple two area system. The two areas are perturbed by disturbances which are exact mirror images of each other. Since the disturbances cancel each other out exactly there is no net imbalance of power on the system and therefore no deviation in the interconnection frequency. The tie line flows will exactly balance the excess power in area one with the deficit in area two. Looking at the problem from the interconnection perspective, it is clear that there is no need for any control generation in this case. The ISO’s in each CA, however, are bound to their obligation to control their ACE. The ACE will show an imbalance in each CA, but will not be sensitive to the fact that these imbalances cancel out on the interconnection level. Therefore, each ISO will attempt to compensate for its own imbalance, setting off an oscillatory flow of power between the subsystems across the tie line. This effect is further amplified by the time delay factor discussed above which causes the control generation to be applied one discrete time period after the imbalance to which it reacts. The net effect is that each ISO wastes a significant amount of valuable control generation on a system that did not require any control in the first place. This simulation shown in Figure 6-1 is meant to demonstrate that:

- A decentralized control structure observing the $A_1$ criterion, which does not take into account the net imbalance on the interconnection, can result in local control signals which fully or partially cancel each other. This signifies a direct economic loss for the ISO’s which will have to, in turn, be recovered from market participants.

- If the B constant in calculation of ACE is chosen so that the control generation applied exactly matches the local imbalance at any time instance then the interconnected system is only marginally stable. This is why we see the additive effect of the disturbances in the simulation. The system can regain stability by reducing this constant for the individual control areas, but this will slow down
the recovery of the nominal frequency.\textsuperscript{7}

\section*{6.4 Moving From $A_1$- to $CPS_1$ and $CPS_2$-based system regulation}

The North American Electric Reliability Council (NERC) has recently replaced the $A_1$ and $A_2$ criteria by the new criteria $CPS_1$ and $CPS_2$ recommended by Jaleeli and VanSlyck in the EPRI Final Report RP35555-10.

The $CPS_1$ criterion states that

\begin{equation}
\text{AVG}(\frac{ACE}{-10B})_1 \times \Delta F_1 \leq \epsilon_1^2
\end{equation}

where $\Delta F_1$ is the one minute average of $\Delta F$, and $\langle \frac{ACE}{-10B}_1 \rangle$ is the average of this quantity over the AGC cycles of one minute [13]. In this criterion, system frequency is used as a proportional weight on the penalty for not tracking the local ACE. The idea is that system operator must maintain their average yearly value of the $CPS_1$ below $\epsilon_1^2$. This allows for some extra leeway since ACE may deviate in the short term. However, in order to be able to meet the yearly average the system operators must still track ACE close enough to guarantee system stability. The main purpose of the new criteria is to give more flexibility for system operators in tracking ACE. This is achieved by using system frequency as a weighting factor. When frequency is close to nominal there is little need for controls. If we examine the expression for $CPS_1$ we find that with $\Delta F$ close to zero, ACE can deviate significantly without violating the inequality. On the other hand if the frequency deviation is substantial, the system operator must maintain his ACE close to zero to stay within the inequality.

\textsuperscript{7}It is important to observe that as energy trades occur across CAs, computation of $\beta_i$ becomes more involved, as well.
Figure 6-1: Market induced instability
6.4.1 Problems with the $CPS_1$ Criterion

1. While the $CPS_1$ criteria has incorporated a frequency weighting factor, it is still based on the area control error. As we discussed earlier, ACE is a local variable. Any trade based on such a criteria will therefore require extensive real-time coordination, and it will be difficult if not impossible to create a systemwide market for controls. The inclusion of the frequency weighting makes this process even harder. Since frequency deviations cannot be easily predicted, the system operator does not know ahead of time how closely he will have to track the area control error. He will therefore be forced to make a series of real-time decisions.

   (a) How closely does one need to track the Area Control Error?
   (b) How much control generation will this require?
   (c) How can one optimally allocate this generation between available generators?
   (d) How much control capacity must be reserved for the next interval?

   Faced with such a complex decision process, system operators are likely to revert to the old practice of contracting a small number of generators to take over the full responsibility for controls. This simplifies the task of real time dispatching, but as we saw in the simulation of the bilateral market structure, relying on a small number of generators to meet unexpected disturbances also reduces the overall economic efficiency of the system.

2. The driving force behind the move from the $A_1$ to the $CPS_1$ criterion was to relax the rigidity of the ACE-based approach. As we have explained this is accomplished by by incorporating a weighting factor in the form of system frequency. This allows system operators to relax their control standards when system frequency is close to nominal. There is however a catch to this reasoning. The area control error is a direct reflection of a local mismatch in load and generation. Frequency, furthermore, reflects the system-wide mismatch in load and generation. Allowing wider deviations in local ACE will therefore inevitable
result in a greater offset of the overall frequency. By relaxing the control criteria when frequency is close to nominal one implements a disguised version of an on/off controller. The system shows no response until frequency approaches critical levels. The control generators kick in at full force. Since the effect of generation/load mismatches is cumulative, this approach does not reduce the overall control effort required to return frequency to nominal. It simply contracts the control response into a shorter period of time. Since the individual system operators have little or no ability to regulate overall frequency, they are forced to respond with tight controls whenever the frequency deviates. I would argue that this does not represent an increase in the freedom of the system operators to decide how to allocate their control generation.

6.5 Market-based Regulation

The above questions suggest that while the CPS$_1$ criterion may have been able to circumvent some of the problems faced by the $A_1$ criterion-based controller, it is not yet implementable as a control algorithm. The problems facing the CPS$_1$ criterion are largely the result of the hard constraint (6.35) imposed by the bound on frequency. This makes it hard to provide gradual incentives for individual generators to initiate control actions before the constraint is reached. It would be preferable to have a soft constraint in the form of a linear penalty on frequency which could be distributed among the generators within an area. Recall the basic model (6.3) relating frequency and net generation on the interconnected system. It states that there exists a linear relation between the frequency deviation and the net power imbalance on the system. Relation (6.3) re-written for the entire interconnection is

$$\Delta P_G = -10\beta \Delta F$$  

(6.36)

The proportionality constant $\beta$ in (6.36) tells us how much control generation is needed to balance the entire interconnected system in order to keep $\Delta F$ within a prespecified threshold $\epsilon$. 

71
The job of the ISOs in the future will be to distribute components of this constant optimally among individual generators. Assume that we have \( n \) generators participating in AGC. Each generator is assigned a constant \( k_i \). The generator \( i \) is then responsible to provide a level of control generation \( \Delta P_{Gi} = k_i \Delta F \) for any given frequency deviation \( \Delta F \). The total amount of control generation for the interconnected system will then be given by \( \sum_{i=1}^{\infty} k_i \Delta F \).

Now if the control constants are distributed to meet the constraint

\[
\sum_{i=1}^{\infty} k_i = 10 \beta
\]  

(6.37)

then we will satisfy the relation,

\[
\sum_{i=1}^{\infty} k_i \Delta F = 10 \beta \Delta F = -\Delta P_G
\]  

(6.38)

and so the quantity of controlling generation applied will match the total imbalance on the system. The beauty of this system is that it does not matter how many generators participate in AGC or where they are located, as long as their individual control constants add up to the systemwide total. This means that the system operator can auction off control responsibility for his area to generators over the entire interconnected system, allowing him to take advantage of inexpensive generation in other subsystems.

Specific auction rules would have to be developed, similar to auction for scheduling generation in energy markets. One qualitative difference, however, comes from the fact that the regulating generation may or may not be actually used when made available. Depending on how are market prices for regulation designed, i.e., if they are such that only used regulating power is paid for or even the unused (but available) power is paid for, different market strategies will evolve. Bidding for control will only make sense if it is economically attractive, relative to bidding for generation in the energy market.
6.5.1 Advantages of the modified $CPS_1$ criterion

There are several benefits from modifying the $CPS_1$ criterion as suggested here. The most obvious are:

1. No redundancy caused by controllers counteracting each other.

   We saw in the simulation of the $A_1$ controller how it is possible for a decentralized control algorithm to be counteracting itself by sending out multiple control signals which cancel each other out. This is not possible in the case of the modified $CPS_1$ criterion since all generators respond to the same signal, the deviation in systemwide frequency. As long as all control constants are of the same sign, the control efforts of all generators will be in the same direction.

2. Accountability.

   The amount of control generation expected to be provided by a generator participating in AGC is fully specified by his control constant $k_i$. The ISO can therefore hold each generator responsible for its contract to control the system and impose penalties on generators that do not fulfill their contract.

3. Efficiency.

   The control scheme combines the advantage of being coordinated in its allocation of responsibilities, with practical need to be localized in its real time operation. By distributing the control constants in a systemwide bidding process one can achieve the cheapest allocation of control generators. This could result in significantly lower costs over a system which minimized control costs one control area at a time. Furthermore by assigning a proportionality constant rather than specifying specific power output levels the system operator is no longer required to coordinate the control process in real time.

6.5.2 Who pays for system regulation and how much?

The above only proposes means for an ISO to ensure sufficient generation for system regulation, and acquire it through market-based bidding. This must be paid by the
parties causing the need for this regulation.

There are at least three qualitatively different ways of charging for system regulation:

1. Charge everyone according to the base load ratio share.

   This is the simplest solution, however, it lacks incentives not to create the need for system regulation. The formula does not provide a mechanism for differentiating between two users of the same scheduled power, and drastically different amplitudes and rates of deviations from schedules.

2. Have a settlement process periodically and charge according to the actual deviations from schedules.

   This is a good solution, however, it would require much new metering and recording by all system users. It is not clear if the additional cost of doing this could be justified solely on the basis of reducing the charges for system regulation. The general trend, e.g., [10], is toward installing more advanced metering for various purposes, and it may make this approach economic in the near future.

3. Have a regulatory requirement for all system users to provide their estimates of amplitudes and rates of deviations in power away from the scheduled.  

   This is easily provided at the user's level, and could be checked from time to time. This information could become essential to the ISO’s prediction/estimate of the amount of generation needed for regulation. At the same time, without any additional metering (except for sporadic auditing), it would enable a fair allocation of system regulation charges. We suggested a means of implementing this in Ch 4. By requiring each generator and load entering into a bilateral contract to provide estimates on deviation bounds, the system operator can provide individualized access fees designed to recover control costs fairly.

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8Observe from (6.38) that in order for the ISO to ensure sufficient regulating power, he should have an estimate of total $\Delta P_G$ to meet $CPS_1$ criterion in the area of his responsibility.
6.6 Remaining need for coordination

It appears from the above analysis that, given the right control performance criteria for frequency regulation, one could envision entirely market-based provision for regulating the interconnection frequency. This raises questions concerning need for any interconnection (tertiary) level coordination for frequency regulation. In order not to draw misleading conclusions, several concerns are pointed out here.

Possibly the most important is to reiterate that automatic system regulation described here is not responsible for stabilizing imbalances evolving at arbitrary rate and amount, including the ones caused by the unplanned equipment outages. The implied objective of AGC, as pointed out in [9], is to regulate relatively small real power mismatches evolving at slow rates under normal operating conditions. Much coordination may be required for stabilizing other dynamic processes on the interconnected system, both under normal and emergency conditions.

The ultimate objective of coordination is to ensure that the interconnected system as a whole operates in secure and optimal fashion. At present, in a regulated industry, there is very little coordination for regulating the interconnection frequency. The control performance criteria are only recommended, and not mandatory, nor subject to economic penalties when not met. Under a market-based frequency regulation there must be high penalties for not meeting contractual obligations. For example, if the promised share $k_i$ in (6.37) is not met, this will actually cause unexpected power imbalance and this situations may require real-time coordination at the interconnected system level. Coordination for frequency regulation is particularly important when the demand/generation mismatch in a particular CA happens to exceed the regulating capacity available. A potential approach to minimal coordination has been recently proposed in [2, 3, 8].
Chapter 7

Conclusion

When faced with the reality of a deregulated industry, the attitude of many utilities and system planners could be described by the phrase 'how can we absorb the new market conditions with the least possible change to our old operating patterns'. Deregulation is seen as a potentially dangerous disturbance, increasing the degree of uncertainty and unpredictability of the electric power network operations. It is, therefore, tempting to deal with this increased volatility by expanding security margins, requiring larger operating reserves and widening the powers of the system operator to dispatch generation. While such a measure would help to ensure the technical security and performance of the network, it would be equally certain to degrade the economic efficiency of the market, counteracting the main reason for the deregulation process. The underlying message in this thesis is that deregulation provides an opportunity to revisit the fundamental paradigm through which we view system security and performance. By incorporating financial feedback into the technical model of the electric power network, we arrive at a complete dynamic model for the system. Based on this model, we were able to define the tradeoff which exists between short run control over network operations, and the long term growth defined by new financial investments. A system operator may gain short term control of the generators in his area by dispatching their output to achieve a system wide optimum. The same operator, however, has no means of controlling long terms investments into new generating units. By forcing generators to operate at output levels other than
those dictated by their own economic profit, the system operator will inevitably offset the long term evolution of generation capacity and thus reduce the efficiency of the system. The tri-market structure for trading power which we propose here, is designed to make use of the economic adaptive process in which producers reallocate their generation capacity between markets to optimize individual profits. The simulation of the system showed how this process results in a global optimum without requiring the system operator to intervene by dispatching generators. As a result, the profits incurred by generators are based purely on their value to the market. New investments will therefore be allocated in areas where they are most needed, that is where they will yield the highest profit. The principle of minimal interference by the system operator is extended to the problem of creating a unified inter-area market for control generation. By revising the traditional role of control areas, we were able to derive a new control criteria which not only lends itself to inter-area trade, but also eliminates the need for real time dispatching and coordination by the system operators. By trading the responsibility to track frequency, a global state of the network, rather than discrete units of power, the system operators need merely coordinate their financial purchases of control contracts to assure the availability of sufficient control reserves. While further work is required on the optimal algorithms for tuning individual controllers, the decentralized scheme of controlling frequency carries the decisive advantages of simplicity and transparency in technical operation, competitive bidding and operating cost recovery. The entire concept of the proposed market structure needs further development to accommodate transmission line flow constraints.
Bibliography


