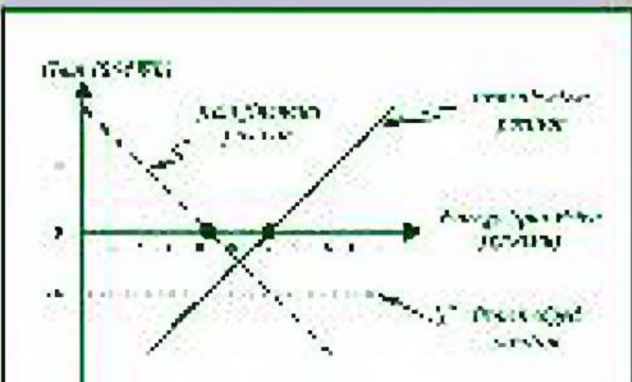
Restructured Electrical Power Systems

Operation, Trading, and Volatility



Mohammad Shahidehpour
Muwaffaq Alomoush

Restructured Electrical Power Systems

POWER ENGINEERING

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Operation, Trading, and Volatility

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SERIES INTRODUCTION

Power engineering is the oldest and most traditional of the various areas within electrical engineering, yet no other facet of modern technology is currently undergoing a more dramatic revolution in both technology and industry structure. Worldwide, deregulation, privatization and restructuring have transformed the business and operating context within which the electric power industry must operate. While these government and societally mandated rules have in no way changed the basic physical laws that define how electricity behaves, they have dramatically changed the way that the electric industry must function to attain its business and customer-service goals.

The sheer number and scale of these changes have made it a challenge for anyone involved – utility executive, regulator, utility planner, system operator or electricity trader – to grasp firmly how the modern electric industry operates. Thus, this newest addition to Marcel Dekker's Power Engineering Series, *Restructured Electrical Power Systems: Operation, Trading and Volatility*, is particularly appropriate. Professors Shahidehpour and Alomoush have created a comprehensive yet accessible reference that covers both the framework within which modern electric production, transportation and trading systems operate, and the intricacies of the analytical, engineering, and business operations that must function within that framework.

Modern power industry operation is particularly difficult to understand because of the dichotomy between electricity's business and physical manifestations. From the business perspective, electric power is a fungible commodity, something that can be traded much like oil, wheat, or coffee, and for which futures markets and hedging systems can and do exist. But in its physical manifestation, electricity is quite unlike all other traded commodities. Perhaps the fundamental difference is that it cannot be stored to any significant degree. This greatly affects how it must be managed as a business asset, and greatly constrains how its present and future market prices do or don't interact, as compared to other commodities. In large part due to its "storage-less" nature, electricity can be transported only in a real-time basis, and in a manner heavily constrained by myriad physical laws that are complicated in their interactions but nearly instantaneous in their impact. This means that transportation and delivery more totally define product quality than in other industries, and also means that in a practical sense electricity is not entirely fungible in many situations.

The net effect of all of these differences is that modern electricity trading and wholesale transportation systems are quite different from anything seen previously, either in the electric industry or in any other industry. For this reason, this volume is all the more remarkable, both for the clarity of its presentation and for the comprehensive way in which the authors explain how every facet of the industry interacts with and impacts the whole. Professors Shahidehpour and Alomoush have created an excellent reference for the experienced power engineer or executive who needs a solid background on modern wholesale power exchange and grid operation. In addition, their book is also a very good tutorial for the student who desires to learn the intricacies behind what is literally the fastest moving commodity being traded anywhere in the world.

Like all the books in Marcel Dekker's Power Engineering Series *Elements of Restructured Electrical Power Systems* provides modern power technology in a context of proven, practical application; useful as a reference book as well as for self-study and advanced classroom use. The series covers the entire field of power engineering, in all of its specialties and subgenres, and aims at providing practicing power engineers with the knowledge and techniques they need to meet the electric industry's challenges in the 21st century.

H. Lee Willis

PREFACE

The electric power industry is in the midst of a major restructuring process in which electricity would be traded as a commodity. Electricity is a $200 billion per year market, which makes it the largest commodity market in the United States. This book discusses topics that are the critical ingredients in understanding electric power industry restructuring. The California energy shortages and rolling blackouts in 2000-2001 have further reinforced the need for a book on this subject which would help the reader understand the transition from the electricity of the past to the electricity of the future.

For many decades, electric utilities monopolized the way they generated, transmitted, controlled, and distributed electricity to customers in their service territories. In that monopoly, each utility managed the three main components of electric power systems, i.e., generation, transmission and distribution. In the restructured system, the main tasks of these three components remain the same as before; however, to comply with FERC Orders, new types of unbundling, coordination and rules are established to guarantee competition and non-discriminatory open access to all users in the interconnection.[1]

The United States restructured its electric power markets the last few years of the twentieth century in order to foster the competition. Reform has focused on transforming the wholesale market for electricity into a competitive market at the national level, and importance has been placed on providing a competitive retail market at the state level.

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[1] Interconnection in the United States refers to any one of the three large transmission systems. The Eastern Interconnection covers most of the area east of the Rocky Mountains in the United States and Canada. The Western Interconnection covers an area that is mostly west of the Rocky Mountains in the United States and Canada, as well as a small portion of Mexico. ERCOT Interconnection covers much of Texas.

Ultimately, small customers such as households will be able to select their energy providers in much the same way that they now choose a long-distance telephone carrier.

In response to the electric industry restructuring, new phenomena, new circumstances, new risks, and new tools have emerged. Some of these new topics have risen for the lack of experience with newborn issues, while others have embarked as a necessity for the proposed structures. Although the new electric power structure requires new tools and approaches for decision-making and improving the efficiency of the power network, it is evident that applying theorems and models of other commodities to electricity markets could frequently mislead market participants in the restructured electricity industry. In this market, energy trading tools would help buyers and sellers sign up freely for a range of energy resources, various types of electricity products and different energy alternatives in geographical regions, while they take into consideration special circumstances of energy markets that differ from other commodity practices.

The primary objectives of this book are to present a background on electricity restructuring, to provide insight on new trends in power systems operation and control, and to highlight advanced topics in electricity markets. These topics are covered in various chapters by illustrative examples and graphical representations that will help readers acquire ample knowledge on the respective subjects. This book is suitable for readers from different disciplines, including college students and instructors, electricity traders, hedgers, regulators, vendors, manufacturers, consulting companies, electric utilities, and researchers. Readers will find answers to several questions including: Why is a restructuring necessary? What are the components of restructuring? How is the new structure different from the old monopoly? What are the outcomes of restructuring? How is the restructuring implemented? What are the new trends in restructuring? What are the new tools in restructuring? How are interchange transactions analyzed and approved? How is an optimal decision made in the energy market? How would the communication links work in the restructured electric power industry? What are the characteristics of energy markets in the United States and across the globe?

OUTLINE OF THE BOOK

Chapter 1 provides an introduction to the electric utility industry and its functions. This chapter is a general review of restructuring for power engineers and includes introductory information for non-electrical engineering majors with an interest in utility restructuring. The chapter reviews key issues in restructuring and different restructuring models including stranded costs, market operations, transmission pricing, congestion management, PoolCo model, bilateral contracts and the hybrid model.

Chapter 2 provides a discussion on major U.S. market models, Independent System Operators (ISOs) in the United States and major ISO functions as related to the FERC Order 888. These models include California, Pennsylvania–New Jersey–Maryland (PJM) interconnection, New York Power Pool (NYPP), Electric Reliability Council of Texas (ERCOT), New England ISO and Midwest ISO. The chapter discusses some of the shortcomings and advantages of these models, presents comparisons among models, and reviews topics such as horizontal and vertical market power, stranded costs, tics, market clearing prices, Contracts for Differences and transmission pricing.

Chapter 3 introduces the Open Access Same-Time Information System (OASIS), presents a comprehensive review of OASIS, discusses the FERC Order No. 889 and elaborates on exploring OASIS as an electronic information system. OASIS allows users to instantly receive data on the current transmission network operating status, capacity of a transmission provider (transmission availability), request of transmission services, available transmission capability, and transmission pricing. This chapter discusses requirements of transmission providers, types of information on OASIS such as the availability of transmission services, hourly transfer capacities between control areas, hourly firm and non-firm power scheduled at various points, current outages information, load flow data, current requests for transmission service, and secondary information regarding capacity rights that customers wish to resell. In addition, the chapter discusses how the information is posted on OASIS, what are the required interfaces for this posting, which part of information is secure and which part is public, how OASIS enables any transmission customer to communicate through requests to buy and responses to sell available transmission capabilities, and how utilities use OASIS to share operating data regarding transmission availability, generation capability, system loads, interchange, area-control error, frequency and operating reserves. The chapter will also discuss whether or not OASIS has a data link to other systems.

Chapter 4 presents the tagging system and discusses the major contributions of the NERC's Policy 3. The chapter illustrates the Constrained Path Method (CPM) and shows the philosophy behind the transition from the old tagging system to the new system and functional requirements of a software used by market participants to meet the minimum NERC Policy 3 requirements. In addition, the chapter shows procedures for canceling and curtailing interchange transactions. It explains how tags are created and submitted, and types of information contained in the tag. The functional specifications are presented that explain obligations and duties of all parties to an interchange transaction, required data to represent a transaction and specific mechanisms for exchanging the data electronically. The chapter helps readers understand the three main services in electronic tagging–Tag Agent Service, Tag Authority Service, and Tag Approval Service–and their interdependency. It explains how tags are initiated, authorized and approved. In addition, the chapter illustrates some of the tagging concepts using graphical representation and provides examples that help readers grasp the entire picture of interchange transactions. Finally, the chapter elaborates on implementation, curtailment, and cancellation of interchange transactions.

Chapter 5 presents various characteristics of electric energy trading and focuses on key issues of trading systems. A description of successful trading tools is presented and qualifying factors of a successful trading system are addressed. The chapter concentrates on main derivative instruments such as futures, forwards and options. Different categories of traders, trading hubs, price volatility and green power trading are discussed. Electricity contract specifications of the New York Mercantile Exchange (NYMEX) and Chicago Board of Trade (CBOT) are presented and the presentations are supported by pertinent examples for energy trading.

Chapter 6 provides more information on possible hedging mechanisms in the restructured electric power industry. It presents basics of hedging tools in electricity markets, new derivatives that are created especially for electricity markets, types of risks, and motivations that lead to more risks in electricity markets. In addition, the Midwest crisis that happened in June 1998 – the unforgettable mark in the U.S. electric industries – is presented to show why hedging strategies are important in electricity markets. It gives a detailed overview of sources that lead different market players to suffer from financial price risk, gives an overview of how players of energy markets may use electricity financial derivatives to hedge different risks, and shows shortcomings in the electricity derivatives pricing model. The chapter also discusses major challenges to electricity derivatives, which include implementing reliable forward curves, inadequacy of existing price indices, basis risk, and inadequacy of traditional pricing models. Forward price curves and counterparty risk are presented, followed by a discussion on how California deals with counterparty risk. Also illustrated in the chapter is how the Greeks are used to analyze exposures of a portfolio or a position. The chapter presents a discussion on hedging tools for weather-related risks, and shows numerous examples for using different hedging tools such as swap transaction, caps, floors, swaption, swing contracts, and weather-related derivatives. Many examples are presented regarding these issues.

Chapter 7 discusses electricity pricing and its impact on electricity market operations. The chapter presents electricity price volatility and means of measuring volatility in electricity market prices. Various indexes and price hubs in the United States are introduced and a case study for California is presented. The chapter discusses basic risks in electricity pricing and presents different models for pricing. The construction of forward curves for long-term pricing is discussed and a detailed discussion for short-term electricity pricing is presented. The chapter compares the characteristics of electricity price forecasting with those of load forecasting in power systems. The application of artificial neural networks in short-term electricity pricing is discussed and practical case studies are presented.

Chapter 8 presents issues related to RTO. In order to promote efficiency in wholesale electricity markets and to guarantee that electricity consumers pay the lowest price possible for reliable service, the FERC recently has improved its regulations by proposing the formation of RTOs. In addition to improving grid reliability and correcting the non-discriminatory practices, FERC's objective is to improve market performance, and to create light-handed regulations. The chapter will familiarize readers with RTOs and will discuss issues on mimimum characteristics and minimum functions of an RTO. The sources of engineering and economic inefficiencies, which are present in the operation, planning and expansion of regional transmission grids include: difficulty in calculating ATC values, parallel path flows, limited scope of available information and the use of non-market approaches to managing transmission congestion, planning and investing in new transmission facilities, pancaking of transmission access charges, absence of clear transmission rights, absence of secondary markets in transmission service, and possible disincentives created by the level and structure of transmission rates.

Chapter 9 presents a review of certain electric utility markets outside the United States. Although the number of case studies is limited, it provides an interesting perspective for challenges faced by electricity restructuring across the globe. Among the models discussed in this chapter are the Nordic Power Exchange, Australia National Electricity Market, restructuring of electricity in Canada and electricity industry models in England and Wales. In each case, the chapter reviews the specific characteristics of the case and provides a comparison with the restructuring models in the United States. The chapter provides several numerical examples to help readers examine the model more thoroughly.

Appendices Appendix A provides readers with a comprehensive glossary of terms and definitions for restructured electric power systems. The glossary includes definitions of terms in generation, transmission, distribution, trading, risk management, hedging strategies, interchange transactions (tagging), ancillary services, OASIS, entities of restructuring, and many others. Appendix B represents a sample of electricity contract specifications. Part B1 of this appendix discusses NYMEX and Part B2 is on Palo Verde and California/Oregon Border (COB) futures and options contract specifications. Parts B3-B6 cover CBOT electricity market specifications.

In addition, various definitions and pertinent discussions are provided as footnotes throughout the book, to help readers relate to the subject more closely. The brackets within the text refer to references provided at the end of the book.

Mohammad Shahidehpour
Muwaffaq Alomoush

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Mohammad Shahidehpour
Muwaffaq Alomoush

CONTENTS

CHAPTER 1

OVERVIEW OF KEY ISSUES IN ELECTRIC UTILITIES RESTRUCTURING

Summary: Electric power restructuring offers a major change to the vertically integrated utility monopoly. The change manifests the main part of engineers' efforts to reshape the three components of today's vertically integrated monopoly: generation, distribution and transmission. In a restructured environment, the main tasks of these three components will remain the same as before, however, to comply with FERC orders, new types of unbundling, coordination and rules are to be established to guarantee competition and non-discriminatory open access to all users. This chapter will find answers to several questions including, *why is the restructuring needed? How is the restructuring implemented?* Topics such as major components of restructuring models, market power, stranded costs, transmission congestion contracts, contracts for differences and transmission pricing will be touched in this chapter. In this chapter, we focus on restructuring process in the Unites States and a few other countries, discuss some of the proposals in detail and present comparisons between proposals. We present these subjects in a simplified manner to enable readers with different backgrounds to acquire ample knowledge as related to electric industry restructuring and to provide a general idea on how restructuring is being implemented.

1.1 INTRODUCTION

For many decades, vertically integrated electric utilities monopolized the way they controlled, sold and distributed electricity to customers in their service territories. In this monopoly, each utility managed three main components of the system: generation, transmission and distribution. Analogous to perceived competitions in airline, telephone, and natural gas industries which demonstrated that vertically integrated monopolies could not provide services as efficiently as competitive firms, the electric power industry plans to improve its efficiency by providing a more reliable energy at least cost to customers. A competition is guaranteed by establishing a restructured environment in which customers could choose to buy from different suppliers[1] and change suppliers as they wish in order to pay market-based rates.

To implement competition, vertically[2] integrated utilities are required to unbundle their retail services into generation, transmission and distribution; generation utilities will no longer have a monopoly, small businesses will be free to sign contract for buying power from cheaper sources, and utilities will be obligated to deliver or wheel power over existing lines for a fee that is the same as the cost (non-discriminatory) of delivering the utility's own power without power production costs. The vertically integrated system is steadily restructuring to a more market-based system in which competition will replace the role of regulation in setting the price of electric power.

As in the case of restructuring in airlines and long-distance communication, it is expected that the electric power restructuring will fulfill a main objective, that is, to significantly *reduce the cost of power* charged to small businesses and consumers. The cost of electricity generation will be reduced by driving prices through market forces and more competition; this task will be accomplished by creating an open access environment that will allow consumers to choose a provider (*customer choice*) for electric energy. In this environment customers will have the option of *choosing the level of service reliability* which will provide greater *incentives for short and long term efficiencies* than is provided by economic regulation. The competitive forces will improve economic efficiency by further expanding the geographic horizon in the operation of the interconnected generation and transmission systems.

Individuals working on restructuring would agree on a basic principle that access to transmission services should accommodate

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[1] Supply is the process of buying electricity in bulk and selling it to customers.

[2] Vertical integration is an arrangement where the same company owns all the different aspects of making, selling and delivering a product or a service.

consumer choice and supply competition. Restructuring in electricity industry will create *new business opportunities* where new firms selling new products and services will appear, consumers will have alternatives in buying electricity services, and *new technologies* such as metering and telecommunication devices will develop.

In this regard, on April 24, 1996 the Federal Energy Regulatory Commission (FERC)[3] issued the Final Rule 888 requiring all public utilities that own, control or operate facilities for transmitting electric energy in interstate commerce to file open access non-discriminatory tariffs[4]. This rule caused public utilities to functionally unbundle wholesale generation and transmission services. In addition, FERC issued Rule 889 for the development of an electronic communication system called, Open Access Same-time Information System (OASIS). These Rules gave birth to new classes of entities such as PoolCo which manages information, independent of power generators, retailers and users, and does not own any power facilities. PoolCo, rather than producing electricity, manages information in a competitive market and examines services necessary to ensure least cost reliable system operations [Fed99][5].

"How should the transmission system be restructured in order to meet objectives?" are debated among proposals issued for an open access and competitive environment. The two approaches considered are the *Bilateral Model* and the *PoolCo Model.* A *Hybrid Model* is also suggested that combines the best features of two schemes. The first approach represents a market where most electricity transactions take place under specific contracts between generators and distributors, marketers or final customers. A centralized spot market dealing with short-term power transactions manages the second approach. These models rely upon an Independent System Operator (ISO) to coordinate transmission functions on a fair and equal basis, manage the flow of power over the transmission system, and ensure reliability and security[6] of the overall system.

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[3] A set of acronyms is provided in Appendix A.

[4] A schedule of rates or charges for transmission.

[5] Brackets refer to references given at the end of the book.

[6] Reliability of a system is interpreted in terms of adequacy and security, where an adequate amount of capacity resources should be available to meet peak demand

Many features of this newborn environment are being debated. For example, a competition requires that no single firm or small group of firms be able to dominate the market (*market power*[7]). Another issue is whether small businesses will be asked to pay billions of dollars in uneconomic utility company costs through *stranded cost*[8] surcharges, which are sometimes considered as past business mistakes.

Many new concepts have appeared to facilitate the way we deal with restructuring. ISO, Power Exchange (PX), Scheduling Coordinators, Bilateral Contracts, Fixed Transmission Rights, Transmission Congestion Contracts, Locational Marginal Prices, Inter-zonal and Intra-Zonal, Congestion Credits, Congestion Charges, Bidding Process, Simultaneous Feasibility, Auctions, Capacity rights, Market Power, Stranded Costs, Hour-Ahead Market, Day-Ahead Market, Real-time Market, Market Clearing Price and many other terms are created in different places for different proposals. Some of these concepts are common to all models, some are not, and frequently same concepts are named differently in existing proposals.

In this chapter, we review the key issues in restructuring and focus mainly on the restructured markets in the United States. We start with reviewing different restructuring proposals and their components, and analyze their markets. We provide a historical background on the ISO functions and review two important components in restructuring, namely, Schedule Coordinator (SC) and Power Exchange (PX). We review topics such as market power, stranded costs, Transmission Congestion Contracts, Contracts for Differences and transmission pricing. At the end we present concepts for analyzing these markets such as congestion management.

(adequacy) and the system should be able to withstand changes or contingencies (security) on a daily and hourly basis.

[7] Market Power is defined as owning the ability by a seller, or group of sellers to drive price over a competitive level, control total output or exclude competitors from a relevant market for a significant period of time. Later we will discuss this issue in more detail.

[8] Stranded costs are the costs of uneconomic commitments or investments that utilities have made under traditional monopoly regulation, such as investments in inefficient power plants, which are unlikely to be recovered through electric rates set in competitive markets. Later we will discuss this issue in detail.

1.2 RESTRUCTURING MODELS

Three major models are being discussed as alternatives to the current vertically integrated monopoly. The three models are:

- PoolCo Model
- Bilateral Contracts Model
- Hybrid Model

Elements of a certain electric power industry define the nature of competition and models or institutions that support the competition process. In adopting a model, the following issues are being debated regularly:

- Who will maintain the control of transmission grid?
- What types of transactions are allowed?
- What level of competition does a system warrant?

A PoolCo is defined as a centralized marketplace that clears[9] the market for buyers and sellers where electric power sellers/buyers submit bids and prices into the pool for the amounts of energy that they are willing to sell/buy. The ISO or similar entities (e.g. PX) will forecast the demand for the following day and receive bids that will satisfy the demand at the lowest cost and prices for electricity on the basis of the most expensive generator in operation (marginal generator). On the other hand, in the second model, bilateral trades are negotiable and terms and conditions of contracts are set by traders without interference with system operators.

The main characteristic of the first model is the establishment of independently owned wholesale power pools served by interconnected transmission systems. This pool becomes a centralized clearing market for trading electricity which would implement competition by forcing distribution utilities to purchase their power from the PoolCo instead of trading with generating companies. These companies sell power at a market clearing price (MCP) defined by the PoolCo, instead of a price

[9] Clearing is the situation when all suppliers are willing to provide and all customers are willing to purchase power at the market price.

which is based on generation cost (as is the case in a vertically integrated monopoly). MCP could be defined differently, but the most widely used definition is "the price of highest selected bid". The final price for spot market power may exceed MCP to account for charges that the ISO could obligate customers to pay for the associated ancillary services[10] and to cover ISO's overhead costs. Some proponents of this structure claim that such auction would induce suppliers to bid their true marginal costs. The lower power costs made possible by the competitive generation market would then be passed on to customers by the distribution utility. Initially, most PoolCo proposals did not permit direct power sales from generators to retail customers, but in reality, all customers either directly or through the distribution companies would purchase power from the pool.

The second model, which is based on bilateral contracts, may also be referred to as Direct Access Model. As the name implies, customers are free to contract directly (bilaterally) with power generating companies. By establishing an appropriate access and pricing standards, customers transfer purchased power as restricted to the power transmission and distribution over utility wires. Under this model, a single centrally dispatched regional power pool is not obligatory as under the first model.

Even though the three proposals seem different in approach to guarantee competition, several features are common to all three. Some of these features are competition among generation providers, continued regulation of monopoly in transmission and distribution functions, and establishment of a vertically integrated entity responsible for operating

[10] Ancillary services are defined as services which are required to support the transmission of capacity and energy from resources to loads while keeping a reliable operation of the transmission system of a transmission provider in accordance with Good Utility Practice. A Good Utility Practice is any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. A Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

the transmission grid and maintaining the security of power system. The role of this vertically integrated entity could differ from model to model.

1.2.1 PoolCo Model. The PoolCo model is comprised of competitive power providers as obligatory members of an independently owned regional power pool, vertically integrated distribution companies, vertically integrated transmission companies and a single and separate entity responsible for: establishing bidding procedures, scheduling and dispatching generation resources, acquiring necessary ancillary services to assure system reliability, administering the settlements process and ensuring non-discriminatory access to the transmission grid. PoolCo does not own any generation or transmission components and centrally dispatches all generating units within the service jurisdiction of the pool. PoolCo controls the maintenance of transmission grid and encourages an efficient operation by assessing non-discriminatory fees to generators and distributors to cover its operating expenses.

In a PoolCo, sellers and buyers submit their bids to inject power into and out of the pool. Sellers compete for the right to inject power into the grid, not for specific customers. If a power provider bids too high, it may not be able to sell power. On the other hand, buyers compete for buying power and if their bids are too low, they may not be getting any power. In this market, low cost generators would essentially be rewarded. Power pools would implement the economic dispatch and produce a single (spot) price for electricity, giving participants a clear signal for consumption and investment decisions. Winning bidders are paid the spot price[11] that is equal to the highest bid of the winners. Since the spot price may exceed the actual running of selected bidders, bidders are encouraged to expand their market share which will force high cost generators to exit the market. Market dynamics will drive the spot price to a competitive level that is equal to the marginal cost of most efficient firms.

[11] The spot market is where market generators are paid for the electricity that they have sold to the pool and market customers are charged for their electricity consumption.

To give the reader an idea on how price signals could play an important role in a restructured environment, we consider the following example.

Example 1.1:Impact of Price Signals on Demand Consumption

Figures 1.1 and 1.2 show the idea of price signals and their impact on consumption behavior. Let's assume that an Industrial Customer (IndustCo) consumption pattern in a vertically integrated electric industry, in a certain day, would look like that shown in Figure 1.1. In this figure, the price of electricity in ¢/KWh is fixed, and the IndustCo has no incentives to change its consumption pattern. While in a competition-based market, when the IndustCo receives a real time price signal, it could change its consumption pattern in response to the price (See Figure 1.2). In Figure 1.2, the IndustCo reduces its usage at times of high prices. As the price jumps from 6¢/KWh at 5 a.m. to 8¢/KWh at 9 a.m. the IndustCo starts decreasing its consumption. As the price continues to increase from 8¢/KWh at 9 a.m. to 16¢/KWh at 6 p.m. the IndustCo continues decreasing its consumption. When the price decreases after 6 p.m. the IndustCo increases its usage of electricity.

The consumption response to price could reduce the need for maintaining expensive generating facilities that are rarely used, and enhance the real-time reliability by not letting the consumption to exceed supply.

The ISO in a PoolCo is independent of transmission and generation owners for operating the transmission grid. Competitive generators submit bids to the ISO on a day-ahead basis specifying the amount of energy available, price and delivery points, while distribution companies do the same for loads. The ISO, based on submitted bids, forecasts that short run regional energy demand and dispatches generation in the region to balance generation with load and maintain reliability.

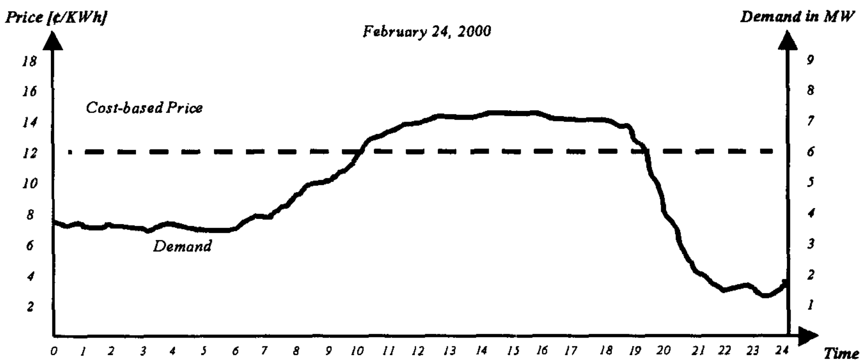

Figure 1.1 *Behavior of a Demand in a Vertically Integrated Power Market*

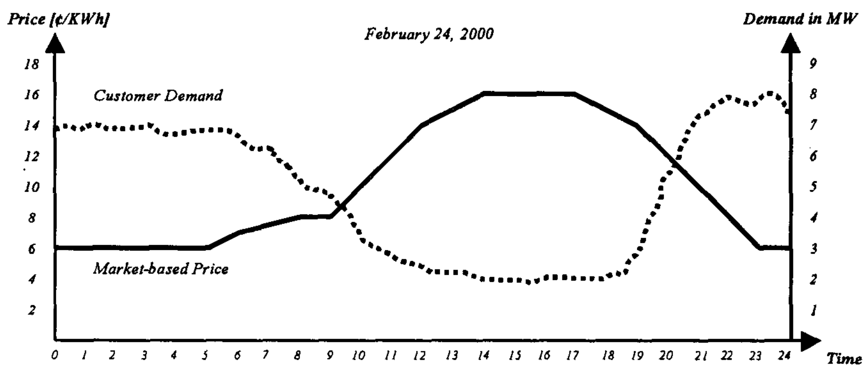

Figure 1.2 *Response of a Demand to Price Signals*

Although buyers and sellers in a PoolCo are prevented from making individual contracts for power, participants may hold optional financial instruments called *Contracts for Differences* (CFDs). These contracts are long-term price hedging bilateral contracts between generators and distribution utilities or retail customers. These contracts allow a physical dispatch of individual generating units by their owners and allow consumers to establish long-term prices. When used, a power seller is paid a fixed amount over time that is a combination of short-term market price and an adjustment for the difference. CFDs are established as a mechanism to stabilize power costs to customers and revenues for generators. These contracts are suggested due to the fact that the spot price set by PoolCo fluctuates over a wide range and is difficult to forecast over long periods. Using CFDs, any differences between the spot price and the contract price would be offset by cash payments by generators to customers; in other words, by holding these contracts, customers gain protection against unexpected spot price increases and generators could obtain a greater revenue stability. An example of CFDs is as follows: a buyer (load) and a seller (generator) agree on a price of \$5/MWh. When PoolCo's price (MCP) drops to \$4/MWh, the buyer pays \$4 to the PoolCo and \$1 (difference) to the seller. When MCP increases to \$6/MWh, the buyer pays \$6 to the PoolCo and is paid \$1 by the seller. Even though CFDs are claimed to support bilateral contracts, various parties are interested in trading available services directly based on their own terms and conditions and not through a PoolCo.

1.2.2 Bilateral Contracts (Direct Access) Model. The Bilateral Contracts model has two main characteristics that would distinguish it from the PoolCo model. These two characteristics are: the ISO's role is more limited; and buyers and sellers could negotiate directly in the marketplace. In this model, small customers' aggregation is essential to ensure that they would benefit from competition.

This model permits direct contracts between customers and generators without entering into pooling arrangements. By establishing non-discriminatory access and pricing rules for transmission and distribution systems, direct sales of power over a utility's transmission and distribution systems are guaranteed. Wholesale suppliers would pay transmission charges to a transmission company to acquire access to the transmission grid and pays similar charges to a distribution company to acquire access to the local distribution grid. In this model, a distribution company may function as an aggregator for a large number of retail customers in supplying a long-term capacity. Also, the generation portion of a former integrated utility may function as a supplier or other independent generating companies, and transmission system would serve as a common carrier to contracted parties that would permit mutual benefits and customers choice. Any two contracted parties would agree on contract terms such as price, quantity and locations, and generation providers would inform the ISO on how its hourly generators would be dispatched.

The ISO would make sure that sufficient resources are available to finalize the transactions and maintain the system reliability. To maintain reliability in real time, the suppliers would supply incremental and decremental energy bids to prevent transmission flow congestion. Here, a cost-based transmission pricing would provide a non-discriminatory access to transmission and distribution systems. As long as the power network is not constrained, this pricing scheme is perfect, but as constraints arise, pricing procedures would be necessary. To predict possible constraints, load flow models are used by considering various generating units and transmission lines. In addition to predicting constraints, these models could determine power flow contributions of individual generators to constrained flows as well as transfer capabilities of transmission and distribution systems. The users who value scarce facilities[12] the most are those who acquire it, where use is cost-based and would motivate users to value it high through their bids. System users who lose in the bidding process would have to find other power providers to supply their loads or modify their load profiles.

1.2.3 Hybrid Model. The hybrid model combines various features of the previous two models. The hybrid model differs from the PoolCo model as utilizing the PX is not obligatory and customers are allowed to sign bilateral contracts and choose suppliers from the pool. The pool would serve all participants (buyers and sellers) who choose not to sign bilateral contracts. The California model is an example of the hybrid model. This structure has advantages over a mandatory pool as it provides end-users with the maximum flexibility to purchase from either the pool or directly from suppliers. A customer who would choose a PX option with CFDs could acquire the economic equivalent of bilateral contracts.

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[12] System components that are expected to be of high demand to market participant and have possibility to be overloaded.

As in the PoolCo case, if generators opt to compete through the pool, they would submit competitive bids to the PX. All bilateral contracts would be scheduled to meet their loads unless they would constrain transmission lines. Loads not provided bilaterally would be supplied by an economic dispatch of generating units through bids in the pool.

The existence of the pool can efficiently identify individual customer's energy requirements and simplify the balancing process of energy supply. The hybrid model would enable market participants to choose between the two options based on provided prices and services. The hybrid model is very costly to set up because of separate entities required for operating the PX and the transmission system.

In the following, we learn more about the functions of an ISO in a restructured power system.

1.3 INDEPENDENT SYSTEM OPERATOR (ISO)

1.3.1 Background. In the past, during the cost-of-service regulatory operation, system operators preserved the system reliability by ensuring that generation and load were matched on moment-to-moment basis as load could not be predicted with certainty. Vertically integrated utilities operated their own system, performed the economic dispatch of generation and managed sales to and purchases from other control areas.

In a vertically integrated monopoly, utilities created regional centrally dispatched power pools to coordinate the operation and planning of generation and transmission among their members in order to improve operating efficiencies by selecting the least-cost mix of generating and transmission capacity, coordinating maintenance of units, and sharing operating reserve requirements and thus lowering the cost to end-use electricity customers. The centrally dispatched power pools are classified as:

- Tight power pools: they have customarily functioned as control areas[13] for their members, perform functions such as unit

[13] A control area is an electrical system, bounded by interconnection metering and telemetry. On second-to-second basis, it regulates, via automatic generation control

commitment, dispatch and transaction scheduling services. Examples of this kind of pools are New York Power Pool (NYPP), New England Power Pool (NEPOOL), Pennsylvania, New Jersey, Maryland (PJM) Interconnection, Colorado Power Pool and Texas Municipal Power Pool.

- Loose power pools: they have generally had more limited roles, and in contrast to tight pools, have a low level of coordination in operation and planning. The most significant role of these pools has provided support in emergency conditions. Members of these pools could coordinate and work together to form principles and practices for interconnected operation and form standards for adequacy of regional power supply. Loose power pools did not provide control area services.
- Affiliate power pools: in this kind of pools, generated power which was owned by the various companies was dispatched as a single utility. Pools have had extensive agreements on governing the cost of generation services and use of transmission systems.

During the last few years, competition in the generation sector has increased due to a growth in the number of power suppliers, while the open access to transmission system was more limited. Limitations came as vertically integrated utilities favored their own generation when transmission was congested, and limitation arose by preventing other utilities or suppliers full access to transmission system. Power pools controlling access to regional transmission systems made it difficult for non-members to use pool members' transmission facilities by establishing complex operating rules and financial arrangements. Also, restrictive membership and governance of pools were practiced occasionally in a way that large utilities prevented changes in policies and rules of the pool which led to closing pool membership to outsiders. Unfair industry practices generally impacted the growth of a competitive generation market and were motive forces for the FERC to order

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(AGC), generation within its boundaries, and schedules interchange back and forth across the inter-ties to match its system load while contributing to frequency regulation of the interconnection.

transmission owners to provide other parties an open access to transmission grids. However, in some instances transmission customers were not entitled to services that transmission owners had for themselves. On the other hand, FERC had to review requests on a case-by-case basis which might have taken more time and led to improper timing of permission to use the grid.

A competitive generation market and retail direct access necessitated an independent operational control of the grid. However, the independent operation of the grid was not guaranteed without an independent entity, the so-called Independent System Operator (ISO). An ISO is independent of individual market participants such as transmission owners, generators, distribution companies and end-users. The basic purpose of an ISO is to ensure a fair and non-discriminatory access to transmission services and ancillary services, maintain the real-time operation of the system and facilitate its reliability requirements.

FERC Order 888 required transmission owners to provide a *comparable service* to other customers who did not own any transmission facilities. The owners were required to treat their own wholesales and purchases of energy over their own transmission facilities under same transmission tariffs they apply to others. After this order, each transmission owner filed a pro forma tariff to implement the Order 888 by specifying terms and conditions of transmission services applicable to all customers.

Separating transmission ownership from transmission control is seen as the best application of the pro forma tariff. The first separation started in California (1994) where two utilities proposed establishing a regional company to control some or all generators and all transmission facilities. This idea developed to the ISO concept in which the transmission system is independently operated. The concept of the ISO is being recognized by many regions in the United States, especially after the approval from the FERC that a properly structured ISO is an effective non-discriminatory way to comply with the Order 888. FERC encourages the development of ISO that ensures all market participants within their physical limitations access the transmission system. A good ISO implementation guarantees independent transmission system operation to ensure that utilities do not favor their affiliates in transacting power. In addition, FERC Order 889 requires all market participants to obtain pertinent transmission information from the Open Access Same-time Information System (OASIS).

1.3.2 The Role of ISO. The primary objective of the ISO is not dispatching or re-dispatching generation, but matching electricity supply with demand as necessary to ensure reliability. ISO should control generation to the extent necessary to maintain reliability and optimize transmission efficiency. It is claimed in some places that an ISO operating as a control area would be an extension of vertically integrated utility monopolies. On the other hand, bilateral contracts are scheduled through the control area and communicated to the ISO. The ISO would continually evaluate the condition of transmission system and either approve or deny requests for transmission service.

In its Order No. 888, FERC developed eleven principles as guidelines to the electric industry restructuring to form a properly constituted ISO, through which public utilities could comply with FERC's non-discriminatory transmission tariff requirements. The eleven principles for ISOs are[14]:

(1) The ISO's governance should be structured in a fair and non-discriminatory manner.

(2) An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

(3) An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.

(4) An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well defined and comply with applicable standards set by NERC and the regional reliability council.

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[14] Federal Energy Regulatory Commission, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Service by Public Utilities," Order No. 888, Washington, DC, April 24, 1996.

(5) An ISO should have control over the operation of interconnected transmission facilities within its region.

(6) An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

(7) An ISO should have appropriate incentives for efficient management and administration and should procure services needed for such management and administration in an open market.

(8) An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or a Regional Transmission Group (RTG) of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

(9) An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.

(10) An ISO should develop mechanisms to coordinate its activities with neighboring control areas.

(11) An ISO should establish an Alternative Dispute Resolution (ADR) process to resolve disputes in the first instance.

An ISO is mainly responsible for maintaining system integrity by acquiring resources necessary to remove transmission violations, balance the system in second-to-second manner and maintain system frequency at an acceptable level to retain stability. According to the FERC Order 888, the ISO is authorized to maintain transmission system reliability in real-time. To comply with the FERC Order 888, each ISO may take one of the following structures:

The first structure is mainly concerned with maintaining the transmission reliability by operating the power market to the extent that the ISO would schedule transfers in a constrained transmission system. An example of this proposal is the Midwest ISO.

The second proposal for an ISO includes a PX that is integral to the ISO's operation. In some proposals such as those of the UK and the PJM interconnection, the PX would function within the same organization and under the control of the ISO; the ISO is responsible for dispatching all generators and would set the price of energy at each hour based on the highest price bid[15] in the market.

In its Order 888, FERC also defined six ancillary services that must be provided by or made available through transmission providers. These ancillary services include:

(1) Scheduling, Control and Dispatch Services

(2) Reactive Supply and Voltage Control

(3) Regulation and Frequency Response Services

(4) Energy Imbalance Service

(5) Operating Reserve, Spinning and Supplemental Reserve Services

(6) Transmission Constraint Mitigation

As Order 888 implies, transmission customers may self-provide these services or buy them through one of the following methods:

(i) Providers of these services advertise their availability via the OASIS or commercial exchanges

(ii) The ISO provides these services in real-time and charges transmission users.

An essential task of the ISO in all restructuring models is the service of mitigating transmission constraints. This management process

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[15] This method has traditionally had a shortcoming in the sense that some suppliers are able to game the market by raising bids on generators that consistently set the market price.

includes billing and accounting procedures for the cost of mitigating constraints and paying those participants who provide mitigation services. Also, the ISO will ensure that proper economic signals are sent to all parties, which in turn, will encourage efficient use and motivate investment in resources capable of alleviating constraints. Transmission users who are looking to schedule transactions crossing constrained paths must either possess capacity rights on these paths, reschedule their transactions, or purchase supply or interruptible load on the load side of constrained lines to mitigate constraints.

In emergency conditions, the system reliability is an absolute responsibility of ISO. In emergency situations, the ISO has the authority to commit and dispatch some or all system resources or components. The ISO has the ability to call for increase or decrease in generation and to curtail loads to maintain system security.

To make these services available, the ISO contracts with service providers so that the services are available under the ISO's request. When a service provider is called by the ISO, the provider is paid extra to cover its operating costs. Capacity resources are contracted seasonally by the ISO and providers send their bids to an auction operated by the ISO. The ISO chooses successful providers based on a least-cost bid basis. When determining the winners, the ISO takes into account factors such as time and locational constraints and the expected use of resources. If the ISO finds that spot market services are less expensive than contracted ones, the ISO experiences its authority by acquiring these services from the energy spot market.

The following example illustrates the role of ISO in providing operating reserves.

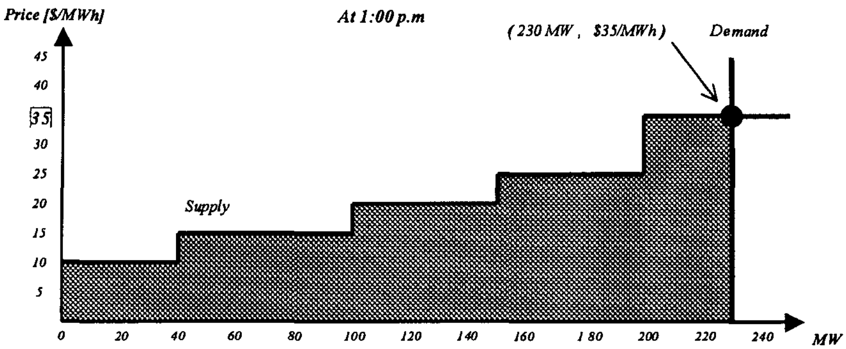
Example 1.2: (Operating Reserves)

Assume that a hydroelectric generator, which has a 30 MW capacity and can be brought up and running in 4 minuets, offers its 30 MW capacity in the operating reserve market. It submits a reserve price offer of \$2.5/MW for each hour of the entire next day, along with an energy offer price of \$42.5/MWh. Also, assume that there are two customers, C_1 and C_2, that can cut back quickly their usage of electricity. C_1 can cut up to 15 MW in 5 minuets, so it decides to submit a bid to the operating reserve market of 15 MW at \$1.5/MW for each hour of the entire next day and a maximum energy bid price of \$55/MWh. C_2 can cut up to 10 MW in 5 minuets, so it decides to submit a bid to the operating reserve market of 10 MW at \$2/MW for each hour of the entire next day and a maximum energy bid price of \$70/MWh.

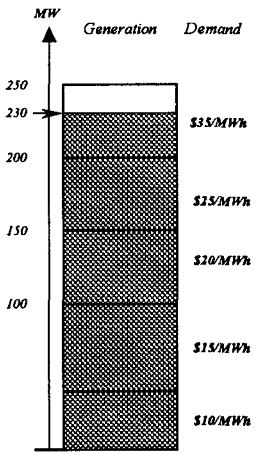
The ISO anticipates that it will need a large operating reserve, say 55 MW, so it accepts the generator's offer and the customers' bids. Assume that the MCP of the operating reserves is \$2.5/MW/h. Each winning participant in the operating reserve market will be paid the MCP to stand by in case of contingency. The generator will be paid \$1800 (or \$2.5/MW/h×30 MW× 24h), C_1 will be paid \$900 (or \$2.5/MW/h× 15MW× 24h), and C_2 will be paid \$600 (or \$2.5/MW/h×10 MW× 24 h).

In the next day, say at 1:00 p.m., let's assume that supply and demand equilibrium is initially established at 230 MW (in the spot market). The spot market price of electricity at this point is \$35/MWh. The net supply curve of all generating units is as shown in Figure 1.3. The supply segment of \$20/MWh is offered by a single generating unit that has a capacity of 50 MW. As shown in Figure 1.3, the unit (supply segment) that is dispatched last (in the spot market) is producing 30 MW of its total capacity of 50 MW, and has available capacity of 20 MW.

Now suppose the generating unit that is producing 50 MW at \$20/MWh tripped out due to severe weather conditions at 1:10 p.m. which disconnected the line joining this generating unit to the system. The supply curve after the unit outage is shown in Figure 1.4. At 1:10 p.m., demand is still 230 MW, and the supply has a shortage of 50 MW. At this point, the ISO has to replace the sudden loss of capacity in the remainder of the hour (from 1:10-2:00 p.m.), before more capacity can be dispatched in the spot market. So the ISO has to reduce the demand if possible or/and provide the required power from operating reserves.

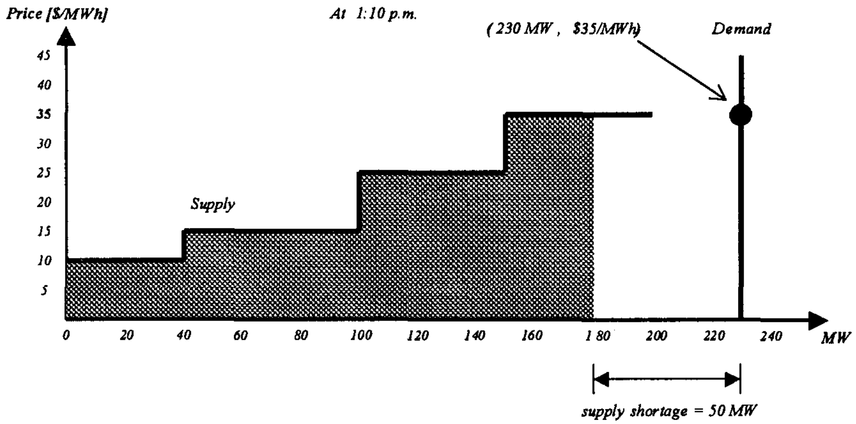


1.3.a Supply and Demand Curves of Initial Situation

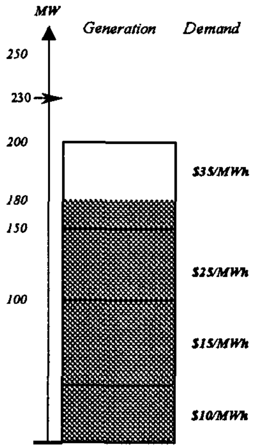


1.3.b Total Production and Production of each Generating Unit of the Initial Situation

Figure 1.3 *Initial Situation*



1.4.a Supply and Demand Curves after the Unit Outage



1.4.b Total Production and Production of each Generating Unit after the Outage

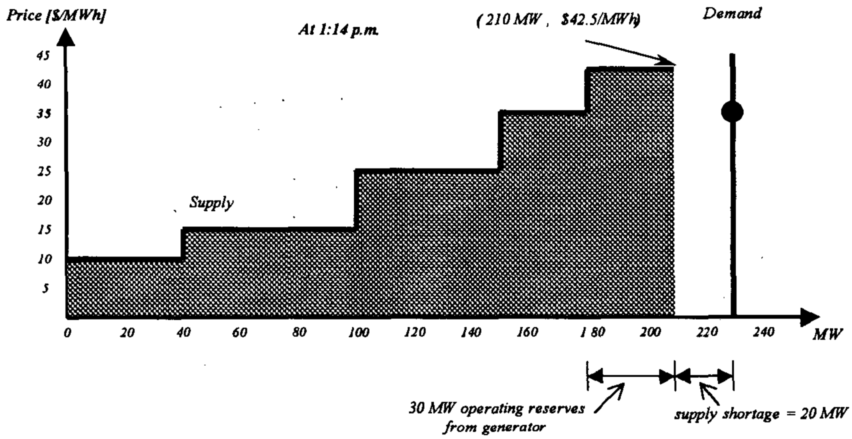
***Figure 1.4** Situation after the Unit Outage*

The ISO dispatches the 30 MW generator (see Figure 1.5), and the generator is paid \$42.5/MWh. To restore the balance, the ISO also dispatches off 15 MW from C_1 and 5 MW from C_2 (See Figure 1.6). The ISO pays \$20/MWh (or \$55/MWh-\$35/MWh) to C_1 and \$35/MWh (or \$70/MWh-\$35/MWh) to C_2 for the electricity that it has dispatched off. The payments to the three participants (generator, C_1 and C_2) continue until replacement energy can be provided from the spot market.

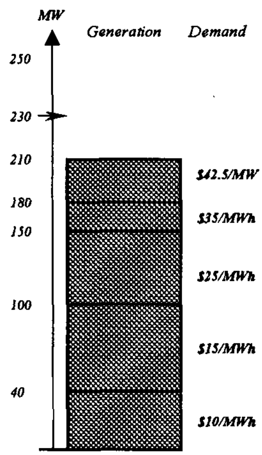
In some models, additional tasks are assigned to the ISO such as metering, bookkeeping, billing and settlement functions. The ISO collects metering data from metered buses, calibrates meters and verifies metered data through tools such as state estimators; parallel metering may be done by other entities in real-time to support the ISO in the process. After all contracts have taken place in real-time, the ISO posts system conditions including injections and withdrawals at each node of the system for each hour. It is the responsibility of the ISO to maintain all metering and settlement data generated within its control area and between control areas. Complying with the FERC Order 889, the ISO is responsible to post data and information flow on the OASIS where the ISO provides metering data and clearing information. Market participants will make benefits from this posted information to trade in the clearing market. At the end of each settlement period, the ISO charges any market entity holding a net negative balance for the period and pays any entity holding a net positive balance.

1.4 POWER EXCHANGE (PX)

Even though short-term and long-term financial energy transactions could be in bilateral forms in the electricity industry where contracted parties agree individually for certain terms such as price, availability and quality of products, industry restructuring proposals have concluded the necessity of creating a new marketplace to trade energy and other services in a competitive manner. This marketplace is termed Power Exchange (PX) or, as sometimes called, spot price pool. This marketplace permits different participants to sell and buy energy and other services in a competitive way based on quantity bids and prices.

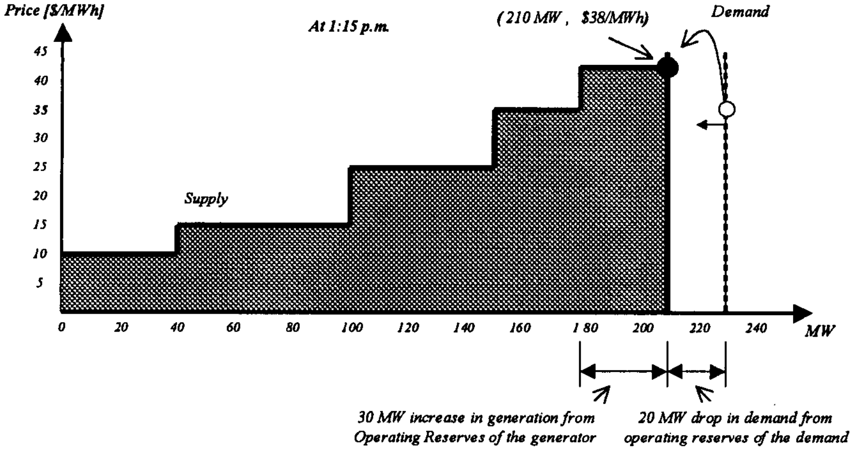


1.5.a Supply and Demand Curves after the ISO dispatches the 30 MW generator

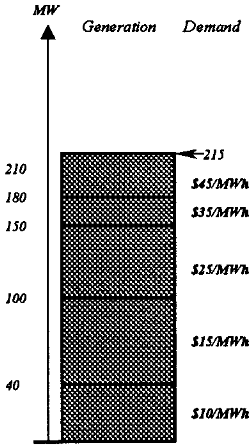


1.5.b Total Production and Production of each Generating Unit after the ISO dispatches the 30 MW generator

Figure 1.5 *Situation after Using Available Operating Reserves*



1.6.a Supply and Demand Curves after the ISO dispatches off the 20 MW



1.6.b Total Production and Production of each Generating Unit after the ISO dispatches off the 20 MW

Figure 1.6 *Situation after Drop of C_1 and C_2 Demand*

Participants include utilities, power marketers,[16] brokers,[17] load aggregators,[18] retailers,[19] large industrial customers and cogenerators.[20]

PX is a new independent, non-government and non-profit entity which accepts schedules for loads and generation resources. It provides a competitive marketplace by running an electronic auction where market participants buy and sell electricity and can do business quickly and easily. Through an electronic auction, PX establishes an MCP for each hour of the following day for trades between buyers (demands) and sellers (supplies). In this marketplace, PX does not deal with small consumers. Add to that, PX manages settlement and credit arrangements for scheduling and balancing of loads and generation resources. As a main objective in its work, PX guarantees an equal and non-discriminatory access and competitive opportunity to all participants. It is claimed that participants entering the PX get more cost-effectiveness by

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[16] Marketer: An agent for generation facilities. It markets power on behalf of the generators, may arrange transmission or ancillary services as needed, considered as an intermediary between the buyer and the seller, and expected to reduce prices for customers. It is claimed that marketers may are able to provide risk management services even for retail customers.

[17] Broker: An agent for other entities in negotiating contracts to purchase and/or buy electric energy and other services without owning any transmission or generation facilities, and at the same time does not take ownership of the energy purchased or sold for its agents.

[18] Load Aggregator: Any marketer, broker, public agency, city, county, or special district, that combines the loads of multiple end-use customers in facilitating the sale and purchase of electric energy, transmission, and other services on behalf of these customers. Load aggregators will be municipal or private entities that organize customers in order to obtain more favorable contracts from retailers or marketers. Load aggregators are specialized in bringing buyers together, may arrange for additional services, and negotiate contract terms with retailers and energy service companies for their clients.

[19] Retailers: An electric service provider that can be aggregators, brokers, and marketers who enters into a direct access transaction with an end-use customer. They compete on the basis of price and services to reach and sell (market) only electricity or electricity and other services (e.g. energy efficiency and/or load management and others).

[20] Cogenerator: An entity that owns a generation unit that produces electricity and another form of useful thermal energy such as heat or steam to be used for industrial, commercial, heating or cooling purposes, and cogeneration is the simultaneous production of both usable heat or steam and electricity from a common fuel source.

removing the complexities of arranging generation, transmission and energy purchases.

In general, the PX includes a day-ahead market and an hour-ahead market. Here we discuss these markets in general, and later we elaborate on them when we discuss some market models in the United States.

1.4.1 Market Clearing Price (MCP).

PX accepts supply and demand bids to determine a MCP for each of the 24 periods in the trading day. Computers aggregate all valid (approved) supply bids and demand bids into an energy supply curve and an energy demand curve. MCP is determined at the intersection of the two curves and all trades are executed at the MCP, in other words, the MCP is the balance price at the market equilibrium for the aggregated supply and demand graphs. Figure 1.7 shows the determination of MCPs for certain hours when demand (D_i) varies. Generators are encouraged to bid according to their operating costs because bidding lower would lead to financial losses if MCP is lower than the operating cost and bidding higher could cause units to run less frequently or not run at all.

1.5 MARKET OPERATIONS

1.5.1 Day-Ahead and Hour-Ahead Markets.

In the day-ahead market and for each hour of the 24-hour scheduling day, sellers bid a schedule of supply at various prices, buyers bid a schedule of demand at various prices, and MCP is determined for each hour. Then, sellers specify the resources for the sold power, and buyers specify the delivery points for the purchased power. PX schedules supply and demand with the ISO for delivery. Supply and demand are adjusted to account for congestion and ancillary services and then PX finalizes the schedules.

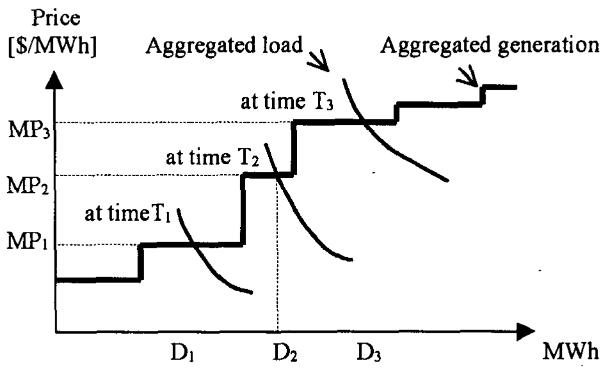

Figure 1.7 Process of Determining MCP in PoolCo

The hour-ahead market is similar to day-ahead, except trades are for 1 hour, and the available transfer capability (ATC)[21] is reduced to

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[21] ***Source***: The NERC Engineering Committee (EC) and Operating Committee (OC) Glossary of Terms Task Force (GOTTF), http://www.nerc.com/glossary/glossary-body.html:

(a) Available Transfer Capability (ATC): A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

(b) Total Transfer Capability (TTC): The amount of electric power that can be transferred over the interconnected transmission network in a reliable manner based on certain conditions.

(c) Transmission Reliability Margin (TRM): The amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. See Available Transfer Capability.

(d) Capacity Benefit Margin (CBM): The amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements.

include day-ahead trades, and bids are not iterative in this market. Once the MCP is determined in the PX, market participants submit additional data to the PX. The data would include individual schedules by generating unit, take out point for demand, adjustment bids for congestion management and ancillary service bids. After this stage, the ISO and the PX know the injection points of individual generating units to the transmission system. A schedule may include imports and/or exports. To account for transmission losses[22], generator's schedules are adjusted where real losses are only known after all metered data are processed.

1.5.2 Elastic and Inelastic Markets.

An *inelastic*[23] *market* does not provide sufficient signals or incentives to a consumer to adjust its demand in response to the price, i.e., the consumer does not have any motivation to adjust its demand for electrical energy to adapt to market conditions. In a market that has a demand, MCP for energy is determined by the price structure of supply offers. The concept of inelastic demand is directly related to the concept of firm load, which formed the basis of the electricity industry for many decades before the introduction of open access and energy markets. Customers use the concept of *elastic demand* when they are exposed to and aware of the price of energy and arrange their affairs in such a fashion as to reduce their demand as the price of the next available offer exceeds a certain level.

The following example illustrates how the elasticity of demand in a market has some serious impacts on the energy market and the power system itself, and demonstrates how the pool price cap[24] (price ceiling) in energy markets with inelastic and elastic demand may play important role. The example also illustrates the need for capacity reserves.

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[22] In the California model, losses are equal to generated power in MW multiplied by one minus the Generator Meter Multipliers (GMM). GMMs are published for each generator location and scheduling point by the ISO prior to bidding in the day-ahead market.

[23] Measure of the price sensitivity to the demand.

[24] Price cap is a ceiling or a maximum trading price for energy which is imposed on market participants (by the pool or by the ISO) when certain failures in the supply – demand balance are encountered.

Example 1.3: (Impact of elastic and inelastic demands)

Tables 1.1 and 1.2 give the aggregated demand and aggregated supply (for two cases) for an electrical system at a given instant in time. Figure 1.8 shows the amount of electrical load and two different energy supply offers made into the market. As we see from the figure, supply curves show elasticity, i.e., there are different price offers for energy for each of the supply curves, while the demand (vertical line in the figure) remains inelastic, i.e. demand for energy is the same, regardless of the price of energy (or the inelastic demand shows no price sensitivity). That means the demand in this case is a price taker. In Figure 1.8, MCP is $35/MWh for supply curve 1 and $27.5/MWh for supply curve 2. This implies that price is determined by the structure of supply offers.

***Table 1.1** Aggregated Demand*

Price [$/MWh]	*Aggregated Demand [MW]*
0.00	*150.0*
45.0	*150.0*

***Table 1.2** Aggregated Supply*

Case 1		*Case 2*	
Price [$/MWh]	*Supply in [MW]*	*Price [$/MWh]*	*Supply in [MW]*
0.000	*0.0*	*0.000*	*0.0*
9.99	*0.0*	*7.49*	*0.0*
10.00	*20.0*	*7.50*	*30.0*
14.99	*20.0*	*12.49*	*30.0*
15.00	*40.0*	*12.50*	*50.0*
19.99	*40.0*	*14.99*	*50.0*
20.00	*90.0*	*15.00*	*80.0*
24.99	*95.0*	*17.49*	*80.0*
25.00	*95.0*	*17.50*	*100.0*
29.99	*115.0*	*22.49*	*100.0*
30.00	*115.0*	*22.50*	*110.0*
34.99	*130.0*	*27.49*	*110.0*
35.00	*130.0*	*27.50*	*125.0*
39.99	*130.0*	*32.49*	*125.0*
40.00	*140.0*	*32.50*	*140.0*
		40.00	*140.0*

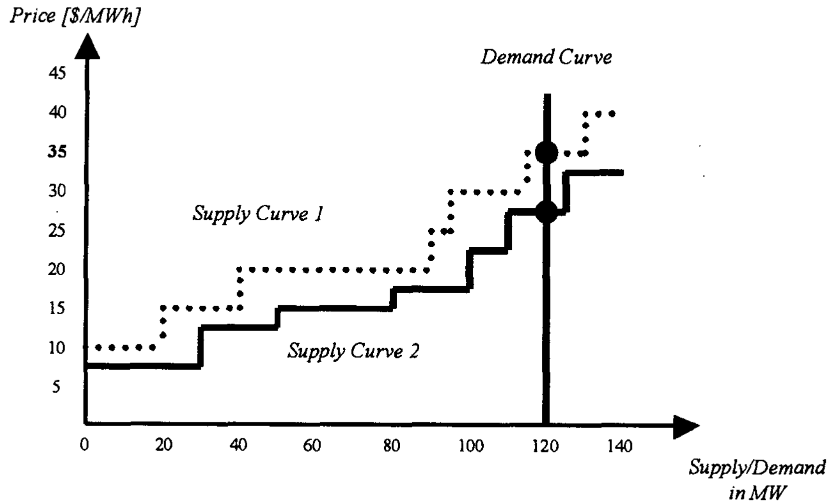

Figure 1.8 Aggregated Curves of Elastic Supply and Inelastic Demand

Now, let's look at another situation, where demand is price sensitive. Table 1.3 gives the total demand at certain hour. A graphical representation of demand and supply curves is shown in Figure 1.9. The supply curve is the same as that of case 1 in Table 1.2 and Figure 1.8. In Figure 1.9, the market displays elastic demand, where the load responds directly to the price of supply offers, i.e., the demand varies with the price of offer. The intersection of demand and supply curves in Figure 1.9 indicates that the current operating point of the market is different from that of Figure 1.8. This operating point defines the current MCP as well as the current level of electrical load.

Table 1.3 *Elastic Demand*

Price [$/MWh]	*Demand in [MW]*
0.000	*120.0*
14.99	*120.0*
15.00	*110.0*
19.99	*110.0*
20.00	*105.0*
32.49	*105.0*
32.50	*90.0*
39.99	*90.0*
40.00	*65.0*

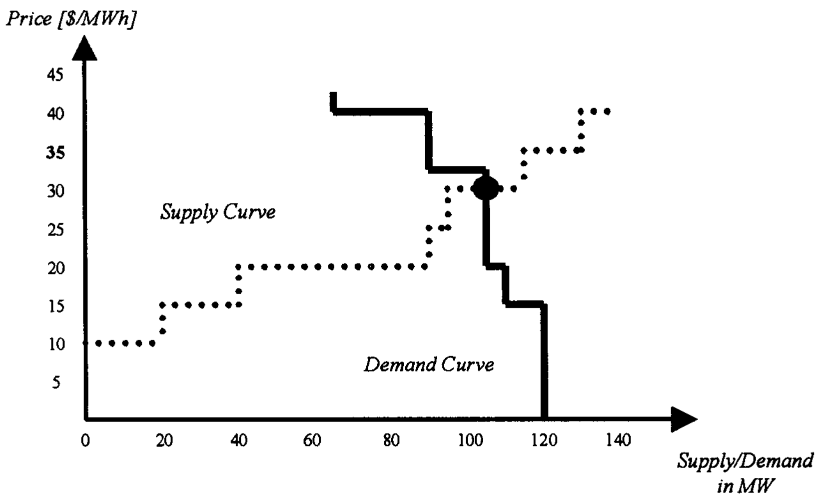

Figure 1.9 *Elastic Supply and Elastic Demand Aggregated Curves*

A market that has an inelastic demand operates normally as long as the supply offers exceed the current demand. When the available offers exceed the demand, an intersection exists between demand and supply curves and MCP can be determined. However, if an imbalance occurs between supply and demand, problems may arise. An imbalance can be due to unanticipated increase in demand, which could be due to weather, and planned or forced outage(s) in supply or/and transmission facilities. Figure 1.10 gives an example of a situation where an imbalance exists. Assume that the inelastic demand increases from 120 to 145 MW due to colder than expected weather. The situation illustrated in Figure 1.10 shows no intersection between supply and demand curves. Such a situation may result in a price spark (a sudden change). In this case, a price cap (ceiling) can be imposed by the pool or the ISO to limit the increase in energy prices. The price tends to increase to high levels because unusual measures need to be taken to restore the balance between supply and demand. The balance is usually restored by either shedding loads which sets MCP at the price cap or, alternatively, by obtaining additional supply sources which could be offered at this maximum price or close to it.

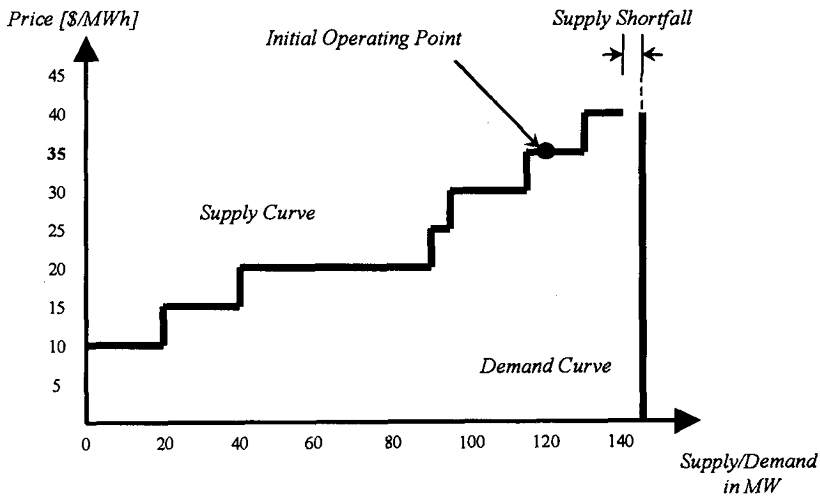

Figure 1.10 Inelastic Demand with a Supply Shortfall

The price cap is entirely an arbitrary value, which can be set as high or as low as is agreed upon. The price cap could have deep effects on MCP without reflecting the true market situation in terms of the availability or unavailability of supply or the willingness of the market to pay a high price for energy.

To the contrary, the problem of restoring the balance between supply and demand is much easier when the demand is elastic. To show that, let's look at another situation. Figure 1.11 shows two supply curves: one is the initial supply curve (case 1), and the other is for the supply with a forced outage of a generation unit that was providing up to 30 MW at \$20/MWh. Assume that the demand is as shown in Figure 1.11. The result of the outage is that the price of energy would increase. The price is \$30/MWh for pre-outage case (see $\mathbf{P_1}$) and \$35/MWh for the post-outage case (see $\mathbf{P_2}$). Because the demand is elastic, the increase in price would cause the demand to decrease and a new balance point is established that would reflect the customers' need for energy and their desire to manage energy costs. Figure 1.11 also indicates what a post-outage MCP will be if the demand is inelastic at the pre-outage level (see point $\mathbf{P_3}$, at an inelastic demand of 105 MW). We note that the elasticity in demand would slow down the rise in price, and the price cap could be unneeded when the market demonstrates demand elasticity.

We notice from this example that elasticity in demand is beneficial in keeping the MCP lower. Elasticity could avoid imposing price caps which would not represent any economic meaning or incentives to market participants. Elasticity also has an impact on the amount of reserves that a power system would require maintaining system's reliability, by reducing or canceling the need for capacity reserves.

The issue of transmission losses is an important issue as it affects the production of dispatched generating units and the economic operation of the system. The following example illustrates the effect of losses.

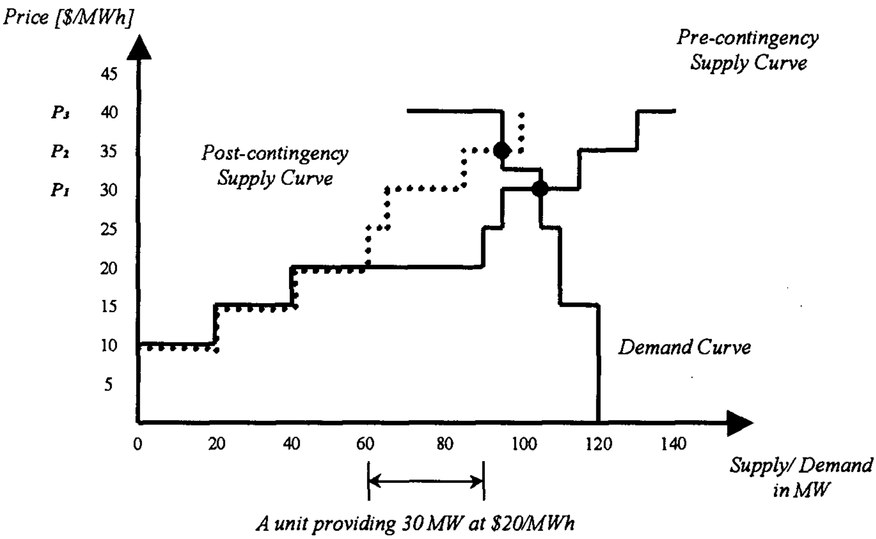

Figure 1.11 Elastic Demand with a Forced Outage of a Generation Unit

Example 1.4: (Impact of losses)

For the system shown in Figure 1.12, let's assume that $P_{loss} = b_1 \; P_1^2$, C_1=10, C_2=12.5, D=40, and b_1=0.005, where b_1 is a loss coefficient. From this figure we have:

$$P_1 = P_{loss} + P_2 = b_1 P_1^2 + P_2 \quad \text{(a)}$$

$$P_{G_1} = P_1 \quad \text{(b)}$$

$$P_{G_2} = D - P_2 = D - (P_1 - b_1 P_1^2) = D - (P_{G_1} - b_1 P_{G_1}^2) \quad \text{(c)}$$

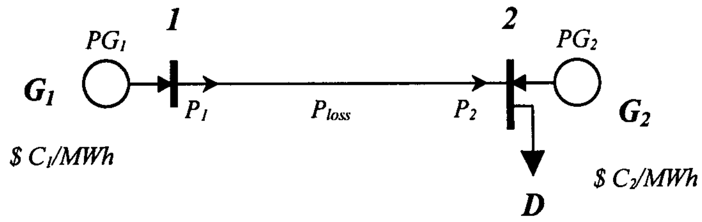

Figure 1.12 *System of Example 1.4*

(1) Let's study three alternatives to serve the load:

(i) Since the generator at bus 1 is cheaper than that at bus 2, one may think it would be better (more economical) if all energy is provided from generator 1 (only G_1 is dispatched). For this option G_1 should generate $P_{loss} + D$, i.e., $P_{G1} = 0.005\,P_{G_1}^2 + 40$. Solving this equation yields, $P_{G1} = 55.278MW$ and P_{loss}=15.278 MW. The cost to serve the load is \$552.278/h (or 55.278 ×10).

(ii) Now suppose that the load is served by G_2 (only G_2 is dispatched). In this case, there is no transmission loss, because D is on the same bus as G_2. G_2 will produce all the demand, i.e., 40 MW for a total cost of \$500/h. (or 12.5×40). Note that even though this generator seems more expensive than G_1, the cost of this dispatch is lower than that of part (i) because of transmission losses. When transmission losses are ignored, G_1 will be cheaper to serve the load.

(iii) Let's see what is the optimal response of both generators to serve the load (both G_1 and G_2 are dispatched). Let T refer to the total cost of serving the load. T is given by:

$$T = C_1\ P_{G_1} + C_2\ P_{G_2} = C_1\ P_{G_1} + C_2 [D - (P_{G_1} - b_1 P_{G_1}^2)] \quad \text{(d)}$$

$$\frac{dT}{dP_{G_1}} = C_1 + C_2[\,0 - (1 - 2b_1 P_{G1})] = C_1 - C_2(1 - 2b_1 P_{G1}) \quad \text{(e)}$$

for $\frac{dT}{dP_{G_1}} = 0$, we have

$P_{G1} = \frac{1-(C_1/C_2)}{2b_1}$, and substituting this into (c), we get

$$P_{G_2} = D - \left(\frac{1-(C_1/C_2)}{2b_1} - b_1\left[\frac{1-(C_1/C_2)}{2b_1}\right]^2\right)$$

When values of C_1, C_2 and b_1 are substituted, we get:

$$P_{G1} = \frac{1-(10/12.5)}{2(0.005)} = 20MW\,,$$

$$P_{G_2} = 40 - (20 - 0.005\ (20)^2) = 22\,MW$$

$$P_{loss} = 0.005\ (20)^2 = 2MW$$

The cost to serve the load under the optimal dispatch is:

$$10\times20+12.5\times22 = \$475/\text{h}.$$

Note that the cost in this optimal dispatch is less than any of the two costs in parts (i) and (ii).

(2) Loss Factor: Loss Factor at bus i (LF_i) points out that if 1 kW is injected at bus j, (1- LF_i) will arrive to bus i. To show the implication of loss factors, let's consider the following two situations:

Case 1: Bus 2 is the reference bus

When P_1=20 MW is injected at bus 1, P_{loss} = 2 MW, and 18 MW arrives at bus 2. When P_1=20.001 MW is injected at bus 1, P_{loss} = 2.0002, and 18.0008 MW arrives at bus 2. The difference due to a 1 kW change is 18.0008-18 = 0.0008 MW or 0.8 kW. That means 0.8 kW (80 % of the 1 kW) arrives to the load bus and 0.2 kW (20 % of the 1 kW) is dissipated as loss when an extra 1 kW is injected at bus 1. Here, the loss factor at bus 1 (LF_1) equals 20%. On the other hand, if 1 kW is injected at the reference bus, the loss is 0, and the loss factor at the reference bus (LF_2) is 0%. The loss price at bus 1 is equal to $LF_1\times$ (price at reference bus), which is $[($LF_1\times C_2$]/MWh or $[$0.2C_2$]/MWh and the loss price at bus 2 (the reference bus) is equal to $LF_2\times$ (price at reference bus), which is $0/MWh. See Figure 1.13.a.

Case 2: Bus 1 is the reference bus

When P_2=22 MW is injected at bus 2, P_{loss} = 2 MW, and P_1 is 20 MW. When P_2=22.001 MW is injected at bus 2, P_{loss} = 0.00125, and P_1 is 19.99875 MW which is calculated as follows:

$$P_{G_2} = D-(P_{G_1} - b_1 P_{G_1}^2)$$

$$22.001 = 40-(P_{G_1} - b_1 P_{G_1}^2)$$

$$P_{G_1} = 19.99875MW$$

The difference in P_1 due to a 1 kW change in P_2 is 19.99875-20 = - 0.00125 MW or -1.25 kW. That means when 1 kW is injected at bus 2, the power at bus 1 decrease by 1.25 kW, i.e., an injection of an extra 1 kW at bus 2 reduces the losses by 0.25 kW (or 25% of the 1 kW). Or we can look at this situation as: injecting 1 kW at bus 2 gives 1.25 kW at bus 1. We say that the loss factor at bus 2 (LF_2) equals -25%. In this case, the loss factor at the reference bus (LF_1) is 0%. The loss price at bus 1 (the reference bus) is equal to $LF_1\times$ (price at reference bus), which is $0/MWh, and the loss price at bus 2 is equal to $LF_2\times$ (price at reference bus), which is $[$LF_2\times C_1$]/MWh or $-$0.25C_1$/MWh. See Figure 1.13.b.

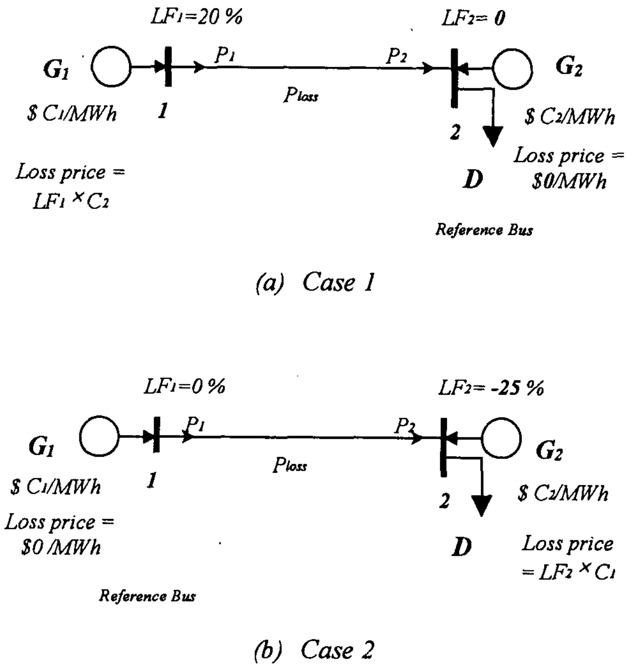

Figure 1.13 *Loss Factors and Loss Prices*

1.6 MARKET POWER

One of the main anti-competitive practices or difficulties that may prevent competition in the electric power industry, especially in generation, is market power. When an owner of a generation facility in a restructured industry is able to exert significant influences (monopoly) on pricing or availability of electricity, we say that market power exists, and if so it prevents both competition and customer choice. Market power may be defined as *owning the ability by a seller, or a group of sellers, to drive price over a competitive level, control the total output or exclude competitors from a relevant market for a significant period of time*. Other than price, any entity that exercises market power would reduce competition in power production, service quality and technological innovation. The net result of practicing market power is a transfer of wealth from buyers to sellers or a misallocation of resources.

Market power is exercised either intentionally or accidentally. For example in the generation sector, market power can be exercised by having an excessive amount of generation in the relevant market (intentionally), by transmission constraints that could limit the transfer capability in a certain area (accidentally), or by running certain generating units during certain periods of time for purposes of maintaining reliability while other units could have been less expensive (accidentally). In the constrained transmission case, some units are restricted to provide power while dominant providers can drive prices up by determining which units to run and which units to keep back from the market. Another example is the case when hourly metering is unavailable for customers, where customers could reduce their consumption as prices go up such as in peak periods. In this case, generating unit owners drive market prices up for energy and capacity to their own benefit. In the transmission sector, transmission owners could exercise market power by providing transmission information to affiliated generating companies and withholding it from other competitors.

There are two types of market power:

1- Vertical Market Power: It arises from a single-firm's or affiliate's ownership of two or more steps in a production and market delivery process where one of the steps provides the firm with a control of a bottleneck in the process. The bottleneck facility is a point on the system, such as a transmission line, through which electricity must pass to get to its intended buyers. A control of a bottleneck process enables the firm to give preference to itself or its affiliate over competitive firms. This concept is applicable to electricity restructuring in the United States where most utilities are vertically integrated in the sense that they own or control generation, transmission, and distribution facilities to deliver electricity to end-user customers in their service territories. Possible vertical market power misapplication arises from the ability of a firm to abuse its control of transmission and distribution facilities, to which, all retail providers must have access, to the advantage of its own generation and retail sales of electricity. A successful development of a well-planned and fully functional ISO may resolve vertical market power problems.

2- Horizontal Market Power: It is the ability of a dominant firm or group of firms to control production to restrict output and thereby raise prices. It arises from a firm's local control or ownership concentration of a single process step in productive assets within a defined market area. If such concentration is sufficient with respect to certain other market conditions, the firm can influence the supply-demand equilibrium, and hence prices, simply by withholding production. This type of market power can not be resolved by the ISO.

Concentration in a market measures the market dominance (degree of monopoly experienced by a firm in a competitive market) using market share data, i.e., how many firms exist in the market, and what are their relative sizes determine the market dominance.

Example 1.5: (Measuring Market Power)

Herfindahl-Hirschman Index (HHI) of market power is a measure of concentration that also reflects the number of participants (or firms) and the inequality of their market shares. HHI is a weighted sum of market shares of all participants in the market. It is defined as the sum of the squares of market shares of all participants. It is given by the following equation:

$$HHI = \sum_{i=1}^{N} S_i^2$$

where N is number of participants and S_i is i^{th} participant's market share in per unit or in %. S_i is calculated by dividing the contribution of the i^{th} participant by the total contribution of all existing participants. The market share is either expressed in per unit (in this case the maximum value of HHI is 1.0) or in percent (in this case the maximum value of HHI is 10,000). For example, a market with just one participant would have an HHI of 10,000 in percent basis and 1.0 in per unit basis. As another example, a market with two participants of equal size (Y) would have an HHI of 5,000 in percent basis and 0.5 in per unit basis. This value is calculated as:

In percent basis:

$$HHI = (\frac{Y}{Y+Y} \times 100)^2 + (\frac{Y}{Y+Y} \times 100)^2 = (50)^2 + (50)^2 = 500$$

In per unit basis:

$$HHI = (\frac{Y}{Y+Y})^2 + (\frac{Y}{Y+Y})^2 = (0.5)^2 + (0.5)^2 = 0.5$$

Table 1.4 gives a case for a power market which has 10 power generation companies (participants). Table 1.5 gives another case, where generation capacities of participants in case 1 are redistributed. We note that HHI values of both cases are different. Since HHI value in case 2 is less than that of case 1, case 2 means less monopoly in the market when the maximum capacity is the only consideration.

Table 1.4 *Case 1 of a Power Market with 10 Power Generation Participants*

Participant No.	Participant Name	Generation Capacity in MW	Market Share in Per unit	Market Share in %	HHI (per unit)	HHI (%)
1	$GenCo_1$	14000	0.280	28.000	0.078400	784.00
2	$GenCo_2$	9700	0.194	19.400	0.037636	376.36
3	$GenCo_3$	8000	0.160	16.000	0.025600	256.00
4	$GenCo_4$	4300	0.086	8.600	0.007396	73.96
5	$GenCo_5$	3500	0.070	7.000	0.004900	49.00
6	PowerCo	3200	0.064	6.400	0.004096	40.96
7	IPP_1	2500	0.050	5.000	0.002500	25.00
8	IPP_2	2000	0.040	4.000	0.001600	16.00
9	IPP_3	1800	0.036	3.600	0.001296	12.96
10	IPP_4	1000	0.020	2.000	0.000400	4.00
	Total	50,000	1.000	100.000	0.163824	1638.24

Table 1.5 Case 2 of a Power Market with 10 Power Generation Participants

Participant No.	Participant Name	Generation Capacity in MW	Market Share in Per unit	Market Share in %	HHI (per unit)	HHI (%)
1	GenCo1	8600	0.1720	17.200	0.029584	295.84
2	GenCo2	8000	0.1600	16.000	0.025600	256.00
3	GenCo3	8000	0.1600	16.000	0.025600	256.00
4	GenCo4	6300	0.1260	12.600	0.015876	158.76
5	GenCo5	4800	0.0960	9.600	0.009216	92.16
6	PowerCo	5500	0.1100	11.000	0.012100	121.00
7	IPP1	3500	0.0700	7.000	0.004900	49.00
8	IPP2	2500	0.0500	5.000	0.002500	25.00
9	IPP3	1800	0.0360	3.600	0.001296	12.96
10	IPP4	1000	0.0200	2.000	0.000400	4.00
	Total	50,000	1.0000	100.000	0.127072	270.72

Example 1.6: (How is Market Power Exercised?)

(A) Exercising Market Power when a Power Supply has a Large Market Share

Figure 1.14 shows a 3-bus system with three generating companies, one at each bus. The three generating companies are $GenCo_1$ with a maximum capacity of 120 MW, $GenCo_2$ with a maximum capacity of 250 MW, and $GenCo_3$ with a maximum capacity of 630 MW.

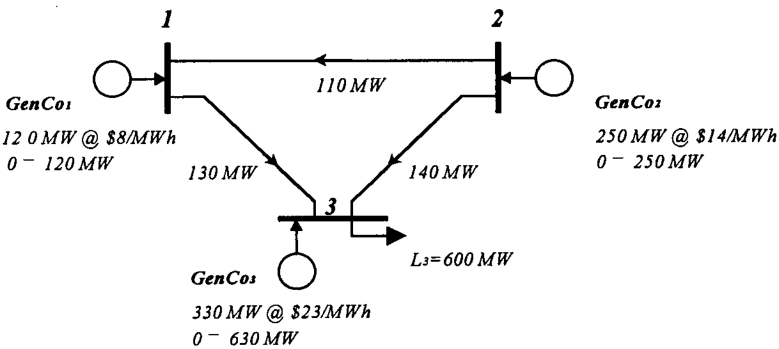

Figure 1.14 Exercising Market Power when a Power Supply has Large Market Share

The HHI for this situation is

$$HHI = \sum_{1}^{3} S_i^2 = (\frac{120}{1000})^2 + (\frac{250}{1000})^2 + (\frac{630}{1000})^2$$

$$= 0.0144 + 0.0625 + 0.3969 = 0.4738 \text{ (in per unit basis)}$$

or,

$$HHI = \sum_{1}^{3} S_i^2 = (\frac{120}{1000} \times 100)^2 + (\frac{250}{1000} \times 100)^2 + (\frac{630}{1000} \times 100)^2$$

$$= 144 + 625 + 3969 = 4738 \text{ (in percent basis)}$$

Note that $GenCo_3$ owns the maximum share of the total generation capacity (=630MW/1000MW=63%). By ignoring the limitation of transmission lines, $GenCo_3$ monopolizes the market, because L_3 needs much more than the total capacity of the other cheaper resources ($GenCo_1$ can generate up to 120 MW at \$8/MWh and $GenCo_2$ can generate up to 250 MW at \$14/MWh). It means when $GenCo_3$ wants to exercise its market power, it can ask for any price for its electric power production to fulfill L_3's need.

(B) Exercising Market Power when Transmission System is Congested

Figure 1.15 shows a 3-bus system with three generating companies, one at each bus. The three generating companies are $GenCo_1$ with a maximum capacity of 250 MW, $GenCo_2$ with a maximum capacity of 350 MW, and $GenCo_3$ with a maximum capacity of 400 MW. The HHI for this situation is

$$HHI = \sum_{1}^{3} S_i^2$$

$$= (\frac{250}{1000})^2 + (\frac{350}{1000})^2 + (\frac{400}{1000})^2$$

$$= 0.0625 + 0.1225 + 0.1600 = 0.345 \text{ (in per unit basis)}$$

or,

$$HHI = \sum_{1}^{3} S_i^2 = (\tfrac{250}{1000} \times 100)^2 + (\tfrac{350}{1000} \times 100)^2 + (\tfrac{400}{1000} \times 100)^2$$
$$= 625 + 1225 + 1600 = 3450 \ (\textit{in percent basis})$$

In this case $GenCo_1$, $GenCo_2$ and $GenCo_3$ own, respectively, 25%, 35%, and 40% of the total generation capacity. Transmission line limits are imposed on the system in this case, as shown in Figure 1.15. Even though the cheapest resources ($GenCo_1$ and $GenCo_2$) have a total capacity of 600 MW, which is adequate to cover the 600 MW required by L_3, the limitations of the transmission lines do not permit L_3 to use $GenCo_1$ and $GenCo_2$. This situation may lead to exercising market power by $GenCo_3$ by imposing a higher than competitive price.

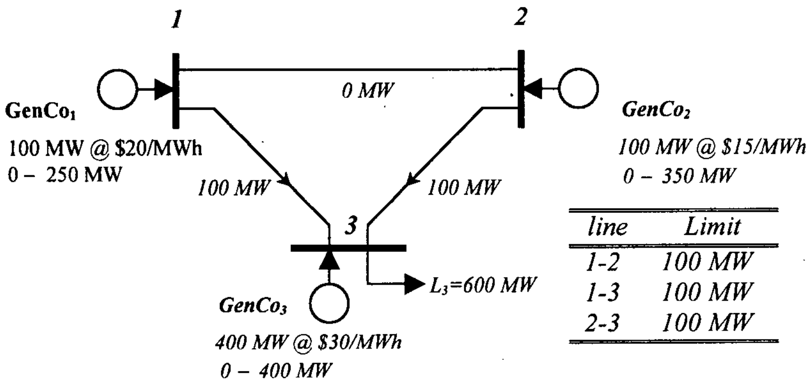

Figure 1.15 *Exercising Market Power when Transmission is Congested*

1.7 STRANDED COSTS

A major and a debatable issue associated with the electric utility restructuring is the issue of stranded costs; how to be determined, how to be recovered and who pays for recovery. Stranded cost is a terminology created under restructuring process. Multiplicity of definitions and interpretations of stranded costs confused people working on restructuring, but in general this term refers to the difference between costs that are expected to be recovered under the rate regulation and those recoverable in a competitive market.

In a vertically integrated monopoly, utilities are used to cover their costs of doing business in rates charged to customers. Costs include operating costs and invested capital costs, where utilities cover these costs and considerable returns on their capitals through rates imposed on customers. But when restructuring is proposed to open market-based competition, and due to the fact that market-based prices are uncertain and sometimes less than vertically integrated rates, financial obligations of vertically integrated utilities may become unrecoverable in a competitive market and the level of revenue earned by a utility may no longer be adequate to cover its costs. If market prices are lower than vertically integrated rates, as many expect, utilities could be faced with investments that are unrecoverable in the competitive market.

Stranded costs still need a more clear definition (what costs should be strandable? what costs are unrecoverable? and to what extent (totally or partially) should be recovered?) and quantification. On the other hand, the duration of recovery or who will pay for recovery is not clear yet and varies from model to model in the United States. In this regard, the big question is whether different participants should pay for uneconomical previous investments.

1.8 TRANSMISSION PRICING

FERC recognized that transmission grid is the key issue to competition, and issued guidelines to price the transmission. The guidelines are summarized such that the transmission pricing would:

(i) meet traditional revenue requirements of transmission owners

(ii) reflect comparability: i.e. a transmission owner would charge itself on the same basis that it would charge others for the same service

(iii) promote economic efficiency

(iv) promote fairness

(v) be practical

Even though transmission costs are small as compared to power production expenses and represent a small percent of major investor-owned utilities' operating expenses, a transmission system is the most important key to competition because it would provide price signals that can create efficiencies in the power generation market. The true price signals are used as criteria for adding transmission capacity, generation capacity, or future loads. Adding transmission capacity to relieve transmission constraints could allow high-cost generation to be replaced by less expensive generation, which would result in additional savings to consumers.

1.8.1 Contract Path Method. It has been used between transacted parties to price transmission where power flows are assumed to flow over a predefined path(s). Despite its ease, this technique was claimed to be a bad implementation of true transmission pricing as power flows would very seldom correspond to predefined paths. Physically, electrons could flow in a network over parallel paths[25] (loop flows) owned by several utilities that may not be on the contract path. As a result, transmission owners may not be compensated for the actual use of their facilities. Added to parallel flows, the *pancaking*[26] of transmission rates is another shortcoming of this method.

As a solution to the pancaking effect, zonal pricing schemes have been proposed by most ISOs. Using a zonal scheme, the ISO-controlled

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[25] The parallel path flows (or loop flows) refer to the unscheduled transmission flows that occur on adjoining transmission systems when power is transferred in an interconnected electrical system.

[26] When a contract path crosses a boundary defining transmission ownership, additional transmission charges would be added to a transaction, which in turn might increase the price of the transaction.

transmission system is divided into zones and a transmission user would pay rates based on energy prices in zones where power is injected or withdrawn. When the zonal approach is used, rates are calculated regardless of paths between the two zones or how many other zones are crossed.

Several ISOs are using a MW-Mile approach to price transmission. The MW-Mile rate is basically based on the distance between transacted parties (from the generating source to the load) and flow in each line resulted from the transaction. This approach takes into account parallel power flows and eliminates the previous problem that transmission owners were not compensated for using their facilities. This approach does not give credit for counter-flows on transmission lines. The method is complicated because every change in transmission lines or transmission equipment requires a recalculation of flows and charges in all lines.

Example 1.7 (Concept of Contract Path)

Figure 1.16 illustrates a 4-bus system with a load of 4,500 MW at bus 4, and a generator at each of buses 1,2, and 3. The system has two 2-line corridors: one between buses 1 and 2, and the other between buses 1 and 3. Also it has two 3-line corridors: one between buses 3 and 4, and the other between buses 2 and 4. Each single transmission line has a rating and impedance as shown in Table 1.6 (assume that resistance = 0). Assume that generators have long term contracts to supply $\mathbf{L_4}$ as given in Table 1.7, where these generators obtained transmission services along the contract paths given in Table 1.7 and shown in Figure 1.17.

Actual flows due to each generator contract and to all contracts are shown in Figure 1.18. We note that actual flows do not follow the contract paths. Even though some of the lines were originally not included in the contract paths (such as the double line 1-3), they carry a non-zero flow. Moreover, some lines carry more than the contractual flows, while others carry less than the contractual values. The flow along the non-contacted path is called loop flow. It is defined as the difference between scheduled contract flow and actual flow on a transmission line.

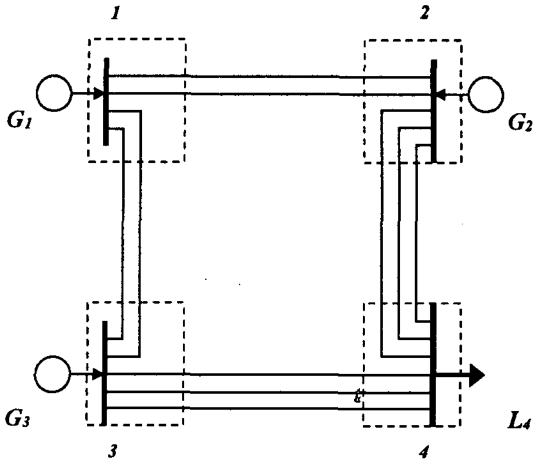


***Figure 1.16** A 4-bus System Used to Illustrate the Concept of Contract Path*

***Table 1.6** Line Data*

Corridor	*Line*	*Reactance*	*Rating (MW)*
1-2	*1-2*	*1.0*	*1,500*
	1-2	*1.0*	*1,500*
1-3	*1-3*	*2.0*	*375*
	1-3	*2.0*	*375*
2-4	*2-4*	*1.5*	*1,500*
	2-4	*1.5*	*1,500*
	2.4	*1.5*	*1,500*
3-4	*3-4*	*1.5*	*1,500*
	3-4	*1.5*	*1,500*
	3-4	*1.5*	*1,500*

***Table 1.7** Contract Data*

Contract Parties	*Value in MW*	*Contract Path*	*Transmission Service Obtained*
$G_1 \rightarrow L_4$	*1,500*	$1 \rightarrow 2 \rightarrow 4$	*1,500*
$G_2 \rightarrow L_4$	*1,500*	$2 \rightarrow 4$	*1,500*
$G_3 \rightarrow L_4$	*1,500*	$3 \rightarrow 4$	*1,500*

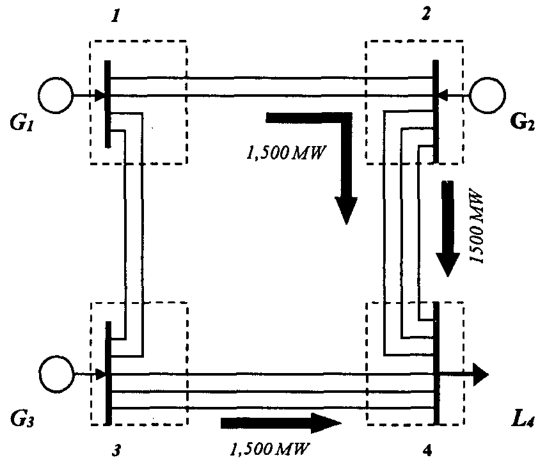
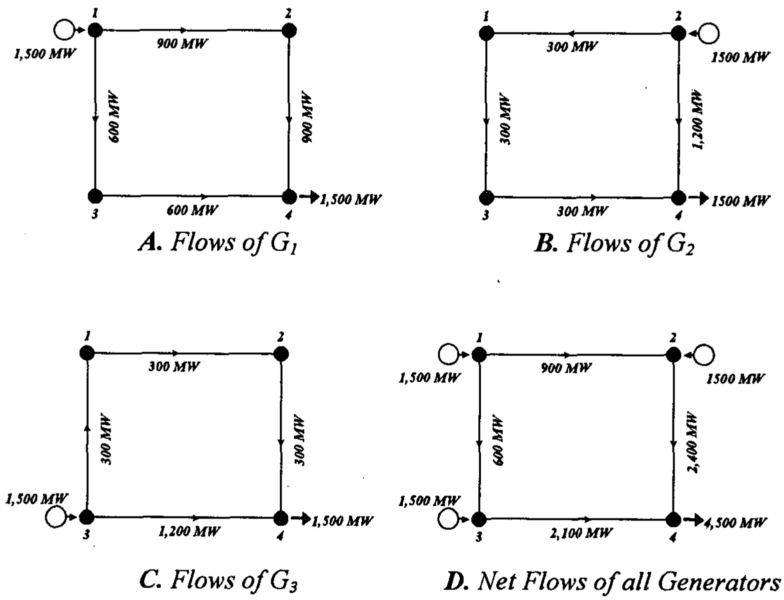


Figure 1.17 Transmission Services



A. Flows of G_1

B. Flows of G_2

C. Flows of G_3

D. Net Flows of all Generators

Figure 1.18 Corridor Flows

1.8.2 The MW-Mile Method. We illustrate this method by an example.

Example 1.8: (MW-Mile Charges)

Figure 1.19 illustrates a 3-bus system and a situation of five transactions between generating units and loads. Table 1.8 shows the system data. Let variable $L_{n,j}$ refer to a load that exists at bus n and supplied by generator j. Assume that a load of 150 MW exists at bus 2 which is supplied by generator 1 ($L_{2,1}$=60 MW) and generator 3 ($L_{2,3}$=90 MW). Also another load of 600 MW exists at bus 3, which is supplied by the three generators, 240 from generator 1, 200 MW from Generator 2, and 160 MW from generator 3 (or $L_{3,1}$=240 MW, $L_{3,2}$=200 MW, $L_{3,3}$=160 MW).

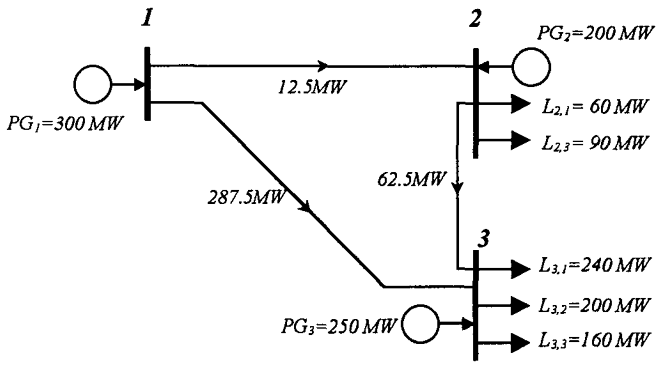


Figure 1.19 3-bus System with Five Transactions

Table 1.8 System Data of the Example

Line	Resistance [Ω]	Reactance [Ω]	Length [Mile]	R [$/Mile]
1-2	0.0	0.30	20.0	5.0
1-3	0.0	0.10	10.0	23.0
2-3	0.0	0.40	40.0	10.0

We assume the system is lossless and we use dc-load flow equations. Furthermore, bus 3 is the reference bus ($\delta_3 = 0.0$) and P_i is the net injection (net generation - net load) at bus i. For this system, we find voltage angles as follows:

$$\begin{bmatrix} 1/0.3 + 1/0.1 & -1/0.3 \\ -1/0.3 & 1/0.3 + 1/0.4 \end{bmatrix} \begin{bmatrix} \delta_1 \\ \delta_2 \end{bmatrix} = \begin{bmatrix} P_1 \\ P_2 \end{bmatrix}$$

or

$$\begin{bmatrix} \delta_1 \\ \delta_2 \end{bmatrix} = \begin{bmatrix} 13.3333 & -3.3333 \\ -3.3333 & 5.8333 \end{bmatrix}^{-1} \begin{bmatrix} P_1 \\ P_2 \end{bmatrix} = \frac{1}{66.6666} \begin{bmatrix} 5.8333 & 3.3333 \\ 3.3333 & 13.3333 \end{bmatrix} \begin{bmatrix} P_1 \\ P_2 \end{bmatrix} \quad \text{(a)}$$

$$= \begin{bmatrix} 0.0875 & 0.0500 \\ 0.0500 & 0.2000 \end{bmatrix} \begin{bmatrix} P_1 \\ P_2 \end{bmatrix}$$

Let x_{mn} refer to the reactance of a line connecting buses m and n, and f_{mn} refer to the flow from m to n. Then,

$$f_{mn} = \frac{\delta_m - \delta_n}{x_{mn}} \quad \text{(b)}$$

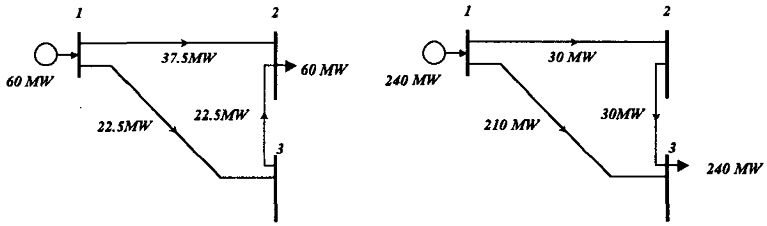
After finding voltage angles, we calculate line flows using Equation b. The net line flows are shown in Figure 1.19.

If $f_{m-n,j}$ is the loading of line m-n due to transaction j, D_{m-n} is the length of line m-n in miles, and R_{m-n} is the required revenue per unit length of line m-n ($/mile), the MW-Mile method uses the following equation to find charges for line m-n corresponding to transaction j (i.e. $C_{m-n,j}$):

$$C_{m-n,j} = \frac{f_{m-n,j} \; D_{m-n} \; R_{m-n}}{f_{m-n}} = \frac{f_{m-n,j} \; Z_{m-n}}{f_{m-n}}$$

where z_{m-n} is the required revenue of line m-n in $, i.e., $z_{m-n} = D_{m-n} \, R_{m-n}$.

Line flows due to each transaction are shown in Figures 1.20–1.22 and detailed in Table 1.9. Note that the total flow in each line given in Table 1.9 is equal to the total flow in each line given in Figure 1.19. Table 1.9 shows MW-Mile charges for each transaction's contributions to line flows as well as the total charges paid by each transaction for its contributions. The table also shows charges paid by all transactions in each line.



a. PG_1 *and* $L_{2,1}$ *b.* PG_1 *and* $L_{3,1}$

Figure 1.20 *Transactions of* PG_1

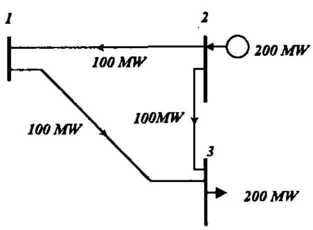
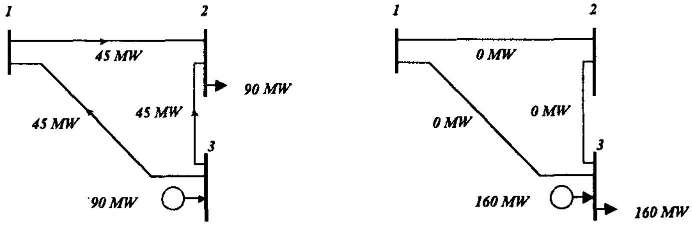


Figure 1.21 *Transaction of* PG_2 *and* $L_{3,2}$



a. PG_3 *and* $L_{2,3}$ *b.* PG_1 *and* $L_{3,3}$

Figure 1.22 *Transactions of* PG_3

Table 1.9 *Impact of each Transaction on Line Flows*

	Transaction j	$f_{1\text{-}2,j}$ (1→2)	Cost [$]	$f_{1\text{-}3,j}$ (1→3)	Cost [$]	$f_{2\text{-}3,j}$ (2→3)	Cost [$]	Total [$]
1.	60 MW : PG_1 →$L_{2,1}$	37.5	**300.**	22.5	**18.**	-22.5	**144.**	**199.5**
2.	240 MW : PG_1 →$L_{3,1}$	30.0	**240.**	210.	**168**	30.	**192.**	**600.0**
3.	200 MW : PG_2 →$L_{3,2}$	-100.	**800.**	100.	**80**	100.	**640.**	**1,520.**
4.	90 MW : PG_3 →$L_{2,3}$	45.0	**360.**	-45.0	**36**	-45.	**288.**	**684.0**
5.	160 MW : PG_3 →$L_{3,3}$	0.0	**0.0**	0.0	**0.0**	0.0	**0.0**	**0.0**
	Total	12.5 MW	**$1,700**	287.5 MW	$302	62.5 MW	**1,264.**	$3,003.

1.9 CONGESTION PRICING

The condition where overloads in transmission lines or transformers occur is called congestion. Congestion could prevent system operators from dispatching additional power from a specific generator. Congestion could be caused for various reasons, such as transmission line outages, generator outages, changes in energy demand and uncoordinated transactions. Congestion may result in preventing new contracts, infeasibility in existing and new contracts, additional outages, monopoly of prices in some regions of power systems and damages to system components. Congestion may be prevented to some extent (preventive actions) by means of reservations, rights and congestion pricing. Also, congestion can be corrected by applying controls (corrective actions) such as phase shifters, tap transformers, reactive power control, re-dispatch of generation and curtailment of loads. A fast relief of congestion may be possible by removing congested lines to prevent severe damages to the system. Before the latter solution takes place, its consequences on existed contracts ought to be studied. To manage transmission congestion, we may initially establish rules for managing the market condition and preventing congestion from developing.

FERC has set guidelines for a workable market approach to mange congestion, which are:

(1) The approach should establish clear and tradeable rights for transmission usage,

(2) The approach should promote efficient regional dispatch,

(3) The approach should support the emergence of secondary markets for transmission rights,

(4) The approach should provide market participants with the opportunity to hedge locational differences in energy prices,

(5) Congestion pricing method should seek to ensure that the generators that are dispatched in the presence of transmission constraints are those that can serve system loads at least cost, and

(6) The method should ensure that the transmission capacity is used by market participants who value that use most highly.

As such, FERC declares that some approaches appear to have more advantages than others. Even though LMPs can be costly and difficult to implement, especially by entities that have not previously operated as tight power pools, FERC suggests that markets that are based on LMP and financial rights for firm transmission service will provide an efficient congestion management framework, and this is due to the following facts:

i- LMP assigns congestion charges directly to transmission customers in a fashion that agrees with each customer's actual use of the system and the actual dispatch that its transactions cause.

ii- LMP facilitates the creation of financial transmission rights, which enable customers to pay known transmission rates and to hedge against congestion charges.

iii- Financial rights entitles their holders to receive a share of congestion revenues, and consequently the availability of such rights congestion pricing resolve the problem of the over-recovery of transmission costs.

Physical transmission rights scheme is another alternative to LMPs scheme, where these rights are tradable in a secondary market. FERC suggests that the ISO may issue these transmission rights initially through an auction or allocation process, and market participants then should show ownership of sufficient rights in a constrained interface before they will be permitted to schedule firm service over the interface. It is said by FERC that this approach considerably reduces the role of ISO in congestion management. FERC sees that while the approach of trading physical transmission rights in a secondary market may prove to be practical in regions where congestion is minor or infrequent, it may not be practical in other regions where congestion is more of a chronic problem.

As we mentioned before, the ISO has the right to order redispatch for reliability purposes, but for congestion management, the ISO should initially depend on market mechanisms to the maximum extent practicable, and at times when markets fail to provide the ISO with the options it needs to mitigate congestion, the ISO must have the authority to curtail one or more transmission service transactions that are contributing to the congestion. Although the act of curtailing a transaction may sometimes require the redispatch of generation, FERC is not requiring the ISO to redispatch any generators exclusively for congestion management purposes.

To solve the congestion problem, several alternatives could be considered such as re-dispatching existing generators or dispatching generators outside the congested area to supply power. The latter alternative is referred to as out-of-merit dispatch. In both alternatives, congestion has costs based on differences in energy prices between locations. In a vertically integrated monopoly, congestion costs were either ignored or hidden as bundled into the transmission charges that in turn were considered as a shortcoming in previous transmission pricing schemes. It was considered a shortcoming because it did not provide a true price signal for efficient allocation of transmission resources or allocated congestion costs to transmission customers who were not causing the congestion.

1.9.1 Congestion Pricing Methods. All new restructuring proposals are taking congestion costs into account by developing appropriate approaches to measure congestion costs and allocate these costs to transmission system users in a fair way that reflects actual use of the transmission system. These approach evolved in three basic methods based on:

1- Costs of out-of-merit dispatch: This is appropriate to systems with less significant transmission congestion problems. In this approach, congestion costs are allocated to each load on the transmission system based on its load ratio share (i.e., individual load expressed as a percent of total load).

2- Locational Marginal Prices (LMPs): This technique is based on the cost of supplying energy to the next increment of load at a specific location on the transmission grid. It determines the price that buyers would pay for energy in a competitive market at specific locations and measures congestion costs by considering the difference in LMPs between two locations. In this approach LMPs are calculated at all nodes of the transmission system based on bids provided to the PX .

3- Usage charges of inter-zonal lines: In this approach, the ISO region is divided into congestion zones based on the historical behavior of constrained transmission paths. Violations of transmission lines between zones (inter-zonal lines) are severe while in the congestion zone transmission constraints are small. All transmission users who use the inter-zonal pay usage charges. These charges will be determined from bids submitted voluntarily by market participants to decrease or increase (adjust) power generation. Adjustment bids reflect a participant's willingness to increase or decrease power generation at a specified cost. An example of this approach is the case of California.

1.9.2 Transmission Rights. These rights are used to guarantee an efficient use of transmission system capacity and to allocate transmission capacity to users who value it the most. These rights are tradable rights referred to as the right to use transmission capacity and represent a claim on the physical usage of the transmission system. Moreover, these rights enable utilities to purchase existing transmission rights more cheaply than expanding the system, thereby avoiding unneeded investments. Efficient usage of the transmission can be improved by willingness to offer capacity reservations to those who value them more.

Another form of these rights is the concept of financial rights (some times called Fixed Transmission Right), which is equivalent to the physical rights. This form is proposed because it is easier for trading and less costly because the usage of a transmission system need not be tied to ownership rights. A financial right is defined for two points on the transmission grid: injection and withdrawal points. A holder of this right either pays or is paid a monetary value based on difference in energy LMPs between the two locations. The initial allocation of these rights will go to transmission customers with existing transmission contracts and to transmission owners on the basis of their need to serve the native load. The ISO also runs a centralized auction for rights (sale and purchase) after a certain period of time. Holders of these rights are free to trade their rights in secondary markets as bilateral contracts. The concept of tradable transmission rights is still a new concept and needs more time and experiments to show its effectiveness. Later we will discuss this concept in detail.

1.10 MANAGEMENT OF INTER-ZONAL/INTRA-ZONAL CONGESTION

Transmission network plays a major role in the open access restructured power market. It is perceived that phase-shifters and tap transformers play vital preventive and corrective roles in congestion management. These control devices help the ISO mitigate congestion without re-dispatching generation away from preferred schedules. In this market, transmission congestion problems could be handled more easily when an inter-zonal/intra-zonal scheme is implemented. A congestion problem formulation should take into consideration interactions between intra-zonal and inter-zonal flows and their effects on power system. In this section, we discuss a procedure for minimizing the number of adjustments of preferred schedules to alleviate congestion and apply control schemes to minimize interactions between zones while taking contingency-constrained limits into consideration.

Existing approaches to manage congestion are based on issuing orders by the ISO to various parties to re-schedule their contracts, re-dispatch generators, cancel some of the contracts that will lead to congestion, use various control devices, or shed loads. Other solutions are based on finding new contracts that re-direct flows on congested lines. Phase shifters, tap transformers and FACTS devices may play an important role in a restructured environment where line flows can be controlled to relieve congestion and real power losses can be minimized. If phase shifters and tap changing transformers are well-coordinated, trading possibility or feasibility margin will be expanded by permitting more contracts to be held and improving system performance while the ISO finds itself in no need to re-dispatch preferred schedules. The contingency-constrained limits can be taken into consideration either during preferred schedule adjustments to mitigate congestion or after adjusting preferred schedules.

In this section, we consider an efficient transmission congestion management, which will be implemented by the ISO. The procedure which includes contingency limits during congestion mitigation, minimize the number of adjustments, and increase the efficiency of the system by eliminating interactions between inter-zonal and intra-zonal subproblems and between each intra-zonal subproblem and other intra-zonal subproblems.

1.10.1 Solution Procedure. Once the ISO receives preferred schedules from the PX, it performs contingency analysis by identifying the worst contingency for modeling in the congestion management. To rank the severity of different contingencies, the ISO may use a Performance Index (PI) to list and rank different contingencies. PI is a scalar function of the network variables such as voltage magnitude, real and reactive power flows. PI has essentially two functions, namely, differentiation between critical and non-critical outages, and prediction of relative severity of critical outages. There are available criteria in the literature to decide how many cases on the contingency list ought to be chosen for additional studies. A few critical contingencies at the top of the list will have the major impact on system security and should be used by the ISO during congestion management.

After contingency analysis, the ISO would check schedules for inter-zonal and intra-zonal congestion and try to minimize the total congestion cost by possibly moving SCs[27] (submit balanced schedules to the ISO), away from their preferred schedules while keeping each SC's portfolio in balance, i.e. generation balances load. The solution procedure is composed of three stages, which are contingency analysis, inter-zonal congestion management and intra-zonal congestion management. Economically, these price-quantity values represent what each SC is willing to pay to or receive from the ISO to remove congestion. Each schedule coordinator may trade transactions with others before submitting preferred schedules to the ISO; these parties may trade power again when preferred schedules are returned to them for revision. The preferred schedules submitted to the ISO by SC and PX are optimal schedules determined by the market clearing price, and schedules submitted by schedule coordinators are basically bilateral contracts that take into consideration the benefits of contracted parties. In this process, adjustment bids (incremental and decremental) represent the economic information on which the ISO will base its decisions to relieve congestion. Adjustment bids include suggested deviations from preferred loads and generation schedules provided by SCs. At each bus, ranges of power deviations along with deviations in price are submitted to the ISO. Incremental bids may be different from decremental bids for adjusting the preferred schedule.

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[27] Scheduling Coordinator: An entity created in California model and certified by FERC and the California ISO that coordinates with the ISO on behalf of generators, supply aggregators (wholesale marketers), retailers, and customers to schedule the distribution of electricity, and submit to the ISO, on hourly basis, balanced schedules of generation to be injected into the transmission grid, and power to be withdrawn from the grid.

The ISO uses incremental/decremental (inc/dec) bids to relieve congestion. Since inter-zonal congestion is more frequent than intra-zonal congestion with system-wide effects, the ISO first solves inter-zonal congestion while ignoring intra-zonal constraints. In the inter-zonal congestion management, primary controls are zonal real power generation and loads at both ends of congested inter-zonal lines. Instead of changing preferred schedules in these zones, the ISO starts by adjusting generations and loads at buses directly connected or in proximity of these inter-zonal lines. If these controls do not accomplish the task, it is perceived that other controls away from these lines will probably not be able to mitigate inter-zonal congestion either. Then the ISO looks for other control devices (such as phase shifters, tap-transformers and FACT devices) close to inter-zonal lines, however, this option requires an AC-OPF model for inter-zonal congestion management. If the inter-zonal congestion is not solvable based on available control options, the ISO will pass on a signal to different schedule coordinators to take action such as changing preferred schedules, providing adjustment bids for generations or loads which were not provided or any other action that would solve the inter-zonal problem such as finding new contracts that would cause counter-flows in inter-zonal lines for eliminating overloads or reducing flows in congested lines. The solution of this problem would provide inter-zonal line flows and adjusted generation and loads in all zones that could mitigate inter-zonal congestion. The adjusted quantities are to be passed on to the intra-zonal subproblem.

Once the inter-zonal congestion is solved, the ISO moves to intra-zonal congestion where it uses inter-zonal flows as equality constraints. This assumption is to guarantee that inter-zonal line flows will not violate limits again and the solution will not swing between the two optimization subproblems. Another option for considering interactions between the two subproblems is by assuming inter-zonal line flows as constant loads or generations (depending on the direction of flows in inter-zonal lines) at buses connected to inter-zonal lines. If generator or load at any bus in a zone is not involved in congestion management and do not submit inc/dec bids, then its minimum and maximum limits will be set to preferred schedules. Since small adjustments in variables could mitigate congestion, control devices such as phase shifters and tap transformers may play an important role in alleviating congestion. These control devices should be checked first here to see if they would remove congestion without any adjustments in preferred schedules or schedules adjusted by the solution of inter-zonal congestion. The ISO checks the first zone for inter-zonal solution, if congestion is detected, it solves that congestion and then goes to the next zone and so on until all congested zones are done. If congestion in any zone is unsolvable, the ISO passes a signal to different parties to adjust preferred schedules. However, since the intention in each zone is to maintain preferred schedules, the ISO would try to solve congestion in each zone using less expensive options such as tap transformers and phase shifters, and if necessary, would solve the problem using expensive options such as power generation and loads close to congested intra-zonal lines.

If no congestion is detected in any zone or on inter-zonal lines, then the submitted preferred schedules are accepted as final real time schedules.

1.10.2 Formulation of Inter-Zonal Congestion Subproblem. The objective of the inter-zonal subproblem is represented by a modified dc load flow for adjusting preferred schedules, where the ISO minimizes the net cost of re-dispatch as determined by the SC's submitted incremental/decremental price bids. In this case, the objective is equivalent to the net power generation cost used in a conventional OPF.

For each deviation from the associated preferred schedule, a price function is provided, i.e., adjusting a generation (inc/dec) at a certain point may have a different price than that of other generators. Also, adjusting a load (dec) may present a price different from that of generation or other load. These prices may represent a linear or nonlinear function of deviations, and price coefficients associated with deviations from preferred schedules reflect the SCs desire to be economically compensated for any increase or reduction in their preferred schedules. If a SC does not provide the ISO with inc/dec bids, the ISO will use inc/dec bids of other SCs for congestion management, and the SC who did not submit inc/dec bids would be automatically forced to pay congestion charges calculated according to other inc/dec bids. The formulation of this subproblem is given as follows:

Objective

- Modified dc power flow to adjust preferred schedules
- Minimize the net cost of re-dispatch as determined by incremental/decremental price bids
- Objective is equivalent to the net power generation cost used in a conventional OPF

Control variables

- SC's power generation in all congestion zones. For each generator a set of generation quantities with associated adjustments for incremental/decremental bids are submitted by SCs
- SCs' curtailable (adjustable) loads. For each load, a set of load quantities with associated adjustments for decremental bids are submitted by SCs. These adjustments are implicit bids for transmission across congested lines

Constraints

- Limits on control variables
- Nodal active power flow balance equations
- Inter-zonal line flow inequality constraints
- Market separation between SCs

1.10.3 Formulation of Intra-Zonal Congestion Subproblem. At each congested zone, the ISO will use a modified AC-OPF to adjust preferred schedules. The main goal is to minimize the absolute MW of re-dispatch by taking into account the net cost of re-dispatch as determined by the SC's submitted incremental/decremental price bids. This objective is equivalent to the MW security re-dispatch with incremental and decremental cost-based MW weighting factors to ensure that less expensive generators are incremented first and more expensive generators are decremented first during the adjustment process. For loads, most expensive loads will be decremented first.

In each zone, congestion management is performed separately while inter-zonal constraints are preserved. The formulation may assume that loads in each zone (at each bus) can contribute to the congestion relief. If any generator or load at any zonal bus is not involved in congestion management and would not submit inc/dec bids, then its minimum and maximum limits are set to preferred schedule values. The formulation of this subproblem is given as follows:

Objective

- Modified AC-OPF to adjust preferred schedules
- Minimize the MW re-dispatch by taking into account the net cost of re-dispatch as determined by the SC's submitted incremental/decremental price bids
- The objective is equivalent to the MW security re-dispatch with incremental/decremental cost-based weighting factors to ensure that less expensive generators are incremented first and more expensive generators are decremented first during the adjustment process. For loads, the most expensive ones will be decremented first

Control variables

- SCs' power generation in congested zones. For each generator a set of generation quantities with associated adjustments for incremental/decremental bids are submitted by SCs
- SCs' curtailable (adjustable) loads in the congested zone. For each load, a set of load quantities with associated adjustments for decremental bids are submitted by SCs
- Reactive power controls including:
  - Bus voltages
  - Reactive power injection
  - Phase shifters
  - Tap-transformers

Constraints

- Limits on control variables
- Nodal active and reactive power flow balance equations
- Intra-zonal MVA, MW, and MVAR line flow limits (inequality constraints)
- Active power flow inequality constraints of inter-zonal lines connected to the congested zone
- Voltage limits
- Stability limits
- Contingency imposed limits

Equality constraints represent the net injection of real and reactive power at each bus in the zone. Inequality constraints reflect real power flows between buses, and stability and thermal limits define line limits. If the MVA flow limit on lines are of interest, then the MVA inequality constraint is included.

The effect of phase-shifters and tap-transformers may be seen as injections of active power and reactive power at two ends of a line between nodes where phase-shifters and tap transformers are connected. Phase-shifters and tap-transformers could also be included in the formulation by modifying the network admittance matrix.

During the intra-zonal congestion management, inter-zonal line flows to the zone under study are modeled as constant loads or generations (depending on the direction of flows in inter-zonal lines) at buses connected to inter-zonal lines. This modeling has two advantages: (1) It disregards inter-zonal line constraints that should be added to intra-zonal constraints, and (2) It cancels interactions between inter-zonal and intra-zonal congestion subproblems while solving the intra-zonal congestion subproblem. The schedules which will be adjusted in the intra-zonal subproblems are the schedules obtained from the inter-zonal congestion subproblem.

In the intra-zonal congestion management, the incremental cost coefficient of a generator at a certain node in a zone is the same as the incremental bid price. The decremental cost coefficient of a generator at a certain node in a zone is anti-symmetric with the decremental bid price with respect to the average of decremental bids in that zone. This assumption is for economical consideration, where less expensive generators would be incremented first to relieve congestion, and more expensive generators would be decremented first when generation reduction is needed. For example, if we have two generators with decremental price bids of \$10/MWh for generator G_A and \$16/MWh for generator G_B then the average decremental price bid is (10+16)/2=\$13/MWh. The decremental cost coefficients of these generators are \$16/MWh for G_A (or 2×13 - 10) and \$10/MWh (or 2×13 - 16) for G_B. The same argument is made for load reduction where more expensive loads in a zone are adjusted (decremented) first, where load increment is not considered.

For the case that we have more than one provider at each bus or more than one demand, in other words, we have more than one SC at one bus, we would index different providers at different locations in each zone. For that reason, we set three different indices in our formulation that would refer to SC, zone and bus.

Example 1.9

(a) Inter-zonal congestion management

Figure 1.23 shows a simple 2-bus, 2-zone system in a certain hour, with two scheduling coordinators (SCs), where $G_{1,1}$, $G_{1,2}$, refer to generation of SC_1 in zone 1(bus 1) and zone 2 (bus 2), respectively, and $D_{1,1}$ and $D_{1,2}$ refer to load of SC_1 in zone 1and zone 2, respectively. Also, $G_{2,1}$, $G_{2,2}$, refer to generation of SC_2 in zone 1 and zone 2, respectively, and $D_{2,1}$ and $D_{2,2}$ refer to load of SC_1 in zone 1 and zone 2, respectively. The figure shows the preferred (initial) schedules of both SCs. Submitted incremental and decremental bids are given next to each generation in this figure. Incremental/decerementaI bids of any SC represent its implicit bids for congested paths.

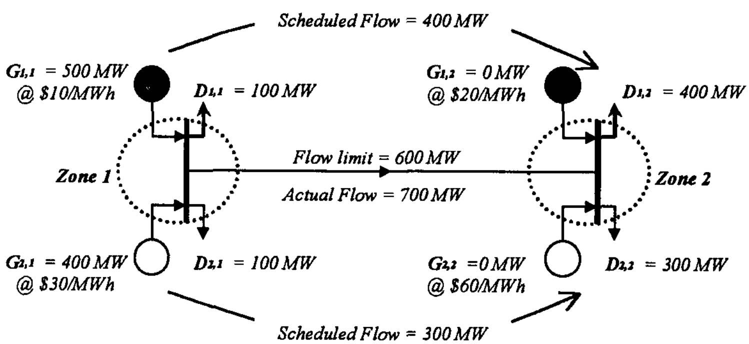

Figure 1.23 Preferred Schedules (before Congestion Management) of Example 1.19

As shown from Figure 1.23, preferred schedules would result in a 100 MW violation on the inter-zonal line between zone 1 and zone 2. SC_1 produces 500 MW in zone 1, where 100 MW goes to its demand in this zone, and the rest (400 MW) crosses the inter-zonal line. Also, SC_2 produces 400 MW in zone 1, where 100 MW goes to its demand in this zone, and the rest (300 MW) crosses the inter-zonal line. For both SCs the flow from 1 to 2 would be 700 MW.

SC_1 places an implicit bid of \$10/MWh, and SC_2 places an implicit bid of \$30/MWh for the congested line between the two zones. Since the bid of SC_2 is higher than that of SC_1, usage of the congested path will be allocated to SC_2 first, then to SC_1. That means scheduled flow of 300 MW of SC_2 will not be altered, while the scheduled flow of SC_1 will be decreased until the line limit is not violated, i.e., scheduled flow of 400 MW for SC_1 will be decreased to 300 MW to make the actual total flow of both SCs equal to 600 MW. The solution after this step is shown in Figure 1.24. To make the required decrease in the inter-zonal path, $\mathbf{G}_{1,1}$ reduces its output from 500 MW to 400 MW, and $\mathbf{G}_{1,2}$ increases its output from 0 MW to 100 MW. After this step, note that $\mathbf{G}_{1,1} + \mathbf{G}_{1,2} = \mathbf{D}_{1,1} + \mathbf{D}_{1,2}$ and $\mathbf{G}_{2,1} + \mathbf{G}_{2,2} = \mathbf{D}_{2,1} + \mathbf{D}_{2,2}$. This is a separation of markets, i.e. an increase (a decrease) in a certain SC's portfolio is compensated by a decrease (an increase) from the same SC.

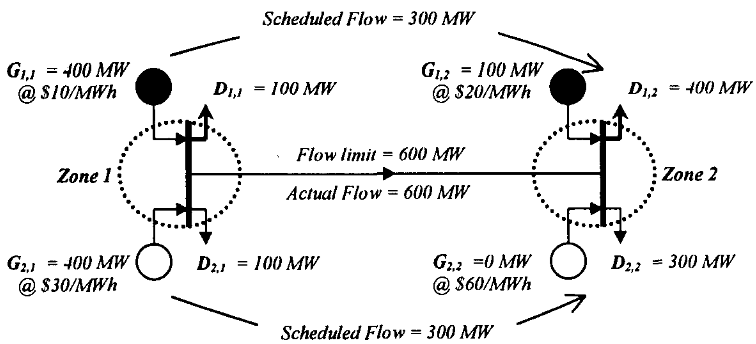

Figure 1.24 *Adjusted Schedules (after Inter-zonal Congestion Management)*

Congestion charges:

SC_1 is the marginal user of the congested inter-zonal line. Therefore, SC_1 sets the price of the congested line at \$10/MWh. The congestion charges for one hour are calculated as follows:

$$\begin{aligned} SC1\ pays:\ 300\ MWh \times \$10/MWh &= \$3{,}000 \\ SC2\ pays:\ 300\ MWh \times \$10/MWh &= \underline{\$3{,}000} \\ Total &= \$6{,}000 \end{aligned}$$

The ISO receives \$6,000 congestion charges from both SCs and then allocates the money to the transmission owner(s) and/or transmission right holder(s) on the path.

(b) Intra-zonal congestion management:

Let's assume that the 2-bus system shown in Figure 1.25 represents a certain congestion zone, and the values shown in the figure represent the schedules after the inter-zonal congestion management. We notice that the intra-zonal line connecting buses 1 and 2 is congested.

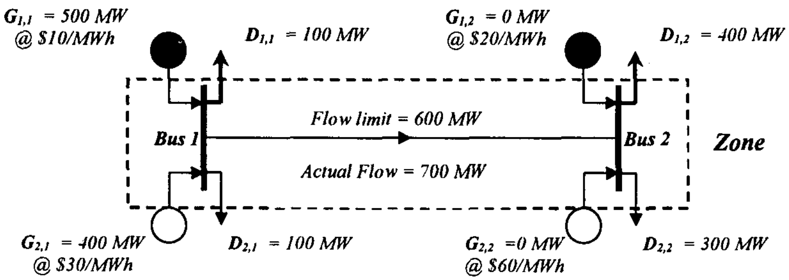

Figure 1.25 Schedules inside a Zone before Intra-zonal Congestion Management

The generator that has the highest decremental bid at bus 1 is $\mathbf{G_{2,1}}$, so this generator will be decremented first. Also, the generator that has the lowest decremental bid at bus 2 is $\mathbf{G_{1,2}}$, so this generator will be incremented first. We need to decrease the flow in the intra-zonal line by 100 MW, so $\mathbf{G_{2,1}}$ is decreased by 100 MW and $\mathbf{G_{1,2}}$ is increased by 100 MW. The solution is shown in Figure 1.26.

Intra-zonal congestion settlement:

$G_{2,1}$ which belongs to SC_2 decreased its output by 100 MW.
Payment by SC_2 to the ISO for $G_{2,1}$ is

$$100 \text{ MWh} \times \$30/\text{MWh} = \$3{,}000$$

$G_{1,2}$ which belongs to SC_1 increased its output by 100 MW.
Payment by ISO to SC_1 for $G_{1,2}$ is

$$100 \text{ MWh} \times \$20/\text{MWh} = \$2{,}000$$

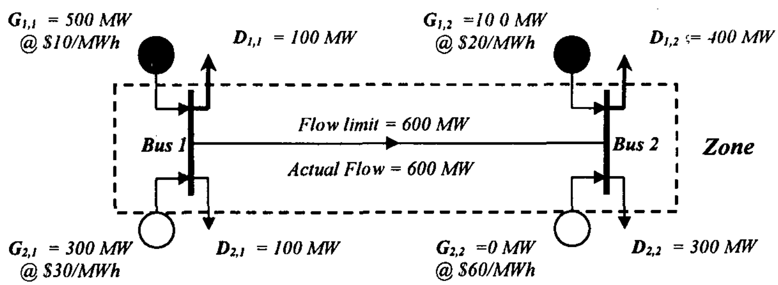

Figure 1.26 *Schedules inside a Zone after Intra-zonal Congestion Management*

Total balance of the ISO = \$3,000 - \$2,000 = \$1,000 (The ISO has a net of \$1,000). The balance (1,000) is located as a zonal uplift to SCs according to their load in and exports from the zone:

SC_1 gets : \$1,000 × 500 MW / 900 MW= \$555.56
SC_2 gets : \$1,000 × 400 MW / 900 MW= \$444.44

Example 1.10

Figure 1.27 shows a simple 5-bus, 3-zone, and 2-SC system. Variables $\mathbf{G}_{k,j}$ and $\mathbf{D}_{k,j}$ refer, respectively, to generation and load of SC_k at bus j, where k=1,2 and j=1,2,...,5. Preferred schedules and incremental/decremental bids are given in Table 1.10. As we mentioned before, incremental/decremental bids of any SC represent an implicit bid for congested paths.

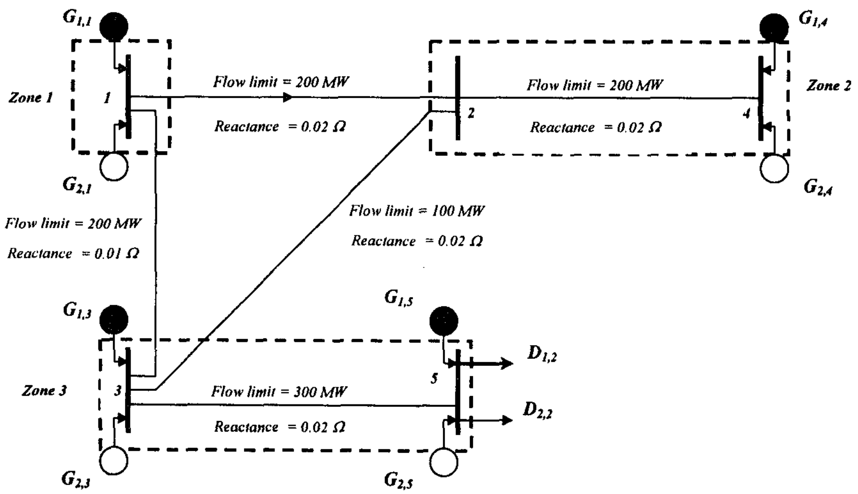

Figure 1.27 System Structure and Data

Table 1.10 Preferred Schedules and Inc/Dec Bids

SC	Variable	Pref. Sch. MW	Inc/Dec $/MWh	Minimum MW	Maximum MW
SC_1	$G_{1,1}$	160	8	0	500
	$G_{1,3}$	0	23	0	500
	$G_{1,4}$	0	13	0	500
	$G_{1,5}$	0	38	0	500
	$\mathbf{D_{1,5}}$	**160**	-	**160**	**160**
SC_2	$G_{2,1}$	240	14	0	500
	$G_{2,3}$	0	38	0	500
	$G_{2,4}$	0	20	0	500
	$G_{2,5}$	0	33	0	500
	$\mathbf{D_{2,5}}$	**240**	-	**240**	**240**

The preferred schedules and flows (with line constraints ignored) are shown in Figure 1.28.

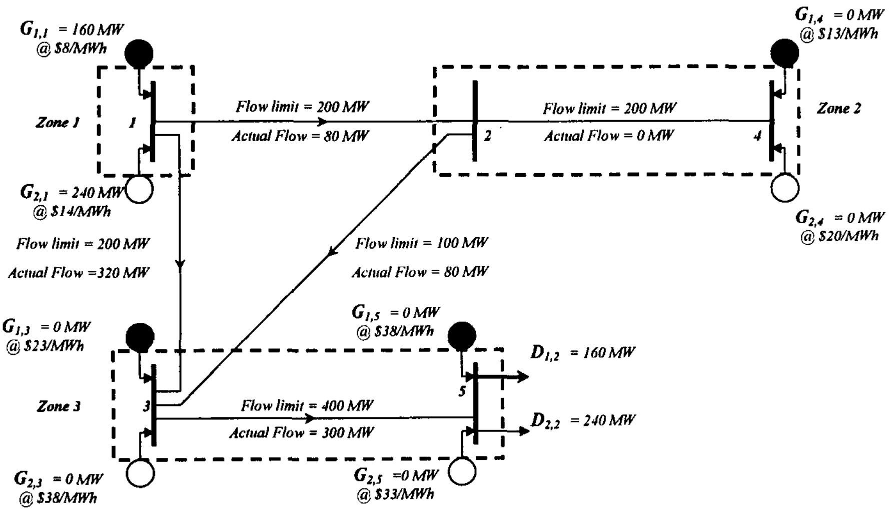

***Figure 1.28** Preferred Schedules and Associated Line Flows*

(a) Inter-zonal congestion management

As shown from Figure 1.28, preferred schedules would result in 120 MW violation on the inter-zonal line between zones 1 and zone 3 (between buses 1 and 3). The solution of the inter-zonal congestion problem is shown in Figure 1.29. After the inter-zonal congestion management, $\mathbf{G_{1,1} + G_{1,3} + G_{1,4} + G_{1,5} = D_{1,5}}$ and $\mathbf{G_{2,1} + G_{2,3} + G_{2,4} + G_{2,5} = D_{2,5}}$ (separation of markets).

Marginal cost of each SC at each bus is shown in Table 1.11.

The inc/dec price of SC_1 at bus 1 is \$8/MWh, while the marginal cost of SC_1 at this bus is \$7/MWh. To interpret this difference, we start from the solution shown in Figure 1.29 and assume that SC_1 has a load at bus 1 and this load is increased from 0 to 1 MW. The optimal response for this load increase will be: $\mathbf{G_{1,4}}$ increases its output from 60 MW to 61 MW at \$13/MWh, $\mathbf{G_{2,1}}$ increases its output from 200 MW to 201 MW at \$11/MWh, and $\mathbf{G_{2,4}}$ decreases its output from 40 to 39 MW at \$20/MWh. The cost of this change is $MC_{1,1} = 1\times13 + 1\times14 - 1\times20 =$ \$7/MWh.

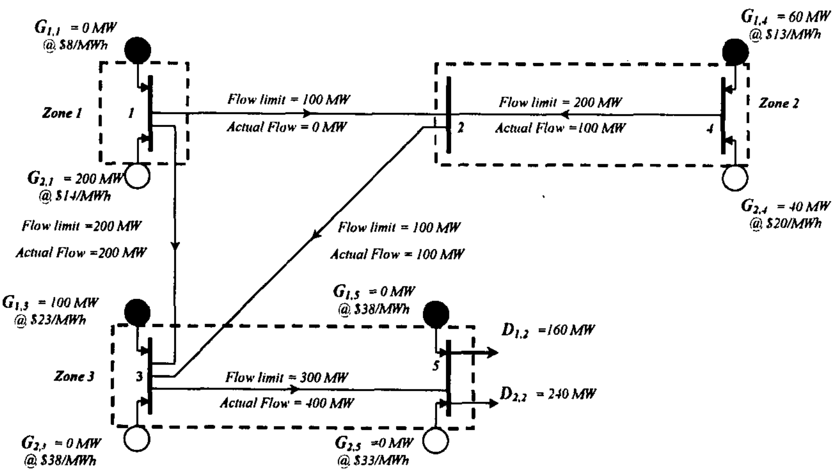

Figure 1.29 Solution of the Inter-zonal Congestion Problem

Table 1.11 Marginal Cost of each SC at each Bus

SC	Bus	Inc/Dec Price	MC in $/MWh
	1	8	$MC_{1,1}$ = 7
	2	-	$MC_{1,2}$ = 13
SC_1	3	23	$MC_{1,3}$ = 23
	4	13	$MC_{1,4}$ = 13
	5	38	$MC_{1,5}$ = 23
	1	14	$MC_{2,1}$ = 14
	2	-	$MC_{2,2}$ = 20
SC_2	3	38	$MC_{2,3}$ = 30
	4	20	$MC_{2,4}$ = 20
	5	33	$MC_{2,5}$ = 30

Now, to calculate the marginal cost of SC_2, let's assume that SC_2 has a load at bus 1 and this load is increased from 0 to 1 MW. The optimal response for this change is that $\mathbf{G_{2,1}}$ will increase its output form 200 MW to 201 MW at $14/MWh, or $MC_{2,1}$=$14/MWh (or 1×14).

To show how $MC_{1,2}$=$13/MWh is calculated and interpreted, let SC_1 have a load at bus 2 and this load is increased from 0 MW to 1 MW. For this change, $\mathbf{G_{1,4}}$ will change its output from 60 MW to 61 MW at $13/MWh which means that $MC_{1,2}$=$13/MWh (or 1×13).

The congestion charges for one hour are calculated as follows: SC1 has 160 MW load in zone 3 at a marginal cost of $23/MWh, has a generation of 0 MW in zone 1 (at bus 1, at $MC_{1,1}$=$7/MWh) , has a generation of 60 MW in zone 2 (at bus 4, at $MC_{1,4}$=$13/MWh), and has a generation of 100 MW in zone 3 (at bus 3, at $MC_{1,3}$=$23/MWh). This implies that:

SC_1 pays to the ISO: 160×23 - 0 × 7 -60×13 - 100 × 23 = $600

SC 2 has a 240 MW load in zone 3 at a marginal cost of $30/MWh, has a generation of 200 MW in zone 1, has a generation of 40 MW in zone 2, and has a generation of 0 MW in zone 3. This implies that:

SC_1 pays to the ISO: 240×30 -200×14 - 40 ×20 = Total = $3,600

Total payment to ISO = \$4,200 (or \$600 +\$3,600).

The ISO receives \$4,200 congestion charges from both SCs and allocate the money to transmission owners and/or transmission right holders.

(b) Intra-zonal congestion management

Note that in Figure 1.29, a violation of 100 MW exists on the intra-zonal line connecting buses 3 and 5 in zone 3. To relieve this congestion, $G_{1,3}$ decreases its output from 100 MW to 0 MW at \$23/MWh, while $G_{2,5}$ increases its production from 0 to 100 MW at \$33/MWh. The situation after this step is shown in Figure 1.30.

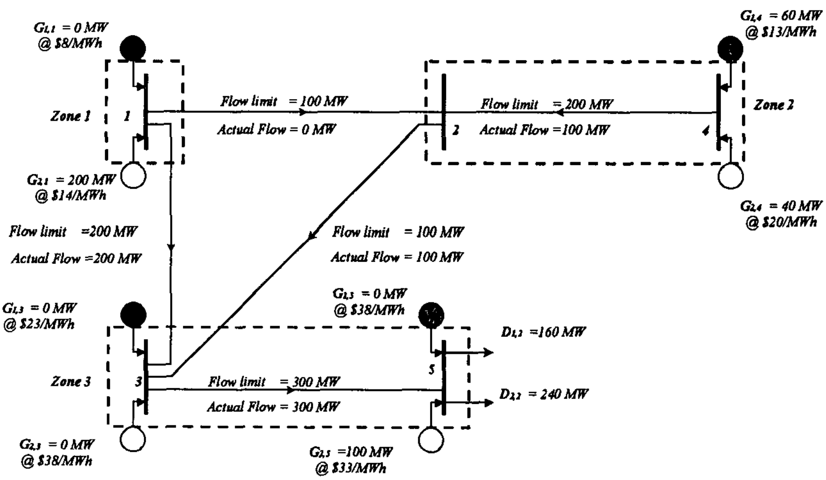

Figure 1.30 Solution of the Intra-zonal Congestion Problem

Intra-zonal Congestion Payments:

$G_{1,3}$, which belongs to SC_1, decreases its output from 100 MW to 0 MW at \$23/MWh, which implies that SC_1 pays the ISO to replace its reduced generation in zone 3. $G_{2,5}$ which belongs to SC_2, increases its output from 0 MW to 100 MW at \$33/MWh, which implies that SC_2 is paid by the ISO for additional generation over its inter-zonal schedule in zone 3. The payments are calculated as:

$SC_1 \rightarrow$ ISO: Payment = Reduction in $G_{1,3}$ × Decremental cost of $G_{1,3}$
= 100 × 23
= \$2,300

ISO $\rightarrow SC_2$: Payment = Increase in $G_{2,3}$ × Incremental cost of $G_{2,3}$
= 100 × 33
= \$3,300

Net payment to the ISO = \$2,300-\$3,300 = - \$1,000

The \$1,000 will be allocated to SCs as a zonal uplift based on their load in zone 3.

$SC_1 \rightarrow$ ISO: Payment = \$1,000 × $D_{1,5} / (D_{1,5} + D_{2,5})$
= \$1,000 × 160 /400
= \$400

SC2 $\rightarrow$ ISO: Payment = \$1,000 × $D_{2,5} / (D_{1,5} + D_{2,5})$
= 100 × 33
= \$600

CHAPTER 2

ELECTRIC UTILITY MARKETS IN THE UNITED STATES

Summary: In this chapter, major market models as related to the ISO in the United States will be presented; these models include California, Pennsylvania–New Jersey–Maryland (PJM) interconnection, New York ISO, Electric Reliability Council of Texas (ERCOT), New England ISO and Midwest ISO (MISO). We discuss some of the shortcomings and advantages of these models and focus on restructuring process in the Unites States, discuss some of the proposals in a detailed manner and present comparisons between proposals.

2.1 CALIFORNIA MARKETS[1]

What made California distinguished in electricity restructuring was the fact that it was the first state in the United States to offer large-scale retail choices and a competitive generation market. The California ISO [Web01, Web02] was created in 1996, and has the second largest control area in the U.S. and the fifth largest in the world. The California ISO is a non-profit association which performs functions similar to those of a tight power pool. The ISO uses a computerized center to send commands through long and high-voltage lines that deliver electricity in California and between Mexico and neighboring states.

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[1] At the time that this book was going to be printed, many drastic changes were being proposed to the California markets. However, the authors decided to include the California model in this book as the historical perspective of the California markets plays a major role in the restructuring of many other markets discussed in this book.

The ISO's main task is to ensure that the power grid is safe and reliable and there is a competitive market for electricity in California. One of the objectives for establishing the ISO is to bring less costly electricity to Californians by enabling them to shop and select the power source and creating open competition in the electric power industry. To implement the ISO, the three investor-owned utilities (IOUs), i.e., Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric were required by the state legislation to release the control of their transmission lines to the ISO to make transmission open to all power marketers for delivering power over the state's transmission system. In the restructured power systems of California, the status of ownership is not changed by the state legislation and transmission lines are still owned as before.

Even though it offers many common entities, restructuring in California is viewed as being totally different from other restructuring proposals in other countries or even those in the United States. The California model was proposed to fit specific needs such as meshed characteristics of the network, frequent transmission congestion, variety of generation resources and implementation of bilateral contracts. One major aspect of the California proposal is that the commitment of generating units and plants remains to be the responsibility of owners and not the market.

The main players that compose the California market structure include the ISO (provides grid dispatch and transmission access services), and Scheduling Coordinators (SCs which submit balanced schedules to the ISO), Power Exchange (PX which creates a spot market for electricity, schedules and settles trades in its markets), Utility Distribution Companies (UDCs which distribute or deliver electricity), Retail Marketers that include Electricity Service Providers (ESPs which provide competitive energy services), Customers (which acquire and consume electricity) and Generators (which generate electricity). A PX is considered as an SC but with limited capabilities, as discussed in this chapter. In the California market, major Investor-Owned Utilities (IOUs) must bid their generation through the PX (obligatory). The transmission grid is owned by IOUs but operated by the ISO.

This proposal has three markets, which are Day-Ahead Market, Hour-Ahead Market and Real-time (Balancing) Market. In these markets, energy, supplementary energy and ancillary services are traded. Ancillary services include spinning and non-spinning reserves, replacement reserves, regulation, and reactive power and black start capability. Interactions among different entities in California are shown in Figure 2.1.

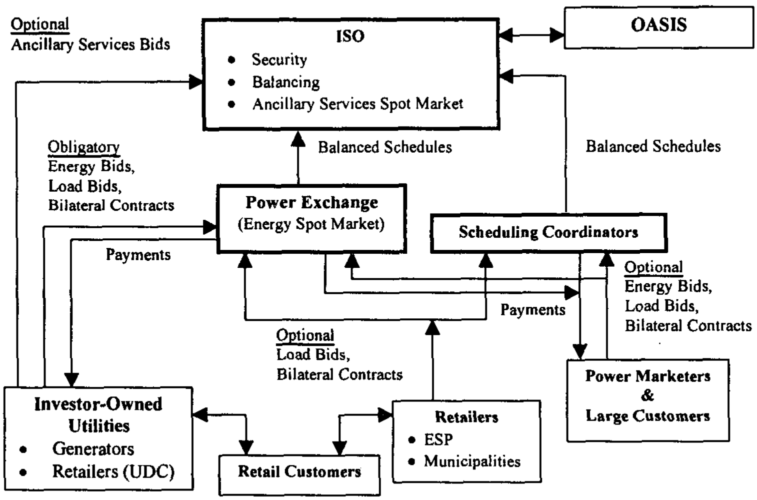

Figure 2.1 *Interactions between the California ISO and other Entities*

2.1.1 ISO. The primary component that is considered as the nerve of the California market is the ISO. The ISO, concerned with the reliability of the transmission grid, balances the operation of transmission grid in real-time. The real-time market is operated by the ISO which uses ancillary services bids and supplemental energy bids submitted through PX and SCs. The ISO also determines the real-time market price after the fact (*ex-post* price) based on actual metered data.

The ISO guarantees a non-discriminatory open access to transmission for all users, manages the reliability of transmission system, acquires ancillary services as required, approves day-ahead and hour-ahead schedules, maintains the real-time balancing of load and generation and settles real-time imbalances, maintains the frequency in the electric power system and conducts congestion management protocols for the transmission system. The ISO also stands as the operator of control-area operators which balances inter-tie schedules with actual flows across inter-ties. The ISO balances the system demand with the power output of local generating units, plus purchases from external electric power systems, minus the energy sold to external systems.

2.1.2 Generation. The second component is the generation sector. Non-investor-owned and independent power producers[2] (or generating companies) could either bid their power into the PX or schedule it through another SC. Generating companies could bid ancillary services through the PX or another SC into the ISO, and as stated in this model, are obligated to respond to instructions issued by the ISO and SCs.

2.1.3 Power Exchange. The third component is the PX [Web02, Web31]. The PX represents the energy spot market where day-ahead and hour-ahead market clearing prices are determined. The PX is a non-profit corporation that is open to all suppliers, provides an efficient and competitive auction and facilitates short-term pool electricity transactions. The PX performs competitive trading in the forward day-ahead and hour-ahead markets (auctions). In these auctions, participants[3] of the PX submit demand and generation bids based on prices and quantities, and the PX determines the MCP at which energy is traded, as discussed in Chapter 1.

As an SC, the PX submits balanced demand and supply schedules for successful bidders to the ISO, and performs settlement[4] functions with the ISO as well as the PX participants such as UDCs, marketers and

[2] Independent Power Producer (IPP): Non-vertically integrated energy producer that generates power for purchase by an electric utility at wholesale prices. The utility then resells this power to end-use customers. IPPs usually do not own any transmission lines.

[3] Participants include buyers and sellers as wholesale power marketers, financial traders, load aggregators, large energy consumers and California municipal utilities as well as in-state and out-of-state utilities.

[4] Process of financial settlement for energy trading.

aggregators (non-utility retailers) and other SCs. In addition to these functions, the PX submits ancillary service bids to the ISO for maintaining the system reliability, adjustment bids (i.e., Dec/inc bids are used to relieve or eliminate congestion on transmission grid) and supplemental energy bids, which are used by the ISO to match loads and resources on a real-time basis.

In the California model, the PX acts as an SC and arranges for the delivery of participants' power anywhere on the ISO's grid, buys or sells ancillary services on participants' behalf, provides up-to-date information about MCPs and facilitates an electricity market in which participants can sell their excess power. Also, out-of-state power can be purchased or sold at the PX at any scheduling points where the ISO-controlled grid connects with neighboring state grids. PX facilitates delivery of energy from the ISO grid to participating entities, whether it is produced in or outside California.

What is interesting is that participants with bilateral contracts can still participate in the PX and make more profits. If the MCP of PX is less than the cost of producing power by a seller, the seller can increase its profits by buying power through the PX and reselling it to its customer at the seller's contract price. Likewise, a buyer who has contracted for more power than its load may sell the excess power at any time into the PX at MCP. If selling power into the PX at the market price is more profitable than using it, participants may opt to cut their power usage in order to sell their excess capacity.

2.1.4 Scheduling Coordinator. The fourth component is the group of SCs. The concept of SC is seen as adding a new dimension to competition in power markets by arranging trading between generators and customers. SC plays as intermediary between the ISO, retailers and customers. Each SC submits balanced schedules and provides settlement-ready data to the ISO. Each SC maintains a year-round, 24-hour scheduling center and provides non-emergency operating instructions to generators and retailers. Each SC provides the ISO with its customers' demand, supply schedule and transmission use[5], and the ISO runs the information thorough a computer program to check for transmission congestions. If no congestion exists, the ISO will send an approval signal to the SC, otherwise, the SC will be advised to sell, buy or trade power to resolve the situation. In this process, the ISO may provide suggested alternatives to the SC for removing the congestion.

Although some analysts see the job of SC as a new kind of monopoly by imposing market power, experiencing gaming and discrimination against certain customers, SC plays a critical role in restructured power systems. In California, for example, SCs are the only market players for generation dispatch and responsible (through adjustment bids) for means that congestion is resolved. This is different from restructuring proposals in New York, PJM and New England where the ISO resolves congestion. Moreover, SCs may negotiate bilateral contract with or between its participants, aggregate contracts between market participants, act as an ESP, deliver services and sign direct retail access contracts with consumers. SCs may also own, contract for or broker generation, and bundle generation and load.

What makes SCs powerful in this model is the fact that only SCs (the PX is also considered an SC) would schedule power in the ISO-controlled system. In the day-ahead and hour-ahead markets, SC's schedule at each hour must balance the power injected into the system and the power extracted from the system. The ISO is not allowed to adjust individual schedules of SCs' participants (generators or consumers), only SCs have this power, with one exception in the case of extreme emergency (such as severe outages) when the ISO is authorized to change generation or/and load to secure the system. Additional issues are highlighted as follows:

- *Major Differences between SC and PX:* Even though the PX is seen as an SC, it has a limited role and trading functionality as compared to other SCs. Hence, customers would have an opportunity to compare the PX and SC for better deals and appropriate terms. This will create more competition between different SCs. The PX would

[5] Transmission use would show the amount of energy the SC believes its participants would need for the next day and generators that would supply the energy.

accept day-ahead and hour-ahead energy bids and loads and, based on these bids, create a competitive energy market for low cost transactions. An SC would have the ability to negotiate with its own generators and client loads and interact with other SCs. SCs disclose resulting schedules to their own participants and are not obligated to pass on any information to other participants, which concludes that SCs could discriminate against some participants. This fact is in contrast to the PX which publishes MCPs based on non-discriminatory auction results and notifies its participants of these results. The non-discriminatory is guaranteed in the PX by matching the lowest incremental generation bid with the highest incremental demand bid, while the SC can price discriminate by matching the next highest willingness to pay for demand with a slightly lower generation price. If an SC imposes price discrimination, it could lead to prices which would be higher than a uniform MCP determined by the PX. In the day-ahead market, SC participants could trade energy for reducing congestion and lowering power costs, while PX traders cannot respond to congestion through bids or trades. This may lead market participants to avoid the PX to prevent possible curtailments in the future. Another problem that limits competition in California and brings additional economical burden on the PX is that the PX must accept the expensive power from California's investor-owned utilities, while SCs are not obliged to do so.

- *Interaction between the ISO and SCs in Congestion Management:* At times when the use of transmission system is at peak, lines in the ISO controlled area could be congested especially when inter-state trading exists. This situation would necessitate the ISO to operate and remove any violations from the system to maintain reliability, protect system components from damage, limit monopoly and finally keep feasibility of all transactions. To ease dealing with this matter, the system would be divided into congestion zones where in each zone (i.e., intra-zonal lines) the congestion is of low possibility with small and limited effect in the proximity of congested components. The tie lines connecting these zones (i.e., inter-zonal lines) would have a high possibility of congestion with a system-wide effect (see Chapter 1).

The ISO has different procedures for inter-zonal and intra-zonal congestion, and SCs have a major role in these procedures. To manage transmission congestion, changes in generation and loads are required, and these changes are implemented by the ISO based on the data passed by SCs to the ISO. When more generation is scheduled for transmission than what can be transmitted by a component, generation on one side of the constrained component must be reduced while generation on the other side of the constrained component must be increased. Adjustable or curtailable loads can play a similar role in the congestion management process[6].

Different SCs interact with the ISO by representing their participants (generators and loads) in day–ahead, hour–ahead and real–time markets. The role of SCs is to offer schedules and bids for their participants in these markets for the purpose of congestion mitigation. In these markets, the ISO issues congestion information, completes SC's trades and re-dispatch resources based on SC's congestion bids. The objective of the ISO in this process is the congestion relief not gaining the minimum cost. In both day-ahead and hour-ahead markets, the ISO accepts schedules and bids from SCs that would reflect acceptable dispatch adjustments. In the real-time market, the ISO can use bids provided by SCs to adjust the congestion.

- *Interaction between the ISO and SCs in Ancillary Services:* In addition to the previously mentioned schedules, each SC could submit schedules and bids for ancillary services and bids to provide power in the real-time market. For every balanced energy schedule, each SC could submit accompanied ancillary services (all or part) that match energy bids. The services provided by the SC are tradable which include spinning and non-spinning reserves, reservation capacity and automatic generation control for regulation. SCs may offer ancillary services to the bid-based ancillary services auction run by the ISO. If SCs choose not to self-provide services in their regions, they may ask the ISO to provide them from its auction.

[6] Curtailment: A mandatory and temporary reduction in load when there is a risk imposed on system components with the possibility of severe conditions.

Secondary markets for ancillary services can facilitate self-provision services.

2.1.5 UDCs, Retailers and Customers. The fourth component is the group of UDCs such as PG&E, SCE and SDG&E which provide distribution services to all electric customers and retailers within their service territories. Distribution services provided by UDCs are composed of metering of delivered energy and billing. Billing would account for consumed electricity and the use of transmission and distribution systems. When UDCs purchase bulk power for their customers, it should be obtained from the PX (the only option). In addition, UDCs may offer bundled energy tariffs to retailers in their territories. Bundled tariffs include meter reading and usage measurement services to other energy service providers.

The fifth component is the group of retailers or energy service providers (ESP). Retailers may market and purchase power for retail customers and serve as demand aggregators for retail loads. Retailers charge retail customers for energy and contracted services, use SCs (including the PX) to schedule generation and load and pay for the received energy and ancillary services.

Finally, the last component is the customers sector (commercial, industrial, residential, and agricultural).

2.1.6 Day-Ahead and Hour-Ahead Markets. As mentioned before, the PX manages day-ahead and hour-ahead markets.

In the **day-ahead market**, participants would bid supply and demand for the next day's 24 hours. This market starts at 6:00 a.m. and closes at 1:00 p.m. of the day ahead of the trading day. When the market closes, the ISO announces the final day-ahead schedules. In this market, a participant may trade and schedule for the next-day delivery, each trade would be subject to mutual payment agreements between the PX and its market participants, and settlements would be based on schedules provided within three days after each trading day.

Once the participants submit bids to the PX, the PX verifies them by ensuring that the content of a bid, such as the bid format, complies with the PX requirements. For verified bids, the PX determines MCP based on participants' supply/demand bids for each hour of the 24-hour scheduling day, as shown in Figure 1.7.

Participants' bids, initially submitted into the day-ahead market auction, are considered as portfolio bids, i.e., will not be referred to any particular unit or physical scheduling plant. The portfolio bids accepted by the PX will then be split into generation unit schedules and submitted to the ISO along with adjustment bids and ancillary service bids. Adjustment bids are used for congestion considerations.

After this stage and based on all unit-specific supply bids and location-specific demand bids, the ISO determines whether there are any transmission congestions, and in the case of congestion, the ISO uses adjustment bids to submit an adjusted schedule to SCs (including PX). This process would create adjusted schedules and transmission usage, and the PX and other SCs either revise their schedules or accept the adjusted schedules and any charges calculated by the ISO. The schedules are then passed on to the ISO as final schedules.

In the **hour-ahead market**, participants perform a similar bidding process as the day-ahead market, where the hour-ahead market begins two hours before the hour of operation. This market provides a means for participants to buy and sell so as to adjust their day-ahead commitments based on information closer to the transaction hour schedules for minimizing real-time imbalances. In this market, bids are unit specific and MCP is determined the same way as the day-ahead market. Once the market is closed, the PX would declare the price and traded quantities to participants.

Balanced schedules submitted by SCs (including the PX) to the ISO would take into account any associated transmission losses, where losses are calculated based on generator meter multipliers which are calculated and posted by the ISO. The components of each SC's portfolio include self-committed schedules for generation, load, import/export and energy trades with other SCs, and may include the schedule of each generator or load entity.

SCs including the PX either self-provide ancillary services or ask the ISO to obtain them. In addition, they may submit bids for ancillary services. The ISO will select proper providers based on economical bid-based calculations. The following example illustrates some of these points.

Example 2.1: (California Market)

This example will illustrate

- Generation/Load Bidding in Day-Ahead Market,
- Calculations of MCP,
- Adjustment Bids,
- Congestion Management Using Adjustment Bids,
- Generation/Load Bidding in Hour-Ahead Market,
- Supplemental Energy Bids, and
- Settlement Procedure and Calculations of Average Price for Actual Consumption and Production

Situation: For this example, assume a four-participant market, i.e., two generation companies ($GenCo_I$ and $GenCo_{II}$) which represent two sellers, and two distribution companies ($DisCo_I$ and $DisCo_{II}$) which represent buyers. The four participants are competing in a two-zone, lossless system. The two zones are connected through a transfer path with a capacity of 80 MW. The system along with demand values and generation limits are shown in Figure 2.2. The example illustrates the situation in a certain hour.

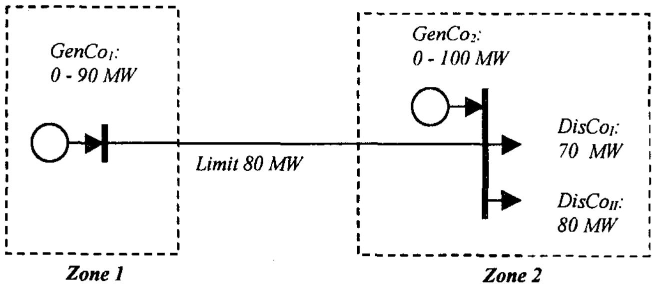

***Figure 2.2** Illustration of Example 2.1*

- **Bidding in Day-Ahead Market:**

Assume the bids provided by buyers are as shown in Table 2.1 and Table 2.2. The bid curves for both DisCos are shown in Figure 2.3. The Aggregated Demand of $DisCo_I$ and $DisCo_{II}$ is shown in Table 2.3, and its curve is shown in Figure 2.4.

Table 2.1 *$DisCo_I$ bids*

Price [$/MWh]	*Demand [MW]*
0	*70.0*
40	*70.0*

Table 2.2 *$DisCo_{II}$ bids*

Price [$/MWh]	*Demand [MW]*
0	*80.0*
22.5	*80.0*
30.0	*65.0*
35.0	*65.0*
37.5	*60.0*
40	*60.0*

Table 2.3 *Aggregated Demands of $DisCo_I$ and $DisCo_{II}$*

Price [$/MWh]	*Demand of $DisCo_I$ [MW]*	*Demand of $DisCo_{II}$ [MW]*	*Aggregated Demand [MW]*
0.00	*70.0*	*80.0*	*150.0*
22.5	*70.0*	*80.0*	*150.0*
30.0	*70.0*	*65.0*	*135.0*
35.0	*70.0*	*65.0*	*135.0*
37.5	*70.0*	*60.0*	*130.0*
40.0	*70.0*	*60.0*	*130.0*

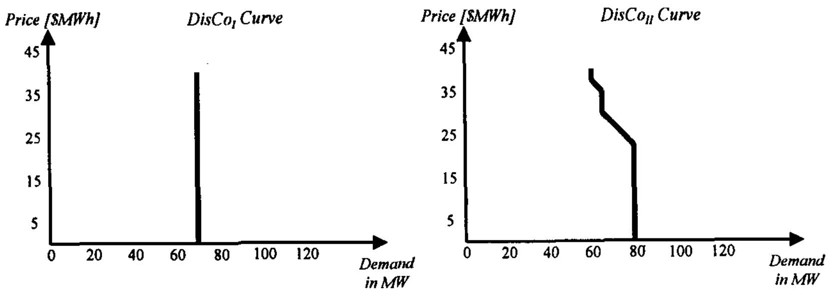

Figure 2.3 Bid Curves of DisCo$_I$ and DisCo$_{II}$

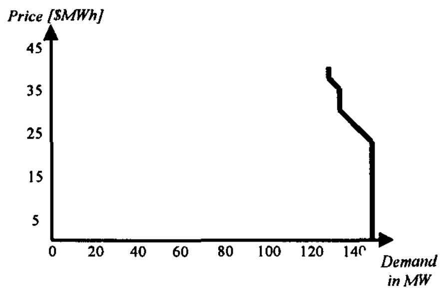

Figure 2.4 Aggregated Demand Curve

For the two GenCos, the bidding data and the associated curves are shown in Tables 2.4 and 2.5, and Figure 2.5, respectively.

Table 2.4 *GenCo$_I$ bids*

Price [$/MWh]	*Supply [MW]*
0.00	*15.0*
19.99	*15.0*
20.00	*90.0*
40.00	*90.0*

Table 2.5 *GenCo$_{II}$ bids*

Price [$/MWh]	*Supply [MW]*
0.00	*0.0*
19.99	*0.0*
20.00	*40.0*
35.00	*60.0*
40.00	*100.0*

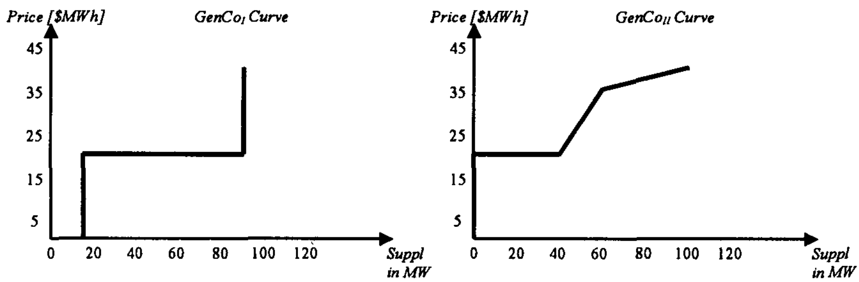

Figure 2.5 *Supply of GenCo$_I$ and GenCo$_{II}$*

The aggregated bids and aggregated curves for both participants are shown in Table 2.6 and Figure 2.6. As shown in Figure 2.7, by combining both aggregated curves in one graph, the market clearing price and market clearing quantity are:

Market Clearing Price = $27.50/MWh
Market Clearing Quantity =140 MW

The distribution of market clearing quantity among participants is shown in Table 2.7. When the ISO applies this distribution of load and generation, the distribution causes the path connecting the two zones to be congested, as shown in Figure 2.8, where the line connecting both zones carries 10 MW above the limit. To resolve congestion, the ISO should use adjustment bids.

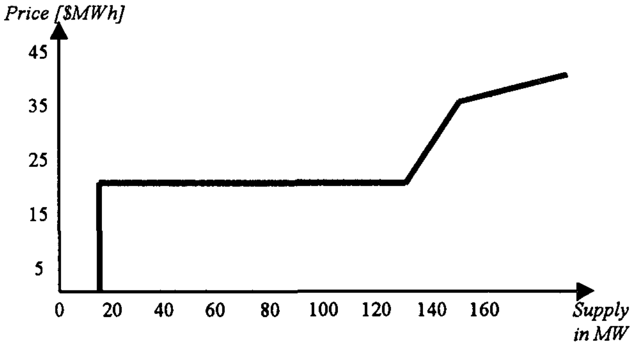

Figure 2.6 Aggregated Supply Curve

Table 2.6 Aggregated $GenCo_I$ and $GenCo_{II}$ bids

Price [$/MWh]	Supply of $GenCo_I$ [MW]	Supply of $GenCo_{II}$ [MW]	Aggregated Supply [MW]
0.00	15.0	0.0	15.0
19.99	15.0	0.0	15.0
20.00	90.0	40.0	130.0
35.00	90.0	60.0	150.0
40.00	90.0	80.0	190.0

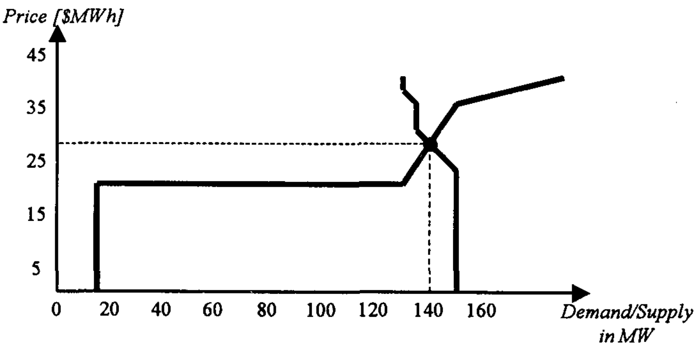

Figure 2.7 Market Clearing Process

Table 2.7 *Distribution of Market Clearing Quantity among Participants*

Participant	Demand
$DisCo_I$	70.0
$DisCo_{II}$	70.0
Total	140.0

Participant	Supply
$GenCo_I$	90.0
$GenCo_{II}$	50.0
Total	140.0

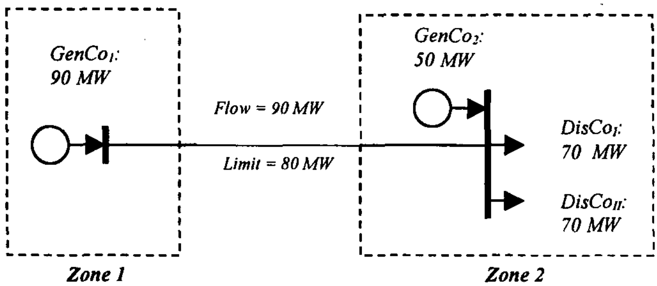

Figure 2.8 *Congestion in the Inter-zonal Path*

- **Congestion Management:**

Since the entire production of $GenCo_I$ is scheduled, this GenCo can not increase its output beyond 90 MW (its maximum limit), so $GenCo_I$ only has a decremental bid. Since $GenCo_{II}$'s maximum limit is 80 and only 50 MW scheduled, this GenCo may have both incremental and decremental bids. Let's fix the demand as scheduled so DisCos would not provide adjustment bids. Assume the adjustment bids for all participants are as shown in Table 2.8.

Table 2.8 Adjustment Bids

Participant	MW	Dec	Inc
$GenCo_I$	50.0	26.0	-
$GenCo_{II}$	20.0	26.0	30.0

Because the path flow violation is 10 MW (from 1 to 2), $GenCo_I$ decreases its output by 10 MW at \$26.0/MWh, and $GenCo_{II}$ increases its output by 10 MW at \$30.0/MWh.

Schedules after day-ahead and adjustments are as follows:

Generation:

$GenCo_I$: 90 - 10 = 80 MW
$GenCo_{II}$: 50 +10 = <u>60 MW</u>
Total 140 MW

Demand

$DisCo_I$: 70 MW (unchanged)
$DisCo_{II}$: <u>70 MW</u> (unchanged)
Total 140 MW

The most expensive incremental bid and the cheapest decremental bid selected in each zone to remove the congestion determine the zonal prices. The schedules of the day-ahead after adjustments along with zonal prices in \$/MWh are shown in Figure 2.9. The prices are the shaded numbers in the figure. The decremental bid of $GenCo_I$ is \$26/MWh which is the price in zone 1, and the incremental bid of $GenCo_2$ is \$30/MWh which is the price in zone 2.

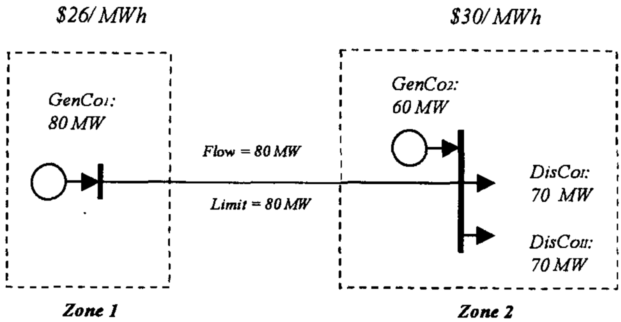

***Figure 2.9** Schedules after Day-Ahead and Zonal Prices*

- **Bidding in Hour-Ahead Market:**

Assume the bids provided by buyers are as shown in Tables 2.9 and 2.10. The bid curves for both DisCos are shown in Figure 2.10. The Aggregated Demand of $DisCo_I$ and $DisCo_{II}$ is shown in Table 2.11, and its curve is shown in Figure 2.11. For $GenCo_2$, the bidding data and the associated curve are shown in Tables 2.12, and Figure 2.12, respectively. The aggregated bids and aggregated curve for the supply is the same as those of $GenCo_2$.

***Table 2.9** $DisCo_I$ Bids*

Price [$/MWh]	Demand [MW]
0	5.0
40	5.0

***Table 2.10** $DisCo_{II}$ Bids*

Price [$/MWh]	Demand [MW]
0	15.0
27.50	15.0
35.00	5.0
40.00	5.0

Table 2.11 Aggregated Demands of $DisCo_I$ and $DisCo_{II}$

Price [$/MWh]	Demand of $DisCo_I$ [MW]	Demand of $DisCo_{II}$ [MW]	Aggregated Demand [MW]
0.00	5.0	15.0	20.0
27.5	5.0	15.0	20.0
35.0	5.0	5.0	10.0
40.0	5.0	5.0	10.0

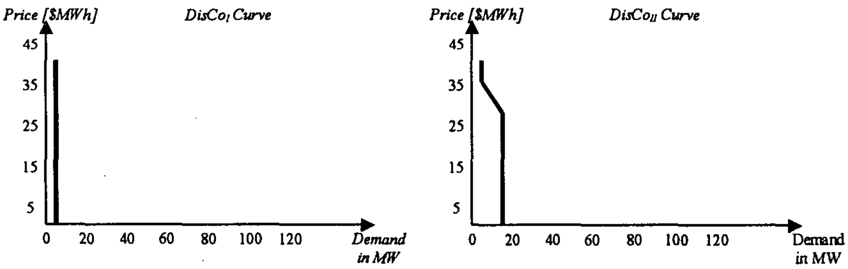

Figure 2.10 Bid Curves of $DisCo_I$ and $DisCo_{II}$

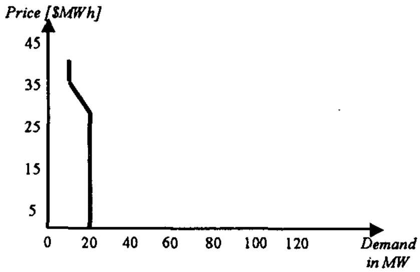

Figure 2.11 Aggregated Demand Curve

Table 2.12 GenCo$_{II}$ Bids

Price [$/MWh]	Supply [MW]
0.00	0.0
27.5	0.0
32.5	20.0
40.0	20.0

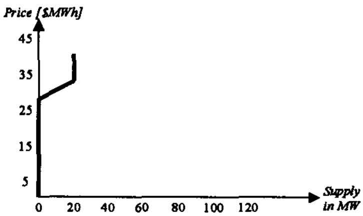

Figure 2.12 *Supply of GenCo$_{II}$*

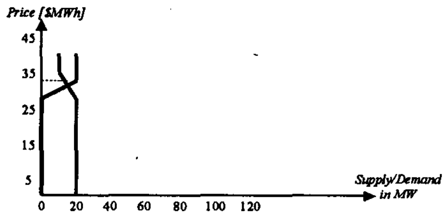

Figure 2.13 *Market Clearing Process*

Combining both aggregated curves in one graph (as shown in Figure 2.13), we obtain the market clearing price and market clearing quantity as:

Market Clearing Price = $32.5/MWh
Market Clearing Quantity =13.33 MW

5 MW of the 13.33 MW goes to DisCo$_I$ and the rest (8.33 MW) goes to DisCo$_{II}$.

- **<u>Hour-Ahead Schedules</u>:**

The hour-ahead schedule is computed as the day-ahead schedule plus adjustment to relieve congestion plus adjustment due to hour-ahead bidding. The net hour-ahead schedules are given in Table 2.13, and shown in Figure 2.14.

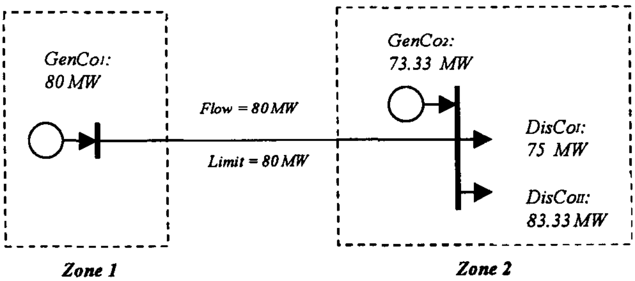

Figure 2.14 *Schedules after Hour-Ahead*

Note that the flow in the line connecting both zones is 80 MW (the maximum limit), and no need for adjusting schedules again to relieve congestion, because it does not exist.

We showed final schedule of each participant in Table 2.13. Now, in real time, let's assume that each load deviates from the final schedule. The final schedules, actual metered amounts, and deviations of loads are shown in Table 2.14.

Table 2.13 *Schedules after Hour-Ahead Bidding*

Participant	DA Schedule	Adjustment	HA Adjustment	Net
$GenCo_I$	90.00	- 10.00	0.00	80.00
$GenCo_{II}$	50.00	+10.00	+ 13.33	73.33
$DisCo_I$	70.00	0.00	+ 5.00	75.00
$DisCo_{II}$	70.00	0.00	+ 8.33	78.33

Table 2.14 *Final Schedules, Metered Data, and Deviations of Loads*

Participant	Final Schedule	Metered Amount	Deviation
$DisCo_I$	75.00	72.50	- 2.50
$DisCo_{II}$	78.33	85.83	+ 8.50
		Net Deviation	+ 6.00

In real time, the load is 6 MW over scheduled amount, which means that imbalance exists in the system, which in turn causes under-frequency occurrence. The ISO is required to restore the frequency by providing extra generation that balances the 6 MW. Note that the $DisCo_I$'s metered value is less than its final scheduled value, which means that $DisCo_I$ would sell an imbalance of 2.5 MW. Also, the $DisCo_{II}$'s metered value is more than its final scheduled value, which means that $DisCo_{II}$ would buy an imbalance of 8.5 MW. The net imbalance of 6 MW would be provided by a generator and managed by the ISO. The ISO may use different categories of energy resources available for real-time imbalance. One option is to use supplemental energy bids, where generators submit supplemental energy bids for real-time energy before each operating hour begins. Supplemental energy bids can be for incremental energy in which generators would be required to increase their scheduled generation. Or, supplemental energy bids can be for decremental energy in which generators would be required to decrease their scheduled generation by buying back energy. In our example, an increase in generation would be required.

Let's assume that $GenCo_I$ and $GenCo_{II}$ provided the ISO with supplemental bids shown in Table 2.15. Since incremental energy is required, the ISO would not use $GenCo_I$ because this would cause the inter-zonal path to be congested, so the ISO would ask $GenCo_{II}$ to increase its output by 6 MW (the net deviation) at $38.0/MWh (i.e., at its incremental price).

Table 2.15 *Supplemental Energy Bids of GenCos*

Participant	*Value*	*Inc. Price*	*Dec. Price*
$GenCo_I$	*10.00*	*37.0*	*20.0*
$GenCo_{II}$	*10.00*	*38.0*	*25.0*

- **Settlement Procedure**

DisCo$_I$:

Day-Ahead Schedule		*70.00 MW*	*at*	*$30/MWh*	*$ 2,100.000*	*(Buy)*
Adjustment to relieve congestion		*0.00 MW*	*at*	*$30/MWh*	*$ 0.000*	
Hour-Ahead adjustment		*5.00 MW*	*at*	*$32.5/MWh*	*$ 162.500*	*(Buy)*
Imbalance		*-2.50 MW*	*at*	*$38/MWh*	*- $ 95.000*	*(Sell)*
Actual Consumption	*Total*	*62.50 MW*			*$ 2,167.500*	*(Buy)*

DisCo$_{II}$:

Day-Ahead Schedule		*70.00 MW*	*at*	*$30/MWh*	*$ 2,100.000*	*(Buy)*
Adjustment to relieve congestion:		*0.00 MW*	*at*	*$30/MWh*	*$ 0.000*	
Hour-Ahead adjustment		*8.33 MW*	*at*	*$32.5/MWh*	*$ 270.725*	*(Buy)*
Imbalance		*8.50 MW*	*at*	*$38/MWh*	*$ 323.000*	*(Buy)*
Actual Consumption	*Total*	*86.83 MW*			*$ 2,693.725*	*(Buy)*

GenCo$_I$:

Day-Ahead Schedule		*90.00 MW*	*at*	*$26/MWh*	*$ 2,340.000*	*(Sell)*
Adjustment to relieve congestion		*-10.00 MW*	*at*	*$26/MWh*	*- $ 260.000*	*(buy)*
Hour-Ahead adjustment		*0.00 MW*	*at*	*$32.5/MWh*	*$ 0.000*	
Imbalance		*0.00 MW*	*at*	*$38/MWh*	*$ 0.000*	
Actual Production	*Total*	*80.00 MW*			*$ 2,080.000*	*(Sell)*

GenCo$_{II}$:

Day-Ahead Schedule		*50.00 MW*	*at*	*$30/MWh*	*$ 1,500.000*	*(Sell)*
Adjustment to relieve congestion		*10.00 MW*	*at*	*$30/MWh*	*$ 300.000*	*(Sell)*
Hour-Ahead adjustment		*13.33 MW*	*at*	*$32.5/MWh*	*$ 433.225*	*(Sell)*
Imbalance		*6.00 MW*	*at*	*$38/MWh*	*$ 228.000*	*(Buy)*
Actual Production	*Total*	*79.33 MW*			*$ 2,461.225*	*(Sell)*

Net MW of DisCos	72.50 MW + 86.83 MW = 159.33 MW
Net MW of GenCos	80.00 MW + 79.33 MW = 159.33 MW
Net payment buy DisCos	$2,167.500 + $2,856.225 = $4,861.225
Net payment to GenCos	$2,080.000 + $2,461.225 = $4,541.225

The net payment made by DisCos is larger than the net payment made to GenCos. The difference of $320 (or $4,861.225 - $4,541.225) is congestion charges, which goes to the owner of the path connecting the two zones. The money flow is shown in Figure 2.15. Note that the congestion charges are equal to flow in the path (after congestion management) times the difference of energy prices between the two zones, i.e., charges = 80 × (30-26)=$320.

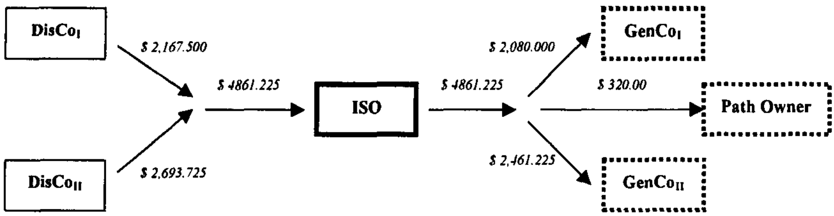

Figure 2.15 Money Flow

- **Calculations of Average Price for Consumption and Production:**

DisCo$_I$: Average Price for Actual Consumption = 2,167.500/62.50 = \$34.68/MWh

DisCo$_{II}$: Average Price for Actual Consumption = 2,693.725/86.83 = \$31.022/MWh

DisCo$_I$: Average Price for Actual Production = 2,040.000/80.00 = \$25.50/MWh

DisCo$_{II}$: Average Price for Actual Production = 2,461.225/79.33 = \$31.025/MWh

In other words, DisCo$_I$ would pay \$34.68/MWh for the actual consumption of 62.50 MW, and DisCo$_{II}$ pay \$31.022/MWh for the actual consumption of 86.83 MW. GenCo$_I$ would collect \$25.5/MWh for the actual production of 80.00 MW, and GenCo$_{II}$ collect \$31.025/MWh for the actual production of 79.33 MW.

2.1.7 Block Forwards Market[6]. For the first year of its day-ahead market operation, the California Power Exchange (CalPX) served as the world's largest totally open market with trading averaging 517,842 MWh daily at an average price of $24.44/MWh. CalPX's market participants were asking the CalPX to offer forward contracts to include on-peak blocks of energy at fixed prices.

On March 31, 1999, the CalPX announced a new product to be introduced during April and May 1999. The new product was the *Block Forwards contracts* which would improve the overall efficiency of the California's electricity market. The efficiency would be improved by offering longer term trading instruments to help market participants, especially large purchasers, hedge hourly price risk by reducing their exposure to potential price volatilities during peak demand periods. Following the FERC approval of CalPX's plans for this market, on June 3, 1999, the CalPX announced that it would open its Block Forwards Market on June 10, 1999.

The market offers monthly on-peak electricity contracts for delivery beginning in July and for the following five months. Each forward block consists of 16 on-peak hours, from 6 a.m. to 10 p.m. daily, for each day of a month, excluding Sundays and certain holidays. Contracts are available for each of the following six months, which includes much of the summer when electrical demand and prices are highest and most volatile in California.

The Block Forwards Market provides CalPX's participants a mechanism to trade standardized monthly block contracts on a forward basis. The contract is an excellent instrument to hedge against hourly price variations for purchases and sales in the day-ahead market. In its order, FERC commented on the Block Forwards Market, "We find that the proposed Block Forwards Market will provide flexibility to buyers and sellers to lock in prices months in advance of the actual delivery date. This will allow participants to manage their financial risk in the energy market of the CalPX."

The CalPX announced that a total of 2,175 contracts were matched during the first six days of electricity trading in the CalPX's Block

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[6] See Chapter 5 for more details.

Forwards Market, and market showed increasing volumes and interest by market participants in the next few days of operation. This volume of trade increased in a short period as market participants used this new product to lock in energy prices for on-peak hours during months when higher demand of electricity increases prices in the spot electricity markets.

Each Block Forwards contract represents a megawatt of electricity delivered over 16 on-peak hours for each day of the month, except for Sundays and certain holidays, which is equivalent to a contract of 400 to 416 MWh of energy over the monthly period. Block Forwards Market participants can trade energy contracts for delivery up to six months ahead of the current month. On September 24, 1999, the CalPX announced that it would develop the CalPX's Block Forwards Market for up to 12 months beyond the current trading month for both the Northern California energy delivery zone (NP 15) and the Southern California energy delivery zone (SP 15). Beginning October 1, 1999, the Block Forwards Market would accept bids for energy sales and purchases in each of the following 12 months to assist market participants in transacting contracts for energy for longer terms. The expansion to 12 months would offer CalPX's participants summer price management with physical delivery and encourage other energy traders to participate in forwards contracts trading, which in turn increase market size and mutual commercial gains of participants.

The forwards market offers energy buyers and sellers an opportunity to avoid their exposure to the volatility of energy prices during peak energy use periods, and at the same time keeps the beneficial characteristics that the CalPX has, which are the market liquidity and price discovery.

Scheduling of energy delivery in the Block Forwards Market can be done through the CalPX's day-ahead market or the bilateral market, and it would not require that Block Forwards Market traders participate in the CalPX's Day-Ahead Market.

To expand the Block Forwards Market outside of California, the CalPX announced – on September 28, 1999 – that it would plan to expand its market by involving monthly energy contracts – starting in March 2000 – for delivery at the Mead Substation (energy-trading hub) in southern Nevada. By doing that, the CalPX would provide energy traders in the western region the benefits of CalPX's services and open marketplace with price discovery for all. In addition, the Mead monthly energy contract would serve as the CalPX's first trading product outside the California energy marketplace, which would also help create efficient markets for the entire West.

Example 2.2: (Block Forwards Market)

A GenCo sold a July 1999 CalPX Trading Services (CTS) forward contract for 50 MW at SP 15. This contract would require the GenCo to make a delivery of 50 MW per hour from 6 a.m. to 10 p.m. (16 hours a day), Monday through Saturday (6 days a week), excluding holidays as SP 15 for the month of July 1999. Figure 2.16 illustrates the delivery days and the delivery hours.

$$50\text{MW (16h/day) (27day)} = 21{,}600 \text{ MWh in the whole month}$$

2.1.8 Transmission Congestion Contracts (TCCs).

To motivate an efficient expansion of transmission capacity in the California's competitive market, Transmission Congestion Contracts (TCCs) were proposed to deal with congestion in a transmission grid. When congestion occurs on a transmission line, a difference in generation prices would exist at two ends (locations) of the line. In other words, any lower cost power generated at the end of a congested line that can be transferred through the limited available capacity to the other end could be sold at higher prices. The additional revenues represented by the difference between prices at the two ends are defined as congestion rentals. If a spot price pool does not exist, these revenues represent an unexpected gain to generators that would sell power through the limited capacity line. To price the transmission in California, the contract networks approach is proposed that would redistribute congestion rentals to TCC holders which in turn would create additional incentives for the expansion of transmission system.

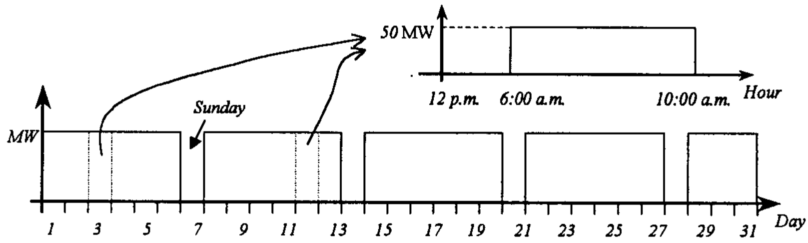

Figure 2.16 *Delivery Days and Delivery Hours in a Block Forwards Market*

In this approach, TCC holders would be entitled to receive a portion of any congestion rentals collected by the ISO based upon spot price differentials. A TCC would be defined between two points on a transmission system in terms of quantity and direction of power flow. A TCC holder is entitled to a payment equal to the difference in spot prices (adjusted for transmission losses) at the two points on the system, times the quantity of TCC contract flows that could not be completed as a result of transmission congestion. For example, the holder of a contract for transferring x MW from point a to point b could receive a monetary compensation equal to $x(\text{Price}_b - \text{Price}_a)$. If congestion does not exist, prices at the two locations would be equal, which would not entitle the holder for any payment. In other words, if there is congestion, the monetary compensation would guarantee that a TCC holder would get the quantity of power specified in TCC at the TCC delivery point for a net cost equal to the price at which power would have been sold in the absence of congestion. TCC can be traded and granted to new investors in a grid. When the possibility of congestion increases, these contracts would become more valuable, which in turn could motivate an efficient expansion of transmission capacity, as new TCCs would exceed the cost of transmission capacity addition.

2.1.9 Comments. In summary, the California market offers some advantages such as: (1) Californians have more than one choice between the PX and bilateral contracts, and the quality of supply is supported, (2) Prices of energy, transmission and ancillary services are set competitively by markets, (3) Transmission efficiency may develop by offering transmission pricing signals, (4) Owners of generating units would have an advantage in the sense that commitment of units is their responsibility and (5) Only the participants who cause congestion would be charged.

In addition to difficulties in operation and high expenses in setting it up, this market has some drawbacks such as: (1) The definition of zonal boundaries is not clear enough, (2) It is hard to consider physical limitations of resources when the same resources are bid in different markets, (3) a conflict with the unit commitment schedule could occur as the ISO adjusts the schedules to mitigate congestion and (4) the CalPX must accept the expensive power from California's investor-owned utilities, which could limit the competition in California where participants could run from the PX to other SCs and bring up additional burdens on PX costs.

2.2 NEW YORK MARKET

2.2.1 Summary. The eight members (TPs) of the New York Power Pool (NYPP) [Web10] decided to break down the pool and proposed to form a substitute represented by an ISO and other institutions such as the PX to comply with FERC rules, maintain reliability in a competitive environment and facilitate a competitive wholesale electricity market. The ISO [Web10], as an independent entity of any market participants, is responsible for bulk power system operations, including coordination of maintenance outage schedules and provision of transmission services on a comparable and non-discriminatory basis. The ISO will also administer and maintain an OASIS for the New York State Bulk Power System. What distinguishes NYPP is the highly meshed characteristics and frequent congestion, and what distinguish this model is its clearing energy and ancillary service markets at the same time which is an advantageous feature over other proposals where separation of markets is implemented. Participants choosing bilateral contracts are required to submit decremental price bids for congestion purposes.

The New York restructuring proposal combines the features of bilateral transactions (as those in the California model) and competitive energy (as pool models in Australia and UK). In this model, (Figure 2.17) buyers and sellers would bid into the PX on energy and ancillary services such as reserve and regulation. TPs[8] owns and operates the transmission network, OASIS is used as a posting system for transmission access and LSEs[9] are responsible for supplying retail customers and submit load forecasts to the ISO. To hedge fluctuations in the price of transmission, TCCs are used as financial instruments.

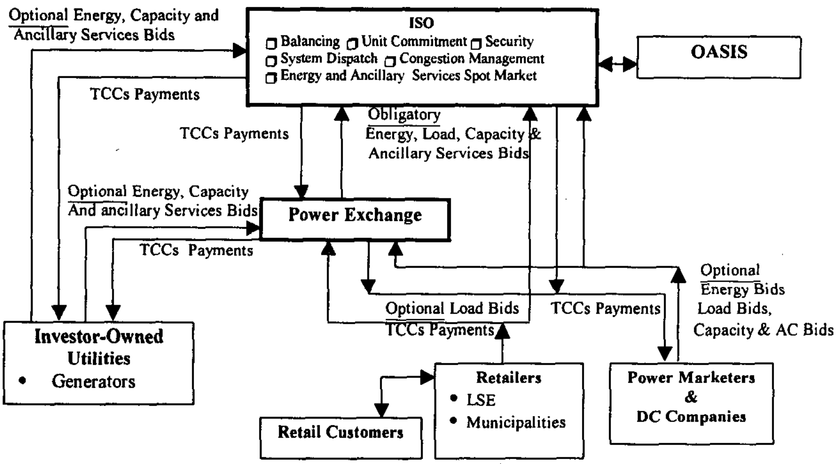

Figure 2.17 Interactions of the New York ISO with other Entities

[8] A transmission provider (TP) is defined as any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce.

[9] Load Serving Entities (LSEs) are wholesale buyers responsible for supplying energy, capacity, and/or ancillary services to retail customers.

2.2.2 Market Operations. Participants of this market either trade through the PX or schedule transactions in a bilateral form, and in both cases they can bid on ancillary services. The bids submitted to the PX are adjustable bids, which include:

- Physical Constraints: Ramp rates, minimum up and down times
- Price bids: energy, start-up and amounts.

The centralized market has two time frames: day-ahead and real-time. In the day-ahead market all LSE, in addition to LSEs that are planning to obtain their power from bilateral transactions, pass to the ISO a load forecast. LSEs have two options for committing units: either commit bilaterally or ask the ISO to commit resources on their behalf. If the ISO option is selected, the ISO uses generator bids in the day-ahead market which include start-up costs, ramp rates, minimum loading requirements, and energy bid prices, and the LSEs would be responsible for the start-up and minimum load costs associated with those units. For the first option, when LSEs commit units bilaterally, they are not responsible for the costs of units committed by the ISO, provided that their actual load is on schedule or lower than the day-ahead load forecast provided to the ISO.

A real-time (balancing) market is operated by the ISO using a centralized five-minute security constrained optimal dispatch, where buyers and sellers can participate in this market up to 90 minutes ahead with flexible bids or submit bilateral schedules for energy as well as some ancillary services. Energy imbalances relative to the day-ahead schedule will be settled based on actual locational energy prices in this market. Thus, there will be two sets of locational prices in day-ahead and real-time markets.

The NY-ISO uses a Security Constrained Unit Commitment (SCUC) software for scheduling day-ahead and hour-ahead to dispatch energy, load, reserves and regulation taking into account network constraints and scheduled outages. The same software is used to calculate Locational Based Marginal Prices (LBMPs) and ancillary services prices. LBMPs are used to calculate the price of supplying loads in different regions of the system, to settle energy markets and to calculate congestion costs paid by transacted bilateral contracts.

The NY-ISO is responsible for resource maintenance scheduling. Each transmission provider would supply the ISO with outage schedules for its own system. The ISO would determine if a particular set of maintenance schedules supplied by transmission providers would negatively affect the reliable operation of the system. The ISO would have the authority to advise them in case the provided schedule is not workable, and in return transmission providers could revise the schedules and re-submit them to the ISO[10].

Restructuring developed a non-profit PX called the New York Power Exchange (NYPE) to facilitate the majority of commercial transactions. Trades in NYPE include energy, capacity and ancillary services. Market participants may establish other power exchanges with the approval of and consistent with protocols of the ISO or regulators. The ISO's role in commercial transactions would be minimized when most transactions in day-ahead and real-time markets are scheduled through NYPE. It is also expected that NYPE would provide additional commercial services such as facilitating forward markets to its members.

By paying a Transmission Service Charge (TSC) to cover transmission providers' revenue requirements, customers including those who are wheeling through or out will have access to the entire transmission grid. Wheel-through or wheel-out customers will pay TSC to TPs in territories where energy would leave the state. TSC, which is collected by the ISO, or directly by TPs, is based on TPs' revenue requirements.

The market structure in NY is voluntary with a centralized unit commitment and economic dispatch. It is voluntary in the sense that buyers and sellers opt to enter either bilateral contracts or the centralized market. Customers can buy energy through:

1- Participating in the centralized market: Market customers would be charged the transmission usage charge which has two components, i.e., TSC, and LBMP.

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10 See: "Maintenance Scheduling in Restructured Power Systems," by Shahidehpour and Marwali; published by Kluwer Publishers, Boston, 2000.

2- Scheduling bilateral transactions: A customer will be charged the transmission usage charge which has the following components: TSC, losses, Congestion Charges (or TCC) and contract price for energy. In bilateral contracts, customers could schedule injections and withdrawals of energy at specified locations, and when bilateral transaction would lead to constrained situation[11], higher-priced generation within the constrained area will be dispatched. The out-of-merit dispatch due to a constrained situation could lead to differences in energy prices at various locations or buses. The difference in prices between any two locations represents congestion charges and marginal losses. This difference represents the economics in scheduling the constrained line between the two locations. To self-supply losses, bilateral contractors would inject power in excess of withdrawals.

Any wholesale buyer or seller would be eligible to participate in this market. Market participants would be able to use transmission facilities of transmission providers without pancaking. Under a statewide transmission tariff, the ISO will publish economic and efficient price signals at the presence of transmission constraints based on locational pricing of energy, transmission and, if possible, ancillary services. To send appropriate market signals to participants, LBMPs are announced and made available on day-ahead and real-time basis.

The monetary congestion charges between any two locations would be equal to the difference between the LBMPs multiplied by the transacted MWh. The congestion charges collected by the ISO will be credited to TCC holders. Similar to that of the California model, TCCs are financial instruments that could hedge congestion costs by entitling the owner to receive the congestion component of the difference in LBMPs between the two locations where the TCC is specified (in direction and MW value). If the congestion component of the difference in LBMPs is negative, the TCC owner is forced to pay the difference (negative congestion rent). By holding TCC, a participant would acquire price certainty on the congestion cost of its intended transaction. TCCs could stabilize transmission charges and are considered as buying

[11] Constrained situation means that sufficient low-price energy can not be transmitted into a constrained area to meet its demand.

financial equivalent of a firm transmission right in advance. A participant can purchase a TCC for a MW quantity corresponding to its intended transaction either from the primary sale of TCCs or in secondary markets, where TCCs are sold periodically. The revenues of selling TCCs are collected and paid to owners of transmission assets to be credited against the TSC of TPs. The proposed structure guarantees that a TP will not recover more than its transmission revenue requirement.

As mentioned before, buyers and sellers can either opt to participate in the centralized market by submitting bids to purchase or sell energy, or alternatively schedule bilateral transactions. The ISO uses the submitted bids to calculate LBMPs while taking into consideration the maximum limits of transmission components. All sellers (suppliers) in the energy market will be paid the applicable LBMP for the energy sold and purchasers pay the applicable LBMP. In NY, suppliers would consist of generators, marketers with resources under contract, price-responsive interruptible loads, and could include utility-affiliated generation.

Locational installed capacity requirements would be established by the ISO based on a statewide reserve requirement. The ISO's locational requirements would be established annually and will apply to all LSEs serving retail loads in the New York State. Each LSE would be required to procure installed capacity commitments sufficient to meet its locational needs for the next year. This requirement would ensure the long-term reliability by requiring that sufficient resources be secured in advance to meet projected peak loads. The process is intended to provide clear market signals so that market participants can make decisions with regard to the future supply of electricity or investment in assets.

Ancillary services are either procured by the ISO (market-based pricing) or provided as self supplied transactions. These services pertain to regulation, frequency response, energy imbalance service, operating reserve - spinning and non-synchronized (supplemental) - and storm watch. Other ancillary services are based on vertically integrated pricing (not market-based) such as reactive supply and voltage control and scheduling, system control, and dispatch services. Black start ancillary service may or may not be market-based priced. Participants which opt to self-supply ancillary services must place resources of ancillary service under the control of ISO so that the ISO could coordinate the provision of services for the entire system.

2.2.3 Comments. As in the case of the California model, the NY model has some powerful advantages and some shortcomings. This model's main advantages include: (1) New York customers have more choices, (2) All market participants are represented in the ISO, (3) Prices of energy, transmission and ancillary services are set competitively by markets, (3) Transmission pricing would signal Transmission efficiency, (4) TCC ensures that congestion charges are paid by parties which would cause congestion, and at the same time, offers certainty in prices, (5) Markets of energy and ancillary services are cleared simultaneously and there is no need to separate these markets as in California and (6) SCUC calculates generation schedules, LBMPs for congestion and ancillary services, simultaneously.

On the other hand, this model has a shortcoming, which is common with the California model, concerning the difficulty and high expenses for setting it up. Other shortcomings are: (1) Secondary markets for TCCs are cumbersome, and (2) Prices are not predictable by market participants because they are based on LBMPs.

2.3 PJM INTERCONNECTION

The Pennsylvania-New Jersey-Maryland (PJM) interconnection [Web04] is responsible for operation in major parts of the following six states: Pennsylvania, New Jersey, Maryland, Delaware, Virginia and District of Columbia. The main responsibilities of the PJM ISO are maintaining the reliability of the transmission grid, operating the energy spot market, transmission planning, unit commitment, operating real-time (balancing) market and settlement and billing functions. In this structure, transmission owner, or a designated party on behalf of transmission owner, operates the local control center in coordination with PJM, transmission access is done through the OASIS and LSEs are responsible for supplying retail customers.

The transmission network is owned by many entities but operated by PJM and two types of services are provided, which are Network

Transmission Service (NTS) and Point-to-Point Service. NTS is used for serving network customers within the PJM control area. The interactions between different market participants are shown in Figure 2.18.

Two markets are defined in this proposal: day-ahead market, which stands as energy spot market, and real-time (balancing) market, which is operated by PJM. In the day-ahead market, Locational Marginal Prices (LMPs) are calculated for all buses of the system and used by the PJM for congestion management. Energy bids are submitted to the ISO by generators and marketers which include start-up costs, no-load costs and energy prices. Load bids are submitted to the ISO by retailers which represent LSEs. Bilateral contracts data are also provided to the ISO by generators, retailers and marketers, which may include transactions with parties from outside PJM control area boundaries. Fixed transmission Rights (FTRs) are used for hedging congestion charges.

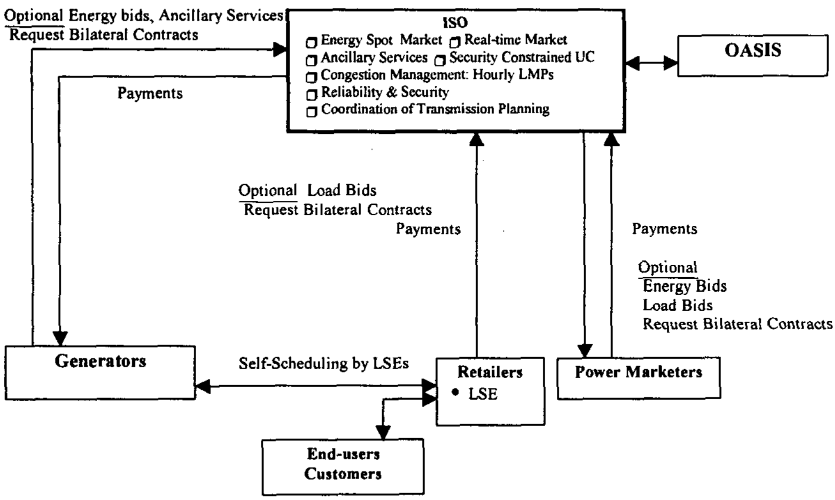

***Figure 2.18** Interactions of the PJM ISO with other Entities*

The energy spot market operations would involve three tasks which are pre-scheduling operation, scheduling operation and dispatching:

- The pre-scheduling operation would take place in the thirty-day period leading up to the operating day. In order to schedule and dispatch the system, PJM control area would maintain the data and information related to transmission and generation facilities. In addition, the ISO would be responsible for answering to capacity resource outage requests, maintaining a system that would collect outage data, performing studies on operating reserves and seasonal forecasted adequacy. The PJM members would also have certain responsibilities for the pre-scheduling time frame.
- The PJM ISO scheduling operation and dispatching would include the day ahead and hourly processes. The day ahead scheduling would happen on the day prior to the operating day, and the hourly scheduling would happen within the 60-minute leading to the operating hour. On a least-cost basis, the ISO would manage to serve the hourly energy and reserve requirements of the control area. The ISO would schedule generation resources on a least-cost basis using prices and operating characteristics submitted by the market participants (sellers). A security-constrained economic dispatch is used for this purpose. For each hour, generating units would be dispatched up to the level that would be required to serve all energy purchases and the PJM control area requirements. The chosen schedules should take into account the security of the control area on a fair basis for all participants.

The power generation required to serve all energy purchases and the PJM control area's requirements is provided by one of three types of resources: self-scheduled by member generators, resources that are bid into the spot market by members (either separate generation or aggregated) and bilateral transactions. When the hourly net generation is less than the hourly load, a member may purchase generation from the spot market.

Market participants would submit bids into the spot market before 12:00 noon of the business day prior to the operating day. Participants bid based on either individual units or aggregated generation. When ISO approves offers, unit commitment would be used to analyze the offers.

Participants might withdraw their offers before the ISO notifies them of the bid acceptance and before 4:00 p.m., and if any offer is improperly withdrawn, the participant owning the offer is obligated to pay non-delivery charges. After 12:00 noon the day before the operating day, the ISO would evaluate the offers and notifies the members of the status of their offers, either acceptance or rejection.

PJM identifies two kinds of bilateral contracts, i.e. internal and external contracts. Two contracted parties could be located within the PJM control area, or one contracted party could possibly cross the control area boundary. The physical impact on the PJM control area operations is more important to the ISO than the financial terms of bilateral contracts. Bilateral contractors should submit all required data for approval to the ISO.

The PJM unit commitment uses marginal scheduler software, which is based on a hybrid dynamic programming technique. The objective function is based on bid prices and takes into consideration constraints related to the system and units. As permitted by the ISO, and to respond to variations in system conditions during the operating period, a member may adjust self-scheduled resources under its dispatch control on an hour-to-hour basis. In this case, the ISO should be notified no later than 60 minutes prior to the hour of adjustment.

Each member of PJM provides some type of ancillary services including operating reserves. Other types of ancillary services are covered by service charges imposed on system users. When the ISO finishes the generation scheduling process, it would check the scheduled generation for supplying the required reserve capacity. Generation units that exist within the PJM metered electrical boundaries of control area would supply regulation, where LSEs would offer the regulating requirement as 1.1% of the forecast peak load during on-peak periods and 1.1 % of the forecast valley period.

2.4 ERCOT ISO

As one of the ten Regional Reliability Councils of NERC, the Electric Reliability Council of Texas (ERCOT) [Web07] used to have two security centers located in the North and the South of Texas to monitor regional security. On August 21, 1996, the ISO in ERCOT was created. ERCOT has a generating capability of about 56 GW and serves about 85% of Texas's electrical load. The Public Utility Commission of Texas (PUCT) approved the filing that orders the ISO, with the responsibility of monitoring the security of the ERCOT's bulk power system, to administer of the ERCOT OASIS and coordinate transmission planning in ERCOT.

As a result of current restructuring and changes in the electric power industry corresponding to nondiscriminatory access and competition, ERCOT recognized that what was needed to guarantee a nondiscriminatory access in the market place, was a security center independent of utilities and any participants. The ERCOT ISO started the operation of a security center in the September of 1996, and members of ERCOT include nine cooperatives and river authorities, six municipalities owning generation or transmission, four investor-owned utilities, four independent power producers, 26 power marketers and nine transmission dependent utilities.

The new Board of the ERCOT ISO is composed of three members from each of the following six market groups:

(1) Investor-Owned Utilities: Include a publicly held company, fitting the Public Utility Regulatory Act (PURA) definition of a "public utility" that owns 345 KV interconnected transmission facilities or more than 500 pole miles of transmission facilities in ERCOT.

(2) Municipally Owned Utilities and River Authorities: Include a municipally owned utility or river authority in ERCOT that owns or controls transmission facilities and dispatchable generating facilities of at least 25 MW, or owns more than 200 pole miles of transmission facilities.

(3) Cooperatives and River Authorities: Include a cooperatively owned electric utility or river authority in ERCOT that owns or controls transmission facilities and dispatchable generation of at least 25 MW, or owns at least 200 pole miles of transmission facilities.

(4) Transmission Dependent Utilities: Include a utility in ERCOT that purchases more than 25 percent of its energy requirements.

(5) Independent Power Producers: Include a non-utility that owns or controls generation in ERCOT.

(6) Power Marketers: Include a power marketer, as defined in PURA, which has registered with the Public Utility Commission of Texas.

In ERCOT, the ISO does not represent a PoolCo function and is not concerned with or responsible for any activities as those of power pool such as generation dispatch, matching of buyers and sellers, or providing ancillary services. The ISO does not have any direct control of transmission network or generation facilities, whereas this control is the responsibility of the ERCOT control areas.

The ISO's three primary areas of responsibility include: Security Operations, Transmission Access/Market Information and Coordinated Regional Transmission Planning and Engineering Support. Even though the first priority of the ERCOT ISO is to maintain the system security, the ERCOT ISO has the authority and responsibilities toward the system, which include other functions such as real-time system monitoring (control area load, spinning reserve, scheduled and actual net interchange, critical transmission component loading and system frequency), response to system contingencies (line loading relief, load shedding, schedule curtailment, re-dispatch, and ordering emergency energy schedules), administration of OASIS (including calculation, posting and updating of ATC[11]), transmission tariff administration, transmission reservation approval, ancillary service verification and energy transaction scheduling, direct dispatch for transmission congestion, transaction accounting, administration of loss compensation and coordination of regional transmission planning for future planned transactions.

In ERCOT, the wholesale transmission service may be either planned or unplanned. When a transmission service is required from designated resources to a specified load and longer than 30 days in duration, the service is called a planned service. Otherwise, it is an unplanned service, in which the transmission use is between a specified load and specified resource, 30 days or less in duration and is available

[11] See Chapter 3.

subject to the availability of transmission capacity over that required for planned service.

When unplanned transactions apply for transmission use, they would take time orders (time stamped), where the approval of service is based on a first come, first served basis. Later, if unplanned transactions are to be re-dispatched for transmission relief purposes or other reliability reasons, curtailments will take place on a last-in basis. Transmission customers after this step (when re-dispatch is needed) either opt to pay re-dispatch cost or cancel the transaction.

The annual capital expense plus operation and maintenance expense for each transmission owner are charged to loads based on their use of the system for their planned resources. This cost is allocated to LSEs based on two factors: the size of the load and the electrical distance between the load and its planned resources. For unplanned transmission service, a scheduling fee will be paid to the ISO per MWh. Unplanned transactions are charged for transmission losses based on a matrix calculated from a load flow calculation between commercial zones, where zones are geographic divisions of ERCOT used to distinguish the locations of loads and generators.

After the ISO calculates ATC for uncommitted capability of the transmission system between two points or "zones" that can be used for unplanned transactions, ATC and TTC values are posted through OASIS. ATC values are announced for each set of zone pairs at every hour of the next week, on-peak and off-peak values per day for the following 23 days, and on-peak and off-peak values per month for the next 12 months. If requested transfers are within the most currently evaluated ATC, they will be approved by the ISO, and if it exceeds the most current ATC, the transaction will be rejected. Any request of an unplanned transaction will be identified of terms of zones of the desired transaction (zone of delivery (generation) and zone of receipt (served load)).

In order to maintain the reliability of the transmission system or relieve transmission line overloads, market participants, under the guidance of the ISO, take actions such as (re-dispatch) cancellation or curtailment of unplanned transactions, rescheduling of planned transactions, engaging in an unplanned transaction to replace or offset planned transactions or rescheduling maintenance of transmission facilities. Based on signals indicating violations on transmission components, either from the ISO or a TP, re-dispatched would be done by market participants taking into consideration existing and approved transactions. Unplanned transactions are the first line of defense that would be used in the re-dispatch process to relieve constrained components, in which the ISO rejects, cancels or curtails unplanned transactions for relieving the constraints. As mentioned before, curtailment will fall initially on the most recently approved schedule requests that are contributing to the problem. The ISO would check other acceptable and practicable options such as rescheduling of planned transactions, replacing planned transactions with new unplanned transactions and/or rescheduling the maintenance of transmission facilities. If the constraint still persists, the ISO would ask certain transmission customers to reschedule the use of their planned resources in a manner that would relieve the constraint. If a constraint could not be mitigated by rescheduling planned resources, the ISO might force transmission customers to take energy from unplanned resources that would remove the constraint, or order transmission providers to reschedule any maintenance of transmission facilities whose outage could contribute to the constraint. The ISO would allocate the extra cost (including additional maintenance cost incurred by the transmission provider) caused by an ordered unplanned transaction to all planned transmission service customers in proportion to their share of the transmission cost of service. In this process, the ISO would post the re-dispatch and curtailment information on OASIS.

2.5 NEW ENGLAND ISO

As a voluntary association, the New England Power Pool (NEPOOL) was established in 1971 [Web05] to assure two objectives: maintaining reliability and achieving economy. NEPOOL was originally limited to customer-serving electric utilities, but later it included non-utility generators, power marketers and brokers. The NEPOOL operation increased the overall reliability of the system and provided saving to utilities and customers.

New England ISO now has a service contract with NEPOOL to operate the bulk power system and to administer the wholesale marketplace. To comply with FERC rules [Web06], New England ISO also hosts an OASIS for TPs in New England. The ISO operates as a single control area, where NEPOOL has a control center to centrally dispatch the bulk power system economically using the most economical generating and transmission equipment available to supply the electric load in the region at any given time.

The organization of ISO is composed of two major areas:

- *System Operations and Reliability*: responsible for the daily dispatch of electricity resources assuring the reliability of the bulk power system, and the administration of the open access transmission tariff, short-term and long-term demand forecasting and reliability planning.
- *Market Operations*: directs residual wholesale electricity marketplace to ensure fairness to all market participants and full competition that could lead to the lowest price for electricity, provides customer services and training support and performs the settlement function in the marketplace by ensuring that sellers in the spot market are paid by purchasers, and tracks bilateral contracts between market participants.

The market of the New England ISO is described as *residual* wholesale electricity market, where residual means that a market participant who produces electricity in excess of the demand can sell the excess into the wholesale market to be used by other participants. The market is a day-ahead-hourly marketplace, where wholesale electricity suppliers and generators would bid their resources into the market the day before, and submit separate bids for each resource and for each hour of the day. ISO orders bids from the lowest to the highest for balancing the expected hourly demand forecast for that hour and each hour in the next day. The ISO then would determine the least cost dispatch sequence for the next day that would reflect the actual bids. Generators will then be dispatched to match the actual load occurring on the system. The highest bid resource that was dispatched to meet the actual load would set the MCP for electricity. This is the price that would be paid to all suppliers by buyers who purchase power from the residual market. The suppliers would be encouraged to bid the most competitive prices to compete for dispatch in the wholesale market. When a bidder bids too high, some of the generators would presumably not be dispatched and the bidder might not earn any revenues.

The New England ISO proposed seven markets to be run under the ISO directions. These markets are one energy market, four ancillary service markets and two capacity markets. The ancillary service markets are:

- ten minute spinning reserve (TMSR) market,
- ten minute non-spinning reserve (TMNSR) market,
- ten minute operating reserve (TMOR) market and
- automatic generation control (AGC) market.

The capacity markets are:

- operable capability market and
- installed capability market.

The energy and capacity markets are residual markets and the other markets are full requirements markets. In a residual market, only the difference between a participant's energy resources and its energy obligations is traded in the ISO market. In other words, a market participant who would produce electricity in excess of demand could sell the excess in the wholesale market. In a full requirements market, all products are traded through the ISO.

Different from other restructuring proposals for a multi-settlement system, the NEPOOL energy market has proposed a single-settlement system. In this system, the ISO of NEPOOL uses day-ahead bids for scheduling, but prices of winning bidders are determined in an *ex-post* fashion, that is based on real-time dispatch. In this process, bids and schedules are submitted in day-ahead, and the ISO would use bids, forecasts, operating and transmission constraints, and bilateral schedules to schedule units for the next day on a minimum-cost basis. The ISO may accept bid and/or schedule changes until an hour before real time. Then the ISO would calculate real-time spot prices (shadow prices) from the actual real-time dispatch optimization problem, taking into account bids and forecasts for next hours. The calculated real-time spot prices are the prices used for settlements, where generators are paid and loads are charged. On the other hand, in a multi-settlement system, bids submitted in day-ahead are used as a basis for scheduling and settlements for day-ahead transactions, and *ex-post* price is only used for deviations from the day-ahead schedule.

In the energy market, participant's excess energy, after supplying its energy obligations, is traded in the ISO energy market. Hourly bids in $/MWh are submitted on a day-ahead basis for each hour of the next day and the ISO then, for the accepted bids and on minimum total cost basis, would schedule generating units that would run on the following day. Later, on an hourly basis, the energy market is settled and all winning transactions would be priced at the *ex-post* energy MCP. In the absence of congestion, all suppliers obtain the same energy price which is the real-time spot price, where each provider gets a monetary value equal to the product of the MWh sold and the MCP, and each buyer is charged the product of the MWh purchased and the MCP. If transmission congestion exists, providers would be paid for an *out-of-merit*[13] order dispatch to mitigate the congestion based on their bids. Basing energy prices on *ex-post* MCP would motivate suppliers to drive the spot price by taking proper actions after posting the day-ahead schedules by the ISO.

In the TMSR market, TMSR is bought or sold through the ISO where hourly bids in $/MW for the next day are submitted to the ISO and, as in the case of the energy market, the hourly market is settled after the fact (*ex-post*). By taking into consideration bid prices, lost opportunity costs[14], and production cost changes, the ISO would use the dispatched units to select the least-cost combination of resources to

[13] Out-of-merit dispatch, as used in this book, refers to resources dispatched by the ISO that do not receive the MCP. These units receive their bid prices for each megawatt hour used by the ISO.

[14] Lost Opportunity Cost is equal to the TMSR (MW) times the difference between the MCP and the energy bid price of the TMSR (MW).

provide the required TMSR for that hour. Hydro units and dispatchable loads are the only entities that could bid into this market when the market begins its operation. The ISO may select fossil-fueled generators (even though they cannot bid into the market) to participate in the market based on lost opportunity costs and production cost changes. The resources chosen to provide this service would be paid the energy MCP for the provided MWh, in addition to lost opportunity cost, production cost changes, and the product of the bid and the MW provided. The ISO would calculate the total cost to provide TMSR and proportionally charge that total to loads.

In the second ancillary services market - the TMNSR market - all TMNSR would be bought or sold through the ISO, where hourly bids in $/MW for the next day are submitted to the ISO, and as the first market, the hourly market is settled at the *ex-post* price (after the fact), and selected resources are paid the product of the MCP and the MW provided as reserved capacity. The ISO would calculate the total cost to provide TMNSR and charge that total to loads, proportionally.

In the third ancillary services market - the TMOR market - the same procedure is followed as in the other markets, where all TMOR would be bought or sold through the ISO as hourly bids in $/MW for the next day are submitted. Here, the markets for all hours are settled at the *ex-post* price, selected resources would be paid the product of the MCP and the MW provided, and the total cost of providing TMOR would be charged proportionally to loads.

In the AGC market, AGC is measured in Regs[15] and bought or sold through the ISO such that hourly bids for the next day are submitted and the markets are settled hourly at the *ex-post* price. The ISO would select winning generating units to provide least-cost energy (based on bids, lost opportunity costs and production cost changes). Winning resources are paid the MCP (according to the amount of time on AGC) times the number of regs plus a payment for the AGC service actually provided plus any lost opportunity costs. The total cost of providing AGC is charged proportionally to loads.

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[15] A Reg is a commodity by which AGC is defined. It represents the response of a unit constrained by the AGC range.

In the first capacity market (operable capability market), the participant's excess operable capability resources after supplying its load plus operating reserve is traded in the ISO operable capability market. The hourly bids in $/MW for the next day would be submitted to the ISO and each of hourly markets would be settled at the *ex-post* price. The ISO would calculate the MCP for each hour based on participants' bids with excess operable capacity. In this market, participants with insufficient operable capability would pay the MCP for each MW to other participants with excess operable capability who bid less than or equal to the MCP.

In the installed capability market, and on the last day of the month, the participant's excess installed capability resources would be traded in the ISO's installed capability market. On a monthly basis, bids are submitted in $/MW-month. The ISO would calculate the MCP based on the bids of those participants with excess installed capacity. In this market, participants with an insufficient installed capability would pay the MCP for each MW-month to other participants with excess installed capacity who bid less than or equal to the MCP.

To manage transmission congestion, NEPOOL has proposed a uniform uplift charge to cover the cost of mitigating the transmission congestion. When transmission congestion exists on transmission paths, the ISO would select generating units in an *out-of-merit* order to solve the minimum cost security-constrained optimization problem and remove the congestion accordingly.

2.6 MIDWEST ISO

The Midwest ISO (MISO) [Web08] was formed in February 12, 1996 and organized by a group of Midwest transmission owners within NERC reliability regions, including the East Central Area Reliability Coordination Agreement (ECAR), Mid-America Interconnected Network (MAIN) and Mid-Continent Area Power Pool (MAPP), which form a large portion of the North American grid. MISO oversees more than 50,000 miles of transmission lines, encompassing more than 78,000 MW of electric generation and serving a territory covering an area over

200,000 square miles[16]. MISO was initially created as a voluntary organization of electric transmission owners in the Midwest to fulfill the need for transmission independence and to meet FERC requirements to insure that Midwest's customers benefit from competition. In addition, the recommendations of EPRI regarding preferred suites of standards for electric utility use would be used throughout MISO.

2.6.1 MISO's Functions. MISO differs from other ISOs since it operates as a single transmission control area that encompasses many individual generation control areas. The MISO's purpose is to assure that all transmission customers would receive non-discriminatory, equal access to the transmission system under its jurisdiction and functional control. In addition to open access to transmission, the MISO's principal objectives are to provide solution to transmission pricing problems[17], resolve loop (parallel path) flows problems, keep and improve power system reliability and security, and coordinate the planning of the transmission system.

According to MISO, individual transmission owners would continue to perform the automatic generation control (AGC) functions for their generation control areas and switching operations under the direction of MISO. MISO would perform the following functions: transmission management, transmission system security, congestion management, ancillary service coordination, transmission and generation planning, accounting and billing, and inadvertent interchange accounting. MISO would be the designated NERC security coordinator with the following functions: planning for next day operations, including security analysis and identifying special operating procedures that might be needed; analyzing current day operating conditions; and implementing the NERC TLR procedure or local procedures to mitigate overloads on the transmission control area.

[16] Documents are available on www.midwestiso.org and www.ferc.fed.us.

[17] Pancaking of rates is an example of pricing problems.

2.6.2 Transmission Management. MISO maximizes revenues associated with transmission services in order to efficiently utilize the transmission system. Transmission management includes the following functions:

- Operations Scheduling: transaction schedules, transaction service, unit commitment, maintenance schedules, area load forecast, and MISO verification.
- Generation Redispatch for Transmission Service Request: In the event of insufficient available transfer capability, MISO would be able to execute the optimal power flow to determine the feasibility and the cost of redispatch to honor the transmission service request.
- MISO OASIS: The MISO OASIS node would include secure interfaces separating the public Internet users of the OASIS and the private MISO Intranet users of the OASIS. MISO would determine TTC/ATC for the short-term (up to two weeks in hourly increments) and for the long term (beyond two weeks in daily increments). ATC calculations would include provision for the following: Firm transactions, Non-firm transactions, On-Peak periods, Off-Peak periods.
- Point-to-Point Transmission Service. MISO would manage firm and non-firm point-to-point transmission service scheduling at designated Point(s)-of-Receipt and Point(s)-of-Delivery. MISO receives, validates, processes, and schedules all transaction requests. The rates to be charged for the various Transmission Services are solely administered by MISO. MISO has the authority to curtail transmission service and to allocate losses and ancillary services. MISO passes through (on a monthly basis) the transmission owner's revenues, associated with transmission services, to the transmission owners.

2.6.3 Transmission System Security. MISO is responsible for the reliability of the MISO transmission system. Generation control area operators are responsible for the reliability of their own generation control areas. MISO is responsible for establishing and implementing operating procedures for normal and emergency conditions. MISO would have the ability to require generation redispatch in order to deal with potential or existing emergency situations. MISO has the authority to order the shedding of firm load and instituting voltage reduction procedures. MISO coordinates the implementation of any reserve sharing agreements among or between generation control areas.

MISO aggregates load forecasts provided by each generation control area and all load serving entities. Operating load forecasts are required for the near term (next day), short term (up to two weeks), and long term (beyond two weeks). Load forecasts are for security analysis studies and reporting. MISO performs a contingency analysis application (typically every 30 minutes) to investigate the impact of losing critical transmission system and generation facilities. MISO considers the effects of cascading outages. The member generation control areas are responsible for maintaining the MISO-scheduled voltages. Voltage schedules are produced on a periodic basis, typically every hour for the upcoming hour. MISO runs a stability analysis application to anticipate the potential for transmission system voltage collapse and loss of generator synchronization. It would investigate the potential for control area separation from the interconnection together with appropriate emergency procedures.

2.6.4 Congestion Management. MISO calculates the required PTDFs[17] and OTDFs[18] to determine the effect of transactions on constrained transmission facilities. The need for any transaction curtailment is also communicated to the affected parties. As the security coordinator, MISO administers the NERC TLR procedure. Under security threat conditions MISO will have the authority to immediately order the generation control areas to redispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until interchange transactions can be reduced utilizing the TLR procedures, or other methods, to return the transmission control area to a secure state.

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[17] Power Transfer Distribution Factors

[18] Outage Transfer Distribution Factors

2.6.5 Ancillary Services Coordination. Ancillary services include, scheduling, system control, and dispatch, reactive supply and voltage control, regulation and frequency response, energy imbalance, operating reserve. MISO would fulfill its requirement by acting as the transmission customer's agent to secure ancillary services from the generation control area operators. MISO would ensure that every scheduled transaction is supported by the required ancillary services and would deny any transaction scheduling request where the required ancillary services have not been arranged. Ancillary services offers for service would be posted on the MISO OASIS node.

2.6.6 Maintenance Schedule Coordination. MISO approves the scheduling of maintenance of transmission facilities making up the transmission system and coordinates with generation owners, as appropriate, the scheduling of maintenance on generation facilities. Planned transmission maintenance requests would be submitted for approval at least two weeks in advance of an outage and MISO assesses the requests with respect to ATCs, ancillary services, and the security of the transmission system. Within two business days of receiving a request, MISO either approves or denies the request. Rejections are accompanied with suggested time frames in which maintenance would be acceptable. MISO has the authority to revoke any previously approved planned transmission maintenance outages in the event of circumstances that compromise the integrity and reliability of the transmission system. MISO coordinates the maintenance of generating units as appropriate to the extent such generator maintenance affects transmission capability or reliability.

2.7 SUMMARY OF FUNCTIONS OF U.S. ISOs

The following table shows summarized functions of different ISOs [Web01, 04, 05, 07, 08, 10, 11].

California ISO	New York Power Pool ISO
• Maintains System reliability, security and stability • Controls dispatch of generation and transmission • Performs balancing function • Schedules feasibility validation • Administers transmission tariff • Administers inter-zonal and intra-zonal congestion management • Incurs unbundled ancillary services from ancillary services spot market • Performs settlements for grid access, congestion, ancillary services • Provides real time control of all ancillary services	• Stands as control area operator • Maintains the reliability and security of the power system • Performs security-constrained unit commitment • Calculates LBMPs • Administers day- and hour-ahead market • Administers ancillary services market • Provides transmission service and ancillary services to eligible customers • Coordinates maintenance scheduling of the transmission system and generating units • Coordinates schedules for generating units under contract to provide installed capacity to the power system • Facilitates the financial settlement of ISO and Power Exchange transactions • Requires customers entering into service agreements under the tariff to maintain appropriate levels of installed and operating capacity.

ERCOT ISO	New England ISO
• Security of the ERCOT system • Market facilitation • No load and generation balance • Coordination of transmission planning • Response to system contingencies • Administration of loss compensation and transmission tariff • Direct dispatch for transmission congestion • Administer OASIS (including ATC) • Provide a forum for coordinated regional transmission planning • Develop operating and reliability guides	• Control area operator • Controls bulk transmission system operation • Dispatches all generation subject to participant self scheduling • Administer market operations: energy market, ancillary services markets and capacity markets • Administers market settlement rules and regional transmission tariff

PJM ISO	MISO
• Operates the PJM control area • Manages and administer the competitive energy market • Maintains security and reliability • Coordinates transmission planning, spot market and balancing • Performs security-constrained unit commitment • Calculates LMPs • Manages FTRs auction • Direct and coordinate the operation of the designated transmission facilities • Administer the transmission tariff, including determination of available transfer capability • Performing system impact studies • Schedule transmission service • Curtailing transmission service • Coordinate regional transmission planning • Support the administration and implementation of an agreement to establish necessary reserve levels and sharing of such reserves	• Maintaining and improving power system reliability and security • Planning coordination of the transmission system • Determining short-term and long-term ATC values • Processing transmission service requests and scheduling of transmission ancillary services • Coordination of generation and transmission maintenance • Implementing pricing policy • Re-dispatching generation for transmission congestion or system security • Collection and distribution of transmission revenues

CHAPTER 3

OASIS: OPEN ACCESS SAME-TIME INFORMATION SYSTEM

Summary: This chapter gives a historical background on and shows the functionality and architecture of OASIS[1]. It also describes interactions of transmission providers and transmission customers with OASIS. In addition, the chapter shows how requests to sell and purchase transmission services are conducted through OASIS. Major types of information posted on OASIS would include available transfer capability (ATC) and total transfer capability (TTC), ancillary service offerings and prices, transmission service products and prices, transmission service requests and responses, facility status information, transmission service schedules, and transmission-related communications. ATC values are key to competitive electricity markets as they are indices that determine whether particular proposed transactions of electric power can or cannot be approved or occur. In this chapter, we define and explain the concepts of TTC, ATC and the related terms in detail. The chapter includes a few examples of OASIS network implementation in various regions of the United States. The presented examples show how the OASIS information could differ from place to place while some basic information is shared by various OASIS implementations.

3.1 INTRODUCTION

In October 1992, the National Energy Policy Act of 1992 (EPAct) was established which offered many changes in gas and electric utility

[1] OASIS includes computer systems and associated communications facilities that public utilities are required to provide for the purpose of making available to all transmission users comparable interactions with the transmission services (TS) information.

industries. This act also guided FERC to issue, on March 29, 1995, its Notice Of Proposed Rulemaking, which became known as Mega-NOPR, regarding the promotion of wholesale competition through open access nondiscriminatory transmission services by public utilities. The Mega-NOPR outlined rules and procedures necessary to promote wholesale competition, and was accompanied by a notice of technical conference and request for comments on Real-Time Information Networks (RINs).

Since Mega-NOPR was released, many conference discussions, technical working group (WG) and committee meetings took place throughout that year which were ended on December 13, 1995 by issuing a related NOPR on Real-time Information Networks and Standards of Conduct[2]. The latest NOPR mainly discussed the technical aspects of the design and operation of RINs. Here, many participants and analysts pointed out that RINs alone would not be adequate to eliminate the traditional advantages that a utility's wholesale marketing affiliate would have in scheduling and purchasing transmission capacity. They further asked in their comments for providing additional safeguards.

In response to Mega-NOPR, the other NOPR and individuals' comments, FERC Order No. 888 and FERC Order No. 889 were issued on April 24, 1996. The two Orders were issued with intent to bring about a competition to the wholesale electricity market, accelerate the market competition, lower electricity prices and create more choices for consumers. FERC Order 888 required transmission providers (TPs) to file Open Access *Pro-Forma* Transmission Tariffs. FERC Order 889 required transmission providers to create an OASIS bulletin board on the Internet, and required transmission providers to functionally separate their transmission employees from wholesale energy sales and purchase employees.

Among the requirements of FERC Orders was the open competition, which could be fulfilled by posting the available information on the Internet. Generally speaking, the available information includes open and uniform tariffs and standard contracts, transmission service products and prices, application forms for requested services, transmission system studies, standards of conduct for transmission provider employees, and transmission capacity information. It was recognized by FERC that the

[2] OASIS was formerly called RINs.

access to transmission network in an electricity competitive environment would necessitate an equal and same-time access to information on transmission availability and price. FERC recommended to make this information available to market participants in a readily available format.

In response to the FERC's policy on open transmission access, the electric power industry developed the OASIS as an Internet-based information network. It is perceived that, by providing open and comparable information to all potential users of a transmission system, the network would constitute part of the foundation for competition in the wholesale electricity supply. OASIS is an electronic Internet-based communication system which is required by FERC to be used by all transmission providers in the U.S. as a near-instantaneous transmission reservation system. With this communication system, competing wholesale utilities, including TPs' own generation operations, will have the ability to monitor simultaneously the transmission availability and costs. This system would provide the on-line transmission information to allow instantaneous reservations and, at the same time, minimize any favoritism given to a TP's affiliated entities.

3.1.1 What is OASIS? OASIS permits posting, viewing, uploading, and downloading of transmission transfer capability in standardized protocols. The data posted on OASIS should clearly identify what service is available, which requests were accepted, denied, interrupted or curtailed, permitting business decisions to be made solely from the OASIS-derived information [Sav97].

OASIS permits its users to reserve capacity on a transmission system, purchase ancillary services, resell transmission service to others, and purchase ancillary services from third party suppliers [Tsi97, Tsi98]. Users can rely on OASIS to obtain information related to transmission system, request services over the transmission system, and provide a process for requesting transmission service. OASIS would enable any transmission customer (TC)[3] or its designated agent[4] to communicate requests for trading the available transmission capability.

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[3] A transmission customer is any eligible customer that can or does execute a transmission service agreement or can or does receive transmission service.

Transmission is the key component to an end-user's reliability in retail wheeling, so understanding how OASIS would function is a critical component of the electricity purchasing process. In addition to the fact that OASIS stands as a major step toward nondiscriminatory availability of information necessary for transmission access, OASIS would strengthen the accountability of both TPs and TCs through the transparency of standards and publicly available electronic processes. Although the OASIS concept is a clever tool invented and developed by the electric power industry sectors to manage and disseminate information that would increase the competitive behavior in this industry, there are still some uncertainties in its future and implementation. The initial successes of OASIS were accompanied by serious operating problems, which necessitated additional developments for supporting competitive wholesale electricity markets.

During the initial implementation of OASIS (which was called the OASIS Phase 1) it encountered criticisms initiated by users, especially customers. Users raised issues such as, OASIS would not consider next-hour reservations to support the short-term energy market, and even though this phase permitted the reservation of transmission capacity, it did not afford the mechanism for scheduling the flow of energy across that capacity. Other problems were raised such as, security tools were inadequate to allow OASIS to become a financial-grade system, customers were requesting dynamic interactions between transmission users and transmission providers, and some users requested more standards for graphical displays.

Some of challenges for the implementation of OASIS included the adoption of more user-friendly operations, standardization of terms and graphics at different nodes[5] of OASIS, consistency in definitions and business practices across nodes, and other problems which will be discussed later in this chapter.

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[4] Designated agent is any entity that performs actions or functions on behalf of TPs and TCs required under TP Tariffs.

[5] The OASIS network is composed of sub-networks called OASIS nodes, in which each regional OASIS is a node.

3.2 FERC ORDER 889

In addition to Order 888, Order 889 was issued to further implement EPAct. This second order required electric utilities to establish OASIS. Transmission owners would also be allowed by FERC to aggregate and develop a joint OASIS for a larger, more contiguous geographic area. This order described the information to be made available on OASIS, presented standards and protocols for posting such information, and presented procedures that should be followed by utilities to respond to requests for transmission services. Moreover, Order 889 defined strict standards of conduct mandating the separation of utilities' wholesale power marketing/merchant activities from their transmission/ reliability operation. Utility personnel involved with wholesale power marketing were required by this order to obtain transmission data through OASIS, like all other competitors.

Order 889 has three components: (i) standards of conduct to separate a utility's transmission operation from the purchase and sale of wholesale electricity, (ii) basic rules and posting requirements of OASIS systems, and (iii) standards and communications protocols for OASIS operation [Oas96a].

FERC Order 889 would guarantee that transmission owners and their affiliates do not have a biased or unfair competitive advantage in using transmission facilities to sell power. The OASIS rule would apply to any public utility that could offer open access transmission services under the open access *pro forma* tariff, including both wholesale and retail transmission customers that are able to receive unbundled retail transmission. TPs are required to: (1) establish or participate in an OASIS that would meet certain requirements and (2) comply with prescribed standards of conduct.

FERC Order 889 established standards of conduct to guarantee that employees of a public utility engaged in transmission system operation would work independent of the other employees who are engaged in utility's wholesale merchant functions[6]. In other words, the standards were designed to prevent employees of a public utility or affiliate

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[6] Wholesale merchant function is the sale for resale, or purchase for resale, of electric energy in interstate commerce.

engaged in marketing functions from obtaining a preferential access to the OASIS related information or from engaging in extremely discriminatory business practices. The independence is required to assure that transmission access is truly open and that employees of the transmission owner and their affiliates do not get any special benefits or information because of their affiliation and they do not have unfair competitive advantages in using the transmission network. Fairness is ensured in the sense that public utilities obtain certain information (such as TTC or ATC) on their transmission system for their own wholesale power transactions through OASIS in the same way that their competitors would obtain the information [Sav97].

In addition to the fact that marketing employees must use the same OASIS information that would be available to other entities to obtain the transmission information, the information must be posted immediately on OASIS if it is provided to marketing personnel. Any employee transfers between affiliated transmission and marketing entities must be posted as well, as FERC requires it in its Order. If a TP would offer discounts for transmission rates or ancillary services to affiliates or full-service wholesale customers, such discounts must also be offered to all buyers using the same path or any unconstrained path. According to FERC order, OASIS would become the tool for assuring a level playing field for all transmission customers and monitoring transmission owner compliance in the electric power industry.

3.3 STRUCTURE OF OASIS

3.3.1 Historical Background. NOPR issued by FERC on March 29, 1995, was accompanied by a notice of technical conference and request of comments from industry on RINs. Based on inputs from the industry, the name was changed to Transmission Services Information Networks (TSIN) which was also recognized as OASIS. A conference was then held in July 1995 to ask the industry to provide its feedback on how the information networks should be developed and what requirements the networks should have. The conference ended with an agreement to form two working groups (WG), composed of representatives from the industry. The two groups were the "*What WG*" and the "*How WG*". On August 10, 1995, FERC announced the formation of the two working groups. Each working group then prepared and submitted reports to FERC describing areas of consensus and differences reached in the group. Considering these reports, FERC issued a NOPR on RIN on December 13, 1995.

The OASIS What WG was the working group that handled questions like, *what information should be posted on an OASIS node?* The conference agreed that NERC would facilitate the What WG. The focus of this group was on questions like, *what information and services should TPs make available to TCs and what transactions to buy transmission capacity or transmission service should take place?*

The OASIS How WG was a voluntary, independent and nondiscriminatory industry group that would develop technical standards and communication protocols for OASIS, and has facilitated the design, development, and implementation of OASIS since August 1995. The WG handled questions like, *how was OASIS going to be implemented?* The conference agreed that the Electric Power Research Institute (EPRI) should facilitate the How WG. The main objective of this group was to set minimum requirements that would guarantee that the information networks would enable an open access transmission. This working group would deal with issues like, network architecture, information access, information model, security and performance for implementing the network.

The OASIS How WG developed a document titled, OASIS Standards and Communication Protocols (S&CP). This document has standards and formats for OASIS nodes [Tsi97, Tsi98, Oas96a]. The S&CP document, which was issued with the final rule, was written by an industry group facilitated by EPRI and issued by FERC in September 1996 [Oas96a, Ost96]. According to FERC Order 889, each utility (or its agent) that would own, control, or operate transmission facilities that are subject to the FERC jurisdiction must create or participate in an OASIS.

The two WGs worked jointly on the OASIS information until early 1996 when the What WG was retired. In April 1997, a new WG was formed which was called Commercial Practices Working Group (CPWG). This WG was an independent and a consensus-based group whose members represented industry segments and took on the responsibility of proposing business solutions for OASIS in addition to other aspects of transmission access.

The CPWG's aim was to resolve business practice issues as needed to ensure a nondiscriminatory transmission access and competitive and reliable electricity markets by advising the How WG on OASIS requirements, in addition to its role on issues related to commercial impacts of reliability standards proposed by NERC. Inside the group, the CPWG's goal was to reach consensus-based solutions as the group voted in two TCs and TPs blocks, and each resolution required a majority of both blocks to pass. The How WG supports FERC's objectives for OASIS by filing a large number of technical standards and protocols used by FERC. The two open and nondiscriminatory forums (i.e., the How WG and the CPWG) operated as a public process to achieve consensus-based results to develop OASIS.

The OASIS How WG used the resolution of "business practice standards and guides" issued by the CPWG as a feedback for developing the updated technical standards. The CPWG specified the market-based needs (needs of market participants), passed those needs to the How WG in the form of functional and performance requirements, and the How WG arranged for the required technical standards to support the requirements.

During its work, the How WG established the following set of guiding principles to design the OASIS [Tsi97, Tsi98, Cau96]:

- The first principle is *nondiscriminatory access to information:* all customers should have an open access to the required information. It was perceived that this principle would be composed of three parts [Tsi96, Tsi97, Tsi98]: (1) A minimum set of OASIS functionalities would be available to all customers; (2) Any additional functionality or increased performance would be made available to all customers on a nondiscriminatory basis, subject to reasonable fees; (3) All information by responsible parties would be displayed on the same page or the same file format as that of TP.

- The second principle *is seamlessness* or *interoperability:* from a customer's point of view, easy access to information from multiple providers on multiple OASIS nodes would imply seamless interconnections. From a technical point of view, this seamlessness implies that all systems are interoperable, from the communications links, to application interfaces, through the database access methods.

- The third principle is *flexibility:* OASIS nodes should have as much flexibility to use existing communications systems, support added functionality, or even be able to use entirely different functions over the long term. Customers should have the flexibility to use commercially available hardware and software that are available from more than one supplier. Both providers and customers should have the flexibility to develop or purchase their own business applications.
- The fourth principle is *expandability:* OASIS nodes must be built with continuous expansion in mind. As new functionality and information requirements would emerge, OASIS nodes must be capable of being upgraded with a minimum loss to the prior investment.
- The fifth principle is *customer-driven:* it is presumed that customers would base their applications around commercially available desktop hardware and software applications, including database managers and spreadsheets. Therefore, the OASIS design must address key customer requirements, including, user friendliness, performance, security, and reliability.
- The sixth principle is *affordability:* providing a basic OASIS functionality must be possible at a reasonable cost while the stated goals for the network would be met and more advanced systems would be allowed and encouraged.

3.3.2 Functionality and Architecture of OASIS. The main focus of the OASIS network is on the dissemination of the ATC information and other required information, processing the transmission service requests, and providing its basic function to support power marketing and energy trading. OASIS is constructed such that it would involve simulation techniques and communication technology to act as a user-friendly tool for supporting the operations of energy markets. The OASIS information, as required by FERC, should be available both on-line and retrievable through the Internet using a set of specified template files [Tsi97, Tsi98, Ma98, Oas96a ,Oas96b, Fer96b, Pjm97, Tsi96, Eia98, Erc 98]. Figure 3.1 is an illustrative structure of the OASIS functionality [Eia98].

OASIS is a network of sub-networks called *OASIS nodes*. Each OASIS node is a subsystem, represented by a computer system that would provide access to the transmission services information by transmission customers. The OASIS node itself may consist of a variety of computing hardware, software, and internal communication networks that comply with FERC requirements. In each region of the United States, there is an OASIS which would serve TPs and TCs in the region. Each regional OASIS would operate as an on-line clearinghouse of transmission and ancillary services information for the region. The regional OASIS together would form a large national OASIS network. The OASIS network was suggested as a means of providing a comparable access to transmission services information. The OASIS network is open to all qualified transmission market participants and other authorized users. All OASIS nodes would be developed as the Internet sites to assure universal access, where a registration and different levels of access codes would be required to assure the security of the system.

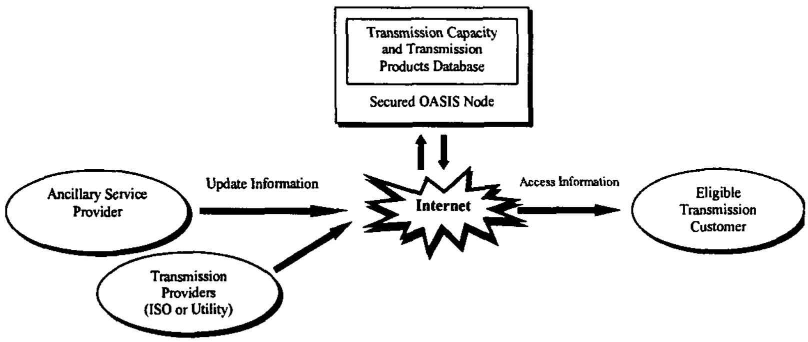

Figure 3.1 *Illustration of OASIS Function*

Public and private Internet networks are used by the OASIS network to give users in the United States and around the world an access to the transmission information. Standard Internet tools were proposed to access and exchange the information through OASIS to make the system open to a wide range of users. The OASIS network would support interactions between TPs and TCs. Registered qualified customers may use standard Internet Web browsers to access OASIS nodes where the OASIS network would use security guards to protect data from unauthorized users, and to limit access to the specific information required by the user.

It was estimated by FERC that there would be 20-35 OASIS sites (nodes) formed by TPs to represent all public transmission in the U.S., and it was also estimated that four respondents, on average, would share each site, where OASIS would use the Internet as a communication media to permit authorized users, such as TCs, to have access to the information from any location in the world. The Internet was proposed as a communication media due to its high functionality, consistency of interconnected networks and the low cost of services [Cau96]. OASIS would enable TCs, through the Internet, to obtain the available information on ATC, costs and tariffs for transmission capacity, and cost of ancillary services [Cau96].

Each regional OASIS would have computer as the OASIS node Web server. This computer is the central storage and management site for the OASIS information. The OASIS node would also have a number of Web client computers that function as OASIS clients for TPs and TCs. The conceptual structure for the Internet-based OASIS network is shown in Figure 3.2.

As shown in Figure 3.2, OASIS nodes are interconnected through the Internet while any two nodes may or may not be directly interconnected. It is the responsibility of *Transmission Services Information Providers* (TSIPs) to install and operate OASIS nodes. Any transmission providers may delegate its responsibility to operate an OASIS node to any entity that is capable of meeting OASIS requirements.

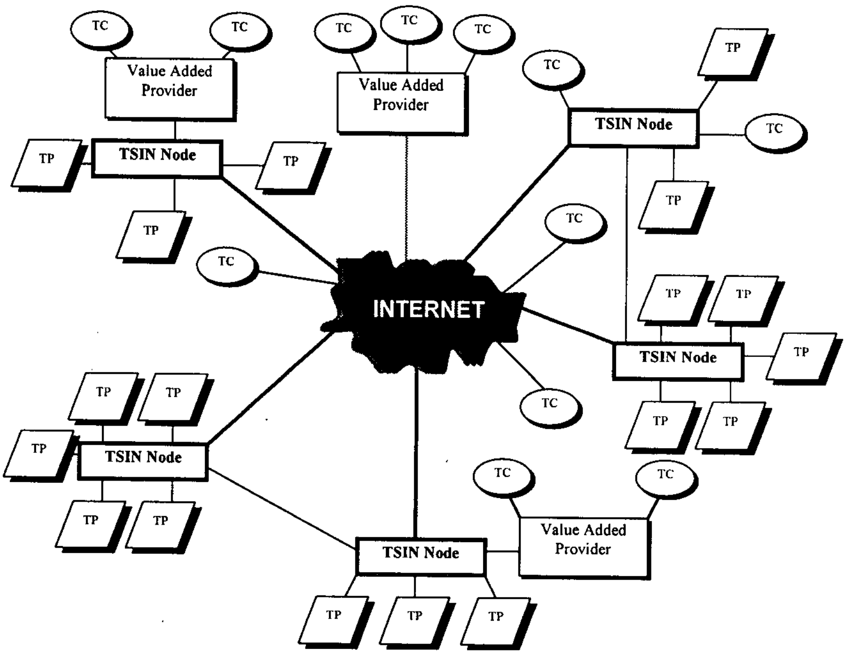

Figure 3.2 The Conceptual OASIS Network

The *structural requirements* of OASIS, according to FERC, would be related to using the Internet as the medium to connect all OASIS nodes to authorized users, via the Internet, who regardless of their physical location, can access the information available on OASIS.

As Figure 3.2 shows, each node is connected to one TP or several TPs, and TCs are either directly or indirectly connected to the OASIS node through the Internet. A TC may opt to use a TSIP as an alternative means to access the OASIS information. If a TC would like to receive the OASIS information with some value-added services (such as data analysis) or in a faster manner than the Internet, the TC may opt to use private connections provided by TSIPs for fees paid to TSIP for this service.

OASIS nodes have three basic interfaces:

(1) interface between the node and the TC (customer-node interface),

(2) interface between different nodes (node-node interface), and

(3) interface between the node and the TP (node-provider interface).

A TP may use OASIS to exchange operational and other information with other TPs using provider-to-provider data links. OASIS functional requirements, set by the How WG, only covered customer-node and the node-node interfaces, where the node-provider interface was left to the TP and TSIP to determine, because this interface would not affect any other parties, i.e., this interface would not affect the ability of customers to access the TS information. The functional requirements also did not specify the design of internal functionality of each node or the internal structure of the customer's system, i.e., it is not of importance which hardware, software, or structures are used. The critical issue is that a system or function would look the same to an outside user and satisfy the specified interface requirements. In addition, OASIS functional requirements did not cover the provider-to-provider data links, because the information to be exchanged would not be the TS information. Functional requirements of OASIS did not place any restrictions on the internal structure (the type or design) of customer systems, including how the TS information is displayed in the customer system. Value-added TPs may provide user interfaces with specifications different from OASIS requirements. In conclusion, specifications for OASIS nodes were established to set the minimum requirements for providing a comparable access to all information and to prevent incompatible systems to develop.

TSIPs provide their customers, upon request and on a cost recovery basis, with the use of private network connections for additional services. OASIS allows the use of single or multiple TPs (a primary TP plus any number of secondary TPs[7]). Secondary TP should use the node designated by the TP and comply with requirements of the OASIS secondary market information. The number of OASIS nodes or the mix of TPs on an OASIS node is not limited.

The OASIS network architecture requires the Internet compatibility such that all OASIS nodes could support the use of Internet tools, Internet directory services, and Internet communication protocols necessary to support access to the required information. To permit customers to access the OASIS nodes through Internet links, it is required to connect OASIS nodes to the public Internet through a firewall to insure security. In addition, nodes would support private connections to any customer who opts, based on its cost paid to TSIP, to have such a connection. The Internet tools used for OASIS Phase 1 (the initial implementation of OASIS) are supported such that a smooth migration path from OASIS Phase 1 to OASIS Phase 2 (an improved implementation of the OASIS) would be ensured.

[7] Secondary TP is any customer who has obtained rights to use transmission facilities and opts to resell transmission services derived from those rights.

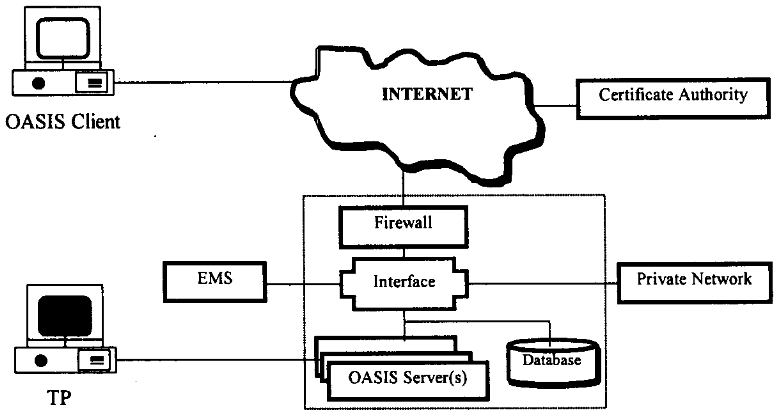

Figure 3.3 *Architecture of OASIS Node*

The architecture of an OASIS node is illustrated in Figure 3.3. Here, the OASIS node is connected to the Internet through a firewall for the security of data. Before accessing the OASIS information, all users should register and log into an account. The database function is threefold: (1) it stores records of ATC and transaction data, (2) queries searches of those records, and (3) acts as a backup in case of system malfunction. The Energy Management System (EMS) is connected to the OASIS node to provide accurate ATC calculations in real time.

3.4 IMPLEMENTATION OF OASIS PHASES

OASIS is being developed in phases. FERC has charged the electric power industry to continue the development of standards and the identification of necessary changes to FERC regulations related to OASIS. As industry development and recommendations proceed, FERC would issue further requirements that would add functions to the current OASIS network.

3.4.1 Phase 1. The so-called OASIS Phase 1 was given to the initial system that was completed and started operating in January 1997. The next version of OASIS is OASIS Phase 2 which is a revised version of OASIS Phase 1. The Phase 1 OASIS was designed to depend on commercially available Internet technologies and to remove barriers that prevent authorized customers to have access to the information. OASIS used common Internet web browsers as a simple approach in Phase 1 which started its commercial operation with 22 nodes shared among 167 TPs. This phase only published transmission information and transmission service transactions.

During its implementation, users of Phase 1 faced or raised several issues, concerning the reliability of power systems [Tsi98]. These issues are summarized as follows:

- The first issue was that the contract path method did not match physical flows on a transmission network, which in turn meant that there would be inconsistency between market view and users of the transmission network on one side and the physical view of the system needed for reliability on the other side.
- The second issue was that the detailed information related to interchange transactions was seen as necessary to adequately monitor power system security, especially when deals included market aggregation of blocks of energy, capacity, and ancillary services among multiple parties.
- The third issue was that the users wanted OASIS to be a tool of next hour reservation and scheduling, however, the understanding of the How WG was that OASIS was intended to support transmission reservations on a day-ahead or long-term basis.
- The fourth issue was inconsistency in user interfaces across different OASIS nodes.
- The fifth concern was about the uncertainty on security and commercial risks of the Internet, where the question was whether or not the Internet is the best platform for electric energy commerce.
- The sixth issue highlighted that the stability limit in addition to thermal and voltage limits should be monitored on a real-time basis

for on-line decisions and should be calculated with an accepted accuracy for short-term presumed scenarios.

It was claimed that the old practice of maintaining system reliability using operating guidelines based on off-line stability studies was not an adequate practice in restructured systems [Tsi98, Sav98].

To implement the OASIS Phase 1, TPs were given the opportunities to freely determine many business practice implementation details based on their understandings of FERC Orders 888 and 889, the OASIS S&CP and individual tariffs. This freedom of choice led to inconsistencies in business practices across OASIS nodes, where customers faced differences in practices as they tried to access information and reserve transmission in a familiar way, but found procedures vary from provider to provider. Differences were observed in packaging of ancillary services, application of discounts, use of "sliding windows" of transmission service, and customer confirmation time limits. Among the issues that caused confusion to customers during the implementation of Phase 1 were inconsistencies among TPs in naming transmission services, where the same product might be named differently from one provider to another, and inconsistencies in defining transmission paths [Tsi98].

3.4.2 Phase 1-A. FERC Order 889-A, which was issued in March 1997, was a Rehearing Order on OASIS that required specific changes to OASIS, especially changes related to on-line transmission and ancillary services price negotiation and discounting, unmasking of identities and prices associated with OASIS reservations, and disclosure of discounts given. FERC Order for Rehearing addressed the standard protocol more definitively and required additional design changes to be considered in Phase 1-A. The industry responded to this order by filing a proposed update to the OASIS S&CP. Improvements requested by both FERC and the industry were combined to be implemented in a new phase of OASIS called Phase 1-A, which was an *upgraded version* of Phase 1 OASIS. The request for proposed developments was filed with FERC on August 11, 1997. Business practice standards and guides were proposed by CPWG and the OASIS How WG was to implement Phase 1-A to achieve improved consistency in the implementation of FERC open access policy and OASIS. Based on a few months of experience, Phase 1-A was started to implement immediate and short-term improvements in OASIS requested by FERC and by the industry.

3.4.3 Phase 2. The concept of Phase 2 of OASIS was established as a phase that implemented the improvements which were seen essential, but which could not be finished in Phase 1. Phase 2 was intended to expand the system's functionality by adding capability to process energy transactions, to manage transmission constraints, and to place next-hour reservations and schedules. FERC Order 889 requested the industry to provide a report on plans for OASIS Phase 2 within seven months of the start of OASIS Phase 1. Since some of the issues mentioned in Phase 1 had direct effects on power system reliability, they were seen to be supported by OASIS Phase 2 as an improvement to Phase 1. These issues included, (1) to use actual flow based reservations instead of contract path reservations, (2) to promote real-time stability monitoring, and (3) to support on-line transaction scheduling. Phase 2 business processes included energy interchange transaction scheduling and constraint management. Phase 2 attempted to be more flexible to accommodate various software and functions, make the system more user-friendly, and require posting requests for energy schedules.

3.5 POSTING OF INFORMATION

3.5.1 Types of Information Available on OASIS. In general, most of the information available on OASIS is provided by TPs for TCs, where TPs are required to either individually or jointly provide an OASIS. Each OASIS is required to provide standardized information on the current operating status and transmission capacity of a TP (transmission availability) and transmission pricing and operate in compliance with standards and communications protocols established and updated under the FERC supervision and control. Users of OASIS would be able, using suitable interfaces such as the Internet, to instantly receive the data available on OASIS.

Even though some basic information would be posted at every OASIS node, the information could vary among regional OASIS nodes based on restructuring models. As minimum requirements, the following information must be provided to TCs on OASIS: *Available Transmission Capability*, *Pricing Information*, *Specific Service Requests and Responses*, *Scheduling Information*, and *Other Transmission-Related Communications* [Tsi96]. These topics are discussed as follows:

- Available Transmission Capability (ATC):

  Posting and updating transfer capabilities (TTC and ATC) is the main type of information on OASIS. Since calculating ATC and TTC would require large-scale computation facilities, it is unrealistic to update the posting of TTC and ATC for all paths at all times. For that reason, FERC has issued separate requirements for two types of paths, namely: constrained paths and unconstrained paths. A *constrained path* is defined as a path for which ATC has been less than or equal to 25% of TTC for at least one hour in the last 168 hours or is calculated to 25% or less of its associated posted TTC during the next 7 days. Otherwise the path is referred to as an *unconstrained path*.

  The ATC information, referred to as the available capacity of interconnected transmission networks, should be available to all transmission users through OASIS to support additional transmission services. OASIS must provide the ATC, in megawatts and in certain directions, for transmission between control areas. This information is required for *posted paths*, i.e., any path in the system that would constrain the commercial usage of a transmission network or any unconstrained path whose information is required by a TC. The posted path would be determined according to FERC Order 889 and the *pro forma* tariff.

  ATC and TTC must also be given on hourly, daily and monthly basis for all constrained paths. For unconstrained paths, daily and monthly ATC must be posted and updated whenever ATC changes by more than 20% of TTC.

  Data and methodologies used to calculate ATC and TTC must be made available upon request for auditing purposes. Any system planning studies must also be made available. For posted paths, firm and non-firm estimated ATC and TTC are published for a 30-day period by hour for the first 168 hours and then by day. In the case that a TP has separate charges for on-peak and off-peak in its tariffs, TP should post on-peak ATC and TTC estimated values, and off-peak ATC and TTC estimated values. ATC and TTC values are also posted on a monthly basis for 12 months. When a transmission service on a constrained path is reserved or ends or when the TTC value on that path changes by more than 10%, a posting for that line should be updated.

- Pricing Information:

  Tariff prices for all transmission services, ancillary services, and other related services must be posted and made available for electronic downloading to customers. TP's complete tariff in a downloadable format is posted for potential customers. Information on discounts made to non-affiliates must be posted within 24 hours of the transaction. Information on discounts made to affiliates must be posted immediately and offered to all other customers using the same path, unconstrained path, or the same ancillary service. The resale of transmission capacity or third party services must be posted on the same location and formatted as transmission provider's postings.

- Specific Service Requests and Responses:

  To process service requests on the OASIS, the FERC has issued requirements for the data to be made available during and after the requests processing. When TCs submit requests for transmission service, they should provide data for the amount of transfer in MW, start and end times, and the power-buying/selling area pair. On the other hand, TPs should in turn provide data indicating their responses, i.e., status of service requests whether accepted, in process, scheduled or rejected, and provide curtailment announcements, and any changes to previously approved requests. Also, historical log should be provided for all transmission services, which include time and date stamp, actions, and modifications in requests and responses.

  All requests for transmission service must be posted by the date and time received, placed in a queue, and the status provided. The result of the request, whether accepted, withdrawn or denied, must also be given and the reason for the denial or interruption, if applicable. The identity of the party requesting transmission capacity can be kept confidential for up to 30 days. Offers to adjust the utility's operation to accommodate a denied request must be posted and offered to other similar parties. When a TC would submit a request for a transmission service to a TP, the TP should reply to the TC when the service is denied. The reply is done through the OASIS and shows the reason of denial and any available alternatives to improve transfer capability. For the case when a transaction is curtailed or interrupted[8], the TP should publish the action showing the reason for the action, and any available alternatives. Upon request of potential customers, all data used to calculate ATC and TTC for any constrained posted path must be made publicly and electronically available within 1 week of its posting. Data are made available at a cost capped at reproduction of material [Sav97].

- Scheduling Information:

  Transmission service schedules must be posted and available for electronic downloading within seven days of the start of the requested service.

- Other Transmission-Related Communications:

  A utility's OASIS can also include "want ads" for other desired services, such as transmission loss service. The OASIS can also provide a messaging service (E-mail). In addition, the utility must post employee transfers between the transmission group and any marketing affiliates, and Standards and Communications Protocols can also be included.

3.5.2 Information Requirements of OASIS. These requirements, as outlined in FERC Order 889, include *information requirements* and *structural requirements*. Structural requirements were discussed before in this chapter (see section 3.3). The *information requirements* for OASIS can be classified in four categories, which are transmission system information, transmission service information, transmission service request and response data and general information. Here,

[8] Curtailments are for reliability reasons and interruptions are pursuant to tariff conditions.

- Transmission System Information include:
  - ATC
  - TTC
  - system reliability.
- Transmission Service information include:
  - complete tariff
  - service discounts
  - ancillary services
  - current operating and economic conditions.
- Transmission Service Request and Response Data Information include:
  - date and time stamp of transmission service requests
  - scheduling of power transfers
  - service interruptions and curtailments
  - service parties' identities
  - audit log for discretionary actions.
- General Information include:
  - "want ads" for transmission products and services
  - announcements
  - value-added services.

A TC who offers to sell transmission capacity that it has purchased is called a reseller. Secondary market information regarding capacity rights that customers (resellers) wish to resell is posted on the OASIS. Through OASIS, a customer would be able to locate power lines with excess capacity and, directly or using a broker, can place a request via OASIS Web sites for access to those lines. Through OASIS, utilities may also share operating data regarding transmission availability, generation capability, system loads, interchange, area-control error, frequency and operating reserves. This data must be made available to any entity with immediate responsibility for operational security (i.e., other than marketing purposes). The data link to EMS will accomplish the task of providing this information. In addition, all final transmission studies must be available in an electronic format upon request to potential customers [Sav97]. Studies are made available at a cost capped at reproduction of material. All information of transactions related to OASIS must be dated, time stamped and stored, should be downloadable within 90 days and kept for three years.

3.5.3 Users of OASIS. Any OASIS node involves four types of users: TP, TC, transmission service information provider (TSIP), and value-added transmission service information provider (VTSIP).

A *TP* is a public utility that owns and controls, or an independent entity that controls, the facilities used for the transmission of electricity. A *TC* is any agent or principal that exercises a service agreement and/or receives transmission service. TCs include established entities, such as TP affiliated or other public utility generators, independent power producers, distribution companies, and newly created entities for the competitive wholesale market, such as marketers/brokers, scheduling coordinators, and load aggregators. In general, categories of customers could be different from region to region. A *TSIP* is an entity that provides the operation of one or more OASIS nodes. A TP or a group of TPs may delegate their responsibility to operate an OASIS node to a TSIP capable of meeting FERC requirements. A *VTSIP* is an entity that uses the TS information like a TC and provides value-added information services to its customers.

TPs are the main users of OAISIS and most TPs that use OASIS are FERC-regulated public utilities in U.S., who are obligated to comply with OASIS requirements. In addition, a considerable number of non-jurisdictional TPs and several Canadian utilities are engaged in OASIS operations. Although, some TPs have developed their own OASIS nodes, the majority has applied the services of commercial information system vendors [Tsi97, Tsi98, Eia98].

TPs are distributed among all OASIS nodes in NERC's regions. NERC includes 10 Regional Councils, which are shown on the map of Figure 3.4, and are listed as follows [Web33]:

(1)East Central Area Reliability Coordination Agreement (ECAR)

(2)Electric Reliability Council of Texas (ERCOT)

(3)Florida Reliability Coordinating Council (FRCC)

(4)Mid-Atlantic Area Council (MAAC)

(5)Mid-America Interconnected Network, Inc. (MAIN)

(6)Mid-Continent Area Power Pool (MAPP)

(7)Northeast Power Coordinating Council (NPCC)

(8)Southeastern Electric Reliability Council (SERC)

(9)Southwest Power Pool (SPP)

(10) Western Systems Coordinating Council (WSCC)

Each NERC's region includes at least one OASIS node. The current URL addresses of all regional OASIS nodes are listed on the nationwide OASIS Management Web page (http://www.tsin.com). Any authorized user can display transmission providers by OASIS nodes or access any regional OASIS (node) by clicking on a NERC's region on the shown map. The OASIS node(s) in each region, along with associated transmission providers and provider codes are detailed in Table 3.1[9].

[9] The data in this table were summarized from the information available in the national OASIS Web site on December 20, 1999.

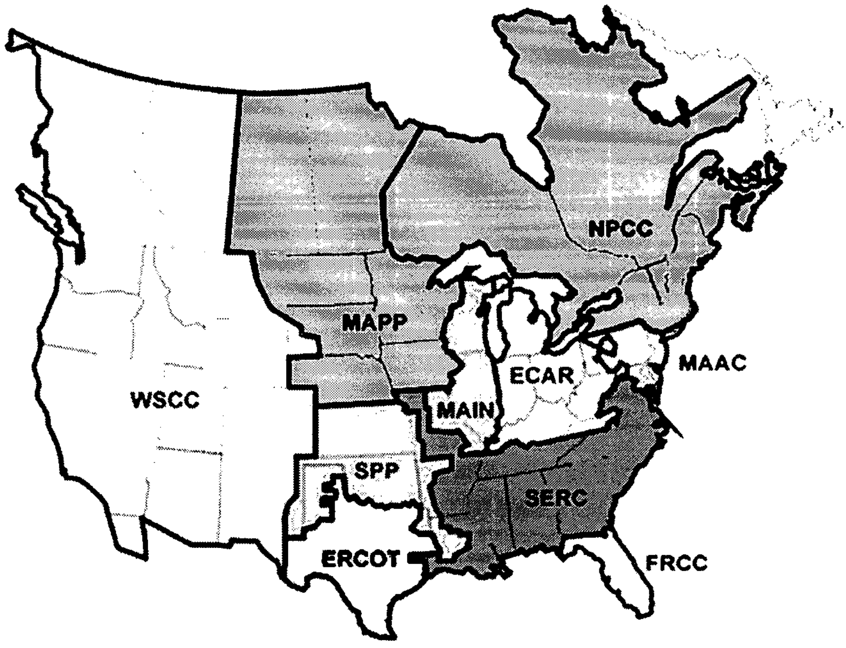

Figure 3.4 NERC's Regions

Table 3.1 OASIS Nodes in NERC Regions

Region	Node	Provider Code	Provider Name
WSCC	APS OASIS	AZPS	Arizona Public Service Company
	Idaho Power Co. OASIS	IPCO	Idaho Power Company
	Imperial Irrigation District OASIS	IID	Imperial Irrigation District
	LADWP OASIS	LDWP	Los Angeles Department of Water & Power
	Northwest OASIS	BPA BCHA MPCO PGE SCL WWPC	Bonneville Power Administration British Columbia Hydro & Power Authority Montana Power Company Portland General Electric Seattle City Light Snohomish County PUD Washington Water Power Company
	PacifiCorp OASIS	DGT PPW	Deseret Generation & Transmission Cooperative PacifiCorp
	Puget OASIS	PSE	Puget Sound Energy
	Rocky Mountain Area OASIS	BEPC CSU PSCO PRPA TSGT WPEL WALM	Basin Electric Power Cooperative Colorado Springs Utilities Public Service Company of Colorado Platte River Power Authority Tri-State Generation & Transmission Association, Inc. West Plains Energy - Colorado Western Area Power - RMR
	SWOASIS	EPE NEVP PAC PNM SRP SPP SMUD	El Paso Electric Nevada Power Company Power Agency of California Public Service Company of New Mexico Salt River Project Sierra Pacific Power Company Sacramento Municipal Utility District
	Western OASIS	TEPC TNPN WALC	Tucson Electric Power Company Texas New Mexico Power Western Area Power Administration - DSW

Table 3.1 OASIS Nodes in NERC Regions (continued)

Region	Node	Provider Code	Provider Name
SPP	SPP OASIS	CSW	Central and South West Services, Inc.
		CLEC	Central Louisiana Electric
		EDE	Empire District Electric Company (The)
		GRDA	Grand River Dam Authority
		KCPL	Kansas City Power & Light Company
		MIDW	Midwest Energy, Inc.
		MPS	Missouri Public Service
		OGE	Oklahoma Gas & Electric
		SWPP	Southwest Power Pool
		SPA	Southwestern Power Administration
		SPS	Southwestern Public Service Company
		SECI	Sunflower Electric Corporation
		WFEC	Western Farmers Electric Cooperative
		WR	Western Resources Inc.
		WPEK	WestPlains Energy - Kansas
SERC	SOUTHERN OASIS	MEAG	Municipal Electric Authority of Georgia
		OPC	Oglethorpe Power Corporation
		SOCO	Southern Company
	VACAR OASIS	CPL	Carolina Power & Light Company
		DUK	Duke Power Company
		SC	Santee Cooper
		SCEG	South Carolina Electric & Gas Company
		SEPA	Southeastern Power Administration
		VAP	Virginia Power
		YAD	Yadkin, Inc.
NPCC	NEPOOL OASIS	BHE	Bangor Hydro Electric Company
		BECO	Boston Edison Company
		CELC	Cambridge Electric Light Company
		CMP	Central Maine Power
		CVPS	Central Vermont Public Service Corp.
		CZN	Citizens Utilities Company
		COM	Commonwealth Electric Company
		EUA	Eastern Utilities Associates (Montaup)
		GMP	Green Mountain Power Corporation
		MEPC	Maine Electric Power Company
		MPSC	Maine Public Service Company
		NEP	New England Power Company
		NRTG	New England Power Pool
		NU	Northeast Utilities System Companies
		UI	United Illuminating
		VELC	Vermont Electric Power Company
	NB Power OASIS	NBPC	New Brunswick Power Corporation

Table 3.1 OASIS Nodes in NERC Regions (continued)

Region	Node	Provider Code	Provider Name
NYPP	**Transmission Provider OASIS**	NYCH	Central Hudson Gas and Electric
		NYCE	Consolidated Edison Company of NY
		NYLI	Long Island Lighting Company
		NYPA	New York Power Authority
		NYNY	New York State Electric & Gas Corporation
		NYNM	Niagara Mohawk Power Corporation
		NYOR	Orange and Rockland Utilities
		NYRG	Rochester Gas and Electric
	TransEnergie OASIS	HQT	Hydro Quebec, TransEnergie
MAPP	MAPP OASIS	BEPC	Basin Electric Power Cooperative
		CIPC	Central Iowa Power Cooperative
		CP	Cooperative Power
		CBPC	Corn Belt Power Cooperative
		DPC	Dairyland Power Cooperative
		HCPD	Heartland Consumers Power District
		HUC	Hutchinson Utilities Commission
		LES	Lincoln Electric System
		MHEB	Manitoba Hydro Electric Board
		MEC	MidAmerican Energy Company
		MAPP	Mid-Continent Area Power Pool
		MPC	Minnkota Power Cooperative
		MP	Minnesota Power Company
		MBMP	Missouri Basin Municipal Power
		MDU	Montana-Dakota Utilities
		MEAN	Municipal Energy Agency of Nebraska
		MPW	Muscatine Power and Water
		NPPD	Nebraska Public Power District
		NSP	Northern States Power Company
		NWPS	Northwestern Public Service Company
		OPPD	Omaha Public power District
		OTP	Otter Tail Power
		RPU	Rochester Public Utilities
		SMP	Southern Minnesota Municipal Power Agency
		SJLP	St. Joseph Light & Power
		UPA	United Power Association
		WAPA	Western Area Power Administration
MAIN	MAIN OASIS	ALT	Alliant
		AMRN	Ameren Transmission Services
		AECI	Associated Electric Cooperative, Inc.
		CIL	Central Illinois Light Company
		CWLP	City Water, Light and Power
		CE	Commonwealth Edison Company
		EES	Entergy
		IP	Illinois Power
		SIPC	Southern Illinois Power Cooperative
		TVA	Tennessee Valley Authority
		UPP	Upper Peninsula Power Company
		WEP	Wisconsin Electric Power
		WPS	Wisconsin Public Service Corporation

Table 3.1 OASIS Nodes in NERC Regions (continued)

Region	Node	Provider Code	Provider Name
MAAC	PJM OASIS	AE	Atlantic City Electric Company
		BGE	Baltimore Gas and Electric Company
		DPL	Delmarva Power and Light Company
		GPUE	GPU Energy
		PECO	PECO Energy Company
		PPL	Pennsylvania Power and Light Company
		PEPC	Potomac Electric Power Company (PEPCO)
		PJM	PJM
		PSEG	Public Service Electric and Gas Company
ERCOT	ERCOT OASIS	CSW	Central and South West Services, Inc.
		CPST	City Public Service
		HLPT	Houston Lighting and Power Company
		LCRA	Lower Colorado River Authority
		MVEC	Magic Valley Electric Cooperative, Inc.
		BPUB	Public Utilities Board
		STEC	South Texas Electric Coop., Inc.
		TUET	TU Electric
ECAR	AEP OASIS	AEP	American Electric Power
	ECAR OASIS	AP	Allegheny Power
		BREC	Big Rivers Electric Corporation
		CIN	Cinergy Corporation
		CONS	Consumers Energy Company
		DP&L	Dayton Power & Light Company
		DECO	Detroit Edison Company
		DLCO	Duquesne Light Company
		EKPC	East Kentucky Power Cooperative
		FE	FirstEnergy Corp.
		HEC	Hoosier Energy Rural Electric Cooperative
		IPL	Indianapolis Power & Light Company
		KU	Kentucky Utilities Company
		LGE	Louisville Gas & Electric Company
		MECS	Michigan Electric Coordinated System
		NIPS	Northern Indiana Public Service Company
		OH	Ontario Hydro
		OVEC	Ohio Valley Electric Corporation
		SIGE	Southern Indiana Gas & Electric Company
FRCC	ENX OASIS	TAL	City of Tallahassee
		FPL	Florida Power & Light
		FPC	Florida Power Corporation
		JEA	JEA
		TEC	Tampa Electric Company

3.6 TRANSFER CAPABILITY ON OASIS

FERC Order 889, mandated the calculation of ATC for each control area and the posting of these values on OASIS to enhance the open access of bulk transmission system by providing a market signal of the capability of a transmission system to deliver energy, which would support competitive bidding in the generation, or energy, market. ATC values posted on OASIS are accessible and displayed by market participants [Gra99].

In addition to engineering perspectives, FERC has ordered that bulk electrical control areas must provide to market participants a commercially viable network transfer capability for the import, export, and through-put of energy.

3.6.1 Definitions. Before going into definitions, let's first distinguish between two widely used terms in the electric power industry, which are transfer *capability* and transmission *capacity*. While values of transfer capability are mainly dependent on and determined by the overall combination of system conditions that include several factors such as generation, customer load demand, and transmission system topology, the transmission capacity usually indicates the thermal rating of a certain component in the transmission network such as a transmission line or a transformer. When we point to transfer capability, we refer to the ability of a network to reliably transfer electric power between two points in the system under certain network conditions. The transfer capability of a transmission path composed of several lines is not directly a function of individual transmission capacities of lines in the path.

The *available transfer capability* (ATC) is a terminology that is used to define and calculate meaningful measures of transfer capability of an interconnected transmission network [Gis99,Eje98,Ner96]. *Transfer capability* (in MW) is a direction-specific measure that indicates the ability of interconnected electric systems to move or transfer power in a reliable manner from one area (i.e., an individual electric system, power pool, control area[10], sub-region, NERC Region, or a portion of any of

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[10] *Control Area* is an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule

these) to another over existing transmission lines (or paths) between those areas under specified system conditions. Since the transfer capability is directional in nature, ATC from Area 1 to Area 2 is not equal, in most cases, to ATC from Area 2 to Area 1, i.e., $ATC_{1\to 2} \neq ATC_{2\to 1}$.

3.6.2 Transfer Capability Issues. Transfer capability is usually calculated based on off-line computer load-flow simulations of the interconnected transmission network under a specific set of assumed operating conditions. Off-line calculations are used due to the fact that a large amount of computation is needed for calculation. The computation of transfer capability is based on linear and nonlinear-based methods, e.g., power flow methods and continuation power flow methods. The nonlinear power flow method is usually time consuming as compared to continuation power flow. Recently, new techniques such as sensitivity-based, linear and generalized search methods have been proposed to reduce the computation time [Shb98, Gra99a, Gra99b, Sau97, Sau98, Ner96]. Several factors are considered during computations such as projected customer demands, generation dispatch, system configuration, base case schedule transfers, and the contingency cases that reflect the degree of required system security.

Uncertainties facing the operation of interconnected electric power systems are generally due to weather conditions, forced and scheduled transmission outages, generation unavailability, and future location of demand and electricity resources. As time passes, electric power systems will get more complicated, more participants will be introduced, and uncertainties will grow which means that the accurate estimation of TTC and ATC gets to be more complicated. That means when projections for transfer capabilities are made for longer time horizons, the degree of uncertainty in presumed conditions and the degree of uncertainty in transfer capabilities will grow. If uncertainties are not managed properly, an unreliable operation of electric power systems could prevail.

Transfer capability computations should consider limits imposed on the system components such as thermal, voltage, and stability limits. In

with other Control Areas and contributing to frequency regulation of the Interconnection.

addition, uncertainties in load forecasts and simultaneous transfers should be taken into consideration. A significant error in load forecasts could result in an increased transmission network loading, which in turn could lead to reduction in transfer capability. On the other hand, loop flows through a transmission network or control area may be caused by transfers between two or more neighboring control areas. Loop flows could cause unpredictable results by either increasing or decreasing the transfer capability.

For these reasons, uncertainties should be quantified properly to increase the efficient use and the security of the system and to provide necessary information for system operation and planning. Uncertainties are expressed by specifying margins during ATC calculations so that when schedules derived from ATC calculations are put in place, the transmission system can reliably transfer the energy and serve the system load. Factors such as transmission line and generating unit outages may dramatically affect transfer capability if they are not taken into consideration. In the following, we discuss the calculation of transfer capability that is used in OASIS.

3.6.3 ATC Calculation. NERC defines ATC as a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is an indication of the expected transfer capability remaining on the transmission network. It is the available transfer capability that could be scheduled to the designated path under the conditions considered in calculating ATC values. ATC is a market signal that refers to the capability of a system to transport or deliver energy above that of already subscribed transmission uses. ATC values are used to determine transmission service commitments.

The ATC value is determined based on other parameters, which are TTC, TRM, and CBM. Mathematically, the ATC value between two points is give as [Ner96]:

$$\mathrm{ATC} = \mathrm{TTC} - \mathrm{TRM} - (\sum \mathrm{ETC} + \mathrm{CBM}) \tag{3.1}$$

where,

ATC	Available Transfer Capability
TTC	Total Transfer Capability between two points
TRM	Transmission Reliability Margin
ETC	Existing Transmission Commitments including retail customer services between the same two points
CBM	Capacity Benefit Margin

These terms are discussed in the following.

3.6.4 TTC Calculation. TTC is the amount of electric power that can be transferred from one area to another over the interconnected transmission network in a reliable manner based on five pre-contingency and post-contingency conditions [Ner96].

TTC is constrained by thermal limit, voltage magnitude limit, and stability limit (voltage stability limit, transient angle stability limit, and dynamic angle stability limit). The thermal limit of a certain transmission network component is the limit that would constrain the amount of transfer that the component can safely handle without being overloaded. Voltage limits are acceptable operating limits on bus voltage magnitudes across the transmission system. Stability limits are the required limits that ensure interconnected transmission system would survive when disturbances are imposed on the system. The constraining condition of the transmission network would shift among the three limits as the operating conditions change over time. TTC is determined as:

$$TTC = Min\{\text{Thermal Limit}, \text{Voltage Limit}, \text{Stability Limit}\} \quad (3.2)$$

Figure 3.5 illustrates how TTC is calculated at each time instant as a minimum of the three limits.

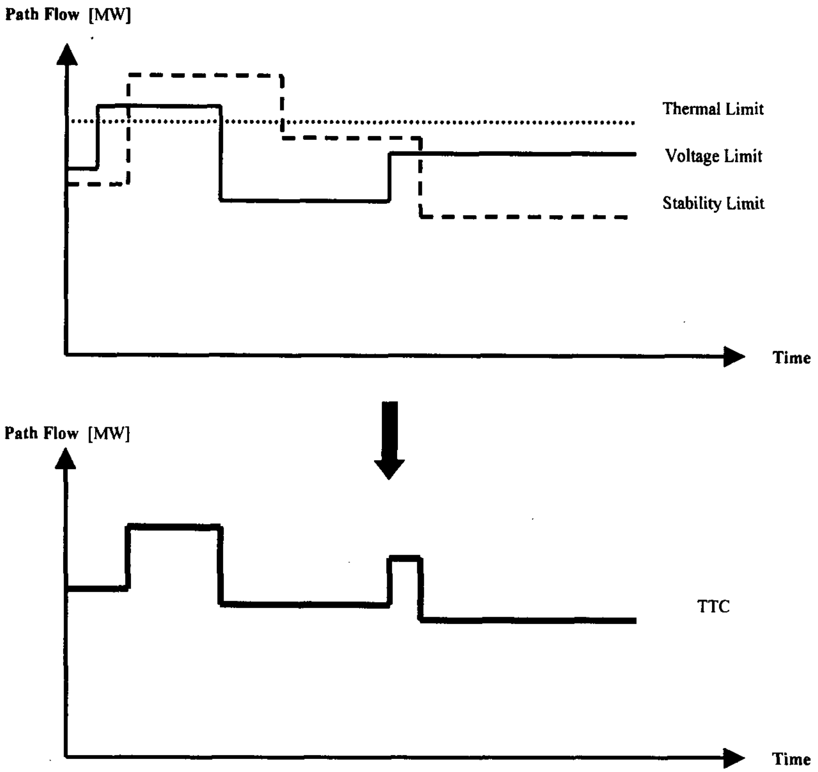

Figure 3.5 Illustration of TTC Determination

TTC is calculated hourly, daily or monthly based on market requirements. Certain factors should be taken into account in TTC calculations such as the list of contingencies that would represent most sever disturbances, accuracy of load forecast, unit commitment, and maintenance scheduling. System control devices such as voltage regulators and reactive power control devices would also have a direct impact on TTC values.

As definitions indicate, TTC and ATC would always be defined for a pair of areas, i.e., a power-selling area and a power-buying area. The definitions also imply that TTC and ATC values are time-dependent as the transmission system conditions would change over time which means that the calculation of TTC, and in turn ATC, would need to be updated continuously to reflect changes in system conditions.

To calculate a point-to-point TTC, i.e., between a source bus and a sink bus, a possible framework for TTC calculation is devised as follows [Shb98]:

(1) Starting from the current operating point of the base case, the load on the sink bus would gradually be increased, and the corresponding load flow would be calculated while the source bus acts as swing (reference) bus. If any of thermal, voltage or stability constraints is reached, the corresponding power transfer from the source to the sink becomes the TTC candidate.

(2) From the prepared contingency list, represent one contingency in the system and the resulting load flow. Starting from this flow solution (similar to step 1), we would increase the load on the sink bus while the source bus acts as a swing bus until system constraints are reached, and the corresponding power from the source to the sink would become a new TTC candidate. All of the contingencies in the list should be handled through this step.

(3) The final TTC for the source-sink pair, at the base operation point, is the minimum TTC of all TTC candidates.

3.6.5 TRM Calculation. Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM) are two transmission margins proposed for considering the inherent uncertainty in interconnected power systems. TPs attained different margins based on their adopted calculation methodology. Correspondingly, NERC issued a paper to better define, quantify and apply these two margins, hoping that different regions will be encouraged to promote a common TRM and CBM calculation methodology [Ner99].

NERC defines TRM as "The amount of transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions, its associated effects on ATC calculation, and the need for operating flexibility to ensure reliable system operation as system conditions change. All transmission system users would benefit from the preservation of TRM by TPs."

TRM accounts for the uncertainty in operating conditions such as those in model parameters (e.g., line impedance) or load forecasting errors. TRM would be time dependent in evaluating ATC, representing a larger uncertainty for longer terms of the ATC evaluation. Components that should be considered in calculating TRM are: (1) aggregate load forecasting error, (2) load distribution error, (3) variations in facility loadings for balancing load and generation within a control area, (4) uncertainties in forecasting the system topology, (5) allowances for parallel path (loop flow) impacts, (6) allowances for simultaneous path interactions, (7) variations in generation dispatch due to component outages, and (8) variations in short-term operator response/operating reserves. The calculated values of these terms may change based on the human experience and means of forecasting the system conditions.

There are several proposed approaches to calculate TRM. The first one is the Monte Carlo statistical approach, which is based on the repeated computation of TTC using variations in the base case data. The second approach is a single computation of TTC using limitations reduced by a fixed percentage. The third approach is based on reducing TTC by a fixed percentage to calculate TRM. The last approach is a probabilistic approach based on statistical forecasting error and other systematic reliability concepts. The second and third approaches would result in a lower ATC value. Each TP would set the TRM in accordance with its own security criterion.

3.6.6 CBM Calculation. CBM is the translation of generator reserve margin into a transfer capability quantity, determined by (or for) LSEs within a host TP. It is the responsibility of TP to determine the needed quantity of CBM by considering the requirements of all TCs entitled to a portion of CBM [Ner99].

NERC defines CBM as "The amount of firm transfer capability preserved for LSEs on the host transmission system where their load is located, to enable the access to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for a

LSE allows that entity to reduce its installed generating capacity below what may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission capacity preserved as CBM is intended to be used by LSE only in times of emergency generation deficiencies."

As the definition implies, beneficiaries of CBM are the LSEs of a host TP. Each LSE would have a reduced need for installed generating capacity, which in turn could mean lower rates for TCs. An LSE would get the benefit from CBM by sharing installed capacity reserves with other parties elsewhere in the interconnected network.

3.7 TRANSMISSION SERVICES

Transacting participants would require transmission services for their transactions throughout their electric power marketing and trading activities. They would submit requests to TPs for these services and each TP in turn would determine whether or not each service submitted to it is feasible (i.e., can be provided without threatening the security of its transmission system). Each TP would make its decision based on quantities derived from ATC, and transactions that are found to be threatening the system security, would not be permitted by TP.

TPs would use measures related to transfer capability in providing transmission services. There are four main types of transmission services provided by TPs, which are differentiated based on two criteria: recallability of service and the time horizon of operation.

- *Recallability* refers to whether or not a service is recallable. It is a TP's right to interrupt all or part of a transmission service for any reason, including the economics, that is consistent with the FERC policy and the TP's transmission service tariffs or contract provisions, while *curtailability* refers to a TP's right to totally or partially interrupt a transmission service due to prevailing constraints that reduce the capability of the transmission network to provide that transmission service, i.e., transmission service is curtailable only at times when system reliability is at risk or emergency conditions exist.

- Time horizon refers to operating horizon and planning horizon. The non-recallable service in operating horizon is called a *non-recallable scheduled* (NSCH) service, while it is called *non-recallable reserved* (NRES) in planning horizon. Likewise, the recallable service in operating horizon is called a *recallable scheduled* (RSCH) service, while it is called *recallable reserved* (RRES) service in planning horizon. That means the service is *scheduled* in operating horizon and *reserved* (for future) in planning horizon. Scheduled transmission service refers to a transfer capability in the operating horizon. In other words, the transfer capability is committed by the TP for this service and is not available to any other participants, whether or not the participant acquiring this service would actually use the service. On the other side, when a TP approves a reserved transmission service for a TC, the TP reserves a part of the transfer capability before the actual power transfer is scheduled (taken place).

TPs uses curtailability and recallability of the transmission services as a basis to establish the priority of services. The three factors that would determine the priority among transmission services are: (1) recallability of the service, (2) time and date stamp of the service request, and (3) the time horizon of service. Non-recallable services (NSCH and NRES) are usually of higher priority (will be served first) in using the transmission network than recallable services (RSCH and RRES). When two non-recallable services are requested with two different time and date stamps (let's say NSCH at T_1 and *NSCH* at T_2, where $T_2>T_1$), the service that is requested at an earlier time (NSCH at T_1) would have a higher priority than the other service that is requested at a later time (*NSCH* at T_2), i.e., priority is on a first come, first served basis. The same logic is used for recallable services. The order of curtailment is opposite to the priority order. Figure 3.6. Illustrates how services would be ordered in priority and in curtailment. As the figure shows, NSCH has a higher priority over *NRES,* and RSCH has a higher priority over *RRES* [Ner96].

Non-recallable ATC (NATC) and *Recallable ATC* (RATC) are two terms related to ATC, which are used to provide a measure of transmission network's capability for the types of transmission services mentioned before. NATC and RATC are functions of time because their calculations depend on transmission system conditions. NATC is calculated as TTC less TRM, less NRES (including the Capacity Benefit Margin), or:

$$NATC = TTC - TRM - NRES \tag{3.3}$$

Recallable Available Transmission Capability (RATC) is calculated as TTC less the TRM, less RTS, less NRTS (including the Capacity Benefit Margin). RATC must be considered differently in the planning and operating horizons. In the planning horizon, the only data available would be Recallable and Non-recallable Transmission Service Reservations, whereas in the operating horizon Transmission Schedules are known.

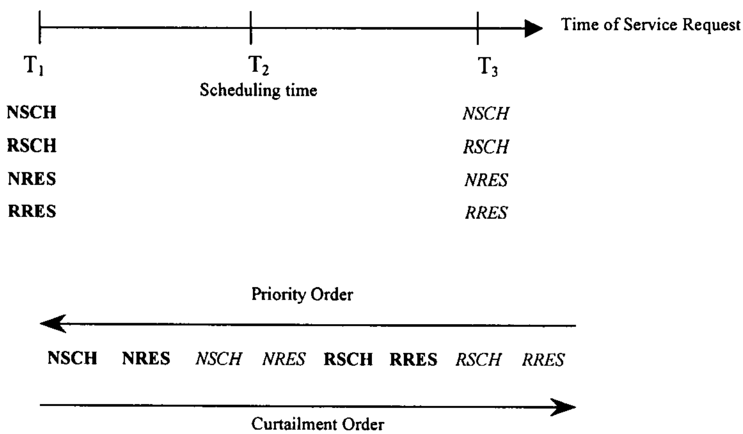

***Figure 3.6** Priority/Curtailment Order of Services*

For the operating horizon:

$$RATC = TTC - \alpha.TRM - RSCH - NSCH\ (\textit{including}\ \text{CBM})\quad ;\ 0 \le \alpha \le 1 \tag{3.4a}$$

For the planning horizon:

$$RATC = TTC - \alpha.TRM - RSCH - NRES\ (\textit{including}\ \text{CBM})\quad ;\ 0 \le \alpha \le 1 \tag{3.4b}$$

where α is a coefficient determined by the transmission provider based on its own system's network reliability consideration.

The ATC value in each time horizon is illustrated in Figure 3.7.

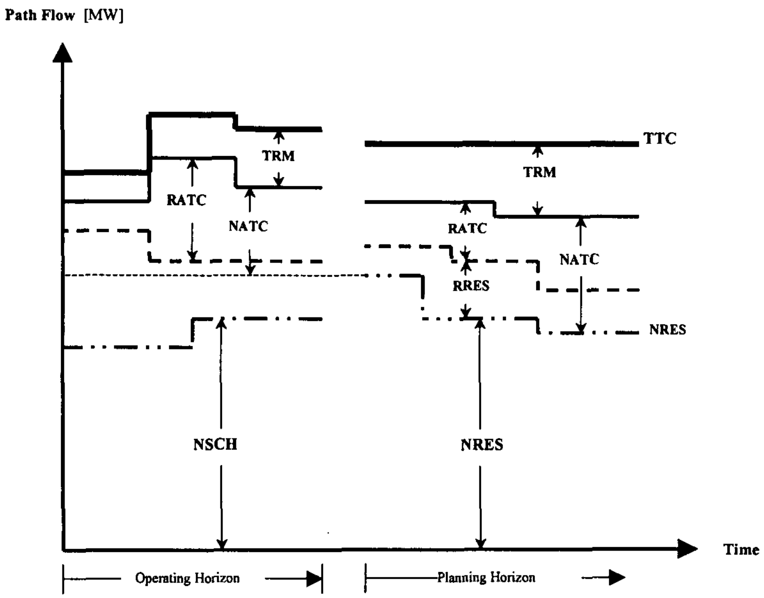

Figure 3.7 *Illustration of ATC Determination*

3.8 METHODOLOGIES TO CALCULATE ATC

NERC has described two methods for the ATC calculation. One is called the *Network Response* method, and the other is the *Rated System Path (RSP)* method. The Network Response method is used to calculate ATC in highly dense, meshed transmission networks where customer demand, generation sources, and transmission systems are tightly interconnected. In such networks, transmission paths that are critical to a certain power transfer cannot generally be identified in advance because of the high dependency on system conditions that would exist at the time that power transfer is scheduled. This method is applicable to many transmission networks in the Eastern and Midwestern parts of the United States. The RSP method is used for transmission systems which are described as sparse networks with customer demand and generation centers distant from one another [Ner96].

To calculate ATC using the Network Response method, for a particular transaction area pair at a single instance of time and under specific system conditions, computer simulations are needed to find the impact (response) of a power transaction, from one area to another, on the entire transmission network flows. The network responses are obtained based on load-flow studies for the interconnected transmission network. A load-flow analysis is initially used to establish the base-case power flow in the network. Then the generation in the power-selling area and the load in the power-buying area are increased by some specified amount to simulate a transfer of power, and then another load-flow study is carried out. The incremental flow on each transmission network component is calculated based on the two load-flow cases. The difference is then normalized according to the incremental generation (load) in the second case. This quantity is called the network response of a transmission line, or network facility, and is denoted by R_{ij}^{l},

$$R_{ij}^{l} = \frac{(f_m^{l} - f_b^{l})}{P_{ij}} \tag{3.5}$$

where

ij	Buying/selling area pair (from area i to area j)
l	Transmission component,

f_b^l Power flow in l for the base case,

f_m^l Power flow in l for the modified case, and

P_{ij} Amount of simulated power transfer.

The available loading capacity ALC_{ij}^l (i.e., unused capacity of each transmission component) is found by subtracting the base-case power flows from the rated value of the transmission component. The ALC_{ij}^l is given as:

$$ALC_{ij}^l = C^l - f_b^l \tag{3.6}$$

where C^l is the thermal limit of the transmission component l.

ATC_{ij}^l for each component l in the transmission network, based on the assumption that the transmission network is linear, is calculated as:

$$ATC_{ij}^l = \frac{ALC_{ij}^l}{R_{ij}^l} \tag{3.7}$$

The ATC value for the area pair (ATC_{ij}) is found as the ATC_{ij}^l of the most constraining transmission component, or:

$$ATC_{ij} = min\{ATC_{ij}^l\} \tag{3.8}$$

This is the value used in the calculation of ATC. To evaluate ATC for a contingency case (single or multiple) or when the system configuration is modified, the procedure is repeated for the altered system to find ATC.

The second method (i.e., the RSP method) has been suggested by NERC as an option to allocate transmission services. In this method, paths between areas of the network are identified, appropriate system constraints are calculated, and ATC is computed for these identified paths and interconnections between transmission providers. The RSP method involves three steps [Ner96]:

(1) Determining the path's TTC,

(2) Allocating the TTC among owners in a multi-owned path to calculate the owner's rights, and

(3) Calculating ATC for each right-holder by subtracting each of their uses from each of their individual TTC rights.

The RSP method includes a procedure to allocate TTC and ATC among owners of the transmission path(s), where the TTC development follows a regional review process in order to achieve a wide-area coordination. The RSP method uses the modeling of realistic customer demands and generation patterns in advance of real-time operations to take into consideration the impacts of parallel path flows (or unscheduled flows) on interconnected systems. The method also uses a maximum power flow test to guarantee that the transfer path is capable of carrying power flows up to its rated transfer capability or TTC.

The procedure for calculating ATC in the RSP method is as follows [Ner96]:

1. Identification of paths for which ATC are to be calculated are made, then a reliability-based TTC (reliability rating) is calculated for each path, and TTC is allocated among the owners based on the negotiated agreement. To calculate a reliability-based TTC of each path, based on agreed upon consistent path rating methods and procedures within the Interconnection, the network is tested under a wide range of generation, customer demand, and outage conditions. The TTC rating usually remains fairly constant, but when system configuration changes, the TTC rating will be recalculated.

2. If necessary, based on prearranged agreements or tariffs, deratings for outages, maintenance schedules or unscheduled flows are allocated to the right-holders.

3. To calculate the ATC value, right-holders will take their respective allocated shares of TTC for a path and subtract the existing commitments.
4. When new commitments affect their ATC, right-holders update and re-post their ATC calculations. A transfer from one area to another, that involves several transmission owners, would require locating and reserving capacity across multiple paths and potentially multiple right-holders.

The rights in a path are negotiated for each of TPs and these allocations become rights that right-holders may use or resell to others as non-recallable or recallable services, except for deratings based upon system operating conditions such as emergency conditions. For more information on methodologies to calculate ATC and its components, the reader is referred to additional references listed at the end of this book.

Example 3.1: (ATC Calculation Using the RSP Method)

Figure 3.8 represents a 4-area transmission network, where a path directly connecting any two areas is composed of two, three or four lines. Each path or line may be owned by different entities (owners). A line $L_{m-n,j}$ refers to the j^{th} line in the path connecting areas m and n. Path m→n refers to the path from area m to area n. Each path is given a directional transfer capability based on the coordination among areas. A transfer capability of each line or path takes into account unscheduled flows and interconnection interactions and effects. Any path may have a transfer capability in one direction different from the transfer capability of the same path in the other direction (i.e., $TTC_{m \to n} \neq TTC_{n \to m}$).

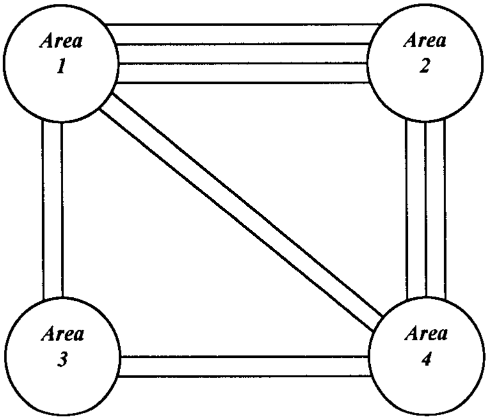

Figure 3.8 Network Structure

The TTC of each path in both directions are shown in Figure 3.9. Also Table 3.2 gives the TTC of each line, in each path, in both directions. The sum of line TTCs of a path is that path's TTC.

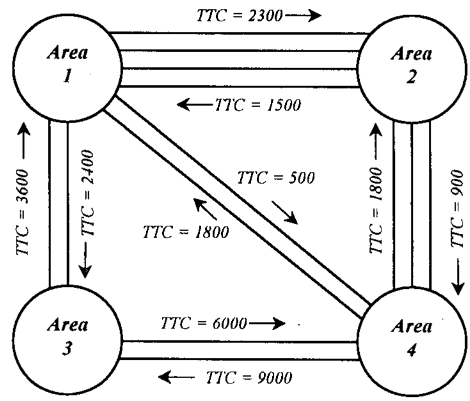

Figure 3.9 TTC Values

Table 3.2 TTC, Reservation, and ATC Values

Path	*Line*	*Line TTC*	*Path TTC*	*Initial Line Reservation*	*Initial Path Reservation*	*Line ATC*	*Path ATC*
1 → 2	$L_{1\text{-}2,1}$	600	2,300	400	1,200	200	1,100
	$L_{1\text{-}2,2}$	500		200		300	
	$L_{1\text{-}2,3}$	700		400		300	
	$L_{1\text{-}2,4}$	500		200		300	
2 → 1	$L_{1\text{-}2,1}$	400	1,500	0	0	400	**1,500**
	$L_{1\text{-}2,2}$	300		0		300	
	$L_{1\text{-}2,3}$	500		0		500	
	$L_{1\text{-}2,4}$	300		0		300	
1 → 3	$L_{1\text{-}3,1}$	1,300	2,400	0	0	1,300	2,400
	$L_{1\text{-}3,2}$	1,100		0		1,100	
3 → 1	$L_{1\text{-}3,1}$	1,900	3,600	1,000	1,700	900	**1,900**
	$L_{1\text{-}3,2}$	1,700		700		1,000	
1 → 4	$L_{1\text{-}4,1}$	250	500	0	0	250	500
	$L_{1\text{-}4,2}$	250		0		250	
4 → 1	$L_{1\text{-}4,1}$	900	1,800	600	1,100	300	**700**
	$L_{1\text{-}4,2}$	900		500		400	
2 → 4	$L_{2\text{-}4,1}$	400	900	0	0	400	900
	$L_{2\text{-}4,2}$	200		0		200	
	$L_{2\text{-}4,3}$	300		0		300	
4 → 2	$L_{2\text{-}4,2}$	700	1,800	300	800	400	**1,000**
	$L_{2\text{-}4,2}$	500		200		300	
	$L_{2\text{-}4,3}$	600		300		300	
3 → 4	$L_{3\text{-}4,1}$	4,000	6,000	0	0	4,000	6,000
	$L_{3\text{-}4,2}$	2,000		0		2,000	
4 → 3	$L_{3\text{-}4,1}$	6,000	9,000	2,000	3,000	4,000	**6,000**
	$L_{3\text{-}4,2}$	3,000		1,000		2,000	

Figure 3.10 shows the path connecting areas 1 and 2. As this figure shows, $TTC_{1 \to 2} = 2{,}300$ MW, while $TTC_{2 \to 1} = 1{,}500$ MW. This path is composed of four single lines. Let's assume that the path belongs to two owners: owner 1 owns line $L_{1\text{-}2,1}$ and owner 2 owns lines $L_{1\text{-}2,2}$, $L_{1\text{-}2,3}$ and $L_{1\text{-}2,4}$. The line $L_{1\text{-}2,1}$ has a TTC of 600 MW from 1 to 2, and 400 MW in the reverse direction. The rest of lines in this path have a TTC of 1,700 MW from 1 to 2, and 1,100 in the reverse direction.

Let's assume that the system has the initial, non-recallable, transmission service reservations shown in Figure 3.11. All reservations are in the directions shown in the figure. The ATC value, in MW, for each path is calculated by subtracting the initial reservation of the path from the TTC of that path. In the same fashion, the ATC values, in MW, for each line is calculated by subtracting the initial reservation of the line from the TTC of that line.

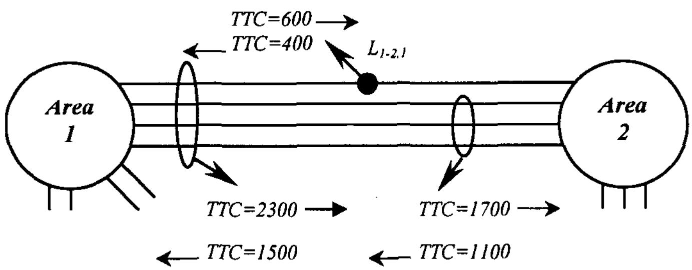

Figure 3.10 *TTCs Values of Path 1-2 and Allocation of TTC to* $L_{1-2,1}$

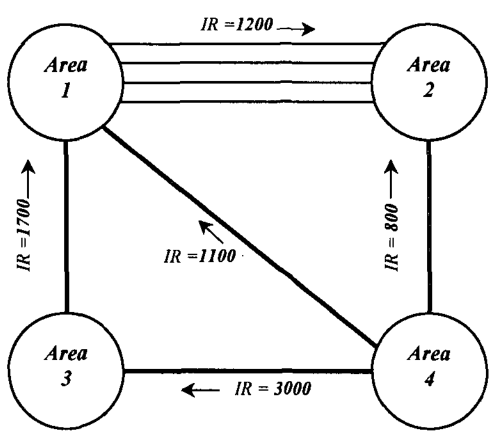

Figure 3.11 *Initial Transmission Service Reservations*

Initial line and path reservations are detailed in Table 3.2. For this example, let's study the following cases:

Case 1: For the TTC values and directions given in Figure 3.9, Figure 3.12 shows the ATC values for the initial reservations shown in Figure 3.11. Let $IR_{m \to n}$ refers to the initial reservation (bolded numbers in the figures) from area m to area n. The path ATC values are calculated as $ATC_{m \to n} = TTC_{m \to n} - IR_{m \to n}$. The line ATC values are calculated as $ATC_{m \to n,j} = TTC_{m \to n,j} - IR_{m \to n,j}$. For this case, the ATC values are detailed in Table 3.2. The path ATC values are:

$$ATC_{1 \to 2} = 2{,}300 - 1{,}200 = 1{,}100 \quad \text{MW}$$

$$ATC_{3 \to 1} = 2{,}600 - 1{,}700 = 900 \quad \text{MW}$$

$$ATC_{4 \to 1} = 1{,}800 - 1{,}100 = 700 \quad \text{MW}$$

$$ATC_{4 \to 2} = 1{,}800 - 800 = 1{,}000 \quad \text{MW}$$

$$ATC_{4 \to 3} = 9{,}000 - 3{,}000 = 6{,}000 \quad \text{MW}$$

Case 2: A 900 MW of non-recallable transmission service is acquired from area 4 to area 3 to area 1, as shown in Figure 3.13. In this case, the ATC of each path is recalculated to reflect this transmission service. The affected paths are **4→3** and **3→1**. The bolded numbers in Figure 3.13 are the initial reservations. The final ATC value of each path is shown next to the path. For example, path **3→1** has a TTC of 2,600 MW and initial reservation of 1,700 MW. With the acquired 900 MW transmission service, the ATC of this path is recalculated as:

$$ATC_{3 \to 1} = 2{,}600 - 1{,}700 - 900 = 0 \text{ MW}$$

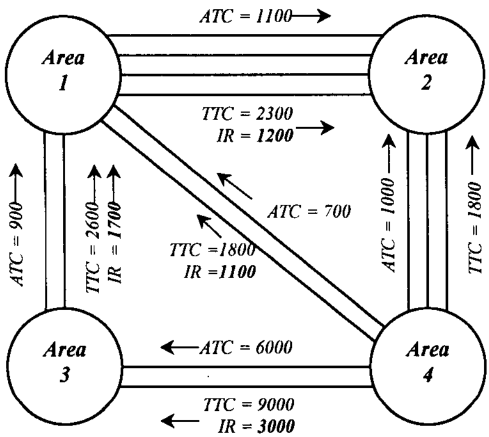

Figure 3.12 Case 1: TTC, Reservation, and ATC Values

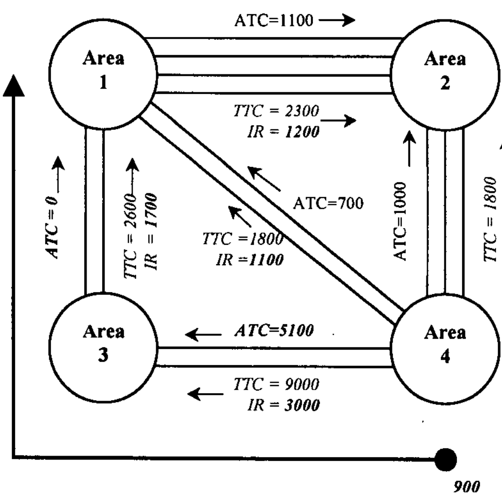

Figure 3.13 Case 2

Case 3: A 150 MW of non-recallable transmission service is acquired from area 1 to area 2, as shown in Figure 3.14. Let's assume that 50 MW of the 150 MW was obtained from owner 1 (owner of $L_{1\text{-}2,1}$) and 100 MW of the 150 MW was obtained from Owner 2 (owner of rest of lines in this path). Path **1→2** is the only affected path. The path ATC values are updated after this new reservation as shown in Figure 3.14.

Line $L_{1\text{-}2,1}$ now has an ATC value of:

$$ATC_{1\rightarrow 2,1} = TTC_{1\rightarrow 2,1} - IR_{1\rightarrow 2,1} - 50 = 600 - 400 - 50 = 150 \text{ MW}.$$

The whole path has a TTC of 2,300 MW (as shown in Figure 3.10, 600 MW for line 1 and 1,700 MW for the rest of lines), and has an initial reservation of 1,200 MW (as shown in Table 3.2, 400 MW for line 1 and 800 MW for the reset of lines). When 50 MW of the 150 MW was acquired for line 1, then 100 MW was acquired for the rest of lines. So, the rest of lines in this path will have an ATC value of 1,700 - 800 - 100 = 800 MW.

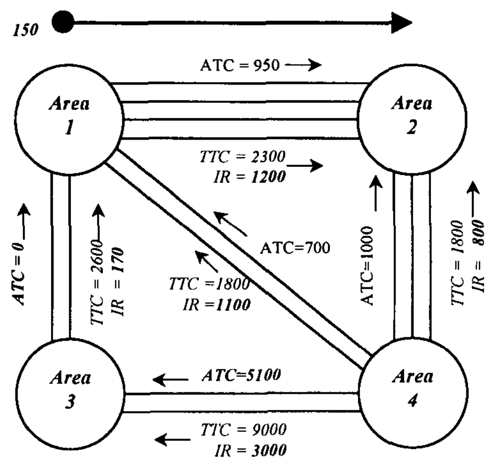

Figure 3.14 *Case 3*

3.9 EXPERIENCES WITH OASIS IN SOME RESTRUCTURING MODELS

3.9.1 PJM OASIS. PJM OASIS, which became operational on January 1, 1997, complies with FERC Order No. 889 requirements. It is the responsibility of PJM OI (Office of the Interconnection) to provide the OASIS node for the transmission network of the PJM control area. PJM OASIS maintains the transmission and the ancillary service information for PJM control area transmission providers and customers, ancillary service providers and customers, and other authorized PJM OASIS users [Pjm97]. Figure 3.15 illustrates the PJM OASIS configuration.

In Figure 3.15, PJM OASIS is composed of two major components (servers) which are, OASIS Web Server and OASIS Database Server. The OASIS Web Server is the OASIS node computer at PJM. It is the server that communicates with PJM OI customers and other OASIS users, and the communications are based on the Web server's Internet software. The OASIS Database Server is the computer at the PJM control center that functions as the database server for the information that is displayed and downloaded for the PJM OASIS users. The URL of the PJM OASIS node is http://oasis.pjm.com.

Information posted on PJM OASIS include Transmission Transfer Capability, Operational Data, Study Information, Transmission Service Products and Prices, Ancillary Service Offerings and Prices, Specific Transmission Service Requests and Responses, Transmission Service Schedules, Outage Schedules, and Other Transmission-Related Communications.

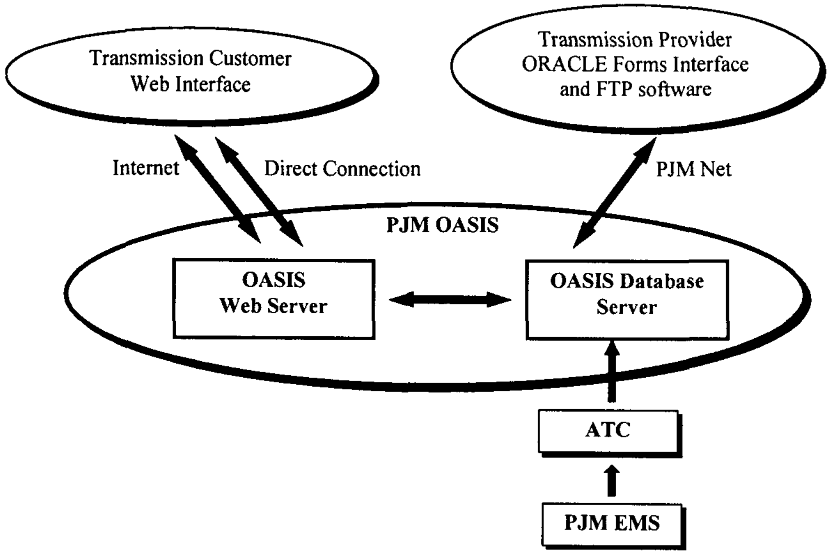

Figure 3.15 *Structure of PJM OASIS [Pjm97]*

OASIS acts as an electronic bulletin board for transmission information, where any provider or customer may post transmission want ads, transmission notices, and other[11] transmission related communications. There is no obligation to respond to these postings. The PJM OASIS is also used by providers, customers or the PJM OI to post transfers[12].

[11] Other communications include the use of OASIS as a transmission-related conference space or to provide transmission related messaging services between OASIS users.

[12] Notices of transfers of personnel as described in FERC Order 889, Section 37.4(b)(2) are posted.

3.9.2 ERCOT OASIS. ERCOT OASIS is administered by the ERCOT ISO. The ERCOT OASIS includes most of the functionality of the FERC mandated OASIS, but it excludes the capability to buy and sell transmission capacity, where planned transmission capacity to serve loads, as the Public Utility Commission of Texas (PUCT) Rules require, is purchased on a yearly basis through applications for planned transmission service. The ERCOT OASIS must be used for scheduling unplanned transactions originating and/or terminating in ERCOT [Erc98].

The ISO acts as a one-stop shop for all market participants to obtain information about the ERCOT transmission system, access the transmission system and to arrange energy transfers. Using OASIS, market participants are able to gain access to the shop. The OASIS is used to [Erc98]:

- Submit requests for Unplanned Transactions to the ISO
- Receive approval of Unplanned Transactions from the ISO
- Post information required from Transmission Providers
- View and download information
- Provide data for energy accounting
- Post tariffs for Ancillary and Transmission Services.

In ERCOT, ATC is the calculated uncommitted capability of the transmission system between two points or zones that can be used for unplanned transactions, where zones are divisions of ERCOT used to identify the geographical locations of loads and generators for the purpose of defining ATC. In ERCOT, planned resources are designated each year, and transactions outside these pairings of loads and generators are considered unplanned transactions under PUCT Rules.

The calculation of transfer capability is generally based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. Each simulation represents a single snapshot of the operation of the interconnected network based on the projections of many factors. The ERCOT would set objectives of the ATC calculation, which are [Erc98]:

- Ensure the security and reliability of the ERCOT bulk transmission system,
- Allow equal and comparable access to the ERCOT bulk transmission system,
- Post an accurate ATC for each pair of zones that can be used by the ISO to approve or reject unplanned transaction requests on the OASIS,
- Enable the adjustment of posted ATCs as unplanned transactions are accepted before they are reflected in each control area's current operating plan, and
- Utilize the ERCOT bulk transmission system by making a reasonable effort to approve a transaction when the available information indicates that the system could support the request.

Both ATC and TTC are posted by the ERCOT ISO on the OASIS. The ERCOT ISO has the authority to intervene in any transaction that threatens system reliability, regardless of ATC. The ERCOT ISO may also modify ATC values if more current data indicates increase or decrease in transfer limits. When transfers requested by users are within the most currently evaluated ATC, they will be approved, and when the transfer capability necessary to accommodate the requested transfer exceeds the most current ATC, the transaction will be rejected, and the user who has requested the transfer will be informed of the reason for rejection and can request an evaluation of whether and to what extent the limiting ATC can be increased by redispatch actions.

When a user requests an unplanned transaction, he/she should specify the zones associated with the desired transaction (source and sink zones). The specification indicates the location of the source (generation), and *the To ATC Zone* indicates the location of the customer (load) served, and the source and customer may be the same. The load zone of an unplanned transaction is defined as the smallest zone that encircles the total loads.

The ERCOT OASIS provides an interface for customers to view the ATC values calculated by the ISO. These values can be viewed from the ERCOT Available Transmission Capacity page for a single hour or for several hours, by selecting the appropriate data in the corresponding boxes, such as Hour, Source ATC Zone, Destination ATC Zone, the minimum ATC in MWs, the starting date and hour, the ending date and hour, the time zone a user would like to view the ATC values, and the sort order for the ATC values to be returned.

CHAPTER 4

TAGGING ELECTRICITY TRANSACTIONS

Transaction Information System

4.1 INTRODUCTION

Historically, the scheduling of energy transfers has been accomplished on a coordinated basis between control areas. When a transmission path crosses more than one control area, the adjacent control areas would arrange for the so-called *contract path* in a sequential fashion. As electrons flow through every line in the transmission system, obeying the laws of physics and not economics, a transaction could result in *parallel flows* on system components that were not originally included in the contact path [Ner96, Ner99b, Ner00a, Ner00b]. In the beginning, parallel flows were not a serious problem since the number of transactions was limited; however, as the number of energy transactions increased dramatically, parallel flows which were not included on the contract path created severe operational problems for many transmission systems. Parallel flows could overload transmission lines and, in some cases, utilities were unable to identify the source of overflows. The first remedy to mitigate overflows was the curtailment of firm and non-firm energy schedules by system operator, which in turn caused more confusion for both marketing entities and utilities.

Due to the aforementioned situations and the new era of restructuring in power systems, it was seen that an internet-based system that could exchange the transaction information among marketing entities, system operators, and security coordinators[1] would be necessary. The internet-based system would afford a more suitable approach to analyzing transmission flows and listing transfer capabilities. In addition, an efficient power system operation could lead to reduction in the number of unnecessary curtailments and the resulting negative impacts on market entities and utility systems [Ner00b].

4.2 DEFINITION OF TAGGING

Tagging or what is known as Transaction Information System (TIS) is a mechanism for scheduling the physical transfer of power between control areas. It was initially established as a mechanism to identify every transaction from source to sink in order to manage Transmission Line loading Relief (TLR) in a proper manner. All tags were then entered into the interim Interchange[2] Distribution Calculator (iIDC) to analyze the effect of each transaction on constrained flowgates. The concept of flowgates was developed by NERC for sharing transmission constraints in managing TLR. The difference between branches/interfaces and flowgates is that while monitored branches and interfaces are normally checked for overflows in the base case and various contingencies, flowgates are checked only in the base case (for the base case flowgates) or in one contingency identified by the flowgate definition [Mcd98, Ner99b, Ner99c, Ner00a, Ner00b].

Usually an energy transaction would involve more than one operating entity: it originates from an entity, may pass through an intermediate entity and ends in a different entity. The electronic documentation of such transaction is the tagging process. Tagging is defined as the process that would involve the communication of information needed to carry out security valuations and scheduling transactions. Tagging is a major step towards electronic scheduling. The tagging documentation would form the coordination of and approval from all the entities involved in a transaction. Tagging is a computerized process, where tags are transmitted computer-to-computer and point-to-point over the public Internet. Here the necessary data should be

[1] Security Coordinator is an entity that provides the security assessment and emergency operations coordination for a group of Control Areas.

[2] Interchange is defined as energy transfers that cross control area boundaries.

provided completely and in a proper manner for validity checks. Otherwise, it may lead to rejection or delay of tags.

4.3 HISTORICAL BACKGROUND ON TAGGING

The interest in a system that would enable an improved exchange of transaction information was initiated by the NERC Interconnected Operations Subcommittee (IOS) in 1996, when it started to design a system called tagging. To secure the energy transaction information, an Excel spreadsheet-based tag entry and retrieval system, which utilized fax and Internet e-mail to transport tags between parties, was tried initially. NERC implemented tagging in July 1997, in which each energy transaction was identified and communicated through an electronic Interchange Transaction tag, and its impact on the transmission grid was calculated by the Interchange Distribution Calculator (IDC[3]). IDC contained a model of the Eastern Interconnection and all tagged transactions. At that time, tagging was spreadsheet-based, which provided system operators with the identity of the source of parallel flows affecting their systems. Using this process, when a transmission line is overloaded due to transactions, IDC would calculate the effect of energy transactions on the existing transmission system. These calculations are aimed to minimize the need for curtailments and to provide a reasonable and economically unbiased basis to curtail transactions. In certain regions, flow-based calculations are made prior to approving a transmission reservation, before the transaction is initiated - in order to minimize unnecessary curtailments [Mcd98, Ner99b, Ner99c, Ner99d, Ner99e, Ner00a, Ner00b, Ner00c, Ner00d].

Later, in 1998, spreadsheet-based tagging evolved to be an easy-to-use Visual Basic based program called NERCtag that relied on e-mail and operator intervention for data exchange [Ner99f, Ner00b]. Even though the new program was an improved solution to tagging, NERCtag still showed some deficiencies, which required more developments to keep up with the growth of the restructured electric power industry. In addition to a considerable operator intervention during the process, one of the main deficiencies in NERCtag was a slow e-mail process for

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[3] IDC involves a process by which the effect of energy schedule on transmission grid is calculated using power transfer distribution factors.

delivering tags. Also entities were concerned that multiple copies of a tag were issued and, at occasions, tag emails were corrupted or altered. Also, PSEs had problems with the disposition and the use of a tag. Add to that, the specification of the tag information was not precise; therefore, different entities interpreted the information differently. Technically, the old tagging system had two main drawbacks [Ner00b]:

(1) Using e-mail and fax for submitting tags proved to be an inefficient method which could not guarantee that all tags were delivered and correctly entered into iIDC.

(2) iIDC was incapable of recognizing reservation priorities in each transmission segment of a tag. For that reason, all transaction priorities were identified with the lowest priority of segments on the tag[4].

As such, there was a necessity for establishing an electronic and automated system with features like a capability to ensure that tags were sent, received, and approved in a timely, reliable manner, and a capability for data validation. NERC decided to switch from the old tagging system to a different system to overcome the shortcomings.

In November 1998, NERC directed the development of an electronic tagging system. Subsequently, the NERC Transaction Information System Working Group (TISWG) issued a document called The Electronic Tagging (E-Tag) –Functional Specification. This document specifies the functional requirements and technical specifications for the implementation of E-Tag. The E-Tag Functional Specification describes information and data exchange needs, services to be provided, and protocols to be used. The document gives vendors the flexibility to choose the type of software or user interfaces to be used, as long as the functional requirements and technical specification are maintained in the E-Tag products.

The NERC issued Policy 3 that defined specifications or requirements of the new tagging system, and the NERC Operating Committee approved the Constrained Path Method (CPM) Resolution

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[4] Frequently Asked Questions About the Electronic Transaction Information System, Version Date: 1/20/99, http://www.nerc.com/~filez/tag/

that required changes to the iIDC to take into account varying priorities of each transmission segment. For TLR and CPM to work efficiently, the resolution required and necessitated the *no-tag-no-deal* concept. The resolution commanded TISWG to build the appropriate specifications for the tagging model and the submission protocol in order to electronically tag and verify all transactions, including hourly deals. In addition, electronic TIS would stand as a mechanism to terminate a tag as control areas (CAs) cancel or partially curtail the tag. When changes on a tag are in place, reloading would be achieved by submitting a new tag. The NERC Policy 3 requests all entities to provide the necessary information on transactions that would pass through every control area. In the case that a transmission path is constrained, security coordinators would use this information to decide which transactions should be curtailed first [Ner00b].

The new protocol was an HTTP-based system that replaced the e-mail-based system. The e-mail-based system was an open-ended system, by which the user would send an e-mail without getting a positive confirmation that the other entity had received the e-mail. The other motivation for the transition was that the e-mail transmission could be held within e-mail routers for an extended period of time and delays could occur for hours or even days with terrible consequences for an hourly market. As stated in the NERC Policy 3, positive confirmation of tag receipt would be called within 10 minutes. This requirement could not be guaranteed in the e-mail-based system while the HTTP-based system would be capable of performing the task. The response system as specified would include basic syntactical checks and the establishment of an initial transaction status [Ner99c, Ner00b].

4.4 HOW DOES A TAGGING PROCESS WORK?

Functional specifications[5] issued by TISWG of NERC for electronic tagging aimed to guarantee that all tags could be transferred electronically between all market entities and, at the same time, guarantee the receipt of tags. The other objective was to improve the

[5] Transaction Information System Working Group, North American Electric Reliability Council., "Electronic Tagging – Functional Specifications," Version 1.4, April 23, 1999, http:/ /www.nerc.com/~filez/tag/

speed and the efficiency for producing transmitting tags, especially to enhance the hourly market. The specifications would also be intended to improve the quality and the uniformity of tags to increase their usefulness. Moreover, specifications aimed to guarantee the uniqueness of all tags entering iIDC or IDC and to guarantee that these tags would accurately match actual transactions. The functional specifications would explain the obligations and duties of all parties to an interchange transaction, required data to represent a transaction, and mechanisms to be used to exchange the data electronically.

Among the functional requirements for an electronic tagging system are: syntactical error handling, circulation of the tag to entities involved in the transaction, collection of approvals from all parties, and uploading of approved tags to IDC. A successful tagging system should take certain factors into consideration, such as specifying which parties in a transaction have responsibility for the data at each step of the exchange, insuring data integrity without duplicating data entry or replicating errors, minimizing the number of data transfers between parties, and providing mechanisms to recognize and overcome system failures [Ner00a, Ner00b].

To comply with NERC specifications, all market participants would be free to use any product (software) that they would desire or design their own to meet the minimum NERC Policy 3 requirements. The NERC specifications come to manage tagging in an efficient way that would guarantee consistencies in the way tags are created and submitted, and to increase efficiencies in grid management for removing any potential reliability problems. The information contained in the tag would generally be considered confidential, particularly in the hourly market. NERC Policy 3 would require participants to comply with certain specifications for submitting transaction tags, where it would be necessary for entities that schedule transactions to use the NERC Interchange Transaction Request Template, specified in Appendix 3A of NERC Policy 3. NERC Policy 3 provides entities with some flexibility for using the Transaction Request Template, while some information is obligatory to be filled out [Ner98].

In October 1998, NERC introduced a software called NERCTag[6] that replaced the NERC's Excel spreadsheet-based tagging program. Entities that use NERCTag would have an interface for creating tags and superior E-mail managing capabilities[7]. This software enabled entities to fill out the NERC Interchange Transaction Request Template [Ner99f, Ner00b].

In 1999, NERC introduced the newest software, called ETAG, to send and receive NERC interchange transaction tags. This program would use the World Wide Web to guarantee, in a reliable manner and in the proper time, that tags are sent, received and approved.

4.4.1 Electronic Tagging Services. Functional requirements for electronic tagging can be understood by discussing its three main services. The three services are the three software components: *Tag Agent Service*[8], *Tag Authority Service*[9], and *Tag Approval Service*[10]. Tag Agent Service should be utilized by all Purchasing-Selling Entities (PSEs)[11]. All control areas should utilize both Tag Authority service and Tag Approval Service. All transmission providers should utilize a Tag Approval Service [Ner99b, Ner99e, Ner00a, Ner00b, Ner00c, Ner00d, Wes00].

- **Tag Agent Service:** As illustrated in Figure 4.1, this service provides the electronic, graphical interface between the PSE and the tagging process, i.e., this service is a software component for creating an initial electronic tag and entering the information that would represent an interchange transaction and transfer the information to the appropriate Tag Authority Service. Tag Agent Service is provided either directly by PSEs or indirectly by a third party chosen by PSEs to provide this service as their agent.

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[6] NERCTag, http://www.nerc.com/compliance/nerctag.html.

[7] http: //www.nerc.com/~filez/tag/tagging.html

[8] Generates and submits new tags to the authority service.

[9] Receives agent submissions and forwards them to the appropriate approval services.

[10] Indicates individual path approval.

[11] PSE is an entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

Figure 4.1 *An Illustration of the Tag Agent Service*

The first thing a Tag Agent Service does is validate the information. Once the validity check is done, the service would build a tag and pass it on, through the Internet, to the Tag Authority Service associated with the Load Control Area[12] (LCA) identified in the tag. On the other hand, if the information does not pass the validity check, Tag Agent Service would notify PSE of the failure and provide it with apparent cause of the failure in the form of an error message. The service also stands as a tool for PSE to check the approval or the refusal status of its transactions. In addition, PSEs would use this service to withdraw, cancel, replace, or early terminate any of its transactions. For an existing tag issued by a PSE, the PSE could withdraw, cancel, or early terminate the tag by using the *CANCEL* message. PSE may opt to use the *REPLACE* functionality of the *SUBMIT*[13] message, which enables PSE to link the issued cancellation of a tag with the acceptance of another tag. In an early version, PSEs were allowed to revise existing tags, but under new Functional Specification, PSEs are not allowed to do that. That means a PSE wishing to revise a tag should first cancel the existing tag and submit a new one, and may link the new tag to the tag being cancelled using the *REPLACE* function. The linking process can be requested in the *SUBMIT* message, which contains optional fields for Replace Tag ID and Replace Tag Key to refer to the tag to be cancelled. PSEs may view the approval or the refusal status of their transactions either by simple polling[14] or through other

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[12] Sometimes, it is alternatively called Sink Control Area.

[13] SUBMIT message is used to request a new tag.

[14] Simple polling is performed by querying the Authority Service at periodic intervals.

agreed upon notification mechanisms such as receiving notifications at certain times; otherwise, the authority service may deliver unsolicited notification messages [Ner99b, Ner00a, Ner00b].

- **Tag Authority Service:** This service is the central point for all interactions with a tag. Also this service "maintains the single authoritative copy of record[15]" for each tag forwarded from any Tag Agent Service to this authority service. Every LCA is responsible for maintaining this service directly by itself or indirectly by assigning a third party as an agent to provide this service. It should be mentioned that a Tag Authority Service is provided by LCA for each tag, i.e., for each tag there is one Tag Authority Service. When the Tag Authority Service receives tags from the Tag Agent Service, it would validate the information and forward all tags to the Tag Approval Service associated with each entity that would have approval rights for the transaction. If the tag passes the check, the Tag Authority Service would produce its own unique Tag Keys to be associated with the tag on the initial transmission of the tag to each of the appropriate Tag Approval Services. On the other hand, if the tag under study fails validation, the Tag Authority Service would notify the PSE that issued the failed tag, via the PSE's Agent Service. The Tag Authority Service would also provide the PSE with the apparent cause of the failure in the form of a coded error message [Ner99b, Ner00a, Ner00b].

  The Tag Authority Service would then collect approvals and refusals issued by Tag Approval Services. The Tag Authority Service would arbitrate and send the final status of the tag to the tag agent, all Tag Approval Services and to the LCA's security coordinator associated with the tag, based on time and/or the messages received from the tag approval services. The Tag Authority Service would enable both tag agent and tag approval services to request and know the current approval status of their tags. The Tag Authority Service would work as a mechanism to partially curtail transactions during TLR.

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[15] Transaction Information System Working Group, North American Electric Reliability Council, "Electronic Tagging – Functional Specifications," Version 1.4, April 23, 1999, http://www.nerc.com/~filez/tag/

The Tag Authority Service would maintain two types of status, which are *Approval Status* and *Composite Status*. The approval status would refer to the individual approval status values. The Tag Authority Service maintains the individual status value for each Tag Approval Service. On the other hand, composite status values would reflect a combined status of all current individual approval status values. The composite status of a tag is made available to the agent service when the agent service would request this status, or when this status would be updated.

- **Tag Approval Service**: As illustrated in Figure 4.2, the Tag Approval Service provides a user and/or programmatic interface between an approval entity and the Tag Authority Service. The interface would enable the approval entity to communicate to the Authority Service the entity's approval or denial decision taken on the tag. This service would receive all transaction tags submitted by agent services through the appropriate authority service, and provide a mechanism for the approval entity to send a response of approval/refusal to the authority service, where the tag approval service maintains a master copy of tag and its status. An approval entity would be a control area or transmission provider as identified on the transaction's scheduling path of a tag. The service could also be provided by any of the entities (or by a third party assigned by these entities as agents) that would have the right to verify the contents of and approve or deny a tag/transaction. These entities include CA, TP, PSE, and SC. The Tag Approval Service would use *INVALID* message to communicate any data validation or internal consistency errors to the Tag Authority Service [Ner99b, Ner00a, Ner00b].

***Figure 4.2** An Illustration of the Tag Approval Service*

When a Tag Authority Service generates a composite status of a tag, it would send the composite status to all approval entities involved in the transaction. Therefore, each Tag Approval Service would maintain an up-to-date composite status for the tag and provide the capability to question the Authority Service for updated status on demand.

Once the tag has passed the validity check, it would then be evaluated by each of the approval entities, i.e., by control areas and transmission providers identified in the tag that have approval rights. To verify the content of a tag and to approve/deny a tag, the control area would assess the transaction's start and end time, energy profile, and scheduling path[16]. The TP would assess valid OASIS reservation number or transmission contract identifier, proper transmission priority, energy profile accommodation[17], OASIS reservation accommodation of all interchange transactions, and loss accounting.

The E-tagging process is shown in the simplified illustration of Figure 4.3. The Tag Agent Service would pass on tags to the Tag Authority Service associated with the sink control area for the interchange transaction. The Tag Agent Service provides the format of the tags that would correspond with the NERC specifications. The agent also provides the PSE with the means to view the status of the interchange transactions whether binding or in progress and the means of canceling an interchange transaction. Once the Tag Authority Service receives the tags from Tag Agent Service in the proper format, it would forward the tags to the Tag Approval Service and the related entities such as TPs, CAs, SCs or ISO. Once the Tag Approval Service has approved or denied the interchange transactions based on operations security criteria, the Tag Authority Service would collect the information from the approval service and provide them to PSEs, Tag Approval Service, SC of the sink and CA. If the SC requests the Tag Authority Service to submit the tag ID[18], the authority would enter the tag ID into the iIDC.

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16 Verifying the proper connectivity of adjacent Control Areas.

17 The energy profile accommodation is to check whether or not the energy profile fit OASIS reservation.

18 Interchange transaction is uniquely identified by a Tag ID and a Tag Key. Later, we will illustrate this issue.

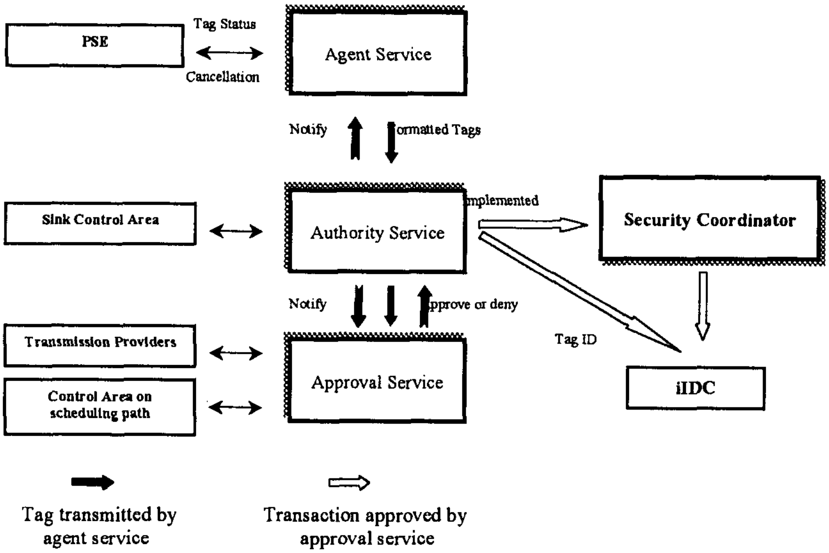

Figure 4.3 Illustration of the E-Tag Process

Figure 4.4 shows the tagging process for a case when three TPs and two CAs are the entities with approval rights on a certain transaction initiated by a certain PSE.

4.4.2 Sequence of Tagging Process. It should be mentioned that the transmission reservation comes before tagging can take place [Ner00b]. Here, the information included in the tag should take into account that the parameters of the proposed energy transaction must encompass parameters of transmission reservation. As Figure 4.5 shows, before a tag agent would submit a tag, it must have confirmed transmission reservations on OASIS, or alternatively must have attained the required transmission rights. When transmission paths are acquired thorough OASIS reservations, the acquired paths turn out to be the energy paths identified in the tag. The parameters of the transmission reservation associated with the acquired paths such as MW, duration, and time will be the boundaries of the tag. The amount of MW proposed to be delivered – as shown in the tag – should be equal or less than the MW transmission capacity reserved over the OASIS or the existing rights that the entity holds.

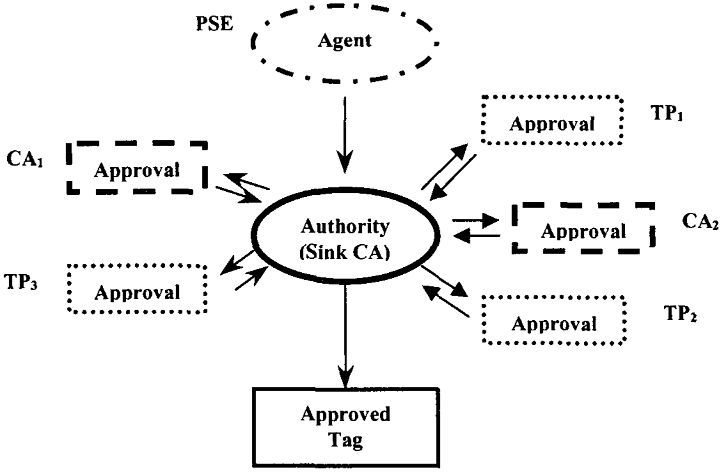

Figure 4.4 *E-Tag Process for a Case with Three TPs and Two CAs*

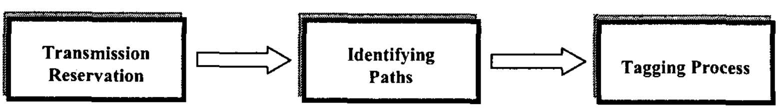

Figure 4.5 *Sequence of Transmission Reservation and Tagging Process*

To maintain the security of each tag, a combination of unique Tag ID and Tag Key numbers are used from the beginning of the tag submission to the end of the approval process.

4.4.3 Transaction Scheduling. The sequence of events to schedule a transaction between a generation control area (GCA) and a load (sink) control area (LCA) through an intermediary[19] control area (Int. CA) is shown in Figure 4.6.

Initially PSE submits a tag for the transaction to the authority service of the LCA (or CA3). When the LCA receives the tag, it would request the approvals of:

- Approval service of control area where the transaction starts (GCA or CA1),

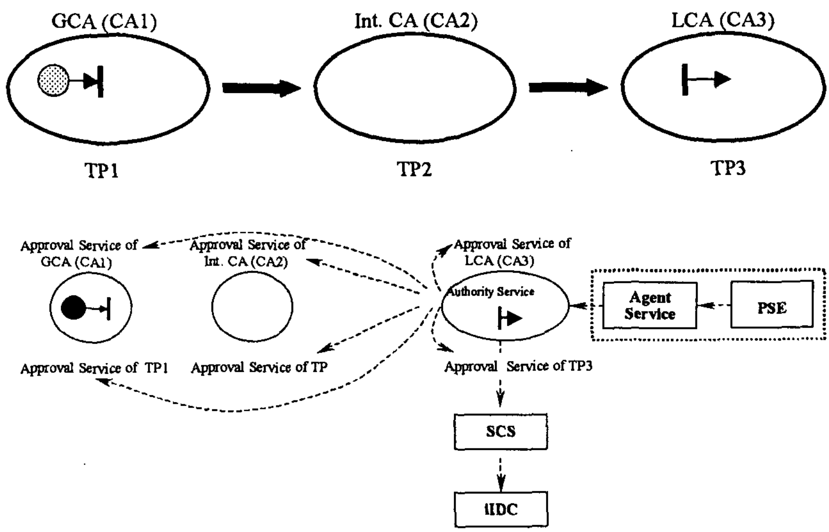

Figure 4.6 Illustration of Sequence of Events to Approve a Transaction

[19] Intermediary control area is a control area on the scheduling path between the source/ generation control area and the load/sink control area.

- Approval service of the transmission provider of GCA (TP1)
- Approval service of control area where the transaction passes through (CA2),
- Approval service of the transmission provider of CA2 (TP2)
- Approval service of control area where the transaction ends (LCA or CA3),
- Approval service of the transmission provider of CA3 (TP3)

After these entities approve the transaction, CA1, TP1, CA2, TP2, CA3, and TP3 would send their approvals to CA3 authority service. After that the CA3 authority service would send notifications to PSE, CA1, TP1, CA2, TP2, CA3, and TP3. The CA3 authority service then sends the tag to the SCs. The SCs enter the tag into the iIDC and then the PSE can ask the CA3 Authority service about the status of the tag or detailed information on the status. If PSE decides to cancel a Tag, it can request the CA3 authority service for cancellation.

4.5 IDENTIFYING TAGS

In order to maintain the security of tags, the Tag Agent Service initiating the tag produces a Tag ID and a Tag Key. The Tag ID and Tag Key are used to uniquely identify the tag to the Tag Authority Service. They will be used by both the Tag Agent Service and Authority Service in all subsequent messages between them. The Tag ID is based on four components [Ner00b]:

(1) GCA registered Code,

(2) PSE originating the tag registered Code,

(3) LCA registered Code, and

(4) A unique transaction identifier number.

On the other hand, the Tag Key contains two parts of information: (1) A 1–6 character code associated with the entity initiating the tag, and (2) A unique 12-character alphanumeric (0–9, A–Z, a–z; case sensitive) security token. It should be mentioned that the Tag ID should continue as unique ID for a period of not less than one year from the stop date and the time associated with the last transaction that was assigned to that Tag ID. In the case of a faxed tag, the Tag ID is assigned by PSE [Ner99b, Ner00a, Ner00b, Ner00c].

When the Tag Authority Service receives a tag from the Tag Agent Service, it checks the tag's validity. The Tag Authority Service would then produce its own unique Tag Key to be associated with the initial Tag ID. Each assigned Tag Key would contain two parts of information: (1) LCA code, and (2) a unique 12-character token. The Tag Authority Service and a Tag Approval Service must indicate both the Tag ID and the Tag Key when they exchange messages related to a certain Tag [Ner99b, Ner00a, Ner00b, Ner00c].

Transaction tagging would require specific information to uniquely identify and represent the characteristics of interchange transactions, and requires technical specifications to electronically communicate the transaction tag information between different entities. This information, when utilized with functional requirements of the Tag Agent, Tag Authority and Tag Approval Services, will form the core to implement the electronic tagging information system. The interchange transaction is uniquely identified by a Tag ID and a Tag Key. The key is required to electronically communicate and control interactions of a tag among Tag Agent, Tag Authority and Tag Approval Services [Ner99b, Ner00a, Ner00b, Ner00c].

For each transaction, the unique Tag ID specifies a code for each of GCA, code of PSE originating the transaction tag, unique transaction identifier, and code for LCA. Any part of the tagging information system should deal with tag ID as confidential information, because the Tag ID and the contents of the tag reveal commercially sensitive information. The unique transaction identifier is a fixed seven characters of upper alpha or digits 0 through 9. It is the responsibility of the Tag Agent Services to guarantee that each Tag ID is unique. The ID of interchange transaction shall not be repeated for at least one year after the transaction is completed to prevent confusion in the implementation of the iIDC.

The transaction Tag ID is accompanied by unique tag keys to electronically exchange tag information. Both pieces of information facilitate controlling communication between the three tag services. The key consists of one-to-six character code associated with the entity initiating the transmission/transfer of the tag, and unique twelve character alphanumeric[20] security token. A key is associated with the initial transmission of a tag from the agent service to the appropriate authority service. The creation of this key is the responsibility of the agent service. The key consists of the PSE code associated with the PSE submitting the tag and a unique twelve character token. For a certain transaction, all exchanged information between the tag agent and tag authority refer to both the tag ID and the tag key assigned by the PSE's tag agent.

Unique Tag Keys are also created by the Tag Authority Service to be associated with the tag on the initial transmission of the tag to each of the appropriate Tag Approval Services. A Tag Key is composed of the CA code associated with the LCA and a unique twelve character token. All following messages communicated between the tag authority and a certain tag approval related to this tag should indicate both the Tag ID and Tag Key appointed by the LCA's Tag Authority.

As we mentioned, the ID of the interchange transaction is assigned by the PSE serving the load or by agreed upon party. The ID format should indicate GCA registered Code, PSE originating the tag registered Code, LCA registered Code, and a unique transaction identifier number. The ID takes the form shown in Figure 4.7.

GCA	**PSE #######**	**LCA**

Figure 4.7 *Format of Tag ID*

[20] 0-9, A-Z, a-z; case sensitive

Example[21] 4.1

A PSE called Electric Power Inc. (EPI) needs to tag a transaction souring in the control area of Power Generation Company (PGCO) and sinking in the control area of Chicago Services (CHIS). For this situation, the Tag ID that could be assigned by the PSE could take the form shown in Figure 4.8, where:

GCA registered Code : PGCO (Power Generation Company)

PSE registered Code : EPI (Electric Power Inc.)

LCA registered Code : Chicago Services (CHIS)

A unique identifier number : 5544332

4.6 DATA ELEMENTS OF A TAG

The following element categories are data elements of a tag that are required (i.e., must be included) on the tag which are the only elements that may be used by the CAs and TPs in their tag assessment procedures. The tag will be judged as complete if it includes these items [Ner00b]:

PGCO EPI• 5544332 CHIC

GCA PSE Unique LCA

Figure 4.8 *Example of Interchange Transaction (Tag) ID Number*

[21] The names in the example are hypothetical.

- **Transaction Administrative Information Requirements:** The information includes Interchange Transaction ID (Tag ID Number)[22], Transaction Start and Stop Dates, Transaction Days[23], Code[24] of Purchasing-Selling Entity, PSE Contact 24-hour Telephone Number, Source Entity (Control Area or name of generator, generator zone, or system for intra-Control Area transactions), and Sink Entity (Control Area or name of load, load zone, or system for intra-Control Area transactions).

- **Energy Profile Information Requirements:** The information includes Start Time[25], Stop Time[26], and MW[27]. The Energy Profile section in tag application form represents the energy needed in various time pieces between Start and Stop times. Generally speaking, the Energy Profile represents a collection of lines that record a time for a flow to start and to stop, and a MW level that the flow should meet. Figure 4.9, depicts a section of the Backup Fax Form that is used to tag a transaction [Ner00a, Ner00b]. In this figure, the fields in the energy profile include fields for the Start and Stop Dates, Repeating Days flags to describe the energy flow throughout the life of the tag, start and stop times, and MW value. The other fields in the energy profile section which include MWh value and ramping information are optional to be filled out. The following example shows how these fields are filled out.

Example 4.2 (Representation of energy profile)

John Randolph would need to tag a transaction that runs 100 MW from 5:00 a.m. to 9:00 p.m. every Monday in December 2000.

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[22] As we mentioned, the Tag ID is a unique identifying number assigned to each tag.

[23] Days of the week on which the energy profile must be executed.

[24] Six-character identification number that PSE has registered with NERC and that is listed in the Master Registry.

[25] Specific clock time (in 24-hour format) of the beginning of service at the Generating Control Area.

[26] Specific clock time (in 24-hour format) of the termination of service at the Generating Control Area.

[27] Amount of MW to be transported from the source for the period defined by Start and Stop Times.

Energy Profile at Source

SUN	MON	TUES	WED	THUR	FRI	SAT
O	O	O	O	O	O	O

START	STOP	MW	MWH	Ramp Start	Duration

Figure 4.9 *Energy Profile Fields in the Tag Form*

The first point in time at which the energy would begin to flow is December 4, Hour Beginning at 05:00. The last point in time at which the energy would flow is December 25, Hour Ending at 21:00.

The Start Date and Stop Date:

Start Date = December 4, 2000

Stop Date = December 25, 2000

The days for which the energy profile needs to be started: every Monday (Repeating Days = Monday).

The profile to run every Monday: Energy Profile = 05:00–21:00 100 MW

In Figure 4.10, the Mon flag in the repeating day flag is ticked to represent the day of the week for which the Energy Profile should be initiated.

Start Date 12/4/00 | **Stop Date 12/25/00**

Energy Profile at Source

SUN	MON	TUES	WED	THUR	FRI	SAT
O	■	O	O	O	O	O

START	STOP	MW	MWH	Ramp Start	Duration
05:00	21:00	100			

Figure 4.10 Illustration of Energy Profile in Example 4.1

- **Transaction Path Information Requirements**: As shown in Figure 4.11, the path transaction information describes the contract path taken by the transaction. This section of information includes fields for references to other documents (e.g., OASIS assignment reference) that describe purchase agreements, levels of service, and other details. It also has fields for other components that should be combined to describe a contiguous path extending from the source to the sink. These components are GCAs, TPs, CAs, PSEs, LCAs and Product Type. The entry in the Product Type field contains a number between 1–7 that refers to the NERC curtailment priority plus the type of transmission product. The entry can take any of the following seven types: 1-NS (Nonfirm Secondary), 2-NH (Nonfirm Hourly), 3-ND (Nonfirm Daily), 4-NW (Nonfirm Weekly), 5-NM (Nonfirm Monthly), 6-NN(Nonfirm Network0, and 7-F(Firm). The PSE field in this section is required for the source PSE, load-serving PSE, and those PSEs with transmission reservations. The Product Level is required only when using multiple reservations for a single transmission segment, i.e., several transmission reservations are combined to meet the capacity requirements of the transaction [Ner00b].

- **Loss Accounting**: As shown in Figure 4.12, this section of information specifies the method in which each transmission provider is being credited for the energy lost in the transmission paths. The loss profile describes the segments of time for which losses are to be applied. Types of losses are: In-Kind, Financial (FIN), Internal (INT), and External (EXT). The In-Kind losses point out that transmission losses will be compensated by purchasing more energy than is required up front. To refer to this type of loss accounting, the Point of Receipt (POR) MW and the Point of Delivery (POD) MW values are modified to show the loss. The Financial losses are losses that are purchased within the price of the transmission service being used. The Internal losses describe a transaction to provide energy with a third party entity that is directly connected to the TP system. The third party will be paid by the transmission customer to provide the extra energy. The External Loss type describes a transaction to provide energy with a third party entity that is not directly connected to the TP system (the transaction requires interchange to be performed). Supply Reference field describes the transaction with the entity providing the energy to compensate the energy lost. As Figure 4.12 shows, the loss accounting section in the tag form includes dates for Transmission Provider[28], Start Time and Stop Times[29], Path, MW at POR, MW at POD, and Loss Supply type [Ner00b].

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[28] TP for which losses are being described.

[29] Specific times the loss accounting will start and end.

Transaction Path

SOURCE	PHONE	FAX

ENERGY	Title/Rights	TRANSMISSION					MISCELLANEOUS	
CA	PSE	TP	Product	PATH	OASIS	LEVEL	INFO	REF

SINK	PHONE	FAX

Figure 4.11 *The Transaction Path Section in the Tag Form*

Loss Accounting

TP	PATH	START	STOP	MW POR	MW POD	TYPE	Supply Reference

Figure 4.12 *The Loss Accounting Section in the Tag Form*

In this section of information the transmission provider field represents the TP for which losses are being described. The Start Time and Stop Times fields are the specific times when the loss accounting will start and end. The MW POR and MW POD fields refer to the MW value at POR and the MW value at POD, respectively. They could be different to account for losses. The Type field refers to loss supply type.

The whole form required to tag transaction is shown in Figure 4.13. In this chapter we use the Backup Fax Form to illustrate tagging information [Ner00a, Ner00b].

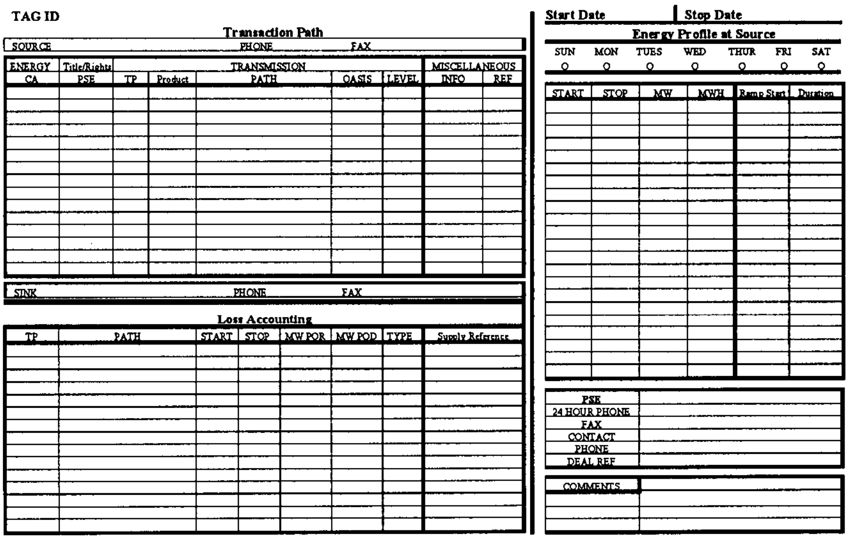

Figure 4.13 Form of E-Tag Information

Example 4.3

John Randolph with the Electricity Services (ELSER) wishes to tag a transaction originating in Control Area A (CAA) and sinking in Control Area B (CAB). He wants the energy to flow at 100 MW during the hours 06:00–22:00 every business day (Monday-Friday) for the entire month of December 2000. He will be using (1) Control Area A hourly nonfirm transmission reserved on the Control Area A OASIS by Power Services Company (PSCO) to move the power from Control Area A to its border with Control Area B through Transmission Provider TP_A, and (2) Control Area B hourly nonfirm transmission reserved on the Control Area B OASIS by ELSER to move the power from Control Area A's border with Control Area B to the Control Area B through Transmission Provider TP_B. Control Area A does not require losses to be scheduled, but Control Area B requires losses to be scheduled at a rate of 2.92% per MW, paid in kind. Figure 4.14 illustrates this transaction and the solution is discussed as follows.

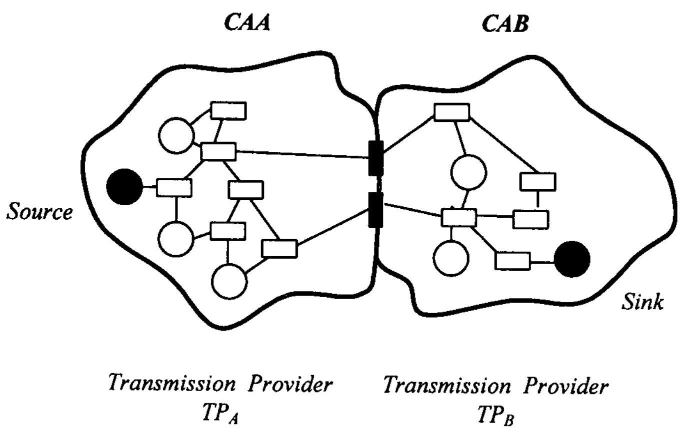

Figure 4.14 *Illustration of Example 4.2*

Tagging the transaction:

John gives the Tag ID CAA ELSER 1223344 CAB to this Transaction. For this illustrative example, the Energy Profile should be identified: The transaction will be repeating on Monday, Tuesday, Wednesday, Thursday, and Friday. The energy flow begins every business day at 6:00 a.m. The hours and flows are 06:00–22:00 at 103 MW. The 103 MW is required, as CAB's transmission losses will consume 3 MW each hour, leaving a net delivery of 100 MW.

$$\text{Electricty John Purchases to account for losses} = \frac{100}{(1 - 0.0292)} = 103\,\text{MW}$$

The next step is to identify the beginning date/time of the first hour, which is December 1, 2000 at 06:00 and the ending date/time of the last hour which is December 31, 2000 at 22:00. These dates are the start and stop dates. See Figure 4.15 (section on Energy Profile).

TAG ID CAA ELSER 1223344 CAB

Start Date 12/01/00 **Stop Date** 12/31/00

Transaction Path

SOURCE PHONE FAX

ENERGY	Title/Rights	TRANSMISSION					MISCELLANEOUS	
CA	PSE	TP	Product	PATH	OASIS	LEVEL	INFO	REF
CAA							G-NF	11AB2
	PSERCO	TPA	2-NH		10001			
	ELSER	TPB	2-NH		12121			
CAB							L	CB112

SINK PHONE FAX

loss Accounting

TP	PATH	START	STOP	MW POR	MW POD	TYPE	Supply Reference
TPA	CAA/CAB	6:00	22:00	103	103		
TPB	CAA/CAB	6:00	22:00	103	100		

Energy Profile at Source

SUN	MON	TUES	WED	THUR	FRI	SAT
O	X	X	X	X	X	O

START	STOP	MW	MWH	Ramp Start	Duration
6:00	22:00	103	1600		

PSE	ELSER Electricity Services
24 HOUR PHONE	(000) 123-4567
FAX	(000) 123-7654
CONTACT	John Randolph
PHONE	(000) 321-7654
DEAL REF	JOHN11-AA

COMMENTS	

Figure 4.15 *Tag Form for Example 4.2.*

John's next step is the documentation of the Transaction Path: John identifies that power is being generated in Control Area A (CAA) on the first line, as nonfirm (G-NF) with an associated generation reference number (say 11AB2). Next, John shows that he is using PSCO's reservation to move the energy from CAA to CA's border with CAB (OASIS Reference Number is 10001). Following this, he shows that he is using a reservation that ELSER purchased to move the energy from the CAB's border with CAA to CAB (OASIS Reference Number is 12121). Last, he identifies that the sink is in CAB and lists an identification of "L" and a reference number for the load (say CB112). See Figure 4.15 (section on Transaction Path).

The last step in tagging the transaction is listing the losses associated with this transaction: Transmission Provider TPA does not ask for losses. John enters TPA and indicates equal POR and POD MW values of 103 MW, indicating that losses are not taken in kind. Note that John lets the Loss Supply value empty to indicate that no other type of loss accounting is being used. Then John enters TPB, who does ask for losses, in the table. As we mentioned before, John lists the values in the POR/POD fields as 103 and 100, respectively. The inequality refers to the fact that losses are being taken in kind. Again, John leaves the Loss Supply value empty. See Figure 4.15 (section on Loss Accounting).

4.7 COMMUNICATION DURING FAILURE RECOVERY

When the electronic communication fails between any of three tag services or the failure of services themselves take place, Tag Agent, Authority, or Approval Services may use "out of band" communication methods for communicating tags or market information outside the E-Tag system [Ner00b, Ner00c].

There are two types of "out of band" communication methods for describing the transaction information: verbal communication via telephone and written communication via fax. If written communication is used, the participant should confirm the tag by telephone. In addition, the reason for the failure of E-Tag and the time that the E-Tag system is expected to be fixed should be indicated.

When a tag service or a participant receives out-of-band tags, the tags received should be treated in a nondiscriminatory manner by that tag service or that participant. The NERC Functional Specification mentions that, "should any party seem to be relying excessively on out-of-band communications methods, pertinent data should be collected and supplied to NERC that would document this behavior." The "out-of-band" communication methods are utilized in various failure scenarios such as:

- Tag Agent would be unable to do any of the following:
  - *SUBMIT* a tag to the Authority,
  - Issue a *CANCEL* message, and
  - Issue a *STATUS* request.
- Tag Authority would be unable to do any of the following:
  - Send *ASSESS* messages to the various Approvals, and
  - Send an *IMPLEMENT* message to the IDC or other forwarding URL.
- Tag Approval entity would not be able to do any of the following:
  - Issue an *UPDATE* message,
  - Issue an *ADJUST* message,
  - Issue a *STATUS* message, and
  - Issue a *DSTATUS* request.

4.8 TRANSACTION STATES

Starting from the time of its initiation, through the approval cycle, and to the end of its life, the tag (transaction) is given states that specify the status such as *approval/denial status* and *composite status* [Ner99e, Ner00b]. The approval status for the tag refers to the situation of the tag with respect to each individual entity that has approval rights over the transaction.

On the other hand, the composite status refers to a single combined situation of the tag based on the individual approvals. The cumulative status of all individual approval statuses is termed as the composite status of the tag. For each tag there is only one composite status. The individual approval states are set by the approval entities – the entities that have approval rights on the transaction, while the composite states are set by authority service.

When a Tag Agent Service submits each tag to the corresponding Tag Authority Service, the Tag Authority Service is responsible for providing the approval status value associated with each entity that has approval rights over the transaction. The Tag Authority Service is also responsible for issuing the composite status of the tag based on the individual approval status values. In addition, the Tag Authority Service returns both the set of individual approval status values and the composite status value of the tag when requested by the Tag Agent Service or Tag Approval Service.

The Tag Authority Service provides unique approval status values for each entity that has approval rights over a tag/transaction. A time stamp (date and time) that refers to updating the approval status of each entity accompanies the approval status. The Authority service uses a time stamp to refer to the date and time the tag was originally transferred to the Tag Approval Service of each entity.

An approval status is independent to the TP/CA who has approval rights. For the same tag, each TP or CA may have different approval status, i.e., some TPs/CAs may have approval status to the tag under study, and other may have denial status to the same tag.

The approval status can be categorized as Initial States, Action States, and Problem States. Each of these categories is summarized in Table 4.1. The State Transitions for Approval Status are illustrated in Figure 4.16.

Each tag has only one possible composite state. The possible states are *PENDING, LATE, ATTN_REQD, DENIED, CONDITIONAL, IMPLEMENT, WITHDRAWN, CANCELLED, and TERMINATED.* These possible composite states are detailed in Table 4.2.

Table 4.1 Categories of Approval Status

Status	Comment	Category of Approval Status
PENDING	Initial status for all tags received by Authority Service	Initial State
QUEUED	Tag is successfully transferred to each Approval Services. Each Approval has to respond as received, otherwise that entity's state stays *PENDING.*	Initial State
STUDY	Indicates that the Approval Service is evaluating the tag	Action States
APPROVED	The Approval Service has approved the tag	Action States
DENIED	The Approval Service has denied the tag. Comment field must contain a reason	Action State
CANCEL	Performed by the submitting PSE to completely cancel a tag	Action State
COMM_ERROR	Failure by Authority Service to transfer tag to Approval Service	Problem States
INVALID	Failure by Approval Service to accept tag	Problem States
<null>	Tag Approval Service not registered on Master Registry. Null not used to evaluate composite status.	Problem States

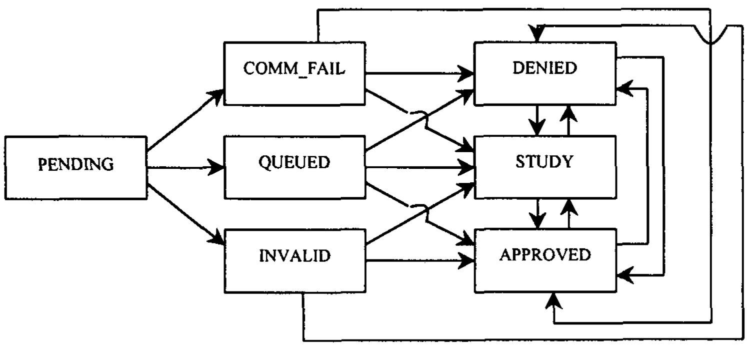

***Figure 4.16** State Transitions for Approval Status*

Table 4.2 Possible Composite States

Composite Status	Comment
PENDING	Initial state for all tags received by Authority Service.
LATE	Initial state for a tag received by the Authority Service after submittal deadline.
ATTN_REQD	Any one of the Approval Services had either a *COMM_ERROR* or *INVALID* tag.
DENIED	Two Possible Conditions: - One of the Approval Services *DENIED* the tag. - If the tag was initially *LATE* and all of the Approval Services did not approve.
CONDITIONAL	- Tag met the timing requirements - No entity denied the tag - Not ALL entities approved the tag - All Approval Services are all in an *APPROVED, QUEUED* or *STUDY* state and approval time has run out. (Passive Approval)
IMPLEMENT	- Tag met the timing requirements - All entities specifically approved the tag
WITHDRAWN	PSE cancelled the tag while it's composite state was *PENDING, LATE,* or *ATTN_REQD.*
CANCELLED	Tag was cancelled after it reached *IMPLEMENT* or *CONDITIONAL*, but prior to the Start Time.
TERMINATED	- Tag was cancelled after the Start Time. - New End Time was indicated in Cancel message.
ADJUSTED	Tag was adjusted by an approval entity

4.9 IMPLEMENTATION, CURTAILMENT, AND CANCELLATION OF TRANSACTIONS

4.9.1 Implementation of Interchange Transactions. To show how interchange transactions are implemented, we consider the following example [Ner98].

Example 4.4 (Interchange Transactions)

Figure 4.17 shows a 4-control area system (CA_1, CA_2, CA_3, and CA_4) that has five interchange transactions:

Transaction 1 (T_1): $CA_1 \rightarrow CA_2$

Transaction 1 (T_2): $CA_1 \rightarrow CA_3$

Transaction 1 (T_3): $CA_1 \rightarrow CA_4$

Transaction 1 (T_4): $CA_3 \rightarrow CA_2$

Transaction 1 (T_5): $CA_4 \rightarrow CA_2$

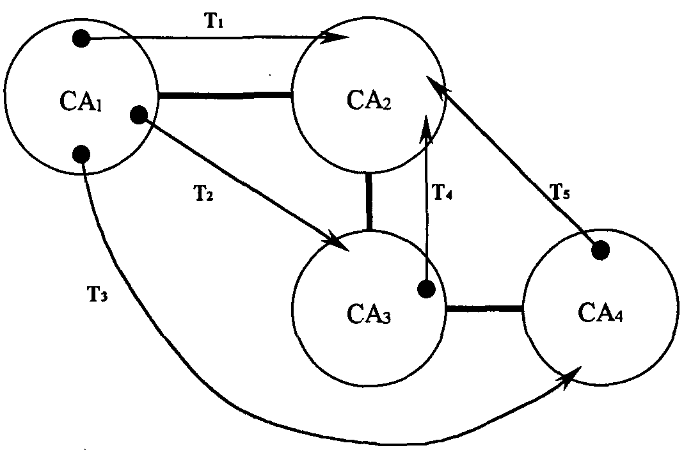

Figure 4.17 Example of Five Interchange Transactions

Case 1: The four control areas are not parties to a transmission agreement (e.g. Regional agreement or ISO)

Table 4.3 shows a summary of the five transactions between different control areas. Let's take T_3 from this table to show how schedules are implemented. For this transaction (T_3), CA_1 is the GCA for T_3 and CA_4 is the LCA. This transaction should pass through the intermediary control areas CA_2, and CA_3. T_3 can be represented as: $CA_1 \rightarrow CA_2$ then $CA_2 \rightarrow CA_3$, and finally $CA_3 \rightarrow CA_4$. The resulting interchange schedules are from sending control area SCA_1 to receiving control area RCA_2, sending control area SCA_2 to receiving control area RCA_3, and sending control area SCA_3 to receiving control area RCA_4.

The control areas CA_1, CA_2, CA_3 and CA_4 calculate the net interchange schedules (IS) given in Table 4.4. The net interchange schedule of any control area i is calculated by adding schedules of this control area that pass through control areas directly connected to control area i.

Case 2: The four control areas are parties to a transmission agreement (e.g. Regional agreement or ISO)

***Table 4.3** Summary of Transactions*

Transaction	*Source Control Area*	*Sink Control Area*	*Intermediary Control Area(s)*	*Description of Interchange Schedules*[30]
T_1	CA_1	CA_2	-	$SCA_1 \rightarrow RCA_2$
T_2	CA_1	CA_3	CA_2	$SCA_1 \rightarrow RCA_2$ then $SCA_2 \rightarrow RCA_3$
T_3	CA_1	CA_4	CA_2, CA_3	$SCA_1 \rightarrow RCA_2$ then $SCA_2 \rightarrow RCA_3$ then $SCA_3 \rightarrow RCA_4$
T_4	CA_3	CA_2	-	$SCA_3 \rightarrow RCA_2$
T_5	CA_4	CA_2	CA_3	$SCA_4 \rightarrow RCA_3$ then $SCA_3 \rightarrow RCA_2$

[30] In this Column, SCA refers to Sending Control Area and RCA refers to Receiving Control Area.

Table 4.4 Summary of Net Interchange Schedules of Case 1

Control Area	Source Control Area	Sink Control Area	Sending Control Area	Receiving Control Area	Net Interchange Schedules	
CA_1	T_1, T_2, T_3	-	T_1, T_2, T_3	-	With CA_2: $IS_{12,T1} + IS_{12,T2} + IS_{12,T3}$	
CA_2	-	T_1, T_4, T_5	T_2, T_3	T_1, T_2, T_3, T_4, T_5	With CA_1: $IS_{12,T1} + IS_{12,T2} + IS_{12,T3}$ With CA_3: $IS_{23,T2} + IS_{23,T3} + IS_{32,T4} + IS_{32,T5}$	Same
CA_3	T_4	T_2	T_3, T_4, T_5	T_2, T_3, T_5	With CA_2: $IS_{23,T2} + IS_{23,T3} + IS_{32,T4} + IS_{32,T5}$ With CA_4: $IS_{34,T3} + IS_{43,T5}$	Same
CA_4	T_5	T_3	T_5	T_3	With CA_3: $IS_{34,T3} + IS_{43,T5}$	Same

In this case, the four control areas are called *Adjacent Control Areas* and they can schedule transactions directly. In other words, when the control areas are adjacent areas, the GCA schedules transaction directly with LCA regardless whether the transaction passes through other control areas or not. The net interchange schedules of this case are shown in Table 4.5. For example, for the interchange transaction T_3 that originates from CA_1 and ends in CA_4 even it passes through CA_2 and CA_3, the control areas CA_1 and CA_4 can schedule T_3 directly with each other.

Table 4.5 Summary of Net Interchange Schedules of Case 2

Control Area	Source Control Area for Transaction	Sink Control Area for Transaction	Sending Control Area for Transaction	Receiving Control Area for Transaction	Net Interchange Schedules
CA_1	T_1, T_2, T_3	-	T_1, T_2, T_3	-	With CA_2: $IS_{12,T1}$ With CA_3: $IS_{13,T2}$ With CA_4: $IS_{14,T3}$
CA_2	-	T_1, T_4, T_5	-	T_1, T_4, T_5	With CA_1: $IS_{12,T1}$ With CA_3: $IS_{31,T4}$ With CA_4: $IS_{42,T5}$
CA_3	T_4	T_2	T_4	T_2	With CA_1: $IS_{13,T2}$ With CA_2: $IS_{32,T4}$
CA_4	T_5	T_3	T_5	T_3	With CA_1: $IS_{14,T3}$ With CA_2: $IS_{13,T5}$

In this case the net scheduled interchange for each control area is:

For CA_1: $IS_{12,T1} + IS_{13,T2} + IS_{14,T3}$

For CA_2: $IS_{12,T1} + IS_{31,T4} + IS_{42,T5}$

For CA_3: $IS_{13,T2} + IS_{32,T4}$

For CA_4: $IS_{14,T3} + IS_{13,T5}$

4.9.2 Curtailment and Cancellation of Transactions.

Control areas confirm interchange schedules starting from the last receiving control area (LCA) by contacting control areas backwards towards the GCA passing through the adjacent intermediary control areas [Ner98].

When an operating security limit is violated or the loss of generation/load happens, and an interchange transaction is to be curtailed, GCAs and LCAs should respond very fast by contacting each other to confirm the curtailment. Also, they should quickly start modifying or revising their corresponding interchange schedules with other adjacent control areas. The curtailment is either commanded by the security coordinator or by agreements between control areas. If a security coordinator initiates curtailment, the security coordinator should pass a signal to the LCA, and then the LCA would contact the source control area and PSE that submitted the tag of the interchange transaction to directly implement and confirm the curtailment. In the case that LCAs and GCAs are not adjacent, they should contact their adjacent control areas on the scheduling path to adjust the interchange schedules.

When a PSE needs a cancellation of an interchange transaction that is in progress, the PSE must contact the LCA to which it submitted the tag of the interchange transaction, and then the LCA directly contacts the GCA and the LCA's security coordinator. In the case that the LCA and GCA are not adjacent, they should contact their adjacent control on the scheduling path. Figure 4.18 depicts the process.

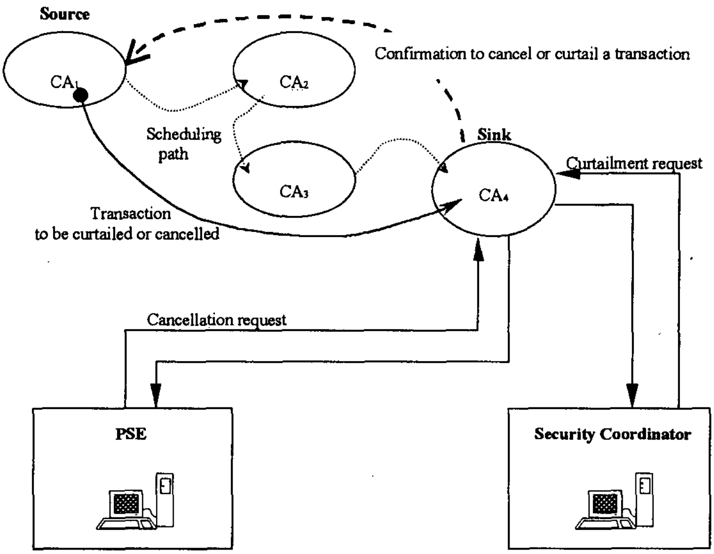

Figure 4.18 Illustration of the Curtailment and Cancellation Process.

CHAPTER 5

ELECTRIC ENERGY TRADING

Summary: A powerful electricity market should be supported and implemented by proper trading tools that take into consideration special circumstances of electricity trading which are different from other commodity trading practices. A successful implementation of a trading system in electric energy and its derivative markets could fulfill restructuring objectives, which include competition and customer choice, and serve vital needs of electricity market participants. A robust trading system could facilitate the transition from a regulated monopoly to restructured and competitive market environments through well-done management processes and capable risk hedging instruments that could capture the risks associated with price volatility and other unexpected changes. In this chapter, we present various characteristics of electric energy trading and focus on key issues in trading systems. A discussion of successful trading tools would be presented. In addition, we would address the qualifying factors of a successful trading system and concentrate on main derivative instruments such as futures, forwards and options. Different categories of traders, trading hubs, price volatility and green power trading would be discussed. The discussion of these topics would be supported by various illustrations and pertinent examples. Green power as environmentally preferred generating technologies to some consumers will also be touched on in this chapter. In Appendix B, we will provide electricity contract specifications in the New York Mercantile Exchange and the Chicago Board of Trade.

5.1 INTRODUCTION

After FERC issued Rules 888 and 889, electric power companies initiated the implementation of these Rules in order to trade electric energy based on a non-discriminatory and fair access to transmission systems. The objective was a price-based competition that would bring efficiency to both supply and transmission sides, in addition to supporting the customer choice. The basic issue in this process was to unbundle the three components of vertically integrated utilities. Separating the components would necessitate efficient and powerful energy trading mechanisms that connect buyers to sellers in power systems and support competitive price discoveries.

The challenge facing different energy traders would remain to be dealing with an extended range of energy resources, various types of electricity products and different alternatives of geographical regions, while maintaining adequacy, fairness, competition, security, timely feedback to participants and motivating the liquidity[1] of energy markets. A well-managed trading system would smoothly facilitate the transition from a regulated monopoly to a restructured and competitive market environment. Efficient trading tools would take into consideration physical and financial trading and special circumstances of electricity trading that are different from other commodity practices.

In a restructured power system, customers would have more opportunities, which also mean more risks. Price swings are a source of fear to many market participants as well as a source of richness to others. The market competition is good as far as there are trading tools that could take into account traders' vulnerability resulting from newborn entities and practices. Managing risk is a primary task of any trading system. This task is perceived harder for electricity, as a non-storable

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[1] Liquidity is the ability to convert an asset into cash equivalent to its current market value. An institution is said to have liquidity if it can easily meet its needs for cash either because it has cash on hand or can easily convert assets into cash. Assets can be converted to cash either through an outright sale of those assets or by using the assets to secure a loan. A market is said to be liquid if the instruments, which are traded in that market, can easily be sold approximately at current market prices. In a liquid market, large blocks of assets can be sold rapidly without significantly affecting market prices. The liquidity of a market is often measured as the difference between the bid and offer prices on assets within that market.

commodity, that is correlated with other volatile commodities such as natural gas and other types of fuel. However, electricity as a *fungible*[2] commodity is easier to trade and hedge its risks if implemented properly. Electricity trading would enable customers to choose providers, support non-discriminatory access to transmission and distribution systems and prevent forming barriers for participants in trading operations.

5.2 ESSENCE OF ELECTRIC ENERGY TRADING

Electricity trading through an exchange[3] started for the first time in 1996 where electricity futures were traded on the New York Mercantile Exchange (NYMEX). NYMEX declared, "electricity is a $200 billion a year market, one of the largest in the U.S. economy.[4] " The Chicago Board of Trade (CBOT), the Chicago Mercantile Exchange (CME), Minneapolis Grain Exchange (MGE) and NYMEX are examples of large exchanges in the Unites States.

We would define trading as an activity in which transactions would take place directly between two participants (i.e., *over-the-counter, OTC*) or indirectly through an organized marketplace or exchange. Electricity trading has two main components, i.e. physical trading and financial trading. In physical trading, supply would be balanced against demand and price would be either determined in advance of trading (*ex-ante*) or after trading (*ex-post*). In financial trading, financial contracts would take place between traders as agreements that would give certainty to traders. Physical trading is usually done through an energy spot market or power pool while financial trading is through a financial market or exchange such as NYMEX or CBOT.

In a nutshell, restructuring brought to us new entities and trends in trading procedures. Unbundling of different services would necessitate the trading of electricity on exchanges or bilaterally, purchased in

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[2] Fungible commodities: Commodities which are equivalent, being in the same class and issued by the same issuer, and are therefore substitutable and interchangeable. A product is said to be fungible (interchangeable) when it can be substituted by its equivalent for purposes of shipment or storage.

[3] A centralized trading operation which requires the use of its clearing account services.

[4] See http: //www.nymwx.com/contract/electric/intro.html.

advance, hedged, and optioned like any other commodity that is exposed to price movements and uncertainties. A trading system should provide market participants with flexibility to react to changing market conditions such as weather and outages. To guarantee payment and delivery, a trading system should make sure that participants would have credibility by asking them to meet a set of financial requirements. Any qualified participant would be required to provide a cash deposit or letter of credit with an adequate value to cover his/her transactions. Any trading system should assure that its employees would not be involved in trading activities and not be allowed to take any position in market operations. Instead of tracking prices over the phone, it would be advantageous to use a computerized system so that trading participants could continuously monitor and update their information on prices.

The trading system should satisfy a few requirements in order to be useful to various users with different resources and needs. A successful trading system should own some essential elements including:

- Stability in price (liquidity). It withstands large volumes of trades with slight changes in price.
- Considerable number of traders. To motivate competitive operations and mitigate market power.
- Price discovery and feedback. All traders should be dealt with fairly in seeing bids, offers and other trades issues that should be made available to different traders at the same time.
- Confidence. Traders would need certainty in transactions to perform as signed.
- Deliverability. Trading system should ensure that the delivery system is physically capable of handling large volumes of energy trades.
- Financial Capability. Trading system should be financially stable to backstop large volumes of transactions.
- Hedging. Trading system should utilize price risk hedging instruments.

- Models. It should support a variety of trading market models. It should facilitate bilateral contracts in addition to spot market and forward market operations.
- Implementation of different users' strategies. Efficient trading models must include negotiation mechanisms and transaction management tools that support partial transactions, transaction approval or cancellation of transactions.
- Security. Trading entries should be processed securely, especially when electronic trading systems are implemented.
- Diversity. It should support diversity of energy participants' geographical locations.
- Speed of processing. It is a vital element for motivating different market participants.
- Real-time. A trading system should support real-time events for traders, e.g. trades are to be posted instantaneously.
- Automation. It would be an advantage for a trading system to have an automated electronic interface such as OASIS to request transmission reservations and related services.
- Impact. A trading system must be capable of analyzing the effect of proposed trades on existing entities, such as transmission components, ATC, congestion relief procedures and others.
- Information. A trading system should provide a comprehensive source of information to traders, where they reach the pertinent information[5] without a need to use other means.
- Charges. To motivate participation in a trading system, trading charges should be reasonable otherwise subscription could drop.

Restructuring in electricity markets could cause generators to compete in attracting customers, which means that customers would have more choices. As opportunities rise, risk possibilities would also increase

[5] Information includes posted ATC, availability of market indices, price signals and congestion related topics.

proportionally. In addition, sources of risk would increase when market participants are not sure of future electricity trading. Restructuring has brought in new terms, participants and derivatives that may not exist in other commodities. Due to these uncertainties, a market participant could enter trading contracts (agreements) with other parties to hedge possible risks. Hedging is defined as having a position in a security[6] or asset to counterbalance the risk associated with another security or asset. Hedgers would use historical prices, current prices and market liquidity to hedge against risk and get better returns. We would discuss these issues further in the following chapters.

5.3 ENERGY TRADING FRAMEWORK: THE QUALIFYING FACTORS

Key elements in qualifying a trading system include,

- good design,
- effective rules,
- independent administration,
- adequate standards for market participants,
- comprehensive trading opportunities and
- availability of market information.

Trading in electricity markets is a risky task because the electricity is much different from other commodities due to reasons that are listed below.

- Electricity is non-storable – once produced, it should be consumed,
- End-users' demand is typically insulated from movements in electricity wholesale prices,

[6] Common or preferred stock; a bond of a corporation or government.

- Trading operation is directly related to the reliability of the grid and transmission limitations,
- Demand and supply should be in exact balance on a moment-to-moment basis,
- Electricity prices are correlated with other volatile commodities.

The above factors would cause more volatility in electricity markets. Hence, the primary objective of an energy trading system would be to create an accessible facility that would enable:

- Participants to discover future prices
- Generating unit owners to allocate supply to feed the demand
- Sellers to deliver electricity to buyers
- Participants to forecast supply and demand
- Participants to hedge possible risks.

To implement these objectives, the main trading system should be composed of many functional blocks or subsystems, where each subsystem has functionality different from other subsystems', and all subsystems are coordinated or interconnected such that a feedback from each subsystem is passed on to other subsystems. The main trading system may include information function (subsystem), analysis function, risk management function, decision-making function, etc.

From participants' viewpoint, trading participants would be required to comply with trading rules that include credit verifications and legal enforcement procedures. All traders would be required to show that they are able to satisfy financial obligations in a high degree of certainty. Trading system's governance[7] should be independent of market participants. A successful trading system should combine clear-sighted and blind market operations[8], and if both types of operations are

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[7] The entity that facilitates and manages trade operations.

[8] When a participant selling (buying) a product does not know the counterparty who is buying (selling) its products or the price that they will settle on, the operation is described as blind operation; an example is the spot market where a generator is

implemented, risk management tools should be available to support the operations.

An important issue in trading is the *certainty* factor that could motivate a trader's confidence. Certainty is guaranteed if trades are completed and delivered as agreed. Certainty is implemented by rules, penalties, failure terms and dispute judgment tools that would govern the trading system and define proper trading practices and responsibilities of both trading sides. As discussed before, one of the trading system priorities is to treat all participants in a fair manner. If this priority is not taken into consideration, participants will no longer trust the trading system and in turn will look for other alternatives that could lead to less competitive situations.

5.4 DERIVATIVES INSTRUMENTS OF ENERGY TRADING

Derivative[9] by definition is a financial contract (instrument), written on an underlying asset, whose value depends on the values of more basic assets. A derivative is not a security, but an agreement between two parties, with opposite views on the market, who are willing to exchange certain risks. A hedger would use derivatives as insurance against market swings, price increases and funding costs while getting better exchange rates in financial markets.

As we will learn in this chapter, the basic derivatives are called *plain vanilla* which include forwards, futures, options and swaps. Derivatives may also represent a combination of basic derivatives such as options on futures, options on a swap, and others. Many derivative instruments are used in electricity trading, but the most common ones applied to energy risk management strategies are futures, forwards, and options.

A forward or futures contract would include an obligation to buy or sell a specified quantity of an asset at a certain future time for a certain price. An options contract would include a right (not obligation) to buy

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unable to identify a certain purchasing party. This is in contrast to a clear-sighted operation in which buyers and sellers are identified and would agree on certain conditions.

[9] Sometimes called contingent claims.

or sell a specified quantity of an asset at a certain future time for a certain price. Swaps are the other type of derivatives that market entities could use for hedging. A price swap is defined as an agreement between two participants that would negotiate in over-the-counter (OTC[10]) markets to exchange (swap) certain price risk exposures over a certain period of time. Swaps are also used to hedge geographic price differences.

In a spot market, electricity is traded for actual physical delivery to the transmission grid, while in forwards, futures and options contracts, electricity is settled either physically or in Contract for Differences[11] (CFDs). A general picture for financial instruments is shown in Table 5.1.

NYMEX was the first exchange that initiated two electricity futures contracts, one for the delivery at the California-Oregon Border (COB) and the second at the Palo Verde (PV) switchyard. Each of them has a size of 736 MWh/month and defined on 23 peak delivery days starting from Monday and ending on Friday with a rate of 2 MW/hour for 16 peak hours[12] (i.e., $2 \times 16 \times 23 = 736$). Other new contracts have been introduced by the NYMEX for delivery at the PJM-Interconnection in the Mid-Atlantic region, the Cinergy transmission system in Ohio, and the Entergy transmission system in Louisiana. Electricity contract specifications for NYMEX and CBOT are given in the Appendix B.

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[10] A market where products are traded by telephone and other means of communications.

[11] These contracts are long-term price hedging bilateral contracts between generators and the distribution utility or retail customers. These contracts allow a physical dispatch of individual generating units by their owners and allow individual consumers to establish prices over long periods. When used, generation seller is paid a fixed amount over time that is a combination of short-term market price and an adjustment with the purchaser for the difference. CFDs are established as mechanisms to stabilize power costs to customers and revenues to generators. These contracts are suggested due to the fact that the spot price set by Poolco fluctuates over a wide range and difficult to forecast over long periods. Under CFDs, any difference between spot price and the contract price would be offset by cash payments between the generator and the customer.

[12] On-Peak hours: between 6:00 a.m. - 10:00 p.m., every day. Off-Peak hours: between 10:00 p.m. and 6:00 a.m. every day.

Table 5.1 Comparison of Spot Commodities and Derivatives Instruments

Market	Delivery	Payment	Seller	Buyer	Place of Trading
Spot	Immediate	Immediate	Obligated to sell	Obligated to buy	Power Exchange (Spot Market)
Futures	In the future	In the future	Obligated to sell	Obligated to buy	Exchange
Forwards	In the future	In the future	Obligated to sell	Obligated to buy	Off-Exchange (OTC)[13]
Call Options	In the future	In the future	Issues the call options and is obligated to sell on request	Holds the call options and has the right to buy	Exchange
Put Options	In the future	In the future	Holds the put options and has the right to sell	Issues the put options and is obligated to buy on request	Exchange

In addition to its role in balancing the provision between buyers and sellers, tradable contracts could generate price signals as a feedback to different participants to take proper actions with more confidence. Balancing is guaranteed by contracts in the sense that contracts would include terms such as volume of trade, deliverability terms (such as time and/or location of delivery), failure conditions and obligations terms. On the other hand, price signals are a feedback to participants to change strategies or to take proper economic actions; for example, based on price signals, a generating party may add a new generating capacity, contract with other parties, find risk-hedge means, look for new fuel resources or switch to other energy sources.

5.4.1 Forward Contracts. A forward contract is an agreement between two parties to buy or sell a certain quantity of an asset at a

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[13] OTC rarely trades futures and options. Exchange rarely trades forwards.

certain future time for a certain price (forward price). A forward contract has a specific expiration at which the asset is delivered and payment is made. Usually, the contract is held between two financial parties or between a financial party and one of its corporate clients. The buyer of the contract is called *long* whose purchase obligates him to accept delivery unless he liquidates his contract with an offsetting sale. The seller of the contract is called *short*. This type of contracts is not normally traded on an exchange. Figure 5.1 illustrates the forward contract concept.

Forwards contracts are used in electricity markets for trading in the future and are settled either by cash within the exchange or by dispatch. Forwards contracts are traded bilaterally or OTC between two counter parties. The agreement would include the amount of commodity, delivery price, delivery date and time, and delivery location. The contracted parties would usually customize the contract in order to make it fit their needs. CFDs, which are used widely in many power pools, are one form of forward contracts. CFDs are usually indexed on the pool price, where the power seller (e.g., generation company) and power buyer (e.g., distribution company) would agree upon a fixed price to trade power. The buyer would pay the seller the fixed price for the consumed energy and the seller would pay the pool based on the spot price. By using CFDs, the buyer would lock in its price and the seller would profit from a lower pool price.

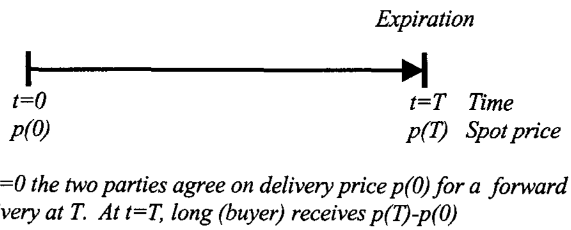

***Figure 5.1** Illustration of Forward Contract*

When an asset is delivered in the forward contract, the pay off is defined in terms of the maturity of the contract. The payoff for a long position[14] (buyer) on one unit of the asset is the delivery price minus the spot price of the asset at maturity; the payoff for a short position (seller) on one unit of the asset is the spot price of the asset at maturity minus the delivery price. Based on market movements, these payoffs could be either negative or positive representing profit or loss.

Forward contracts have some disadvantages including:

- Default risk[15] that is implied in large cash flows and could cause large losses at expiration
- Difficulty in liquidating a custom forward contract prior to expiration

An electronic trading system is an efficient way to trade forward contracts. Any trading system should first define which participants would use the trading system and which products would be tradable. After that, building components of the trading system could be identified. In an outstanding trading system, efficiency would be the first priority, which could be guaranteed by considering certain elements in the trading system. The most important element would be the security, while others include procedures for managing a fair trading and efficient financial procedures for processes like clearing, settlement, risk monitoring and hedging.

Example 5.1

Energy spot price is $10.00/MWh (today). Party A agrees to buy 50 MWh from Party B, a 6-month forward contract at a price of $11.00/MWh. The value of a forward contract is determined based on the asset's market price movement. Initially, the contract is worth zero when parties enter into a contract, but as time goes on, its value would increase or decrease depending on the asset's spot price. If at any later time the asset price would increase, the buyer of the contract (long)

[14] Position refers to a contracted electric power.

[15] Default means that seller will not honor the contract.

would gain[16] and the seller (short) would lose[17]. Here, we distinguish between forward and delivery prices. The delivery price is the fixed price at which buyers and sellers would agree (initially) for a forward delivery at expiration. The forward price would be adjustable depending on the asset market. After the start of the contract, the two prices may coincide.

Example 5.2

Table 5.2 shows hypothetical electric energy prices for spot and forward markets. The first entry of the table (10.0) points out that the energy can be traded in the spot market at \$10.0/MWh for a virtually immediate delivery. The second price (10.6) indicates that the forward contract price to trade energy in one month is \$10.6/MWh.

Let a Distribution Company (DisCo) enter into a long forward contract at t=0 to buy 100 MWh in two months at a price of \$10.8/MWh. This contract would obligate the DisCo to buy 100 MWh for \$1080.0 (100×10.8=\$1080.0). If spot price rises to \$14.00/MWh at the end of two months, the DisCo would gain \$320.0 (or 100×14.0-1080). Likewise, if spot price drops to \$8.00/MWh at the end of two months, the DisCo would lose \$280.0 (or 1080 - 100.0 × 80.0), i.e., the forward contract would make the DisCo pay \$280.0 more than the energy market price.

***Table 5.2** Spot and Forward Market Energy Prices at t=0*

Market	**Price** [\$/MWh]
Spot	10.0
1-month forward	10.6
2-month forward	10.8
3-month forward	11.0

[16] Long position in the forward contract becomes positive.

[17] Short position in the forward contract becomes negative.

5.4.2 Futures Contracts. Futures are standardized contracts which are traded on and cleared by an exchange. A futures contract is defined as an agreement between two parties to buy or sell a certain quantity of an asset at a certain future time for a certain price. A futures contract stands as a firm agreement between two participants to buy or sell a standard block of commodity for an agreed-upon price on a given date in the future. Futures contracts are standardized by the exchange to make them desirable to a large number of participants, which could in turn motivate liquidity. In these contracts, the exchange would ask participants to show credit and deliverability requirements in order to limit the risk of contract default.

Many participants could use futures in the electric power industry. For example, a power producer could sell these futures in NYMEX to lock in a desirable selling price. Large customers could buy NYMEX futures to guarantee that their cost for buying electricity would remain at a desirable level. Marketers could trade futures based on its position and expectations.

Even though the definition of futures contract is the same as that of the forward contract, it differs from a forward contract in many respects. With a futures contract, a participant could lock in the price of a transaction until its expiration on a future date. The futures price would be the spot price on the expiration date. The futures market would represent a zero sum game in which the profit of buyer (seller) would be equal to the loss of seller (buyer).

Futures contracts would differ from forward contracts, as futures are more liquid and less subject to default. The main differences of the two contracts are:

1. It would be less costly, except for the margin[18] and the commission[19], to enter and exit a futures contract. The commodity would never have to change hands, as long as a participant would pay its losses or get paid on the expiration date.

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[18] Financial safeguards to ensure that individuals would perform on their open futures and options contracts.

[19] A fee charged by a broker for executing a transaction.

2. Unlike forward contracts, future contracts are traded in an exchange. Futures contracts are traded among brokers on the trading floor in the exchange, and brokers receive commissions from futures market transactions.
3. A futures contract would have standardized[20] terms, and the terms are usually set by the exchange.
4. A futures contract is usually much smaller than a forward contract.
5. A futures contract has the characteristic of *marking-to-market* (daily settling up). The futures price is reset each day and the holder's profiles or losses are realized every day; for example, if a RetailCo purchased the May energy yesterday and the price of May energy has gone up today, the RetailCo would have money added to its account. This condition would not exist in forward contracts.
6. Most futures positions are closed out prior to expiration - less than 1% of future positions would actually result in the delivery of a commodity.
7. A margin is required for entering a futures transaction.
8. Some futures contracts could call for cash delivery.
9. Futures prices would converge to spot prices at the expiration of a futures contract.
10. A futures contract would usually be held between a participant and the exchange, while a forwards contract would be between two participants or between a participant and an establishment such as a bank.
11. In a futures contract, two contracted parties would not necessarily know each other.
12. The exchange could guarantee that a futures contract would be honored.

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[20] Standardized in amount (e.g., 500 MWh per contract) and contract maturity (e.g., first Tuesday of March). Standardization would increase the liquidity and decrease transaction costs.

13. In a futures contract, the exact delivery date would usually not be specified. The delivery date is specified in the delivery month and the exchange would specify the delivery period during the month. The holder of the short position would have the right to choose the delivery time during the delivery period.
14. In futures contracts, the exchange would specify the product's quality and the location of its delivery.

Example 5.3: (Short Hedge) [21]

Short Hedging is the practice of offsetting the price risk by taking an equal but opposite position in the futures market. Hedgers use the futures markets to protect their business from adverse price changes. An Independent Power Supply (IPS) could fear that the price of its electricity would drop[22]. To secure the cash flow, IPS chooses a short hedging strategy on the electricity futures market. Let's assume that:

- IPS, on January 1, would expect that 100 MWh would be sold in the March cash market at $15.00/MWh.
- In the futures market, IPS would sell a March electricity futures contract for the expected exchange price ($15.00/MWh). The futures sale would be at $1,500.0 (or 100×15).
- On February 15, if prices fall to $13/MWh, IPS would sell 100 MWh for March at $13/MWh. This would entitle IPS to receive $1,300.0 (or 100×13) which means that IPS would encounter $200.0 (or $1,500-$1,300) less than the expected (budgeted) value.

The best thing to do for not standing for delivery would be that IPS buys back its futures contract. When IPS buys back its futures contract for $13.00/MWh, which is worth $1,300.00, it would give IPS a gain in the futures market of $200.0. In this hedging example, cash market sale + future gain = budgeted sum (or $1,300.0 + $ 200.0 = $ 1,500.0).

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[21] See Chapter 6 for additional information.

[22] Means that the budgeted revenue will not be met by the expected inclined price which in turn will affect cash flow of IPS.

5.4.3 Options. The options contract is a contract between two participants in energy markets that gives the holder the right (not the obligation) to trade a designated quantity of an asset or a security at a certain future time (i.e., *maturity, expiration date*) or during a specific period of time for an agreed-upon price (i.e., *strike price*).

An options contract is usually referred to as a derivative security[23], i.e., a participant with an options contract does not have to exercise its right. This is the main difference between options and futures/forwards contracts. To enter an options contract, the buyer pays a *premium*[24] to the seller of the options while in futures and forwards, the buyer does not have to pay any charges. Options on futures would permit entities such as risk managers to define risk and limit it to the cost of the premium paid for the right to buy or sell a future contract plus commissions and fees. The strike price, specific month and expiration date are determined by the commodity exchange.

Options differ from futures in that if the holder of options finds that a futures price is rising but is not worth exercising its options or the futures price is dropping, then the holder may choose not to buy and permit his options to expire. In the case of futures, the contract is either held for delivery or liquidated. In other words, options provide three alternatives: liquidity, delivery or allowing the options to expire worthless.

When a trader would buy an options, it is like the case of purchasing an insurance policy where a trader pays a one-time up front premium and in return acquires protection against a risk that could occur in the designated period. Dual to the case of insurance on a car (if no accident happens the insurance company would make profit), if an options contract is not exercised, the seller (*writer)* would make a profit equal to the premium paid up front.

Many participants could make benefit of holding options contracts; for example a generation company could use options to limit its losses in the case that the price of electricity drops, and make profits when prices

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[23] A derivative security is not a claim to real commodities. It derives its value from other real securities such as stocks and bonds.

[24] Price of an option determined competitively by traders on the exchange trading floor.

rise. A retailer or consumer could take advantage of options for price drops and limiting its exposure to price increases.

There are two basic types of options:

- *Call Options (calls)*: Give the holder the right to buy the underlying asset by a certain date for a certain price
- *Put Options (Puts)*: Give the holder the right to sell the underlying asset by a certain date for a certain price

Traders can trade calls and puts on many exchanges based on the trader's price expectations. If the price (value) of an asset were expected to rise, the trader would enter the call options of that asset. Likewise, if the price (value) were expected to drop, a trader would look for a put option. For example, if energy price is expected to rise, a DisCo would buy energy call options. In summary, a call options contract is a practice to make profit if prices would rise and a put options contract is a practice to make profit if prices would drop.

Let's differentiate between the following three different, but commonly used, terms in options:

- in-the-money,
- out-of-the-money,
- at-the-money.

In-the-money refers to an options that would realize a profit if exercised, i.e., in-the-money is an options which has an intrinsic value[25] because the market price of the underlying is above (below) the strike price of a call (put). A call options contract is in-the-money when the strike price is below the current futures market price. A put options contract is in-the-money when the strike price is above the current futures market price. Out-of-the-money is an options contract that has no intrinsic value because the price of underlying is below the strike price of a call or above the strike price of a put, i.e., out-of-the-money refers to a call (put) options whose strike price is currently higher (lower) than the current market price of the underlying asset –the options would not be profitable to exercise. At-the-money is the point at which an option's strike price is

[25] Difference between an option's strike price and the underlying asset's market price.

equal to the price of the underlying asset. These terms are illustrated in Figure 5.2.

The options buyer (holder) would have three options up until the expiration of the contract:

(i) make on offsetting sale (by selling an opposite cash or futures market position) and receive the current premium, or

(ii) exercise the right to acquire its long (call) or short (put) position in the futures market, or

(iii) let the options expire worthless (do nothing). Rights and obligations of options buyers and sellers are summarized in Figure 5.3.

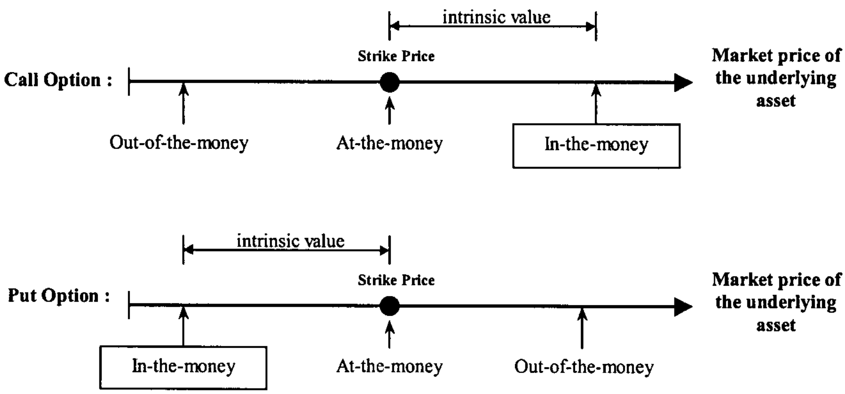

Figure 5.2 *Illustration of In-the-Money, At-the-Money, and Out-of-the-Money*

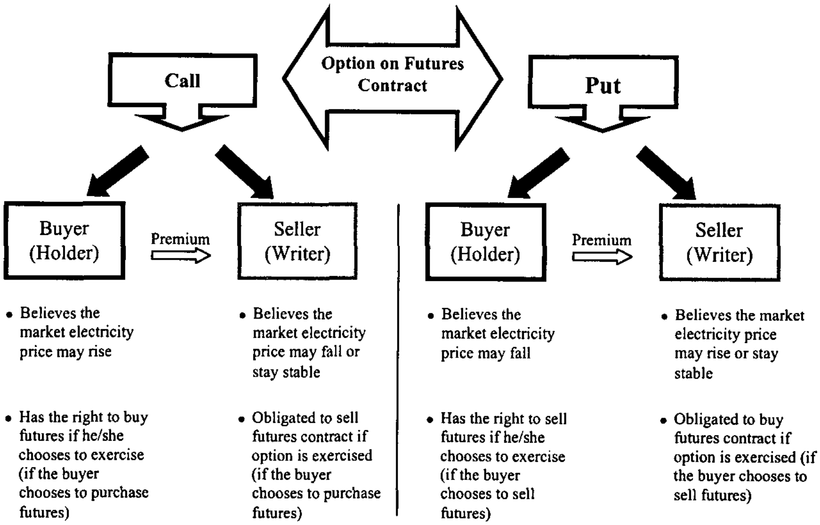

Figure 5.3 *Rights and Obligations of Options Buyers and Sellers*

An options contract is either exercised at any time up to the maturity (*American options*) or only at the maturity itself (*European options*). This is not a matter of geographical location, but a terminology that refers to the time of exercise. The American options may be exercised at any time prior to (and including) the expiration date. The European options may be exercised only at the expiration date. The buyer of a call options would hope that the price at the expiration time would increase and the buyer of a put options would hope the opposite.

Example 5.4

A DisCo would buy 200 call options at a price of \$2.0/option (transaction or entry cost $= 200 \times 2 = \$400.0$) at a strike price of \$15.00/MWh. Let the spot price at $t = 0$ be \$10.00/MWh, the expiration date be three months, and the DisCo could only exercise the options at the expiration time. If the spot price of energy at the expiration time is less than \$10.00/MWh (price at $t = 0$), the DisCo would either exercise buying the contracted amount or not, depending on spot price at the expiration date. If the DisCo would choose not to exercise its right, it would lose the entry cost. For this example, we consider the following three cases:

Case 1: Let's assume that the spot price at the expiration date is \$7.0/MWh. In this case, the DisCo would have two options:

(1) The DisCo would not exercise the right and would lose \$400.00

(2) The DisCo would exercise its right and make a mistake by buying electricity at a price that is higher than the existing price (\$7.0/MWh). The DisCo would lose 200×\$(10 -7)+\$400=\$1000.0

Case 2: Let's assume that the spot price at the expiration date is \$12.0/MWh. In this case the DisCo would have two options:

(1) The DisCo would not exercise its right and lose \$400.00

(2) The DisCo would exercise its right and buy 200 shares at \$10.0/share. If the DisCo would sell its shares immediately, it would gain 200×\$(12-10)=\$400. This would compensate for the entry cost (\$400)

Case 3: Let's assume that the spot price at the expiration date is \$14.0/MWh. In this case the DisCo would have two options:

(1) The DisCo would not exercise its right and lose \$400.00

(2) The DisCo would exercise its right and buy 200 shares at \$10.0/share. If the DisCo would sell its shares immediately, it would gain 200×\$(14-10)= \$800. This would be in excess of \$400 after paying the entry cost (\$400).

Example 5.5: (TCE[26] Call Options)

Utility A would plan to purchase electric power in a future month. This utility would use call options to protect against increasing prices of electricity. Utility A would purchase a TCE call options from Utility B with a strike price of $16/MWh and a premium of $2/MWh. At expiration, the profit/loss of each utility is illustrated in Figure 5.4, where SP stands for the strike price. The negative profit refers to loss. For Utility A, any futures priced at $16/MWh or less would result in a loss equal to the premium, which is $2/MWh. At a futures price of $18/MWh, A's profit (loss) is zero (in this case we say that the transaction would break even) and at any price greater than $18/MWh, Utility A would gain up to an unlimited value. On the other hand, Utility B would see a mirror image of Utility A's position. This profit/loss calculation as futures price varies is calculated and shown in Table 5.3.

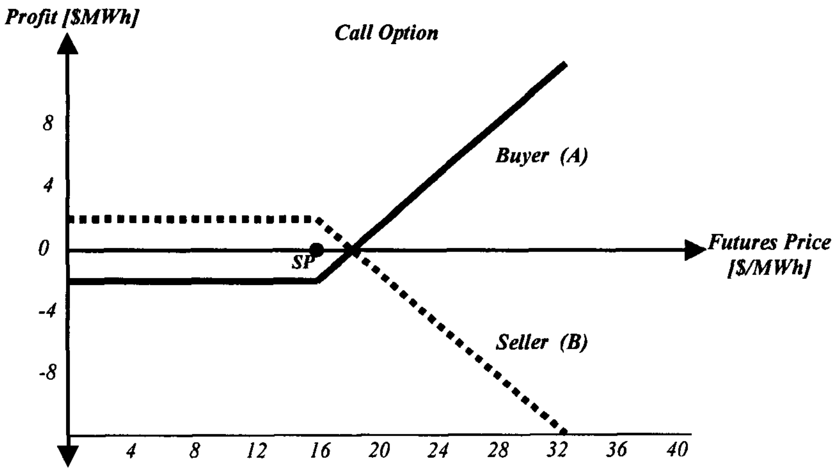

Figure 5.4 Profit/Loss Graph of Example 5.5

[26] Twin Cities Electricity (TCE) contracts are traded at the Minneapolis Grain Exchange (MGE). See http://www.mgex.com

Table 5.3 Profit/loss Calculations of Utilities A and B

Futures price $/MWh	Utility A Payment $/MWh	Utility A Comment	Utility B Payment $/MWh	Utility B Comment
0	-2	Loss	2	Profit
2	-2	Loss	2	Profit
4	-2	Loss	2	Profit
6	-2	Loss	2	Profit
8	-2	Loss	2	Profit
10	-2	Loss	2	Profit
12	-2	Loss	2	Profit
14	-2	Loss	2	Profit
16	-2	Loss	2	Profit
18	0	Breaks Even	0	Breaks Even
20	2	Profit	-2	Loss
22	4	Profit	-4	Loss
24	6	Profit	-6	Loss
26	8	Profit	-8	Loss
28	10	Profit	-10	Loss
30	12	Profit	-12	Loss

Example 5.6

In order to meet the customer demand for on-peak power during the next August, a DisCo would have to purchase more electric power from a supplier. The DisCo decides to purchase on-peak August TCE call options to protect against possible increase in electricity prices. On April 1, let's assume that the on-peak August TCE futures contract would be trading at $20.0/MWh. A $20.0/MWh on-peak August TCE (strike price =$20/MWh) call options contract would be trading for a premium of $2/MWh. If the expected basis (basis = cash - futures) would be zero, the DisCo would calculate its estimated maximum purchase price as the sum of the call options strike price, the premium and the expected basis, which all would add up to $22/MWh (or $20/MWh + $2/MWh + $ 0/MWh).

In late July (before the call options would expire), the DisCo would sell them back if the call options would have any value and let them expire worthlessly if they would not have any value. A contract for physical power deliveries in August would be negotiated at the prevailing cash price during late July.

In late July (when the DisCo's call options would expire), assume that the cash price would be equal to the futures price (or the basis is zero), then the hedging for various market scenarios would be given in Table 5.4.

Table 5.4 *Results of DisCo's Hedging for Various Market Scenarios*

Futures price $/MWh	*Cash Price $/MWh*	*Value of $20/MWh call options*	*Premium $/MWh*	*Net Purchase Price[27] $/MWh*
0	0	0	2	2
2	2	0	2	4
4	4	0	2	6
6	6	0	2	8
8	8	0	2	10
10	10	0	2	12
12	12	0	2	14
14	14	0	2	16
16	16	0	2	18
18	18	0	2	20
20	20	0	2	22
22	22	2	2	22
24	24	4	2	22
26	26	6	2	22
28	28	8	2	22
30	30	10	2	22

[27] Net Purchase Price = Cash Price Paid - Value of Call Option at Expiration + Option Premium Paid

The example shows that the DisCo is protected from increasing purchase prices because the call options contract would gain in value as prices increase. If prices would be lower than the strike price, the DisCo would only incur a loss equal to the amount of premium spent on the initial purchase of the call options.

Example 5.7: (TCE Put Options)

Utility C would sell electric power in a future month because it currently has no sale contracts in place. This utility would use put options to protect itself against a possible decrease in the price of electricity. Utility C would purchase a TCE put options contract from Utility D with a strike price of $22/MWh and a premium of $2/MWh. At the expiration, the profit/loss of each utility is illustrated in Figure 5.5 in which the negative profit refers to a loss. For Utility C, any future price at $22/MWh or more would result in a loss equal to the premium, which is $2/MWh.

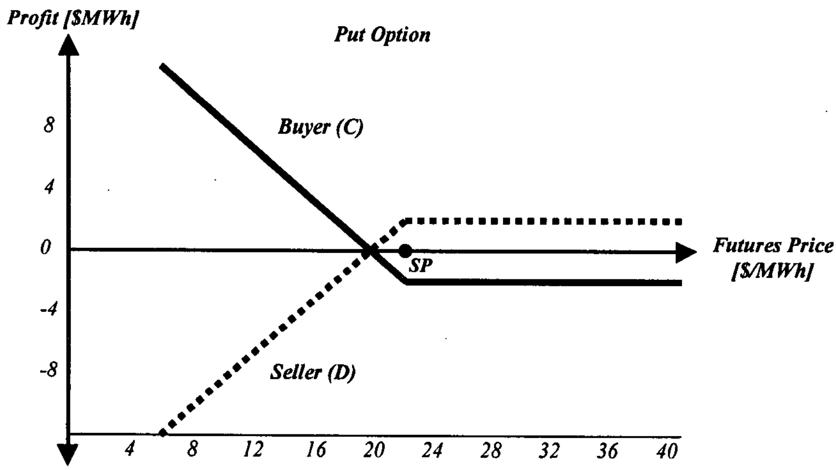

Figure 5.5 Profit/Loss Graph of Example 5.7

At a futures price of $20/MWh, the Utility C's profit (loss) is zero (the transaction breaks even) and at any price less than $20/MWh, Utility C would obtain a gain (profit) up to $18/MWh (at a futures price of $0/MWh). On the other hand, Utility D would see a mirror image of Utility C's position. The profit/loss calculation for different futures prices is calculated and shown in Table 5.5.

Table 5.5 *Profit/loss Calculations of Utility* ***C*** *and Utility* ***D***

Futures price $/MWh	*Utility **C***		*Utility **D***	
	Payment $/MWh	*Comment*	*Payment $/MWh*	*Comment*
0	20	Profit	-20	Loss
2	18	Profit	-18	Loss
4	16	Profit	-16	Loss
6	14	Profit	-14	Loss
8	12	Profit	-12	Loss
10	10	Profit	-10	Loss
12	8	Profit	-8	Loss
14	6	Profit	-6	Loss
16	4	Profit	-4	Loss
18	2	Profit	-2	Loss
20	0	Breaks Even	0	Breaks Even
22	-2	Loss	2	Profit
24	-2	Loss	4	Profit
26	-2	Loss	6	Profit
28	-2	Loss	8	Profit
30	-2	Loss	10	Profit

Example 5.8: (Using the off-peak Put Options)

This example would show how buying a put options contract could protect a utility against possible price drops.

In July 1, 1999, a utility has off-peak electric power purchase in excess of sales for the month of November 1999. The utility would expect that the average purchase price for the November off-peak power is $14/MWh. On July 1, 1999, the off-peak November TCE futures contract is trading at $20/MWh, and the off-peak November TCE $20/MWh (strike price = $20/MWh) put options contract is trading at $2/MWh (premium = $2/MWh). The utility would decide to purchase the off-peak November TCE put options to hedge the possible drop in electricity prices of November. Assuming that the expected basis is $0/MWh, the estimated minimum selling price for the utility is calculated as the put options strike price minus the premium plus the expected basis, which all would add up to $18/MWh (or $20/MWh - $2/MWh + 0).

In late October 1999 (before the November put options expire), the utility would sell the put options back if they would have any value, and let them expire worthless if they would not have any value. Also, in late October, a contract for physical power deliveries in November would be negotiated at the prevailing cash price during late October.

In late October (when the utility's November put options would expire), assume that the cash price would be equal to the futures price (i.e., the basis is zero), The results of the hedge for different possible market scenarios are given in Table 5.6 and illustrated in Figure 5.6.

Table 5.6 Profit/Loss Calculations of using Off-Peak Put Options

Futures price $/MWh	Cash Price $/MWh	Value of $20/MWh put options	Premium $/MWh	Net Selling Price[28] $/MWh
0	0	20	2	18
2	2	18	2	18
4	4	16	2	18
6	6	14	2	18
8	8	12	2	18
10	10	10	2	18
12	12	8	2	18
14	14	6	2	18
16	16	4	2	18
18	18	2	2	18
20	20	0	2	18
22	22	0	2	20
24	24	0	2	22
26	26	0	2	24
28	28	0	2	26
30	30	0	2	28

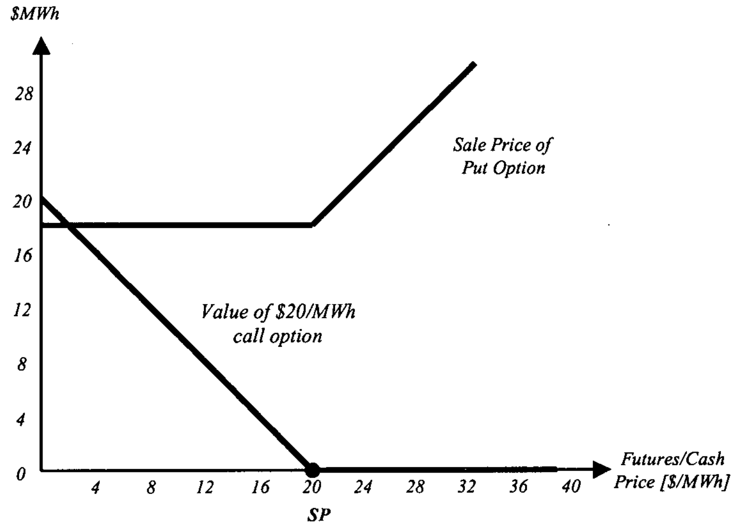

***Figure 5.6** Put Options of Example 5.8*

[28] Net Selling Price = Cash Price Received + Value of Put Option at Expiration - Option Premium Paid

5.4.4 Swaps. The swaps are the other type of derivatives that market participants would use for speculation[29] or hedging contract risks. A price swap is defined as *an agreement between two participants that would negotiate in the OTC market to exchange (swap) certain price risk exposures over a certain period of time.* Swaps were proposed for electric energy markets in 1995 to economically function as futures contracts. In a swap, two types of payment are defined, i.e., fixed payment and variable payment. The buyer of the swap would agree to pay a fixed payment stream, while the seller of the swap would agree to pay a variable payment stream. As in the case of futures contract, the buyer of a swap would make money when prices rise and lose when prices drop relative to the fixed payment. Any swap agreement would be expected to cover the following terms when initiated:

- the fixed price[30],
- the determinant of the variable price,
- the time period covered by the swap, and
- the notional size of the swap[31].

Example 5.9 (Swap)

A GenCo (seller) and a DisCo (buyer) negotiated an agreement for 50 MWh (on peak) that was initially settled against the DJ index of electricity prices at the California-Oregon Border (COB). DisCo agrees to pay a fixed price and receive a price equal to the simple average of a given month's non-firm, on-peak, COB index price published in the Wall Street Journal. The total notional volume is equal to $(50\times16\times6)$[32].

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[29] See Chapter 6.

[30] Negotiated at the time of transaction.

[31] Typically traded in increments of 25 MW on-peak.

[32] Assuming that peak hours are 16h/day (6:00 AM–10:00 PM), six days a week (Monday–Saturday), the total notional volume is equal to the number of MWs multiplied by the number of days in a month (excluding Sundays and holidays) multiplied by 16.

When the average of on-peak DJ COB prices would exceed the fixed price, DisCo (buyer) would receive a positive cash flow from the transaction. When the average of on-peak DJ COB prices is below the fixed price, the GenCo would receive a positive cash flow from the transaction.

5.4.5 Applications of Derivatives in Electric Energy Trading.

Derivatives such as options, forwards, futures and swaps are tradable financial products that play an important role in providing the price certainty for buying and selling electricity. Electricity can be traded as a commodity in the derivatives market like other commodities such as wheat, coffee, gold, natural gas and crude oil.

NYMEX[33] is one of the largest derivative markets in the world. It initiated trading in two electricity futures contracts on March 1996. The first contract is based on the delivery price of electricity at the California-Oregon border (COB). The second contract is based on delivery at the Palo Verde switchyard in Arizona.

After that NYMEX has added Entergy and Cinergy futures and options contracts, based on electricity transmission systems in central and southwestern United States. Electricity options were started on NYMEX in April 1996. A NYMEX options contract is for one NYMEX Division COB futures contract, or one NYMEX Division Palo Verde futures contract, of 736 MWh delivered over the period of a month sometime in the future.

Example 5.10: (Energy Forward Contract)

A forward contract was defined as a contract that is made today to exchange a commodity and supply money at a predefined exchange rate[34] at some predefined date in the future. Money would change hands at the forward price at the contract's expiration date. Consider the following:

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[33] www.nymex.com

[34] In this case, forward contract allows participant (holder) to lock in a price for a future transaction

An IPS would be interested in eliminating the price risk associated with selling its energy production. IPS, today (Jan. 1), enters into a forward contract with a retail company (RetailCo) to sell 80 MWh energy at \$10/MWh in three months (expiration date is April 1). This situation is shown in Figure 5.7.

Spot price of electricity, interest rates, storage costs, and future supply and demand conditions are the main factors that steer up the price of futures contracts. The current price of the underlying cash commodity is the leading factor that could impact the price of a futures contract.

Example 5.11: (A Futures Contract)

A generation company (GenCo) on January 1 (today) plans to sell 200MWh in three months (on April 1). Let's assume that 1 futures contract of energy is 100 MWh, the spot price of energy is \$14/MWh, the April futures price is \$16/MWh and the GenCo would like to lock in the \$16/MWh for its April sale. Let's assume that a distribution company (DisCo) plans to buy the April energy futures. In April, two equivalent commodities would be traded: April energy futures (which is about to expire and hence would obligate the participant to purchase or sell the physical energy), and physical energy (spot energy). At the expiration of futures contract, these two commodities would be the same, (i.e., April energy is the same as the spot energy in April) so they should be traded at the same price.

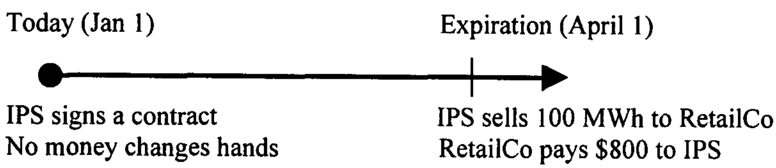

Figure 5.7 *Illustration of Forward Contract*

This is why we say that the futures price of a commodity would converge with the spot price of the commodity at the expiration of the futures contract. This is an important issue if we would use the futures contracts for hedging. The futures contract would obligate the GenCo to sell 200 MWh of energy at the prevailing spot price in April. If the spot energy price would drop to \$10/MWh by April, the future price of April energy would also drop to \$10/MWh and the GenCo would sell its energy at \$10/MWh.

But what did happen to the April futures price of \$16/MWh that presumed the GenCo to sell the April futures for energy? Why would the GenCo sell the energy at the spot price if it had planned to sell for \$16/MWh? The story is as follows: If the futures price would rise, the GenCo (short) would lose money and the buyer (long) would make money; the opposite would happen when the futures price would drop. This is the hedging mechanism that would make the hedge works. See Table 5.7.

In this example, the GenCo would enter into a short April energy futures contract at \$16/MWh, and the next day April energy futures would close at \$20/MWh. Since the GenCo is short contract, GenCo would lose money if the price would rise. Here, the GenCo would lose 200 MWh at \$4/MWh for a total of \$800. This money would be taken from the GenCo's *margin account* that the GenCo had established with its broker. Over the life of the contract, money would be deposited to or withdrawn from the margin account of the GenCo. On any given day, the GenCo's total profit or loss, starting from the date that the GenCo (short) entered into the contract, would be:

***Table 5.7** Effect of Futures Price Changes*

Futures Position	Futures Price change	Cash Flow Effect
GenCo (Short)	Increase	Loss
GenCo (Short)	Decrease	Profit
DisCo (Long)	Increase	Profit
DisCo (Long)	Decrease	Loss

$$\textit{No. of Contracts} \times 100 \times (\textit{Current Future Price - Initial Future Price})$$

Likewise, on any given day, the DisCo's total profit or loss, starting from the date that the GenCo (short) entered into the contract, the DisCo (long) entered into the contract would be:

$$-\textit{No. of Contracts} \times 100 \times (\textit{Current Future Price - Initial Future Price})$$

At expiration, the GenCo's total profit or loss would be:

$$\textit{No. of Contracts} \times 100 \times (\textit{Spot Price - Initial Future Price})$$

When the GenCo sells its energy at the spot price at the expiration of the futures contract, it would realize that the initial \$16/MWh as its futures contract would make up the difference. The following steps illustrate the process:

- Jan 1. The GenCo sells 2 contracts of April energy at \$16/MWh: (No money would change hands, except for margin, since the commission would be paid after the contract is closed out). The GenCo would post a 10% margin (or 10% of $(\$16.00/\text{MWh}) \times (200\,\text{MW}) = \$320$). The GenCo would now be short 2 contracts of April energy. The margin would be the GenCo's money and not a payment for the contract. The GenCo would get any left over margin and pay the commission at the end.

- Jan 2. April energy rises to \$17/MWh. The GenCo would lose \$1/MWh for a total of $(\$1.0/\text{MWh}) \times (200\,\text{MW}) = \$200$. The \$200.0 would be taken from the GenCo's margin account and the account now stands at \$120 (or \$320-\$200).

- Jan 3. The April energy drops to \$15/MWh. The GenCo would gain \$1/MWh with a total of \$1.0/MWh×(200 MWh) = \$200. The GenCo would make the \$200 that it lost yesterday which would be added to the GenCo's margin account. The GenCo's account now stands at \$320 (or \$120+\$200).

- ...
- ...
- April 1, the spot price is at \$10/MWh. The future contract is about to mature and the future price has converged to the spot price of \$10/MWh. The total amount of money that would be added to the GenCo's account is \$1,200 (or (\$16.0/MWh-\$10.0/MWh)×200 MWh), which is the GenCo's profit from the futures contract. That means the GenCo's margin account would stand at \$1520 (or \$320 +\$1200). The GenCo would sell the energy on the open market at \$10/MWh and get \$2000 for the energy plus the \$1520 profit for the futures contract. This would net \$3,200 for GenCo's 200 MWh, which is exactly the \$16/MWh that the GenCo had locked in on Jan 1. The GenCo would also get back its initial margin of \$320.0 minus the round trip commission cost.

Example 5.12

An IPS has entered into a contract to provide the GenCo with 100 MWh in three months at \$15/MWh. At the expiration date, electricity spot price is:

- Case 1: \$17/MWh
- Case 2: \$12/MWh

Consider the following settlement:

Alternative 1: GenCo would pay IPS \$1500 (or 100×15)

Alternative 2: GenCo would pay IPS:

- Case 1: 100 × (17-15) = \$ 200
- Case 2: 100 × (12-15) = - \$ 300 (the IPS pays GenCo).

For a certain month, contracts would be traded between counterparties through brokers announcing the bid price at which they would be willing to buy, and the offer price at which they would be willing to sell. Once a contract is finalized, i.e. buyer and seller would agree upon a price, a recorder would post the price of the contract. In this process, a broker would either be trading contracts for his own or on behalf of his clients.

A position is either closed financially or physically. The first type (financial) which represents the majority of closing positions (more than 90%) is liquidated prior to delivery when a party with a long position would decide to sell, and a party with a short position would decide to buy, a futures contract. In the second type (physical), a holder of a long position would wait until the contract expiration when the contract would end with physical delivery. At maturity, a holder of a short position would be obligated to deliver the energy to the holder of a long position.

An energy derivatives market would require a diverse and large number of participants (buyers and sellers). An increased number of participants would improve the liquidity and help prevent market power, where it would be difficult for any one entity to drive market prices. Market participants should receive timely feedback on electricity price changes for derivative contracts and the spot market, and it would be beneficial if participants would have on-line access to real-time and historical price information through links with an electronic trading system.

Example 5.13: (How can a GenCo use futures?)

On January 1, the GenCo is expecting to sell 500 MWh into the energy spot market in April (GenCo is long electricity). Assume the GenCo is producing power at a cost of $12/MWh. The energy spot price on January 1 is $12/MWh and the futures price for delivery in April is $8/MWh. To hedge the risk of price drops, the GenCo would sell futures contracts for $8/MWh. In April, the GenCo would then sell energy at spot price and buy futures contracts to close out its financial position. If the futures price converges with the spot price as the delivery time arrives and if the futures price is equal to the spot price when the position is closed, the GenCo would be totally hedged against price risks.

- If the spot price rises to $15/MWh, the GenCo would:
  - Receive $15/MWh for its electricity,
  - Pays 15/MWh to close its futures positions, and
  - Receive $8/MWh for its original futures positions.

- If the spot price drops to $6/MWh, the GenCo would:
  - Receive $6/MWh for its electricity,
  - Pay $6/MWh to close out its futures position, and
  - Receive $8/MWh for its original futures position.

We note that in both cases, the GenCo finally obtains $8/MWh for energy delivery and price movements will not affect the GenCo, so the price risk is hedged. The situation and the payoff diagram are shown in Figures 5.8 and 5.9.

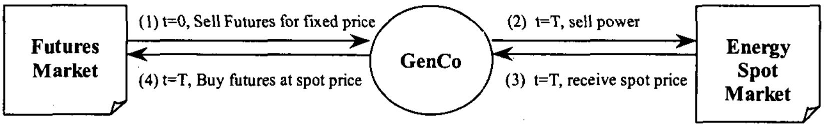

Figure 5.8 *Illustration of How GenCo Can Use Futures*

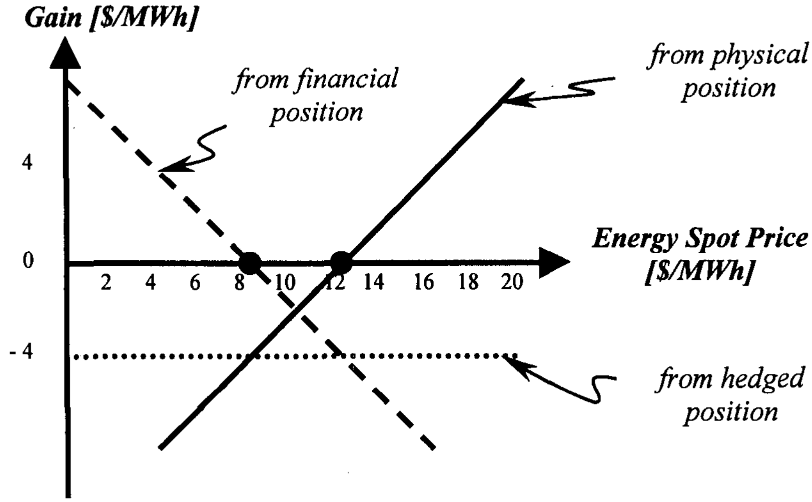

Figure 5.9 *Payoff Diagram Describing "How Can GenCo Use Futures"*

The payoff diagram would tell us how much the GenCo would profit or lose physically and financially as spot price changes during the contract period. For example, if in April, the spot price rises to $14/MWh, the GenCo would gain $2/MWh, and if it drops to $8/MWh the GenCo would lose $4/MWh. This is the GenCo's physical position in this example.

Financially, if the spot price in April drops to $4/MWh, the GenCo would gain $4/MWh because it had sold its futures for $8/MWh (or 8-4 = $4/MWh). To close out this position, the GenCo had bought futures for $4/MWh. On the other hand, if the spot price increases to $11/MWh, the GenCo would lose $3/MWh (or 8-11 = -$3/MWh).

The hedged gain is the sum of gains from both physical and financial positions. For this example, the GenCo has locked in a price of $8/MWh and a loss of $4/MWh.

Example 5.14: A GenCo Uses a Short-Hedge (Using the NYMEX Futures Contract to Protect itself against Price Decline)

It would cost a GenCo $8 to produce each MW and this GenCo expects that the cost would stay the same during the next six months. On November 1, 1999, the GenCo expects that it would sell 1472 MWh in March 2000 in the cash market at $10/MWh. The GenCo's potential revenue from that sale would be $14,720 (or $10/MWh × 1472 MWh). Meanwhile, the GenCo fears a decline in electricity prices, because if the GenCo would enter into a firm contract for March 2000 and the electricity price turns out to be declining below the production cost, the GenCo would suffer a significant loss.

Assume each NYMEX contract covers 736 MWh, which means that the two contracts (or 2 × 736 = 1472 MWh) are equivalent to what the GenCo would expect to sell. The GenCo can enter into the futures market and sell (i.e., the GenCo takes a short position) two NYMEX electricity futures contracts for March 2000, at $10/MWh. The GenCo's total revenue from the two contracts would then be $14,700 (or $10/MWh × 1472 MWh).

Let's study the outcome of the two situations:

Situation 1: Cash market prices decline, as GenCo expected

By February 21st, cash market prices have fallen to $7/MWh. The GenCo sells the electricity for March physical delivery at the cash market price of $7/MWh. This would give the GenCo a revenue of $10,304 (or $7/MWh × 1472 MWh). In the cash market, the situation is as follows:

November 1, 1999: Expected Cash Price = $10/MWh, total revenue = $14,720

February 21, 2000: Cash Market Price = $7/MWh, total revenue = $10,304

Difference = $3/MWh, and total revenue = $4,416.

The revenue is $4,416 less than expected, which is a loss.

The GenCo can now buy back its two NYMEX futures contracts at $7/MWh, with a total cost of $10,304 (or $7/MWh × (2contracts×

736/MWh/contract)). In the futures market, the situation would be as follows:

Previously, the GenCo sold 2 futures contracts for \$10/MWh for a total \$14,720. Now, it would buy back 2 futures contract for \$7/MWh for a total \$10,304. The profit from futures contracts is at \$3/MWh for a total of \$4,416.
The profit would compensate the loss in the cash market. From both transactions, the financial (futures market) and physical (cash market), the net revenue would be:

Net Revenues = \$10,304 + \$4,416 = \$14,720

This net revenue would be equal to the GenCo's revenues expected on November 1, 1999.

Situation 2: Cash market prices rise despite the GenCo's expectation

By February 28th, cash market prices have risen to \$12/MWh. The GenCo would sell the electricity for March physical delivery at the cash market price of \$12/MWh. This would give the GenCo a revenue of \$17,664 (or \$12/MWh × 1472 MWh). In the cash market, the situation would be as follows:

November 1, 1999: Expected Cash Price = \$10/MWh, Total revenue = \$14,720

February 28, 2000: Cash Market Price = \$12/MWh, Total revenue = \$17,664

Difference = - \$2/MWh and Total revenue = - \$2,944

The revenue would be \$2,944 more than expected (i.e., a profit).

The GenCo can now buy back its (two) NYMEX futures contracts at \$12/MWh, at a total cost of \$17,664 (or \$12/MWh × (2contracts× 736/ MWh/contract)). In the futures market, the situation would be as follows:

Previously, GenCo sold 2 futures contracts for \$10/MWh for a total of \$14,720.

Now, GenCo would buy back 2 futures contracts for \$12/MWh for a total of \$17,664.

Loss from futures contracts is at \$3/MWh for a total of \$2,944.

The GenCo's profit from cash market would compensate its loss in the futures contracts. From both transactions, the financial (futures market) and physical (cash market), the net revenue would be equal to:

$$\text{Net Revenues} = \$17,664 - \$2,944 = \$14,720$$

This net revenue would be equal to the expected revenues that the GenCo expected on November 1, 1999.

Figure 5.10 shows revenues, profits and losses of the GenCo at different prices. The two situations are marked on this figure.

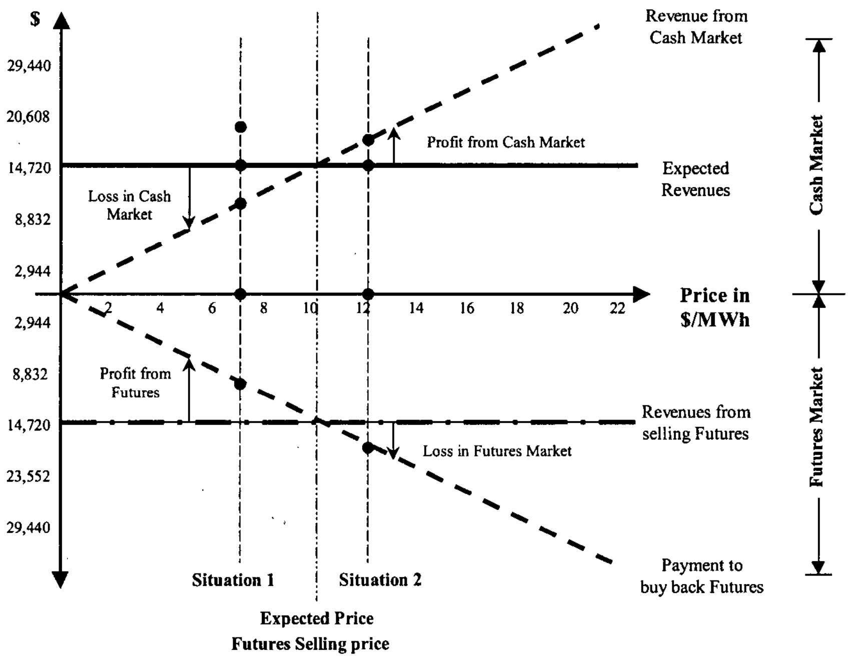

Figure 5.10 Profits, Losses, and Revenues of the GenCo's Short Position

Example 5.15: A RetailCo Uses a Long-Hedge

On November 1, 1999, a Retail Company (RetailCo) expects to buy 736 MWh in March 2000 in the cash market at $10/MWh. The RetaiCo's potential payment for that purchase will be $7,360 (or $10/MWh × 736 MWh). The RetailCo fears an increase in electricity prices, because if the RetailCo enters into a firm contract for March 2000, and the electricity price turns out to be decreasing, the RetailCo could suffer a significant loss in its revenues.

One NYMEX contract is equivalent to what the RetailCo is expecting to buy (1×736 = 736 MWh). Now let's see what is going to happen if the RetailCo goes into the futures market and buys (the RetailCo takes a long position) one NYMEX electricity futures contracts for March 2000, at $10/MWh. The RetailCo's total payment to the one contract will be $7,360 (or $10/MWh × 736 MWh). We will study the outcome of two situations:

Situation 1: Cash market prices declines, despite the RetailCo's expectation

By February 21st, cash market prices have fallen to $7/MWh. The RetailCo buys for the March physical delivery at the cash market price of $7/MWh. This will make the RetailCo incur a payment of $5,152 (or $7/MWh × 736 MWh). In the cask market, the situation is as follows:

November 1, 1999: Expected Cash Price = $10/MWh, total payment = $7,360

February 21, 2000: Cash Market Price = $7/MWh, total payment = $5,152

Difference = $3/MWh, $2,208.

The payment is $2,208 less than expected, which is a profit.

The RetailCo can now sell back its (one) NYMEX futures contract at $7/MWh, with total revenue of $5,152 (or $7/MWh × (1contracts×736/ MWh/contract)). In the futures market, the situation is as follows:

Previously, RetailCo bought 1 futures contract for $10/MWh, a total of $7,360.

Now, RetailCo sells back 1 futures contract for \$7/MWh, a total of \$5,152.

Loss from futures contracts \$ 3/MWh for a total \$ 2,208.

The RetailCo's profit from the cash market would compensate its loss in the futures market. The revenue from both transactions (the financial (futures market) and physical (cash market)) is equal to:

Net Payments = \$5,152 + \$2,208 = \$7,360

This net revenue is equal to the expected RetailCo's revenues on November 1, 1999.

Situation 2: Cash market prices rises, as RetailCo expected

By February 28th, cash market prices have increased to \$12/MWh. The RetailCo buys for the March physical delivery at the cash market price of \$12/MWh. This will let the RetailCo incur a payment of \$8,832 (or \$12/MWh × 736 MWh). In the cash market, the situation is as follows:

November 1, 1999

Expected Cash Price = \$10/MWh, Total payment = \$7,360

February 28, 2000

Cash Market Price = \$12/MWh, Total payment = \$8,832

Difference = - \$2/MWh, \$1,472

The payment is \$1,472 more than the expected amount, which is a loss.

The RetailCo can now sell back its (one) NYMEX futures contract at \$12/MWh, with a total revenue of \$8,832 or \$12/MWh × (1 contract× 736/MWh/contract). In the futures market, the situation is as follows:

Previously, RetailCo bought 1 futures contract for \$10/MWh for a total of \$7,360.

Now, RetailCo sells back 1 futures contract for \$12/MWh for a total of \$8,832.

Profit from futures contracts \$2/MWh for a total of \$1,472.

The RetailCo's profit from the futures market would compensate its loss in the cash market. Revenue from both transactions (the financial (futures market) and physical (cash market) is equal to:

Net Payments = \$8,832 - \$1,472 = \$7,360

This net payment is equal to the expected RetailCo's payment on November 1, 1999.

Figure 5.11 shows revenues, profits and losses of the RetailCo at different prices. The two situations are marked on this figure.

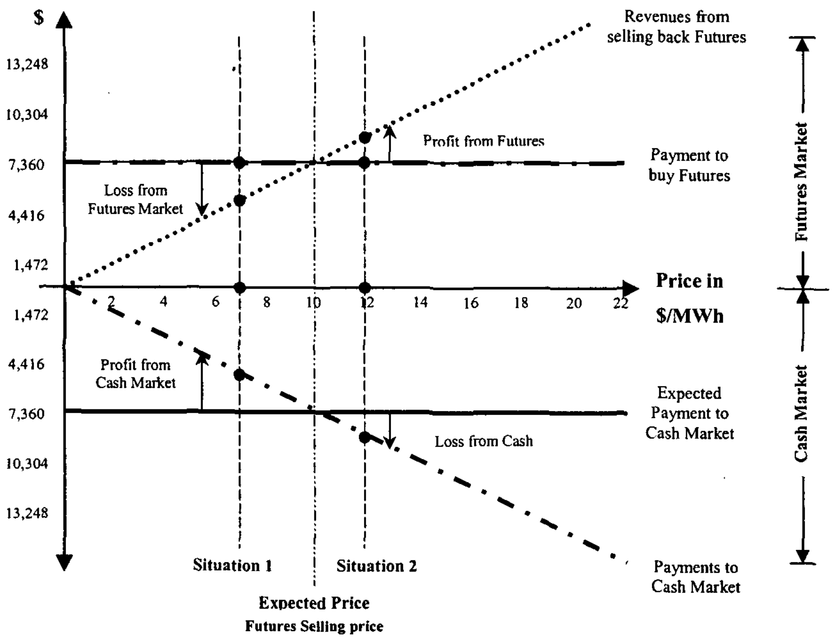

Figure 5.11 Profits, Losses, and Revenues of the RetailCo's Long Position

Example 5.16: (How can a DisCo use futures?)

On January 1, a DisCo is expecting to use 300 MWh in three months and planning to buy it from the spot market in April (the DisCo is short electricity). Energy spot price on January 1 is $14/MWh, and the futures price for delivery in April is $9/MWh. To hedge the risk of price changes, the DisCo would buy futures contracts for $9/MWh to lock in its energy price. If spot price would rise beyond the current spot price, the DisCo would pay more for electric energy. In April, the DisCo would then buy energy using spot price and sell futures contracts to close out its financial position. If the futures price converges with spot price as the delivery time arrives and if the futures price is equal to spot price when the position is closed, the DisCo would be totally hedged against price risk.

- If spot price increases to $16/MWh, the DisCo would:
  - pay $16/MWh for its electricity,
  - receive $16/MWh to close its futures positions, and
  - pay $9/MWh for its original futures positions.
- If the price drops to $7/MWh, the DisCo would:
  - pay $7/MWh for its electricity,
  - receive $7/MWh to close out its futures position, and
  - pay $9/MWh for its original futures position.

We note that in both cases, the DisCo would finally pay $9/MWh for energy delivery, price movements do not affect the DisCo and the price risk is hedged. The payoff diagram of this example is shown in Figure 5.12. The payoff diagram depicts how much the DisCo would profit or lose physically and financially as spot price would change during the contract period.

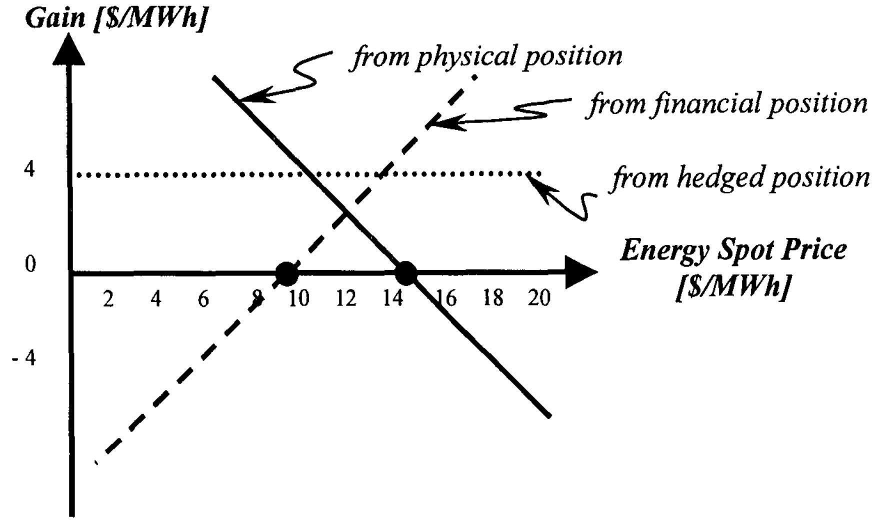

Figure 5.12 Payoff Diagram of the Example 5.16

Example 5.17: (NYMEX)

In January 1, a DisCo has an agreement with a large customer to provide 736 MWh of electricity during April. To guarantee that it would not over-pay a power provider in April, the DisCo would purchase one NYMEX April futures contract. If as of January 1, the April futures contract is at $10/MWh, the DisCo would pay $10/MWh for the contract, for a total of 736MWh×$10/MWh or $7,360. By March 26, the last trading day for April futures or four business days before the first day of the trading month, the spot price of electricity has increased to $13/MWh. The DisCo would purchase 736 MWh from the spot market for a total cost of 736MWh×$13/MWh or $9,568. The DisCo then would sell its futures contract, which has also increased to $13/MWh for a total of 736×13 or $9,568. The DisCo has paid out a net amount of $7,360, which would guarantee that the DisCo would receive electricity in December at $10/MWh rather than $13/MWh.

5.5 PORTFOLIO MANAGEMENT

A portfolio is defined as the overall collection of commodities and financial positions on these commodities owned by a person or a company. The purpose of a portfolio is to reduce risk by diversification. In the electric power industry, portfolio management is an aggregation and management of a diverse portfolio of spot-market purchases, contracts-for-differences, futures contracts and other market-hedging contracts and mechanisms. As we discussed before, electricity markets possess high price volatility, which would necessitate the ability to design and implement hedges for price risks related to predicted and unpredicted volumes not covered through contracts. The structure of a portfolio would differ from one participant to another; for example, an IPP would have a different portfolio than that of a generating utility or a distribution company.

In this section, we explain portfolios in electricity markets, discuss their necessity and present examples of their use by market participants. Figure 5.13 shows an example of a simple portfolio of power generation and contracts over eight weeks; let's say May and June 1999[35]. The figure shows a collection of generation resources (assets) and contracted power (financial positions) owned by a GenCo; this GenCo's portfolio is a collection of a set of positions. The portfolio shown in Figure 5.13 is the GenCo's supply and demand of electricity in MWh for the first eight weeks of May and June 1999. Let's assume that the GenCo has purchase contracts with IPPs. In this figure, the total supply is the self-generation (production) plus contracted purchase, which have negative values, and the energy sold (demand) with positive values.

The GenCo has firm sale contracts[36], spot price-base contracts[37] and open positions[38]. As the figure shows, the GenCo's portfolio has net short position[39] (as in week 2), net long position[40] (as in week 1) or closed

[35] CALPOL Market Report, Issue no. 2, August 1998.

[36] Sales to residential customers.

[37] Partly depending on the spot price, limited by a maximum and a minimum price.

[38] Quantity of the portfolio is exposed to spot price volatility.

[39] Supply is less than demand (under-covered position).

[40] Supply is greater than demand (over-covered position).

position[41] (as in week 7) in each week of the month. A portfolio could have many positions, and each position could exhibit volatility or uncertainty, which would mean that each position would have a risk. The risk of bunch of positions is not the sum of individual risks, but the risk of correlated positions. By managing a participant's portfolio, we could observe variations in the behavior of positions as compared to one another.

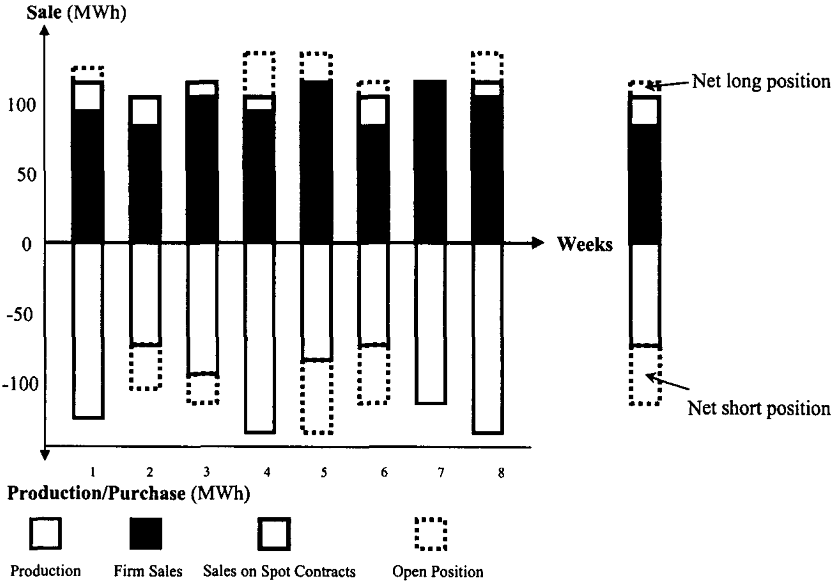

Figure 5.13 An Eight-Week Portfolio of Contracts and Production Resources

[41] Supply and demand are in balance (balanced position).

The elements of a successful portfolio management would include the following:

- The first element is defining the trade-off level between risk (security) and the participant's perceived profit, i.e., the level at which the portfolio should be hedged. A complete security of a portfolio could be implemented by total hedging which could be accompanied by reduced profit opportunities.

- The second element is defining the optimal timing of taking short or long position in the portfolio which would depend on experience with market moves (e.g., when the price is going to rise or drop) and depend on reliable analytical tools and trustable price forecasts.

- The third element is finding the optimal distribution or mix of different positions of the portfolio in order to balance the portfolio, i.e., how many firm contracts, futures contracts, options contracts, swaps, or others should be included in the portfolio.

5.5.1 Effect of Positions on Risk Management. To measure the effect of individual positions on risk and analyze the potentials for profit of a portfolio with a set of positions, a probability platform and standard deviations are used. As the probability distribution function of a portfolio gets more dispersed, the risk of portfolio increases, and vice versa. The cumulative probability for profit distribution of a certain portfolio is another tool for analyzing a portfolio.

Figure 5.14 shows probability distribution functions of two portfolios, where portfolio **1** indicates greater risk than portfolio **2**. Z_1 and Z_2 represent mean values of portfolios **1** and **2**, respectively. The mean value of a portfolio indicates the expected value of profit. In the figure, portfolio **2** has a higher *expected value* of profit than portfolio **1**. So, we are facing a trade-off between risk and profit. Since portfolio **1** has a more dispersed probability distribution than portfolio **2**, the profit potential of portfolio **1** is much larger; in other words, choosing portfolio **1** has the possibility of earning more money than the risk of choosing portfolio **2**.

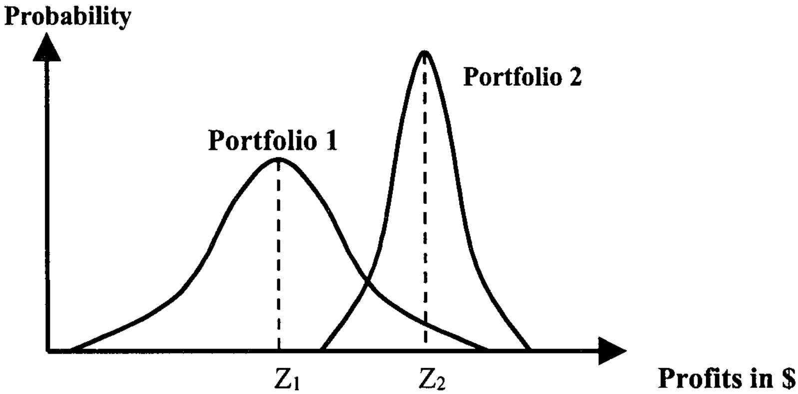

Figure 5.14 Probability Distribution of Two Portfolios

Figure 5.15 shows the cumulative probability of profits for two different portfolios, **A** and **B**. Let's assume that portfolio **B** represents portfolio **A** but with a hedging instrument such as a futures or a forward contract. In other words, the portfolio manager has chosen to close parts of open positions of portfolio **A** by entering a futures or a forward contract (i.e., futures or forward for the purchase of electricity for the desired period); the net result of portfolio **A** plus the new contract is represented by portfolio **B**.

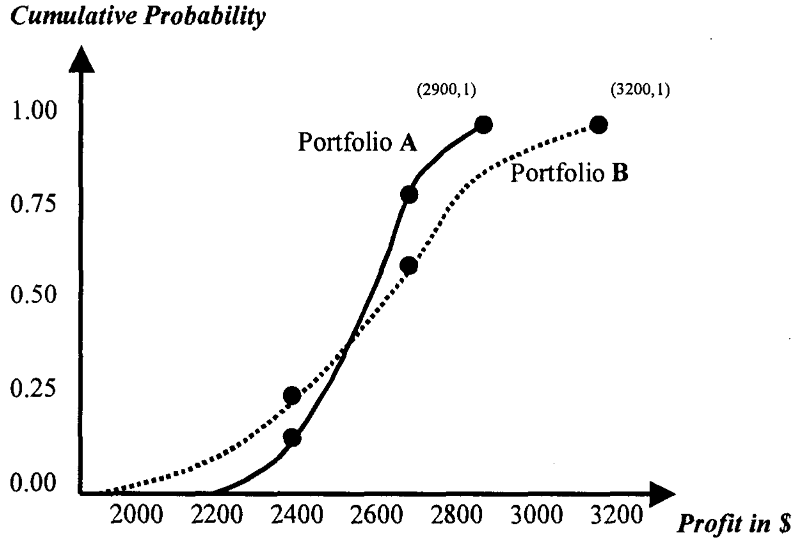

Figure 5.15 Cumulative Probability of Profits of Two Portfolios

A zero cumulative probability means unlikely levels of profit. For example, in Figure 5.15, the profit for portfolio **A** is unlikely to go below $2,200 and the profit for portfolio **B** is unlikely to go below $1,900. The same reasoning would apply to a cumulative probability of 1, where the profit for portfolio **A** is unlikely to go over $2,900 and the profit for portfolio **B** is unlikely to go over $3,200.

The cumulative probability is a tool to analyze how likely a budgeted level of profit is. Assume that a portfolio manager is looking for an acceptability level of budgeted profit $2,700 and a profit below $2,400 is unacceptable. The probability of achieving the budget for portfolio **A** is 20% (or 0.2) as the cumulative probability of the result being lower than $2,700 is 80% (or 0.8, which is 1 minus 0.2). Portfolio **A** represents a 0.15 probability that its profit would be below $2,400.

In Figure 5.15, since portfolio **B** exhibits a less steep cumulative probability, it has a broader probability distribution as compared to that of portfolio **A** (portfolio **B**'s standard deviation is larger than that of **A**). Portfolio **B** has a higher maximum profit potential than **A**'s by $400 (or $3200-$2900, see Figure 5.15). Also the probability of not achieving the budget will increase with portfolio **B**. With portfolio **B**, the budgeted profit ($2,700) would be met with a 40% (i.e., 0.4) probability (or 1 minus 0.6). In addition, with portfolio **B**, there would be a higher probability of not meeting the minimum requirement (remember that a profit below $2,400 would not be acceptable), where the probability of the profit being below $2,400 is 15% (or 0.15) for portfolio **A** and the probability of the profit being below $2,400 is 25% (or 0.25) for portfolio **B**.

5.6 ENERGY TRADING HUBS

Electric energy traders are concerned with price volatility and risk management. Electric energy like other industries such as crude oil, petroleum products and natural gas is increasingly focusing on liquidity at certain geographical locations (hubs) for supporting the price discovery and implementing a higher efficiency in the marketplace.

A hub is a common point for commercial energy trading contracts that is formed as an aggregation of representative buses grouped by region. Contracts are either settled financially or ended with physical delivery. The main aim of proposing hubs is to create price signals for geographical regions of the control area and to reduce the risk of delivering to one particular bus whose price is more volatile during a contingency than a collection of bus prices at a weighted average.

Energy trading could represent a large number of hubs, where each utility or control area would act as a hub or more than one hub, depending on the configuration of the transmission system. Table 5.8 shows the main trading hubs in the United States.

Table 5.8 Main Trading Hubs in the United States

West	Central	East
COB Four Corners Mead Mid Columbia Palo Verde	Ameren ComEd ERCOT Into Entergy MAIN north MAPP SPP	Cinergy Florida-Georgia border Into TVA NEPOOL north ECAR NYPP PJM-west southern Florida

An energy trading hub should possess several elements that would make it a successful trading location. These elements would include:

- A natural supply/demand balancing point
- Reliable contractual standards for delivery and receipt of energy commodity
- Price transparency
- Absence of market power
- Similarity of pricing across the hub
- Robust trading tools to execute large numbers of trades and aggregate transactions
- Liquidity

Homogeneity of prices across the hub is required to insure that sellers will not always seek to deliver energy at the cheapest location, and buyers will not always seek out the most expensive point when prices across the hub would vary. If the similarity of prices is not supported across the hub, the trading location would suffer from the lack of traders as well as the confusion for traders. Trading tools that deal with hubs include electronic trading systems and futures exchanges in addition to scheduling mechanisms to adjust a portfolio of supply to a portfolio of demand. Liquidity on a trading hub is implemented by the presence of a considerable number of buyers and sellers.

5.7 BROKERS IN ELECTRICITY TRADING

A broker is an entity that plays the role of a middleman between two participants (buyers and sellers) that arranges and disseminates information to both participants until an agreement is finalized. With restructuring in the electricity industry, brokers' role is enlarged in wholesale electricity trades when the market liquidity and the volume of transaction increase. The broker aggregates bids from buyers and sellers which makes the market more definable, and prices become more visible which enables the broker to offer better bids and ask spreads on deals as they continue to get market information through deal flow.

In addition to helping traders manage their deals, the broker may give advice to its clients either on risk management or on what might be happening in the market. Furthermore, the broker may provide information on weather, transmission and generation, conduct training and provide educational services to its clients. Using a broker would save time when traders would not have to communicate much in order to agree on a deal. A broker could substitute for much of the groundwork in trading when the broker acquires price offers and bids from many clients. A well-established brokering service should provide clients with the timely market information to let them revise their positions and analyze new opportunities.

5.8 GREEN POWER TRADING

Some trading systems would favor environmentally preferred generating technologies for operating hourly electricity markets. Resources such as geothermal, biomass, wind, small hydro and solar generating technologies could sell their power production into the green energy market, or directly to consumers with a higher price.

In California, an example of trading system that operates a green power market is the Automatic Power Exchange (APX). APX would operate a green power market for up to 168 hours ahead of delivery.

When green power is most attractive among consumers, green power producers would use forward prices to schedule their production. Customers in California would have an incentive for buying green power since the California Energy Commission is providing customers with a 1.5 cent per KWh credit for purchases from in-state renewable generators.

Using a trading system, renewable energy producers would be matched with customers who would prefer green power. Usually, the usage of green power would require customers to pay a premium price for environmentally preferred resources, and these prices should be posted by the trading system. A summary of major renewable sources of electricity is given as follows:

- Geothermal energy: Geothermal energy is the heat transferred from the inner part of the earth to underground rocks or water located relatively close to the earth's surface. Molten rock (magma) which is located several miles below the earth's surface produces heat or steam which heats a section of the earth's crust and warms underground pools of water (geothermal reservoirs). By making an opening through the rock to the surface, the hot underground water may flow out to form hot springs, or it may boil to form geysers. Geothermal reservoirs may provide a steady stream of hot water that is pumped to the earth's surface by drilling wells deep below the surface of the earth. Geothermal energy may be used to produce electricity, where steam is either conveyed directly from the geothermal reservoir or from water heated to make steam and piped to the power plant. The Geysers Geothermal Field located in the northern California is one source of geothermal power where this power plant is considered the largest source of geothermal energy in the world and produces as much power as two large coal or nuclear power plants.

- Hydropower - converts the energy in flowing water into electricity. The quantity of electricity generated is determined by the volume of water flow and the amount of head, the height from turbines in the power plant to the water surface created by the dam. The greater the flow and head, the more electricity is produced. With a capacity of more than 92,000 MW - enough electricity to meet the energy needs of 28 million households - the U.S. is the world's leading hydropower producer. Hydropower supplies 49% of all renewable energy used in the U.S.

- Biomass energy - the energy contained in plants and organic matter - is one of the most promising renewable energy technologies. Instead of conventional fuels, the technology uses biomass fuels - agricultural residues, or crops grown specifically for energy production - to power electric generators. Today, biomass energy account for nearly 45% of renewable energy used in the United States. Biomass is used to meet a variety of energy needs, including generating electricity, heating homes, fueling vehicles and providing process heat for industrial facilities. In the last few decades, biomass power has become the second largest renewable source of electricity after hydropower. Hydropower and biomass plants provide baseload power to utilities. Biomass power plants are fully dispatchable (i.e. they operate on demand whenever electricity is required). About 350 biomass power plants with a combined rated capacity of 7000 MW feed electricity into the nation's power lines, while another 650 enterprises generate electricity with biomass for their own use as cogenerators. National renewable energy laboratory (NREL) researches have helped lower the cost of ethanol fuel from these sources to $1.22 per gallon. The target of current researches is 70¢ per gallon.

- Photovoltaic (PV) systems - most commonly known as solar cells - convert light energy into electricity. PV systems are already an important part of our lives. They power many of small calculators and wrist watches. More complicated PV systems provide electricity for pumping water, powering communications equipment, and even lighting our homes and running our appliances. In a surprising and increasing number of cases, PV power is the cheapest form of electricity for performing many tasks. Costs have dropped from 90¢ per KWh in 1980 to 22¢ today. Photovoltaics are cost competitive in rural and remote areas around the world. The National Photovoltaics Center at NREL is leading federal efforts to improve performance and lower costs.

- Wind energy projects provide cost-effective and reliable energy in the U.S. and abroad. The U.S. wind industry currently generates about 3.5 billion KWh of electricity each year, which is enough to meet the annual electricity needs of 1 million people. Wind energy installations are going up across the country as generating companies realize the benefits of adding clean, low-cost, reliable wind energy to their resource portfolios.

- Solar thermal electric (STE) technologies - parabolic troughs, power towers, and dish/engine systems - convert sunlight into electricity efficiently and with minimum effect on the environment. These technologies generate high temperatures by using mirrors to concentrate the sun's energy up to 5000 times its normal intensity. This heat is then used to generate electricity for a variety of market applications, ranging from remote power needs as small as a few kilowatts up to grid-connected applications of 200 MW or more. Solar-thermal electricity is the lowest cost electricity for grid-connected applications available today, and it has the potential for further, significant cost reductions. While not currently competitive for utility applications in the United States, the cost of electricity from STE can be competitive in international and domestic niche applications, where the price of energy is higher. The goal for advanced STE technologies is to be below 5¢/kWh. The U.S. annually uses more than 71 trillion BTUs of solar energy (1 million BTU equals 90 pounds of coal or 8 gallons of gasoline). The residential and commercial sectors use 60 trillion BTUs, the industrial sector 11 trillion BTUs and utilities 500 billion BTUs.

- Ocean thermal energy conversion (OTEC), is an energy technology that converts solar radiation to electric power. OTEC systems use the ocean's natural thermal gradient - the fact that the ocean's layers of water have different temperatures - to drive a power producing cycle. OTEC system can produce a significant amount of power as long as the temperature between the warm surface water and the cold deep water differs by about 20°C (36°F). The oceans are thus a vast renewable resource, with the potential to help us produce 10^{13} of watts of electric power. The economics of energy production has delayed the financing of OTEC plants. However, OTEC is very promising as an alternative energy resource for tropical island communities that rely primarily on imported fuel.

CHAPTER 6

HEDGING TOOLS FOR MANAGING RISKS IN ELECTRICITY MARKETS

Summary: Competition in wholesale restructured electricity markets has created new financial and physical risks which could include price risk, volume risk, counterparty risk, and others. Even though a number of electricity risks are originated from sources that exist in other commodities as well, these sources could pose more severe consequences in electricity markets due to typical differences between electricity and other commodities such as non-storable nature of electricity and transmission flow implications.

In addition, risks associated with electricity markets would need more attention due to the fact that the electricity market, which is more than $200 billion per year, is one of the largest commodity markets in the United States. During the short period that electricity restructuring has undergone, many additional concerns have been magnified which are considered as wake-up calls for restructuring researchers and market participants. These concerns are essential in determining priorities when designing and implementing reliable and adequate hedging tools and hedging strategies for electricity markets.

The market experience in the past short period highlighted the issue of risks, especially the risk of counterparty default (i.e., failure to deliver on contract), implementation of weather-related derivatives in electricity markets, portfolio management, needs for accurate long-dated forward prices, and others. The lack of electricity market participants' experience, especially hedgers', with proper hedging tools for electricity has resulted in large trading errors at some locations in U.S. markets. These errors have occurred due to applying certain pricing models that would not

consider the major differences between electricity and other commodities.

This chapter will discuss hedging issues in a restructured electric power industry. The chapter will present the major challenges for electricity market participants as they become involved in restructuring, give a detailed overview of sources of financial risks that could lead market participants to panic, give an overview of how players of energy markets could use electricity financial derivatives to hedge different risks. It will present the basic hedging tools in electricity markets, new derivatives that are especially created for electricity markets, types and sources of risks, and motive forces that could lead to risks in electricity markets. The chapter will discuss weather-related derivatives. In addition, the Midwest crisis of June 1998 – the unforgettable mark in the U.S. electric industries – will be addressed to exhibit the importance of hedging in electricity markets. It will show various shortcomings in the electricity derivatives pricing model. Moreover, it will present illustrative examples for implementing hedging tools.

6.1 INTRODUCTION

Reshaping of the electric power industry has launched new dimensions in electricity markets. In addition to traditional players, many new competitors have emerged in electricity markets with different strategies that would reflect the competitors' projection of electricity economics and its competitive dynamics. What makes the subject more intriguing is that the competitors have to deal with three separate electricity linked businesses: generation, transmission and distribution. In this environment, a market participant could be forced to deal with both electric energy and non-electric commodities.

The increase in the number of participants and opportunities in restructured electricity markets would make it more difficult for participants to implement hedging strategies that could protect their operations and revenues from emerging risks. The short experience with electricity markets shows the vitality of hedging tools to participants' survival. Supply-demand dynamics, for example, if not hedged in proper ways could cause prices of replacement energy to rise to thousands of dollars per MWh.

Different from other commodities, electricity prices are highly unpredictable and are expected to remain as such in the near future which can be attributed to weather-driven factors, problems with fuel and equipment transportation over long distances, correlations with other commodities, and operational factors in transmission and generation of electricity.

Hedging is described as a large challenge to electricity markets. In electricity markets, hedging strategies differ widely from one participant to other, based on the participant's objectives and market forces that are correlated with that participant's operation. Hedgers and other participants find the problem more sophisticated in electricity markets due to the fact that electricity is a non-storable asset and affected directly by other commodities. A wide range of hedging instruments is getting to be available since the electric power industry is exposed to different types of risks, and participants must understand the nature of complications before deciding on proper hedging tools and strategies.

Different participants in electricity markets, especially investors, are exposed either directly or indirectly to different types of financial fluctuations in foreign exchange rates, interest rates, commodity prices and equity[1] prices. For example a rise of the Canadian dollar may lead to large losses for market participants in the United States that trade energy with Canada.

Price fluctuations present risks and this is one of the motivations that let participants make an effort to hedge risks in order to protect themselves from unexpected changes or events. This is similar to a situation when a person takes out insurance for his car against its exposure to an accident or a theft. Improving or maintaining the competitiveness of an entity is another motivation for hedging the exposure of the entity to financial risks. As in any other industry, power entities interact and exist jointly, and every party would compete with others to reach customers in order to make more profits and to attract investments. Educated personnel, experience and management approach are the main factors that define best strategies to hedge risks. It is conceivable to find two power generating companies with similar

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[1] Equity is the difference between the market value of a property and the amount owed on that property. See: http: //www.coldwellniagara.com/glossary.html.

exposure to fluctuations in the financial market; one would make profits while the other suffers from losses due to completely different policies and hedging strategies.

Participation of financial traders in electricity markets is expected to increase the liquidity of electricity markets and improve market efficiency. Financial traders would predict price changes (volatility) of the electricity, make gains by trading electricity derivatives such as options and futures based on their price projections, and trade their future positions[2] before a contract is expired or delivered. If their price projections are in the right direction, they earn profits and lose otherwise. On the other hand, buyers, sellers and hedgers use these financial instruments to remove price risks and lock in their desired price for the electricity whether or not the market price increases.

Futures and options could provide market players with more flexibility than long-term fixed bilateral contracts. Price risk management instruments are often developed either by a power pool, a security exchange, bilaterally (OTC) or by financial intermediaries. Regardless of the environment where they are formed, these instruments are usually derived from price discoveries in power pools and exchanges.

The Midwest crisis of June 1998 was a shock to restructuring researcher and considered as a wake-up call to them to find proper instruments to hedge risks of creditworthiness of counterparties in electricity markets. This crisis showed how risky *sleeve transactions*[3] were and how they could cause market instability. It also showed that a participant who did not properly hedge its transaction risks could be forced to buy power in hourly markets with very high prices.

This chapter will show numerous examples for using different hedging tools such swap transaction, caps, floors, swaption, swing contracts, and weather-related derivatives. In addition, many other

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[2] Net total of a trader's open contracts in a particular underlying commodity.

[3] Sleeving in electricity markets describes the situation when a participant for a fee (commission) acts as an intermediary between two other participants when one of them has bad credit or does not have creditability that the other requires; in other words, the intermediary takes title to the power on behalf of the two participants and guarantees the performance of the contract when a default occurs.

examples are presented on related issues. The examples are supported with graphical illustrations as required.

6.2 RISK

Risk is the exposure to uncertainty, i.e. the degree of uncertainty of future net returns. A common classification of risks is based on the source of underlying uncertainty. The classifications could include *operational risk*, *market risk*, *liquidity risk*, or *credit risk*. These topics are discussed as follows.

- Operational risk could result from errors made in instructing payments or settling transactions.
- Market risks would represent the potential for changes in the value of a position resulting from market price changes.
- Liquidity risk is a financial risk resulting from a possible loss of liquidity; liquidity risk is reflected in the inability of a firm to fund its illiquid assets. There are two types of liquidity risks: specific liquidity risk and systematic liquidity risk. Specific liquidity risk is the risk that a particular institution would lose liquidity, and this may happen if the institution's credit rating falls or something else happens such that counterparties avoid trading with or lending to the institution. On the other hand, systematic liquidity risk is the risk that the entire market would lose liquidity and this risk affects all participants in a market. Markets have a tendency to lose liquidity during periods of crisis, high volatility or major unpredicted events. Liquidity risk has a tendency to compound other risks and is mostly harmful to institutions that are experiencing financial difficulties with an instant need for cash.
- Credit risk would estimate the potential loss because of the inability of counterparty to meet its obligations, i.e., it is the risk in the counterparty's ability or willingness to meet its contractual obligations. An example of credit risk is the situation of a bank that would make loans to customers. If the customers fail to

make timely principal or interest payments, the bank could face credit risk.

6.3 DEFINITION OF HEDGE

Hedge is a transaction that may consist of cash instruments or derivatives and is used to offset risks associated with certain positions by establishing opposing positions. A hedge could offset an exposure to changes in financial prices of other contracts or business risks. In general, hedge is defined as a position or combination of positions, which could reduce some types of risk. Hedge often indicates partially offsetting a long position in one security with a short or short equivalent position in a related security. An example of a hedge is the purchase or sale of futures contracts to reduce the interest rate risk by offsetting cash market transactions at a later date.

Hedging is the process of reducing uncertainty of future price movements. Hedging is an operation undertaken by a trader or dealer who wishes to protect an open position, especially a sale or a purchase of a commodity, currency, security, etc., that is likely to fluctuate in price over the period that the position remains open. This process could be implemented by a purchase or a sale of derivative securities, such as options, to reduce or neutralize all or part of the risk of holding another security. For example, undertaking forward sales or purchases in the futures market, or taking out an option which would limit the exposure to price fluctuations is regarded as hedging.

Hedger[4] is a participant who would enter the market with the specific intent of protecting an existing or anticipated physical market exposure from unexpected or adverse price fluctuations. For example, a generation company may contract to sell a large quantity of energy for delivery over the next six months. Electricity products would depend on raw materials such as natural gas that could fluctuate in price. If the generation company would not have sufficient raw material in stock, an open position could result. The generation company may hedge the open position by purchasing the required natural gas on a futures contract, and

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[4] For more information on hedgers see section 6.8.

if the company has to be paid for the natural gas in a foreign currency, the company's currency needs could be hedged by other contracts.

Two-way hedge and one-way hedge are hedging contracts which are dependent on the contract's strike price and spot price. In a two-way hedge contract, buyer and seller would agree on a payment from one to the other when the strike price is either higher or lower than the spot price. For example, when a power generating participant would agree with a retailer for a two-way hedge contract, the generating party would pay the retailer the difference between the spot price and the strike price when the spot price would get to be higher than the strike price, and the retailer would pay the generating party when the spot price drops below the strike price. In a one-way hedge, only the generating party would pay the retailer when the spot price is higher than the strike price, and nothing would be paid to generating parties when the opposite occurs. In this type of contract, a retailer would pay an annual fee.

The energy that is traded by means other than hedging contracts would be through the spot price market where the spot price is calculated by balancing supply with demand using a bidding system. Even though the volume of trades in the spot price market is low compared to other types of markets, spot price is usually used as an index to strike price in hedging contracts, and market participants would devote a considerable attention to spot price for redirecting their movements.

Market participants can use insurance packages offered by insurance companies to hedge risks such as hedging the expensive cost of replacement power when an outage takes place, hedging counterparty risks or hedging extreme price spikes due to unexpected weather conditions or due to similar reasons. Weather-related derivatives are implemented in electric industry restructuring as risk hedging tools to hedge risks associated with unpredictable weather conditions. Weather derivatives are the only contracts that offer energy providers a procedure to hedge volumetric risk. As an example, a weather derivative can be used in the form of an options contract with a strike point set at a specified number of degree-days (DDs) or set based on maximum or minimum temperatures. We will discuss this issue later in this chapter.

6.4 SOURCES OF ELECTRICITY MARKET RISKS

6.4.1 Supply Shortage. A supply shortage could cause electricity prices to increase sharply, where a shortage in supply could be created due to unpredicted high temperatures (that could increase the load) or generation outages. When supply is in shortage, market participants would compete to reach scarce resources, utilities would do their best to fulfill native peak load obligations, marketers would try to secure power to avoid defaulting on their contracts with market participants, and suppliers would try to avoid blackouts. These reasons along with pressure from state regulators and politicians are all significant factors that motivate prices to increase sharply in a volatile electricity market.

6.4.2 Defaults. The default of participants could cause traders to doubt the creditworthiness of their counterparties and their ability to deliver the contracted power. A major default may lead to widespread effect and severe price run-up.

In electricity markets, participants could engage in a series of contracts, for example, **A** with **B**, **B** with **C**, **C** with **D** and so on. When **A** (seller) defaults on call options contracts with **B** (i.e., the contract would not be honored by **A,** because **A** has no ability to fulfill the contract if the contract is exercised by **B**), **B** may default on its commitments or contracts with participant C and so on. Cascaded defaults in electricity markets may cause severe losses to some participants, large and unfair rewards to others, bankruptcy and lawsuits, which could damage reputations and decrease the level of trust between market participants. Because **A** (sellers) would not be able to cover the contract, **A** would probably be obligated to pay liquidated damages.

These issues are against competition – the core topic of restructuring. When a chain of defaults would happen, nervousness and fear of more contract defaults could control market operations, which would definitely lead to more run-up in prices. Creditworthiness associated with energy derivatives markets should be one of the priorities for hedging risks in electricity markets. Creditworthiness of counterparties should be rated or classified by approved credit rating agencies or, alternatively, should be regulated by FERC. Participants in electricity market operations should recognize the potential risks and disseminate their resources among available hedging alternatives to increase their chance for survival in this competitive and restructured market.

6.4.3 Transmission Constraints. Another considerable factor in designing hedging strategies is transmission constraints. Under constrained situations, transmission line loading relief and curtailments could cause run-up in prices. In addition, a constrained situation could reduce the ability of transmission providers to transfer power, which in turn could force market participants to request more power from the hourly spot market, and contribute to price spikes. A constrained situation could be caused either by line outages because of weather conditions or by heavily loaded lines. A constrained situation could be tied to the supply-demand balance in a region. When a region would suffer from supply shortages, power will be imported from other regions, which could cause congestion. On the other hand, transmission loading relief actions may require participants to reschedule large sums of power, which could also contribute to price run-ups. The loss of a generating unit could cause participants to contract power from other regions to replace the loss; if the transacted power is not feasible due to line relief actions, increase in price could be expected.

6.4.4 Price Information. Inadequacy in realistic and timely price information is another source of risk in electricity markets, especially at times when markets have major events such as outages of large generation units, defaults and other factors that could cause price spikes. If a participant (buyer) is under pressure to find a replacement power, and does not have any adequate information on what others are paying for power, the participant may get overcharged for its purchase of power. This fact would necessitate price signals in electricity markets to help reduce risks associated with price volatility. See Chapter 7 for more information.

6.4.5 Lack of Experience. Market participants' lack of experience with hedging tools could be another source of risks in electricity markets. Hedging tools would reduce or alleviate risks, while insufficient experience could increase risks. The inexperience may lead participants to pay higher prices than necessary; for example, a successful trader or a buyer who would need energy during the next month could decide either to buy later from the spot market or to sign a bilateral contract now. Success would only be guaranteed by good experience in applying hedging tools and in future market movements. Another point to be highlighted in this regard is that market participants should understand the terms of their contracts, such as ensuring that their contracts have liquidated damages provisions in case of defaults by counterparties, curtailment provisions for firm transactions, and the price of emergency power to prevent counterparties from taking advantage of the emergency situation to manipulate the market and increase prices sharply.

6.5 VALUE-at-RISK (VaR)

A reliable hedging strategy is not the one that would hedge the exposure of an individual risk, but the one that is designed based on a comprehensive analysis of various risks in a portfolio. For example, entering a futures contract may reduce the impact of a particular risk on a portfolio or aggravate the impact on the portfolio; this could happen because the futures contract would be related to other positions or contracts in the portfolio[5].

Before designing hedging strategies to manage exposures to risks, a participant should *identify* exposures to several risk factors and *quantify* these exposures. The next step is to analyze interactions among these exposures. A participant has to *define* which exposures contribute to the risk and which exposures have *positive impacts* on its portfolio. Building hedging strategies is based on certain measures. The main measure is called *Value-at-Risk* (VaR).

VaR is a number (an estimate) that tells a market participant, due to market movements, how much its portfolio or position may lose in a particular time period (horizon) for a given probability of occurrence. The given probability is called *confidence level*, which represents the degree of certainty of the VaR estimate. The common value of confidence level is 0.95 (or 95%) which means that 95% of the time the

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[5] Value at Risk for Energy, http ://www.commodities-now.com/online/dec98/var.html

participant's losses will be less than VaR, and 5% of the time the losses will be more than VaR. Figure 6.1 shows the idea of confidence level. Using VaR would enable participants to minimize the variability in their revenues. VaR is also a decision tool that tells the participant which risk is worth taking and to what extent each risk should be hedged. In addition, VaR gives a participant the diversification benefits for having different positions in the portfolio.

Example 6.1

(a) Horizon: one week

Confidence level: 95%

VaR: $1 M

Explanation:

1-0.95 = 0.05 = 5/100=1/20

This means that losses in excess of $1 M will occur about once in every 20 weeks.

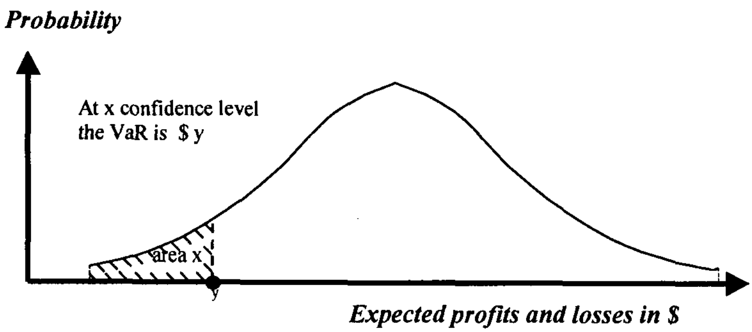

Figure 6.1 Illustration of Value-at-Risk and Confidence Level

(b) Horizon: one day

Confidence level: 96 %

VaR: \$1 M

Explanation:

1-0.96 = 0.04 = 1/25

This means that losses in excess of \$1 M will occur about once in every 25 days.

Example 6.2

If a portfolio's 1-week, 95% value at risk is \$2 M, then the portfolio would be expected to lose less than \$2 M over 95 weeks out of 100. This estimate is based upon the portfolio's current structure and recent market conditions.

Various methods for calculating VaR include: Closed form VaR, Monte Carlo VaR, Historical VaR and Delta-gamma VaR. Each methodology has its own strengths and weaknesses. Value at risk is sometimes referred to as capital at risk, earnings at risk or dollars at risk.

6.6 COUNTERPARTY RISK (The Midwest Case)

Exposure to the risk of fluctuating prices in electricity markets would necessitate adequate and reliable hedging tools. Financial exposure should be quantified and trading parties should own tools for credit checks and strategies to reduce the counterparty risk. A reliable and stable electricity market would have credit requirements to directly address the counterparty risk.

Before restructuring, electricity was traded between large utilities in a bilateral form, i.e., buyers and sellers were usually located in the same geographical region, trading was largely regulated and price behavior was steady. However, under restructuring, a large number of non-utility power marketers have entered the electricity market and unregulated trading is an acceptable mode. In addition, trading is not restricted to a specific geographical region but extended to include many geographical markets. As a result, credit risk concerns are raised now. Traditionally, credit risks have been addressed using corporate/parent guarantees or letters of credit.

Due to price volatility in electricity markets, bilateral power trading would have a higher chance of unexpected financial losses. Defaults in electricity markets could leave a wide impact on many if not all market participants. A stable power market is a market that would not be affected by a default or series of defaults. In the California PX (CalPX), the risk of default is pooled over the entire exchange.

To hedge a market participant from a counterparty risk, the market may:

- require each participant to place a security deposit for covering a possible default
- observe trading activities to ensure that the exposure would not exceed a participant's deposit.

The example is the case in the CalPX, where the pool is the counterparty for both buyers and sellers. When a security deposit is not adequate to cover losses from a default, the PX distributes uncovered losses among all participants over an entire month's trading volume. That means the risk of default is pooled among its participants. The CalPX would provide the electricity market with a stabilizing effect, by creating a liquid market, where prices would not be considerably affected by transient events. This market would have,

- a wide range of participants from all states,
- high volume and binding credit requirements,
- a one-time single-price auction.

In the next section, we will discuss the disaster that happened in the Midwest and the Eastern power markets, in June 1998, where wholesale prices increased to an unpredicted level of more than $7,000/MWh. The default caused a sequence of events that reached many regions throughout the North America through trading operations of power marketers. The event of Midwest resulted in price spikes in the Western market when a power marketing firm could not cover its contracts, and a few electricity traders incurred losses in hundreds of millions of dollars.

Analyzing this event is important for entities that seek hedging strategies. The event highlights some major factors that lead to extreme price spikes in electricity markets and shows how a default would be transferred from a regional market to other markets. The losses attributed to this event urged counterparty risk evaluations in many parts of the United States. In these series of events it was reported that energy prices at the CalPX were kept stable.

6.6.1 What Did Happen in the Midwest? In the fall of 1997, Federal – a small marketer – had sold many call options to other market participants. In the period of 22-24 June 1998, more than 20 Midwestern and Canadian nuclear and coal units were down either due to planned maintenance/ returning to service later than expected or due to forced outages caused by storm. In this period, unexpected hot weather hit the Midwest and the Eastern United States. As a result, load demand was higher than the level of all available generation. During this period, prices in the Into Cinergy[6] hub rose to a range of \$290/MWh to \$550/MWh.

Some market participants had previously bought call options for energy at low prices around \$50/MWh, and when prices rose to much higher levels those parties were exercising their options contracts to meet their needs. Unfortunately, some of the sellers did not meet their contract obligations by not providing physical capacity or by generation contracts to other parties. As a result, Federal – a sellers of options – defaulted with a buyer (FirstEnergy).

In an electricity market, if market participant **A** is seen to be undercapitalized and exposed to counterparty risk, participant **B** would not be willing to deal with **A** directly. Instead, **B** would deal with a middleman **C** that would have a strong generation availability and financial reputation and would accept to make a deal with **A**. In other words, **B** would buy contracts from **C** where **C** would earn a margin on the transaction. This process is defined as *sleeving*[7], where **C** would accept to take a position (such as call options) on contracts that would

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[6] Into Cinergy is a trading area in Ohio and Indiana where traders can make futures contracts.

[7] See footnote on sleeving in Section 6.1.

not be supported by physical capacity. In the case of the Midwest, **A** represented Federal, **B** represented FirstEnergy and **C** represented Springfield.

On June 25, prices hit the limit of $1500/MWh due to an unfortunate and unexpectedly loss of a nuclear unit of FirstEnergy caused by tornado damage. When the default news spread, some participants who were expecting prices to increase to much higher levels, rushed to buy as much power as they could, and what made the situation worse was that Springfield announced that it would not perform on the options that it had sleeved for Federal, which led prices to increase sharply to $7,500/MWh in real-time trading and $4,900/MWh for pre-scheduled power.

In this process, many entities were severely affected. Many factors accumulated and caused wholesale prices for electric energy to run-up in several Midwestern states for the three-day period where hourly spot prices of electricity jumped from an average of ≈$30/MWh to more than $7,000/MWh. The severe price spikes caused several utilities to lose tens of millions of dollars on replacement power in order to keep their reputation during those hot days. During this crisis, customers were unaffected by price run-up due to the fact that retail rates were regulated in the Midwestern states. Without any rate regulation, a small customer or a family would have paid thousands of dollars for electricity on those three days. This crisis was a lesson on how vital hedging strategies are and how much a major event in electricity market could impose severe consequences on participants.

6.6.2 Factor Contributing to Counterparty Risk. Experts in the electric power industry have agreed-upon several factors that contributed to the Midwest crisis. These factors are *weather*, *insufficient generation*, *insufficient transmission*, and *inexperience*. The first two factors are not related to restructuring (i.e., might happen without restructuring), and the others are related to restructuring practices. Understanding the effect of these factors on restructuring would clarify the importance of hedging strategies and provide guidance on how and when the best strategies should be implemented. The contribution of each factor is detailed in the following:

(1) Weather: Unseasonably high temperatures, that accompanied the heat wave in late June 1998, caused people to stay inside and turn on their air conditioners, which increased the demand beyond forecast.

(2) Insufficient Generation: Scarcity in generated power could occur at inconvenient times due to equipment forced outages. Forced outage of a number of generating plants could cause cascaded price spikes in electricity markets.

(3) Insufficient Transmission: Transmission constraints, caused by congestion or insufficient transmission facilities, could cause price increases when power cannot be transmitted into areas with generation shortages. As restructuring proceeds, the transmission problem could be resolved by additional investments in the transmission grid. Outages in transmission facilities with high traffic are also expected to cause price spikes. Planned outages, if not scheduled properly, may also lead to similar impacts.

(4) Inexperience: One of the main reasons for price spikes would be the lack of experience of market participants, especially traders, with electricity market conditions. Participants may lack necessary resources and experience to protect their consumers, when power marketers default on their obligations. In the summer of 1998, defaults on power sales led to unusual short-term trades which caused severe pressures on electricity markets and severely impacted those power companies that were relying on defaulting trading companies. Federal Energy Sales (Ohio), Power Company of America (Connecticut) and the city of Springfield (Illinois) defaulted on supply contracts because of the price explosion.

6.6.3 Managing Counterparty Risk. Responding to the Midwest crisis, FERC issued a report that discussed factors resulting in the Midwest states' events and highlighted various strategies and tools to manage risks in power markets. The report pointed out that the following risk management tools are essential for wholesale trading in restructured power markets:

(1) Over-the-counter (OTC) options: most commonly used hedging tools.

(2) Futures trading: commodities ex-changes offering futures for electricity, including contracts sponsored by NYMEX, CBOT, and the Minneapolis Grain Exchange.

(3) Insurance: new policies for traders help reduce risk by protecting against the expensive cost of replacement power in the event of generating unit outages, managing counter party risks and protecting against extreme price fluctuations.

(4) Weather-related derivatives: a small number of trading companies offer contracts based on a certain number of degree-days[8] or maximum/ minimum temperatures.

Electricity price spikes and supply shortages in the Midwest in late June, 1998 served as a reminder to restructuring participants that restructuring would necessitate effective risk-management strategies. One way of hedging against the Midwest situation is to increase the supply, which may take a while to study and implement. In addition, maintenance decisions should not be based on old power plant operation models, and economics of maintenance decisions should not be the only factors to be taken into account. Since replacing the lost power during price spikes or peak periods is an expensive option, the volatility of electricity markets would necessitate the operation of power plants with more reliable information in real-time and adequate knowledge in projecting future prices. As we discussed, an unplanned outage is a critical factor in price, which would necessitate hedging against forced outages. To do that, market participants may use OTC derivatives to offer call options that would guarantee backup power at a reasonable price in the case of outages. Other alternatives would include issuing weather-outage-based derivatives with payment or power replacement when high temperatures and unit outages occur.

6.6.4 CalPX and Counterparty Risk. The CalPX stands as a one-time, single-price auction when participants submit bids for loads and generation for the day-ahead market. Bilateral trading for the next-day power is conducted over several hours each morning in small transactions that are sensitive to fluctuations in demand or supply. In a

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[8] See Section 6.9.

bilateral transaction, if **A** buys from **B**, then **B** is the counterparty of **A**, while if **A** buys from a pool, the pool is the counterparty of **A**. In other words, all buyers and sellers dealing with the pool are the counterparty of **A**, and if any default happens by an individual party who is unable to cover its default by security deposits, the risk of default is spread among pool participants. The California's PX requires all participants to post a security deposit - a corporate or a parent guarantee qualifies for the CalPX Approved Credit Rating - that would cover the expected level of business with the PX through one billing cycle including the lag time between close of the month and the time when payment is due. If a CalPX's participant does not qualify for an Approved Credit Rating, the participant must post a security deposit in the form of *letter of credit* issued by a bank, a *security bond* issued by an insurance company or a *cash deposit* in an escrow account. In the CalPX, if the buyer's default is not fully covered by the required security deposit, the resulting liability would be spread across all participants, over all MWh traded in the billing cycle in which the default occurred.

Example 6.3

Assume that the average daily volume of energy in the CalPX is 500,000 MWh and the CalPX's average price is \$20/MWh. Also, the period that would cover transactions for the billing month plus those incurred during the following month prior to when cash payment would be received is 46 days.

The default situation: Participant **A** is a buyer of 500 MW from the CalPX. Let's assume that **A** has default with liabilities of 10% in excess of its security deposit.

Calculations: Monthly volume of energy traded in PX is

$$(500{,}000 \text{ MWh/day}) \times (30 \text{ day}) = 15{,}000{,}000 \text{ MWh}.$$

Buyer's security deposit is:

$$(500 \text{ MW/day}) \times (24 \text{ hours}) \times (46 \text{ day}) \times (\$20/\text{MWh}) = \$11{,}040{,}000.$$

The participant **A** has default with liabilities of (10%) × (\$11,040,000) = \$1,104,000 in the whole period. Sellers would bear a reduction of \$1,104,000/15,000,000 = \$0.0736/MWh.

On a daily basis, the CalPX would observe trading operations of its participants by comparing each participant's cumulative 46-day trading operation with the security deposit and notify the participant if the cumulative value has reached 80% of the security deposit. In this case, a participant should increase its deposit within one day if it would desire to trade at or above the level of its secured exposure. The CalPX would not permit a participant to trade once its cumulative exposure is equivalent to its security deposit.

The price in a pool is a reliable indicator that would measure the impact of forces that could influence supply and demand convergence. We could record that the effects of many forces on the competitive price of electricity would help market participants create proper financial instruments for hedging price risks, make financial investment, take optimal marketing decisions, and understand and compare prices for bilateral contracts (OTC trades) against pool prices. To fulfill this, the pool should implement liquidity, have a standardized unit of trade, a delivery period, a specified quality and locations of delivery and receipt. These specifications would in turn help market participants hedge price risks using electricity derivatives such as futures and options.

Small participants, who could not withstand price risks in bilateral trading, might hedge price risk by participation in a pool. In California, the PX would reduce the risk of delivery default for buyers and the payment default for sellers, which would hedge price risks for new and small participants. In the case of delivery default, the PX would stand as an alternative supply; in the case of payment default, the liability would be pooled.

6.6.5 Lessons Learned in Risk Management. From this discussion we learn the following lessons:

- Defaults are caused by either a failure to physically deliver power on existing contracts or a failure to pay for supplied power. The Midwest event was caused by the first type.
- Taking a position on contracts (such as call options) that would not be supported by physical generation or dealing with undercapitalized participants is a risky practice and could harm the reputation of a participant if contracts would not be honored. Default in a certain

region by a participant could transfer and cause secondary effects in other regions.

- During market defaults, participants might sustain severe trading losses or large trading profits. This depends on their understanding of what would happen after default.
- Exercising market power is a concern during a default.
- Defaults are highly expected at times of extreme loads or forced outages.
- Counterparty risk is more eminent in bilateral-based trading than pool-based trading.
- Credit policies and instruments should be re-evaluated by different participants, especially marketers to take into consideration the risk associated with a seller's failure to deliver and the resulting cost of replacement power.

As restructuring would reach maturity, market conditions should be qualified to reduce the possibility of severe price fluctuations and its impact on market players. To reach this level, considerations should be given to adequate administration or control, encouraging more investments in generation capacity and transmission facilities, and implementing reliable hedging strategies. For example, main interfaces or transmission facilities that would usually be congested every summer or located in critical periods should be given more consideration to improve their capabilities, and consideration should be initiated before the major spikes re-occur. Nobody could guarantee that similar price spikes would not re-occur, especially when some of the conditions that led to the Midwest price spikes are to be present during the next several years until restructuring would reach maturity and some factors such as unexpected weather conditions and unplanned outages could occur at any time.

One way of hedging risks in electricity markets is that a participant would have *diversified supply portfolios*; in other words, a participant should not depend on a single supplier and should consider several providers in different locations. This is to guarantee that the loss of suppliers would not force a participant to buy replacement power in large quantities from hourly markets, and to facilitate additional power transfers when a supplier's transaction would be curtailed or constrained due to outages.

One other option for hedging the risks of price spikes is *involving retail customers in mitigating risks* by adjusting their power usage in peak times. If customers could obtain the information on real-time price signals, they could respond accordingly by modifying their consumption profile at times. This would be done by implementing proper demand side management procedures, such as interrupting the consumption based on contractual agreements between customers and providers, or requesting large retail customers and certain industrial customers to sell their firm power back to their providers when loads are at their peak or in emergency conditions.

6.7 THE GREEKS[9]

Derivative instruments could provide many risk exposures based on time and market movements. In order to select and adjust hedging strategies in an optimal manner or to enter new positions, it is necessary to know specific exposures to each source of risk in the market. Correspondingly, the Greek letters: Delta, Gamma, Theta, Vega and Rho are used for representing various sensitivities of derivatives.

The Greeks are sensitivities that analyze exposures of a portfolio or a position; for example if a portfolio is composed of many positions, then it will have a delta for each position. The market variables that have impact on the Greeks are time, implied volatility and the position of the *underlier*[10] in relation to strike prices. The Greeks are used by derivative traders to hedge their positions. A perfectly hedged position is the one for which all the Greeks – with the possible exception of theta – are zero. Hedging a derivatives position would be possible by maintaining the Greeks within reasonable bounds and obtaining a balance or trade-off between their respective exposures.

[9] http://www.contingencyanalysis.com/

[10] Underlier is a delivery-settled derivative instrument or commodity which is delivered under the contract. For example, if a futures contract requires the future delivery of 100 MWh of energy, then the underlier is energy.

Delta and Gamma would measure *changes in the value of an underlier*. Changes in the value of an underlier are a main source of risk in portfolios. Delta is the first-order measure of sensitivity to an underlier and Gamma is the second-order measure of sensitivity to an underlier. Delta captures the magnitude and direction of a portfolio's sensitivity to the underlier and Gamma is a measure of convexity, i.e., Gamma would capture the curvature's direction (downward or upward) and magnitude of a position or a portfolio. When Gamma is positive, the curvature would open upward and a negative Gamma means that a curvature would open downward. It illustrates how quickly a portfolio or a position becomes unhedged when the underlier would change. For an option, Gamma is the change in an option's delta for a one-point change in the price of the underlier, or gamma is the delta of delta. The gamma of a long calls or puts option position is always positive - the delta increases as the underlying price increases and falls as the underlying price falls. For an option, Delta is a measure of how sensitive an option's price is to changes in the underlying, for that reason Delta is useful as a hedge ratio.

Example 6.4

A futures option that has a Delta of 0.5 implies that the option price increases 0.5 for every 1 point increase in the futures price. For small changes in the futures price, the option works as one-half of a futures contract. Constructing a Delta hedge for a long position in 10 calls, each with a Delta of 0.5 would require selling 5 futures contracts.

To illustrate the meaning of the Greek variables Delta, consider Figure 6.2 which shows a relationship between the value of portfolio and the underlier. The slope of the curve at any value of underlier is the Delta at this value, which tells us whether the portfolio value increases or decreases with an increase in the underlier. At the value 105 of the underlier, the portfolio Delta (slope) is 0.0714, which means an increase of $0.0714 M in the portfolio value for each unit increase in the underlier. So, the Delta captures the magnitude and direction of a portfolio's sensitivity to the underlier. For this portfolio (see Figure 6.2), the Gamma is negative (curvature opens downward).

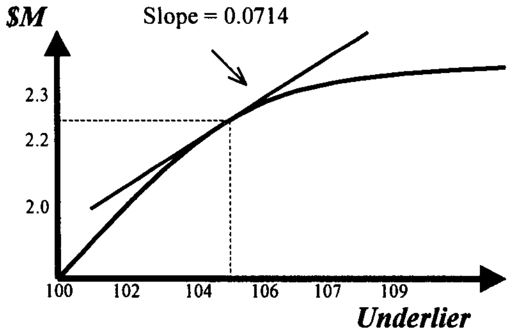


Figure 6.2 Relationship between the Value of Portfolio and the Underlier

Example 6.5

Suppose that a GenCo's portfolio is exposed to the NYMEX futures contract and has the NYMEX futures Delta of 1.0 million, this means that the portfolio will gain about \$1 M if the futures price rises \$1, and lose \$1 M if the futures price falls \$1.

Vega is a price or sensitivity of a derivative or portfolio to implied volatility and usually is used in hedging instruments which entail optimality as in the case of put options, call options, caps and others. For an option, Vega represents the change in the value of an option for a 1 percentage point increase in implied volatility. The Vega of a long calls or puts option position is always positive. Figure 6.3 gives the response of call option's price to changes in implied volatility. The option's Vega in this figure is 0.0333.

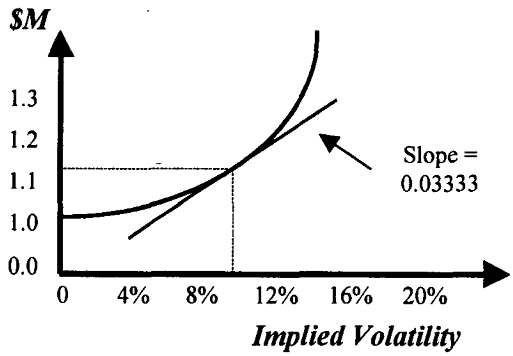


Figure 6.3 Relationship between Value of Portfolio and Implied Volatility

Rho measures sensitivity to interest rates, where interest rates affect the price of a derivative instrument – today's price of a derivative should be the discounted mean of its future cash flows, and interest rate would determine the rate at which discounting is performed. Rho is also a linear risk measure that represents the slope of a tangent line to the portfolio's price as a function of interest rates.

6.8 RISK EVALUATION IN ELECTRICITY TRADING

Derivatives can be used in electricity trading by two different approaches: a trader can *hedge* by off-loading risk or a trader can *speculate* by taking on risk. *Hedging* is locking in prices to control exposure to volatile markets for risk management or revenue loss minimization. On the other hand, *speculation* is venturing (gambling) for one objective that is increasing the profit by anticipating market movements.

In general, traders of derivatives (forward contracts, future contracts, options and others) may be classified as *hedgers, arbitrageurs and speculators:*

- ***Hedgers*** would look into reducing a presumed price risk, i.e., they are interested in eliminating the exposure to changes in the price of an asset. To do that, hedgers would use derivatives to reduce the risk or alleviate it totally. Most derivatives used for hedging are zero-sum games, i.e., for each winner, there would be a loser, and what is won by someone would be lost by another. For example, when market participant **A** sells a future with a loss of $100 to participant **B**, participant **B** gains $100.

- ***Arbitrageurs*** would look into a riskless profit by entering simultaneously into two or more markets that have contrariety in prices. The futures price and spot price should converge on the delivery date to totally hedge the risk in price movements. The main risk that would accompany futures is the difference between futures price and the spot price at the delivery date. This difference is called *basis* and the risk associated with basis is called *basis risk*. Factors that may lead to occurrence of basis are differences in time, location, or quality of the commodity. If a basis could exist, an arbitrageur would secure its profit; for example, if the energy futures price was $11/MWh, but spot price was $8 near the delivery date, then an arbitrageur would buy electricity in the spot market for $8/MWh, sell a futures contract for $11/MWh and guarantee a $3/MWh profit. When the demand in the spot market of energy would increase, the spot price could go up, and when futures contracts to be sold increase, the price of futures could drop and cause the two prices to converge. However, the two prices may not converge due to complications in energy delivery. Basis risk may also occur as a result of transmission line constraints and differences in transmission costs.

- ***Speculators*** would take a position in the market by gambling (betting) on the price of an asset. Speculators use derivatives in their speculations to reduce the risk of price movements. GenCo, DisCo, customers, marketers or brokers may speculate using futures contracts to make a profit. If any of these market participants expects that the energy spot price would rise, it would buy energy futures and if the opposite is expected, the participants would sell energy futures. For example, if a marketer expects an increase in spot price, it would receive the future spot price when it sells a futures contract to close out its position and would pay a lower price for the futures contract that was originally bought. See Figure 6.4.

Risk may also appear when an entity over-estimates the amount of energy that it generates or consumes. Suppose that a GenCo was expecting to have an excess of 500 MWh in three months, so it would sell a futures contract for this amount at $12/MWh. When the delivery time came, the GenCo discovered that it would need the excess generation to serve its own customers due to an increase in demand or a forced outage of a large plant. In this situation, the GenCo would be speculating in the energy futures market. The GenCo would lose money if the price of electricity increases and make money if the price of electricity decreases.

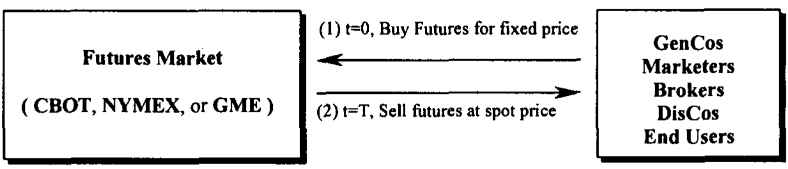
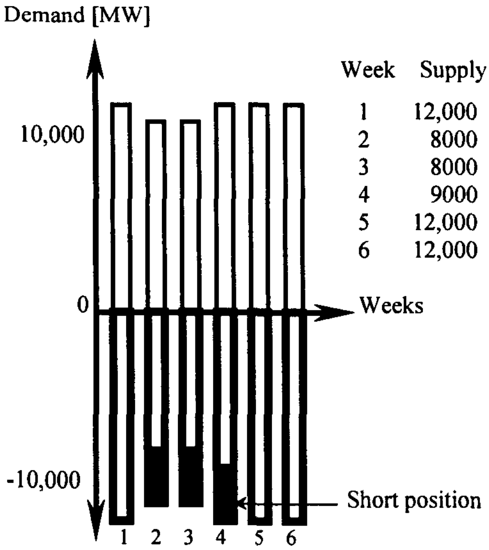


Figure 6.4 Speculation using Futures Contracts

Example 6.6

Let's assume that a portfolio manager of a GenCo has the portfolio shown in Figure 6.5. The portfolio has the net short positions in second, third and fourth weeks as shown in the figure. The manager has three alternatives: keep the short position (sell contracts), take a long position (buy contracts) or close the position (buy contracts to balance the supply and the demand.)



Week	Supply	Demand	Net	Position
1	12,000	12,000	0	closed
2	8000	11,000	-3,000	short
3	8000	11,000	-3,000	short
4	9000	12,000	-3,000	short
5	12,000	12,000	0	closed
6	12,000	12,000	0	closed

Figure 6.5 *A Portfolio of Six Weeks*

Alternative strategies:

- The portfolio manager was speculating on price increase and entered a purchase contract of 300 MWh/Week (flat) for the three weeks at a price of \$20/MWh.
- The portfolio manager was speculating on price decrease and decided to take a short position (no change).

Suppose that the average energy price of the three weeks turned out to be \$23/MWh, what is the outcome of each strategy?

For the first alternative, the manager chose to enter the contract, alleviate the risk and secure a level of profit equal to \$27,000 (or 3000 MWh/Week)× (3 weeks)× (\$23/MWh-\$20/MWh).

For the second alternative, the manager chose to maintain a net short position, so the GenCo would lose \$27,000 on this individual position.

Comment: Choosing one of the two alternatives should not be based on a hunch or personal feeling, but on analytical tools and price forecast models that could predict the future condition to a large extent.

6.8.1 Swap Transaction as a Hedging Instrument. One of the simplest and most common instruments in designing hedging strategies for electricity price risks would be a swap. A swap can be used to hedge the risk of spot price fluctuations. It is a financial and negotiable OTC tool in which two participants (with different expectations about the direction of price movements) would agree to exchange (swap)[11] a certain price risk exposures over a pre-determined period of time; in other words, swap is an exchange of cash flows.

Swap transactions are classified as short-term and long-term transactions, where the first one would be valid from one month to six months and the second one for a period from six months to many years.

[11] ***Swaption*** is an option on a swap that gives a participant the option to either increase or decrease the period of the swap or gives a participant the option to either increase or decrease the volume of the swap. Swaptions give more certainty to the market and reduce the price volatility of the option.

The two counterparties would agree to pay each other the difference between an agreed-upon fixed price and a specified fluctuating price index that would follow the volatility of the market during the period covered by their agreement. The fixed price is usually the average market price. Any of Dow Jones Indexes, Index of McGraw-Hill's Power Markets Week, Indices of NYMEX or others can be used as a price index in a swap transaction. When the index price is greater than the agreed-upon price, the seller pays the buyer; otherwise the buyer pays the seller.

Swap transactions are costless (do not need any up-front payment) and not standardized, but participants can customize their contractual terms to meet their particular needs. Through this contract a participant could swap exposure to floating prices in return for an agreed-upon fixed price. Swap contracts would include terms that refer to fixed price, settlement period and a floating price reference, where the fixed price may differ in each time step of this period, and the amount of electricity (volume in MW) in each time step of the period is covered by the contract. The quantity to be hedged is chosen by the two participants involved in the swap transaction.

The majority of swap transactions would involve an exchange of periodic payments between two participants, in which one of them would pay a fixed price and the other would pay a variable price. When participant **A** owns a swap contract with participant **B** for hedging a price risk, the swap contract would enable **A** to isolate himself from price risks. Here, **A** would pay the agreed-upon fixed price and receive the floating price. When combined with customer's floating payments, the financial contract could convert an unpredictable cost to a known fixed amount.

Under a swap transaction, the settlement would be in cash against an agreed-upon market price index, and the notional[12] quantities of power would not be exchanged. A buyer of a swap would make profit when prices increase above a fixed payment level, and lose when prices decrease below a fixed payment level. An important note here is that the

[12] The notional quantity (amount) for a derivative instrument is the quantity of the underlier to which the contract applies. For example, a futures contract on 500 MWh of electricity has a notional amount of 500 MWh.

contracted parties can customize their terms in order to have a provision for credit risk or the risk of counterparty default.

Swap-based tools are useful for both power suppliers and consumers. A supplier that would use swaps coupled with a physical position could lock in the specific price for the product it would sell, and a customer could use swaps to lock in the specific price for the product it would purchase. Locking in prices would be the main idea by which suppliers and consumers would acquire more control over variable revenues and costs in their businesses.

An electricity supplier who would fear the instability in its revenue, which depends on volatile fuel markets, could use swaps to attain revenue stability. Also, a customer who would fear an increase in energy prices could enter into swap transactions to hedge expected high prices. Figure 6.6 shows cash flows of a swap transaction in electricity market.

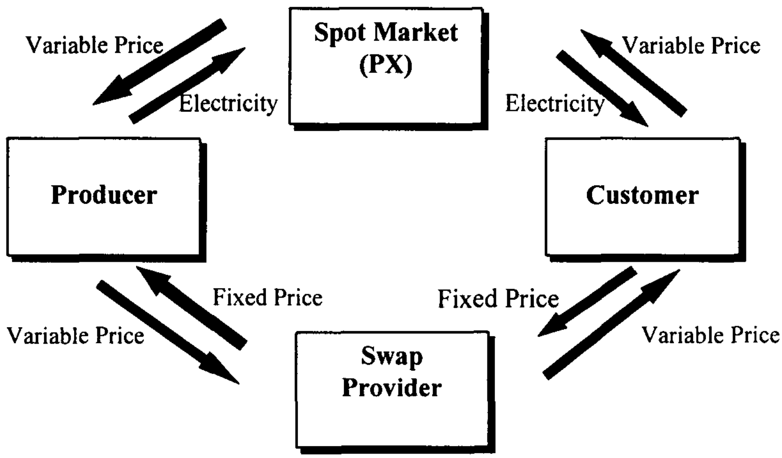


Figure 6.6 Cash Flows of a Swap Transaction in Electricity Market

Example 6.7

Consider a large customer that has a constant demand for 100 MWh of energy per month and is concerned with volatile electricity prices. The customer would enter into a three-year electricity swap with a marketer (an intermediary, a swap dealer, a swap provider or market maker). The current spot price of electricity is \$20.0/MWh. The customer would agree to make monthly payments of \$20.2/MWh to the marketer.

The notional principal is 100 MWh. The marketer would agree to pay the customer the average daily price of electricity during the preceding months. Figure 6.7 shows the situation. Remember that in a swap transaction, no exchange of physical electricity would take place between counterparties. The customer has reduced (not eliminated) its exposure to volatile electricity prices based on a difference between the spot price and the average spot price in the market. The customer would pay the spot price and receive the last month's average spot price from the marketer. It would also pay the marketer \$20.2/MWh over the life of the contract.

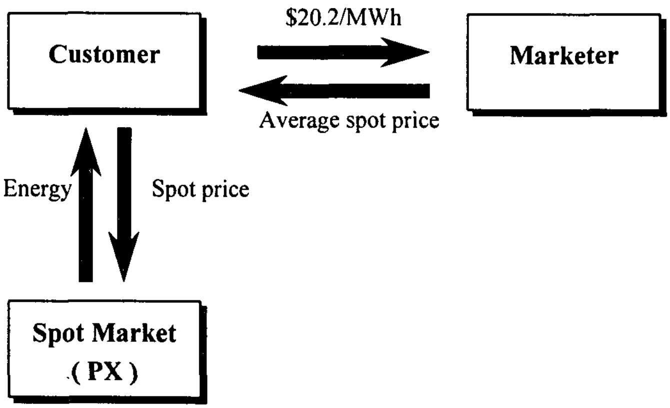


***Figure 6.7** Illustration of Example 6.7*

6.8.2 Additional Hedging Tools.

- ***Spread*** is used by a participant who would simultaneously buy and sell options or futures in the same market (electricity) or another related market (such as natural gas) in order to make profits from price differential between contracts. Furthermore, when there is a seasonal variation in demand for electricity, the participant would buy a contract in the expiration of a futures contract while selling a contract in a different expiration.
- ***Caps* and *floors*** are other hedging tools that would be used in energy markets against price risk. A cap would set an upper limit on price (ceiling price or maximum price) to protect an electricity consumer against rising prices and, at the same time, allow him to benefit from falling prices. On the other hand, a floor would set a lower limit on price to protect an electricity suppliers against price declines and, at the same time, allow him to benefit from price increases.
- ***Swing contract***[13] (take-or-pay contract, or variable base-load factor contract) is a contract in which a participant would have the option to change (swing) the contracted amount to a new amount, for a limited number of times. In a swing contract, buyers of electric energy would be inclined to have extra flexibility for an additional amount of electricity over the contracted load, which may be needed on a certain number of delivery dates (these dates may not be exactly known). The change may be required because of demand fluctuations which could be due to weather or spot price changes.
- ***Collar*** is a supply contract between a buyer and a seller of electricity, whereby the buyer is assured that he would not have to pay more than a maximum price, and the seller is assured of receiving a minimum price.

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[13] http: //www.fea.com/fea_cons_ed/papers/swing_art.htm.

Example 6.8: (Using an option collar as a hedging tool)[14]

Suppose that a participant (purchaser of electric energy) would be interested in capping future rising prices. The participant may use a call option to limit (cap) the increase, but if the cost (premium) of this option is larger than the level that the participant is willing to pay, then the participant may use an option collar as a hedging strategy.

For this situation, suppose that a distribution company (DisCo) has a 40 MW base load during on-peak hours of on-peak days. Assume that on May 15, 1999, DisCo would desire to cap the increase in electricity prices for July 1999. As a hedging strategy, DisCo would buy a COB call options from participant $\mathbf{P_1}$ (DisCo would pay a premium to $\mathbf{P_1}$) and simultaneously sell a COB put options to participant $\mathbf{P_2}$ ($\mathbf{P_2}$ would pay a premium to DisCo) with the same expiration. The call option would cap the price of the electricity for DisCo, while the income from the sale of the put option would reduce the premium.

For a 40 MW on-peak day, DisCo will need 14,720 MWh in July 1999, a month with 23 on-peak days (40 MW × 16 hours/day × 23 days). The 14,720 MWh is equivalent to 20 futures contracts (14,720 MWh / 736 MWh)[15]. DisCo can create a collar for July by buying 20 July COB calls and selling 20 July COB puts.

On May 15, DisCo would buy the $28/MWh July COB call at a premium of $2.5/MWh and sell the $22/MWh July COB put at a premium of $2.00/MWh. Also assume that on June 27, July COB futures is traded at $33/MWh, July COB calls at $5.0/MWh and puts expire valueless. The calculations are summarized in Table 6.1.

The results in the table show that using the collar would reduce the premium (the cost of protection) from $36,800 to $7,360 ($2.50/MWh to $0.5/MWh or (7360/(20×736)=$0.5/MWh). The call alone would limit the DisCo's upward price exposure at $30.50 ($28/MWh +$2.50/MWh), but the collar would reduce that to $28.50/MWh ($30.50/MWh - $2.00/MWh). The DisCo would obtain a higher margin of protection for less net premium.

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[14] CBOT Electricity Futures and Options, http://www.cbot.com/.

[15] Remember that the size of one NYMEX futures contracts is 736 MWh.

Table 6.1 Summary of the Results of the Example

Time	Cash	Result in $	Options	Results in $
May 15			Buy 20 $28/MWh July COB puts at $2.50/MWh premium	20 × 736 × 2.5 = - $36,800
			Sell 20 $22/MWh July COB puts at $2.00/MWh Premium	20 × 736 × 2.00= $29,440
			Net Premium Paid	- $ 7,360
June 27	Buy 14,720 MWh at $33/MWh	14,720 ×33 = $ 485,760	Sell 20 $28/MWh July COB calls at $5.0/MWh	20 × 736 × 5 = $ 73,600
			Option Gain	$66,240
Cash cost		$ 485,760		
Option gain		$ 66,240		
Net Cost		$ 419,520		
Net Price	$419,520/(14,720 MWh) = $28.5/MWh			

6.9 HEDGING WEATHER RISKS

The changing weather could cause changes in cash flows and earnings of various electricity market participants, where changes are uncertain and sometimes totally unexpected events could take place. The uncertainty or volatility in weather conditions could cause financial uncertainties for participants; this uncertainty is referred to as the weather risk. Weather risk is a business risk caused by temperature volatility which could cause every day uncertainty in cash flows, expenses and earnings faced by electricity business; in other words weather volatility could create volatility in expenses and revenues.

In a regulated monopoly, electric utilities would adjust energy rates that are imposed on customers when weather changes would increase the utility's costs. But this philosophy is no more working or acceptable in a restructured environment, where a customer's choice is supported. Here, a buyer would choose the supplier from many alternatives and the price is a main factor in this process. This evolution would necessitate new techniques for hedging weather risks. Instead of transferring the extra costs stemming from weather changes to customers, hedging approaches should transfer the risks and associated costs to counterparties. Consideration of weather risks is an important task in the competition for electricity business, i.e., reasonable revenues and smaller volatility in earnings.

It is expected that the cost of weather hedging products would be low as compared with that of other commodities. Another advantage is that customized weather hedging tools or indices could be built based on an individual customer's needs. Weather hedging is the only means of managing the volume risk in electricity markets. Weather hedging is also described as reliable, safe and fair, since weather data is accurate and more objectively collected than that of any other major commodity or financial index. Official weather data for many years is provided by government sources.

Electricity market players should have a position in weather changes during their trades or transactions. Weather derivatives should be integrated with other derivatives in order to totally hedge risks in electricity markets. Here, it is not required to predict the weather very accurately in order to protect a business from weather risk, rather the aim is to find counterparties who would be able to absorb weather-related risks. The subject of weather derivatives in restructuring electricity markets is still at its initial stages, has very few accessible literature resources and would require more learning especially by traders.

Weather is one of the main factors in determining the market participants' earning performance, and in some cases, drastic weather changes could causes participants to have a sluggish net performance. Cool summer weather could reduce the electricity consumption by residential and commercial customers and in turn reduce sales of electricity. As electricity sales would decrease, the demand for natural gas and coal would drop as well. Similarly, when the average temperature in winter would rise above expectation, it would reduce the consumption of electric power and natural gas for space heating. Also, sudden changes in weather could cause run-up in fuel supply costs, which could affect independent power producers with fuel supply contracts. Excessively dry seasons would reduce hydropower productions and increase the price of electricity. Weather changes would certainly impact the performance of electricity markets and its participants.

In the past, market players in other industries have dealt with weather risks by either absorbing the risks or managing risks with inefficient hedging tools. Electricity market participants should introduce a new class of weather risk management instruments combined with price risk management tools that could effectively hedge volume-related risks caused by volatility in average temperatures over specified time periods.

6.9.1 Background. Different market participants modify their cash streams by using weather hedges. Hedging is usually based on variables, such as Degree-Day (DD), Heating Degree-Day (HDD), and Cooling Degree-Day (CDD). Degree-Day is a unit that would measure the deviation of a day's average temperature from the arbitrary standard temperature (in US, usually 65 degrees Fahrenheit). DD is a way of calculating heating or cooling value; in other words, it would record how hot or how cold it has been over a 24-hour period. The day's average temperature would be found by adding a day's highest and lowest temperatures, and then dividing it by 2; DD is found by subtracting this average temperature from the standard temperature. HDD is a commonly used measure for the relative coolness of weather in a given region during a specified period of time. Usually, CDD would be used to estimate air-conditioning usage during a warm weather, and HDD is used to estimate heating needs during a cold weather.

CME has exchange-traded, temperature-related weather derivatives, which are HDD and CDD futures as well as options on futures. Many business sectors may use these contracts to either protect their revenues when the demand would drop or hedge excessive costs due to unfavorable weather conditions. CME futures and options on futures are traded based on indices of HDDs and CDDs for selected population centers and energy hubs with significant weather related risks throughout the United States, where selected cities are chosen based on specific factors such as population, variability in seasonal temperatures and OTC trades of HDD and CDD derivatives[16].

The CME HDD Index is an accumulation of daily HDDs over a calendar month, with $100 attached to each HDD for final cash settlement, as shown in the following examples. The CME CDD Index is also an accumulation of daily CDDs over a calendar month, with $100 attached to each CDD for the final cash settlement. The final settlement price for each monthly contract is based upon the calculated HDD or CDD Indices. Figure 6.8 shows the HDD and the CDD corresponding to each daily average temperature.

OTC refers to trading in financial instruments transacted off organized exchanges, where the transacted parties negotiate all details of the transactions or agree to certain market conventions. In the OTC market, months of October through March are usually covered by HDDs and months of May through August are usually covered by CDDs. The other two months (April and September) are referred to as *shoulder* months.

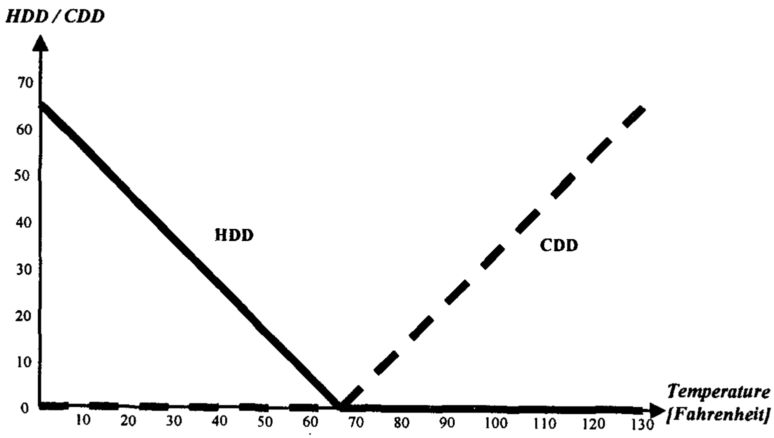

Figure 6.8 *HDD and CDD Corresponding to Daily Average Temperature*

[16] Weather Futures & Options, Chicago Mercantile Exchange, http://www.cme.com/weather

Example 6.9

(a) Assume that the highest and lowest temperatures on Saturday 14, June 1999 are 72° and 68° degrees, respectively. The average temperature on that day is 70° (or (72°+68°)/2). Assume also that the standard temperature is 65°. Since the average is higher than 65° by 5°, then there would be 5 cooling degree-days (there would be no heating degree-days).

(b) Assume that the highest and lowest temperatures on Tuesday 12, June 1999 are 63° and 61°, respectively. The average temperature in that day is 62°. Assume also that the standard temperature is 65°. Since the average is lower than 65° by 3°, then there are 3 heating degree-days (there would be no cooling degree-days).

Example 6.10

An electricity producer must purchase an adequate quantity of natural gas to cover its production for a heating season in order to meet the customer demand. If average winter temperatures are warmer than expected, the sales volume of energy will decrease, which will result in excess gas and associated storage expenses to the producer. On the other hand, if the winter is colder than expected, the producer will not have sufficient gas to cover the customer demand and in turn will be forced to pay relatively expensive spot prices. This producer could utilize weather derivatives to hedge unexpected future risks.

Example 6.11

(a) Let's assume that the daily minimum and maximum temperatures for the City of Chicago in the month of January are as shown in Table 6.2. With 31 days in the month of January, the daily average temperatures and the corresponding HDD and CDD indices are also calculated in this table. The accumulated HDD and CDD indices are 1361 and 0, respectively. With an HDD index of 1361 for January, the nominal value of a futures contract for Chicago will be \$136,100 (or 1361 HDD index × \$100).

(b) Let's assume that the daily minimum and maximum temperatures for the City of Chicago in the month of June are as shown in Table 6.3. With 30 days in the month of June, daily average temperatures and the corresponding HDD and CDD indices are also calculated in this table. The accumulated HDD and CDD indices are 0 and 205, respectively. With a CDD index of 205 for June, the nominal value of a futures contract on Chicago will be \$20,500 (or 205 HDD index × \$100).

A possible electric power usage versus temperature is shown in Figure 6.9. The illustration shows how consumer demand for power would rise and fall when temperatures deviate from 65 ° Fahrenheit.

An electric power utility or a power provider may use CME weather contracts to hedge their volumetric risk resulting from a winter that would be warmer than expected or a summer that would not be very hot. Utilities and power providers fear lower consumer demands when winter or summer temperatures are close to the 65° Fahrenheit baseline. The volumetric risk may seriously impact a utility's or a provider's revenue stream when HDDs and CDDs are unseasonably low. For example, when there is less need for summer air conditioning, a power company's future revenue stream would be affected, and the company could consider selling CME CDD futures or purchasing CDD put options to hedge possible drops in prices. As another example, if historical CDD data for a city would show summer temperatures in the 70's, but a recent forecast shows the next month's temperatures in the 90's, the company may choose to hedge with a purchase of an out-of-the-money CDD call, because a warmer than expected summer weather may necessitate more costly and less efficient generating units to operate during the peak usage periods. A long position in CDD calls (buying call options) would compensate for unexpected expenditures due to warmer than expected temperatures. Likewise, a cooler than expected or a warmer than expected winter may severely impact a company's revenues.

Table 6.2 *HDD/CDD of January in the City of Chicago*

Day	Day's Minimum Temp.	Day's Maximum Temp.	Daily Average Temperature	HDD	CDD
1	22.0	29.0	25.5	39.5	0.0
2	25.0	34.0	29.5	35.5	0.0
3	16.0	30.0	23.0	42.0	0.0
4	18.0	26.0	22.0	43.0	0.0
5	12.0	24.0	18.0	47.0	0.0
6	21.0	35.0	28.0	37.0	0.0
7	12.0	26.0	19.0	46.0	0.0
8	16.0	28.0	22.0	43.0	0.0
9	16.0	26.0	21.0	44.0	0.0
10	12.0	18.0	15.0	50.0	0.0
11	20.0	33.0	26.5	38.5	0.0
12	16.0	30.0	23.0	42.0	0.0
13	18.0	26.0	22.0	43.0	0.0
14	12.0	24.0	18.0	47.0	0.0
15	11.0	26.0	18.5	46.5	0.0
16	12.0	26.0	19.0	46.0	0.0
17	16.0	28.0	22.0	43.0	0.0
18	16.0	26.0	21.0	44.0	0.0
19	12.0	18.0	15.0	50.0	0.0
20	18.0	26.0	22.0	43.0	0.0
21	19.0	32.0	25.5	39.5	0.0
22	19.0	28.0	23.5	41.5	0.0
23	12.0	24.0	18.0	47.0	0.0
24	11.0	24.0	17.5	47.5	0.0
25	12.0	26.0	19.0	46.0	0.0
26	16.0	29.0	22.5	42.5	0.0
27	16.0	26.0	21.0	44.0	0.0
28	12.0	18.0	15.0	50.0	0.0
29	15.0	22.0	18.5	46.5	0.0
30	16.0	30.0	23.0	42.0	0.0
31	16.0	25.0	20.5	44.5	0.0
		Accumulated HDD/CDD		1361.0	0.0

Table 6.3 HDD/CDD of June in the City of Chicago

Day	Day's Minimum Temp.	Day's Maximum Temp.	Daily Average Temperature	HDD	CDD
1	65.0	80.0	72.5	0.0	7.5
2	68.0	77.0	72.5	0.0	7.5
3	64.0	77.0	70.5	0.0	5.5
4	72.0	84.0	78.0	0.0	13.0
5	60.0	77.0	68.5	0.0	3.5
6	69.0	83.0	76.0	0.0	11.0
7	74.0	80.0	77.0	0.0	12.0
8	66.0	79.0	72.5	0.0	7.5
9	63.0	84.0	73.5	0.0	8.5
10	68.0	80.0	74.0	0.0	9.0
11	57.0	80.0	68.5	0.0	3.5
12	70.0	80.0	75.0	0.0	10.0
13	65.0	75.0	70.0	0.0	5.0
14	69.0	84.0	76.5	0.0	11.5
15	65.0	80.0	72.5	0.0	7.5
16	68.0	77.0	72.5	0.0	7.5
17	64.0	77.0	70.5	0.0	5.5
18	62.0	78.0	70.0	0.0	5.0
19	60.0	77.0	68.5	0.0	3.5
20	59.0	78.0	68.5	0.0	3.5
21	64.0	80.0	72.0	0.0	7.0
22	66.0	79.0	72.5	0.0	7.5
23	63.0	81.0	72.0	0.0	7.0
24	68.0	76.0	72.0	0.0	7.0
25	67.0	77.0	72.0	0.0	7.0
26	60.0	75.0	67.5	0.0	2.5
27	65.0	75.0	70.0	0.0	5.0
28	69.0	84.0	76.5	0.0	11.5
29	55.0	80.0	67.5	0.0	2.5
30	54.0	77.0	65.5	0.0	0.5
		Accumulated HDD/CDD		0.0	205.0

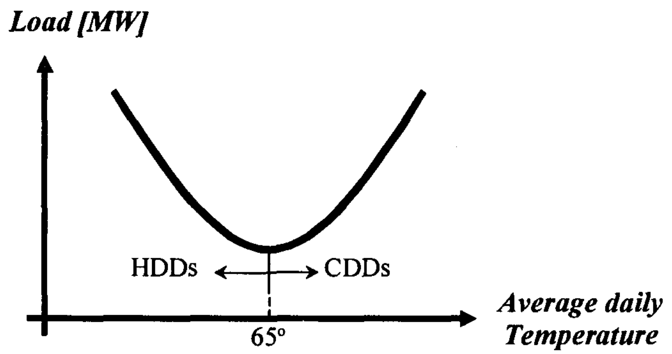

Figure 6.9 Electric Power Usage versus Temperature

CME HDD/CDD Index futures contracts are cash settled and legally binding agreements to buy or sell the value of the HDD/CDD Index at a specific future date. The full value of the contract would not be transferred, rather there would be a final marking-to-the-market based upon the HDD/CDD Index, with the final gain or loss applied to the customer's accounts.

HDD/CDD futures have a notional value of $100 times the CME HDD or CDD Index and contracts would be quoted in HDD/CDD Index points. For example, an HDD Index of 500 would mean that the futures contract have had a notional value of $50,000 (500 HDD × $100). The tick[17] size would be 1.00 HDD or CDD Index points with each having a value of $100.

Example 6.12

On September 10, 1999, an IPP sold the November 1999 HDD futures (i.e., IPP took a short position) on the City of Chicago at a price

[17] A minimum change in price, either up or down.

of 800. If, on October 11, 1999, the IPP closed out the position by buying the futures contract back at a price of 690, that would mean the IPP would have a gain of $11,000 ($100 × 110 HDD Index points) on the position the IPP took in September. See Figure 6.10.

At any given time, CME would list twelve consecutive contract months of HDD and CDD futures and options. For example, on June 10, 1999 there would be twelve consecutive months of HDD and CDD futures trading with expiration months listed from June 1999 through May 2000. CME would list twelve consecutive months to quickly accommodate any market makers who would like to increase the number of months employed to create HDD or CDD seasons to suit their own needs.

The buyer (the holder) of a call or put option on CME HDD/CDD futures may have an unlimited profit potential with the risk limited to the price (premium) paid for the option. The option seller would accept the potentially unlimited risk in return for the option premium at the time of sale. An HDD or CDD call option would give the buyer the right, but not the obligation, to buy one HDD/CDD futures contract at a specific price (strike or exercise price). Also, an HDD/CDD put option would give the buyer the right, but not the obligation, to sell one HDD/CDD futures contract.

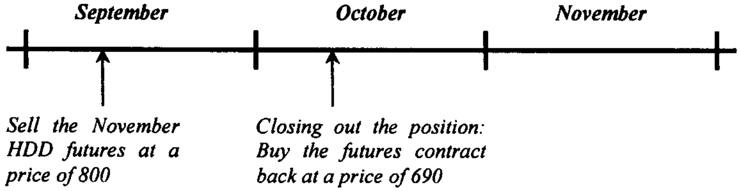

Figure 6.10 *Illustration of Example 6.12*

These rights can be exercised at the buyer's choice but not before expiration. Options on CME HDD/CDD futures are European Style – they may be exercised only at expiration. Alternatively, the option itself can be resold (offset) on the Exchange. To offset a call purchase, a trader may sell the same call (with same expiration and same strike price); likewise, to offset a put purchase, a trader may sell the same put. At the expiration, open option positions may be automatically exercised and assigned if the options are in-the-money (they have intrinsic value).

The underlying instrument for each CME HDD/CDD Index options contract would be one HDD/CDD futures contract, where an option contract would be valued at \$100 × the premium price of the option. For example, a quote of 4.00 would represent a premium of 4 price ticks (or \$100 × 4 = \$400).

Example 6.13

(a) The underlying October 1999 HDD futures are trading at 750, an at-the-money 750 strike HDD call might be trading at 8.00 and have a value of \$800 (\$100 × 8 HDD Index points).

(b) The underlying November 1999 HDD futures are trading at 800, an out-of-the-money 800 strike HDD call might be trading at 4.00 and have a value of \$400 (\$100 × 4 HDD Index points).

Example 6.14

The CME Degree Day Index is the cumulative total of daily HDDs or CDDs over a calendar month. If we refer to the daily average temperature by T, then the daily HDD and daily CDD are given by:

$$HDD = Max\ (\ 0\ ,\ 65^o - T\ )$$

$$CDD = Max\ (\ 0\ ,\ T - 65^o\ )$$

In CME, the futures contract and options on futures contract trading terminate and contract would settle at 9:00 a.m. Chicago time on the first exchange business day which is at least 2 calendar days following the last day of the contract month.

Let's assume that a DisCo would sell electricity in the City of Chicago. The retail price that the DisCo would charge in the winter is locked in at \$80/MWh. With a normal winter, the sale quantity would be forecasted as 1,000,000 MWh. The projected revenue for the forecasted value would be 1,000,000 MWh × \$80/MWh =\$80 million

The DisCo would fear that the coming winter could be relatively mild and the sale quantity would be decreased below the forecasted value, as customers would need less electricity for heating. The DisCo would observe that the sale quantity is positively correlated with the CME Chicago HDD Index with a weather risk sensitivity of 0.8, as shown in Figure 6.11. For example, a 2% decrease in the CME HDD index would result in a 1.6% (0.8 × 2%) reduction in sale quantity (or 0.016 × 1,000,000 = 16,000 MWh, which would reduce the sale to 984,000 MWh). Therefore, the DisCo would use the Chicago HDD Index future as a cross hedge for the DisCo's revenue oscillations.

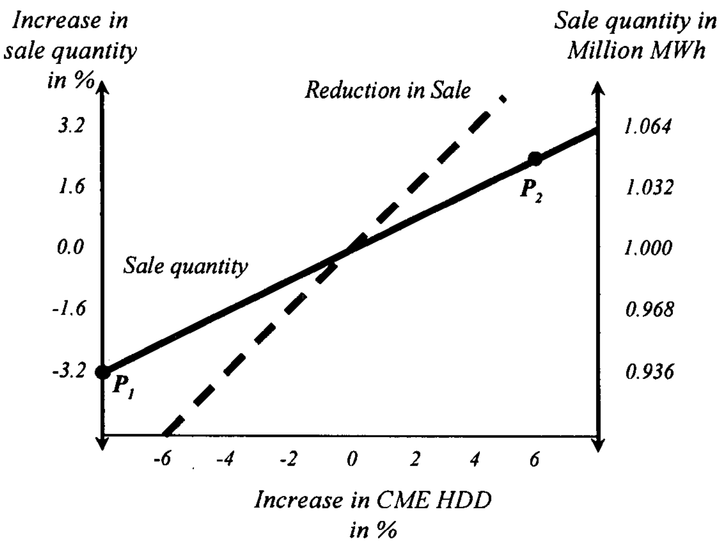

Figure 6.11 *Change in Sale Quantity versus Change in CME HDD*

In order to stabilize the revenue in the winter, the DisCo would consider selling the Chicago HDD Index January 2000 futures that are valued at $1,250[18]. In order to discover the number of HDD contracts to sell, or what is referred to as the hedge ratio, the DisCo would know that a 1% decline in the HDD Index corresponds to a 0.8 % fall in revenue. A 1% decline in the HDD Index, at current price levels, would be worth $1,250 (0.01 × 1,250 HDD price × $100 per HDD tick). A 0.8% decline in revenue would be worth $640,000 (0.008 × $80,000,000 projected revenue).

Hedge Ratio	= Change in Revenue / Change in Contract Value
512 contracts	= $640,000 / $1,250

On October 1, 1999, the DisCo shorts 512 of the January 2000 HDD futures at a price of $1,250. So, let's study two scenarios:

(a) Case 1: winter turns out to be mild (as it was expected)

On February 2, 2000, the January 2000 Chicago HDD contract would settle at 1,150. As a result, the DisCo's sales quantity would be reduced by 64,000 MWh, which is calculated as follows:

Change in HDD	= (1,250 – 1,150)/1,250 = 0.08 or 8%
Reduction in Sale	= Change in HDD × Sensitivity × forecasted Sale
	= 0.08 × 0.8 × 1,000,000 = 64,000 MWh.
DisCo's sale	= forecasted sale - reduction in sale
	= 1,000,000 - 64,000
	= 936,000 MWh (or 0.936 million MWh)

(See point P_1 in Figure 6.11). A reduction of 64,000 MWh in sales would lead to a reduction in the DisCo's revenue of $5.12 million (or

[18] Hedger usually uses seasonal hedge that involves the sale of a strip of HDD contracts, for example October 1999 through March 2000. In the example we are assuming the entire hedge is placed in the January contract, which is typically the coldest month of the year in Chicago.

\$80/MWh× 64,000 MWh). However, the DisCo would realize that the revenue reduction would be offset by the gain from its futures position of \$5.12 million, which is calculated as follows:

Futures contract size = \$ 100 × the CME Degree Day Index

Gain from futures position = (\$100 per tick × (1,250 – 1,150) × 512 contracts)

= \$5,120,000

(b) Case 2: winter turns to be very severe (to the opposite of what was expected)

On February 2, the January 2000 Chicago HDD contract would settle at 1,325. As a result, DisCo's sales quantity would be increased by 96,000 MWh, which is calculated as follows:

Change in HDD = (1,325-1,250)/1,250 = 0.06 or 6%

Increase in Sale = Change in HDD × Sensitivity × forecasted Sale

= 0.6 × 0.8 × 1,000,000 = 48,000 MWh.

DisCo's sale = forecasted sale + increase in sale

= 1,000,000 + 48,000

= 1,048,000 MWh (or 1.048 million MWh).

(See point P_2 in Figure 6.11). An increase of 48,000 MWh in sale would lead to an increase in the DisCo's revenue of \$3.84 million (or \$80/MWh × 48,000 MWh). The increase in the DisCo's revenue would be offset by the loss from its futures position of \$3.84 million (\$100 per tick × (1,325 – 1,250) × 512 contracts).

This example illustrated how hedging with HDD futures can be used by the DisCo to eliminate revenue fluctuations caused by changes in winter weather.

Example 6.15: (Using a CDD Weather Collar to Stabilize Earnings)

A power marketing company (PMC) is located in the City of Chicago. The PMC is concerned with revenue fluctuations as a result of poor weather, especially in summer months. The PMC would like to avoid possible cash flow problems during the next 12 months and is looking to protect itself from a cold summer and avoid a premium payment. The PMC would decide to use a weather collar to stabilize its earnings. The PMC asked a weather derivatives company (WDC) to help it find a seller of a collar to achieve revenue stability and avoid paying an upfront premium. The WDC provided the PMC with a study which carried out a regressive comparison between revenues and temperature during the last few years. The WDC observed that each CDD variation from the average for the period April to September would affect the PMC's revenue by $8,000. Historical data would produce an agreed-upon average cumulative CDD of 320 with a reference temperature of 65° F.

The WDC selected a seller (a writer) of the collar that provided the PMC with revenue protection below 300 CDD (i.e., (320-300)/320=0.0625, or 6.25% below the average) at $8,000 for each CDD. For example, if the index at the end of September was 280 CDD, the writer of the collar would pay $160,000 to the PMC (or (300-280) × $8,000 = $160,000). The cost of this protection is offset by agreeing to a ceiling of 340 CDD ((i.e., (340-320)/320=0.0625 or 6.25%) above which the PMC would pay the writer of the option $8,000 for each CDD. For example, if the Index at the end of September was 360 CDD then the PMC would pay $160,000 to the writer (or (360 - 340) × $8,000 = $160,000). Figure 6.12 illustrates this situation.

The example showed that, at no initial cost, the PMC has guaranteed protection for a cold summer in return for which it has agreed to give up some of its profit during a hot year.

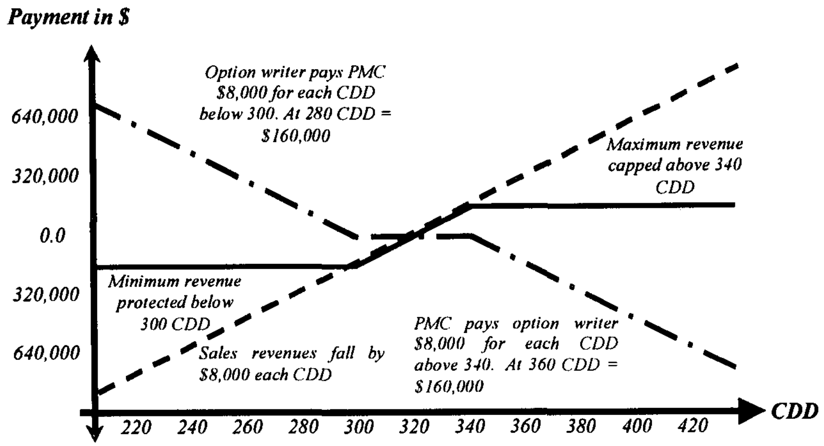

Figure 6.12 *Using a CDD Weather Collar for Earnings Stability*

There are some factors that are to be considered when designing or implementing hedging tools for weather risks. Firstly, weather has no physical markets and it is impossible to store a cold January until July or to transport a rainstorm from one state or region to others. Secondly, weather risk is localized, and no indices in weather have commercial meaning to broad markets. Different from other commodities, weather is physically uncontrollable by human, market dynamics or regulations. Finally, changes in weather in a certain region are fairly available to all participants.

Weather cannot be forecasted beyond a few days with enough accuracy, which would make weather-related commercial decisions at risk. But good knowledge and experience in weather data would help, to a large extent, hedge weather-sensitive commodities by transferring risks to counterparties.

6.9.2 Weather Hedging Tools. Weather risk management tools include caps, floors, collars and swaps with payouts defined as a specified dollar sum multiplied by differences between the HDD level specified in the contract (the strike) and the actual HDD level which occurred during the contract period.

The first type of weather derivatives is the *Cooling and Heating Degree-Day Option*. The option would provide a one-sided hedge towards the downside, while preserving upside potential. Options on DDs would include puts and calls, and the buyer would have to pay an up-front premium for the hedge. When a market participant, such as a generation company, would be interested in hedging a very hot summer or a very cold winter, the participant can reduce weather risk by buying DD calls or puts (floors). The strike price is a pre-specified level of DDs and the settlement price is the actual DD level for a set time period. Purchasing a DD call by a participant would mean that the participant (buyer) is planning a protection against higher than normal HDD's or CDD's. Purchasing a DD put would mean that the buyer is planning a protection against lower than normal HDD's or CDD's. Purchasing or selling a DD option would entail paying or receiving a premium for the right to exercise the option at some future expiration date.

The second type of weather derivatives is *Cooling and Heating Degree-Day Swap*. This is a swap that would receive (pay) a floating payment proportional to a change in Degree-Days over the accrual period, and pay (receive) a fixed payment. Swaps would entail setting a fixed (an agreed-upon) CDD or HDD level (for example 8000 CDD's or 1000 HDD's) and then comparing that level with the actual level of HDD's at a certain time and place, e.g., the month of March in Chicago, Illinois. The actual level is called the *floating level* since its value is not known until the actual information is available, for that reason we would refer to swaps as fixed for float tools or instruments. Swaps can be used to stabilize cash streams associated with cooling and heating energy. Swaps are used as reliable hedges of heating costs, because when DD over the accrual period under study is a negative number, it would give a positive number of HDD. This would lead to a negative floating payoff, which is a hedge for the resulting positive heating costs, because a large number of HDD implies a large volume of energy and a high price for it. There is no premium paid for a swap transaction.

The third type of weather derivatives is *collar*. Collars would put boundaries on natural outcomes, limiting them to a desired range. Collar is built using a combination of put and call options to limit both weather-related risk and potentially reduce premium risk. Using collars would provide a zone of comfort in which a participant can operate to limit risks. The swap is seen as a special case of a collar where the cap and floor strikes are the same.

The fourth type is *digital product (structure)* which is used to cause lump sum cash transfers between contract parties whenever specified conditions are met. These structures are useful in situations where risk and associated costs come in discrete amounts and not in variable amounts. Digital structure would provide a payment to a company if a pre-specified level is obtained; it differs from standard option products as it would not pay a cash flow until the agreed- upon level has been reached. A power company that would like to be compensated if a certain temperature is achieved may choose to use a digital structure. For example, a power company in Chicago could use a digital product in July if the temperature in Chicago (i.e., a specific location) would be above 90° (e.g., a specified level). This type of derivative would be suitable for both heat waves and cold snaps.

Hybrid products or Embedded Weather Agreements: Different combinations of weather derivatives can be used to hedge weather-related risk and a combination can be modified or designed to fit individual participants' needs. These products can be used particularly for electricity market participants to combine weather hedges and physical energy delivery in a single transaction, or to combine weather hedging instruments with price hedges and physical energy supply.

Participants may use cap agreements, floor agreements, and costless collar as hedging tools. Under cap agreements, the seller would pay the buyer whenever a defined weather index would fall above the strike level. The payment would be equal to the number of weather units the index deviates from the strike level times a notional[19] dollar amount per unit. The buyer would pay the seller an up front lump-sum premium for the transaction. On the other hand, under floor agreements, the seller would pay the buyer whenever a defined weather index would fall below the strike level. The payment would be equal to the number of weather

[19] Notional Amount per HDD is the dollar amount to be paid per HDD levels above/below HDD strike level(s).

units the index deviates from the strike times a notional dollar amount per unit. The buyer would pay the seller an up front lump-sum premium for the transaction. For costless collar agreement, seller would pay the buyer whenever a defined weather index would fall above a cap strike level and the buyer would pay the seller whenever the weather index would fall below a floor strike level. The payment in either case would be equal to the number of weather units the index deviates from the strike times a specified dollar value per unit. The transaction would not have an up front lump-sum premium. Weather Index is usually the cumulative HDD in the contract period(s).

6.9.3 Examples[20]

Example 6.16: (Degree-Day Swaps)

An IPP would sell a swap to a DisCo and in return the IPP would obtain a compensation as a pro rata/DD whenever DDs is less than the agreed-upon strike level. On the other hand, whenever DDs is above the strike level, the IPP would pay the DisCo. The sum of the swap and the IPP's revenue from the operations would be a more stable revenue stream. The DisCo would see a mirror effect. The DisCo would be looking to stabilize his total cost of energy consumption. Figure 6.13 illustrates this example.

Example 6.17: (Degree-Day Options)

A GenCo would buy a put option from a participant P, where P would pay the GenCo a pro rata per DD if DDs is less than an agreed-upon strike level. This would compensate the GenCo's lower revenue from operations, and make a minimum floor on GenCo's total revenues. On the other hand, whenever DDs is more than the strike level, the GenCos would pay P nothing but the option premium. The GenCo would make benefits from increased operating revenues. Figure 6.14 illustrates the DD options.

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[20] See Jack Cogen, "What is Weather Risk?" PMA Online Magazine, 05, 98, www.retailenergy.com/articles/weather.htm

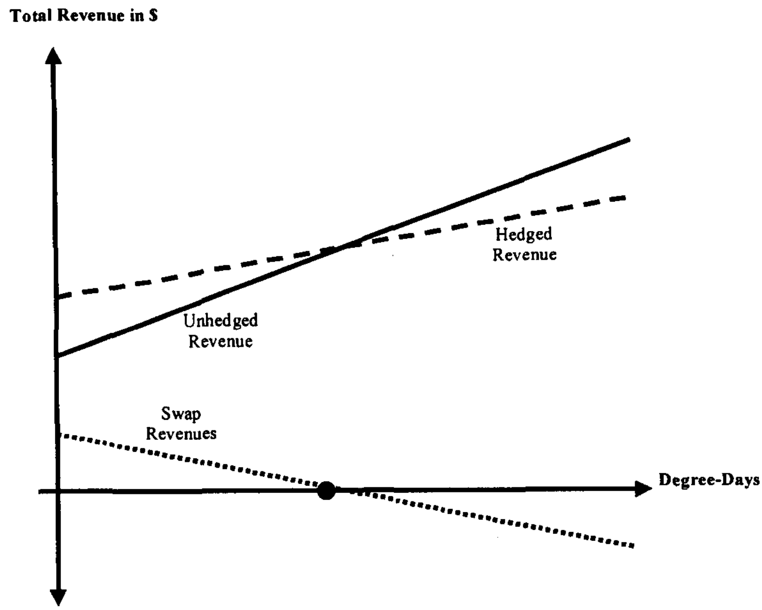

Figure 6.13 Degree-Day Swap

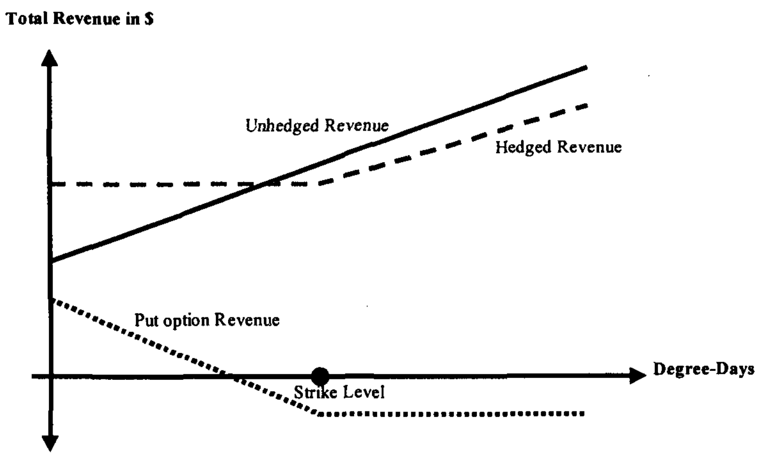

Figure 6.14 Degree-Day Options

Example 6.18: (Rainfall Collars)

To hedge a rainfall, an IPP would buy a rainfall put option from participant $\mathbf{P_1}$ with a low strike level (X_1) and sell a call option to participant P_2 with a high strike level (X_2). If the rainfall settles between X_1 and X_2, no payout would take place between contracted parties. If the rainfall settles below X_1, the IPP would receive pro rata payment per inch of rainfall from $\mathbf{P_1}$. If the rainfall settles above the high strike, the IPP would pay $\mathbf{P_2}$. When combined with the producer's natural revenues from operations, the total revenue pattern outside X_1 and X_2 would be stabilized by the hedge. However, between X_1 and X_2, the total revenue would follow the unhedged trend. See Figure 6.15.

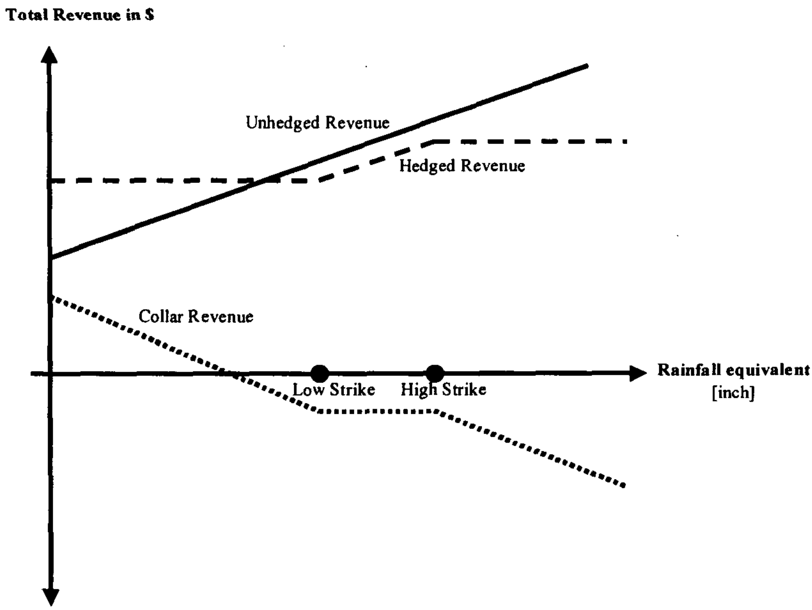

Figure 6.15 Rainfall Collar

Example 6.19: (Digital Structures)

Suppose that a GenCo is subjected to a fixed cost of bringing a peaking facility on line whenever temperatures exceed a T_1 degree. In the example shown, a two-tier cost structure occurs from normal unhedged operations. The GenCo buys a digital hedge which mirrors this condition, thus compensating for the costs when they occur. The digital hedge ensures a fixed cost of operations regardless of the weather outcome. See Figure 6.16.

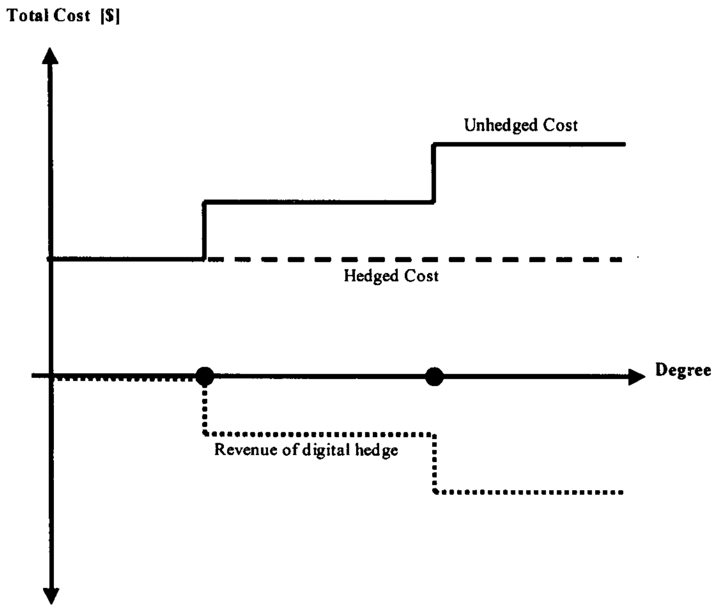

Figure 6.16 Digital Structure

Example 6.20: (Degree-Day Collar)

Assume that the revenue of participant **A** would increase as temperature would rise (i.e., its revenue would correlate with the total number of CDD). Participant **A** would enter into a DD collar transaction with participant **B** to hedge its weather exposure[21].

First, the revenue loss (gain) of participant **A** caused by a 1 CDD decrease (increase) from the mean is calculated and denoted as "r". r is the rate of change in revenue for a change in temperature. Participant **A** would then specify a floor in revenue, which would correspond with a floor in total CDDs. Participant **A** would purchase this floor to lock in the revenue protection. If the total CDDs fall below the degree-day floor by X, participant **B** would pay participant **A** an amount equal to $X \times r$. This payment would approximately compensate the Participant **A**'s revenue loss beyond the predefined floor level.

To finance the purchase of the floor, participant **A** would sell participant **B** a cap. By selling the cap, participant **A** would give up some of its upside if the temperature (total CDDs) would exceed the cap level.

Figure 6.17 illustrates the situation.

6.10 CONCLUSIONS

Reshaping the electric power industry has given new scopes to electricity markets, where many new competitors have emerged with a wide array of strategies to deal with generation, transmission and distribution and their associated risks. In this reshaped environment, it is not uncommon to see a participant that would deal with both electric and non-electric commodities.

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[21] The first thing the counterparties would do is to calculate the number of cooling or heating degree-days in a normal year for the area where participant's revenue is affected by the temperature. Data is available from the National Weather Service.

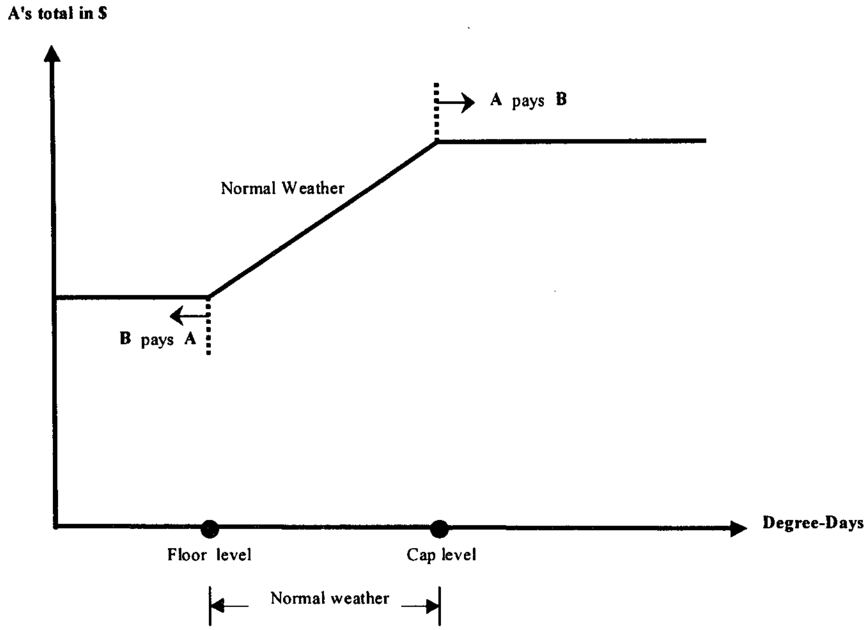

Figure 6.17 Degree-Day Collar

The involvement of a huge number of market participants in the operation of wholesale power markets has increased the competition and the volume of trades, which in turn have increased the market risk and the physical size of the electricity market as the largest commodity market in the United States. The additional number of participants and more opportunities in restructured markets have put more burden on participants for implementing hedging strategies that would protect their operations and revenues from emerging risks.

The short period of experience in restructuring in the United States gives a clear picture on how vital hedging tools are to participants to survive, how electricity is different from other commodities and how its factors drive up electricity prices. The new risks created by competition in restructured electricity markets such as price risk, volume risk, and counterparty risk have unique consequences in electricity markets due to non-storability of electricity and transmission implications. During the short period of restructuring, many concerns have been magnified which are considered as wake-up calls to restructuring researchers and market participants to determine their priorities when designing and implementing reliable and adequate hedging tools and hedging strategies. The market experience in the past short period highlighted issues of counter-party default, implementation of weather-related derivatives in electricity markets, portfolio management, needs for an accurate long-dated forward prices, and others.

The short period of restructuring also showed that inexperience of market participants, especially hedgers, in hedging tools resulted in large errors during their operations. New trends in electricity restructuring necessitate creation of robust hedging tools to help market participants overcome risks. Developing these tools in the right direction as time passes is also an important issue until restructuring reaches maturity. Successful hedging strategies and hedging tools, in addition to maintaining reliability of the power system, help market participants guarantee a margin of profits in a volatile and competitive market. Before designing a hedging strategy, a participant should acquire an adequate knowledge in the basics of the hedging tools, should have accurate projections for future market movements, and should take into account future unexpected events.

Hedging is described as a large challenge that is uneasy to apply to electricity as in the case of other commodities. In power markets, hedging strategies differ widely from one entity to another based on the entity's objectives and market forces that are correlated with that entity. Improving or maintaining the competitiveness of an entity is another motivation for hedging the exposure of the entity to its financial price risk. As in any other industry, power entities interact and exist jointly, and every party competes with others to reach customers in order to make more profits and to attract investments. Experience, educated personnel and management approach are the main factors that define best strategies to hedge risks. If these factors are integrated in the best manner it may enable an entity to hedge risks and know competitors' movements. Market participants, to reduce exposure to unforeseen price fluctuation, use hedging instruments where they buy financial instruments to form a position that is equal and opposite to a position in the cash market. These hedging instruments, if implemented properly, will efficiently help participants manage the risks of price fluctuations and counterparty uncertainty.

This chapter presented a discussion on sources of risk in electricity markets followed by a discussion on the Midwest crisis that happened in June 1998. The crisis has been detailed as it is related to defaults of counterparts and to illustrate how hedging strategies play an important role for participants of electricity markets. After that the chapter mentioned the considerations that should be taken into account in hedging risks of electricity markets. A discussion on value-at-risk and volatility in electricity markets has been detailed to show the mathematical meanings. The main driving forces that cause volatility in electricity prices such as load uncertainty, fuel price, and irregularity in hydro-electricity production, unplanned outages, constrained transmission (congestion), and market power have been presented where we showed the contribution of each to price volatility.

Counterparty risk and a discussion on how California's PX deals with counterparty risk have been presented in this chapter. Meanings of portfolio management and the Greeks are illustrated in the chapter and we show how the Greeks are used to analyze exposures of a portfolio or a position. In addition to that, the chapter presented a discussion on hedging tools of weather risk. The chapter shows numerous examples of using different hedging tools and the examples are supported with graphic illustrations whenever we had the chance to do that.

CHAPTER 7

ELECTRICITY PRICING

Volatility, Risk, and Forecasting

Summary: This chapter reviews some of the essentials of electricity pricing. Electricity prices are strongly related to physical characteristics of a power system such as loads, meteorological conditions, fuel prices, unit operating characteristics, emission allowances, and transmission capability. Electricity has a distinct characteristic since it cannot be stored economically and transmission congestion may prevent free exchange of electricity among control areas. Thus, electricity price shows the greatest volatility among various commodities and if we simply utilize available algorithms used for forecasting prices of other commodities, we could expect fairly low accuracy.

The main driving forces that cause volatility in electricity prices such as load uncertainty, fuel price, and irregularity in hydro-electricity production, unplanned outages, constrained transmission (congestion), and market power are discussed in the chapter.

This chapter also discusses the major challenges to electricity derivatives, which include implementing reliable forward curves, inadequacy of existing price indices, basis risk, and inadequacy of traditional pricing models. The chapter presents a discussion on hedging tools for weather risk, volatility and risks involved with price forecasting, and a practical approach for calculating the short-term price of electricity.

7.1 INTRODUCTION

With the introduction of restructuring to the electric power industry, electricity price forecasting has been the key to operating a power market. Electricity is a non-storable commodity and its supply and demand must be matched at all times. Otherwise, maintaining the steady state frequency would become a serious problem. Since supply and demand dynamics are forced to play out constantly, price of electricity is often determined for short-time periods.

The demand for electricity could vary significantly according to the time of day. Electricity demand is generally higher during day-time hours, known as the peak period, and lower during night-time hours, known as the off-peak period. Without the possibility of storage, i.e. an essential feature in other commodity markets, it is impossible to smooth out electricity prices between peak and off-peak periods. Regionally, electricity demand will also vary seasonally, with some areas experiencing their peak demand during the summer while others would peak in the winter. The demand for electricity can be very uncertain, as it is largely weather related and, in many cases, not very sensitive to prices.

Because of the limited available information, the accuracy of price forecasting for a generating company (GenCo) may not be high. However, an accurate estimation of price could help a GenCo determine its bidding strategy or set up bilateral contracts more precisely in electricity market. A GenCo could exert market power if it could predict the price more accurately.

Engineers in the electric power industry have been familiar with short-term load forecasting for some time. However, applying the existing load forecasting algorithms may result in erroneous price forecasting. More specifically, the existing simulation methods would be too complex to implement and modular time series analysis with heuristic logic would be too simple to generate accurate results. The artificial neural network (ANN) method, on the other hand, would be a simple and powerful tool for forecasting electricity prices.

7.2 ELECTRICITY PRICE VOLATILITY

In the restructured electric power industry, it is common to read or hear expressions such as *"the volatility of electricity prices has been high during the period of January and February", "the PX market will create an environment with volatile pricing - very low at times of low demand, high at times of high demand, and very high at times of high demand and limited supply", "annualized volatility of on-peak prices", "annualized volatility of off-peak prices", "electricity markets are highly volatile"*, and similar expressions which point out the volatility of electricity market. This section provides a detailed explanation of volatility and its impact on electricity pricing. In addition, the section gives a brief mathematical background on volatility, shows some examples and discusses the main motive forces for causing volatility in electricity markets.

Price volatility is a measure of instability in future prices or uncertainty in future price movements. For example, when we plot a histogram of the spot price of energy between January-March, the dispersion of the spot price provides an indication of the volatility. In electricity markets, volatility is used to analyze different hedging strategies and portfolios. Volatility is time dependent and could reflect the value of electricity derivatives such as futures and options; when spot price is highly volatile, the value of the energy option would be high. Figures 7.1 shows the price curves for PJM, which is non-homogeneous, and its variations show a little cyclic property.

Although electricity price is very volatile, it would be possible to identify certain patterns and rules pertaining to market volatility. It is also possible to use historical price movements to forecast future prices.

Compared to non-energy commodities, electricity price is the most volatile. A study released in 1997 [Web45], pointed out that the annualized volatility of WTI oil future contracts is about 28%, while it is 54% for NYMEX Henry Hub natural gas future contracts, 62% for COB and 57% for Palo Verde electricity future contracts, respectively. In the electricity spot markets, the annualized volatility in the same period for COB is about 180%, while it is 300% for MAIN and 450% for the Power Pool of Alberta.

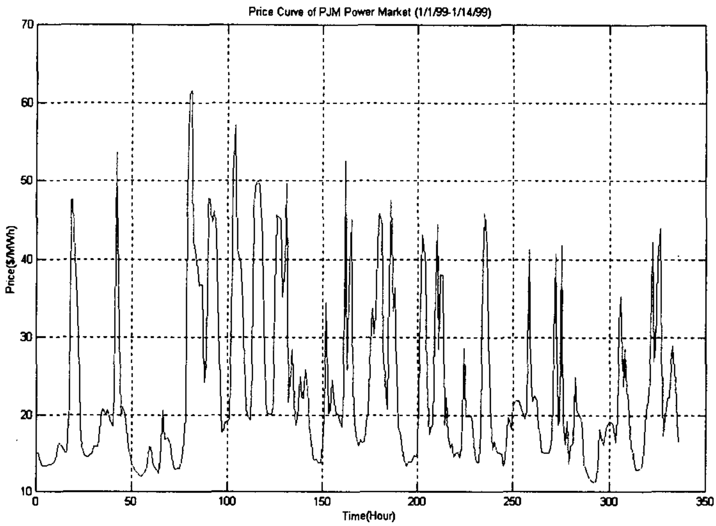

Figure 7.1 Price Curve of PJM Power Market from 1/1/99 to 1/14/99

Practicing market power by dominant generators could cause volatility, in addition to raising prices over competitive levels[1]. Load forecasting error is an important factor in price volatility and when forecasting errors exist along with market power, the volatility in price could be more severe. In UK, for example, prices are high because the two largest generators dominate the market by practicing market power. In Scandinavia and New Zealand, the state owns the dominant generators, which stabilize the price, but, in turn, prices are above

[1] Tim Mount, " Market Power and Price Volatility in Restructured Markets for Electricity," Proceeding of the Hawaii International Conference on System Sciences, January 5-8, 1999, Maui, Hawaii.

competitive levels. Another reason for price spikes could be the forced outages of power system components.

In response to this problem, different techniques have been proposed, which include limiting the ownership of dominant generators. Analysts debated recently on two auction models for pricing the electricity in spot markets: a uniform price auction and a discriminatory price auction. In the first type, all generators are paid the same based on the marginal unit (the highest accepted bid), while in the latter one the generators are paid what they offer in their bids. Some analysts concluded that both approaches would lead to a competitive situation and the mitigation of market power to a large extent would be reached if the number of market participants were sufficiently large. Others indicated that price volatility is much lower in the case of discriminatory price auction.

In electricity, volatility has three main sources: supply, demand and unexpected outages. Demand depends on factors such as weather, seasonal occasions, time of day and others. Supply depends on factors such as fuel in addition to weather that has an impact on supply. Fuel price is a main factor in volatility of prices as caused by supply; for example, natural gas prices are volatile which in turn leave a direct impact on electricity prices. Outages are caused by many factors, including weather conditions, overloaded lines and faults imposed on the transmission system or generating units.

The fact that the cost of generating electricity is based mainly on the cost and the availability of the fuel used in generation does not change by switching from regulated monopoly to open access restructured markets. Utilities used to average their fluctuating hourly costs of electricity (which were based on economic dispatch) and come up with a single cost-based rate, and users on the other side were mandated to accept this rate. Some large customers were buying electricity on an hourly-based price. In a restructured environment, hourly prices are expected to swing as they used to, with a main difference that a competitor should be competing with a large number of other competitors. In this environment, competitors bid into the market, not necessarily based on their costs but on anticipated price that takes into account movements of other competitors, market situation and supply-demand condition. This behavior would cause increased price volatility and motivates customers to take proper actions. A customer for example may seek other providers with low rates or change its consumption pattern when electricity price rises in certain hours of the day or in seasonal occasions. If a provider continues to provide a customer with volatility-free hourly prices, the provider should take the risk and find proper hedging strategies.

In order to reduce price volatility in the energy market, a trading system may allow customers to sell electric energy back through the trading system in certain hours. In the following, we further discuss the factors which could contribute to volatility in electricity markets.

7.2.1 Factors in Volatility. Every electricity market is expected to have variable price patterns while proceeding from one stage to the next. This procession could be due to many factors such as entry of new players to the market, destructive gaming, bidding behavior, and availability of generation units and transmission components. As time passes, the market could correct itself to reach a final phase where prices would be predictable to a large extent and adequate rules could be implemented in modeling the whole marketing process.

During transient stages of restructuring in Britain, the electricity market experienced less price volatility due to the existence of what is called *vesting contracts*[2], but market participants suffered considerably from increasing uplift costs associated with ancillary services. As time passed, market rules were modified to correct the market behavior and stabilize prices. The Nordic Power Exchange (Nord Pool) has a large price volatility because of its dependence on hydroelectric generation, which is in turn dependent on weather conditions, whether it is dry or rainy. In Victoria, Australia, electricity average prices decrease over time, but with high volatility which at times reached an order of 1,000%.

Various factors resulting in volatility include:

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[2] Vesting contracts are used by participants entering a competitive market - especially a market in which there is excess capacity - to hedge the risk of price volatility by controlling the price path during transition to a fully competitive wholesale electricity market. The contracts apply only in the wholesale market and are written between retailers or large customers and generators. See: www.tg.nsw.gov.au/sem/faq/, and www.treasury.nsw.gov.au/research/trpnov95/isspr.htm#four_6.

- **Load Uncertainty**: The power generation required to meet the load is directly correlated with weather conditions, which are sometimes unpredictable. Due to unexpected temperature changes, especially from low to high, the actual load could be at times very different from the forecasted load. If the weather forecast is uncertain, the load forecast could be uncertain. One option is to consider a higher demand than predicted, which possibly could commit higher cost units, which would in turn cause electricity market prices to increase. Errors in load forecasts and load scheduling are major reasons of price swings. When the ISO forecasts the load, based on historical information and meteorological data, and receives load schedules from market participants, it compares the two entities to determine the generation required to serve the load in addition to generation reserve required to maintain reliability. Considerable errors in load forecast may lead to sever conditions for system operation and increase in prices. When the actual load is considerably more than the forecasted load, on-line generation may be inadequate to serve the load which necessitates the generation reserve to be called upon; this action will in turn reduce the amount of reserves available to support the power system during a severe disturbance, aggravate the system performance or generation deficiency, and motivate prices to increase unexpectedly.

- **Fuel Prices**: The fuel used by generating units to produce electricity is a volatile commodity with its price depending on market conditions such as demand-supply convergence conditions, transportation, storage expenses and other factors. Fossil fuel, hydro, nuclear and unconventional sources of energy could be used in generating electricity, with different costs, which are reflected on electricity prices. When marginal generating units use a certain type of fuel with fluctuating price, the electricity price could fluctuate as well. For example, it is perceived that natural gas is the main type of fuel for generating electricity in California, and marginal generating units use natural gas nearly 80% of time to produce electricity. Natural gas is also used in winter to heat residences, which could increase natural gas prices for producing electricity. Hence, volatility in natural gas prices could reflect electricity prices. On the other hand, other types of fuel may not have a similar impact on electricity prices; for example, costs of coal and nuclear fuels are generally steady and would only change considerably on a long-term basis. Generating units with these types of fuel will usually be dispatched first.

- **Irregularity in Hydro-Electricity Production**: In some regions, hydro-electricity is produced rather inexpensively in certain times of the year due to the availability of water resources; in the remaining times of the year, thermal units are used when water quantity is reduced, which could impact electricity prices. In states like Washington, Oregon and California, a rainy winter would enable hydroelectric resources to generate abundant electricity in the following spring and early summer. In other times of the year, more expensive generating units that usually use either natural gas or coal would replace these resources. This in turn could cause the price of electricity to rise.

- **Unplanned Outages**: The imbalance between the supply and demand could cause large fluctuations in prices: When supply is less than demand or when demand is changing rapidly, price spikes could arise and when this is accompanied by a generation outage at peak hours, price spikes could be very high. When the system load increases, the marginal cost of generation increases and more expensive peaking units (such as gas-fired units) would be brought on line which could lead to large price spikes.

- **Constrained Transmission (Congestion)**: When transmission capability is insufficient to withstand scheduled flows, the price of electricity on the load side of a congested path could be increasingly volatile and uncertain because smaller low-cost generation cannot be transmitted to loads during hours when transmission congestion exists.

- **Market Power**: Exercising market power by electricity market participants could manipulate prices and cause price volatility. In California, the PX monitors market operations, and trading rules would be altered to prevent market manipulation when these practices could arise. Market participants may use financial contracts to hedge price volatility risks. At the same time that the volatility in prices could cause large losses, it could also cause large profits if predicted earlier. Financial contracts would enable participants to adjust exposures to volatility and to limit the level of risk. The most commonly used electricity contracts are futures and forward contracts.

- **Market Participant:** Market participants themselves may cause price volatility in one of two ways: either by misrepresenting the actual amount of their loads or by performing gaming practices. In the first type, participants either under-schedule or over-schedule their loads. Both cases would require a response from the ISO in the imbalance energy market. Under-scheduled load may significantly change the price of energy in the imbalance market when reserves are inadequate. Market participants may tend to go for a gaming process when they submit insufficient load schedules to hedge high prices in the PX energy market. They presume that it would be possible to save money through the imbalance energy market by submitting insufficient load schedules to the PX to get cheaper imbalance energy from the ISO. The net result of this behavior would be an unreliable situation in the operation of the power system.

7.2.2 Measuring Volatility. Historical volatility is defined as the annualized standard deviation of percent changes in futures prices over a specific period. It is an indication of past volatility in the marketplace. In historical volatility, a financial variable's volatility is directly estimated from recent historical data for the variable's value. Historical volatility gives an indication of how volatile the variable has been in the recent past for which historical data is tracked. Implied volatility is a measurement of the market's expected price range of the underlying commodity futures based on market-traded options premiums[3]. Implied volatility is a timely measure, which reflects the market's perceptions today. Implied volatility can be biased, especially if they are based upon options that are thinly traded[4].

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[3] Glossary of Terms, http://www.nymex.com/exchange/glossary.html
[4] Contingency Analysis, http://www.contingencyanalysis.com/

We use *standard deviation* (σ), which measures the uncertainty or dispersal of a random variable. When a financial variable (random variable) such as electric energy price is described as highly volatile, it means that it has a high standard deviation. In other words, standard deviation is a measure of the volatility of a random variable such as spot price. Figure 7.2 illustrates how standard deviation would measure the high volatility (Figure 7.2.a) and low volatility (Figure 7.2.b). Probability distribution functions in both cases are given in Figures 7.2.c and 7.2.d.

As shown in Figure 7.2, standard deviation for a specific range of a random variable X is a measure of the width of the probability distribution of the variable X. Standard deviation (i.e., square root of variance) is a measure of risk. On the other hand, the variance (expected value of squared deviations from the mean) is a measure of the dispersion of a probability distribution. As we all know,

Standard deviation =

$$\sigma = \sqrt{Expected\ value\ of\ [X^2] - (Expected\ value\ of\ [X])^2}$$

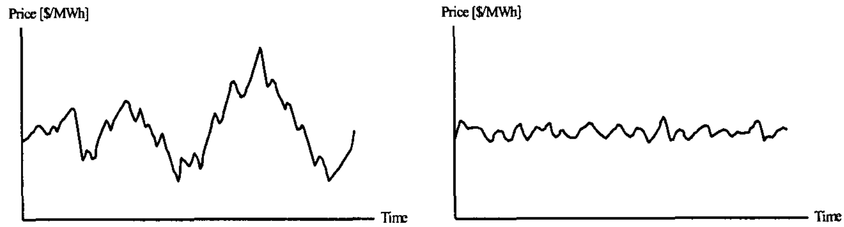
$$= \sqrt{E[X^2] - (E[X])^2}$$

Variance $= \sigma^2 = E[X^2] - (E[X])^2$

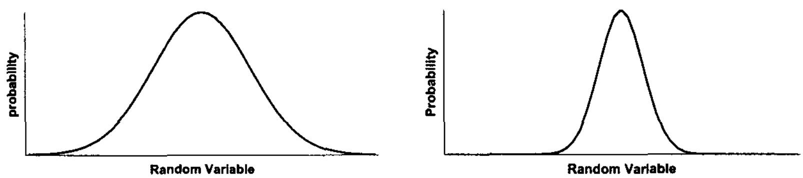
Volatility[5] $= v = \sigma / \sqrt{t}$; t=1/252[6]

[5] Volatility is the standard deviation normalized by time, where time is expressed in annual terms.

[6] In electricity markets, 252 is the number of business days of a year



a. Random variable with high volatility *b. Random variable with low volatility*



c. High standard deviation *d. Low standard deviation*

***Figure 7.2** Volatility-Standard Deviation Relations*

Example 7.1

Assume that in January 25, the PX's spot price is $30.0/MWh, and the volatility of the PX's price is calculated to be 0.15 (15%), then the PX's price is expected to be within the range of $30 \pm 0.15\times30$ or $[25.5,34.5]/MWh in 68%[7] of the next year.

The annualized percent volatility is the percent volatility that would occur over a one-year period. It is found by scaling the daily volatility by

[7] 68% corresponds to one standard deviation, i.e., 68% of the time, observations will be within one standard deviation of the mean, and the other 32% of observations lie more than one standard deviation away from the mean.

$\sqrt{number\, of\ market\ days\, in\, a\ year}$. In electricity markets, annualized volatility is found by multiplying the standard deviation of daily price changes with the square root of 252 (i.e., the number of business days of a year). Figure 7.3 illustrates the example.

Example 7.2

A participant in electricity market has 1% daily volatility estimate for his investment. This implies that the daily returns for his investment are expected to vary (in average) about 1% from day to day. The annualized volatility is:

$$\sigma_{annualized} = \sigma_{daily} \times \sqrt{252} = 0.1 \times 15.874 = 0.15874 \text{ or } 15.874\,\%$$

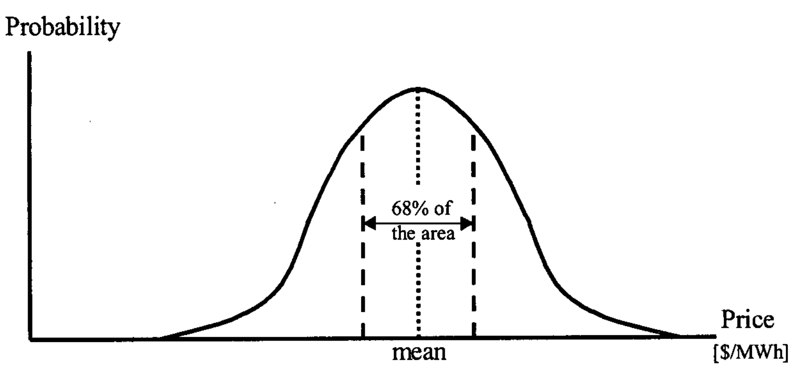


Figure 7.3 Illustration of the Example

7.3 ELECTRICITY PRICE INDEXES

To analyze price volatility, Dow Jones (DJ) price indexes are used. Dow Jones publishes volume-weighted price indexes for the following locations[8] (as was available on January 13, 2001):

- *California Oregon Border*: The Dow Jones California Oregon Border (DJ-COB) Electricity Index is the weighted average price of electric energy traded at the California-Oregon and Nevada-Oregon Borders, quoted in dollars per megawatt hour. Volume is in megawatt hours.
- *Palo Verde*: The Dow Jones Palo Verde (DJ-PV) Electricity Index is the weighted average price of electric energy traded at Palo Verde and West Wing, Arizona, quoted in dollars per megawatt hour. Volume is in megawatt hours.
- *PJM Sellers' Choice*: The Dow Jones Pennsylvania-New Jersey-Maryland (DJ-PJM) Sellers' Choice Electricity Index is the weighted average price of electric energy traded for delivery in the Pennsylvania, New Jersey, Maryland market, quoted in dollars per megawatt hour. Volume is in megawatt hours.
- *PJM Western Hub*: The Dow Jones Western Hub Electricity Index is the weighted average price of electric energy traded at PJM Western Hub quoted in dollars per megawatt hour. Volume is in megawatt hours.
- *Mid-Columbia*: The Dow Jones Mid-Columbia Electricity Index is the weighted average price of electric energy traded for delivery at Mid-Columbia quoted in dollars per megawatt hour. Volume is in megawatt hours.
- *Four corners (4C)*: The Dow Jones Four Corners (DJ-4C) Electricity Index is the weighted average price of electricity traded

[8] EnergyOnline,
Dow Jones Indices, http://www.energyonline.com/default.asp, and
Explanatory Notes, http://www.energyonline.com/dji/idxnotes.asp

for delivery at Four Corners, Shiprock and San Juan, New Mexico, quoted in dollars per megawatt hour. Volume is in megawatt hours.

- *NP-15*: The Dow Jones NP-15 Electricity Index is the weighted average price of electric energy traded for delivery at NP-15 quoted in dollars per megawatt hour. Volume in megawatt hours.
- *SP-15*: The Dow Jones SP-15 Electricity Index is the weighted average price of electricity traded for delivery at SP-15 quoted in dollars per megawatt hour. Volume is in megawatt hours.
- *Cinergy*: The Dow Jones Cinergy Electricity Index is the weighted average price of electricity traded into the Cinergy Control Area quoted in dollars per megawatt hour. Volume is in megawatt hours.
- *Mead/Market Place*: The Dow Jones Mead/Market Place Electricity Index is average price of electric energy traded for delivery at Mead, Market Place, McCullough and Eldorado quoted in dollars per megawatt hour. Volume is in megawatt hours.

DJ on-peak price index for COB may be compared with the on-peak PX day-ahead prices. Likewise, DJ on-peak price index for the Palo Verde (PV) may be compared with the on-peak PX day-ahead prices. In analyzing different trade operations, some specific factors are compared such as average prices, volumes of trades and volatility. The analysis can give an indication of price stability during a time period, trends in prices either declining or inclining and comparisons of volumes of trade between different locations. For example, in California, a comparison could be made for volumes traded on PX, COB and PV.

In electricity markets, Dow Jones indexes work as benchmarks for price discovery. As an illustration of these indexes, Table 7.1 and Figure 7.4 show the May 1999 Dow Jones Palo Verde Electricity Index, as was available in May 25, 1999, where[9]:

- Firm energy: Electric energy that meets the minimum criteria of being financially firm and backed by liquidating damages.
- Non-Firm: Electric energy that it is subject to interruption for any reason at any time.

[9] EnergyOnline, Explanatory Notes, http://www.energyonline.com/dji/idxnotes.asp

Table 7.1 Weighted Average Price of Electricity traded at Palo Verde and West Wing, Arizona

DATE	NON-FIRM				FIRM			
	ON-PEAK		OFF-PEAK		ON-PEAK		OFF-PEAK	
	Price	Volume	Price	Volume	Price	Volume	Price	Volume
5/18/99	21.76	1050	13.69	750	30.09	20976	18.36	720
5/17/99	24.71	1298	14.05	440	28.92	13840	18.50	200
5/16/99	21.14	575	13.06	930	28.75	0	16.75	200
5/15/99	19.71	350	13.00	100	27.47	21600	16.37	760
5/14/99	21.77	956	14.00	100	27.55	20800	16.37	760
5/13/99	21.29	425	19.69	80	28.21	19600	16.05	1000
5/12/99	22.96	84	15.61	265	26.60	26800	14.82	760
5/11/99	21.51	1338	13.76	844	25.19	19840	13.00	400
5/10/99	20.47	2060	11.01	590	28.34	17840	17.50	400
5/09/99	15.17	825	11.18	855	24.50	400	15.75	0
5/08/99	18.05	1130	12.34	1185	27.26	18000	15.56	320
5/07/99	23.98	1164	14.95	215	27.26	18000	15.00	200
5/06/99	22.66	916	12.80	750	28.36	15200	14.42	2360
5/05/99	22.91	2250	12.12	835	26.57	16032	13.60	496
5/04/99	19.80	2180	11.95	1075	25.71	19040	11.75	200
5/03/99	21.30	445	10.67	150	26.73	25200	13.93	1000
5/02/99	18.00	150	10.63	735	20.00	240	13.50	0
5/01/99	13.02	2915	10.62	1734	23.11	29200	12.00	600

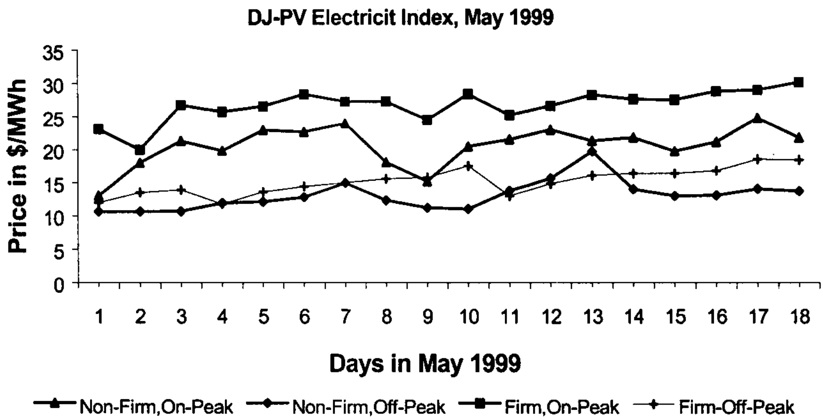


Figure 7.4 Price Index

- On-Peak Hours: Between 6:00 a.m.-10:00 p.m., every day, prevailing time.
- Off-Peak Hours: Between 10:00 p.m. and 6:00 a.m. every day, prevailing time.

7.3.1 Case Study: Volatility of Prices in California. In California, the ISO's average *ex-post* price and the PX's average day-ahead price were very different in each day between April 1- May 27, 1998. During this period, prices were extremely volatile at some times. The large changes in the ISO's ex-post price were due to over/under generation which were caused by: increased temperature beyond the expected value, ISO's forecasting errors, and excess hydroelectric generation. During April 1998, some factors caused electricity prices to go up in the Western region of California. These factors were constrained transmission at certain times on the California-Oregon inter-tie and disruption in coal and nuclear generation.

In physical contracts, a seller has an obligation to deliver the electricity that buyer and seller have agreed-upon at the predefined future time. In contrast to physical contracts, financial contracts do not include the delivery of electricity. Financial contracts are either cash settled based on the contracted future price, or cash settled based on the difference between the contracted future price and a reference price. In both alternatives, the contracted electricity quantity would be used for the settlement calculation. The difference between the reference price (such as the ISO's *ex-post* price) and contract price are settled daily for future contracts utilizing margin calls, in which market participants pay the margin to a clearinghouse (exchange).

In California, physical contracts of electricity that are scheduled for delivery to buyers on a future expiration date, must be scheduled with the ISO before the delivery date. Figure 7.5 illustrates the idea of financial contracts. For example, two parties (e.g., IPS and GenCo) agree initially (in January) on a price P_{Con} with an expiration date in July. The two parties will settle based on the difference between the price at which they confirmed the contract and the ISO *ex-post* price. On a monthly basis, each party pays or is paid by the counterparty based on the difference between the two prices.

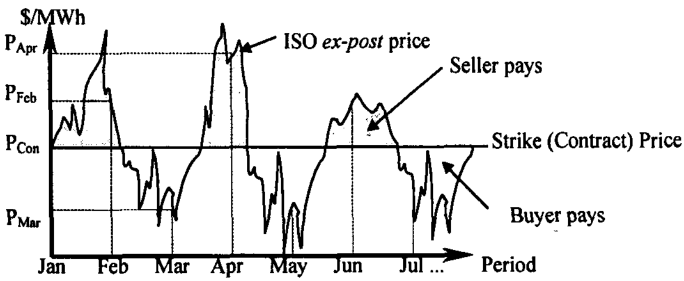


Figure 7.5 Financial Contracts

To analyze the volatility of prices in California, four prices are usually compared during the analysis. The prices are the *annualized volatility* of Cal PX, COB, PV and Cal ISO. For each price either on-peak or off-peak prices are used. Hypothetical data that illustrates this issue are shown in Table 7.1. Also, price differential between Cal ISO and PV is usually compared with price differential between Cal ISO and COB. Likewise, price differential between Cal PX and PV is usually compared with price differential between Cal PX and COB. A hypothetical figure illustrates this comparison in Figure 7.6. In addition, the Cal ISO and Cal PX prices are usually compared.

Table 7.1 Annualized Volatility of Off-Peak Prices

	January	February	March	April
Cal ISO	900	1700	3800	800
Cal PX	200	1000	800	400
PV	100	210	220	480
COB	120	190	570	250

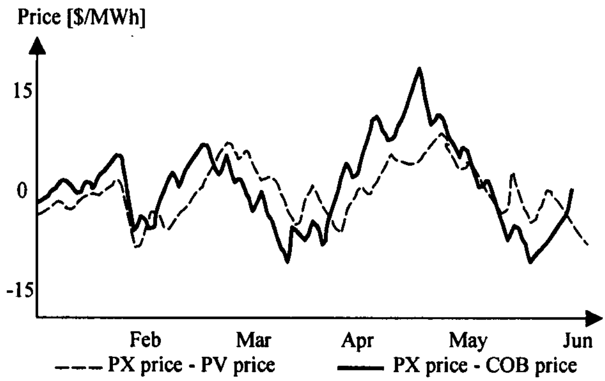


Figure 7.6 Hypothetical On-Peak Price Differentials of Five Months

A typical analysis of electricity price indicates that the price of Cal ISO is much more volatile than the Cal PX price, the COB price is less volatile than that of PV and the Cal PX price movements would track Cal ISO price movements. All these examples are hypothetical which represent the set of conclusions that an analyst could obtain from price analysis and comparisons between price differentials. Another issue that is of concern during the analysis is the daily volume of trades on different markets.

The following section discusses a means of measuring the risk involved in electricity price volatility.

7.3.2 Basis Risk. The difference between the electricity spot price and the price of the nearest futures contract for the electricity at any given time is called *basis*. *Basis risk* represents the uncertainty as to whether the cash-futures spread will widen between the times a hedge position is implemented and liquidated.

Example 7.3

The NYMEX COB futures contract is designed for delivery in the western United States. When a participant such as a consumer from the eastern U.S. tries to hedge price risk and uses NYMEX COB futures contracts, the participant could expose itself to a large basis risk.

Prices differ from region to region and even though, under normal circumstances, prices in any two regions could show a reliable correlation, the same prices under other circumstances could swing in opposite directions. This is due to the fact that there is not a single, interconnected electricity market in the U.S., and electricity prices are affected by regional supply and demand conditions, the technology and the type of fuel used in generating power. In addition, NYMEX futures offer only one set of contract terms specifying on-peak power, creating another source of basis risk where the market demonstrates large price swings between on-and off-peak load times. The same problem happens in CBOT contracts.

Basis contracts are used by market participants to hedge changes in differential price between any two locations (for example, NYMEX futures at the PV trading point and a different location.) By using these contracts, participants would lock in price differences between the two points.

Example 7.4

A power producer would like to lock in electricity price in city **C**, California. The producer sells a 10,000 MWh futures contract to a participant through NYMEX for \$20/MWh for a delivery in three months. Also the producer sells a basis swap to a marketer (basis swap counterparty) such that the producer agrees to pay the **C** spot price (in three months) in exchange for the COB price (in three months) plus a premium of \$1.0/MWh received from the marketer.

Assume that in three months, the **C**'s spot price is \$25/MWh and the COB spot price is \$30/MWh.

In three months:

- The producer sells electricity in **C**

- Receives the **C**'s spot price ($25/MWh): 25×10,000 = $250,000
- Pays the **C**'s spot price ($25/MWh) to the marketer: 25×100 = $250,000
- Receives the COB spot price ($30/MWh) plus a fixed premium from the marketer: 30×10,000 +1.0×10,000= $300,000+$10,000.
- Buys a futures contract for the COB spot price ($30/MWh): 30×10,000 = $300,000

Results: The producer	Receives	Pays
	$250,000	$250,000
	$300,000 +Premium	$300,000
Total =	$550,000 + Premium	$550,000
or	$550,000 + $10,000	$550,000

→ Net: producer receives a premium of $10,000

Here, all transactions cancel out and the producer would expect to receive the fixed price for the original futures contract ($20/MWh) plus the premium received from the marketer. The cash flows of this example are shown in Figure 7.7.

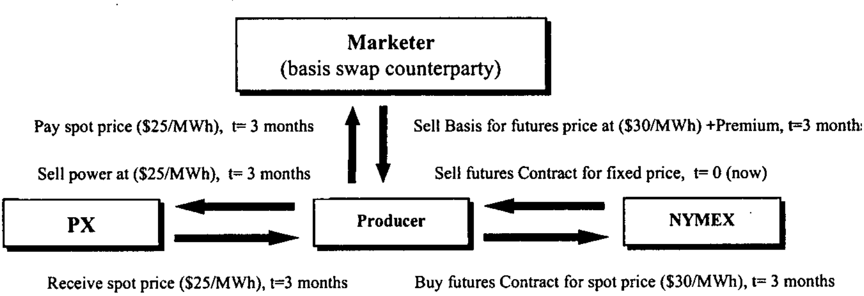


Figure 7.7 Cash Flows of a Producer's Basis Swap Transaction

7.4 CHALLENGES TO ELECTRICITY PRICING

7.4.1 Pricing Models. One of the major problems facing market participants, especially hedgers, in restructured electricity markets in the U.S. is the problem of large errors caused by using unsophisticated versions of the Black-Scholes[10] model to price physical power options. This model was originally derived as a pricing model to value European securities options and futures options. In addition to other assumptions, this model assumes that the price volatility is constant and the price series is continuous. Some alternatives to pricing physical power options have been proposed based on this model to take into consideration the nature of electricity that is different from other commodities.

Some market participants insist on utilizing pricing models other than the Black-Scholes model. It is claimed that using the Black-Scholes model to price electricity options would result in large errors due to the assumptions that this model applies to electricity without taking into account the market's special circumstances. The Black-Scholes proposes the following price dynamics:

$$\frac{dF(t,T)}{F(t,T)} = b\,\mathrm{dW(t)}$$

where,

$F(t,T)$	Price at time t for future delivery of power at time T
b	Constant Volatility
dW(t)	Standard Brownian motion[11] (also known as Wiener Process)

When this model is used to price the hourly or daily delivery of electric power, some problems could arise. These problems are:

[10] Named after Fischer Black and Myron Scholes who derived the model

[11] Brownian motion is a Markovian process, i.e., it has no memory and the change in the process over the next time interval is independent of what happened in the past.

(1) Customer loads are following complex daily patterns and are sensitive to weather fluctuations which implies high volatility: The classical Black-Scholes model assumes a constant volatility, does not take into account the weather impact on volatility over the period of the option and does not discriminate between on-peak and off-peak conditions.

(2) Electricity is a non-storable commodity: The short-term supply is largely affected by physical system dynamics such as generation and transmission outages that would result in large price spikes. The Black-Scholes model assumes smooth price changes under these circumstances.

(3) Generating units could be forced out in unplanned manner during peak-demand summer months. Unplanned outages cause electricity prices to increase dramatically in the market due to the fact that more expensive units will be needed to serve the load.

In a nutshell, any framework to price physical power options should take some factors into consideration. These factors include the physical nature of electricity, generation availability, dynamic volatility, transmission limitations and changeable load.

7.4.2 Reliable Forward Curves. A forward curve of electricity presents a set of forward prices for electricity, i.e. it determines a set of current market prices for the sale of electricity at specified times in the future; the curve determines the present value of electricity to be delivered in the future. For other commodities that have been traded for a long time, forward curves are readily established, but for electricity in a restructured environment, much of the appropriate market information is not yet available due to the short experience. The challenge is to construct and use forward curves based on limited available data.

Forward curves in electricity markets work as benchmark or index of value. When the curve shows higher future prices, current values of production facilities and purchase agreements will increase. On the other hand, a decreasing forward curve means that the value of existing sales agreements and a utility's customer base are decreasing. In the next section, we will elaborate on forward curves.

Constructing forward curves should take the risk explicitly into account: incorporate estimates of market uncertainty in ways that will be most useful for decision-making and integrate forward curves into participants' own analytical models. To build a forward curve for mid-term prices, futures and options prices should be analyzed coupled with the probabilistic system modeling. Even though the load growth and fuel price shifts affect long-term electricity prices considerably, long-term electricity prices are driven by performance improvements such as improvements in new generation technology. For long-term prices, market data provide little guidance in constructing forward curves and building the curve is mainly based on the probabilistic system modeling, asset investment and retirement analysis.

7.5 CONSTRUCTION OF FORWARD PRICE CURVES

7.5.1 Time Frame for Price Curves. Constructing a forward curve depends mainly on a time frame, which may be for a few months (short-term), a few years (medium-term) or over several years (long-term). In short-term, the price of electricity changes mainly with changes in weather conditions, supply outages, and interregional power flows. In short-term, guidance is offered by historical spot price data coupled with deterministic system modeling. Load growth, shifts in fuel price, and customer response to retail price changes would determine medium-term price fluctuations.

7.5.2 Types of Forward Price Curves. As was mentioned in the preceding section, one of the major challenges facing market participants is the lack of reliable long-dated forward prices. In restructured power markets, suppliers are competing to reach end-use customers with the lowest possible price that would guarantee profits. Wining a customer's contract is generally based on pricing strategies that would take into account electricity market trends and the information on the true cost of serving customers. The forward price of electricity is the key in pricing retail and wholesale electricity. Forward curves represent a good starting criterion to price electricity and, if utilized with experience in knowing variations in customer characteristics and supply/demand situations, they produce hedging strategies for different market participants such as suppliers, marketers, independent power suppliers and others. In this section, we highlight this topic which is very important in restructured electricity markets and the resources on this topic are very rare.

Even though the age of restructuring is still short, historical spot prices can be used to model forward price projections or forecasts, and as time passes, modeling forward prices will be improved by incorporating current market data, acquiring experience in market movements and effects of large transactions. A consideration should be given to interactions between electricity and other economic variables that drive electricity prices such as fuel cost, weather patterns, supply outage, transmission outages, regulatory developments and any other factors that affect electricity prices[12].

To construct reliable forward curves and predict volatility for a specific period of time, estimates should be based on analyzing the supply and demand balance in the electricity markets, and by utilizing uncertainties in fuel prices and load.

Forward curves take on three behaviors: *Backwardation, Contango,* and a combination of the two.

- **Backwardation.** It is a market situation in which futures prices are lower in each succeeding delivery month. In other words, backwardation refers to markets where shorter-dated contracts are traded at a higher price than that of longer-dated contracts. Backwardation is also called the inverted market, and it is expressed by plotting the price variation with time as shown in Figure 7.8, where electricity price curve slops downwards as time increases. Backwardation gives a forward/spot market relationship in which the forward price is lower than the spot price. The cause of backwardation in electricity markets is that it is necessary for forward prices to trend upward towards the expected spot price in order to attract speculators (buyers) to enter into trades with hedgers (sellers). The opposite of backwardation is contango.

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[12] Electricity Derivatives, http:// www.schoolfp.cibc.com/yb98/chap01.htm

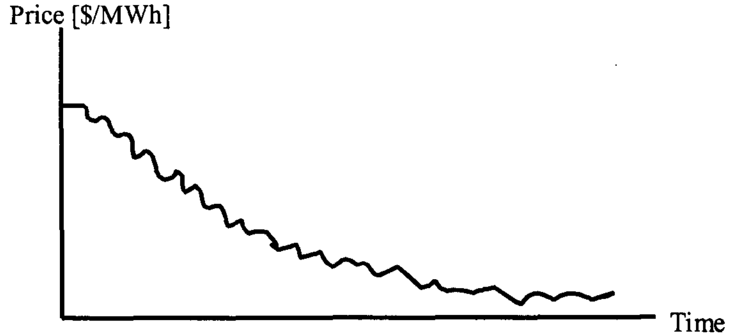

Figure 7.8 Illustration of Backwardation (Inverted Market)

- **Contango.** Opposite to the case of backwardation, contango is a term often used to refer to electricity markets where shorter-dated contracts traded at a lower price than longer-dated contracts in futures markets. When a market situation exists such that prices are higher in the succeeding delivery months than in the nearest delivery month, we say contango exists. It is expressed by plotting the prices of contracts against time, where electricity price curve slops upwards as time increases as shown in Figure 7.9. Contango gives a forward/spot market relationship in which the forward price is greater than the spot price. Often, the forward price exceeds the spot price by approximately the net cost to carry/finance the spot electricity or security until the settlement date of the forward contract.

- **Combination.** Figure 7.10 shows a combination of the two previously mentioned behaviors of forward curves. This is an example of a situation when the forward curve takes a backwardation form in the short-term part of the curve and a combination of two in the long-term part of the curve. The behavior of the curve depends on expectations regarding the supply/demand balance in the market in addition to other seasonal factors that drive prices.

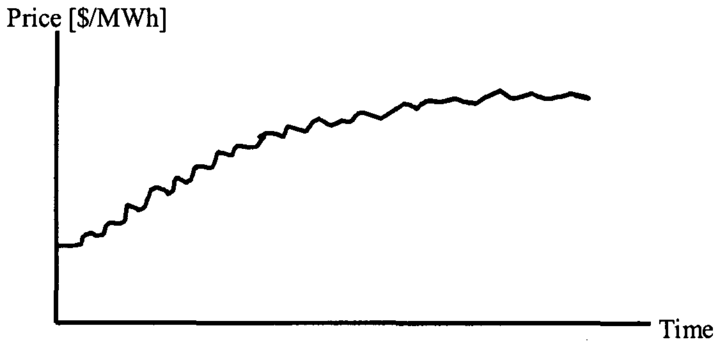

Figure 7.9 Illustration of Contango

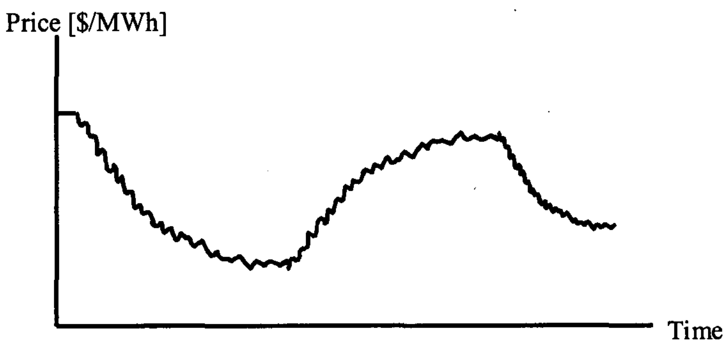

Figure 7.10 A Forward Curve Combines Backwardation and Contango

In the following, we will discuss the forecasting process for the short-term price of electricity.

7.6 SHORT-TERM PRICE FORECASTING

There are many physical factors that would impact short-term electricity price. In practice, it would be impossible to include all these factors in price forecasting, because either the factors are unknown or the related data are unavailable. The sensitivity analysis is a good way of selecting the prominent factors in price forecasting. Given a factor, if the price is insensitive to this factor, we could claim that the factor is not impacting the price and could be ignored with minute error in price forecasting.

7.6.1 Factors Impacting Electricity Price. An analysis of price movements presents a conceptual understanding of how factors could affect the price. For simplicity, we only discuss variations of spot price, or market clearing price (MCP), in this section.

After an auctioneer (ISO or PX) receives supply and demand bids, it aggregates the supply bids into a supply curve (S) and aggregates the demand bids into a demand curve (D). The intersection (S) and (D) represents the MCP, as is illustrated in Figure 7.11.

According to this figure, we would present the following discussions.

(1) Basic Analysis of Price Movements

- Case B1: S curve is shifted upward: MCP increases and quantity decreases.
- Case B2: S curve is shifted downward: MCP decreases and quantity increases.
- Case B3: D curve is shifted upward: MCP increases and quantity increases.

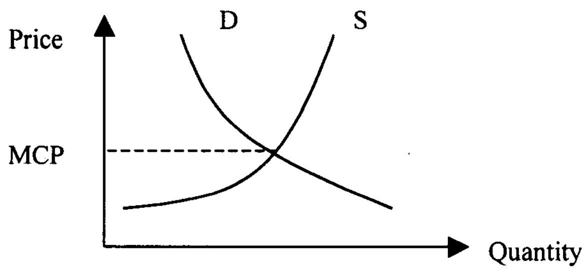

Figure 7.11 Calculation of MCP

- Case B4: D curve is shifted downward: MCP decreases and quantity decreases.
- Case B5: S curve is shifted to the left: MCP increases and quantity decreases.
- Case B6: S curve is shifted to the right: MCP decreases and quantity increases.
- Case B7: D curve is shifted to left: MCP decreases and quantity decreases.
- Case B8: D curve is shifted to right: MCP increases and quantity increases.

(2) Actual Cases Pertaining To The Above Price Movements

- Case A1: Supplier would decrease the price. This is case B2.
- Case A2: Demand would increase the price. This is case B3.
- Case A3: A generator would be force-outaged (or a bid is withdrawn). This is case B5.
- Case A4: A new supplier would enter the market. This is case B6.
- Case A5: A generator would be restored. This is case B6.

- Case A6: A new demand would enter the market. This is case B8.
- Case A7: Gas (or oil) price would decrease. Suppliers would then decrease their prices. So, it is case B2.
- Case A8: Gas (or oil) price would increase. Suppliers would then increase their price. So, it is case B1.

It is vital to perform the above seemingly simple analysis, as it would exhibit the variation of price in practical markets. For example, we would learn, from the above analysis, that the price of gas (or oil) could affect MCP.

7.6.2 Forecasting Methods.

- **Simulation Method:** Usually the analysis of price volatility is based on the probability distribution for each of a series of key drivers. The users can determine the distribution of input variables using historical data. For example providers could use a beta distribution, which requires the estimation of the maximum, minimum and the most likely value of input variables. To capture the effects of uncertainty, samples are drawn from the distribution of the input variables using Monte Carlo methods and a scenario is created. For each scenario the tool is used to simulate the market prices. Running a sufficient number of scenarios then produces a stable distribution of long-term market prices. The volatility indices and all the traditional measures are then developed from the statistical distribution of the variable. In addition to the forward price volatility calculations, the distribution of generator revenues under various outcomes for the drivers must also be determined. This provides information relating to the risk associated with participation in the supply market.

- **Artificial Neural Network Method:** The artificial neural network method has received more attention in the field of forecasting because of its clear model, easy implementation and good performance. The method was applied before to load forecasting in electric power systems. Here, we use the MATLAB for training the artificial neural network in short-term price forecasting, which provides a very powerful tool for analyzing factors that could impact electricity prices.

7.6.3 ANALYZING FORECASTING ERRORS

Let V_a be the actual value and V_f the forecast value. Then, Percentage Error (PE) is defined as

$$PE = (V_f - V_a) / V_a \times 100\% \tag{7.6}$$

and the Absolute Percentage Error (APE) is

$$APE = |PE| \tag{7.7}$$

then, the Mean Absolute Percentage Error (MAPE) is given as

$$MAPE = \frac{1}{N}\sum_{i=1}^{N} APE_i \tag{7.8}$$

MAPE is widely used to evaluate the performance of load forecasting. However in price forecasting, MAPE is not a reasonable criterion as it may lead to inaccurate representation. The problem with this MAPE is that if the actual value is large and the forecasted value is small, then APE will be close to 100%. In addition, if the actual value is small, APE could be very large if the difference between actual and forecasted values is small. For instance, when the actual value is zero APE could reach infinity if the forecast is not zero. So, there is a problem with using APE for price forecasting. It should be noted that this problem does arise in load forecasting, since actual values are rather large, while price could be very small, or even zero.

Alternate Definition of MAPE: One proposed alternative is as follows. First we define the average value for a variable V:

$$\overline{V} = \frac{1}{N}\sum_{i=1}^{N} V_a \tag{7.9}$$

Then, we redefine PE, APE and MAPE as follows:

Percentage Error (PE):

$$PE = (V_f - V_a)/\overline{V} \times 100\% \tag{7.10}$$

Absolute Percentage Error (APE):

$$APE = |PE| \tag{7.11}$$

Mean Absolute Percentage Error (MAPE):

$$MAPE = \frac{1}{N}\sum_{i=1}^{N} APE_i \tag{7.12}$$

The point here is that we would use the average value as the basis to avoid the volatility problem.

7.6.4 Practical Data Study. In this section, we use artificial neural networks to study price forecasting based on the practical data. We will study the impact of data pre-processing, quantities of training vectors, quantities of impacting factors, and adaptive forecasting on price forecasting. We will also compare the artificial neural network method with alternative methods. The new definition of MAPE is illustrated with practical data and its advantages are discussed.

We use the data for California power market in our study, mainly including system loads and unconstrained MCPs, from 1/1/99 to 9/30/99. The curves are given below in Figures 7.12 and 7.13. Additional data can be obtained from:

http://www.ucei.berkeley.edu/ucei/datamine/datamine.htm.

In the following, we present a few of our observations based on using artificial neural network for price forecasting.

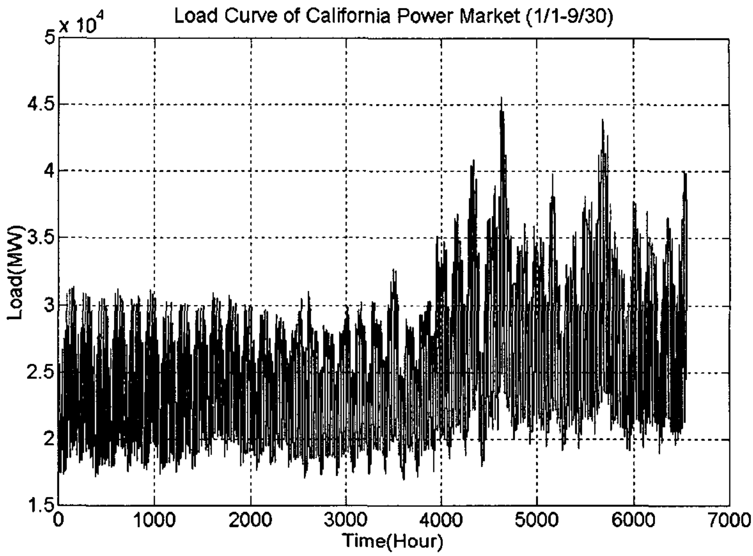

Figure 7.12 Load in California Power Market from 1/1/99 to 9/30/99

7.6.4.1 Impact of Data Pre-Processing. First we do not pre-process the data. Figure 7.14 shows the forecasting results for practical data in Figure 7.13 from 05/29 to 06/04, in which the curve with asterisk shows the forecasted price. The new MAPE is about 50% which is unacceptable. MAPE is very large since the actual prices are zero in some occasions. (6:00 AM in 05/29 for example, hour 6 in Figure 7.14) or close to zero (6:00 AM in 06/04 for example, hour 150 in Figure 7.14). In this case, the traditional MAPE would have failed severely to provide a reasonable index to measure the quality of forecast.

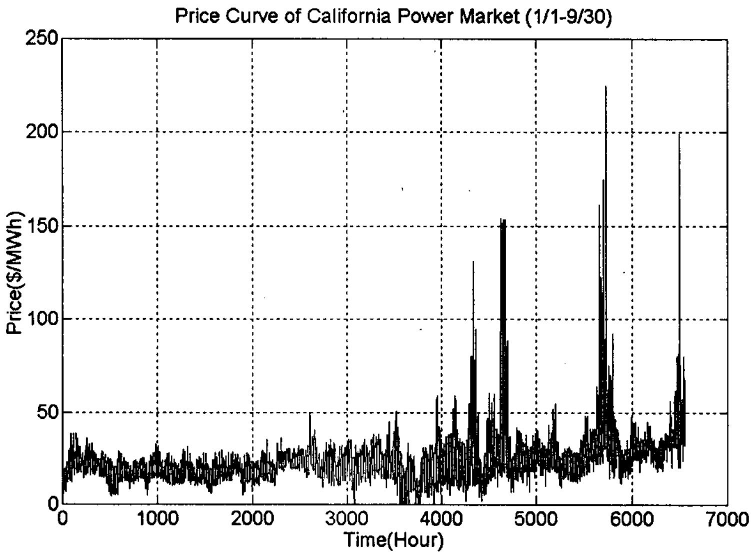

Figure 7.13 *Price Curve in California Power Market from 1/1/99 to 9/30/99*

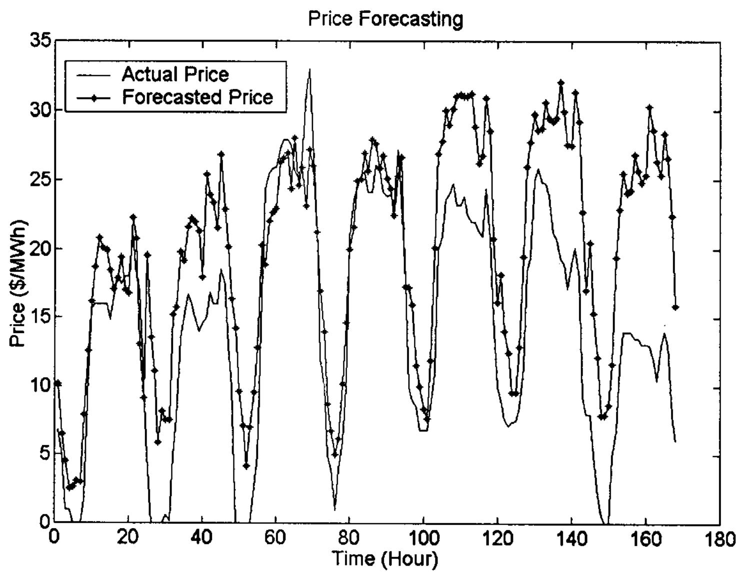

Figure 7.14 *Application of New MAPE on Forecasting*

Now, we study the impact of data pre-processing for artificial neural network. Figure 7.15 shows the actual prices of Figure 7.13 from 7/1 to 8/4 with spikes in 7/1, 7/12, 7/13, 7/14 and 7/15. The training period is from 7/1 to 7/28 and the testing is for a period from 7/29 to 8/4. Two data pre-processing methods for eliminating price spikes are considered: limiting price spikes or excluding price spikes.

If we limit price spikes (i.e., if the price is larger than 50 \$/MWh, we set it to 50 \$/MWh), the training and testing performances will both be improved (training MAPE will be 7.66% and testing MAPE will be 13.82%). If we exclude the days with price spikes, the training and testing performances will both be improved more significantly (training MAPE is 5.35% and testing MAPE is 11.43%).

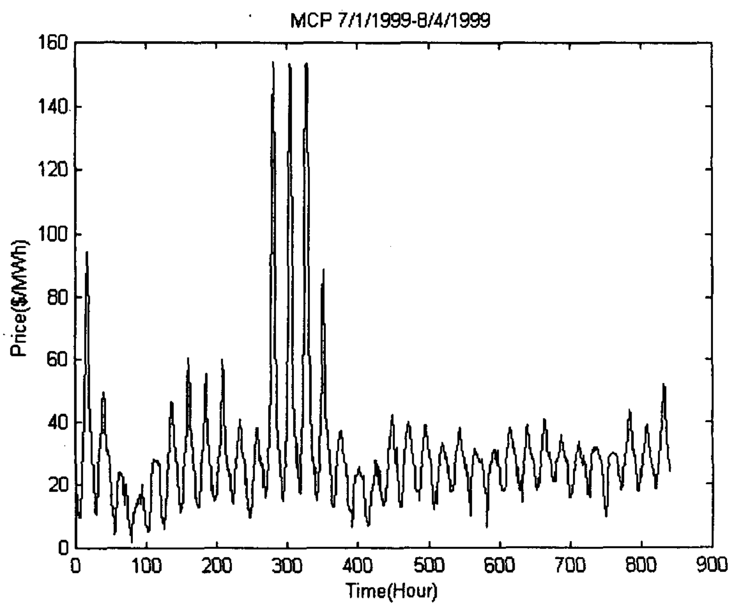

Figure 7.15 Impact of Data Pre-processing on Forecasting

The improvement in training MAPE is due to the disappearance of price spikes (excluded or limited). Consequently, without price spikes, network training can find a more general mapping between input and output. Thus, testing MAPE will also be improved.

Since price spikes are the indicative of abnormality in the system, we do not intend to delete them from the training process. Hence, we adhere to the option of limiting the magnitude of spikes, rather than eliminating them totally.

7.6.4.2 Impact of Training Vectors. In this section, we use the data in Figure 7.13 again and study the impact of the quantity of training vectors on forecasting performance. In Table 7.2, the study period is from 2/1 to 4/4. The testing period is fixed, from 3/29 to 4/4 (1 week). The training period could be varying from 1 week to 8 weeks and the Case No. corresponds to the number of weeks in training. In Case 1, the training period is from 3/22 to 3/28 (1 week). In Case 2, the training period is from 3/15 to 3/28 (2 weeks). In Case 8, the training period is from 2/1 to 3/28 (8 weeks). The training periods of Case 3, 4, 5, 6 and 7 are defined similarly.

Since the weights of neural network are initialized randomly, every time we train and test the neural network, we will get a somewhat different result. To decrease the effect of random errors, we repeat the training and testing procedure five times for each case with the results shown in Table 7.2, and Figure 7.16 compares the testing MAPEs for different cases.

From Figure 7.16, we see that testing MAPEs would first decrease with the increase in the quantity of training vectors (from Case 1 to Case 4), then remain flat (from Case 4 to Case 6), and finally increase as we further increase of quantity of training vectors (from Case 6 to Case 8). The reason is discussed as follows.

Table 7.2 Impact of the Quantity of Training Vectors[+]

Case No	Training Vectors	Testing Vector	Testing MAPE (%) Average	Minimum	Maximum
1	3/22 thru 3/28(7)	3/29 thru 4/4(7)	12.77	12.59	12.96
2	3/15 thru 3/28(14)		12.21	11.68	12.56
3	3/8 thru 3/28(21)		11.88	11.64	12.13
4	3/1 thru 3/28(28)		11.19	11.11	11.25
5	2/22 thru 3/28(35)		11.21	11.13	11.45
6	2/15 thru 3/28(42)		11.26	11.14	11.48
7	2/8 thru 3/28(49)		11.63	11.57	11.70
8	2/1 thru 3/28(56)		11.80	11.40	12.09

[+] In "training vectors" and "testing vectors" columns, "3/22thru3/28" means "from 3/22 to 3/28" and "(7)" means "7 vectors", and so on.

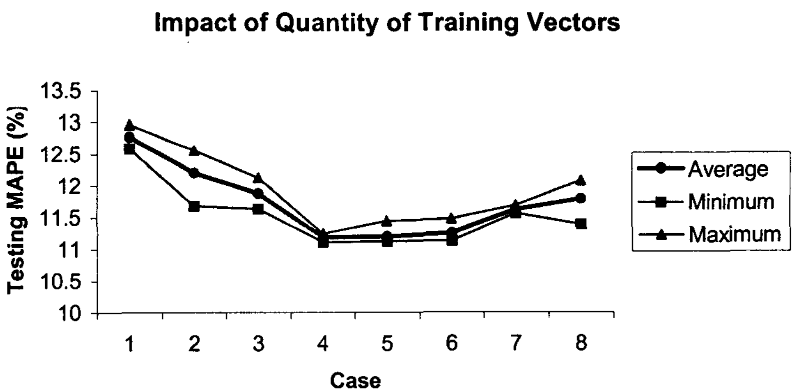

Figure 7.16 Impact of Training Vectors

At first, by introducing more training vectors, we present a more diverse set of training samples, which would result in a more general input-output mapping. Thus, the forecasting performance, measured by the testing MAPE, would improve. However, as we keep increasing the number of training vectors, the diversity of training samples would no longer expand and the additional training would not improve the forecasting results. Thus, the forecasting performance would remain flat. We should point out that by further increasing the number of training vectors, (Cases 6 through 8), the artificial neural network could be over-trained. In other words, the artificial neural network would have to adjust its weights to accommodate the input-output mapping of a large number of training vectors that may not be similar to the testing data to a large extent. Thus, the forecasting performance could get worse with further increasing the number of training vectors.

From the above analysis, the training quality could depend on both diversity and similarity of training vectors. In our study system, Cases 4 through 6 represent a reasonable compromise between diversity and similarity.

On the other hand, Case 4 would require a smaller training time than Cases 5 and 6. So, Case 4 would be the best choice since it can get a good forecast (a smaller testing MAPE here) with smaller effort (less training time). This is not to say that Case 4 is the best for all systems. For other systems, we may first perform a test similar to that described in this section to find the best choice.

7.6.4.3 Impact of Adaptive Forecasting. We can either use the fixed training weights or upgrade the weights frequently and adaptively according to the test results. We refer to the latter case as our adaptive forecasting method.

Studying the profile of price curves, we would expect that the adaptive modification of network weights would provide a better forecast. In Table 7.3, results are shown for comparing non-adaptive and adaptive cases. Here, we learn that, in most cases, adaptive forecasting would provide more accuracy. The reason is that adaptive forecasting takes the newest information into consideration.

Table 7.3 Comparison of Non-adaptive and Adaptive Forecasting

Case No.	Training Vectors+	Testing Vectors	Testing MAPE	
			non-adaptive	adaptive
1	2/1 thru 2/28 (28)	3/1 thru 3/7 (7)	14.04	8.71
2	5/1 thru 5/28 (28)	5/29 thru 6/4 (7)	52.94	25.81
3	7/1 thru 7/28 (28)	7/29 thru 8/4 (7)	12.53	12.59
4	8/1 thru 8/28 (28)	8/29 thru 9/4 (7)	11.59	10.23

+ In "training vectors" and "testing vectors" (28) means "28 vectors"

In Table 7.3, Case No. 2 deserves more attention when there are zero prices in 5/29, 5/30 and 5/31 (see Figure 7.14) and non-adaptive forecasting would not identify this information. In comparison, adaptive forecasting can identify this information and modify network weights accordingly. In essence, adaptive modification of network weights could be critical for getting a good forecasting.

7.7 CONCLUSIONS

The demand for price transparency increased ever since the restructuring process began and the number of participants and marketing operations increased. This is due to the need to enhance the financial stability of electricity markets, which is in turn due to changes in strategies or approaches to buy and sell electricity, which is completely different from the traditional methods under the regulated monopoly. Add to that is mergers of new financial tools and entry of non-electricity participants in electricity markets. All these facts motivated participants to demand efficient tools for price discovery in order to hedge their risks and survive in a competitive market.

In this chapter, we have reviewed some basic concepts in electricity price forecasting, such as price calculation and price volatility. Because of its importance, we also discussed the issue on factors impacting electricity price forecasting, including time factors, load factors, historical price factor, etc. We used the artificial neural network method to study the relationship between these factors and price. We proposed a more reasonable definition on MAPE to avoid the demerits of traditional methods on measuring forecasting in the context of electricity price forecasting. Practical data study showed that a good data pre-processing was helpful, i.e., using too many training vectors or considering too many factors is not good for price forecasting. Practical data study also showed adaptive forecasting could improve forecasting accuracy. We concluded that the artificial neural network method is a good tool for price forecasting as compared to other methods in terms of accuracy as well as convenience.

CHAPTER 8

RTO: REGIONAL TRANSMISSION ORGANIZATION

Summary: Even though many changes have happened to the electric power industry since the two fundamental Orders 888 and 889 were issued, FERC observed that there remained significant barriers to participate in competitive electricity markets and to reach the greatest possible economy. Inefficiencies in the reliability, operation, planning, and expansion of transmission grid, in addition to discriminatory conduct practiced by transmission owners against market participants motivated FERC to introduce the concept of Regional Transmission Organizations (RTOs) [Hoe99, Hog99, Mer00]. This chapter will review the essence of RTOs and bring together many topics that were discussed earlier in this book.

8.1 INTRODUCTION

Under Federal Power Act (FPA), FERC has the authority to ensure that rates, terms and conditions of transmission and sales for resale in interstate commerce by public utilities are just, reasonable and not unduly discriminatory or preferential. FERC also has the authority to promote and encourage regional districts for the voluntary interconnection and coordination of transmission facilities by public utilities and non-public utilities for the purpose of assuring a sufficient supply of electric energy throughout the U.S. with the greatest possible economy.

Since FERC issued its Order 888 and Order 889 in 1996, which contain the foundation required for competitive wholesale power markets, the electric power industry has experienced a wide range of restructuring activities that involve a movement by many states to form retail competition, the divestiture of generation plants by traditional electric utilities, mergers among traditional electric utilities and among electric utilities and gas pipeline companies, the growth in the number of participants such as power marketers and independent power suppliers entering the marketplace, and the establishment of ISOs to administer large parts of transmission system. Since that time, trade activities in bulk power markets have considerably increased and the transmission grid has been loaded heavily and in new fashions. Later, FERC cited several reasons for issuing the final rule on RTOs. Among those reasons were the following:

- Opportunities for undue discrimination continue to exist that may not be remedied adequately by functional unbundling,
- Improper information sharing with respect to some public utilities, i.e., non-compliance with (violations of) the standards of conduct. For example, unauthorized exchanges of competitively valuable information on reservations and schedules between transmission system operators and their own or affiliated merchant operation employees. Likewise, a transmission provider could quickly confirm requests for firm transmission service by an affiliate, while service requests from independent marketers would take much longer to approve.
- Some market participants are reluctant to share operational real-time and planning data with transmission providers because of the suspicion that they will be providing an advantage to their affiliated marketing groups, which in turn impair the reliability of the electric systems.
- Lack of market confidence may discourage generation expansion and results in higher consumer prices.
- Fears of discriminatory curtailment may discourage access to existing generation or discourage entry by new sources of generation that would otherwise alleviate electricity price spikes.
- Suspicion about ATC calculations by participants would let market participants see transactions involving regional markets as more risky transactions, which could constrain the market area and consequently reduces competition and raise electricity prices for consumers.

Hence, on May 13, 1999, FERC issued a Notice of Proposed Rulemaking (NOPR) on RTOs. In the NOPR, FERC proposed a set of minimum characteristics and functions for RTOs, and asked different electric power industry sectors to comment on the NOPR as a feedback to make any changes before a final order could be issued. Some of the comments received by FERC were agreeing with the FERC's proposal, while the others were against the proposal. Every market participant was trying to protect its own interests, which created conflicting objectives and interests. The main debate was on whether or not the formation of RTOs should be voluntary, whether or not FERC had the authority to require the formation of RTOs, whether the RTO would be a for-profit entity or not-for profit entity, whether or not RTOs had an independent authority to set transmission tariffs, and whether or not RTOs had the authority to have the function of market-monitoring.

Based on its views and the inputs from different sectors, FERC issued a final rule, called FERC Order No. 2000[1], in which FERC adopted most of the proposal in NOPR in addition to new requirements for RTOs.

8.2 HISTORICAL PERSPECTIVES FOR ESTABLISHING RTOS

FERC Order No. 888 and FERC Order 889 introduced the ground required to develop and motivate competitive bulk power markets in the U.S., which were issued in April 1996. These rules required public utilities to provide non-discriminatory open access transmission services and included stranded cost recovery rules that would provide a fair transition to competitive markets.

The two orders were accomplishing much of the objectives they asked for. But, they were not ideal to solve the additional problems that arose since power markets started to develop competitive markets. Major changes that occurred between the years 1997 and 2000 include:

[1] Federal Energy Regulatory Commission, Docket No. RM99-2-000: Regional Transmission Organizations, Order No. 2000, FINAL RULE, December 20, 1999

(1) Many integrated utilities have divested some or all of their generating assets. FERC reported that more than ten percent of the U.S. generating capacity was either sold or under contract to be sold. Buyers of this capacity included traditional utilities with specified service territories and independent power producers with no required service territory.

(2) Merger activities among electric utilities or between electric utilities and natural gas utilities increased.

(3) The number of new participants in the electric power industry such as independent and affiliated power marketers, generators, and power exchanges increased.

(4) The volume of trade in electricity market increased.

(5) Efforts were made at state levels to introduce retail competition.

(6) Adoption of new and different uses of the transmission grid was considered.

Due to these major changes in the electric power industry, the transmission grid was being used more intensively (i.e., more transmission system loading), which caused transfer limitations and lead to power curtailments. Furthermore, in different ways than in the past, power was being flown in unprecedented amounts and in unexpected directions. These major changes impacted the ability of power systems to maintain security in operating the transmission system under conditions for which it was not planned or designed. As FERC mentioned, the increased use of TLR procedures and the growing number of TLR incidences are an indication that the increased and different use of the transmission system is stressing the grid.

After restructuring was proposed and competition increased, even though the demand was increasing on the transmission system, the planning and construction of transmission and transmission-related components and facilities were not kept with the competition. It was noticed that most of the planned projects were for local system support, and the tight coordination of generation and transmission planning was decreased as vertically integrated utilities divest their generation assets. It was also perceived that most of the new generation was being proposed and developed by IPPs.

In addition to the increased stress on transmission grid, the transition to the new market structure resulted in new challenges and circumstances, such as experiencing many events that led to abnormal (very high) spot prices. These challenges led to calls for price caps, accusation of market power, and a questioning of the effectiveness of transmission open access and wholesale electric competition. A major reason for these negative consequences was cited as the lack of regional coordination in areas such as maintenance of transmission and generation systems and transmission planning and operation. These facts necessitated major changes to reliability procedures that traditionally functioned properly to ensure that the power flow was maintained in a competitively neutral fashion. Bulk power systems can and should be operated reliably and efficiently when coordinated over large geographic areas, though these systems could be regionally independent in nature.

Since the evolution of competitive electricity markets, ISOs have been developed in many regions of the U.S. to ensure system security and reliability and to maintain a competitive behavior in generation markets. It is argued though that larger ISOs could help the system acquire advantageous features over smaller ISOs. Firstly, a larger ISO is capable of better identifying and addressing reliability issues. Secondly, loop flows that are encountered due to the growing number of transactions are absorbed internally when larger ISOs are adopted. Thirdly, a larger ISO could conceivably promote transmission access across a larger portion of the network, and thus improve market efficiencies and promote greater competition. Finally, a larger ISO could eliminate the possible pancaking of transmission rates, which in turn allows a greater range of economic energy trades across the network.

8.3 FERC NOPR ON RTO

NOPR on RTOs, proposed and issued by FERC on May 13, 1999, recognized and discussed FERC's concerns with the means of managing the transmission grid. NOPR also included a discussion on the traditional management of transmission grid by vertically integrated electric utilities. FERC categorized into two main groups the remaining difficulties that prevent full competition in wholesale electric markets. These difficulties are:

1. The operation and expansion of the transmission grid suffer from engineering and economic inefficiencies: Since the transmission facilities of any single utility in a certain region are part of a larger and integrated transmission system, engineering and economic inefficiencies take place when each separate operator or transmission provider makes independent decisions about the use, limitations and expansion of its piece of the interconnected grid. The independent decisions are usually taken based on incomplete information, which in turn have major and instantaneous consequences on the transmission facilities of all other neighboring systems and transmission providers. This problem was magnified when increased demands were placed on the transmission grid due to increases in bulk power trade, large shifts in power flows, and an increasingly decentralized competitive power industry. These changes impacted trade patterns and industry structure, and consequently certain operational problems became more significant and difficult to resolve.

2. Transmission owners continued, unduly, discriminating in the operation of their transmission systems by favoring their own or their affiliates' power marketing activities: Utilities that have monopoly control of transmission facilities and at the same time have power marketing interests, the utilities have poor incentives to provide equal quality transmission service to their power marketing competitors. Those utilities act in their own self-interest, which may hurt others. They act in their own self-interest by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets to favor their own generation. FERC mentions that functional unbundling does not change the incentives of vertically integrated utilities to use their transmission assets to favor their own generation, but instead attempt to reduce the ability of utilities to act on those incentives.

FERC received numerous comments in response to the RTOs' NOPR. The Final Rule on RTOs is adopted by FERC based on these comments, even though there were opponents to RTOs. Participants who are opposing RTOs have claimed benefits of RTOs can be realized without RTOs, the NOPR does not attempt to quantify any of the claimed benefits of RTOs, ISOs have saved ratepayers money in those areas where ISOs have been established, and the costs of establishing RTOs is high and must not exceed the benefits.

8.4 FERC'S FINAL RULE ON RTO

In Order No. 2000, FERC listed twelve goals for RTOs, including four characteristics and eight functions. The minimum characteristics and functions proposed by FERC for a transmission entity to qualify as an RTO are designed to ensure that any RTO will be independent and able to provide reliable, non-discriminatory and efficiently priced transmission service to support competitive regional bulk power markets. The minimum characteristics that an RTO must satisfy include independence from market participants and scope, regional configuration, operational authority, and short-term reliability. The minimum functions that an RTO must satisfy include tariff administration and design, congestion management, parallel path flow, ancillary services, OASIS, TTC and ATC, market monitoring, planning, and inter-regional coordination. The inter-regional coordination was not proposed explicitly in the NOPR, but in the final rule, FERC added this function explicitly.

FERC Order 2000 gives the industry participants flexibility in structuring RTOs that satisfies the minimum characteristics and functions. As FERC mentions in this order, its does not propose to obligate or prevent any one form of organization for RTOs or obligate or prevent RTO ownership of transmission facilities. The minimum characteristics and minimum functions spelled out by FERC in the order could be accomplished by different organizational forms, such as ISOs, TransCos, combinations of the two, or even new organizational forms not yet discussed in the industry or proposed to FERC. The FERC states in its order that it is not proposing a certain organizational format for regional transmission institutions or the establishment of fixed or specific regional boundaries.

FERC encourages an open architecture policy related to formulation of RTOs, where any proposed formulation of RTO should give the RTO and its members the flexibility to refine their organizations in the future in terms of structure, operations, market support and geographic scope to meet market needs. In the same time, FERC will offer the regulatory flexibility to assist these improvements.

In the Order, FERC establishes guidance on flexible transmission ratemaking that may be proposed by RTOs, including ratemaking treatments that will address congestion pricing and performance-based regulation. FERC will consider on a case-by-case basis incentive pricing that may be appropriate for transmission facilities under RTO control.

By October 15, 2000, all public utilities that own, operate or control interstate transmission facilities were required to file with the FERC a proposal for an RTO that complies with the minimum characteristics and minimum functions set by the order to be operational by December 15, 2001. Otherwise, utilities that did not propose RTOs should provide FERC with a description of efforts to participate in an RTO, any existing obstacles to RTO participation, and any plans to work toward RTO participation. Public utilities that are participating in an approved regional transmission entity that agree with the FERC's ISO principles are excused from this requirement. Proposals for RTOs include the transmission facilities of public utilities as well as transmission facilities of public power and other non-public utility entities to the extent possible.

8.4.1 Organization of an RTO. To form RTOs, FERC allows flexibility in the type of RTO structures or forms. In the final rule, FERC does not prescribe either a Transco, ISO or some other structures. FERC will accept an ISO, a TRANSCO, a hybrid form, or any other organizational form as long as the proposed RTO meets FERC's minimum characteristics and minimum functions and other requirements. FERC believes that, at this time, it should follow a voluntary approach to participation in RTOs. A voluntary approach will be able to achieve FERC's objective, which is for all transmission-owning entities to put their transmission facilities under the control of RTOs in a timely manner. Even though FERC has decided that it is in the public interest to provide for a voluntary approach to RTO formation that is based on encouragement, guidance, and support from the FERC, this does not imply that all aspects of the final rule are voluntary, but public utilities must file either an RTO proposal or a report on the obstacles to participate in RTO. FERC expects that all transmission owners will participate in good faith in the collaborative process to form RTOs.

Regarding the organizational form of an RTO, some market participants claim that an ISO is the better form of RTO than ISO, because an ISO has no incentive either to favor transmission solutions to solve congestion constraints or to preserve congestion, while others claim that TransCo are better because they introduce a profit motive for efficient operation and expansion. FERC offers flexibility in the organizational form of RTOs, to take the differing conditions facing various regions into consideration. Any innovative structures and forms that meet the needs of the market participants while satisfying the minimum requirements of the final rule are welcome by FERC. As FERC states, some may propose to start operation in one form and transform to another form at a future date, and final rule does not necessarily require that a single organization perform all of the functions itself.

Regarding its structure, RTO could act as an ISO (non-profit institution), stand-alone transmission companies (for-profit Transcos), hybrids or any other form that could accomplish the aims of Order No. 2000. The flexibility in determining the future structure of RTOs is one of the appealing advantages of the final rule.

8.5 MINIMUM CHARACTERISTICS OF AN RTO

FERC establishes minimum characteristics that an RTO must satisfy, which include:

1. Independence from market participants
2. Scope and Regional Configuration
3. Operational Authority
4. Short-term Reliability

Characteristic 1: Independence from Market Participants. Without this fundamental characteristic, the threat of vertical discrimination in acquiring access to transmission services could weaken the effectiveness of RTOs.

Characteristic 2: Scope and Regional Configuration. The RTO's scope ought to be large enough in order to achieve the regulatory, reliability, operational and competitive objectives of the FERC final rule. A satisfactory scope is determined by factors such as geographic distance, the numbers of buyers and sellers covered by the RTO, the amount of load served, and the number of miles of transmission lines under hierarchical[2] control.

As FERC states in the rule, RTO should operate all transmission facilities within its proposed region. RTO's boundaries are recognized as follows:

- Facilitate essential RTO functions,
- Encompass a highly interconnected and contiguous geographic area,
- Deter the exercise of market power,
- Take into account existing regional boundaries (e.g. , NERC regions)
- Encompass existing control areas and regional transmission entities,
- Take into account international boundaries.

Characteristic 3: Operational Authority. RTO should have operational authority in a non-discriminatory manner for all transmission facilities under its control and must be the security coordinator for its region. The authority to control transmission facilities includes, but is not limited to, functions which are switching transmission elements into and out of operation in the transmission system such as transmission lines and transformers, monitoring and controlling real and reactive power flows, monitoring and controlling voltage levels, and scheduling and operating reactive resources.

When an RTO acts as a NERC security coordinator, it will be responsible for: Performing load-flow and stability studies to anticipate, identify and address security problems, Exchanging security information with local and regional entities, Monitoring real-time operating characteristics such as the availability of reserves, actual power flows,

[2] Hierarchical control is a form of power system control that relies on a master-satellite control structure, which establishes a single controlling authority without requiring the construction of a single, consolidated control room. In a master-satellite hierarchical control structure the RTO operates one central and multiple distributed control centers.

interchange schedules, system frequency and generation adequacy, and Directing actions to maintain reliability, including firm load shedding.

FERC suggested that the personnel of existing control centers might become employees of the RTO or remain as employees of the control center owner, while being supervised by RTO personnel. FERC leaves it optional to the region to choose the combination of direct and functional control that fits its circumstances, but the RTO must have clear authority to direct all actions that affect the facilities under its control, including the decisions and actions taken at any satellite control centers.

Characteristic 4: Maintaining the Short-term Reliability. RTO is given exclusive authority by FERC to maintain the short-term reliability of the grid. As FERC mentioned, there is no time gap between what is included within short-term reliability and the RTO's planning responsibilities. FERC will not require the RTO to rely on market mechanisms in every instance to maintain short-term reliability.

Maintaining the short-term reliability involves:

- Interchange scheduling,
- Redispatch authority,
- Transmission maintenance approval,
- Generation maintenance approval,
- Facility ratings,
- Liability, and
- Reliability standards.

As related to interchange scheduling, FERC decides that the RTO must have exclusive authority to receive, confirm and implement all interchange schedules. This function will automatically be assumed by RTOs that operate a single control area. If the RTO structure includes control area operators who are market participants or affiliated with market participants, the RTO will have the authority to direct the implementation of all interchange schedules. If the RTO filing includes a structure in which non-RTO control area operators receive sensitive information, FERC will require the RTO to monitor for any unfair competitive advantage, and report to the FERC immediately if problems are detected. FERC will require the RTO or any entities who operate control areas within the RTO's region that require access to commercially sensitive information to sign agreements that separate reliability personnel and the relevant information they receive from their wholesale merchant personnel.

Regarding redispatch authority, FERC declares that the RTO should have the authority to order the redispatch of any generator connected to the transmission facilities the RTO operates if the redispatch is needed to maintain the reliability of the transmission system. Each RTO is to develop procedures for generators to offer their services and also to compensate generators that are redispatched to maintain reliability. In order to maintain the reliability of the transmission system, the entity that controls transmission must also have some control over some generation. This control should be in general based on competitive basis (through a market) where the generators compete by submitting offers for their services and the RTO chooses the least cost alternatives. Also, FERC makes it clear that RTO authority does not extend to initial unit commitment and dispatch decisions for generators. However, for reliability purposes, the RTO should have full authority to order the redispatch of any generator, subject to existing environmental and operating restrictions that may limit a generator's ability to change its dispatch. In addition, RTO has authority to redispatch generation if it is required to prevent or manage emergency[3] situations, such as abnormal system conditions that necessitate automatic or immediate manual action to prevent or limit equipment damage or the loss of facilities or supply, which could endanger the reliability of the electric system, or to restore the system to a normal operating state.

Regarding transmission maintenance approval, FERC explained that when the RTO operates transmission facilities owned by other participants, the RTO has the right to approve and disapprove all requests for scheduled outages of transmission facilities to guarantee that the outages can be accommodated within established reliability standards. RTO is given this right of controlling maintenance of transmission facilities due to the fact that outages of transmission components impact

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[3] When all constraints and loads are satisfied, the system is in its normal state; when one or more physical limits are violated, the system is in an emergency state; and when part of the system is operating in a normal state yet one or more of the loads is not met (partial or total blackout), the system is in a restorative state.

the overall transfer capability of the transmission grid, where if a component is taken out from service, the power flows on all regional facilities will change, which in turn may lead other transmission components to be overloaded, which finally leaves negative impacts on the system reliability. RTO may coordinate individual maintenance schedules with other RTOs and with expected seasonal system demand variations. It is an advantage for RTO to have access to extensive information, which help it have more accurate assessments of the reliability effect of proposed maintenance schedules than individual, sub-regional transmission owners. On the other hand, if the RTO is a transmission company that owns and operates transmission facilities, these reliability assessments will be an internal company matter.

However, if there are several transmission owners in the RTO region, the RTO will need to review transmission requests made by the various transmission owners.[4]For this situation, transmission owners submit their requests of preferred maintenance outage schedules to the RTO for authorization, then RTO reviews and test these schedules based on reliability criteria, then approves specific requests for scheduled outages, requires changes to maintenance schedules when they do not pass the reliability criteria, and finally updates and publishes maintenance schedules as necessary. In the case that planned maintenance of a transmission owner is rescheduled by the RTO, the transmission owner is compensated by the RTO for any costs incurred by the required rescheduling only if the previously scheduled outage had already been approved by the RTO. FERC encourages the RTO to establish performance standards for transmission facilities under its direct or contractual control, where these standards could take the form of targets for planned and unplanned outages. FERC mentions that the reasoning behind this requirement is that two transmission owners should not receive equal compensation if one owner operates a reliable transmission facility while the other operates an unreliable facility.

Regarding generation maintenance approval, even though there are reliability advantages to the RTO to hold the authority over proposed generation maintenance schedules, FERC explains that the RTO is not

[4] Since some of these transmission owners may also own generation, they may have an incentive to schedule transmission maintenance at times that would increase the prices received from their power sales. A transmission company, not affiliated with any generators, would not have these same incentives.

required to have this right. Because of the close relevance between generation and maintenance of system reliability, it is essential for generator owners and operators to provide the RTO with advance knowledge of planned generation outage schedules so that the RTO can use this information in its reliability studies and operations plan. If such information is provided to the RTO, the RTO is prohibited from sharing the information of the generation maintenance schedule with any other market participants, or affiliates of market participants.

Regarding facility ratings, FERC explained that RTO is not required to establish transmission facility ratings, even though FERC encourages such ratings to be determined, to the extent practical, by mutual consent of the transmission owner and the RTO, taking into account local codes, age and past usage of the facilities. Initially, as FERC recognizes, the RTO may use existing values for equipment ratings and operating ranges to ensure reliable system operation. Later, when an RTO has experience in operating or directing the operation of the transmission facilities in its region, FERC expects this responsibility to transfer to the RTO because, as FERC says, facility ratings have at least an indirect effect on the ability of the RTO to perform other RTO minimum functions such as planning and expansion, ATC and TTC.

Regarding liability, FERC will determine the extent of RTO liability relating to its reliability activities on a case-by-case basis.

Regarding reliability standards, FERC declares that the RTO must perform its functions in a fashion that agrees with established NERC (or its successor) reliability standards, and notify the FERC immediately if implementation of these or any other externally established reliability standards will prevent it from meeting its obligation to provide reliable, non-discriminatory transmission service.

8.6 MINIMUM FUNCTIONS OF AN RTO

FERC has set eight minimum functions that an RTO must perform. An RTO must:

(1) Administer its own tariff and employ a transmission pricing system,
(2) Create market mechanisms to manage transmission congestion,
(3) Develop and implement procedures for parallel path flow issues,

(4) Serve as a supplier of last resort for ancillary services,
(5) Operate an OASIS site for transmission facilities under its control,
(6) Monitor markets to identify design flaws and market power,
(7) Plan and coordinate transmission additions and upgrades, and
(8) Adopt inter-regional coordination.

Function 1: Tariff Administration and Design. RTO is the sole authority for evaluating and making decisions related to approving all requests for transmission service and requests for new interconnections. This function is granted to RTO to ensure a non-discriminatory service within the region. RTO has the independent authority to file tariff changes, and the RTO's tariff must not result in transmission customers paying multiple access charges.

Function 2: Congestion Management. RTO is required to ensure the development and operation of market mechanisms to manage transmission congestion seen as superior to curtailment procedures which do not take into account the relative value of transactions. The market mechanisms must provide all transmission customers with efficient price signals regarding the consequences of their transmission usage decisions.

Function 3: Parallel Path Flow. The formation of RTOs, which cover large geographic scope of transmission scheduling and expanded coverage of uniform transmission pricing structures, could internalize the effect of parallel path flow in their scheduling and pricing process within a region. Each RTO should have measures in place to address parallel path flow issues within its own region and between RTO regions. FERC will allow up to three years after start-up to address parallel path flow issues between regions.

Function 4: Ancillary Services. RTO has the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided. Ancillary services must be included in the RTO administered tariff for transmission customers. If a participant chooses self-supplying or acquires ancillary services from a third party, the RTO must determine if the transmission customer has adequately obtained these services.

RTO must promote the development of competitive markets for ancillary services and real-time balancing operated by either the RTO or another entity that is not affiliated with any market participant.

Function 5: OASIS, TTC and ATC. As related to this function, the final rule mainly involved the following issues:

- OASIS: An RTO is the single OASIS site administrator for all transmission facilities under its control. It is seen that a single OASIS site for each region instead of multiple sites will enable transactions to be carried out more efficiently. FERC gives an RTO the flexibility to contract out OASIS responsibilities to another independent entity. An RTO may participate in a *super-OASIS* jointly with other RTOs.
- ATC Calculation: The RTO itself is required to calculate ATC values based on data developed partially or totally by the RTO in order to ensure that ATC values are based on accurate information and consistent assumptions. In the event of a dispute over ATC values, RTO values should be used pending the outcome of a dispute resolution process.

Function 6: Market Monitoring. In its NOPR, FERC introduced the concept of market monitoring to be performed by each RTO. This function is vital to guarantee that regional markets do not result in wholesale transactions or operations that are unduly discriminatory or preferential or provide opportunity for the exercise of market power. In addition, market monitoring could provide information regarding opportunities for efficiency improvements. In this function, every RTO would be required to monitor markets for transmission service and the behavior of transmission owners and propose appropriate actions and recommendations on market power abuses and market design flaws to the FERC affected regulatory authorities.

Function 7: Planning and Expansion. FERC gives the RTO an absolute responsibility to plan and expand transmission within its region in order to provide efficient, reliable and non-discriminatory service. This responsibility should be in coordination with the related appropriate state authorities. RTO, as a single independent entity, would coordinate regional actions, in order to guarantee a least cost outcome that maintains or improves existing reliability levels. In essence,

- Since the RTO will have ultimate responsibility for planning the entire transmission system within its region, FERC expects that the functions of an RTG will ultimately be assumed by an RTO to avoid unnecessary duplication of effort.

- Any public utility will still have its existing obligation under the pro forma transmission tariff to expand or upgrade its transmission system upon request. Because an RTO may not own all of the facilities it operates, FERC shall evaluate each RTO proposal to ensure that the RTO can direct or arrange for the construction of expansion projects that are needed to ensure reliable transmission services.

- The pricing mechanisms and actions used by the RTO as part of its transmission planning and expansion program should be compatible with the pricing signals for shorter-term solutions to transmission constraints (i.e., congestion management) so that market participants can choose the least-cost response. Otherwise, their choices may reflect less efficient outcomes for the marketplace.

Function 8: Inter-regional Coordination. Whether or not another RTO exists in other regions, FERC requires each RTO to build mechanisms to coordinate its activities with other regions and address inter-regional problems concerning *seams* between RTOs.

The standardization of transmission transactions is required because many transactions will cross RTO boundaries, and large number of customers will do business with multiple RTOs. Without standardized communications protocols and business practices, the costs of doing business will be magnified because market participants will need to install additional software and add personnel to transact with different RTOs and regions. As such, to promote inter-regional trade, standardized methods of moving power into, out of, and across RTO territories will be needed. In addition, standards for communications between customers and RTOs must be developed to permit customers to acquire expeditiously common services among RTOs.

The integration of reliability practices involves procedures for coordination of reliability practices and sharing of reliability data among regions in an interconnection such as procedures that address parallel path flows, ancillary service standards, and TLR procedures.

The integration of market interface practices involves developing some level of standardization of inter-regional market standards and practices such as coordination and sharing of data needed to evaluate TTC and ATC values, transmission reservation practices, scheduling practices, and congestion management procedures.

8.7 BENEFITS OF RTO

Based on the conclusions of FERC in the final rule and discussions on RTOs, we summarize the main benefits of establishing RTOs in the following points:

(1) Improving efficiencies in the management of the transmission grid,

(2) Improving grid reliability,

(3) Fewer opportunities for discriminatory transmission practices,

(4) Resulting in improved market performance,

(5) Facilitating lighter-handed governmental regulation,

(6) Improved congestion management,

(7) More accurate estimates of ATC,

(8) More effective management of parallel path flows,

(9) More efficient planning for transmission and generation investments,

(10) Increased coordination among state regulatory agencies,

(11) Reduced transaction costs,

(12) Facilitation of the success of state retail access programs,

(13) Facilitation of the development of environmentally preferred generation in states with retail access programs, and

(14) Help improve power market performance, which will ultimately result in lower prices to the Nation's electricity consumers.

Efficiencies in the management of the transmission grid are improved through the following: use of regional transmission pricing, accurate estimation of ATC, efficient planning for grid expansion, facilitating state retail access programs, creation of reasonable transmission rate with unified regional loss factors, eliminating transmission pancaking, eliminating incorrect calculations of ATC and TTC, providing unbiased ATC information, help identify the best place on the grid to locate new generation and provide more efficient planning for transmission and generation investments

Regional grids through the formation of RTOs in all regions of the nation is very important for both electric markets and natural gas markets for the many reasons: among them, RTOs will:

- Remove the artificial boundaries that are now restricting trading markets and raising prices.
- Guarantee that the grid is operated in a non-discriminatory, efficient fashion.
- Promote improved pricing for electric grid services.
- Help get new electric transmission facilities built through planning and arranging transmission expansions, coordination with the appropriate state authorities, and finally through the market based congestion management techniques the RTO will utilize, which will send accurate price signals about the true cost of congestion, which in turn will induce transmission capacity investment.
- Attract new generation participants.
- Provide a more powerful and effective regional tool for reliable grid management through eliminating the current scheme of scattered and balkanized grid management, regional planning for loop flow, dealing with the seams among grid management regions, improved regional congestion management, and facilitating necessary grid expansions,
- Have positive impacts on the natural gas industry. For example, making the electric grid function more efficiently and reliably will spur new gas-fired electric generation units. Under RTO structure, these facilities will be able to sell their power to a much larger market, and entrepreneurs will be encouraged to site the new gas-fired generation in areas that now suffer from transmission bottlenecks. The increased demand for natural gas-fired electric generation will also require an increase in pipeline construction.

CHAPTER 9

ELECTRIC UTILITY MARKETS OUTSIDE THE UNITED STATES

Summary: We reviewed major market models as related to the ISO in the United States in chapter 2; these models include California, Pennsylvania–New Jersey–Maryland (PJM) interconnection, New York Power Pool (NYPP), Electric Reliability Council of Texas (ERCOT), New England ISO and Midwest ISO (MISO). Here, we present in this chapter the experience of some other countries with restructuring. We discuss some of the shortcomings and advantages of these models, focus on restructuring process, and discuss some of the proposals in a detailed manner; these models include Nordic Power Exchange, Australia National Electricity Market, Power Pool of Alberta, the Independent Electricity Market Operator (IMO), and electricity Industry in England and Wales.

9.1 NORD POOL (THE NORDIC POWER EXCHANGE)

Nord pool was the first international power exchange in the world. It is responsible for facilitating electricity trade in the Nordic region. It has an hourly-basis physical spot market for electricity and a financial futures market for trading contracts up to a duration of three years. In addition, Nord pool has a clearing service. Market participants, who would like to buy or sell certain quantities of power for each hour of the following day, submit their bids to the spot market in each morning. In the afternoon, the pool decides exchange quantities and electricity prices for all 24 hours of the day. Svenska Kraftnät and its Norwegian counterpart Statnett SF own the Nord pool [Abb98, Chr98, Myr99, Nat98b, Nor98a, Nor98b, Nor99, Pen96, Tab96, Web 55].

In Norway, the installed capacity is estimated to be about 27 GW with an annual consumption of 120 TWh. Most of the power plants (nearly 650 plants) are hydroelectric plants. The generation sector is highly competitive. There are 30 major players, where the largest player in generation sector is a state-owned company called Statkraft SF which owns 30% of the capacity. Many distribution companies have generating plants. Statnett SF – a state-owned company – operates the 11,000 km-line central transmission grid (132-420 kV) and the Norwegian part of the inter-connectors with Sweden, Finland and Denmark. Statnett owns 80% of the facilities and leases the rest from other companies. Regional companies and local distribution companies run low voltage distribution networks. In Norway, some extremely small distribution companies, each with few employees, retain a retail sales function.

Norway and Sweden have established a wholesale electricity market, implemented in January 1996, and recognized as Nord Pool (The Nordic Power Exchange). To sell or buy electricity in the Nord Pool marketplace, participants would trade in a daily spot market, concluded at the day-ahead stage, and in a weekly financial contract market [Abb98, Chr98, Myr99, Nat98b, Nor98a-b, Nor99, Pen96, Web 55].

Starting in January 1996, the Norwegian-Swedish Exchange opened the door to trade electricity on a competitive basis across national borders. In this market, there is a market operator (Nord Pool), two system operators (Statnett in Norway, and Svenska in Sweden), and two regulatory institutions i.e. the Norwegian Water Resources and Energy Administration (NVE) in Norway, and Nätmyndigheten (NUTEK) in Sweden.

At the end of each year, the system operator, in coordination with grid owners and market participants (generators), validates transmission and distribution tariffs to be valid for the next year. The system operators establish the so-called *price areas* for the total supply area based on congestion possibilities on the transmission grid. The number of price areas does not exceed three. Information regarding the price areas are passed onto the market participants to start their bidding[1] in spot market, where each bid has to be related to one price area, and in the case that the

[1] Unit owners or operating agents perform these bids

system is announced to be one price area, each operation agent or unit owner provides one bid [Nor98b].

Nord Pool is composed of three organized markets in addition to the bilateral trade system. The Nord Pool, which acts as a market operator, is responsible for the clearing process in the three organized markets. In 1996, around 30% of generation in Norway was traded thorough the pool, and the rest was traded as bilateral contract engagements. The three organized markets are:

1- Spot Market: This market is a day-ahead market operated by the power exchange (Nord Pool). In spot market, traders submit offers to sell or bids to buy electricity they expect to produce or consume. Trading in this market is non-mandatory. Spot price is set equal to the marginal offer to supply or bid to buy accepted by the Exchange. Electric power is traded in the spot on a daily basis for delivery on the following day, where participants are obligated to pay. Participants set bids for purchases and for every hour during the day, where each contract is composed of one-hour duration, one load in MWh/h, and one price (NOK/MWh) in which NOK refers to Norwegian Kroner. The pool determines the price of the market equilibrium (the balance price for the aggregated supply curve and aggregated demand curve). This price is called the *system price*. System price is used for settlements of energy, and participants use area prices as price signals for future planning and other purposes, because they indicate participants' total costs and income for purchases and sales of electricity [Nor98b].

2- Regulating (imbalance) Market: It is a single-buyer model for purchase of network frequency support. This physical market stands for short-term adjustments. Imbalances between trades in the daily spot market and the actual amounts produced or consumed by traders are settled in this market. Trading in this market is also non-mandatory. The price for this market is set as follows: if total gross demand exceeds total demand in the spot market, the price for imbalance market is set equal to the highest accepted offer to supply; and if total gross demand is less than total demand in the spot market, the price for imbalance market is set equal to the lowest accepted bid to buy [Nor98b].

3- Futures Market: It is an over-the-counter (OTC) forward trade in energy, a financial market that has effects on money flow and does not have any physical effects on the system. The weekly contracts are purely financial commitments [Nor98a, Nor99].

The grid operator runs the power exchange, for ancillary services and energy balancing. Bilateral contracts are handled outside the market, but contract parties are charged for energy imbalances based on their contribution to an imbalance. Network constraints are modeled in the Nord Pool using a simplified model, which results in zonal prices. Ancillary services are provided by the network operator and recharged on a pro-rata basis to suppliers. In the balancing market, a system operator buys power daily or demand reduction as required, and re-charges market participants as a capacity fee on a pro-rata basis. If overload (congestion) is discovered, the market-clearing price in each area is adjusted to create enough imbalances in each area to relieve the congestion. In Sweden, grid operators may use the concept of counter trades to mitigate the congestion, where energy supply bids that would cause counterflows in congested paths are selected by the operator and are paid their asking prices [Nor98b].

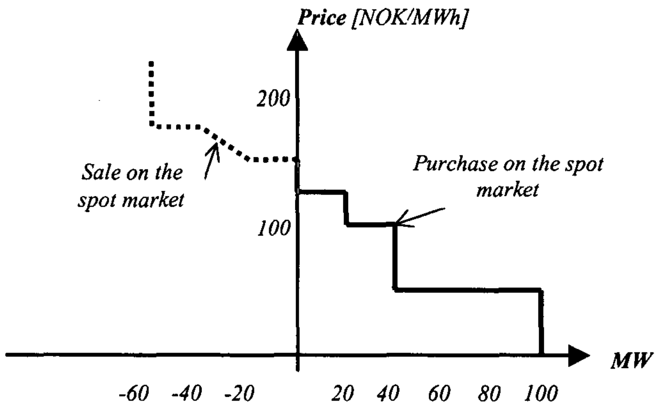
Among the advantageous features of this market structure is that it involves direct bilateral contracts between participants, which would eliminate contract for differences, which in turn would reduce risk and save money for some transacted parties. This market would promote customer choice since trading in the market is optional. In addition, the responsibility of dispatching and managing generating units remains with owners.

When generating capacity hits its limit in the central grid, the Norwegian system operator (Statnett SF) would partition the country into bidding areas where participants must bid in balancing sale obligations with contractual purchase rights, including own generation and demand. On a weekly basis, Nord Pool would announce information of bidding areas for the following week to all participants, based on system operator's data in Norway (Statnett SF). Based on Norwegian participants' connection points in the central grid, each participant would know locations for bids and offers. Sweden and Finland are always in one area.

Each participant would determine its own production pattern, its contractual rights and obligations in each bidding area for each hour of the next day, and sales or purchases in the spot market. Based on this planned portfolio, a price-differentiated bid and offer for each bidding area and each hour will be prepared for the bidding process in Nord Pool. The bid/offer prepared for a certain day and a certain hour shows purchase and/or sale quantities with different prices. Participants send their bid/offer data to Nord Pool in Norway and Sweden either electronically or via fax. The price of a participant's trades will be known only when all the participants have submitted their bids and the price has been determined for all participants. When the final price is determined, each participant will receive an exchange quantity corresponding to participant's price-differentiated bid or offer.

Example 9.1: (bid/offer structure in the Nord Pool)

Figure 9.1 gives an illustrative example of the bid/offer structure in Nord Pool. Participant should indicate area, day, week, and time information for the bid/offer to be submitted [Nor98b].



Time:			Day:			Week:			Area:			
Price	0	50	51	100	101	125	126	151	151	175	176	800
MW	100	100	40	40	20	20	0	0	-20	-40	-60	-60

***Figure 9.1** Participant's Bid/Offer Curve*

9.1.1 Congestion Management. Transmission constraints within Norway and between Norway and Sweden are treated by dividing the market into areas (zones). The network operator (Statnett) defines the areas based on its information on the possibility of flows. These zones are usually defined and declared on a weekly basis, and zones may be revised within the week such as between the day-ahead stage and delivery. In this market, Sweden is treated as one zone [Chr98, Gla97, Nor98b].

After defining the zones, the Nord Pool first establishes a *system price*, which matches offers and bids without considering transmission constrains. Then Nord Pool determines prices for each zone which reflect the marginal cost of meeting demand in that zone, given the respective transmission constraints. On a daily basis, system operators (national grid companies) in Sweden, Norway and Finland determine maximum available transmission capacities for trades in spot market between countries and zones, while giving priority to transmission between countries. Then, for a possible congestion between bidding zones, system operators use a certain pricing process in the spot market to modify power flows, where the price is decreased in (deficit[2]) zones and increased in (surplus[3]) zones until the flows on congested paths are reduced to their capacity limits. Market participants would incur the costs of removing the congestion through the concept of *capacity fee* [Chr98, Gla97, Nat98b, Nor98b].

To solve the problem of congestion in Norway, the spot price would be adjusted so that power transfer between any two zones would fall below the respective line limits. Figure 9.2a demonstrates a system composed of two zones 1 and 2. The total demand and generation in zone 1 (G_1 and D_1) and in zone 2 (G_2 and D_2) are aggregated to form the total system generation (G_{1+2}) and total system demand (D_{1+2}). System price ($\mathbf{P_s}$) at the equilibrium point of G_{1+2} and D_{1+2} is as shown in Figure 9.2.b. Initially, ($\mathbf{P_1}$ and $\mathbf{P_2}$) were prices at equilibrium points of the zone's aggregated generation and demand, as shown in Figures 9.2.c and 9.2.d. These prices are modified to zone prices ($\mathbf{P_1'}$ and $\mathbf{P_2'}$) as follows: sales are charged in surplus zones, while purchases receive a credit. Likewise, in deficit zones, sales receive a credit, while purchases are charged. The

[2] The deficit area has higher sales and lower purchases.

[3] The surplus area has higher purchases and lower sales surplus.

net effect is a zonal price for all trades of spot market and regulating market within that zone.

The whole process is explained as follows:

Once Nord Pool receives offer/bid data from each participant, the Pool aggregates the bids and offers together on an offer graph (sale) and a demand graph (purchase). The price at the intersection of offer and demand graphs (i.e. the balance or equilibrium point) is the system price, or $\mathbf{P_s}$. This price is the unconstrained system price, where constraints in the national grid are neglected initially. The next step is checking whether the power flow between any two bidding zones would exceed the respective capacity limits.

Physically, electricity always flows from the low-price zone to the high-price zone, as shown in Figure 9.2.a. If the capacity limits are exceeded, the price is used in the market to restore flow between two zones to capacity limit. The price in the low-price (surplus) zone is increased and is reduced in the high-price (deficit) zone. The adjustment in each zone is done by first determining the point where the capacity fee is zero (point $\mathbf{P_1}$ for zone 1 in Figure 9.2.d and at point $\mathbf{P_2}$ in zone 2 in Figure 9.2.c) based only on zones' bids and offers. The price curve in the surplus zone is shifted for an additional purchase, which corresponds to a value equal to capacity (see the figure) and a corresponding shift is done for the sales graph in the deficit zone. This process would result in the calculation of zone prices $\mathbf{P_1'}$ and $\mathbf{P_2'}$. Then the capacity fee in each price zone is calculated as the difference between the system price and the zone price. The capacity fee in the surplus zone is $\mathbf{P_s} - \mathbf{P_1'}$ and $\mathbf{P_s} - \mathbf{P_2'}$ in the deficit zone. In the surplus zone, sellers pay capacity fee and buyers get credits, while the opposite happens in the deficit zone [Gla97, Nor98b].

If flows show that the capacity limits between bidding zones are not violated, the system would only have one price zone, and the capacity fee would be zero. If any constraints arise during delivery, constrained situations are handled through the imbalance market[4].

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[4] Imbalances are handled by the regulating power market on the Norwegian side and by the balance service on the Swedish and Finnish side.

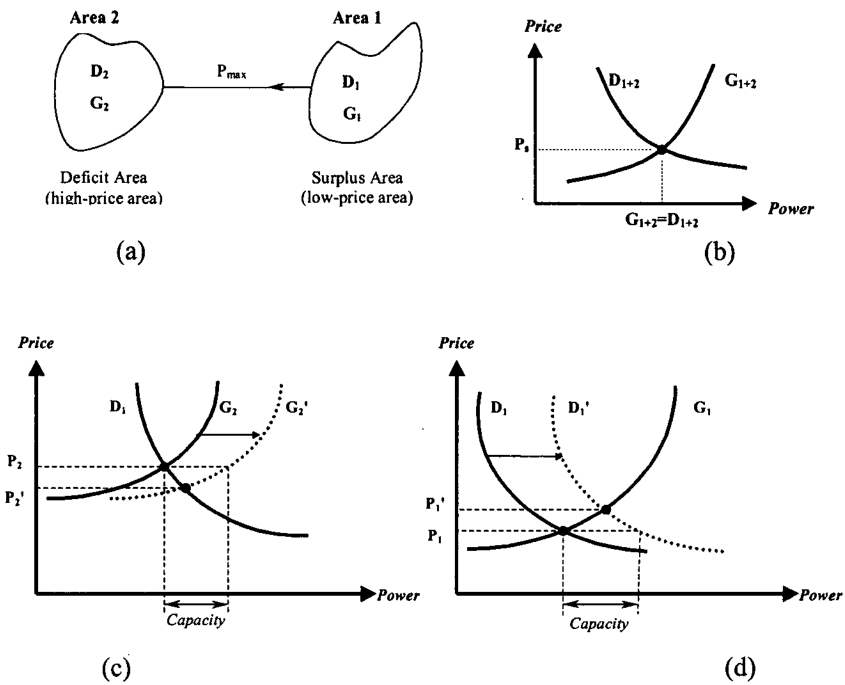

Figure 9.2 Determining P_s, P_1 and P_2

Internal congestion is handled differently in the different countries. In Norway, congestion is resolved through adjusting the spot market trades. Sweden and Finland, which are treated as one bidding zone in the spot market, have different methodology. Sweden and Finland use the concept of *counter purchase* to relieve internal bottlenecks. The concept is that the grid operators in these countries (Swedish National Grid Company (Svenska Kraftnät) in Sweden and Fingrid in Finland) pay for the downward regulation in the surplus zone and the upward regulation in the deficit zone. Market participants in these countries are charged for counter purchases through tariffs for power transmission. The concept of counter purchase is not related to the spot price or the spot market operations.

The costs of losses are recovered through the energy charge within transmission tariffs. These are based on the point of the customers connection to the transmission grid and could vary by region, season, time of day and for different load situations.

9.1.2 Bilateral Contracts. Bilateral contracts are treated differently in two cases. The first case is when contracts are between Norwegian parties, and the second case is when bilateral contracts are conducted between Norway and Sweden. In the first case, the Nord pool recognizes two situations: contracts with one connection point of sale and contracts with two different connection points of sale. In the one connection point contract, there is one point of sale for contract fulfillment, where the seller is obligated to deliver in the zone specified by the contract[5] and the seller should take the contractual quantity into consideration in its bids and offers of the sale (delivery) zone, i.e., if the delivery point is the buyer's zone, the seller must bid the delivery as a purchase in the buyer's zone. If the sale point is the seller's zone, the buyer offers it as a sale in seller's zone. In a two-connection point's contract, there are two points of sale (i.e. the buyer's connection point in one zone and the seller's delivery point in other zone), where the seller and the buyer must take the contractual quantity into consideration in their bids and offers[6]. We note that in both situations, transacted parties should consider the exchange on bilateral contracts in their bids and offers to the spot market. In both cases, bilateral contracts that are included in spot market operations are treated as spot transactions and used as other transactions to remove any congestion [Gla97, Nor98b].

In the second case when bilateral contracts exist between Norway and Sweden, two mechanisms are used to deal with contracts based on

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[5] The contract should indicate whether the delivery area (sale area where the seller is obligated to deliver) is the seller's area or the buyer's area.

[6] The contract should indicate the two points of sale: the buyer's connection point in one area and the seller's delivery point in other area. For this situation both participants consider the contractual quantity at their bids and offers submitted to the spot market, where the seller offers the agreed-upon contractual volume as a sale in seller's delivery point and the buyer bids on the same contractual quantity as a purchase in buyer's area. This means that both participants implement their bilateral contract deliveries in the bids and offers submitted to the spot market.

whether the contracts are arranged under the so called *5-TWh arrangement*[7], or the contracts are agreements to hedge the price. The bilateral contracts that are not given priority in the transmission between the two countries are delivered as price hedging contracts. A price-hedging contract is an agreement that buyers and sellers use to hedge a price against the spot market's price [Nor98a]. The agreement indicates a contractual price and includes one volume. When the spot price rises over the contractual price, the seller pays the difference between the two prices to the buyer and payment is reversed when the spot price decreases below the contractual price. See Figure 9.3 for illustration.

Example 9.2

As illustrated in Figure 9.4, a seller in Norway (in zone D) and a buyer in Sweden (in zone A) signed a bilateral contract to exchange a 100 MW at a contractual price of 50 NOK/MWh.

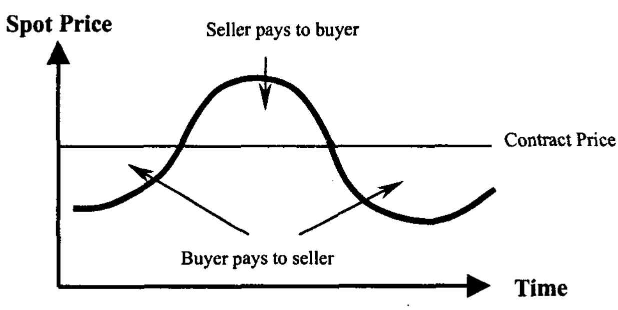

Figure 9.3 Illustration of Price-Hedging Contract

[7] These are contracts on export from Norway to Sweden, where quotas at a total of 5TWh/yr were given to and divided between Norwegian producers and companies to export electric power. These contracts were given priority for transmission between the two countries. Nord Pool stopped dealing with contracts under this agreement on December 31 1998.

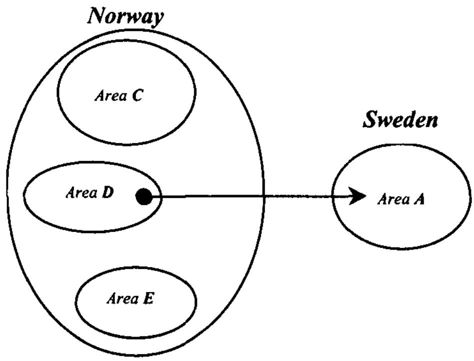

Figure 9.4 Illustration of Example 9.2

If the two parties convert this bilateral contract to spot market transaction, they should include this transaction in their bids/offers, i.e., the seller must follow the balance requirement according to Norway and the buyer must follow the balance requirement according to Sweden. The seller offers the contract as a sale in zone D and the buyer (counterpart) bids on the contract as a purchase in zone A. If the system spot price is determined as 70 NOK/MWh, the seller pays the difference (70-50= 20 NOK/MWh) to the seller for each MWh exchanged.

9.1.3 Marketplace for Electric Power Options

Nord Pool has an organized financial marketplace for electric power options. Electric power options are traded at *Eltermin*, the Nordic Power Exchange's Futures Market [Nor98a, Nor99]. Participants in electric industry use these contracts as instruments or hedging tools to manage risk and forecast future income and costs related to power trading. Market participants use a combination of forward, futures and options electric power contracts to spread and reduce risk and improve the yield in their electricity trading portfolios against unexpected changes in prices.

The options contract pre-specifies an agreed-upon price (the strike price or exercise price), and agreed-upon date (the exercise date). In options contracts there are two parties, the seller and the buyer. The seller is called writer, and the buyer is called holder. The buyers pays a premium to the seller to have the right to exercise the contract. The seller is obligated to complete the transaction if the buyer wants to exercise the contract. If the buyer does not exercise his right within the predefined period (the option lapses), he loses the premium he paid, and the seller's profit is the premium. Figure 9.5 illustrates the options contract's concept.

Nord Pool has standardized its electric power options to improve the functionality of power derivatives market [Nor98a, Nor99]. A standardized options contract has the following fixed terms and conditions: specification, volume, expiration, and strike (exercise) price. Specification contains the ticker symbol, a description of the underlying product, and other conditions corresponding to the electric power option. Volume refers to the number of trading units in MWh. Nord Pool sets 1 MW as a contract size of electric power options. Volume of an options contract varies according to the underlying futures or forward contract. For the expiration term, an options contract may be traded starting from the day it is first listed until its expiration time.

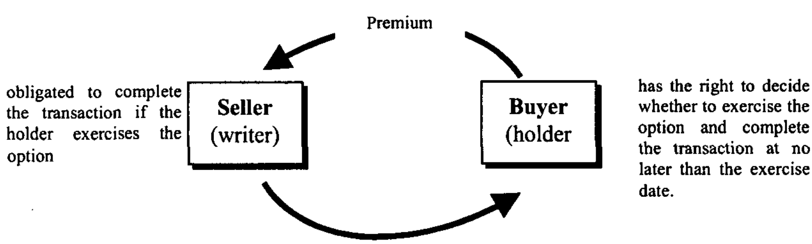

***Figure 9.5** Options Contract's Concept*

A participant may trade in the option or exercise the rights accompanying it before its expiration. On the last trading day of an option (the closing day), all rights related to the contract lapse and the option becomes valueless, where contract's buyer (holders) loses its right to exercise the option, and option seller (writer) has no obligations. The exercise price of an options contract (in NOK/MWh) is the amount of money that an options buyer (holder) pays if and when it uses its right.

Nord Pool has two types of electric power options: European-style (EEO) and Asian-style (AEO). Both types are differently standardized and are traded and cleared at Nord Pool. The two types have the same exercise price and exercise price interval, while each has a different specification, volume and premium quotation [Nor98a, Nor99].

9.2 AUSTRALIA NATIONAL ELECTRICITY MARKET

Before 1990, in each state or territory of Australia, the electricity industry (production, transmission, distribution and sale of electricity to final end customers) was controlled and managed by a single vertically integrated state owned authority or a combination of state owned authorities. In addition, state governments and their authorities were mainly driving investments in new generation. State governments, as shareholders, set electricity rates to cover the industry's costs in addition to returns. State governments in Australia started in 1991 to establish rules and reforms for the new restructured and competitive electricity industry. The new form of this industry would be composed of separate elements: generation, transmission and distribution, and retail supply[8].

The National Electricity Market (NEM) was initiated in December 1998 to represent the wholesale market for the supply and purchase of electricity in five Australian states and territories[9] in addition to a administration of open access to transmission and distribution networks in those states and territories. The main objectives of the NEM are competitive market, customer's ability to choose its supplier for trading,

[8] Selling electricity to end users for a tariff based on their metered consumption.
[9] The Australian Capital Territory, New South Wales, Queensland, South Australia, and Victoria

customer's ability to gain access to the interconnected transmission and distribution network, and equitable treatment of those participating in the market. In addition, no particular energy source or technology should be treated more favorably or less favorably than another energy source or technology, and provisions regulating trading of electricity in the market should not treat intrastate trading more favorably or less favorably than interstate trading of electricity. In May 1996, the governments of the five Australian states and territories formed two companies to implement NEM. The first company is the National Electricity Market Management Company Limited (NEMMCO) that manages and facilitates the wholesale electricity market. The second one is the National Electricity Code Administrator Limited (NECA) that supervises, administers and enforces the National Electricity Code (the Code). The Code represents procedures and rules for wholesale electricity trading and access to electricity networks. The aimed results of NEM are promoting a more flexible, cost effective and efficient electricity industry while delivering lower electricity prices to end users [Abb98, Nat98a, Nat99, Web53-54].

The Code defined the main functions of NEMMCO as: registering new code participants, managing the power system to keep supply and demand in balance based on the generating capacity available to the wholesale market, keeping security of power system, administering the spot market including calculation of spot prices, metering, and spot market settlements, registering meter providers in accordance with the Code, arranging adequate ancillary services, and coordinating global power system planning in conjunction with network[10] service providers and in consultation with market participants.

In the wholesale electricity market, the electricity output from all generators is centrally pooled and scheduled to meet the electricity demand. The pool managed by NEMMCO has two main ingredients: the centrally coordinated dispatch process and the spot market. In the centrally coordinated dispatch process, electricity supply and demand requirements are continually balanced by scheduling generators to produce sufficient electricity to meet customer demand. Generators compete by providing dispatch offers (prices for different levels of generation) to NEMMCO. Market customers[11] may submit dispatch bids,

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[10] Transmission and distribution networks.

[11] Retailers and end use customers who are wholesale Market Participants.

comprising prices and associated quantities of demand they wish to be scheduled in the dispatch process. NEMMCO dispatches the scheduled generation and demand with the objective of minimizing the cost of meeting electricity demand based on offers and bid prices. The spot market is the market where generators are paid for the electricity they sell to the pool, and retailers and wholesale end use customers pay for their electricity consumption. A spot price for wholesale electricity is calculated for each half-hour period during the day and is the clearing price to match supply and demand. NEMMCO calculates this spot price using the daily price offers and bids. In general, all electricity must be traded through the spot market [Abb98, Nat98a, Nat99, Web53, Web54].

The spot market movements can be seen as price signals to generators, customers, and network service providers to help them participate in future investment options for new generation, demand side management, and network expansions.

Generators and retailers also trade in financial instruments such as hedge contracts outside the pool to hedge the fluctuations in spot prices which vary every half hour in response to electricity supply and demand. These hedge contracts do not affect the operation of the power system in balancing supply and demand in the pool and are not vertically integrated under the Code. The Code defines an open access regime that furnishes a set of rules and standards to ensure generators and customers have a fair and nondiscriminatory access and connection to electricity networks. To ensure that electric energy is delivered to customers in a safe and reliable manner and meets the suitable quality of supply standards, the Code includes and defines technical requirements for the electricity networks, generating plant and connection equipment at customer side.

The pool operation, managed by NEMMCO, covers the interconnected power system including the Australian Capital Territory, New South Wales, South Australia and Victoria. NEMMCO also managed a separate pool that coverd the Queensland power system until a planned electricity interconnection with New South Wales was established.

In addition to managing the operation of the wholesale electricity market and security of the power system, NEMMCO is responsible for developing the wholesale electricity market with the objective of improving its efficiency, and coordinating power system planning for the wholesale electricity market. In addition to NEMMCO, Code Participants include network service providers, generators, market customers[12], and special participants[13]. Figure 9.6 illustrates the structure of NEMMCO's electricity market [Abb98, Nat98a].

Generators are classified into four different categories based on their size and whether they are required to participate in the wholesale electricity market. The first type is the *scheduled generator*, which is a generator or group of generators with an individual or aggregate nameplate rating at or above 30 MW at one site. This type of generator is required to have its output scheduled by NEMMCO. The second category is the *non-scheduled generator*, which is a generator or group of generators with an individual or aggregate nameplate rating of less than 30 MW at one site. This type of generator is not required to have its output scheduled by NEMMCO. The third type is the *market generator*, which is a generator whose production is bought partially by a regional retailer or by a customer located at the same network connection point [Nat98a].

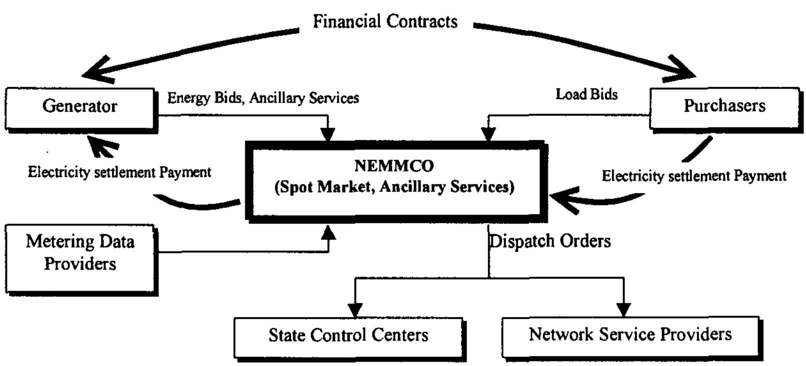

Figure 9.6 *NEMMCO's Market Structure*

[12] Retailers and end use customers.

[13] The System Operator and Distribution System Operator.

This type is obligated to sell all of its sent out output through the spot market. The last type is the *non-market generator*, which is a generator whose production is bought completely by a regional retailer or customer located at the same network connection point. This type of generator does receive payment from NEMMCO for electricity sent out at its connection point.

Market customer refers to a retailer or end-use customer. A retailer is the entity which buys wholesale electricity on behalf of their franchise customers. A retailer may also provide electricity to non-franchise customers who opt not to buy electricity from their retailers. End-use customers are those market customers[14] who are registered with NEMMCO and meet NEMMCO requirements. Market customers buy and consume energy directly from the wholesale market. As an additional advantage to those customers, they have the choice of submitting demand bids in the pool if they install the needed tools to automatically permit adjusting their demand according to their demand price bids.

Network service provider is that entity which is registered with NEMMCO, own (or lease), and operate a transmission or distribution network. Network service providers are required by the Code to maintain their networks secure to enable participant in the NEM such as generators, retailers, and customers trade electricity in an open access manner. It is the responsibility of network service providers to plan for the expansion of their network, operate their network and provide access to a generator or customer that needs connection.

The system operator and distribution system operator are registered with NEMMCO and called special participants. NEMMCO has designated an agent (person) for itself called a system operator, with the responsibility of carrying out some of NEMMCO's activities to manage the operation of the power system. The other agent (person) is a distribution system operator whose responsibility is to manage the operation of a distribution network, direct its operations during a power system emergency, and manage the transfer of electricity through the distribution network to the end-use customers.

[14] Such as industrial (factories), commercial (offices) and homes.

NEMMCO has the responsibility of managing the power system on a daily basis and keeping its supply and demand in balance. NEMMCO uses a centrally coordinated dispatch process to balance the short-term supply and demand for the electricity pool. NEMMCO matches its forecasted demand with the generating capacity declared available by scheduled generators to estimate whether adequate capacity is available to meet the daily peak demand in addition to adequate reserves to maintain the system reliability at times when failures in generating units or the transmission network take place. When reserves are inadequate during certain failure situations, NEMMCO may obligate customers to shed[15] their loads to ensure a balance between supply and demand.

NEMMCO uses its forecasted demand and plant availability information provided by generators to supervise the future adequacy of generating capacity. This process is called a Projected Assessment of System Adequacy (PASA) [Nat98a]. PASA projections are published by NEMMCO to market participants. Generators use PASA projections to determine the optimal timing of unit maintenance, and market customers use PASA to plan for their consumption patterns. Two types of PASA are published by NEMMCO, one is long-term (two-year) projection and the other is short-term (seven-day) projection. The first type of projection is updated at least weekly which shows daily generating capacity compared to the forecasted peak demand, and the second one is a seven-day-ahead projection which is updated at least daily and to show the generating capacity compared to the forecasted demand at each half hour in seven days [Nat98a].

NEMMCO uses a centrally coordinated dispatch process to schedule generators to meet the forecasted demand. Scheduled generators submit a daily dispatch offer to NEMMCO in each day. The dispatch offer indicates to NEMMCO how much electricity a generator is prepared to sell and at what price above the minimum level of generator output (self-dispatch level) at each half hour of the next day. In addition to the self-dispatch information, the offer includes information on increments of generating capacity above and below the self-dispatch level with their associated prices. On the other side, each market customer informs NEMMCO of the available capacity of its scheduled load. In addition, a market customer may provide dispatch bids to NEMMCO, showing

[15] Reduce electricity consumption.

prices and associated quantities of demand. For each half hour during the day, market customers show how much energy they prefer to buy for their scheduled loads, in different increments of consumption, with associated prices. NEMMCO uses this information of offers and bids to determine the winning generators to be scheduled to meet the forecast. Here, NEMMCO schedule generators sequentially starting from the lowest price offer up to more expensive ones until enough generation is obtained to meet the demand [Nat98a].

It is also the responsibility of NEMMCO to contract the required ancillary services for maintaining the power system security and ensure acceptable levels of supplies quality. Among these services are maintaining reactive power resources to control bus voltages and contracting back-up generators to restore the system in case of a blackout.

One of the key issues in this market is to determine the spot price[16], the price at which all market generators and market customers settle their sales and purchases of electricity. NEMMCO uses the price offers and demand bids to calculate the spot price, where NEMMCO uses a two-step process. In the first step, NEMMCO determines the marginal cost of supply to meet demand for each five minute interval in a half hour after adjusting the offers and bids for electrical losses (this price is called the dispatch price which is the offer price of most expensive generator (the last generator) brought into operation to meet the demand). In the second step, NEMMCO calculates the spot price as a time-weighted average of six dispatch prices in a half hour (five minute intervals). After determining spot prices, they are published by NEMMCO at the end of each half hour during the current trading day. The following example illustrates these concepts [Nat98a].

Example 9.3: (Calculation of Spot Price in NEMMCO)

Figure 9.7 shows the load profile for the time period [1:00–1:30 p.m.] where points P_1–P_6 represent loads at the ends of 5-minute

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[16] The spot market is the market where market generators are paid for the electricity that they should have sold to the pool and market customers are charged for their electricity consumption.

intervals. The generator offers (bid price and maximum capacity) in this 30-minute interval are shown in the figure.

The generators are arranged in an economic order from the cheapest to the most expensive. For P_1, two generators are dispatched totally (G_1 and G_2) with a dispatch price of \$15/MWh (i.e. bid price of the most expensive generator in G_1 and G_2). For P_2, three generators (G_1, G_2 and G_3) are dispatched totally with a dispatch price of \$18/MWh (i.e. bid price of the most expensive generator in G_1, G_2 and G_3). For P_3, generators G_1, G_2 are dispatched totally and G_3 is dispatched partially to meet the demand with a dispatch price of \$18/MWh (the bid price of the most expensive generator in G_1, G_2 and G_3). P_4 is the same as P_1. For each of P_5 and P_6, G_1, G_2 and G_3 are dispatched totally and G_4 is dispatched partially with a dispatch price of \$25/MWh (i.e. bid price of the most expensive generator in G_1, G_2, G_3 and G_4). The spot price of the 30-minute period is calculated as the average dispatch price of the six sub-intervals, i.e., spot price = (15+18+18+15+25+25)/6= \$19.33/MWh.

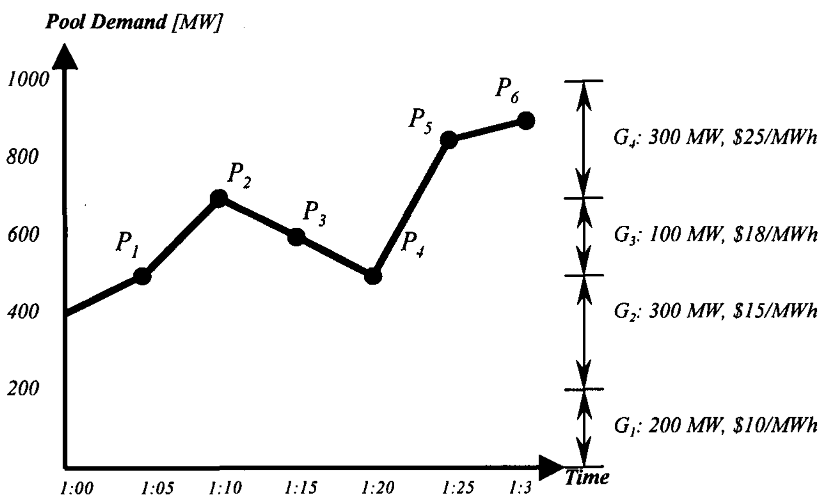

Figure 9.7 Pool Demand from 1:00 PM to 1:30 PM

NEMMCO uses the concepts of regional reference node and intra-regional loss factors relative to the regional reference node to represent transmission losses for transporting electricity from generators to the market participants' connection points. Loss factors are pre-calculated using a historical analysis of electrical losses within a region. These factors are used during the central dispatch to modify offer and bid prices in the dispatch of generators for balancing the demand. NEMMCO first determines the regional reference node for each region, and then uses the intra-regional loss factor between the market participant's connection point and the regional reference node to calculate the local connection price[17] for each participant's.

During calculations of spot prices, NEMMCO also considers the flow limits of the interconnectors across the States and Territories. At times when an interconnector limit is reached, NEMMCO may bring more expensive generators into operation in a state, when a lower priced generation from another state causes overload of interconnector. It uses interconnector capacities between geographical areas to determine how many electrical regions are required in the National Electricity Market, and calculates a regional reference node price for each region.

The Code specifies a value for the Value of Lost Load (VoLL) as $5000/MWh. VoLL is used as a maximum limit to which the spot prices may rise when involuntary load shedding is required at times when generation is inadequate to balance the demand. NEMMCO obligates every market participant to install, in arrangement with an appropriate and registered metering provider, an appropriate meter to register and store half hourly electricity readings. A market participant should also have a communications method capable of uploading meter data to the NEMMCO metering database for settlement purposes. Data forwarding service to NEMMCO is done through a metering data agent[18].

Billing and settlements of transactions related to the spot market are the responsibility of NEMMCO. NEMMCO is the administrator of all spot market transactions. In the case of payment default by a market

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[17] What a participant pays (receive) equals the spot regional spot price times intra-regional loss factor. The product is called connection price.

[18] These are agents accredited by NEMMCO for the purpose of data forwarding, and a market participant should select one of these agents.

participant, NEMMCO does not have any exposure. Market participants are required to use an electronic settlement system to settle payments with the pool and for the collection and payment of market fees[19]. Payments related to generators include payment for electricity generated, payment for ancillary services provided, and market fees. Payments of customers include charges for electricity consumed, charges for ancillary services consumed and market.

NEMMCO has two centers to manage the pool and the operation of the power system: National Dispatch and Security Centers. Each of the two centers operates computer systems to manage the power system and market, and in the case of a failure of one of the centers, the other center may take the responsibility of managing the power system and market. NEMMCO's computer systems consist of the Market Management system (MMS), and Scheduling, Pricing and Dispatch System (SDP). MMS includes bidding and reporting system and settlements system. In addition to providing market information reports, the first system receives offers from scheduled generators and bids from market customers. The second system prepares invoice accounts for participants based on their metered generation or consumption. On the other hand, SPD includes dispatch system and spot price calculation system. The dispatch system schedules generators to meet electricity demand based on offers and bids submitted to MMS. The spot price calculator determines the spot prices of regional reference nodes.

In addition to the two centers, two data communications networks are implemented to support the NEM: NEMnet, and CONTROLnet. NEMnet is used by participants to capture offers and bids information and disseminate reports, while CONTROLnet connects each of the regional control centers[20] to NEMMCO's National Dispatch and Security Centers, and is used to remotely control generator productions by transmitting electronic signals from NEMMCO's dispatch system to generators.

Without any intervention or knowledge[21] of NEMMCO, buyers and sellers of electricity may hold long-term or short-term contracts to

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[19] Owed to NECA/NEMMCO to recover their costs.

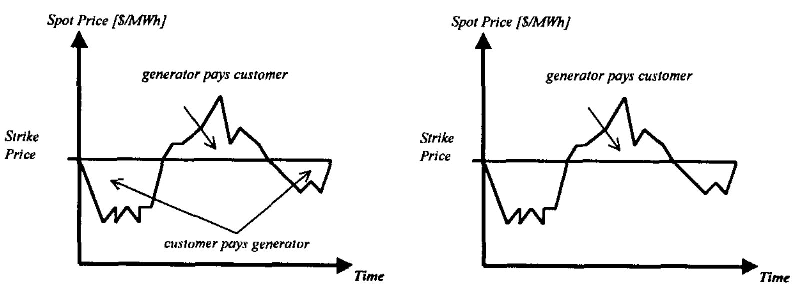
[20] Control centers of New South Wales, Queensland, South Australia and Victoria.

[21] Unless contracted parties have decided to register the contract with NEMMCO as part of a reassignment agreement.

manage risks associated with price volatility. These bilateral contracts are financial hedging instruments, which set an agreed-upon price for electricity, have no impact on the physical electricity flows and are not standardized or vertically integrated by the Code. The financial contract requires the two parties exchange cash against the spot price. Participants may use two types of hedge contracts: the two-way hedge (swap) and the one-way hedge contract (option), see Figure 9.8 for illustration. A participant that uses these contracts could be generators, retailers, and customers. The contracts may consist of bilateral and negotiated deals, and over-the-counter (OTC) derivatives provided by brokers or derivative exchanges. The following example shows how cash against the spot price is exchanged when a two-way hedge is used for hedging spot price risks.

Example 9.4: (Swap or 2-way hedge)

A GenCo and RetailCo signed a contract for 200 MWh of electricity at a strike price of $25/MWh. Assume that the GenCo produced 200 MWh and the RetailCo's electricity consumption was 200 MWh. The variation of spot price versus time is shown in Figure 9.9. The payment for two cases is studied:



a- Two-Way Hedge Contract b- One-Way Hedge Contract

***Figure 9.8** Hedge Contract to Exchange Cash against Spot Price*

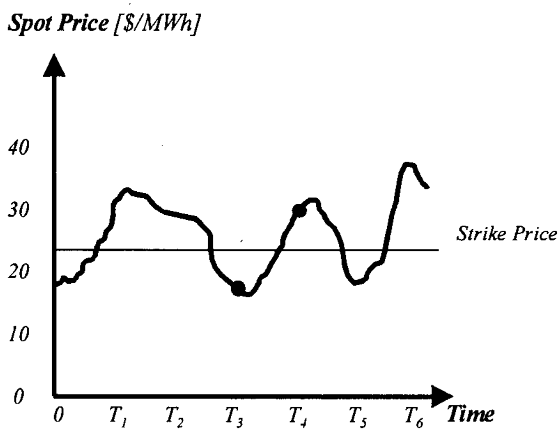


Figure 9.9 *Spot Price versus Time*

(a) Case 1: The expiration date is T_4 (i.e. spot price is greater than the strike price)

At time T_4, spot price is \$30/MWh. The spot price is greater than the strike price, which means that the GenCo pays to the (RetailCo). This payment is 200 MWh × (\$30 - \$25)/MWh = \$1,000.

The net effect on the GenCo's financial position is:

200 MWh × \$30 =	\$6,000	Spot market revenue
- 200 MWh × \$5 =	- \$1,000	Hedge payment
	\$5,000	Net revenue

The net effect on the RetailCo's financial position is:

200 MWh × \$30 =	\$6,000	Spot market price
- 200 MWh × \$5 =	- \$1,000	Hedge payment
	\$5,000	Net payment

Note that the net revenue and net payment are equivalent to 200 MWh × $25/MWh.

(b) Case 2: The expiration date is T_3 (i.e. spot price is less than the strike price)

At time T_3, spot price is $17.5/MWh. The spot price is less than the strike price, which means that the RetailCo pays to the GenCo. This payment is 200 MWh × ($25 - $17.5) = $500.

The net effect on the GenCo's financial position is:

200 MWh × $17.5 =	$3,500	Spot market revenue
200 MWh × $ 7.5 =	$1,500	Hedge payment
	$5,000	Net revenue

The net effect on the RetailCo's financial position is:

200 MWh × $17.5 =	$3,500	Spot market price
200 MWh × $7.5 =	$1,500	Hedge payment
	$5,000	Net payment

Also, note that, in this case, the net revenue and net payment are equivalent to 200 MWh × $25/MWh.

Network pricing (charges) includes *connection charges* and *use of system charge*. Each market participants pay these charges to local network service provider. The use of system charge covers payments for using the local distribution network and the use of the transmission network. Participants pay network charges regardless what spot price or trading arrangements are made by a participant. Network charges are designed in a way that would provide incentives to economically and efficiently expand and maintain the transmission and distribution networks. Participants are entitled to acquire a satisfactory level of network service for paying charges. Market participants may negotiate the level of network services with the network service provider based on a suitable adjustment to network charges [Nat98a].

9.3 RESTRUCTURING IN CANADA

9.3.1 Power Pool of Alberta. In 1982, the Electric Energy Marketing Act (EEMA) was established in Alberta to average the costs of generation and transmission of the three utilities: Alberta Power Limited, Edmonton Power, and TransAlta Utilities. Later, Stakeholders and the Government of Alberta started discussions to develop a replacement for EEMA to make a transition from the government vertically integrated electrical market to an open and competitive electricity marketplace. The discussions ended with recommendations in October 1994, followed by legislation and decisions in May 1995. The decisions are included in the new Electric Utilities Act (EUA), which replaced EEMA, which would encourage a move from the old vertically integrated market to competitive pool market. The legislation established a power pool, which is a not-for-profit corporation that would permit the development of an efficient electricity marketplace based on fair and open competition. In addition to creating competition, the new pool was seen as a way to decrease administrative costs of providing and generating electricity in Alberta. The new EUA separated the old system, for regulatory purposes, into three separate elements: power generation, power transmission, and power distribution. The EUA has been in effect since January 1, 1996 and EUA established two new entities to create the required open access to enable competition. The two entities are a power pool and a transmission administrator (TA). Fairness and open competition, efficiency and independence are the principles for both the pool and the transmission grid work [Alb96, Alb99, Alb00, Lon98, Nat98b, Pow99, Pow00, Web50].

The pool was seen as a system that would increase the number of participants in the generating sector, especially with the entrance of independent power producers (IPPs), which in the past had to negotiate with the existing utility generators to sell power. With the creation of the pool, those IPPs and the importers have the opportunity to compete with existing utility generators in both the market to supply power and the market to supply new generating capacity. The advantage in the new marketplace belongs to generators that can produce power at a lower cost. This fact will necessitate all market participants to steadily discover new ways to improve their operating efficiencies and cut their production costs [Alb96, Alb99, Alb00, Pow99, Pow00, Web50].

Under the EUA, the TA is responsible for the overall coordination of the transmission system in the province of Alberta and responsible for setting tariffs for system access. Since 1996, the Grid Company of Alberta Inc (GridCo) has been assigned the role of the TA. GridCo was formed through a shareholders' agreement among The City of Calgary Electric System, Edmonton Power Inc., TransAlta Utilities and Alberta Power Limited, which are the four utilities in Alberta that own transmission facilities. In June 1998, ESBI Alberta Ltd. (EAL)[22] became Alberta's TA. The transmission facilities are still owned by the four utilities and the whole system is managed and vertically integrated as a single entity. Buyers and sellers which trade electricity through the Power Pool should arrange for transmission through the TA. Any participant that pays a common rate acquires a non-discriminatory access to the transmission system. The TA agrees and contracts with each transmission owner to provide transmission service. The TA also stands as the clearinghouse for financial settlements between the transmission owners and buyers[23] of transmission services. It is responsible for setting province-wide tariffs for transmission access and coordinates with the power pool in topics such as the generation needed for operating reserve, regulation, and voltage support. Distribution companies buy system access and pay for it based on the province-wide tariff. By doing this, all transmission users would pay a common, postage-stamp charge for transmission regardless of their locations in Alberta [Alb96, Alb99, Alb00, Lon98, Pow99, Pow00, Web50].

The Power Pool of Alberta, which started operating on January 1, 1996, does not buy and sell electric energy itself, but is the market for electricity that is bought and sold in the province of Alberta. Generators (including independent power producers), marketers and importers are the entities in Alberta, which sell energy through the Pool. Distributors, retailers[24], marketers, direct access customers, and exporters are the

[22] EAL is owned by the Electricity Supply Board of Ireland; which is responsible for the generation, transmission, distribution and sale of electricity in Ireland.

[23] Buyers of transmission service include generators, distributors, industrial systems, direct access buyers, importers and exporters.

[24] Independent retailers are eligible to participate in the Power Pool as of Dec. 31, 2000.

entities that buy energy through the Pool. Since the time that the Pool started operating, all of the wholesale electric energy bought and sold in Alberta, in addition to energy imported and exported through Alberta, has been traded through the Power Pool of Alberta. The Pool carries out two main functions: operation of the energy market and real-time coordination of the Alberta's power grid. The Pool operates the market by receiving offers[25] to sell and bids to buy from market participants, and then establishes an hourly market price for electricity by matching supply with demand.

EUA allowed six distribution companies to buy electric energy from the Pool for sale to customers in distributors' service areas. Recently, in 1998, the Alberta government revised the EUA to promote more developments in the Alberta's competitive electric industry. The amended legislation brings terms for the introduction of customer choice, such that consumers may either continue to buy electricity from their traditional suppliers or find other new suppliers. The first phase of customer choice started on April 1, 1999, where the distribution companies in Alberta were required to have direct access tariffs ready by April 1, 1999. A customer under the new legislation may opt to purchase its electric energy directly from the Pool, while continuing to purchase transmission and distribution services from its existing distribution company. A customer should meet some requirements to be an eligible direct access customer. The requirements are: customers should have time-of-use meters, should receive electricity from the Alberta interconnected system at a voltage level equal or greater than 25kV, should be able to increase/decrease its consumption or system support services within 1 hour of receiving a dispatch, and should satisfy the requirements set out by the regulations [Alb96, Alb99, Alb00, Pow99, Pow00, Web50].

Figure 9.10 illustrates the main players in this electricity Market.

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[25] Suppliers of electricity place offers to supply hourly blocks of energy at specific prices. Supply offers may come from utility-owned generating companies, independent power producers, or marketers importing power from other provinces or the U.S. Electricity purchasers place bids to buy blocks of energy at specific prices. Bids, like offers, are placed for each hour of the next day and for the following six trading days, with prices fixed for the next day. Demand bids are submitted by Alberta distribution companies and by marketers buying power for export.

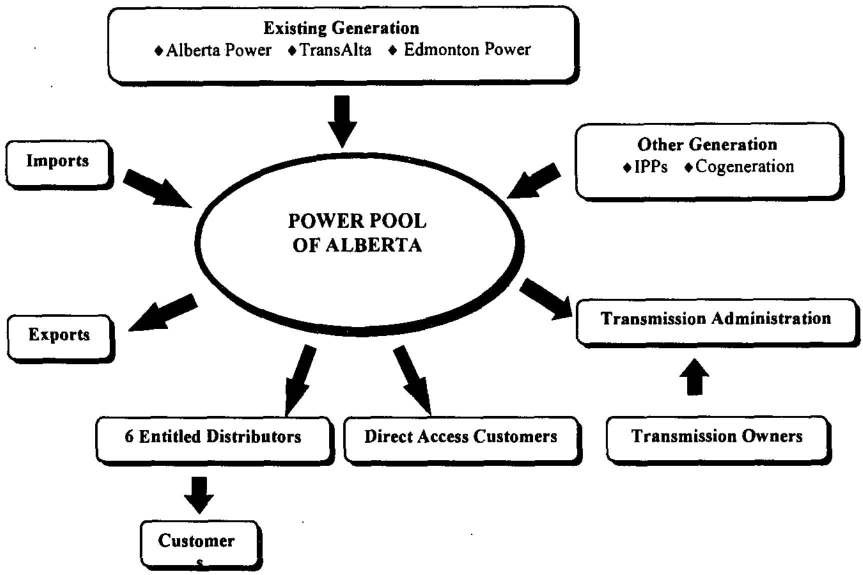

Figure 9.10 Power Pool of Alberta

The independent Power Pool Council oversees the operation of the Power Pool of Alberta. The Council is responsible for ensuring that the Pool is operated as a fair, open and efficient electricity marketplace. The government of Alberta assigned independent individuals with no interest in the electric industry to the Council. The Council predetermined rules to guarantee that market entities compete on a fair basis and that no one entity can drive the long-term pool price or impose how much consumers pay for electricity. In addition, the Council approves the annual budget of the Pool. To manage Pool operations, it is also the responsibility of the Council to assign a Power Pool Administrator and a System Controller. The Pool administrator is the entity that receives energy supply offers and demand bids, sets the schedule for dispatching generating units, reports the Pool price for each hour and accomplishes financial settlement for the electric energy traded through the Pool. The System Controller dispatches offers of generation and imports additional generation to balance the system, ensures the safe and reliable operation of the system, and arranges for system support services.

In addition to maintaining an open access and a non-discriminatory competitive market for electricity, and establishing an hourly market price for which all power is bought and sold, the Pool determines and coordinates which units run to produce electric power in any given hour, based on the prices offered by generators to sell energy. In the Pool, at any hour, the lowest-price units are selected first.

The Power Pool of Alberta deals with two types of loads: price responsive loads and non-price responsive loads. Any load in Alberta is one of the two types. Electricity for non-price responsive load is currently forecasted by the Pool Administrator on a daily basis and is not bid–in by participants. Participants can bid–in for the price responsive load. In the case of price responsive load, the distributor or exporter is willing to take energy from the Pool if the Pool price is less than its bid price. All bids and offers provided by participants to the Pool are automatically applied against curtailable loads [Alb96, Alb99, Alb00, Pow99, Pow00, Web50].

The Power Pool of Alberta works on a day-ahead basis, where the Pool's participants submit offers to sell and bids to buy electricity for the following day, and then the Pool determines a market price for electric energy by matching supply with demand. Offers and bids are received by 10:00 a.m. The Pool uses offers, bids and calculated prices to publish forecasts of electricity supply, demand, and Pool price for the next day. In addition to the price determined in the day-ahead, the Pool determines the real-time price of electricity and publishes both prices on the Pool's web site.

On the day-ahead, the Pool participants would submit their hourly offers and bids for a 7-day trading period. The offer prices and bid prices are fixed for the first day (participants may not change or modify), while they have the option to alter offers and bids for the other days, and bid quantities (volumes) can be re-declared at any time. Participants would establish offers and bids for each hour of the next day and for the following six days. Each offer is to supply hourly blocks of energy at particular prices, and each bid is to buy blocks of energy at particular prices. To schedule generators and loads and determine market prices, the Pool ranks offers and bids starting from the least expensive and ending with the most expensive and then publishes a schedule for the next trading day. The schedule includes forecasted generation offers being accepted, demand bids scheduled to be accepted, import and export amounts and forecasted Pool price. In real time, the Pool dispatches the required generation and processes import offers and demand bids to serve the system demand and exports. The Pool uses the actual dispatch to calculate the hourly Pool price. The Pool then uses the Pool price to settle with buyers and sellers each month, where all participants who are producing electricity would receive the hourly Pool price for electricity generated and all participants who are buying electricity pay the Pool price for the electricity [Alb96, Alb99, Alb00, Pow99, Pow00, Web50].

It is the responsibility of the Pool to maintain a safe and reliable operation of the Alberta's electric system. To do that, the Pool is obligated to maintain supply and demand in balance, by commanding suppliers and buyers to adjust their amount of energy. To accomplish the system control functions, the Power Pool of Alberta has a System Coordination Center.

The Pool requires a candidate participant to sign a participation agreement[26], pay a participation fee, pay a trading charge[27], sign a transmission agreement with TA, and meet Pool's technical control and communication requirements. In addition, participants that are

[26] A participation agreement is a contract to comply with pool rules and pool code.

[27] Trading charges are used to recover the pool's operating costs. A trading charge is a fee per MWh on energy volume traded through the Pool. Each participant pays the trading charge. The pool will post any changes to the trading charge on the Power Pool Web site. The trading charge is set by the Power Pool Administrator and approved by the Power Pool Council.

purchasing from the Pool must satisfy prudential requirements[28], and participants that are supplying generation must meet the Power Pool's Generation Connection Requirements.

The Alberta transmission system is joined to a wide network that is extending through the western United States and connected to the system in British Columbia. During emergency situations, the neighboring systems could help one another. In general, the existence of these systems could improve the reliability of the entire interconnection. In addition to the rules of the Pool and TA, the Alberta's transmission system follows standards and rules created by regional organizations such as the Western Systems Coordinating Council (WSCC) and the Northwest Power Pool (NWPP)[29].

To maintain the frequency at 60 Hz when the Alberta's daily demand for electricity would fluctuate, the System Controller dispatches generating units in order to keep energy supplied to the system in balance with the amount of energy taken out of the system. In addition, the System Controller would ensure that the system keeps a certain amount of additional generating capacity (operating reserve) to deal with demand increases and possible supply disruptions. The System Controller deals with the operating reserves either through automatic controls in the case that a spare capacity is required to keep supply-demand balance, or instruct participants who are providing this service to manually control the operating reserve. The System Controller is always operating in coordination with TA and the distribution companies in Alberta.

Customers that buy electric power from distribution companies in Alberta fall into two categories. The first category is for customers that buy firm power,[30] such as residential consumers. The second category is

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[28] Prudential requirements were established to ensure that participants could meet financial obligations associated with trading in the pool. Participants may maintain at least an "A" bond rating, provide a letter of credit, or need to provide a line of credit, which the pool would have access to in case of default payments. The Pool itself is not required to maintain a credit function. Utilities, municipalities and TA would automatically meet the Pool's prudential requirements.

[29] The Northwest Power Pool is a voluntary organization comprised of major generating utilities serving the Northwestern U.S., British Columbia and Alberta.

[30] Distributors supply this power at all times.

for interruptible load customers,[31] such as industrial customers with fuel-switching capability. When the supply is disrupted suddenly due to a line/generator outage or damage, an imbalance between supply and demand would happen which may disturb the system frequency, and may lead to widespread outages and interruption of services. To keep system frequency within acceptable limits, the Alberta's power grid utilizes both automatic[32] controls and manual[33] procedures. For under-frequency situation, the power system in Alberta is directed to reduce a predetermined amount of demand automatically and in stages until system frequency is restored and the system regains a balance between supply and demand. When the system is restored, the System Controller provides distribution companies with directions to restore service to interrupted customers. In other situations such as in the case of gradual shortages[34] in supply or when the power system is being restored following an emergency, the System Controller instructs participants to manually control (curtail) firm loads rather than using automatic controls to restore the balance. The System Controller would determine how much the total system demand must be reduced to restore the balance and instruct distribution companies to curtail their demand.

Each distribution company would decide on the amount of load curtailment that it could handle in its service territory. This situation may arise when a generating unit is forced out of service, while other units are already down for planned maintenance. The System Controller follows TA's policies and the Pool's rules in both under-frequency load shedding and firm-load curtailment. The TA's policies are originally developed in coordination with the transmission system owners, generating units owners and distribution companies.

The Pool orders participants' offers and bids for each hour based on their prices into a merit order. The merit order is established for every

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[31] Customers that buy power from distributors under agreements that permit their electricity supply to be interrupted.

[32] Automatic controls such as automatic generation control (AGC) and under-frequency load shedding schemes. Under-frequency is the situation when system frequency drops below 60 Hz, such as when supply is disrupted suddenly and the Alberta grid is separated from British Columbia.

[33] Manual procedures such as load curtailment directives.

[34] For example, if a generating unit is forced out of service, while other units are already down for planned maintenance, supply may fall short of demand.

hour of the next day and is used by the System Controller in the dispatch of energy. The merit order for an hour is composed of many (maybe hundreds) blocks of energy. The Pool then matches energy supply with demand, establishes a minute-by-minute SMP[35] for electricity, and determines an hourly market price, which is posted on the Pool's Web site. The hourly operating schedule considers some factors such as transmission constraints and unit operating constraints. The steps used to calculate the price are as follows [Alb96, Pow99]:

- Participants would submit energy supply offers and demand bids to the Pool.
- For each hour of the trading day, Pool schedulers order offers and bids based on their prices, into a stacked merit order.
- The merit order produced for each hour is passed into the System Controller.
- To keep supply and demand in balance throughout the day when the demand fluctuates, the System Controller would dispatch the next offers or bids in the merit order.
- Every minute, the last[36] energy block dispatched sets the SMP.
- SMP is published on the Pool's Web site and updated every five minutes.
- The time-weighted average of the 60 one-minute SMPs is calculated at the end of the trading hour. This is published as the official Pool price at which all energy traded during the hour is cleared.

When the demand for electricity fluctuates around the balanced point, the Pool restores the balance between supply and demand by issuing dispatch instructions to power suppliers and purchasers regarding the amount of energy that is to be supplied into or taken out of the system. The Pool's instructions are based on supply offers and demand bids available in the merit order. When system demand increases, the System Controller moves up the merit order by operating more expensive

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[35] System Marginal Price
[36] Marginal unit

offer (supply) and decreasing supply to buyers who are willing to pay (as reflected from in their bids). On the other hand, when system demand declines, the System Controller moves down the merit order, by instructing some generators to decrease their output and serving more demand bids. The following example illustrates how the System Controller dispatches on and off supplies and purchases and calculates SMP for some situations [Pow99].

Example 9.5

For this example, at a certain hour, let's assume that there are five suppliers and two purchasers of electric power that would submit offers and bids to the Power Pool of Alberta. Each bid or offer is assumed to be one block. Figure 9.11 shows the offers and bids. The offer/bid quantities and prices are:

Offer	1	: 40 MW, \$7.50/MWh
Offer	2	: 50 MW, \$12.5/MWh
Offer	3	: 30 MW, \$15.0/MWh
Offer	4	: 40 MW, \$20.0/MWh
Offer	5	: 40 MW, \$30.0/MWh
Bid	1	: 20 MW, \$10.0/MWh
Bid	2	: 20 MW, \$25.0/MWh

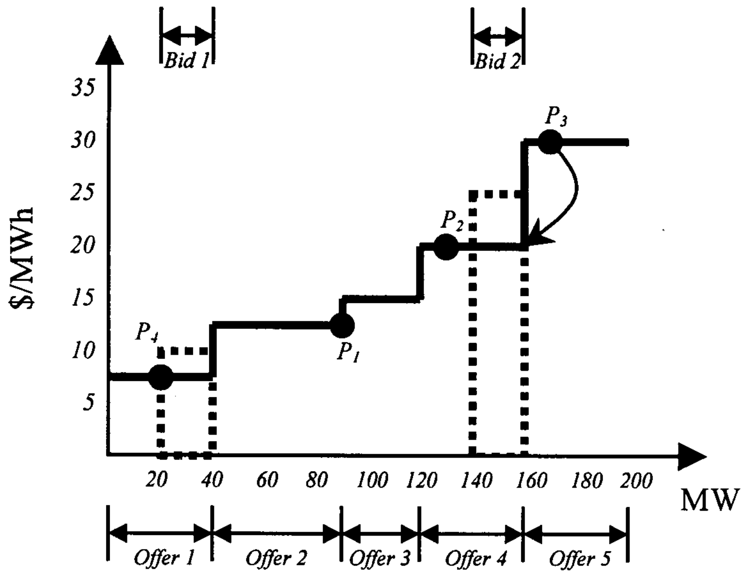

Figure 9.11 Example of Alberta's Pool Calculations

(a) The system demand in this hour is 90 MW. Offer 1 and offer 2 are fully dispatched to meet the demand, because the demand is 90 MW, and the total dispatched generation of both offer 1 and offer 2 is 40 +50=90 MW. Offer 2, which is the most expensive offer dispatched last, sets the SMP at $12.5/MW. The balance point is P_1 in the figure.

(b) Starting from P_1 in part (a), the demand increases by 40 MW (i.e. the total demand now is 130 MW), then the Pool will fully dispatch offer 3 and partially dispatch Offer 4. In this case, Offer 4 sets the SMP at $20/MWh. See P_2 in the figure.

(c) Starting from P_2 in part (b), the demand increases by another 40 MW (i.e. the total demand now is 170 MW. See point P_3 in the figure). In this case, a person may think that the Pool would dispatch Offer 5 (as seen from P_3 in the figure). This would increase the SMP to \$30/MWh, which is beyond the limit of bid 2 (remember that participant of bid 2 is willing to pay up to \$25/MWh). So, to meet the increase in demand, the Pool would fully dispatch Offer 4 with part of bid 2, i.e. the participant who submitted bid 2 and is taking 20 MW, will be dispatched back to 10 MW. In this situation, bid 2 will set the SMP at \$25/MWh, because it is only partially served.

(d) Starting from P_1 in part (a), the demand decreases by 70 MW (i.e., total demand now is 20 MW), then the Pool will fully dispatch-off Offer 2 (as seen from P_4 in the figure). There is enough energy from Offer 1 available to supply all 20 MW of bid 1, then bid 1 will be dispatched-on and Offer 1 will set the SMP at \$7.5/MWh.

(e) Starting from P_1 in part (a), the demand decreases by 60 MW (i.e., the total demand now is 30 MW), then the Pool will fully dispatch-off offer 2. Since the system demand now is 30 MW, there is an extra 10 MW from offer 1, i.e., there is not enough energy available to supply all 20 MW of offer 1, and bid 1 will be partially served (10 MW) and will set the SMP at \$10/MWh.

9.3.2 The Independent Electricity Market Operator (IMO). The Ontario government's legislation on competition in Ontario's Electricity Supply Industry founded a non-profit entity, which had no links to any market participant, and was called the Independent Electricity Market Operator (IMO) to manage the new electric market structure as an essential step for a competitive electricity marketplace. The main objective of the IMO is to create electricity markets that give suppliers in Ontario an opportunity to compete for providing power to both wholesale and retail customers, establish a fair system that would allow customers direct access to the electricity supplier of their choice, produce a reliable and efficient power system, and replace the old vertically integrated rates policy with a competitive price policy set by competitive markets [Ipp99, Imo99].

The IMO is composed of two main components: System Operator and Market Operator. The System Operator is responsible to maintain the security and the reliability of the bulk power system, i.e. it administers physical transactions, dispatches resources in real time to keep supply and demand in balance, administers and resolves security constraints to keep the system secure, administers system emergency conditions and instructs system resources in case of emergencies. The Market Operator is responsible for collecting offers (from sellers) and bids (from buyers). It manages market trading in electricity and related products, including settlements of associated accounts. It also oversees compliance with market rules and administers performance of market participants. It also helps ensure that the competition would develop without abuse of market power [Ipp99, Imo99].

- ***IMO Bidding, Dispatch, Scheduling, and Control:*** As shown in Figure 9.12, the IMO manages two types of markets, i.e., physical markets and financial markets. Physical markets include real-time markets and procurement markets. Real-time markets treat energy, operating reserve and capacity reserve. The procurement markets treat contracted ancillary services and must-run contracts. Physical markets include energy forwards and transmission rights [Ipp99, Imo99].

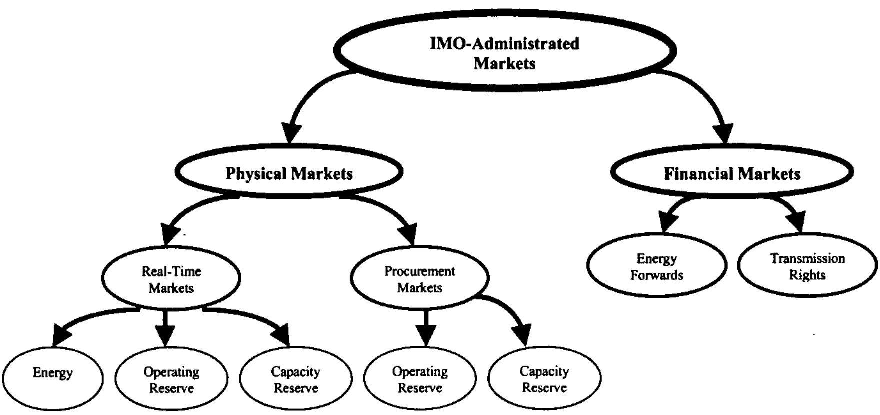

***Figure 9.12** An Overview of IMO's Market Structure [Imo99]*

IMO does not include a market for bilateral contract energy, but market participants can submit physical bilateral contract data to IMO to make it involved in settlement processes if participants opt to do that, and also submission of bilateral contract data helps IMO manage and maintain the reliability of the grid. If participants conduct any bilateral trade within the local grid, they do not need to inform the IMO, while they are obligated to inform the IMO of their traded quantities for any traded energy that goes into the main grid. IMO uses the provided quantity to manage congestion situations. Participants are not required to provide IMO with their bilateral contracts, but required to submit price bids in order to guarantee that loads will be supplied. To guarantee that the bid will be accepted, the best thing a participant can do is to bid zero.

In IMO's structure, ancillary services will be procured based on a competitive process. IMO will not deal with the long-term market.

- ***Real-Time Market Bidding – "Dispatch" Data:*** Market participants are initially required to submit the physical characteristics of their facilities (generation and load) to IMO, and IMO would register these data. In a biding process, each participant would submit one offer for each generating facility to supply energy to the market, and each participant would submit one bid for each load facility to take energy from the market [Ipp99, Imo99].

For each hour of the daily dispatch, an offer or a bid would include a maximum price and quantity, and may contain up to 20 price/quantity pairs for each hour. A seller of energy (generator) may opt to submit a negative-priced offer, which means that the generator accepts paying up to that price in order to have its energy taken rather than reducing its output. A buyer of energy (load) may also opt to submit a negative-priced bid, which means that the load accepts taking more energy than it has bid for. Any energy trades going through the grid (imports and exports) have to be included in the dispatch data provided to the IMO.

On the day before scheduling, market participants submit their bids and offers between 6:00 a.m.–11:00 am. At 11:00 a.m., IMO aggregates all offers (of each hour in 24 hours) into one offer graph, and aggregates all bids of each hour (of each hour in 24 hours) into one bid graph. IMO then uses the aggregated graphs to determine the *Pre-Dispatch* schedule. The pre-dispatch schedule will be issued to all participants by noon of the day before and is used as a reference for the next day's actual operations. The aim of pre-dispatch schedule is to ensure the feasibility of schedules while meeting all security and adequacy requirements, identifying difficulties facing the system, and determining the remaining transmission margins for additional trades. The pre-dispatch schedules are not binding to market participants as next-day schedules, but participants may see them as guidelines for planning to meet the required level of operation.

IMO uses a constrained (considering transmission system constraints) model of the algorithm to establish the pre-dispatch schedule. In the pre-dispatch schedule process, IMO stacks offers and bids based on their prices, and then optimizes *reserve offers* with energy offers while considering the network configuration, expected outages and security requirements. During this process, IMO identifies specific must-run bids and calculates the associated payments. In addition to the constrained pre-schedules process, IMO uses an unconstrained model of the algorithm to produce a projected market schedule and market price for each hour in the dispatch day. IMO also issues the projected market schedule to all participants at noon on the day before.

IMO sends information to all market participants. The information includes energy prices and operating reserve prices at each node, total system losses, total system load, regional operating reserve requirements, aggregated load curtailment exercised, aggregated must-run generation scheduled, any regional reserve shortage, a list of the network and security constraints that change the pre-dispatch schedule, projected uniform market prices of energy and operating reserves in Ontario, projected market prices of energy and operating reserves in each inter-tie zone outside Ontario, and a revised IMO System Advisory Report. IMO also sends certain information to each participant. The information includes the pre-dispatch and market schedule for the participant's facility, security or load constraints affecting the participant's facility, and any expected use of its facility for must-run or ancillary services contracts [Ipp99, Imo99].

Up to 4 hours before the real-time operation, a market participant has the option to freely modify its bid/offer. Participants may also make any changes to bids/offers, not exceeding 10% in MW or price, between 4 and 2 hours before real time. Any change in time or over 10% would require an approval from IMO. IMO decides whether modified bid/offer results in significant changes to resources or requirements, before reissuing the pre-dispatch schedule. After receiving any modifications on bids/offers, IMO determines the final pre-dispatch schedules, just prior to real time and forwards them to any marginal[37] or affected participants.

IMO determines the real-time dispatch schedule during the hour of operation, where the IMO's main objective is to keep the load and generation in balance while maintaining system security requirements. IMO uses a constrained-model algorithm for real-time dispatch. The schedule is determined at 5-minute intervals in the hour of operation starting from the beginning of the hour. The real-time schedule gives the final dispatch data from the market participants, generation status and security limits, real-time system measurements and the latest projections, and evaluates the most accurate estimates of loads for market participants.

Three forms of dispatch instructions would control facilities in IMO operations: *automatic dispatch instructions*, *IMO directions and orders*, and *automatic generation control (AGC)*. The automatic dispatch instructions are the instructions published by IMO to a marginal participant to change its output or reserve obligation, which involve new energy dispatch, rate of change, expected reserve requirements, must-run requirements and ancillary service requirements. IMO directions and orders would involve manual ancillary dispatching, manual reserve activation notification, notification for final release of outages and manual energy dispatch when required. The automatic generation control is the control of generating facilities[38] up to 200-300 MW of capacity at any time to manage the system on a moment-to-moment basis. In the first two types, IMO issues the instructions to participants and the participants control the response. The third type is directly and remotely control by IMO. IMO uses an energy management system (EMS) to monitor its performance in real time [Ipp99, Imo99].

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[37] A marginal participant is the participant that is not running at full capacity.
[38] IMO will contract with suppliers to provide this service.

9.4 ELECTRICITY INDUSTRY IN ENGLAND AND WALES

The United Kingdom (UK) includes four separate countries: England, Wales, Scotland, and Northern Ireland. The four countries are considered as three regions, where England and Wales are in one region, and Scotland and Northern Ireland represent the other. As related to the electricity industry, England and Wales are governed by the same Acts of Parliament and are treated the same in terms of structure. On the other hand, Scotland and Northern Ireland are governed by slightly different Acts of Parliament and have a very different electricity industry structure. In this section, we present the electricity industry in England and Wales [Abb98, Ele99, Gre98a, Gre98b, Nat98b, New97, Tab96, Zor91, Web51, Web52].

Before competition started in UK electric industry, the Central Electricity Generating Board (CEGB) owned most of electrical power generation and transmission facilities in England, then the CEGB sold its electricity to twelve Area Electricity Boards (AEBs), which took the rule of distributing electricity to the customers. The federal Electricity Council – which had representatives for CEGB and for each AEB – coordinated industry policies. With this structure, the government set the price of electricity and generators were obligated to supply electricity. This system was seen as a government-controlled monopoly. Few years before 1990, public opinion and political forces started criticizing this controlled monopoly and invited to privatize the electricity industry, including privatization of nuclear stations. This motion ended with passing the Electricity Act in 1989, which called the transition of electrical industry ownership from government to private investors, and would encourage competition, improve efficiency, involve more employee, and reduce prices to customers.

In 1990 England started privatization and introduced competition into its electricity industry, where the majority of government-owned electrical power production and distribution were sold off, and main changes taken place in the ownership and management of power generation, transmission, and distribution. This new structure necessitated the formation of the Pool as a means to trade electricity

[Abb98, Ele99, Gre98a, Gre98b, Nat98b, New97, Tab96, Zor91, Web51, Web52].

To implement competition, the government-controlled CEGB was separated, in April 1990, into four parts: National Power company, PowerGen company, Nuclear Electric company and the National Grid Company (NGC). The National Power and PowerGen companies were formed from the fossil fuel generation plants of CEGB and the Nuclear Electric company was formed from the nuclear generation of CEGB. NGC was formed to take control of the transmission system. Since the National Power and PowerGen companies were producing most of the electricity, there was a concern that they would exercise market power which in turn might drive prices up. This fact required regulators to take action to increase competition in generation sector to reduce market monopoly. The action ended by selling some of the National Power and PowerGen plant production[39] to new participants, and new generators entered the market.

Competition could not be introduced to the transmission industry, instead NGC was formed as a vertically integrated natural monopoly to maintain the national transmission system. The role of NGC, as the Electricity Act stated, was "to develop and maintain an efficient, coordinated and economical system of electricity transmission and to facilitate competition in the generation and supply of electricity." The NGC charges for transmission system usage are divided into two components: connection charges and use of system charges.

In the distribution side, the twelve Area Electricity Boards were changed to investor-owned Regional Electricity Companies (RECs) in December 1990, where each REC provides electricity to customers in its area. In 1998, customers had the choice to buy electricity from any supplier. Suppliers pay for electricity to be transmitted across NGC and distributed to their customers. Duties of suppliers include publishing prices, reading meters, issuing bills, and processing payments. Any entity can apply to be licensed as a supplier. Large industrial and commercial customers can select their suppliers of electricity, but domestic and small

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[39] In 1990 National Power and PowerGen accounted for 78 per cent of total output and together with Nuclear Electric for 94 per cent. By 1998 National Power and PowerGen together accounted for 41 per cent of total output and with Nuclear Electric for 58 per cent.

business customers are required to buy their electricity needs from their local public electricity suppliers.

The marketplace where all electricity produced or consumed in England is sold and purchased in the Electricity Pool of England and Wales is the wholesale market. On a day-ahead basis, at 10:00 a.m., all generators are required to submit their bids[40] and information to the Pool showing generation they are willing to produce for each half-hour of the following day, plus any operating constraints such as the minimum generating levels and rate (ramp time) at which a generating unit can increase or decrease its output. It is the responsibility of NGC (Grid Operator) to schedule and dispatch generation daily to meet the actual demand. NGC produces a forecast of demand (plus reserve) considering weather condition and demand usage patterns for each half hour of the following day and then schedules generators' offered bids to meet this demand. Generation scheduling is done by NGC through pooling all electricity generation together to balance customers' demands (hourly based on load projections) for each half hour. NGC selects winning[41] generators based on the lowest bids available to meet the projected demand, and this process will determine the System Marginal Price (SMP) for each half hour (the price of the most expensive generator). The selection of winning bids does not take constraints into consideration (unconstrained schedule). When the actual demand is different from the projected demand, or when some of the low bidding generation is unavailable at the projected time due to transmission constraints or mechanical failures, reserves are used to balance generation with demand [Abb98, Ele99, Gre98a, Gre98b, New97, Tab96, Zor91, Web51-52].

Figure 9.13 shows the structure of electricity industry in England and Wales.

The period from 5:00 am on one day until 5:00 am on the next day is called the schedule day. Each schedule day is divided into 48 half-hour periods, each is called a settlement period. By 10:00 am each day, every generator submits its *day-ahead offer* into the Pool (the available output

[40] Each day generators submit day-ahead bids into the Pool for the amount and price of electricity they are willing to generate at every half-hour period of the following day.

[41] This is done by using a computer system called Generator Ordering and Loading (GOAL), which has the objective of producing the lowest cost generation schedule for the whole day, considering all plant limitations and generator bids.

output and the price at which it is willing to generate electricity from each of its centrally dispatched generating units at its power stations during the following schedule day. The grid operator forecasts the demand, and then uses a scheduling system, i.e. GOAL, which schedules centrally dispatched generating units to meet the demand and a pre-defined reserve added to the demand forecast. The objective of GOAL is to determine a minimum cost day-ahead schedule, based on offered prices and outputs, but disregarding any physical constraints. This schedule is called the unconstrained schedule.

In each settlement period j, the price of the last flexible centrally dispatched generating unit scheduled to meet the forecast demand for that period sets the SMP_j in £/MWh. SMP_j constitutes the basis of the payments to generators for centrally dispatched generating units scheduled for generation in the unconstrained schedule [Web51].

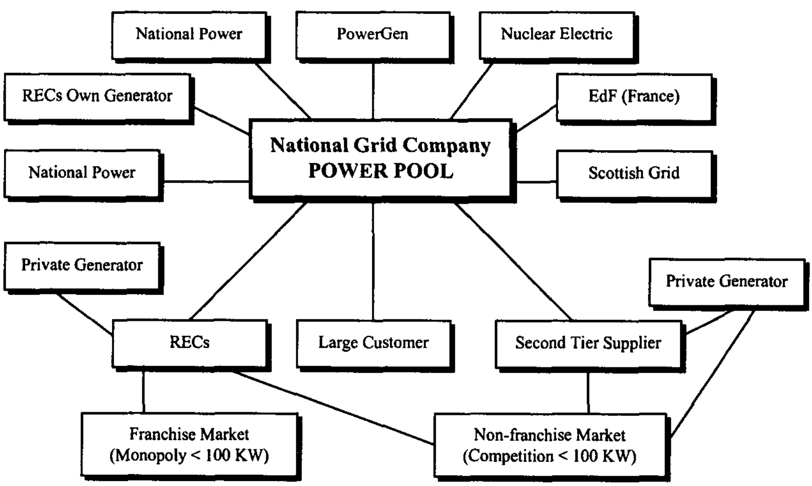

Figure 9.13 Structure of Electricity Industry in England and Wales

After calculating SMP, generators are paid at the Pool Purchase Price (PPP) which is equal to SMP plus capacity payment. Capacity payment is a payment that provides an incentive to generators to maintain an adequate margin over the level of demand. Capacity payment is high at times when there is little excess generation available, but decreases down to zero when there is a large excess of generation. On the other hand, suppliers buy from the Pool at a price called the Pool Selling Price (PSP[42]), which is PPP plus uplift. Suppliers pay for the amount of electricity they actually extract (consume) at each grid supply point[43] magnified by a factor that considers average transmission losses. The uplift pays for a number of additional costs incurred on the day and includes unscheduled availability payments[44], and additional generation costs resulting from unexpected increases of demand, and between generators' forecast availability and actual availability. In equation form, these prices for any settlement period (half-hour) j, are represented as [Abb98, Web51]:

$$PPP_j = SMP_j + CPj$$

where;

$$CP_j = LOLP \times (VLL - SMP\,j\,)$$

and

CP	Capacity Payment
LOLP	Loss of Load Probability[45]
VLL	Value of Lost Load[46]

In this market structure, bilateral contracts are possible but through Contract for Differences (CfDs). A CfD denotes a cash flow based on

[42] Slightly higher than the Pool Purchase Price.

[43] The point where electricity enters the distribution system from the National Grid.

[44] Payments to generating units that were available but not required to run.

[45] LOLP is the probability that demand will exceed the available generation. It is calculated after consideration of forecast demand and availability of generation offered.

[46] A value fixed annually. It represents the price consumers are assumed to be willing to pay to avoid loss of supply.

the Pool price. As we mentioned, transmission constraints are initially ignored in the calculation of the SMP, then costs related to transmission constraints are included in an uplift payment added to the purchase price of energy from the Pool.

Ancillary services, except spinning reserve, are contracted by the grid operator and are recovered through an uplift charge on the energy purchasers. Spinning reserve is paid through the market, and paid for by purchasers through uplift charges. Other charges, which are paid as uplift charges, include additional scheduling error costs, administration costs, and losses. Based on the grid operator's estimation, reserve is treated by modifying demand forecast, where the reserve is scheduled by uplifting the demand forecast to consider reserve requirements.

APPENDIX A

ACRONYMS

A

ADR	:	Alternative Dispute Resolution
AGC	:	Automatic Generation Control
ANCI	:	American National Standards Institute
APX	:	Automatic Power Exchange
ATC	:	Available Transfer Capability

B

C

CalPX	:	California Power Exchange
CBM	:	Capacity Benefit Margin
CBOT	:	Chicago Board of Trade
CCAPI	:	Control Center Application Program Interface
CDD	:	Cooling Degree-Days
CFD	:	Contract for Differences
CIM	:	Common Information Model
CME	:	Chicago Mercantile Exchange
CPM	:	Constrained Path Method
CTS	:	CalPX Trading Services
COB	:	California Oregon Border
CPWG	:	Commercial Practices Working Group

D

DAM	:	Day-Ahead Market
DDs	:	Degree-Days
DF	:	Delivery Factor
DisCo	:	Distribution Company
DJ	:	Dow Jones
DNS	:	Domain Name Service

E

ECAR	:	East Central Area Reliability Coordination Agreement
EEMA	:	Electric Energy Marketing Act (Alberta)
EIA	:	Electronic Industries Association
EMS	:	Energy Management System
EPAct	:	The National Energy Policy Act
ERCOT	:	Electric Reliability Council of Texas
ESP	:	Electricity Service Provider
ETC	:	Existing Transmission Commitments
EUA	:	Electric Utilities Act

F

FACTS	:	Flexible AC Transmission System
FERC	:	Federal Electric Regulatory Commission
FRCC	:	Florida Reliability Coordinating Council
FTRs	:	Fixed Transmission Rights

G

GCA	:	Generation Control Area
GenCo	:	Generation Company
GMM	:	Generator Meter Multiplier
GSF	:	Generator Shift Factor
GUP	:	Good Utility Practice

H

HAM	:	Hour-Ahead Market
HDD	:	Heating Degree-Days
HHI	:	Herfindahl-Hirschman Index
HTML	:	Hyper Text Markup Language
HTTP	:	Hypertext Transport Protocol

I

ICCP	:	Inter-Control Center Communications Protocol
ICCS	:	Integrated Control Center Systems
IEC	:	International Electrotechnical Commission
IEEE	:	Institute of Electrical and Electronic Engineers
iIDC	:	Interim Interchange Distribution Calculator
Int.CA	:	Intermediary control area
IndeGO	:	Independent Grid Operator
IOUs	:	Investor-Owned Utilities
IPP	:	Independent Power Producer (Provider)
IPCP	:	Internet Protocol Control Protocol

IP	:	Internet Protocol
IS	:	Interchange Schedule
ISO	:	Independent System Operator
ITU	:	International Telegraph and Telephone Consultative Committee

L

LBMP	:	Locational Based Marginal Price
LCA	:	Load Control Area
LSE	:	Load Serving Entity
LF	:	Loss Factor
LMP	:	Locational Marginal Price

M

MAAC	:	Mid-Atlantic Area Council
MAIN	:	Mid-America Interconnected Network, Inc.
MAPP	:	Mid-Continent Area Power Pool
MCP	:	Market Clearing Price

N

NATC	:	Non-recallable Available Transfer Capability
NECA	:	National Electricity Code Administrator Limited
NEMA	:	National Electrical Manufacturers Association
NEMMCO	:	National Electricity Market Management Company Limited
NEPOOL	:	New England Power Pool
NERC	:	North American Electric Reliability Council
NOPR	:	Notice of Proposed Rulemaking
Nord Pool	:	The Nordic Electricity Exchange
NPCC	:	Northeast Power Coordinating Council
NRES	:	Non-recallable Reserved
NSCH	:	Non-recallable Scheduled
NTS	:	Network Transmission Service
NYMEX	:	New York Mercantile Exchange
NYPP	:	New York Power Pool

O

OASIS	:	Open Access Same-time Information System
OPF	:	Optimal Power Flow
OSI	:	Open Systems Interconnection
OTC	:	Over-the-Counter

P

PJM	:	Pennsylvania–New Jersey–Maryland Interconnection
POD	:	Point of Delivery
POR	:	Point of Receipt
PPP	:	Point-to-Point Protocol
PSEs	:	Purchasing-Selling Entities
PURPA	:	The Public Utility Regulatory Policy Act of 1978
PUCT	:	Public Utility Commission of Texas
PX	:	Power Exchange

Q

QFs	:	Qualifying Facilities

R

RATC	:	Recallable Available Transfer Capability
RCA	:	Receiving Control Area
RetailCo	:	Retail Company
RINs	:	Real-Time Information Networks
RRES	:	Recallable Reserved
RSCH	:	Recallable Scheduled
RSP	:	Rated System Path
RTG	:	Regional Transmission Group
RTO	:	Regional Transmission Organization

S

SC	:	Scheduling Coordinator
SCA	:	Sending Control Area
SCUC	:	Security Constrained Unit Commitment
SERC	:	Southeastern Electric Reliability Council
SLIP	:	Serial Line Internet Protocol
SNMP	:	Simple Network Management Protocol
SPP	:	Southwest Power Pool
SSL	:	Secure Sockets Layer
S&CP	:	Standards and Communication Protocols

T

TC	:	Transmission Customer
TCC	:	Transmission Congestion Contract
TISWG	:	Transaction Information System Working Group
TLR	:	Transmission Loading Relief
TMNSR	:	Ten Minute Non-Spinning Reserve
TMSR	:	Ten Minute Spinning Reserve

TP	:	Transmission Provider
TransCo	:	Transmission Company
TRC	:	Transmission Revenue Credits
TRM	:	Transmission Reliability Margin
TS	:	Transmission Services
TSC	:	Transmission Service Charge
TSIN	:	Transmission Services Information Networks
TSIPs	:	Transmission Services Information Providers
TTC	:	Total Transfer Capability

V

VaR	:	VALUE-at-RISK
VoLL	:	Value of Lost Load
VTSIP	:	Value-added Transmission Service Information Provider

U

UDC	:	Utility Distribution Company

W

WAPA	:	Western Area Power Administration
WEPEX	:	Western Power Exchange
WICF	:	Western Interconnection Coordination Forum
WOR	:	West-of-Colorado River transfer path
WRTA	:	Western Regional Transmission Association
WSCC	:	Western Systems Coordinating Council

APPENDIX B

A SAMPLE OF ELECTRICITY CONTRACT SPECIFICATIONS[1]

Part B1: NYMEX Division: Entergy and Cinergy Electricity Futures and Options Contract Specifications

Trading Unit

Futures: 736 megawatt hours (MWh) delivered over a monthly period.

Options: Either one NYMEX Division Cinergy electricity futures contract or one NYMEX Division Entergy electricity futures contract.

Trading Hours

Futures and Options: 9:40 A.M. - 3:10 P.M. for the open outcry session. After hours trading is conducted via the NYMEX ACCESS℠ electronic trading system Mondays through Thursdays, 4:15 - 7:15 P.M. New York time.

Trading Months

Futures: 18 consecutive months.

Options: 12 consecutive months

Price Quotation

Futures and Options: Dollars and cents per MWh.

Minimum Price Fluctuation

Futures and Options: $0.01 per MWh ($7.36 per contract).

[1] See [Web 42,43]

Maximum Daily Price Fluctuation

Futures: $15.00 per MWh above or below the previous day's settlement price for the first two contract months. Initial back month limits of $6.00 per MWh above or below the previous day's settlement price rise to $12.00 per MWh if the previous day's settlement price in any back month is at the $6.00 limit. In the event of a $7.50 per MWh move in either of the first two contract months, back month limits are expanded to $7.50 per MWh from the limit in place in the direction of the move. No price limits in the first nearby month during the last half hour of trading.

Options: No price limits.

Last Trading Day

Futures: Trading terminates on the fourth business day prior to the first day of the delivery month.

Options: Expiration occurs on the business day preceding the termination of the underlying futures contract.

Exercise of Options

By a clearing member to the Exchange clearinghouse not later than 5:30 P.M., or 45 minutes after the underlying futures settlement price is posted, whichever is later, on any day up to and including options expiration.

Options Strike Prices

Twenty strike prices in increments of $0.50 per MWh above and below the at-the-money strike price, and the next ten strike prices in increments of $2.50 above the highest and below the lowest $0.50 increment. Above $50, strike prices will be listed in $2.50 increments except for the at-the-money strike price. The at-the-money strike price is the $0.50 increment nearest to the previous day's settlement of the underlying futures contract. Strike price boundaries are adjusted according to the futures price movements.

Delivery Location

Cinergy Futures: Into the Cinergy Transmission System at any interface designated by the seller.

Entergy Futures: Into the Entergy Transmission System at any interface designated by the seller.

Delivery Rate

Two MWs throughout every hour of the delivery period (this can be amended upon mutual agreement of the buyer and seller).

Delivery Unit

The delivery unit is determined by the number of days in the delivery month:
23 on-peak days, delivery unit is 736 MWh
22 on-peak days, delivery unit is 704 MWh
21 on-peak days, delivery unit is 672 MWh
20 on-peak days, delivery unit is 640 MWh
19 on-peak days, delivery unit is 608 MWh
The delivery unit will be equal to or less than the contract unit.

Delivery Period

Entergy: 16 on-peak hours on each delivery day, beginning with the hour ending 0700 (6 A.M.) and concluding with the hour ending 2200 (10 P.M.) Central prevailing time.

Cinergy: 16 on-peak hours on each delivery day, beginning with the hour ending 0800 (7 A.M.) and concluding with the hour ending 2300 (11 P.M.) Eastern prevailing time.
(These can also be amended at the time of delivery by mutual written consent of the buyer and seller.)

Exchange of Futures For, Or in Connection With, Physicals (EFP)

The buyer or seller may exchange a futures position for a physical position of equal quantity by submitting a notice to the Exchange. EFPs may be used to either initiate or liquidate a futures position. EFP deadline is 10 A.M. (Eastern prevailing time) on the first business day following termination of trading.

Scheduling

Buyer and seller must follow transmission provider scheduling practices.

Position Limits

5,000 contracts for all months combined, but not to exceed 350 in the last three days of trading in the spot month or 3,500 in any one month.

Margin Requirements

Margins are required for open futures and short options positions. The margin requirement for an options purchaser will never exceed the premium paid.

Trading Symbols

Futures:	Cinergy (CN)
	Entergy (NT)
Options:	Cinergy (NO)
	Entergy (OT)

Part B2: Palo Verde and California/Oregon Border Electricity Futures and Options Contract Specifications

Trading Unit

Futures: 736 megawatt hours (MWh) delivered over a monthly period[2].

Options: Either one NYMEX Division COB electricity futures contract or one NYMEX Division Palo Verde electricity futures contract.

Trading Hours

Futures and Options: COB: 9:40 A.M. – 2:55 P.M.; Palo Verde: 9:40 A.M. – 2:55 P.M. for the open outcry session. After hours trading is conducted via the NYMEX ACCESS electronic trading system Mondays through Thursdays, 4:15 –7:15 P.M. New York time.

Trading Months

Futures: 18 consecutive months.
Options: 12 consecutive months.

Price Quotation

Futures and Options: Dollars and cents per MWh.

Minimum Price Fluctuation

Futures and Options: $0.01 per MWh ($7.36 per contract ($8.64 *)).

Maximum Daily Price Fluctuation

Futures: $15.00 per MWh ($12,960*) for the first two months. Initial back month limits of $3.00 per MWh rise to $6.00 per MWh if the previous day's settlement price in any back month is at the $3.00 limit. In the event of a $7.50 per MWh move in either of the first two contract months, back month limits are expanded to $7.50 per MWh in all months from the limit in place in the direction of the move.

[2] Beginning with the October 1999 contract, the unit was changed to 864 MWh.

Options: No price limits.

Last Trading Day
Futures: Trading terminates on the fourth business day prior to the first day of the delivery month.
Options: Expiration occurs on the business day preceding the termination of the underlying futures contract.
Exercise of Options
By a clearing member to the Exchange clearinghouse not later than 5:30 P.M., or 45 minutes after the underlying futures settlement price is posted, whichever is later, on any day up to and including options expiration.

Options Strike Prices
Increments of \$0.50 (50 cents) per MWh with 20 strike prices above and 20 below the at–the–money strike prices, and the next ten strike prices are in increments of \$2.50 above the highest and below the lowest existing strike prices for a total of 61 strike prices. The at–the–money strike price is the nearest to the previous day's close of the underlying futures contract. Strike price boundaries are adjusted according to the futures price movements.

Delivery Location
The Palo Verde high voltage switchyard for the Palo Verde contract; the interconnection point at the California-Oregon border of the Pacific Northwest/Pacific Southwest AC Intertie, including the California Oregon Transmission Project for the California/Oregon border contract.

Delivery Rate
Two megawatts (MW) throughout every hour of the delivery period (this can be amended upon mutual agreement of the buyer and seller).

Delivery Unit
The delivery unit is determined by the number of days in the delivery month:
27 on–peak days = 864 megawatt hours delivery...27 days×16 hours×2 Mw = 864
26 on–peak days = 832 megawatt hours delivery...26 days×16 hours×2 Mw = 832
25 on–peak days = 800 megawatt hours delivery...25 days×16 hours×2 Mw = 800
24 on–peak days = 768 megawatt hours delivery...24 days×16 hours×2 Mw = 768
The delivery unit will be equal to or less than the contract unit.

Delivery Period

Sixteen on–peak hours: hour ending 0700 (6 A.M.) to hour ending 2200 Pacific prevailing time (10 P.M.). (These can also be amended at the time of delivery by mutual written consent of the buyer and seller.)

Exchange of Futures For, Or in Connection With, Physicals (EFP)

The buyer or seller may exchange a futures position for a physical position of equal quantity by submitting a notice to the Exchange. EFPs may be used to either initiate or liquidate a futures position.

Scheduling

Buyer and seller must follow Western Systems Coordinating Council scheduling practices.

Position Limits

5,000 contracts for all months combined, but not to exceed 350 in the last three days of trading in the spot month or 3,500 in any one month.

Margin Requirements

Margins are required for open futures and short options positions. The margin requirement for an options purchaser will never exceed the premium paid.

Trading Symbols

Futures: Palo Verde: KV
California/Oregon Border: MW
Options: Palo Verde: VO
California/Oregon Border: WO

Part B3: CBOT ComEd HUB ELECTRICITY FUTURES SALIENT FEATURES

Trading Unit

1,680 megawatt hours (MWh)

Price Basis

U.S. dollars and cents per megawatt hour

Tick Size

$0.01 (1¢) per MWh ($16.80 per contract)

Daily Price Limits
The maximum permissible price fluctuation in any one day shall be $7 per MWh above or below the preceding day's settlement price for any month succeeding the nearby trading month. Price limits are removed for the nearby trading month.

Trading Hours
8:00 a.m.-2:40 p.m., Chicago time

Contract Months
Monthly: number of listed contracts subject to determination by CBOT Board of Directors

Opening/Closing Procedure
Simultaneous

Position Limits
Subject to determination by CBOT Board of Directors

Reportable Position
25 contracts (in any one month)

Last Trading Day
Trading will terminate on the fourth business day prior to the first calendar day of the delivery month

Delivery Location
Commonwealth Edison's Control Area

Delivery Rate
5 MW

Delivery Times
Every on-peak hour (6:00:01 a.m. through 10:00:00 p.m., Chicago time) for all on-peak days of the delivery month

Delivered Power
Amount depends on the number of on-peak days in the delivery month:
1,520 MWh for delivery months with 19 on-peak days
1,600 MWh for delivery months with 20 on-peak days
1,680 MWh for delivery months with 21 on-peak days

1,760 MWh for delivery months with 22 on-peak days
1,840 MWh for delivery months with 23 on-peak days

Scheduling

Buyer and seller must follow prevailing Mid-America Interconnected Network (MAIN), ComEd Control Area, and FERC scheduling practices.

Ticker Symbol

BZ

Part B4: CBOT ComEd HUB ELECTRICITY OPTIONS ON FUTURES SALIENT FEATURES

Trading Unit

One CBOT ComEd Hub Electricity futures contract

Price Basis

U.S. dollars and cents per megawatt hour

Tick Size

$0.005 (½¢) per MWh ($8.40 per contract)

Daily Price Limits

The maximum permissible price fluctuation in any one day shall be $7 per MWh above or below the preceding day's settlement price for any month succeeding the nearby trading month. Price limits are removed for the nearby trading month.

Trading Hours

8:00 a.m.-2:40 p.m., Chicago time

Contract Months

Monthly: number of listed contracts subject to determination by CBOT Board of Directors

Opening/Closing Procedure

Simultaneous

Position Limits

Subject to determination by CBOT Board of Directors

Reportable Position
25 contracts (in any one month)

Last Trading Day
Trading will terminate at noon on the fifth business day prior to the first calendar day of the delivery month

Strike Prices
Multiples of one dollar ($1.00) per MWh

Exercise
Any business day that the option is traded

Expiration
Unexercised in-the-money options will be automatically exercised after the close on the last day of trading

Ticker Symbols
BZP, BZC

Part B5: CBOT TVA Hub Electricity Futures Salient Features

Trading Unit
1,680 megawatt hours (MWh)

Price Basis
U.S. dollars and cents per megawatt hour

Tick Size
$0.01 (1¢) per MWh ($16.80 per contract)

Daily Price Limits
The maximum permissible price fluctuation in any one day shall be $7 per MWh above or below the preceding day's settlement price for any month succeeding the nearby trading month. Price limits are removed for the nearby trading month.

Trading Hours
8:00 a.m.-2:40 p.m., Chicago time

Contract Months
Monthly: number of listed contracts subject to determination by CBOT Board of Directors

Opening/Closing Procedure
Simultaneous

Position Limits
Subject to determination by CBOT Board of Directors

Reportable Position
25 contracts (in any one month)

Last Trading Day
Trading will terminate on the fourth business day prior to the first calendar day of the delivery month

Delivery Location
Tennessee Valley Authority's Control Area

Delivery Rate
5 MW

Delivery Times
Every on-peak hour (6:00:01 a.m. through 10:00:00 p.m., Chicago time) for all on-peak days of the delivery month

Delivered Power
Amount depends on the number of on-peak days in the delivery month:
1,520 MWh for delivery months with 19 on-peak days
1,600 MWh for delivery months with 20 on-peak days
1,680 MWh for delivery months with 21 on-peak days
1,760 MWh for delivery months with 22 on-peak days
1,840 MWh for delivery months with 23 on-peak days

Scheduling
Buyer and seller must follow prevailing Southeastern Electric Reliability Council (SERC), TVA Control Area, and FERC scheduling practices

Ticker Symbol
BA

Part B6: CBOT TVA Hub Electricity Options On Futures Salient Features

Trading Unit
One CBOT TVA Hub Electricity futures contract

Price Basis
U.S. dollars and cents per megawatt hour

Tick Size
$0.005 (½¢) per MWh ($8.40 per contract)

Daily Price Limits
The maximum permissible price fluctuation in any one day shall be $7 per MWh above or below the preceding day's settlement price for any month succeeding the nearby trading month. Price limits are removed for the nearby trading month.

Trading Hours
8:00 a.m.-2:40 p.m., Chicago time

Contract Months
Monthly: number of listed contracts subject to determination by CBOT Board of Directors.

Opening/Closing Procedure
Simultaneous

Position Limits
Subject to determination by CBOT Board of Directors

Reportable Position
25 contracts (in any one month)

Last Trading Day
Trading will terminate at noon on the fifth business day prior to the first calendar day of the delivery month

Strike Prices
Multiples of one dollar ($1.00) per MWh

Exercise
Any business day that the option is traded

Expiration
Unexercised in-the-money options will be automatically exercised after the close on the last day of trading

Ticker Symbols
BAP, BAC

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