A STUDY OF THE ENGLAND AND WALES POWER POOL

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ABSTRACT

Bidding for electricity supply, as adopted by the UK electric power system, is one of the best ways to introduce competition among electricity suppliers. This thesis research concentrates mainly on the study of the rules governing the operation of the England and Wales Power Pool, with the objective to explain and justify these rules through rigorous theoretical analysis, and to provide a deeper understanding of the pool operation. In order to provide a broader picture beyond the pool operation, an extensive review of the electricity industry in England and Wales as a whole is also presented.

In the theoretical aspects of the thesis, several tools are used, namely, the Switching Curve Law derived from the solution of the Unit Commitment problem through the Lagrangian Relaxation approach, as well as the game theory and Bayesian analysis.

RÉSUMÉ

La méthode de l'appel d'offre pour l'approvisionnement en électricité telle qu'adoptée par le système électrique britannique, est l'une des meilleures façons d'introduire la compétition parmi les fournisseurs d'électricité. Cette recherche se concentre principalement sur les règles gouvernant l'exploitation du England and Wales Power Pool, avec pour objectif d'expliquer et de justifier ces règles à travers une analyse théorique rigoureuse, ainsi que de fournir une compréhension de l'exploitation d'un "pool". Afin d'élargir cette vue au-delà de l'exploitation du pool, une revue approfondie de l'industrie électrique en Angleterre et au Pays de Galles est présentée.

En ce qui concerne les aspects théoriques de cette thèse, plusieurs outils sont utilisés, tels que "the Switching Curve Law" dérivé de la solution du problème d'engagement des groupes basée sur la méthode de relaxation de Lagrange, la théorie des jeux et l'analyse Bayésienne.

CONTENTS

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ACRONYMS

ADP	-	Availability Declaration Period
AP	-	Availability Payment
CFDs	-	Contracts For Differences
CE	-	Capacity Element
CEGB	-	Central Electricity Generating Board
DP	-	Dual Problem
ECNZ	-	Electricity Corporation of New Zealand
EMCO	-	Electricity Market Company
EWPP	-	England and Wales Power Pool
GP	-	Genset Price
IP	-	Incremental Price
IPPs	-	Independent Power Producers
ISO	-	Independent System Operator
MAP	-	Minimum Average Price
MCP	-	Market Clearing Price
MHR	-	Minimum Heat Rate
MMC	-	Monopolies and Mergers Commission
NEM	-	National Electricity Market
NGC	-	National Grid Company
NS	-	No-load and Start-up
OFFER	-	Office of Electricity Regulation
PAC	-	Payment Adequacy Constraint
PPP	-	Pool Purchase Price
PR	-	Period Residual
PSA	-	Pooling and Settlement Agreement
PSP	-	Pool System Operator (only in chapter 1)
PSP	-	Pool Sale Price
RECs	-	Regional Electricity Companies
RPP	-	Relaxed Primal Problem
RPI	-	Retail Price Index
SC	-	Spare Capacity
Settlement GOAL	-	Settlement general ordering and loading
SMP	-	System Marginal Price
SMPD	-	SMP Determination
SP	-	System Price
SPD	-	Settlement Period Duration
SWB	-	Select the Winning Bidders
TSS	-	Transmission Service Scheme
UC	-	Unit Commitment
UK	-	United Kingdom
UMIS	-	Uplift Management Incentive Scheme

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This thesis is dedicated to my parents.

Chapter 1 Introduction

1.1 Background

Since the late 1980's, following the success of deregulation in the telecommunication, airline, gas, and other industries, the electricity industry in several nations has also undergone a similar process. Among these nations, the United Kingdom (UK) is the most prominent pioneer whose experience offers valuable lessons for others. In particular, Australia has emulated the so-called UK model in their electricity industry reform [1-1], while other regions have proposed to follow the UK experience as a policy guideline in their efforts for electricity industry reform.

The UK electricity industry reform was carried out in three stages, England and Wales first, followed by Scotland and, finally, Northern Ireland [1-2]. Therefore, though often known as the UK model, the major experience and lessons come from England and Wales.

The electricity industry reform which started on March 1, 1989 in England and Wales features radical changes in ownership, structure as well as regulation. First, the vertically integrated, nationalized power industry was divided into four distinct businesses, namely, generation, transmission, distribution, as well as supply. Then, with the exception of nuclear generation utilities, the electricity companies in England and Wales were largely privatized. A power pool, called the England and Wales Power Pool (EWPP), was established to accommodate competition in generation. Finally, several regulatory policies were setup to conform to the new environment. As of the writing of this thesis, the England and Wales electricity industry reform is not yet a decade old, however, some valuable experiences and lessons, both in engineering and economics, can be extracted from its performance, which are helpful for those countries or regions which are undergoing or have proposed electricity industry reform.

This thesis research concentrates mainly on the study of the rules governing the operation of the England and Wales Power Pool, with the objective to explain and justify the power pool rules though rigorous theoretical analysis, and to provide a deeper understanding of the pool operation. In order to provide a broader picture beyond the pool operation, an extensive review of the electricity industry in England and Wales as a whole is also presented.

The rest of this introduction to the thesis is organized as follows. In section 1.2, various issues regarding power industry reform are addressed, such as its necessity, its possibility, its difficulties, as well as guidelines for implementing such reforms. Then, in section 1.3, two opposing models for competition in generation, poolco and bilateral contract models, are introduced and discussed. In section 1.4, some of the main international electricity industry reform experiences are addressed. Finally, in section 1.5, the organization of the current thesis is presented.

1.2 Electricity Industry Reform

Historically, the power industry has been operated as a monopoly. Electricity utilities have a statutory responsibility for providing electrical energy, while customers are protected from monopoly power by government price regulation. Although the electricity industry can be divided physically into generation, transmission, and distribution, it is economically integrated. Thus, customers receive only one bill for the electricity provision without splitting it among the above-mentioned components.

Since the last decade, based on the idea that competition is more effective than regulation in promoting efficiency [1-1], the electricity industry in a number of countries has undergone an important reform, a decision which has drawn great attention internationally, and also initiating a global trend. The nature of this reform is described in the following sections.

1.2.1 What is Electricity Industry Reform?

Electricity industry reform is primarily motivated by the desire to improve its financial performance [1-3] through the introduction of competition. Although often referred to as deregulation, electricity industry reform signifies more than deregulation, generally comprising utility ownership changes (privatization and divestiture), organizational changes (restructuring), as well as government regulatory changes (deregulation). However, since the term "deregulation" has already been commonly accepted to indicate the above-mentioned three elements of reform, in this thesis, the terms "electricity industry reform" and "electricity industry deregulation" are interchangeable.

Nonetheless, deregulation means different things to different people. For utilities, deregulation means more competition and less regulation while, for governments, deregulation means diminishing control over the electricity industry. For customers, deregulation means that they have a choice to buy electricity from different suppliers and the potential of price reduction and service standard improvement.

1.2.2 Is Electricity Industry Reform Necessary?

At the end of the nineteenth century, electricity systems were mostly privately owned, but with time, they were nationalized and regulated [1-5] for reasons such as economies-of-scale, war and economic depression. Under this structure, the government obliges the electricity utilities to meet their customers' demands [1-4]. To fulfill this responsibility, utilities were required to make the necessary capital investment to meet increasing loads, to build and operate generating stations, to construct and maintain transmission and distribution networks, as well as to install and read metres [1-7]. This monopoly system worked well in terms of reliability, but experience has shown that it is virtually impossible to improve its economic efficiency without reform [1-3]. Although unanimity has not been reached yet, and not all of the mechanisms and implications behind the electricity reform are fully understood, many people believe that deregulation will bring benefits to the entire industry, including the end-users [1-14].

Customers also welcome deregulation since under a regulated environment they have no choice over their suppliers. A poll in the US in April 1997 showed that about 73% of the public wanted Congress to support deregulation of the electricity industry [1-6]. In addition, with deregulation, it is also likely that customers will have more service options such as "green power [1-6]" and a tradeoff between reliability and price [1-8].

1.2.3 Is Electricity Industry Reform Possible?

Until the last decade, in almost all nations, the electricity industry was operated as a monopoly with government regulation. This was due to two fundamental beliefs. The first is that electricity industry is a "natural monopoly" [1-9], which means that a single utility can provide electricity at a lower rate than a number of producers[1] [1-10, 1-15]. Another belief, which is particularly influential in Europe, is that the problems in the electricity industry are pure technical problems which can be solved solely by engineers. Whether the electricity industry reform is possible depends on whether these two beliefs can be refuted.

Since the last decade, both of the above-mentioned beliefs have been challenged profoundly because of technology improvements and the desire for higher financial efficiency [1-11]. Today, the electricity industry in many nations is no longer deemed as a natural monopoly since electricity generation and supply are potentially competitive industries, even though transmission and distribution systems are still natural monopolies [1-10]. The concept that producing and delivering electricity are purely engineering matters also does not hold any longer since measures of economic and technical efficiencies are fundamentally different [1-8].

- **Natural Monopoly Era is Over**

In the past 20 years, technology developments have undermined the concept that the electricity industry is a natural monopoly [1-8], and therefore, have shaken the foundation of the old industry structure. Technology improvements in material science and in the space program has led to much more efficient turbines, moreover,

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1 John C. Moorhouse describes natural monopolies in [1-9]: "Economies of scale and scope, and the economies associated with vertical integration mean that unit costs decline throughout the relevant range of production as output increases. Such economies preclude competition, according to the conventional view, because a single firm could supply the entire service area at lower cost than could two or more firms. Given its cost structure, an established utility could undercut its rivals and drive them from the market. Moreover, attempted entry represents a waste of resources either because of an unnecessary duplication of facilities or because such investment would not be viable in the face of undercutting. Secure from competition, the monopolist would exploit the consumer if not for regulation or state ownership."

the drop in gas prices makes gas a favorite fuel to generate electricity in many countries [1-11]. Thus, currently generation plants using combined cycle gas turbines are efficient in much smaller sizes than in the past. For example, the typical investment cost for gas units in 1996 ranges from $500 to $800 per KW, compared to around $3,000 per KW for nuclear stations [1-15].

Even before the concept of deregulation was introduced, the emergence since the 1970's of Independent Power Producers (IPPs) had already challenged the monopoly ownership in generation utilities. Elliot Roseman and Anil Malbort described as follows the existence of IPPs [1-16]: " They plant the seeds for the top-to-bottom change in the structure of government-owned utilities — seeds that ar e hard to stop from growing once they take root."

Globally, outside of Canada and the US, by 1996 there existed more than 600,000 MW of IPPs capacity, either on line or planned [1-16]. In the US alone, in 1996 there was about 60,000 MW of IPPs capacity, accounting for 7% of the total [1-16]. Most of these IPPs own small-size generation plants of the order of 200 MW.

Moreover, in terms of system reliability, relying on many small-sized plants is more reliable than a few large-scale plants [1-8]. Constructing small-sized plants near loads also potentially reduces transmission congestion, and possibly reduces the need for new transmission lines [1-9].

- **The Electricity Business Raises Problems Beyond Engineering Solutions**

Traditionally, the operation of the electricity industry was considered as a pure engineering problem rather than a business management problem since in a vertically integrated monopoly, the reliability is the vital criterion of judging the industry performance. Consequently, it was believed that the public would be best served by a staff of engineers [1-8].

However, the above-mentioned belief was challenged by the increasing concern for financial efficiency. It was discovered that the technical and economic efficiencies can diverge prominently [1-8], and that the desire for cheaper electricity and better financial efficiency cannot be reached solely by the efforts of engineers.

■ **Competition is Possible**

Summarizing the above discussions, it cab be conclude that the era of the traditional vertically integrated monopoly in the electricity industry is over, and competition in generation becomes possible. Furthermore, competition in generation will inevitably induce competition in electricity supply to retail end-customers, thus offering customer choice over the suppliers. In conclusion, the time is ripe for electricity industry reform.

1.2.4 Why Electricity Industry Reform is difficult?

In many countries, the electricity industry has been the last major regulated monopoly to undergo reform [1-17]. This trend can be attributed to the facts that compared with other industries, the electricity industry is more difficult to deregulate for the reasons that follows. As was discussed in section 1.2.1, the major objective of electricity industry reform is to improve financial efficiency. This objective, however, should not be achieved at the expense of reliability, the maintenance of which is already an intricate task, becoming even more complex under a deregulated environment.

The complexity of maintaining power system reliability under a deregulated environment is due to the difficulty of satisfying physical constraints, particularly, simultaneous generation and consumption balance and the transmission network constraints. Besides physical constraints, financial problem of the stranded cost recovery, additionally complicates electricity industry reform.

- **Power Balance**

Since electricity essentially cannot be stored[2], real-time control is required to match instantaneously the total generation and consumption. To accomplish this under the deregulated environment, new information technology tools will be needed beyond what is available today to handle the expected extensive financial activities (e.g. bilateral transactions) that will affect the power balance.

- **Transmission Constraints**

The physical laws which govern the transmission of electricity also lead to difficulties in the implementation of the industry reform. Electricity flows according to Kirchhoff's laws through the transmission network which can be considered to be a limited resource. Therefore, depending on the transmission-usage rate structure, the value of the electricity transferred from a specific generator to a specific customer depends not only on the generation cost, but also on the location of the generator and load. An additional difficulty arises under some rate structures or network congestion since the transmission charge for a given transaction may then be closely intertwined with all the other transactions. Therefore, how to price transmission services and how to manage the multiple financial activities which can potentially overload the network need careful study.

[2]Electricity can be stored by pumped storage facilities, but it is very expensive.

■ **Stranded Costs Recovery**

Under a regulated monopoly environment, based on the principle of economy of scale, electricity utilities built large generating plants and fully expected to recover all their capital investment from their stable captive customer base. Today, under a deregulated environment, these previously captive customers are free to shop around for the best possible contract. This fundamental change would leave many former monopolistic utilities and their shareholders with significant debts known as stranded costs [1-19].

Stranded costs can be also defined as investments or assets owned by former regulated electric utilities that are likely to become uncompetitive under a deregulated environment [1-20]. Generally, stranded costs include investment in generators, transmission and distribution networks, as well as long-term contracts for fuel and electricity [1-21]. There is no doubt that stranded costs will place some utilities at a disadvantage, and therefore, should be recovered in order to create a fair competitive market. However, no unanimity on how to recover the stranded costs has been reached yet, and this subject is still under comprehensive discussion [1-1, 1-19, 1-20, 1-21, 1-22].

1.2.5 How to Reform the Electricity Industry?

The implementation of electricity industry reform is globally polymorphic, reflecting the diverse nature of the world. Such diversity can be seen in several elements, namely, governmental structure (federal or unitary), demographic, geographic, economic, as well as political environments. Although the abovementioned elements differ strongly from region to region, many common features still exist.

■ **The Electricity Industry Should be Split into Independent Businesses**

Electricity generation and supply (retail) are potentially competitive industries, however, transmission and distribution are natural monopolies [1-10]. Therefore, to enable competition, it is necessary to separate the competitive parts from the regulated monopolies, and to split electricity industry into several businesses, typically generation, transmission, distribution and supply, which are defined as follows.

Generation is the process by which fuels or renewable resources are converted into electric power; transmission is the process by which electricity is transferred in bulk from generators to suppliers; distribution is the process of delivering electricity from suppliers to customers [1-18], and supply is the process of trading electricity with final customers. Figures 1.1 and 1.2 show examples of the old vertically integrated structure and a hypothetical model of the deregulated structure.

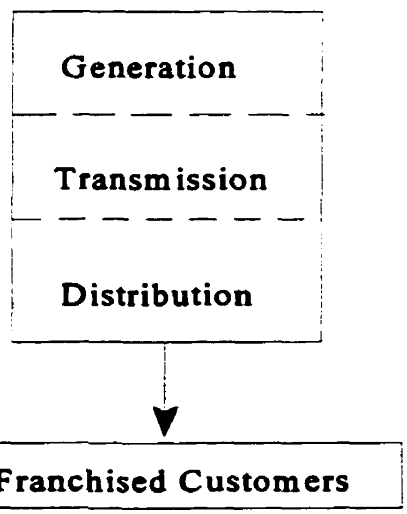

Figure 1.1 Vertically Integrated Monopoly Structure

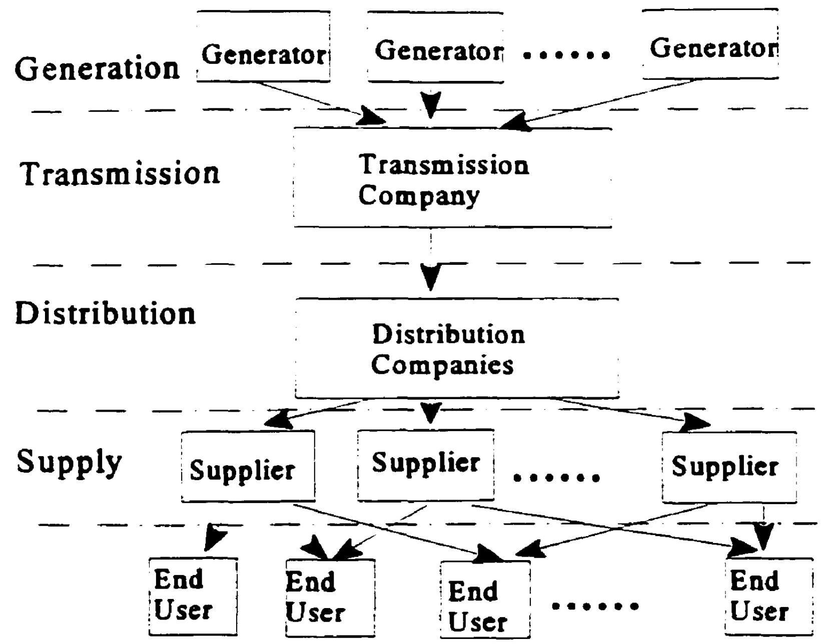

Figure 1.2 A Hypothetical Example of Restructured Power Industry

■ **Divestiture and Privatization**

To introduce competition, it is necessary and essential to break the monopoly into several companies, each of which is small enough so that it does not have notable market power. Depending on the extent of competition, either generation sector or both generation and supply sectors should be divided into a number of companies. Competition can be held between private companies, between several state-owned companies, as well as between private and public companies. Therefore, privatization is just an optional choice for the implementation of power industry reform. Experience also suggests that efficiency depends more on the form of electricity industry structure than on the form of ownership [1-1]. However, it is true that private companies are more efficient than public entities to the extent that the former is more likely to resist political interferences [1-22].

■ **How Much Competition?**

Sally Hunt defined four basic models of the new structure for the electricity industry according to the degree of competition [1-11], which are shown in table 1.1.

Table 1.1 Four Basic Models for Electricity Industry Structures

Definition	Mono poly	Purchase Agency	Wholesale Competition	Retail Competition
Is generation competitive?	No	Yes	Yes	Yes
Do suppliers have choice?	No	No	Yes	Yes
Do customers have choice?	No	No	No	Yes

Model one presents a traditional monopoly structure, while model two presents a structure with a single buyer which chooses among a number of generators. Model three allows wholesale competition in which there are more than one suppliers and all suppliers have choices over generators, while model four additionally allows retail competition in which all customers can choose suppliers, broadly speaking, either from suppliers or directly from generators. Models three and four are commonly adopted globally, and model three is the hypothetical model for England and Wales reformed power system, while model four is the hypothetical model similar to the proposed California model [1-11].

■ **Wholesale and Retail Market Frameworks**

One essential element of the reformed electricity industry is a market framework which is established to accommodate competition. Two commonly adopted frameworks are wholesale and retail markets, which corresponds to models three and four in table 1.1. The retail market is also known as supply market, and these two terms are used interchangeably in this thesis.

In the wholesale market, electricity distribution suppliers (retailer) are free to choose generation companies or buy from a centralized power pool, therefore, generation companies must decrease price in order to be competitive. Compared with the traditional vertically integrated structure, there is no big difference for customers although prices may be lower.

On the other hand, in the retail market customers are free to choose retail suppliers or even to directly choose generation suppliers. The pressure of not loosing customers forces both generation and distribution supply companies to provide competitive prices and more service options. The retail market is also known as direct access [1-25].

The wholesale market can stand alone while a retail market must be implemented along with a wholesale market. Without retail competition, customers are not able to express their willingness to pay various prices at various quantities of electricity services, therefore, customers may not get enough benefits from the deregulation, and electricity services options may be limited [1-35].

In many nations, such as the UK and Argentina, the wholesale market has been successfully established, and the retail market has been partially implemented. Experience also shows that besides building a retail market, providing economic incentive regulation over the electricity business can also bring benefits to customers [1-35].

In the wholesale market, system reliability requires coordination between generation and transmission, and the coordination inevitably brings conflicts of interests between different market participants. Therefore, the establishment of an independent system operator (ISO) becomes necessary and essential for the wholesale market operation [1-35].

■ **Open Access**

In a wholesale market, for the purpose of fostering competition, transmission open access is required so that all participants in the wholesale market can equally access to transmission service as long as capacity is available [1-5]. In retail competition, open access of distribution services should also be required.

■ **Separate Transmission From Generation and System Operation**

The generation utilities rely on transmission networks to delivery electricity to customers, and therefore, the decisions regarding transmission pricing, dispatch rules, as well as new investment in the transmission network can affect the value of generation [1-19], that is, specific settlement regarding the transmission planning and operation can place individual or a group of generators at an advantage or a disadvantage over other generators and customers. For example, when the transmission network is overloaded, which generator should be turned off, and how to compensate for this generator will greatly affect the values of those generators which locate in weakly-connected areas. In addition, due to the property of transmission networks, many techniques for manipulating transmission and system operation to affect the value of generation are complex, elusive, and hard to detect and manage through regulatory oversight.

For the above reasons, the implements of the generation competition in many nations have completely separated the ownership of generation from the ownership or control of transmission networks [1-8]. Such separation provides an easy, transparent and practical solution.

■ **Financial Regulation is Still Necessary**

As it was mentioned earlier, electricity generation and supply are potentially competitive industries, while transmission and distribution systems remain natural monopolies [1-10]. Therefore, financial regulation is still required over the transmission and distribution businesses. Even in the competitive market, regulation is necessary if some players have notable market power to manipulate the market price, or if the electricity generation capacity is less than the demand.

In addition to the traditional rate-of-return regulation, price-caps regulation was introduced by the UK electricity deregulation. Compared with the traditional rate-of-return regulation, price-cap regulation additional provides an economic incentive for monopolies to improve their financial efficiency [1-1].

1.3 Two General Models for Competition

Generally, there are two opposing models to implement competition in the electricity industry, namely, bilateral contracts, and poolco models [1-17, 1-26], and bilateral contract model can be applied to both wholesale and the retail competition while the poolco model is mainly applied to wholesale competition.

■ **Poolco Model**

In the poolco model, all competitive market participants combine to form a "super-utility" in the form of a power pool [1-17], and a sealed-bid multiple-winner auction system is used. Electricity sellers, or both sellers and buyers are required to submit bids on price and quantity to the pool, and the Pool System Operator (PSP) determines which bids are accepted as well as the pool price. In the poolco model the PSP has certain responsibilities such as ensuring power balance, maintaining reliability, as well as coordinating transmission access and services [1-17]. The prominent feature of the poolco model is its centralism. Figure 1.3 shows a hypothetical poolco model.

Generally there are two types of bids, seller and buyer bids. Buyer bids are also known as demand-side bids which refer to the maximum price at which the buyer wishes to purchase a specified amount of power, while seller bids generally include energy, no-load, start-up and reserve bids[3].

Two merit-order lists can be formed according to the bids, one for sellers and another for buyers. If the demand-side bids are not implemented, the merit-order list for buyers can be deemed as a vertical line corresponding to the forecasted demand. Generally the merit-order list curve for sellers is an upward curve since the higher the price, the more the generators wish to generate, while the curve for buyers is a downward curve. These two curves converge at a certain point on which the generation schedule can be determined and the market clearing price (MCP) can be based. Figure 1.4 shows the above described process.

[3] Energy bid refers to the expected incremental price corresponding to the output level; no-load and start-up bids refer to the expected price associated with the fixed generation cost independent of output level and the start-up cost; reserve bid refers to the expected payment for keeping the generator in reserve [1-26].

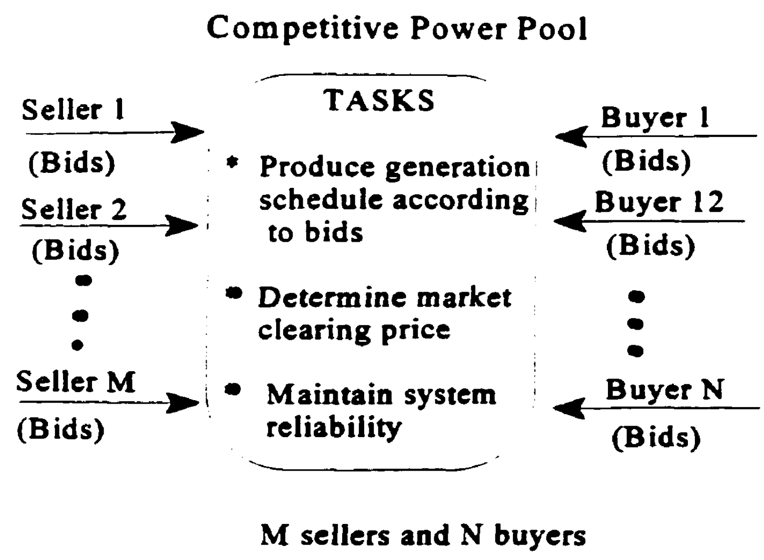

Figure 1.3 Hypothetical Poolco Model

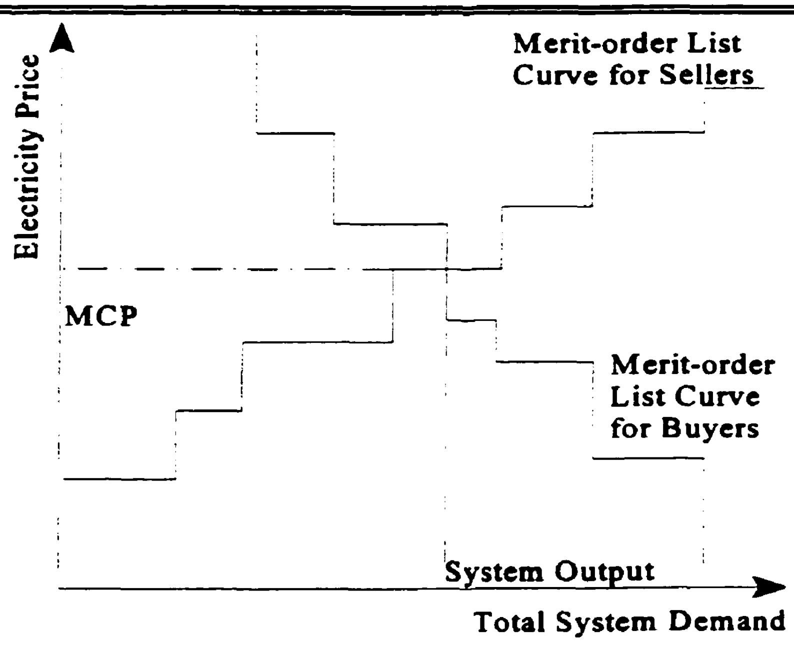

Figure 1.4 How Poolco Works

■ **Bilateral Contract Model**

In a bilateral contract model, trade is independently arranged among sellers, buyers, and possibly brokers. This model, which allows all participants to shop around and negotiate the best contracts for themselves, is based on the principle that free market competition is the best way to improve financial efficiency, and economic incentives are better than external enforcements in achieving high economic efficiency [1-17]. Figure 1.5 shows an example of the bilateral contract model.

In the both bilateral contract and poolco models, a new element called independent system operator (ISO) should be introduced to maintain the system reliability, to coordinate scheduling and dispatch, to administer contracts which overload the transmission network, to provide ancillary services, as well as to administer billing and settlements in the system [1-26]. However, several problems related to ISO's responsibilities such as transmission pricing, load flow allocation,

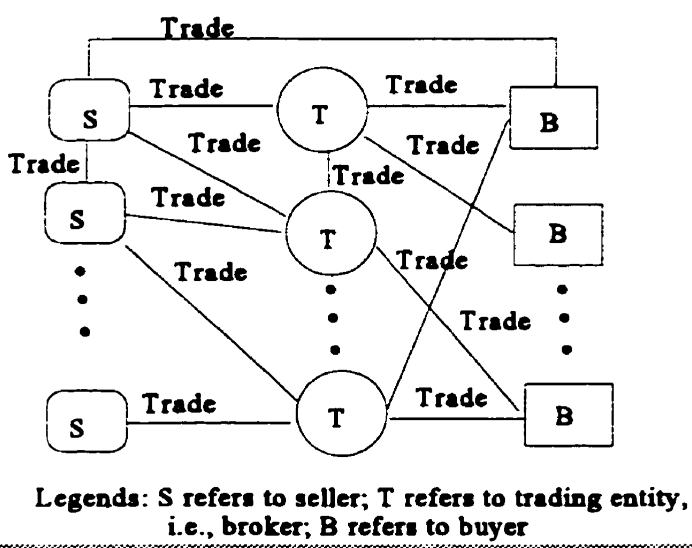

Figure 1.5 Hypothetical Bilateral Contract Model

loss allocation, as well as available transmission capacity, are not fully understood yet, and are currently the subject of extensive research [1-12, 1-13, 1-27, 1-28].

- **Poolco Model Versus Bilateral Contract Model**

One major difference between the poolco and the bilateral contract models is that the poolco model handles only short-run transactions in a single spot market, in which electricity being purchased is delivered immediately [1-26], while in the bilateral contract model, long-term or future contracts are more common.

Another major difference is that the poolco model essentially is centralized while the bilateral contract model is not. Therefore, the poolco model is easier to be implemented because the system operation and coordination responsibilities are easier to be achieved through a centralized system. The main difficulties in implementing the bilateral contract model are the power balance problem and transmission constraints as presented in section 1.2.4.

In terms of economic efficiency, the bilateral contract model is better than the poolco model since the latter requires a centralized utility, a power pool, to coordinate the transmission, and it has no natural incentive to operate efficiently [1-17]. In the UK, this problem has been solved in part by introducing a number of economic incentives for the pool to operate more efficiently.

In fact, as evidenced by existing systems, pure poolco and pure bilateral contract models do not exist. All electricity system reforms adopt both models although usually one dominates over the other. In England and Wales, the poolco is the dominant model, while in Norway the bilateral contract model is the dominant one.

1.4 Worldwide Experiences

In the last 15 years, the electricity industry has been radically reformed throughout the world. The first electricity industry reform was carried out by Chile in 1982, followed by the UK, Norway, Sweden, Australia, New Zealand, Argentina, Peru, and currently many states in the US. In this section, the experience in Chile, Argentina, Norway, Australia, and New Zealand is presented

1.4.1 Chile

Chile, although not drawing as much attention as the UK, is the first nation which reformed its electricity industry. The reform, which was part of a broader rationalization of the economy, started in 1978 and was enforced under military rule [1-23]. The legislative change was made in 1982 [1-32].

Chile initiated competition in its electricity industry by instituting a wholesale market [1-29]. First, large customers were allowed to purchase electricity from any generators or distribution suppliers [1-29]. Then, the regulated price was linked with the market price so that small customers could share the benefits resulting from competition, and the electricity market price was also used as a signal for investment [1-29].

The Chilean wholesale electricity market consists two parts, a spot market handled by a power pool and a bilateral contract market [1-32]. Only large customers have the right to choose suppliers and the regulator sets the electricity price for small customers based on the spot wholesale market price [1-32].

The reformed Chilean power system is the first example in the world to demonstrate that competition could be introduced into electricity generation by sharing the transmission system among all electricity utilities which pay for the transmission services. However, serious problems exist in the Chilean system, mainly caused by the predominance of one generation company in one of its two independent systems, the SIC[4]. Since there was no requirement for divesture and generation / transmission separation in Chile, one major generation company bought the whole transmission network, and later this company was purchased by an investment group which also owned the largest distribution company [1-29]. Thus, most resources in the SIC are owned and controlled by one company, and consequently, fair competition becomes impossible.

1.4.2 Argentina

In Argentina, the electricity industry reform which began in 1992 was primarily motivated by the desire to improve its financial efficiency and to attract foreign investment needed to upgrade the system [1-29]. In contrast to the UK, Argentina's reform was a passive choice forced by its sluggish economy. By 1992, the electricity industry in Argentina "... had deteriorated badly and was characterized by several operational and financial difficulties ... [1-36]" It was the inability to improve the performance of the electricity industry that led to the reform in 1992 [1-1].

Before 1992, the electricity industry in Argentina had four federal utilities, two large hydro plants jointly owned by Argentina-Paraguay and Argentina-Uruguay respectively, and 19 provincial utilities. Around 80% of its electricity, approximately 15,000 MW, was generated by non-nuclear plants.

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[4] Due to its long and narrow geographical feature, Chile has two separate power systems, one is SING, and the other SIC.

In January 1992, Public Law 24,065 (Electric Law) was legislated, forming a framework for the restructuring and privatization of the electricity industry [1-1]. Since then, in Argentina, electricity utilities were largely divested and privatized, and a competitive market was established. The market structure of Argentina's electricity industry was basically guided by the Chilian electricity industry reform experience of ten years earlier, however, it revised some unsuccessful approaches adopted by Chile. It separated the ownership and operation of transmission from generation, and required transmission to provide open access [1-29]. Dispatch was handled by an agency separated from the transmission facility. A wholesale market structure in the form of a power pool and a merit-order centralized dispatch was also adopted [1-29], along with a limited retail competitive market.

Argentina took two steps to restructure its electricity industry, first to divide the federal electricity utilities into several small companies, then, to privatize them. In 1992, a national electricity wholesale market, also known as a power pool, was established to accommodate competition. Three large utilities, Segba, Ayee and Hidronor, which produced 80% of the total demand, were split into 25 generation [1-29], one high voltage national transmission, six low voltage regional transmission, and some distribution companies. The above companies and several provincial utilities were largely privatized. However, the nuclear utility and the two bi-national hydro plants were not privatized. The Electric Law mandates that no generation company can own more than 10% of the total system capacity, and therefore, the notable market power existing in Chile was prevented in Argentina.

The wholesale market is administered by Cammesa , which is a non-profit, independent system operator jointly owned by the government and generation companies [1-1]. Cammesa basically has three duties, dispatching, determining prices, and maintaining the system reliability [1-1]. The entire wholesale market can be split into three parts, bilateral contracts, seasonal market, and spot market. Bilateral contracts are signed freely between generation companies and electricity suppliers (including large customers), and typically last one year. However, hydro plants are only allowed to contract up to 70% of their capacity [1-1]. Alternatively, the seasonal market is a market whose price is determined by Cammesa basically based on water levels, and maintained for six -month periods [1-1]. Buyers who wish to purchase more power than the quantity specified in their contracts can buy the extra power either from the seasonal market or from the spot market. The spot market is essentially a one-hour based poolco auction system where both buyers and sellers bid prices and quantity. Generation companies may buy power from the spot market to fulfill their contracts in excess of their actual generation, and large customers may also buy from the spot market to meet their short-run load modification [1-1].

While the wholesale market is administered by Cammesa, the whole reformed electricity industry is regulated by Eme, the federal regulating body established in 1992 [1-29]. Eme enforces the Electric Laws, arbitrates disputes between electricity companies, regulates prices in transmission and distribution, as well as sets electricity supply service standards [1-1]. Eme essentially copied the UK price-cap regulation in transmission, distribution and supply [1-1].

The electricity industry reform in Argentina is clearly a success and has drawn international attention. Table 1.2 compares the performance of the electricity industry before and after reform.

Table 1.2 Electricity Industry Performances in Argentina [1-31]				
Year	Spot Price ($/MWh)	Thermal Unit Availability	Distribution Losses (%)	Transmission Outage (hour)
1992	41.85	48.2	21	1,000
1993	32.12	59.8	20	900
1994	24.99	61.3	18	650
1995	22.30	69.9	12	300

The experience from Chile and Argentina, which is called the "Southern Cone" model, is now being adopted widely in Latin America, including Peru (starting in 1993), Bolivia (1995), and Colombia (1995) [1-29]. This model can be summarized as a combination of bilateral and poolco models. Basically, this model splits the entire electricity industry into five specific business, namely, generation, dispatch, transmission, distribution, and distribution supply [1-29], and the dispatch, which schedules, dispatches, and coordinates the electric power generation, is separated from transmission. Competition is realized fully in the wholesale level and partly in the retail level [1-29].

1.4.3 Norway

Norway's Energy Act of 1991 started its electricity industry reform by unbundling the entire industry into generation, transmission, distribution, and supply [1-2]. In contrast to the UK centralized poolco system, the electricity industry in Norway is decentralized and bilateral contract model dominates the market and a power pool simply balance the power generation and consumption [1-2]. The Norwegian model is also adopted by Sweden, and Finland [1-34].

Before 1991, in Norway there were around 80 generation companies and 200 distribution companies, largely municipally owned and generating their own electricity. The largest company, the Statkraft, owned about one third of the generation capacity [1-2]. The Norwegian government owned 80% of the transmission lines [1-2].

Since 1991, the transmission business within the Statkraft was resumed by a new company called Statnett Market SF, which owns 80% of the transmission lines and leases the remaining 20% which belong to 30 companies [1-2]. Later on, a market operator, the Statnett AS, was established to handle the wholesale market, and the existing power pool, Samkjoringen, started to serve the spot market. The electricity companies in Norway are only partly privatized, with 55% of generation belonging to municipalities, 30% belonging to the Statkraft, and 15% belonging to private companies.

Roughly speaking, the Norwegian electricity wholesale market can be divided into a bilateral contract market and a spot market with the first dominating over the second[5]. The spot market accepts bids both from buyers and sellers. In addition, the supply competition is also fully developed, and the customers are free to shop around for the best prices. Customers with energy demand of 400 MWh are mandatorily required to install hourly metres, while those with 400 MWh or less can install metres or accept bills based on their load profile [1-2]. The framework of the deregulated Norwegian power industry is presented in figure 1.6.

Transmission is regulated and priced similarly to the UK (see section 8.1 for the UK transmission regulation.) However, unlike the UK, the transmission losses in

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5 Around 70% electricity is traded through bilateral contracts in Norway.

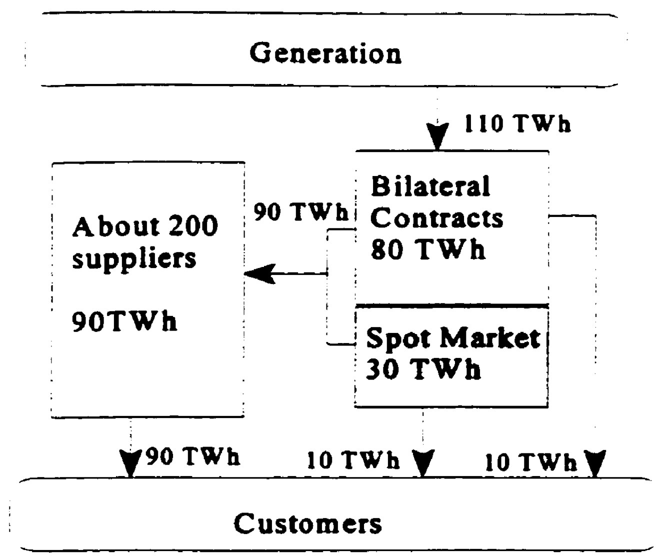

Figure 1.6 Framework of Norwegian Reformed Power Industry [1-2]

Norway are recovered through a charge for transmission services instead of a pool price element[6].

1.4.4 Australia

The electricity industry reform efforts in Australia started in 1991 [1-1], when regional governments agreed to cooperate to create a competitive electricity market in the southern and eastern regions. Unlike the UK, Australia had never nationalized its electricity industry and thus, all states[7] have their own electric systems with weak

6 In England and Wales, power system losses are included in the pool price.

7 Australia have nine states and territories, namely, Australia Capital Territory, New South Wales, Northern Territory, Queensland, Southern Australia, Tasmania, Victoria, Western Australia, and Snowy Mountains.

interstate inter-connections. The electricity industry reform in Australia, therefore, has been ongoing in both state and national levels. The most radical reform occurred in Victoria which basically emulated the UK model while other states have also been undergoing various degrees of reform. However, so far, until 1997, only Victoria and New South Wales have a wholesale generation market in place [1-1]. In the next few subsections, we present the electricity industry reform in Victoria, New South Wales, and the national level.

- **The Reform in Victoria**

The electricity industry reform in Victoria started in October, 1993 when the vertically integrated State Electricity Commission was split into generation, transmission, and distribution. Then, in 1994, the generation division was further split into five companies, and the Victor Power Exchange was established to operate the wholesale market [1-1]. The transmission business was assumed by Powernet Victoria, and the distribution business was restructured into five companies, which further separated the distribution and supply functions [1-1]. Since 1995, most of these electricity companies were privatized [1-1], and the newly created system has strict limitations on cross-ownership of the generation and distribution businesses [1-37].

At the beginning stage of deregulation, all customers were franchised customers who had to purchase electricity from their assigned distribution companies. Since 1996, large customers were allowed to choose suppliers, and full supply competition is scheduled to arrive in December 2000.

- **New South Wales**

Before electricity reform, the New South Wales Pacific Power Company was a vertically integrated utility responsible for generation and transmission [1-33]. In February 1995, the transmission business was separated from it to form a transmission company named TransGrid [1-1]. The generation capacity of Pacific Power was further split into three companies, Macquarie Generation with 4,660 MW capacity, Delta Electricity with 4,820 MW, and Pacific Power which retained the remaining 3,205 MW capacity [1-33]. The distribution business was restructured into six state-owned companies, which were, again, financially separate [1-33].

TransGrid is responsible to develop and implement a wholesale competitive market, which started to work in 1996, and will continue to operate until replaced by the National Electricity Market (NEM) [1-33]. The wholesale market is established in the form of a power pool where both buyers and sellers are allowed to bid. Retail competition is not fully implemented yet although large customers have a choice over the suppliers.

In contrast to Victoria, New South Wales has not privatized its electricity companies yet [1-1]. However, in May 1997, the New South Wales treasurer, Michael Egan, announced his intention of privatizing the electricity companies [1-1].

- **National Reform**

The efforts of the electricity industry in Australia to reform can be traced back to 1991 when all states agreed to cooperate to establish a national electricity market [1-1]. In September 1995, the National Grid Management Council preposed a National Electricity Code (the Code) which outlined the basic functions of the

National Electricity Market (NEM). The code was approved in November 1996. As specified in the Code, the process of establishing a competitive electricity market includes the unbundling of the old electricity industry structure, ensuring open access in the transmission grid, creating a pool system to handle electricity trading, encouraging inter-state trade, ensuring customers have choice over the suppliers, pricing and regulating transmission and distribution business [1-1].

Although referred to as national market, NEM initially includes only Victoria, New South Wales, Southern Australia, Queensland, and the Australia Capital Territory, with the potential expansion into Tasmania. Due to geographical factors, Western Australia, and Northern Territory will not join the market, and other regions will join at a later time. The market is scheduled to be fully-fledged in 2001 when both wholesale and retail competition are implemented.

Because of geographical factors, the national electricity transmission grid is not nationalized. Therefore, to enable the operation of the NEM, three main transmission links are to be built, namely, between New South Wales and Southern Australia, between New South Wales and Queensland, and between Victoria and Tasmania. In addition, the ownership of the transmission network will be transferred to the national government.

The wholesale market includes three trading arrangements: long-term bilateral contracts, short-term forward trading and spot market trading. Supply companies rely on long-term contracts to meet long-term forecasted demand, on forward trading to meet short-term demand, and on the spot market to balance power. At the initial stage, only large customers, known in Australia as "contestable" customers, are allowed to choose suppliers. The framework of the NEM is presented in figure 1.6.

1.4.5 New Zealand

The electricity industry reform in New Zealand was part of a sequence of economic reforms trigged by the foreign exchange crisis in 1984 [1-25]. Its objective is to establish market mechanisms, to introduce competition, and to reduce administrative regulation as much as possible [1-25]. Before the reform, the generation utilities and the transmission network were owned directly by the government Electricity Department, and owned by Electricity Power Boards which were local government distribution entities [1-25].

Electricity industry reform in New Zealand started with corporatisation (restructuring). Deregulation efforts started in 1992 when the Energy Companies Act, a law governing the deregulation, was authorized [1-1]. In 1987, the Electricity Corporation of New Zealand (ECNZ) was established, assuming the generation and transmission businesses previously owned by the Electricity Department [1-25]. Then, in July 1994, Transpower, which took care the transmission business, was

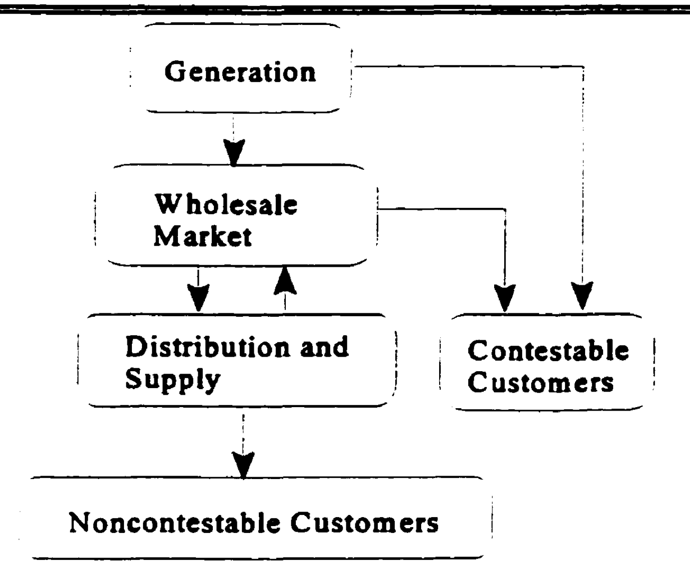

Figure 1.6 Australia National Electricity Market

separated from the ECNZ [1-25]. Later in 1995, 30% of the generation capacity in the ECNZ was assumed by a newly formed company named CONTACT [1-25]. Meanwhile, some new generation companies also emerged, and by 1998, it is estimated that 15% of the total demand is generated by private companies [1-23]. The electricity supply authorities were also corporatised into 40 companies since 1992 [1-25]. In April 1994, full deregulation both in the generation and supply businesses was implemented, offering all customers the right to choose suppliers [1-25].

To enable wholesale competition and coordinate the wholesale market, the Electricity Market Company (EMCO), which is jointly owned by Transpower, ECNZ, CONTACT and the Electricity Supply Association, was formed in 1993 to run an electricity exchange market [1-25]. This exchange started operation in 1995 [1-25]. The electricity exchange market consists of a spot market, bilateral contract market, and a forward market[8] [1-25]. Suppliers usually hold contracts with fixed quantity and a two-way hedge, with which those companies which bought less than their contracted quantities are credited for the differences, and those which purchased more are charged for the differences based on the spot price [1-25].

Privatization is not implemented in New Zealand, and the electricity companies are mostly state owned. Wholesale competition is not fully successful because of the predominance of the ECNZ in the generation market, whose declared marginal cost usually define the spot market price [1-25].

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8 Forward market refers to the market which governs contracts with a predetermined price for the next few days. It is designed to meet the short-term demand change for customers.

1.5 Organization of the Thesis

This thesis is arranged as follows. As we have seen, Chapter 1 provides the background of the research. The remaining chapters are organized as follows. In chapter 2, the England and Wales Power Pool (EWPP) as well as other essential elements of the reform in the EWPP are introduced. Also in this chapter, the research scope of this thesis is defined since it is closely related to the EWPP rules. In the next four chapters, four questions regarding the Pool operation are answered, namely, (1) What is the theoretical base behind the Pool scheduling method? (2) Why is the special method called Table A/B adopted by the Pool? (3) Why is marginal cost pricing chosen over average cost pricing? and (4) Why is the uniform pricing adopted instead of discriminatory pricing? Later, in chapters 7 and 8, gaming behaviour and some important issues are discussed to give the reader a broader picture. Finally in chapter 9, conclusions are presented.

Chapter 2 The England and Wales Power Pool

The privatization of the British power industry which started on March 31, 1990 has led to a dramatic structural change in the electricity industry [2-6]. According to the office of electricity regulation (OFFER), "The new industry structure is designed to encourage competition in generation and supply of electricity and to regulate price for activities where the scope for competition is limited, such as transmission and distribution." [2-1].

2.1 Old Structure and New Structure

In retrospect, the deregulation of the UK power industry can be traced back to the last decade. In 1983, the UK Energy Act permitted individual persons or companies to use public networks to transmit electrical energy, thus initiating the first step to open access of the transmission network [2-6]. In February 1988, the government white paper "Privatizing Electricity" was presented, formally proposing privatization [2-5]. The legislation concerning privatization is contained in the Electricity Act 1989 [2-6]. Finally, on March 31, 1991, often referred to as Vesting Day, privatization was implemented. These actions made the UK the first developed nation to break the monopoly in the electricity industry.

Before privatization, the Central Electricity Generating Board (CEGB), owned by the government, was in charge of almost all generation and transmission of electricity in England and Wales. It had a statutory obligation to schedule, dispatch and produce electricity to satisfy the national demand [2-2]. Prices for bulk supply to Area Boards and very large consumers, were set by the Electricity Council, which is a regulating body, at levels designed to meet financial targets laid by the government. The distribution and supply services, including setting customer rates, were managed by local Area Boards, which were also government owned monopolies [2-2].

On Vesting Day, the old electricity industry structure was dissolved and a new structure was established. The restructuring took several steps. First, the Office of Electricity Regulation (OFFER) was instituted to provide independent regulatory oversight of the UK electricity industry [2-7] Then, the whole industry was divided into four distinct businesses which are generation, transmission, distribution, as well as retail supply, and the CEGB and the Area Boards were split into several private companies [2-7]. Finally, a power pool was introduced as a competitive electricity market.

The two main duties of the regulating body, the OFFER, are (i) to prompt competition in generation, and (ii) to protect consumers from unreasonable price [2-14]. In theory, generation is not regulated but, in practice, OFFER has been drawn into monitoring the major generation utilities, especially those who have notable market power [2-7].

The CEGB was divided into four companies. These are the public owned National Power, PowerGen, National Grid Company (NGC) and the state owned Nuclear Electric [2-6]. The fossil fuel generation capacities within the CEGB were assumed by the National Power and the PowerGen; while the nuclear capacities remained state owned under the auspices of the Nuclear Electric [2-9]. The transmission business was taken by the NGC, which is responsible for the running of the national high voltage transmission system, the national grid. The NGC has no generation capacities except two pumped storage facilities, which are quite important in balancing the system [2-7]. Thus, the generation is separated from the transmission service. The supply and distribution business were privatized as twelve Regional Electricity Companies (RECs) [2-5]. It is the privatization mentioned above and allowing generators equal access to the national grid that made generation competition possible.

In the new structure, most consumers, known as franchise consumers, are connected to the network of RECs, although a few large non-franchise consumers, e.g., steelworks and paper plants, are connected directly to the national grid. Non-franchise consumers consuming 1 MW or more are allowed to purchase energy directly from any licenced suppliers. This privilege was expanded to costumers consuming 100 MW or more in 1994 and, eventually, will be expanded to all consumers in 1998 [2-5].

An important element of the new structure is a power pool. On Vesting Day, the England and Wales Power Pool (EWPP) was established for the trading of electricity between generators and suppliers [2-3]. The EWPP, operated by the NGC, is the heart of the new structure. Virtually all the physical electricity transactions go through the power pool [2-4], however, the pool itself does not buy or sell electricity. It serves as an electricity spot market; all generators bid into it and all RECs are entitled to purchase from it. Basically, the two main goals to be achieved by the NGC in its daily operation are to make generation schedules and to determine the electricity spot market prices. Since most of the consumers do not have the right to choose a supplier, only generation competition has been realized in the UK, at least until retail competition is instituted in 1998.

2.2 EWPP Overview

In the old industry structure, the publicly owned utilities coordinate generation and dispatch with each other. However, in the new structure, the generation utilities compete instead of coordinating their output with each other. This requires the EWPP to introduce a mechanism to form a competitive electricity market. An auction system is a natural choice. In such a system, the power pool essentially acts as a centralized "super-utility," so that all generators connected to the national grid can bid in prices and quantities for the provision of electricity energy. In a sense, the electricity is "pooled" into the pool and all suppliers can buy energy from it. This facilitates competition, thus creating a fair price for electricity via market forces.

A generation utility that wishes to trade electricity through the pool must first become a pool member and sign the Pooling and Settlement Agreement (PSA) with all other pool members. The PSA defines the rules for energy trading and specifies the responsibilities of the various parties. Table 2.1 gives several responsibilities within the NGC in EWPP's daily operation [2-3].

Every day the generation utilities offer bids on prices and amount of power they wish to sell for the next day. The above data and forecasted load are input into the Settlement general ordering and loading (Settlement GOAL) program to make a preliminary generation schedule for every half hour to meet the forecasted demand at the minimum pool cost. This preliminary schedule, whose purpose is to derive the pool prices, does not consider transmission constraints and is worked out one day before the schedule day. Later, a practical generation schedule with transmission constraints consideration is also produced by the NGC for the purpose of generation scheduling.

Table 2.1 Responsibilities of Various Parties within NGC According to the Pooling Settlement Agreement	
PARTY	RESPONSIBILITY
Settlement System Administrator	Responsible for the determination of pool settlement system prices and for the production of trading reports to pool members for each settlement day
NGC Grid Operator	Responsible for the maintenance and stability of the national grid, and responsible for the generation dispatch and real time system operation to ensure that voltage and frequency tolerances are not violated.
NGC Ancillary Services	Responsible for the provision of ancillary services required to ensure system stability, such as load following, VARs, and black start.
EPFAL	Responsible for the transfer of the pool funds from the RECs to the generators.

The pool prices are derived as follows. First, a system marginal price (SMP) is derived as the highest marginal price or incremental price of a "flexible" generator which is scheduled to run according to the preliminary schedule. There are two different SMP calculation methods. Roughly speaking, one method (Table A) is for peak load periods while the other method (Table B) is for off-peak load periods. Since the SMP only represents the short run marginal price, a capacity element (CE) is also added to the SMP to obtain a pool purchase price (PPP), $PPP = SMP + CE$. Several constraints (e.g., transmission flow, plant operation, stability) as well as load forecast errors, generation shortfall, and other factors can additionally increase the electricity price. All these factors are lumped under a price component called uplift.

Finally, the pool sale price (PSP) is defined as the sum of PPP and uplift, $PSP = PPP + uplift$. By 4 p.m., the SMP and CE for the next schedule day are made available to each pool member. The only uncertain price element from a day ahead perspective is the uplift, which can only be computed after the fact [2-9].

Generally speaking, generators will be paid at the rate of PPP for the energy they produced, while suppliers will pay PSP for the energy they buy. The difference between PPP and PSP, the uplift, is set to cover the cost associated with various services required to meet the constraints and uncertainty mentioned above. It should be nôted that the net payment to and from the pool equals zero. The transfer of funds that follow the trading of electricity throughout the pool is carried out by an administrative unit within the NGC called EPFAL.

The electricity retail prices charged by the RECs are regulated through a price cap. The majority of the end consumers, known as franchise costumers, purchase electricity from suppliers at a fixed rate independent of the variation in pool prices [2-9], however, large non-franchise costumers have an option to pay according to the variation of the half-hour spot market pool prices.

Since RECs buy electricity from the pool at the rate of PPP and supply end consumers at a fixed rate which does not reflect the variation of the PPP, most of them hedge against the risk associated with the PPP volatility by purchasing contracts for differences (CFDs) [2-7]. CFDs are not contracts to deliver electricity, but to transfer funds. Typically, one-way CFDs provide payment to the suppliers (buyers) when the PPP exceeds a predetermined strike price. Two-way CFDs also provide payment to the generators (sellers) when the PPP falls below a strike price [2-14]. CFDs also played an important role to protect the UK coal industry at the beginning of the restructuring of the electricity industry [2-7].

The transmission business is a hybrid. The maintenance and construction of the national grid are run by the NGC outside of the pool, and are run under a price cap regulation. The transmission charge is location based. There is a negative charge for generation in the south where the load is the heaviest, and a positive charge in the north in where there is an excess of generation [2-7]. The operation of the grid is run by the EWPP. The costs associated with grid operation are passed through the pool via the uplift [2-7].

The UK deregulation was referred to in jest as a "half market" because the initial rules allow only generators to submit bids. Things were changed in December 1993 when a scheme called DSB1 was introduced to the EWPP to encourage demand-side participation in SMP determination [2-18]. Under this scheme, twelve large consumers can submit bids for the prices and load they wish to shed at each half hour. However, the demand-side participation is not yet complete in the EWPP.

The EWPP rules are exceptionally complex. The following sections in this chapter summarize and highlight the important parts of such rules. Section 2.3 presents the time scheme used in the EWPP. The bidding information required by the EWPP is shown in section 2.4. Section 2.5 explains how to classify the schedule day into two types of periods (Table A/B). GOAL program is presented in section 2.6. Finally, section 2.7 and 2.8 explain how the prices are worked out and how the pool payments are made and balanced.

2.3 Settlement Agreement Timetable

The generation schedule and the electricity price are determined for every half hour, (known as the Settlement Period Duration, SPD) for an interval known as the Schedule Day Duration, SDD. The SDD starts at 5 a.m. and last for 48 half-hours.

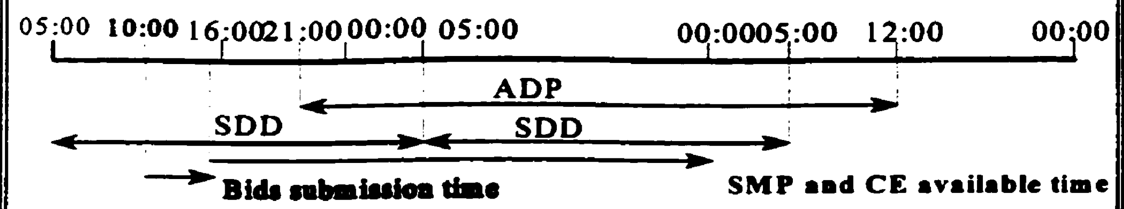

Figure 2.1 Settlement Timetable

The SDD timing is chosen to ensure a smooth changeover during a low load period, that is, around 5 a.m.

The Availability Declaration Period (ADP) runs 39 hours, from 9 p.m. on the day before the SDD to 12 p.m. after the SDD. The generation utilities must submit their Day Ahead Offer Files for the full ADP by 10 a.m. on the day before the SDD. The SMPs and CEs of all periods in a SDD are available to all pool members by 4 p.m. on the day before the SDD.

Since the generation utilities submit Day Ahead Offer Files every day for the next ADP, the offer data may overlap with that of the previous offer. Generally, the old offer data is replaced by the new one. Figure 2.1 shows an example of the above quantities, which together define what is called settlement time table.

A program called Settlement Runs is used for the calculation of the payments. Metered data are collected and input into the Settlement Run. The Pool Funds Administrator receives the result from the Settlement Run and authorizes the funds transfer, generally, within 28 days after the SDD.

2.4 Bidding Information

Every day by 10 a.m., the electricity generation utilities are required to submit a Day Ahead Offer File for each of their gensets (genset is one unit or group of units which are considered jointly for the purpose of dispatch). The bidding file contains information on availabilities, prices, as well as operational characteristics of the genset for the next ADP. The following is a brief summary of the bidding information: [2-2]

2.4.1 Offered Genset Availability

The genset submits an offer stating whether it wishes to sell. If yes, the maximum output level should also be submitted. This offer covers every minute of the next ADP. The maximum level permitted availability is 999 MW.

2.4.2 Genset Operational Characteristics

A genset is required to submit to the power pool its operational characteristics, such as ramp-up and ramp-down rates as well as minimum up and down times.

2.4.3 Prices for the Next ADP

Each genset must submit one set of prices for the entire ADP. The EWPP does not require gensets to reveal their real operational cost. Therefore, a genset's bidding prices do not necessarily reflect its real operational costs. The offered prices are specified by the so-called Willans' Line containing eight parameters as shown in Figure 2.2: the no-load price c_0, the elbow points P_B and P_C, the incremental prices λ_{AB}, λ_{BC}, and λ_{CD}, as well as the power output range, $[P^{min}, P^{max}]$. Bidders can submit no more than three segments for a genset (Subsequently increased to 10 segments in 1995). The start-up price is also required by the EWPP.

A genset may offer a special price called maxgen price if the genset can operate above its stated availability for a while when needed. The genset will be paid for its maxgen operation at the rate of the maxgen price specified in its offer file.

All offered prices must be less than the maximum values specified by the EWPP. Table 2.2 shows the maximum values.

2.4.4 Inflexibility Declaration

A genset may be declared inflexible if it can only operate at or above a certain output level, or if it is unable to shutdown between daily peaks.

Table 2.2 Maximum Values of Bidding Prices

Term	Incremental Prices	No-load Price	Start-up Price	Maxgen price
Maximum Value	1000 £/MWh	10,000 £/h	100,000 £/time	10,000 £/MWh

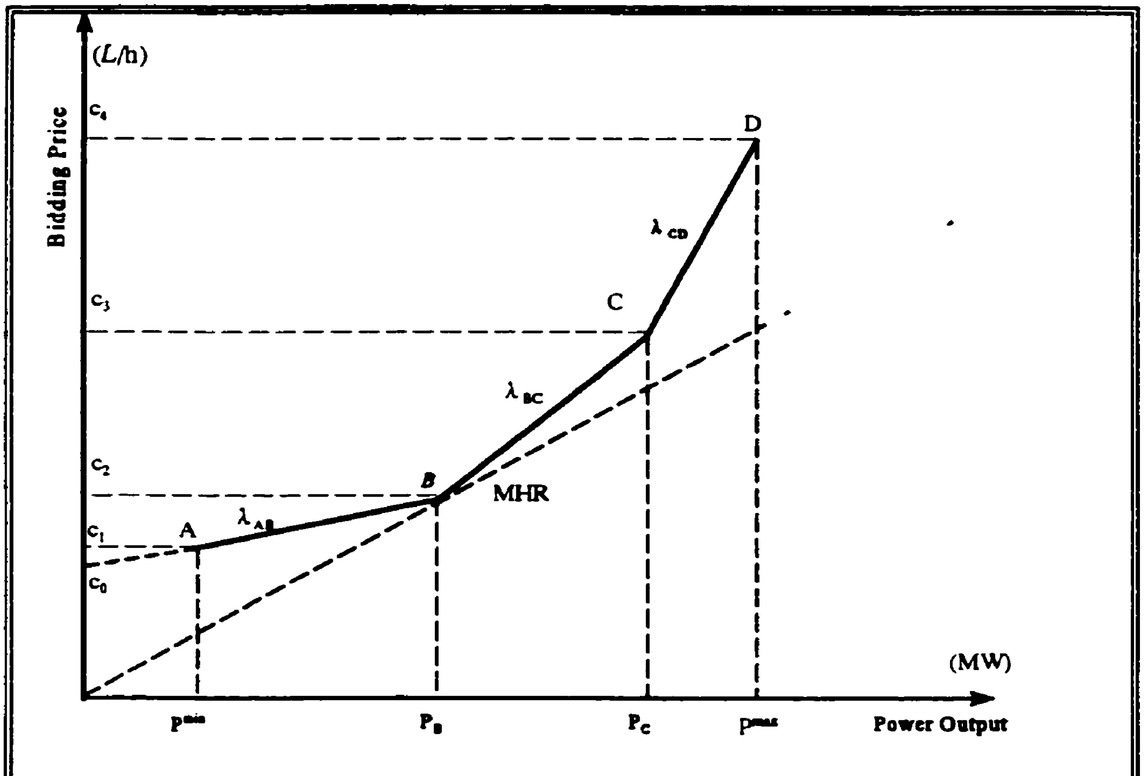

Figure 2.2 Willans' Line

At any time a genset may submit a Redeclared Availability Declaration, which contains revised data for its availability and inflexibility. This might happen when a genset becomes available at a different output level or a genset declared not available becomes available.

If a genset fails to submit Day Ahead Offer File, or the submitted file contains invalid data, the settlement system administrator has the power to use the last notification available from the genset or the most recent offered data.

2.5 Demand Forecasting and Schedule Periods Classification

Every day by 10 a.m., the Grid operator produces a national demand forecast for each SPD in the next ADP, based mainly on historical data and weather forecasts. The demand from large consumers, external pool members and NGC pumped storage is added to the forecast to get a demand curve.

Given the demand curve, the NGC operator divides the 48 half-hours in the next SDD into two categories, namely the Table A and Table B periods. Generally, the Table A period is a peak load period and the Table B period is an off-peak load period. This classification facilitates the price determination.

To define the Table A and Table B periods, the peaks and troughs must be defined first. Peaks and troughs are settlement periods which lie at the maxima and minima of the demand curve. Mathematically, assuming that D_j is the load during period j, peaks can be defined as $D_{j-1} < D_j \geq D_{j+1}$, while troughs can be defined as $D_{j-1} \geq D_j < D_{j+1}$. Minor peaks, which associated with a drop of less than 500 MW are not classified at this step.

The periods from the start period to the first peak, from one peak to the next peak, and from the last peak to the end period are treated as troughs. However, the first and the last periods in the SDD are treated as peaks if their demand is greater than the demand of their neighbours.

For each trough, two intermediary variables are defined, the genset spare capacity (SC) and period residual (PR). The SC is defined as the margin between the total availability and the sum of demand and reserve. PR is the minimum SC at the adjacent peaks associated with the trough. Each trough period with $SC - PR > 1000\ MW$ is defined as Table B period. All the other periods are Table A periods. Essentially, Table B periods are periods with more spare capacities while Table A periods are periods with less spare capacities.

After the above steps, an adjustment is necessary to maintain the ratio of the number of Table A periods to Table B periods. From 9 p.m. to 5 a.m., only 7 out of 16 half-hours are allowed to be Table B periods; from 5 a.m. to 5 a.m. next day, only 20 out of 48 half-hours are allowed to be Table B periods; from 5 a.m. to 12 a.m., only 5 out of 14 half-hours are allowed to be Table B periods. If the initial step produces more Table B periods, the Table B periods with the low margin between SC and PR are redefined as Table A periods until the above condition is satisfied. It will be shown later that the no-load cost and start-up cost are covered only through Table A periods. The adjustment mentioned above is to ensure that the winning bidders can get adequate payment to cover all their costs.

2.6 Settlement Goal

Given the bids and forecasted load, the pool dispatcher creates a generation schedule to meet the load at minimum pool cost. To perform this task, the dispatcher employs a program called Settlement Goal which essentially uses a merit order list approach [2-3]. The Settlement Goal does not take into account transmission limits and, therefore, the schedule is only a preliminary version for the purpose of selecting a set of successful bidders and to determine the electricity price.

The Settlement Goal functions as follows: [2-18]

(a). For each genset, find the minimum heat rate point (MHR). This point (Point B in Figure 2.2) corresponds to the minimum average price (MAP).

(b). Segments with incremental prices (IP) less than the MAP are re-assigned an IP which equals MAP.

(c). Segments are ranked according to their IP to form a merit order list.

(d). Add the capacity of each segment in order of increasing IP to form a scheduled generation versus IP curve (Figure 2.3).

(e). Given the curve and the forecasted demand, a preliminary schedule can be obtained.

2.7 Pool Prices

The prices at which electricity are bought and sold under the pool trading arrangements is determined for every half-hour so that the pool can be considered as an electricity "spot market" with a uniform market clearing price. The price at any time, as in any other market, reflects the market equilibrium between supply and demand.

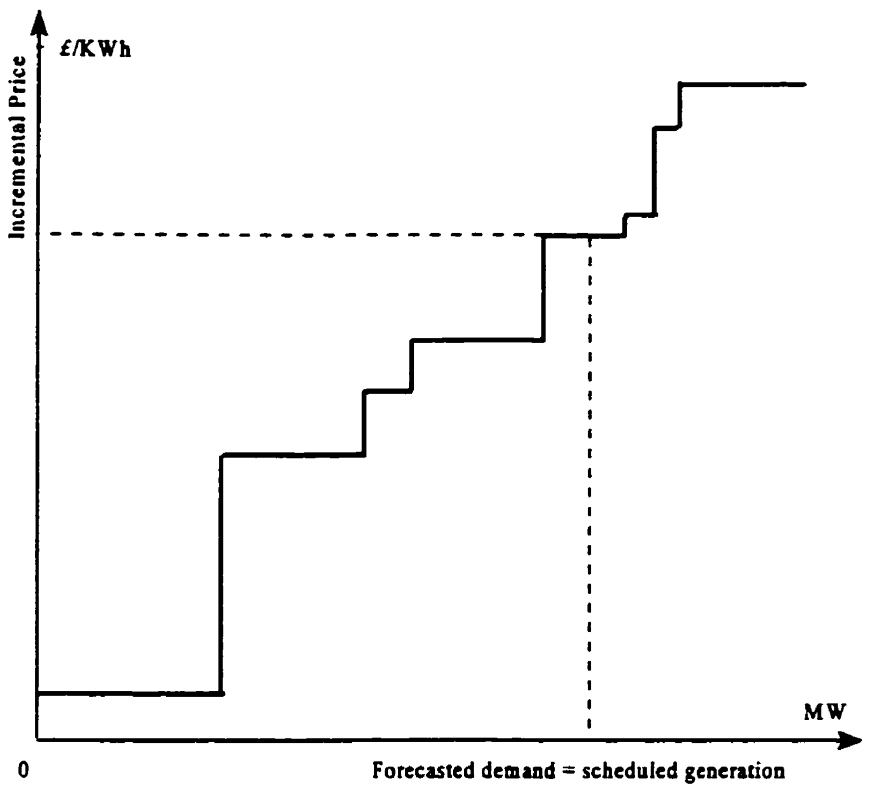

Figure 2.3 Merit Order List Approach

The EWPP electricity price consists of four elements, namely, system marginal price (SMP), capacity element (CE), uplift, and transmission losses price.

2.7.1 System Marginal Price

The SMP is energy element of the pool price. It is derived from the unconstrained preliminary generation schedule with different calculation methods for Table A Period and Table B Period. The derivation of SMP is as follows:

(a) Suppose V_{ij} and VR_{ij} are the scheduled level in MW for generation and reserve for genset *i* in schedule period *j* according to the unconstrained schedule. We define the genset's unconstrained generation in MWh, $U_{ij} = [V_{ij-1} + V_{ij}] \times 0.5 \times SPD$, and similarly, the genset's unconstrained reserve, $UR_{ij} = [VR_{ij-1} + VR_{ij}] \times 0.5 \times SPD$.

(b) To find SMP, first, the intermediate variables GP_{ij} are found for each genset *i* during period *j*.

(i) For a table B period, the GP is the offered incremental price corresponding to the unconstrained generation U_{ij}.

(ii) For Table A period,

$$GP_{ij} = INC_{ij} + \frac{\sum_{start}^{end} [(NL_{ij} \times SPD) + ST_{ij}]}{\sum_{start}^{end} (U_{ij} + UR_{ij})} \tag{2.1}$$

where INC_{ij} is the incremental price corresponding to the scheduled output level; NL_{ij} is the offered no-load price; ST_{ij} is the offered start-up price; *start* and *end* are the genset start and shut down times; U_{ij} is the genset unconstrained generation and UR_{ij} is the genset unconstrained reserve.

(c) To ensure that gensets receive adequate payment and to avoid high SMP, the GP is revised if a genset is scheduled to operate as a pulse generator (on-off during one or two periods), or if a genset is turned on and off within Table B periods.

(d) All gensets are labelled flexible or inflexible. A genset which declares to be inflexible in the Day Ahead Offer File is labelled inflexible. If a genset is scheduled to run in the unconstrained schedule for more than two hours and it is running up or down at its maximum rate in one SPD, it is labelled inflexible. A genset who runs at or above its maximum generation both at the beginning and the end of a SPD is also labelled inflexible. All the others are labelled flexible.

(e) SMP is the highest GP of these flexible gensets retained by the merit order dispatch.

2.7.2 Capacity Element

Capacity Element is based on the idea that, if a genset is not used to serve load frequently, i.e., it has a low load factor, it might not receive enough payment through SMP to remunerate its cost and investment [2-7]. In the long run, generators must have a reasonable return for their investments, otherwise nobody will build new plants. For these reasons, the CE is added to the SMP which, in the long term, is expected to reflect the cost of building new power stations needed to meet peak demand. The CE is worked out by NGC through a complex formula. The basic idea is to pay more while the spare capacity, i.e. the system capacity less the demand, is small and pay less when the spare capacity is large. Clearly, the larger the CE, the more investors will be willing to build new plants and vice versa. The formula is:

$$CE = LOLP_j \times (VLL - SMP) \tag{2.2}$$

where $LOLP_j$ is the loss of load probability for settlement period j and VLL is value of lost load. The LOLP is calculated by NGC, and is evaluated from the difference between the national total availability and demand. The VLL is set as a fixed value which changes every year. The value for VLL is expected to determine the extent to which investors will be willing to build new plant in excess of the actual maximum demand on the system.

2.7.3 Uplift

Uplift is the price component related to the power system constraints and many other factors. There are several constraints that increase the electricity rate. They are transmission constraints (some combinations of generating units overload the transmission system), plant characteristics (the dynamics of plant, for example, some generators take many hours to start), and system stability (in order to maintain a stable system, it is necessary to have sufficient reserve, it is also necessary for some generating units to produce "reactive" power) [2-8]. These constraints and the purchase of ancillary services will require the suppliers to pay more than SMP and CE. Uplift also covers an availability payment, that is, the declared available capacities in the bids which are not standby both in preliminary schedule and practical schedule receive availability payment which is tied to CE. The costs associated with the load forecast errors, and the difference between the generation schedule and the real generation are also cover by the uplift. All the costs mentioned above are added and spread over the Table A Period under the uplift, thus, the uplift is a mixture of many elements.

2.7.4 Transmission Losses Adjustment

Transmission losses are the difference between the metered generation and demand. The price adjustment for losses is proportional to the total energy losses at the price of PSP.

2.7.5 Pool Prices

Since SMPs and CEs for the next SDD are available to all pool members by 4 p.m. one day before the SDD, the SMP and CE can be considered as a forward market price. However, the uplift and transmission losses can not be forecasted. Therefore, the uplift is spot price.

Pool purchase price (PPP) is defined as the sum of SMP and CE, and the pool sale price (PSP) is defined as the sum of PPP, uplift, and transmission losses price. Table 2.3 gives an example of the prices [2-16], and Table 2.4 gives the UK electricity retail price for domestic and industry supply [2-17].

Table 2.3 The EWPP Prices in November 1996

Average Price	SMP	PPP	PSP
(£/MWh)	18.46	22.04	24.01

Table 2.4 The UK Electricity Retail Price in 1996

Average Price	Domestic Price	Industry Price
(£/MWh)	92.9	46.3

2.8 Who Gets What?

The transfer of funds that follows the trading of electrical energy throughout the pool will be carried out by EPFAL, the pool fund administrator within the NGC. Generally speaking, gensets are paid at the rate of PPP, while the suppliers pay at the rate of PSP. The difference between PPP and PSP is paid to the various parties who provide the ancillary or other services.

Gensets are paid for generation, spinning reserve, as well as for having the plant available, simply by submitting bids. The gensets which provide ancillary services receive corresponding payment. In addition, gensets also receive payments to recompense them for out-of-merit operation due to system constraints and forecasting errors. Some gensets also receive marginal adjusted payments if their operational costs are not covered through the SMP. Generation utilities are penalized if they do not follow the NGC's instructions.

The fund settlement can be summarised as follows:

2.8.1 Payment for Generation

Gensets are paid for energy generation. They are paid at the rate of PPP for the energy they produce if they operate according to the unconstrained schedule.

2.8.2. Payment for Spinning Reserve

Gensets are paid for reserve at the rate of PPP less the corresponding bidding incremental price if they operate according to the unconstrained schedule.

2.8.3. Payment for Offering Availability

Gensets are also paid for any generation capacity declared available, but not used either as generation or as reserve in the unconstrained schedule. This payment is called availability payment (AP), and it is worked out according to the following formula:

$$AP_{ij} = (XP_{ij} - W_{ij} - WR_{ij}) \times LOLP \times (VLL - \max(BP_{ij}, SMP_j)) \qquad (2.3)$$

where the subscript ij refers to genset i in period j. XP_{ij} is the declared available energy; W_{ij} and WR_{ij} are the generation and the reserve energies derived from the unconstrained schedule; BP_{ij} is the bidding incremental price; SMP_j is the SMP in period j. AP_{ij} is set to zero if it is negative.

The above subsections summarise the payments for the unconstrained schedule, which are illustrated in Figure 2.4.

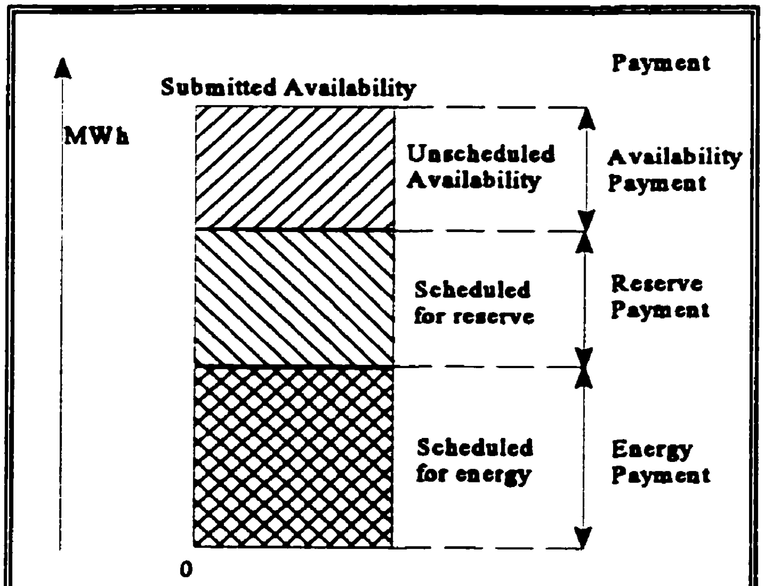

Figure 2.4 Payments for the Unconstrained Schedule

2.8.4. Ancillary Service Payment

Gensets which provide ancillary services are paid for the services.

2.8.5. Maxgen Payment

Gensets offering maxgen services are paid at a maxgen rate if they are chosen to operated above their maximum declared availability for a short period. The payment is,

$$GMP_{ij} = MP_i \times (A_{ij} - XD_{ij}) \tag{2.4}$$

where GMP_{ij} is the genset maxgen payment; MP_j is the offered maxgen price in £ per MWh; A is the energy generated in maxgen operation and XD is the declared maximum availability times the maxgen operation time. Again, GMP_{ij} is set to zero if it is negative.

2.8.6. Payments for Out-of-merit Generation

Many factors, like transmission constraints, load forecast errors, and genset unavailability result in difference between the metered output and the unconstrained-scheduled output. This difference is compensated according to the difference between the cost of the metered output and the cost of the unconstrained schedule, based on the genset offer prices. This compensation is called metered payment. The procedure of calculating metered payment is illustrated as follows:

Suppose genset i is scheduled to generate P_1 according to the unconstrained schedule, but actually generates P_2 due to the reasons mentioned above. First, it receives $P_1 \times SMP$ as the energy payment. Then, if $P_2 > P_1$, genset i must sell the extra energy, $(P_2 - P_1) \times SPD$, to the market at the rate of offer bid price.

Therefore, the total payment for energy is:

$$P_1 \times SPD \times SMP + (P_2 - P_1) \times SPD \times Price_{bid} \tag{2.5}$$

where $Price_{bid}$ is the corresponding bidding price.

Otherwise, if $P_2 < P_1$, genset i must buy back the energy it should have produced, $(P_2 - P_1) \times SPD$, from the market at the rate of offered bid price. Therefore, the total payment for energy is:

$$P_1 \times SPD \times SMP - (P_1 - P_2) \times SPD \times Price_{bid} \tag{2.6}$$

where $Price_{bid}$ is the corresponding bidding price.

Following are two special examples of the metered payment.

(a) Gensets which are not in the unconstrained schedule, but are ordered to operate due to constraints (constrained on), are paid at their bid price for energy payment. They are also paid AP according to equation 2.3.

(b) Gensets which are in the unconstrained schedule, but are ordered not to operate due to constraints (constrained off), are paid at the rate of PPP less the bid price. The bid price is subtracted since such gensets do not run and therefore, should not be compensated for the operational cost.

To avoid gensets making more profit by redeclaring inflexibility, the metered payment, if positive, is set to zero if the genset is declared inflexible [2-11].

2.8.7. Marginal Adjustment Payment

Gensets will be paid for "marginal plant adjustment" if the operational cost is not covered through other payment. Chapter 4 will give details.

2.8.8. Pool sale Price

Suppliers are charged at the rate of PSP, which equals SMP plus CE and uplift.

2.9. Research Scope

The main motivation of this thesis is to understand and analyse the EWPP rules. Since it was a joint effort from both power system experts and economists that made the UK power industry deregulation became a reality, the understanding of the EWPP rules needs knowledge in both power engineering and economy.

Several issues arise from the EWPP bidding rules, and are analysed in this thesis.

(i) To understand more fully the theoretical basis behind the Settlement Goal;

(ii) The reasoning behind Table A and Table B periods classification;

(iii) The logic behind the EWPP use of marginal cost pricing

(iv) Why does the EWPP employ uniform pricing instead of discriminatory pricing?

(v) The Gaming behaviour under the EWPP rules.

Chapter 3. The Switching Curve Law — Theory Behind the EWPP Goal Program

Since the preliminary unconstrained schedule aims to meet the forecasted demand at the pool minimum cost, the objective of the Settlement Goal program can be considered as a unit commitment (UC) problem. In this chapter, we show that this program has a solid theoretical base from the solution of the UC problem through the Lagrangian Relaxation approach and, in particular, the Switching Curve Law.

In this chapter, therefore, the concept of Switching Curves in the context of UC is introduced and the Switching Curve Law is developed first. Then, we apply the Switching Curve Law to justify the reasoning behind the Settlement Goal. Finally, it is shown that, just as with the Switching Curve Law, there are cases when it fails to find the optimum UC, so can the Settlement Goal fail. However, one advantage of Lagrangian Relaxation is that, although it does not always find the optimum UC, it does provide an upper bound on the difference between the found UC and the optimum UC. This upper bound is called the duality gap [3-2]. In those cases where the duality gap is large, we suggest a way to find a better solution closer to the optimum.

3.1 Unit Commitment and the Switching Curve Law

The Switching Curve Law, derived from the solution of the UC problem through the Lagrangian Relaxation technique, is presented in this section. UC is a traditional tool in regulated power systems which schedules generators to meet load at the minimum generation cost. Mathematically, UC can be formulated as a complex, mixed-integer, non-linear programming problem that consists of scheduling the on/off modes of available generators in the power system over the planning horizon. From an analytic point of view, UC can be solved when a switching-on condition, called the Switching Curve Law, which governs the switching mechanism of generation units, is found to be true and is applied [3-1].

The static UC problem can be formulated as follows [3-2]: for each time interval, minimize the total cost of generation to meet the load, P_d, and to satisfy the minimum reserve margin, R. This formulation is termed the primal problem,

$$\underset{u,\,P}{Minimize} \sum_{i=1}^{n} u_i\, C_i\,(\,P_i\,) \tag{3.1}$$

Subject to:

$$\left.\begin{aligned} &\sum_{i=1}^{n} u_i\, P_i = P_d \\ &\sum_{i=1}^{n} u_i\, P_i^{\max} \geq P_d + R \\ &P_i^{\min} \leq P_i \leq P_i^{\max} \end{aligned}\right\} \tag{3.2}$$

where $u_i = 1$ when the unit i is on, and $u_i = 0$ when the unit i is off; C_i is the cost function of generator i; P_i is the real power output of the generator i; P_i^{min} and P_i^{max} are the generator output limits.

The Lagrangian function is defined as follows:

$$L(\underline{u},\underline{P},\lambda,\alpha) = \sum_{i=1} u_i C_i(P_i) - \lambda \left\{ \sum_{i=1} u_i P_i - P_d \right\} - \alpha \left\{ \sum^{n} u_i P_i^{max} - P_d - R \right\} \tag{3.3}$$

where λ and α are the Lagrange multipliers for the system load and the reserve constraints respectively.

The dual problem (DP) is then:

$$\underset{\alpha,\lambda}{Maximize} \left\{ \underset{\underline{u},\underline{P}}{Minimize}\ L(\underline{u},\underline{P},\lambda,\alpha) \right\} \quad S.\ t.:\ \alpha > 0 \tag{3.4}$$

The solution of the DP involves two steps. The first, known as the Relaxed Primal Problem (RPP), minimizes the Lagrangian function with respect to the vectors $\underline{P}$ and $\underline{u}$. This minimum can be proven to be a lower bound of the optimum total generation cost in the primal problem [3-3, 3-4]. The second step in equation 3.4 maximizes the Lagrangian over the Lagrange multipliers α and λ, finding the highest lower bound to the optimum of the primal problem. The solution of the RPP can also be, in turn, decomposed into two problems. One is the well-known economic dispatch which minimizes the operation cost to find the optimal generation $\underline{P}$ as a function of λ with fixed $\underline{u}$. The second sub-problem minimizes the operation cost with respect to the unit commitment combination, $\underline{u}$, after replacing $\underline{P}$ by $\underline{P}(\lambda)$, for a specified pair of Lagrange multiplies (α, λ). This sub-problem is formulated as:

$$\underset{\underline{u}}{Min}\, L(\underline{u},\underline{P}(\lambda),\lambda,\alpha) = \underset{\underline{u}}{Min} \sum_{i=1}^{n} u_i \left[C_i(P_i(\lambda)) - \lambda P_i(\lambda) - \alpha P_i^{\max}\right] \quad S.\ t.:\ u_i = \{\ 0,\ 1\ \} \tag{3.5}$$

For each unit i, we define a switching function:

$$S_i(\lambda,\alpha) = C_i\ (P_i(\lambda)) - \lambda\ P_i(\lambda) - \alpha\ P_i^{\max} \tag{3.6}$$

From equations 3.5 and 3.6, since u_i can take only two values (0 or 1) the following conditions to find the optimum unit commitment combination $\underline{u}$ must be true [3-1],

$$u_i(S_i(\lambda,\alpha)) = \begin{cases} u_i = 0, & S_i(\lambda,\alpha) > 0 \\ u_i = 1, & S_i(\lambda,\alpha) < 0 \\ u_i = 0 \ \ or \ \ u_i = 1, & S_i(\lambda,\alpha) = 0 \end{cases} \tag{3.7}$$

The conditions stated in equation 3.7 are known as the Switching Curve Law. The curve along which the switching function is equal to zero is called a Switching Curve [3-1],

$$S_i(\lambda,\alpha) = 0 \tag{3.8}$$

Since various models can be used to approximate the actual running cost of a generation unit, the shape of the Switching Curve will also depend on the chosen model. For the Willans' Line model as described in equation 3.9 and Figure 3.1, the corresponding Switching Curve is shown in equation 3.10. Figure 3.2 is an example of several Switching Curves from a numerical simulation.

$$C_i(P_i) = \begin{cases} c_{1,i}, & P_i \le P_i^{\min} \\ c_{1,i} + \lambda_{AB,i}(P_i - P_i^{\min}), & P_i^{\min} \le P_i \le P_{B,i} \\ c_{2,i} + \lambda_{BC,i}(P_i - P_{B,i}), & P_{B,i} \le P_i \le P_{C,i} \\ c_{3,i} + \lambda_{CD,i}(P_i - P_{C,i}), & P_{C,i} \le P_i \le P_i^{\max} \\ c_{4,i}, & P_i \ge P_i^{\max} \end{cases} \tag{3.9}$$

$$\alpha P_i^{\max} = \begin{cases} c_{1,i} - \lambda P_i^{\min}, & \lambda \le \lambda_{AB,i} \\ c_{2,i} - \lambda P_{B,i}, & \lambda_{AB,i} \le \lambda \le \lambda_{BC,i} \\ c_{3,i} - \lambda P_{C,i}, & \lambda_{BC,i} \le \lambda \le \lambda_{CD,i} \\ c_{4,i} - \lambda P_i^{\max}, & \lambda \ge \lambda_{CD,i} \end{cases} \tag{3.10}$$

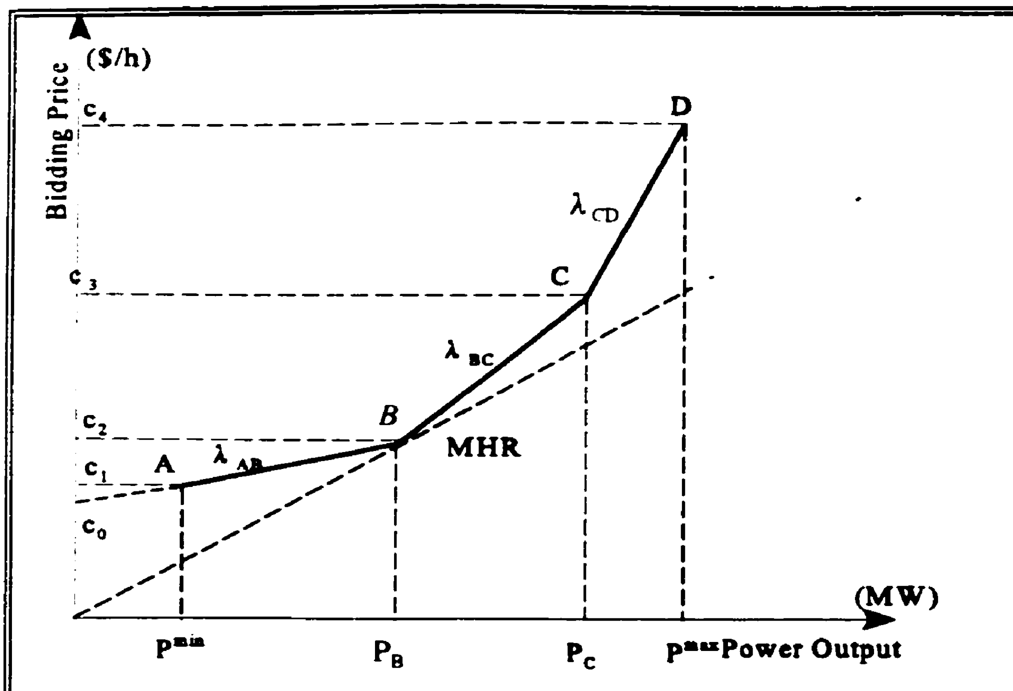

Figure 3.1 Willans' Line

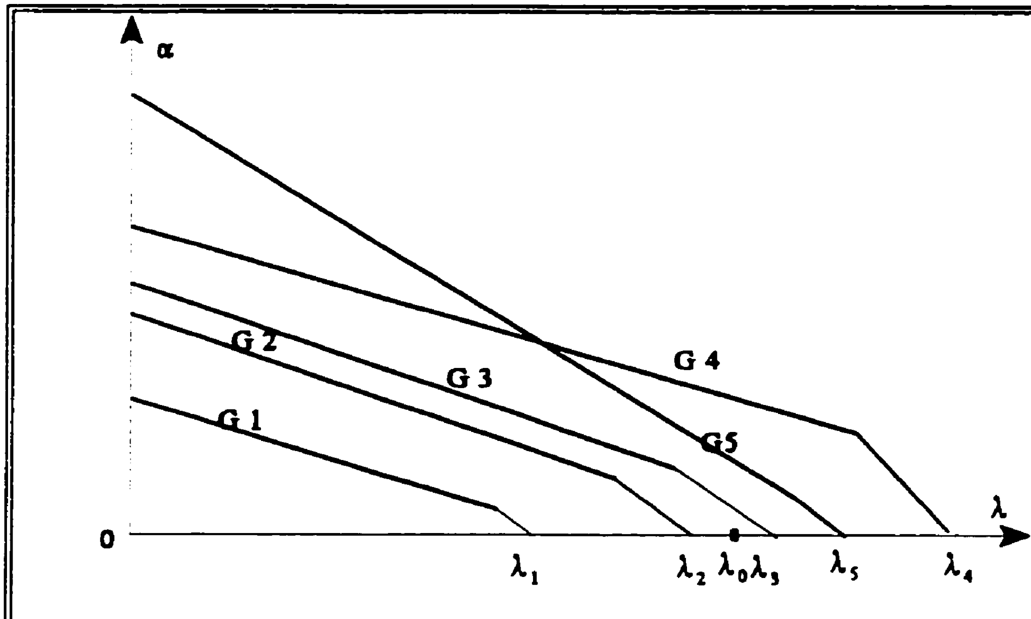

Figure 3.2 Switching Curves for 5 Gensets

From equations 3.6 and 3.8 the common properties of the Switching Curves follow [3-1]:

1. The Switching Curves are continuous over the α-λ plane.

2. The Switching Curves are composed of several segments, (four in the case of the three-piece Willan's Line model).

3. Since all segments have negative slopes, α decreases monotonically with increasing λ.

4. The α-axis intersect occurs at the non-negative value, α_i, given by

$$\alpha_i = c_{1,i}/P_i^{max} \tag{3.11}$$

5. The λ-axis intersect occurs at the non-negative value, λ_i, which coincides with the minimum average cost.

From the definition of the Switching Curve shown in equation 3.8 and Switching Curve Law shown in 3.7 , we get:

$$\begin{aligned}\frac{C_i(P_i(\lambda))}{P_i(\lambda)} &< \lambda + \alpha\frac{P_i^{\max}}{P_i(\lambda)}, \quad u_i = 1 \\ \frac{C_i(P_i(\lambda))}{P_i(\lambda)} &> \lambda + \alpha\frac{P_i^{\max}}{P_i(\lambda)}, \quad u_i = 0\end{aligned} \tag{3.12}$$

Assuming that there is no reserve requirement in the system, i.e. $\alpha = 0$, equation 3.12 states that the unit should be turned on if its average cost is less than the system incremental cost and off if the average cost is greater than the system's incremental cost. It can be easily shown that, for a genset, the point where the average cost equals the incremental cost, coincides with the minimum average cost point or MHR (see appendix 3.2).

3.2 Link Between the Goal Program and the Switching Curve Law

As mentioned in the last section, one of the goals of the EWPP bidding rules is to do a preliminary schedule and dispatch of the generation to meet the forecasted demand at minimum cost to the Pool. This problem is essentially a static UC problem and therefore the Switching Curve Law applies.

From the EWPP dispatcher's point of view, the bidding prices and availabilities from the gensets can be treated as the cost functions, so that the dispatcher can make a preliminary generation schedule by solving a static UC problem. Later in this section, the solution of the UC problem through the Switching Curve Law will be compared with the EWPP schedule.

The Switching Curve Law helps to explain the switching mechanism in term of

λ and α, that is, the system incremental cost of the load and reserve respectively. However, it is more common to specify load and reserve (P_d, R) instead of (α, λ). As it will be shown in this section, the Switching Curve Law can be defined either in the (α, λ) plane or the (P_d, R) plane.

Consider the case when there is no spinning reserve constraint, i.e. α equal to 0. When the load increases from zero to the maximum system capacity, λ increases from zero to its maximum, and generators will be turned on in the sequence of 1, 2, 3, 5, 4 (see figure 3.2). Mathematically, the relation between P_d and λ can be expressed as a non-decreasing monotonic function of λ:

$$P_d = \sum_{i=1}^{n} u_i(\lambda)\, P_i(\lambda) \tag{3.13}$$

where $P_i(\lambda)$, which is a function of λ, can be derived from equation 3.9 and be expressed as:

$$\begin{cases} P_i(\lambda) = P_i^{\min} & \lambda \le \lambda_{AB.i} \\ P_i^{\min} \le P_i(\lambda) \le P_{A.i} & \lambda = \lambda_{AB.i} \\ P_i(\lambda) = P_{B.i} & \lambda_{AB.i} < \lambda < \lambda_{BC.i} \\ P_{B.i} \le P_i(\lambda) \le P_{C.i} & \lambda = \lambda_{BC.i} \\ P_i(\lambda) = P_{C.i} & \lambda_{BC.i} < \lambda < \lambda_{CD.i} \\ P_{C.i} \le P_i(\lambda) \le P_i^{\max} & \lambda = \lambda_{CD.i} \\ P_i(\lambda) = P_i^{\max} & \lambda > \lambda_{CD.i} \end{cases} \tag{3.14}$$

Since λ is the SMP, equation 3.12 represents the behaviour of SMP versus load. Applying this equation to the data in the appendix 3.1, we get the same generation schedule (see figure 3.3) as the EWPP schedule. In this figure, the total generation increases in discreet steps when a new segment is added or a new genset is turned on.

In section 3.1, it is shown that the λ-axis intersect of the Switching Curve occurs at the non-negative value λ_i, which coincides with the minimum average cost. In other words, the Switching Curve Law for the system with zero capacity margin can be rewritten as: "The unit should be on/off if the system incremental cost is higher/lower than the MHR point ," which, in essence, is the same as the EWPP merit order approach. Therefore, the Switching Curve Law analytically explains the nature of the Settlement Goal heuristics.

The EWPP heuristics does not take the system reserve margin into consideration. Using the Switching Curve approach instead of the EWPP rules

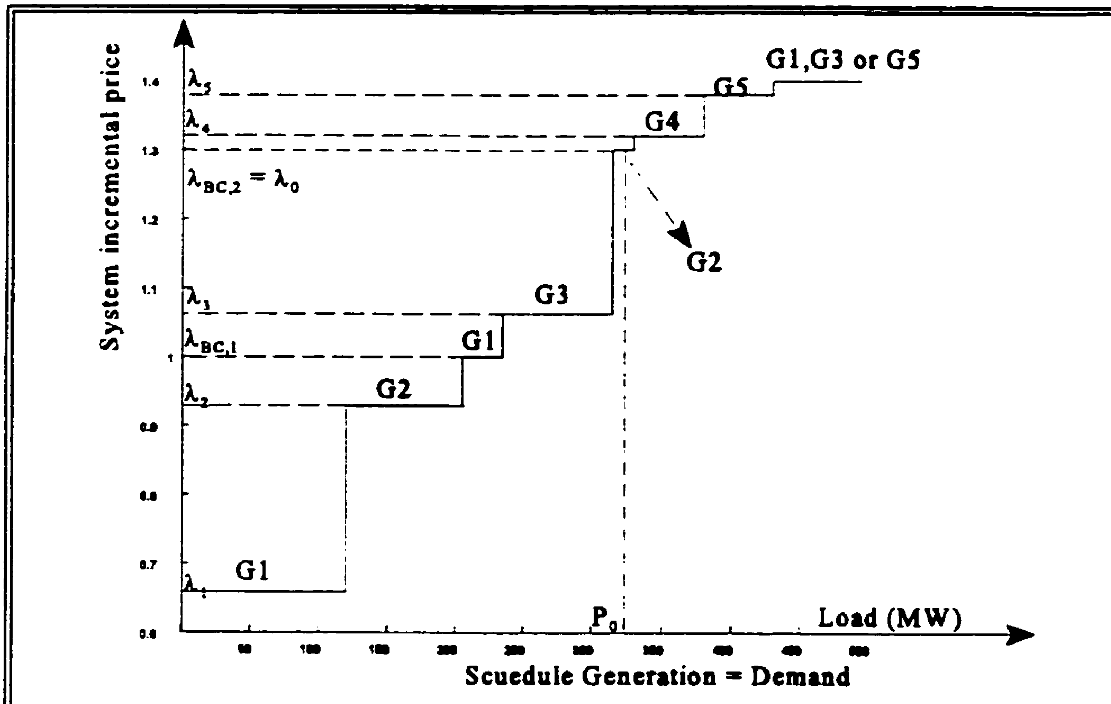

Figure 3.3 Generation Schedule

would permit us to find the generation schedule for the system with spinning reserve requirements ($\alpha > 0$).

3.3. Improvement to the Switching Curve Law

It was found through numerical testing that the optimum combination of the committed units does not always coincide with the order specified by the Switching Curve Law. This discrepancy, if it occurs, usually happens between the last generator turned on and the next one in the Switching Curve order. The following gives a physical explanation of this kind of inaccuracy.

For simplicity, consider the case when system reserve margin is equal to zero ($\alpha = 0$). Suppose the total generation output is $P=P_0$; the system incremental cost is $\lambda=\lambda_0$, and λ_0 is very close to λ_i (i =3 in figure 3.2) corresponding to the minimum average price of generator i. Let the load increase by ΔP such that the total demand $P_0+\Delta P$ cannot be met if $\lambda<\lambda_3$. According to the Switching Curve Law, generator 3 should then be turned on. Once this new unit is on, the economic dispatch determines a new system incremental cost, $\lambda=\lambda'$. It might happen that $\lambda'<\lambda_3$, meaning that generator 3 works in an uneconomic status where the unit average price is higher than the system incremental price. Therefore, the unit commitment should either rely on the previous committed generators or skip generator 3 and search among the remaining ones. Alternatively, if we turn on generator 5 (see figure 3.2) which is on the right side of generator 3 in the Switching Curve order, the new system incremental cost, $\lambda=\lambda''$, might be higher than λ_5, in which case, generator 5 is working in an economic mode ($AP_5 < IP_5$).

The following is an example of the above discussion. Figure 3.4 shows the average price (AP) and incremental price (IP) curves of two neighbouring generators i and j. λ_i and λ_j are the MAP of units i and j respectively. P_i and P_j are the corresponding power outputs. λ' is the system IP determined by the economic dispatch if unit i is turned on, while λ'' is the system IP when unit j is on. It can be seen that if the power output of units i and j varies between the interval from P_j to P_i, it is more economic to turn on generator j instead of generator i because its IP is greater than the AP in this interval.

An improved unit commitment using Switching Curves can be obtained by adding to the algorithm another search which tests the extra combinations obtained by interchanging the neighbours of the last committed unit.

Since the nature of the Settlement Goal is basically the Switching Curve Law, the EWPP preliminary schedule might also deviate from the optimal solution.

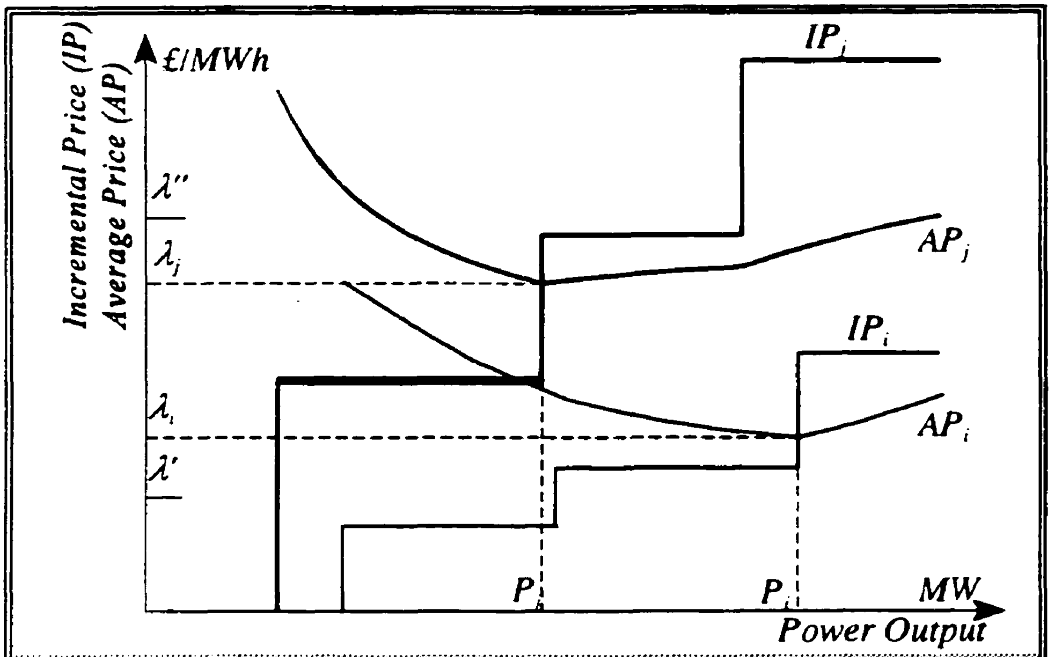

Figure 3.4 Average Cost, Incremental Cost vs Load

Chapter 4. Table A/B Method --- An Approach to Lower Consumer Payment

As shown in chapter 2, the derivation of the SMP needs two steps. First, the EWPP uses the GOAL program to generate preliminary unconstrained schedules, from which the winning bidders are selected. Then, the EWPP calculates the SMP, using the Table A/B method. Several questions arise from the above procedures. What is the optimum method to calculate the SMP? Does the GOAL program give the appropriate set of winning bidders in terms of pool payment minimization? What is the objective of the Table A/B method? What is the logic behind it? Are there any alternative approaches to replace the EWPP approach? These questions will be answered in this chapter.

This chapter is organized as follows. The mathematical model for the SMP calculation is first established in section 4.1. Then in section 4.2 the solution given by the EWPP GOAL program is compared with the exact solution given by the mathematical model. The Table A/B method is examined in section 4.3 to explain how the method achieves its objective. Section 4.4 shows how the Table A/B method is refined for some special circumstances. Later, the discussion is extended to consumer payment minimization with average cost pricing in section 4.5, which leads to the question of comparison between marginal cost pricing and average cost pricing. This question will be discussed further in chapter 5. Finally, two numerical simulations are presented in section 4.6 to illustrate the conclusions of section 4.2 and 4.3.

Before we start the discussion, several terms used in this chapter are defined. First, we define the no-load and start-up (NS) cost. The no-load costs refer to the fixed generation cost not related to the output level, and the start-up cost is the cost associated with generation start up. As shown in section 2.4, the genset bidding prices include three parts: a) start-up price in £ per start, b) no-load price in £ per hour and, c) energy production price or incremental price in £ per MWh. The first two cost elements are denoted by the term "NS cost." In addition, since the bidding prices can be considered as costs from the pool's point of view, the words "price" and "cost" are interchangeable in this chapter, referring to the bidding price.

4.1 Mathematic Framework for SMP Determination

One important function that the EWPP performs daily is to determine the SMP for every Settlement Period Duration (SPD). Mathematically, this function can be formulated as an optimization problem whose objective is to minimize the total pool payment, subject to several constraints. Besides the physical constraints shown in equation 3.2, the EWPP must also satisfy an economic constraint, namely, the payment adequacy constraint (PAC). This constraint guarantees that the winning bidders receives a total payment at least as high as specified in the offer files over the whole scheduled horizon.

The EWPP pays all winning bidders one price, the SMP. Therefore, how to calculate the SMP is very important for pool payment minimization. As shown in chapter 2, the SMP is the highest Genset Price (GP) from those gensets labelled as flexible. The GP consists of two elements, which are the incremental cost corresponding to the output level, the price element related to the NS cost. The first element, the incremental cost, indicates that the EWPP employs the incremental cost pricing policy. The second element is included in the GP to satisfy the payment adequacy constraint since the average price of some gensets may always be greater than their incremental price.

It should be noted that the PAC ensures all winning bidders get enough reimbursement to recover their cost during the entire scheduled horizon. However, the PAC does not specify that the cost incurred during a period must be paid back during the same period. Therefore, how to allocate the total NS cost during the whole schedule horizon becomes a problem. To solve this problem, a new optimization variable, NS, the NS cost allocation variable, is then introduced into the optimization problem.

Summarizing the above ideas, the SMP determination (SMPD) problem can be formulated as:

$$\begin{aligned} &\underset{U_{i,j},\, P_{i,j},\, NS_{i,j}}{Min} \quad \sum_{j=1}^{T} SMP_j \times P_{d_j} \\ &SMP_j = \underset{i}{Max}\ (GP_{i,j} \times U_{i,j}) \\ &GP_{i,j} = IC_{i,j}(P_{i,j}) + \frac{NS_{i,j}}{P_{i,j} \times \Delta T} \end{aligned} \tag{4.1}$$

Subject to:

$$\sum_{i=1}^{n} U_{i,j} P_{i,j} = P_{d_j} \qquad \textit{for all period } j \tag{4.2}$$

$$P_i^{\min} \le P_{i,j} \le P_i^{\max} \qquad \textit{for all period } j \tag{4.3}$$

$$\begin{aligned} \sum_{j=1}^{T} NS_{i,j} = &\sum_{j=1}^{T} U_{i,j} N_i + \\ &\sum_{j=0}^{T-1} (U_{i,j+1} - U_{i,j})\, U_{i,j+1}\, S_i \qquad \textit{for all genset } i \end{aligned} \tag{4.4}$$

where subscript i and j refer to genset i and schedule period j; $U_{i,j}$ is the UC variable; $P_{i,j}$ is the scheduled generation variable; $NS_{i,j}$ is the NS cost allocation variable; T is the number of the schedule periods; $GP_{i,j}$ is the genset price; P_{d_j} is the system load; $IC_{i,j}$ is the incremental price corresponding to $P_{i,j}$; ΔT is the schedule period duration, which is a half hour in the EWPP; P_i^{min} and P_i^{max} are the genset output limits; N_i is the no-load cost; S_i is the start-up cost; both N_i and S_i are specified in the offer file of genset i. The constraint expressed in equation 4.4 ensures that the NS cost will be recovered during the whole schedule period.

The SMP determination problem defined by (4.1) is a highly complex integer minimax optimization problem. To simplify the computation, the EWPP divides the problem into two subproblems, and uses heuristic approaches to solve them. The first subproblem is to select the winning bidders (SWB) and to allocate generation to each winning bidder, and the second is to calculate the SMP. Does this simplified approach give a good solution close to the exact optimum solution? This question

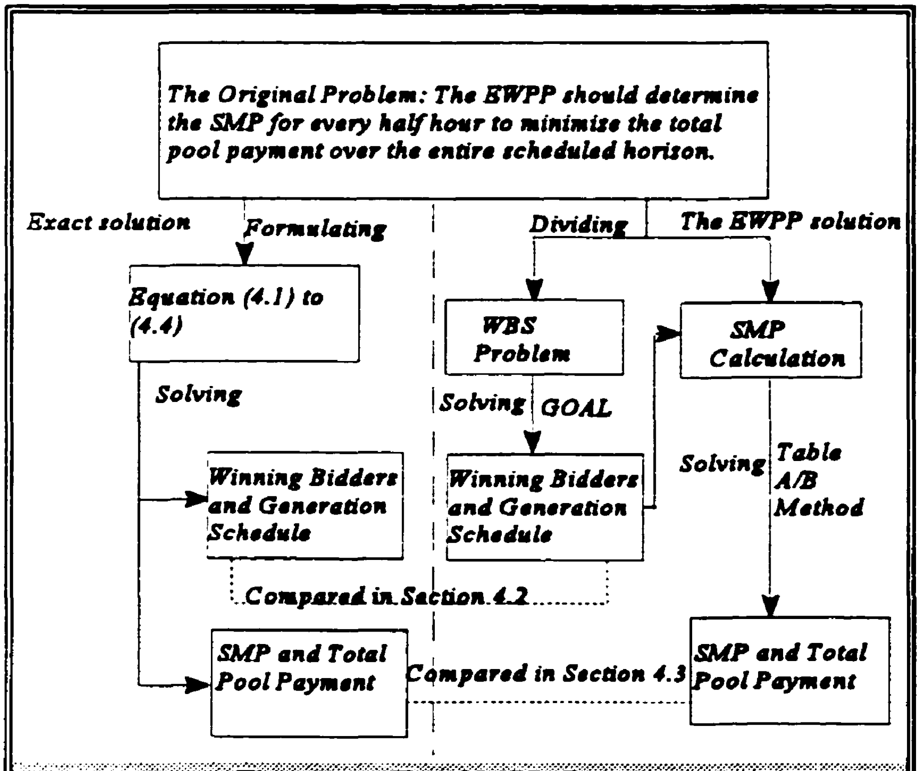

Figure 4.1 The SMPD Problem

will be answered in following sections. The exact solution is compared with the solution of the first subproblem and the second subproblem in section 4.2 and 4.3 (see figure 4.1). The comparisons show that the simplified approach gives a solution quiet close to the exact solution.

4.2 Selection of the Winner Bidders

To solve the SWB problem, the EWPP uses the GOAL program to generate preliminary schedules, from which the winning bidders can be selected.

Essentially, the GOAL program solves an UC problem, whose objective is to minimize the generation price, that is, $\sum_j \sum_i U_{ij} C_i(P_{ij})$. This objective does not necessarily coincide with the objective of the SMP determination problem, which is to minimize the total pool payment, in other words, $\sum_j SMP_j P_{d_j}$. Thus, the EWPP is supposed to solve a given problem (SMPD problem), but it solves another (SWB problem) instead. Do these two problems have the same solution? If the solutions of the two problems are different, how large is the difference? To answer these questions, we analyse two circumstances, namely, a static example, the other dynamic.

Static Example:

First, let's consider the static case, that is, to compare the solutions of the two problems in one period. As shown in chapter 3, the SWB probiem is solved through a modified merit-order-list approach. In this approach, the generation capacities are committed in increasing order of the incremental price or Minimum Heat Rate (MHR) until the system load, P_d, is met. Let us define the corresponding incremental price or MHR as the system price (SP). In essence, the SP is the minimum possible price whose cumulative associated generation is equal to the system load. Therefore, the SP equals the system incremental price resulting from the SMP determination problem. In the static case, the winning bidders and the generations allocated to each winning bidder resulting from the two problems are equal.

Dynamic Example:

Then, we analyse the dynamic case, that is, to compare the solution of the two problems over more than one period. Without considering the NS cost, the two problems also give the same solutions. However, when we take the NS cost into consideration, the solutions given by the two problems might be different. The following gives an intuitive understanding of this conclusion through an example.

Suppose the system load is 800 MW during period 1 and 1000 MW during period 2. A cheap genset produces 600 MW, supplying the base load. The remaining load, 200 MW in period 1 and 400 MW in period 2, is to be supplied by two other gensets in competition with each other, G1 and G2. Assume the bid price is $A + BP_1$ for G1 and is $C + DP_2$ for G2. Let the start-up prices of both gensets be very high, which means that only either G1 or G2 will be selected for both periods. If the total generation cost of G1 over the two periods is less than that of G2, that is, $\sum_{j=1,2} C_1(P_{1,j}) \le \sum_{j=1,2} C_2(P_{2,j})$, G1 should be selected as the winning bidder according to the SWB solution. However, according to the SMPD solution, it is possible that the total pool payment of running G1 is greater than that of running G2, and therefore G2 should be selected. In this example, according to the SWB solution, the criteria for selecting G1 is $2A + (200 + 400)B < 2C + (200 + 400)D$, while the criteria is $(B + 2A/400) \times 1000 + 800B < (D + 2C/400) \times 1000 + 800D$ according to the SMPD solution. These two different selection criteria may result in different winner bidders. The essence of the above analysis can be summarized as follows. The most expensive winning bidder, the SMP taker, given by the SWB solution, is cheaper in total generation cost than to turn on other gensets. However, turning on this genset may result in higher total pool payment over the entire scheduled horizon than to turn on other gensets. Figure 4.2 illustrates the above analysis. Assume that A and C are fixed. If the variables B and D fall in the area below Line 1, G1 is the winning bidder according to the WBS solution; if the B and D fall into the area above Line 2, G2 is the winning bidder according to the SMPD solution. It is obvious that if B and D fall into the shaded area, the WBS and SMPD problem give different winning bidders.

From the above analysis, we see that the solutions given by the SWB and SMPD problems might be different. However, experience shows that this difference only happens to the SMP taker and its neighbouring gensets in the merit order list. Therefore, for large system, the exact and the EWPP solutions are quite close to each other.

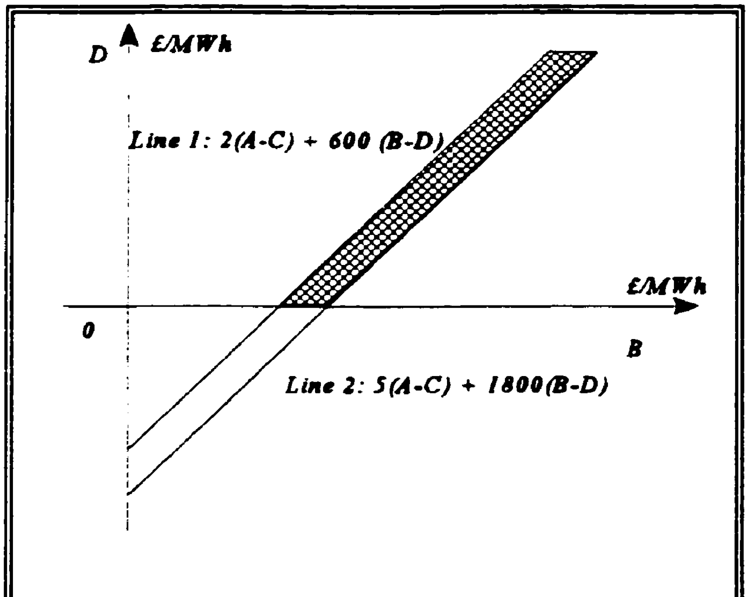

Figure 4.2 Comparison Between WBS and SMPD Solutions

4.3. Justification of Table A/B Method

The EWPP divides the SMPD problem into two subproblem, the SWB problem and the SMP calculation problem. It is shown in section 4.2 that the SWB problem gives a set of winning bidders which may be different from the exact solution of the SMPD problem. However, in practice, this difference is normally small. In this section, we are going to analyse the second subproblem, namely, the SMP calculation problem. First, the exact mathematic formulation is presented, then the heuristic method employed by the EWPP, the Table A/B method, is analyzed.

4.3.1 Formulation of the NS Redistribution Problem

Suppose the generation schedule has already been obtained through the GOAL program. This means that the optimization variables U_{ij} and P_{ij} in (4.1) are already known. Thus, what remains to be determined is the NS cost allocation variable, NS_{ij}. Note that this variable is optimized to total pool payment minimization, without affecting the generation schedule. This is done by redistributing the total amount of the NS costs (fixed by the U_{ij} and P_{ij}) over the entire time horizon. Then, the SMPD problem can be formulated as:

$$\begin{aligned} &\underset{NS_{i,j}}{Min} \sum_{j=1}^{T} SMP_j \times Pd_j \\ &SMP_j = \underset{i}{Max}\ (GP_{i,j} \times U_{i,j}) \\ &GP_{i,j} = IC_{i,j}(P_{i,j}) + \frac{NS_{i,j}}{P_{i,j} \times SPD} \end{aligned} \tag{4.5}$$

Subject to:

$$\sum_{j=1}^{T} NS_{i,j} = \sum_{j=1}^{T} U_{i,j} N_i + \sum_{j=0}^{T-1} (U_{i,j-1} - U_{i,j}) U_{i,j-1} S_i \quad \textit{for all genset } i \tag{4.6}$$

The problem formulated in (4.5), although much easier to solve than (4.1), is still a minimax optimization problem with high computational complexity. Nevertheless, it can be argued that the solution of (4.5) has certain tendencies: (i) From the GP definition equation in (4.5), one can see that to avoid high GP value during off-peak period, that is, low value of P_{ij}, the optimization variable NS_{ij}, tends to zero; (ii) On the other hand, during the peak load periods, where P_{ij} is high, NS_{ij} can be non-zero without excessive increase of the GP. To solve (4.5), the EWPP uses a simplified heuristic approach called the Table A/B method to redistribute the total NS cost. The Table A/B method allocates the total NS costs evenly among all Table A periods (see section 2.5 and 2.7), which are basically peak periods. This method allocates zero NS cost to Table B (off-peak) periods. In most circumstances, this method ensures that the SMP during the peak load period is higher than the SMP during the off-peak load period. It also gives lower pool payments than those resulting from allocating no-load evenly through the schedule horizon and allocating the start-up cost to the interval when the genset is turned on (uniform allocation method) [4-1].

4.3.2 Comparison of Table A/B Method and Uniform Allocation Method

It was shown in section 4.1 that the EWPP divides the SMP determination problem into two subproblems, namely, the SWB problem and the SMP calculation problem. After solving the SWB problem through the GOAL program, the EWPP uses the Table A/B method to calculate the SMP. However, compared to the uniform allocation method, the Table A/B method is complex and indirect. Why does the EWPP choose this method instead of the more natural uniform allocation method? To answer this question, a comparison between the two methods is required.

In this section, therefore, the total pool payment resulting from the Table A/B NS allocation mechanism (method 1) is compared with the payment resulting from the uniform allocation method (method 2). The payments are compared during the Table A and B periods separately. For simplicity, let us consider the case of only no-load cost allocation (without start-up cost allocation), and suppose that the offer bidding price consists of only one segment: $C(P_i) = N_i + b_i P_i$, where N_i is the no-load cost and b_i is the incremental price.

First, let us compare the payments during the Table A periods. During the Table A period τ, the SMP resulting from method 1 (SMP_1^τ) is greater than or equal to the SMP given by method 2 (SMP_2^τ). Since this is true for every τ, the total pool payment under the Table A/B method is also greater than or equal to the payment under method 2. Suppose $GP_{1,i}^\tau$ is the genset price resulting from method 1 for genset i during period τ, and $GP_{2,i}^\tau$ is the genset price resulting from method 2. The difference between the genset price and SMP_2^τ can be defined as:

$$\Delta SMP_i^\tau = GP_{1,i}^\tau - SMP_2^\tau = \frac{\sum_{t \in T_A + T_B} U_i^t N_i^t}{\sum_{t \in T_A} U_i^t P_i^t} + b_i - SMP_2^\tau \qquad (4.7)$$

where the Table A periods set is T_A, and the Table B periods set is T_B.

Generally, SMP_2^τ is relatively high since some expensive gensets are turned on during the peak load periods. Hence, ΔSMP_i^τ is less than zero for most gensets. Normally, the difference between $GP_{1,i}^\tau$ and $GP_{2,i}^\tau$ for an expensive genset i is very small since genset i only operates for limited periods, and may only operate during the Table A periods. Therefore, in those cases when ΔSMP_i^τ is greater than zero, it is very small.

Moreover, the difference between SMP_1^τ and SMP_2^τ can be expressed as:

$$\Delta SMP^\tau = SMP_1^\tau - SMP_2^\tau = \max(0, \max_i(\Delta SMP_i^\tau)) \tag{4.8}$$

The total payments difference between method 1 and 2 during all Table A periods is:

$$\Delta PAY_A = \sum_{t\in T_A} \Delta SMP^t P_d^t = \sum_{t\in T_A} \max(0, \max_i(\Delta SMP_i^t)) P_d^t \tag{4.9}$$

Since ΔSMP_i^t is either less than zero or very small, the difference of the total payments resulting from the two different methods, ΔPAY_A, is small during Table A periods.

Next, we made comparison during the Table B periods. Since in method 1, all NS costs are allocated to Table A periods, the total payment resulting from method 1 is less than or equal to the total payments given by method 2. The pool payment difference over entire Table B periods consists of two elements, which are the no-load costs during Table B period and the difference caused by incremental price differences. Normally, the second item is trivial. The difference can be formulated as:

$$\Delta PAY_B = -\sum_{t\in T_B} \max_i \left(\frac{U_i^t N_i^t}{U_i^t P_i^t} + b_i\right) P_d^t + \sum_{t\in T_B} \max_i (b_i)\, P_d^t \le 0 \qquad (4.10)$$

Generally, $|\Delta PAY_A|$ is very small, while $|\Delta PAY_B|$ is relatively large since gensets turned on during Table A periods are also likely to be turned on during Table B periods. That explains why the Table A/B method results in lower total pool payment than the one resulting from the uniform allocation method. A numerical simulation is presented in section 4.6.

4.4 Refinement of Table A/B Method under Special Circumstances

As mentioned earlier, the Table A/B method predetermines the NS cost allocation by basically allocating the NS costs to peak load periods. This method is simple, but must be refined for some special circumstances. One is when a genset is turned on and off during Table B periods, and it never gets a chance to operate during the Table A period. Therefore, the genset does not get NS cost reimbursement through the Table A/B method. In this case, a side payment must be made to satisfy the payment adequacy constraint.

Another special case is that of a genset set to pulse operation, that is, to start during one period and shut down during the next period. (See Figure 4.3)

From equation 2.1, we know that the genset price (GP) is very high in this case because the scheduled generation, that is, the shaded triangle area in figure 4.1, is

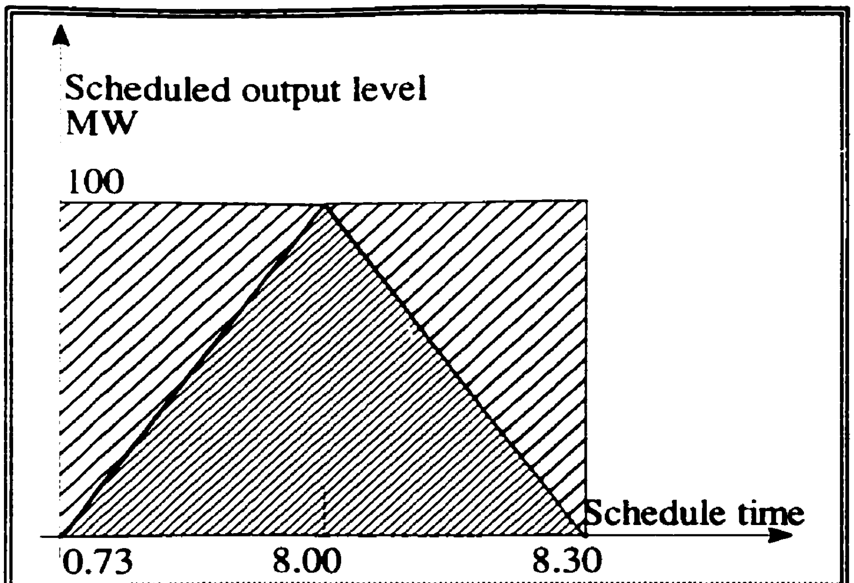

Figure 4.3 Genset Pulse Operation

small. Since the SMP is the highest GP, which likely is the GP of the pulse operation genset as shown in figure 4.3, the GP of the genset probably leads to a high SMP and eventually to a high pool payment. To avoid this, the EWPP uses the genset offered available energy, i.e., the rectangle instead of the triangle area in figure 4.1 to derive the genset price. The genset receives a side payment to cover its cost.

4.5. Pool Payment Minimization with Average Cost Pricing

One of the constraints that the EWPP face is the payment adequacy constraint, which guarantees that the winning bidders receive total payment at least as high as specified in the offer files. On the other hand, the EWPP also should minimize the cost to the pool. These are the two faces of one coin. The Table A/B method is an approach which successfully decreases the pool payment while satisfying the payment adequacy constraint. In this section, we look further other approaches for pool payment minimization.

The SMP is the highest Genset Price (GP) from those gensets labelled flexible. The GP includes two parts, which are the incremental price and the price element corresponding to the NS cost allocation. It has been proposed that if we replace the first price element in GP, that is, the incremental price, with the corresponding average price with zero NS cost allocation, the total pool payment may be lower than the one resulting from the EWPP method. This idea is due to S. Hao in [4.1], and can be formulated as follows:

$$\min_{U_{i,j},\, P_{i,j},\, NS_{i,j}} \sum_{j=1}^{T} SAP_j \times Pd_j$$

$$SAP_j = \max_i \left(GP_{i,j} \times U_{i,j}\right) \tag{4.11}$$

$$GP_{i,j} = AC_{i,j}(P_{i,j}) + \frac{NS_{i,j}}{P_{i,j} \times \Delta T}$$

Subject to:

$$\sum_{i=1}^{n} U_{i,j} P_{i,j} = Pd_j \qquad \textit{for all period } j \tag{4.12}$$

$$P_i^{\min} \le P_{i,j} \le P_i^{\max} \qquad \textit{for all period } j \tag{4.13}$$

$$\sum_{j=1}^{T} NS_{i,j} = \sum_{j=1}^{T} U_{i,j} N_i + \sum_{j=0}^{T-1} \left(U_{i,j+1} - U_{i,j}\right) U_{i,j+1} S_i \qquad \textit{for all genset } i \tag{4.14}$$

where SAP_j called the system average price is the price in £/Mwh paid by the pool to each winning bidder; $AC_{i,j}$ is the average price corresponding to $P_{i,j}$ with zero NS cost allocation. Note, the only difference between (4.11) and the general formula of the EWPP problem in (4.1) is in the derivation of the GP. SAP is the counterpart of the SMP in the EWPP approach. The expectation of this approach is that SAP will be less than SMP.

Since each genset scheduled on will receive the highest GP (average price and the price element associated with the NS cost allocation) among all winning bidders, the payment adequacy constraint is automatically satisfied. Moreover, this method induces lower pool payment than the EWPP approach because the average price is always less than or equal to the incremental price for those gensets that have convex cost curves and zero NS cost allocation. As like the EWPP method in (4.5), the presented approach allocates most of the NS costs to the peak periods. Therefore, the price in peak periods is higher than the price during off-peak periods. The question is whether the method described during equation 4.12 (method 1) is better than the method adopted by the EWPP (method 2). To answer this question, we should compare the average cost pricing policy (method 1) and the incremental pricing policy (method 2).

In a pure competitive environment, that is, one where each market participant does not have enough market power to influence the market price, if the bidders employ the same bidding strategy, it is true that method 1 is better than method 2 in payment minimization. However, as it will be shown in chapter 5, the equal bidding strategy assumption does not hold since an "invisible hand," the market forces, may induce bidders to adopt different strategies. Therefore, the statement " rule 1 is better than rule 2" is problematic. The comparison between the average cost pricing and the incremental pricing is a big topic and it will be presented in more detail in chapter 5.

In addition, under a duopoly environment, like the EWPP, where there are several big players who have enough market power to affect the market clearing price, method 1 is more vulnerable to bidders' collusion and gaming behaviour than method 2. A detailed discussion will also be presented in chapter 5.

4.6 Numerical Simulation

4.6.1 Numerical Simulation for Section 4.2

Section 4.2 shows that the solutions given by the SMPD and SWB problems might be different. The following simulation demonstrates the above result.

We use a three-genset system as an example. Suppose the cost function of the gensets are formulated as $C_i(P_i) = a_i + b_i \times P_i$, and the start-up cost is S_i.

The gensets bidding prices are shown in table 4.1 and the system load is shown in table 4.2. The SWB solution is given in table 4.3. The solution given by the SMPD problem is shown in table 4.4. The pool payments given by different calculation methods are shown in table 4.5.

Table 4.1 The Genset Bidding Prices

	a_i (£/h)	b_i (£/MWh)	P^{min} (MW)	P^{max} (MW)	S_i (£/Start)
G0	1000	60	200	600	10000
G1	2000	75	100	400	10000
G2	3600	70	100	400	10000

Table 4.2 The System Load During 0 a.m. to 2 a.m.

Time	0 -- 1	1 -- 2

Table 4.2 The System Load During 0 a.m. to 2 a.m.		
Load (MW)	1000	800

Table 4.3 The Generation Schedule Given by the SWB Solution		
Time	0 -- 1	1 -- 2
G0 (MW)	600	600
G1 (MW)	400	200
G2 (MW)	0	0

Table 4.4 The Generation Schedule Given by the SMPD Solution		
Time	0 -- 1	1 -- 2
G0 (MW)	600	600
G1 (MW)	0	0
G2 (MW)	400	200

Table 4.5 The Pool Payment Resulting from Different Methods (£)		
	SWB solution	SMPD solution
Optimal NS allocation	145000	144000
Table A/B Method	145000	NIL
Even NS allocation	173000	NIL

In this example, the criteria for selecting G1 according to the SWB solution is $2A + (200 + 400)B < 2C + (200 + 400)D$, which is true in this example as

4900 < 114000. Alternatively, the criteria for selecting G2 according to the SMPD solution is $(B + 2A/400) \times 1000 + 800B > (D + 2C/400) \times 1000 + 800D$ which is also true in this example as 145000 > 144000. These two different selection criteria result in different winner bidders.

4.6.2 Numerical Simulation for Section 4.3

Section 4.3 shows that the total pool payment resulting from the uniform allocation method is higher than that resulting from the Table A/B method. The following example demonstrates the result. We use a 4-gensets system as an example. Each genset submits a bidding price in the form of $C_i(P_i) = NL_i + b_i \times P_i$.

The gensets bidding prices are shown in table 4.6 and the system load is shown in table 4.7. The Table A/B classification is shown in table 4.8. The generation schedule given by the UC solution is shown in table 4.9. Table 4.10 and 4.11 shows the system marginal price resulting from the Table A/B method and uniform allocation method. Table 4.12 shows the total pool payment resulting from the two methods. Table 4.13 shows the value of ΔPAY_A and ΔPAY_B in equation 4.9 and 4.10.

Table 4.6 Gensets Bidding Prices

	G1	G2	G3	G4
NL (£/h)	2400	1200	600	1200
b (£/MWh)	36.0	39.0	40.0	40.0
P^{min} (MW)	150	100	50	100
P^{max} (MW)	600	400	200	400

Table 4.7 The System Load During 0 a.m. to 12 a.m.

Time	0 -- 4	4 --- 7	7 --- 9	9 --- 11	11 --- 12
Load (MW)	600	800	1200	800	600

Table 4.8 Table A/B Period Classification

Period	0 - 1	1 - 2	2 - 3	3 - 4	4 - 5	5 - 6	6 - 7	7 - 8	8 - 9	9- 10	10- 11	11- 12
Classification	B	B	B	B	A	A	A	A	A	A	A	B

Table 4.9 Generation Schedule (in MW)

	0 - 1	1 - 2	2 - 3	3 - 4	4 - 5	5 - 6	6 - 7	7 - 8	8 - 9	9- 10	10- 11	11- 12
G1	600	600	600	600	600	600	600	600	600	600	600	600
G2	0	0	0	0	0	0	0	200	200	0	0	0
G3	0	0	0	0	400	400	400	400	400	400	400	0
G4	0	0	0	0	0	0	0	0	0	0	0	0

Table 4.10 System Marginal Price Derived from Table A/B Method (£/MWh)

0 - 1	1 - 2	2 - 3	3 - 4	4 - 5	5 - 6	6 - 7	7 - 8	8 - 9	9-10	10-11	11-12
36.0	36.0	36.0	36.0	42.9	42.9	42.9	43.0	43.0	42.9	42.9	36.0

Table 4.11 System Marginal Price Derived from Uniform Allocation Method (£/MWh)											
0 - 1	1 - 2	2 - 3	3 - 4	4 - 5	5 - 6	6 - 7	7 - 8	8 - 9	9-10	10-11	11-12
40.0	40.0	40.0	40.0	42.0	42.0	42.0	43.0	43.0	42.0	42.0	40.0

Table 4.12 The Total Payment (£)	
Table A/B Method	Even Allocation Method
365600	374000

Table 4.13 ΔPAY_A and ΔPAY_B	
ΔPAY_A (£)	ΔPAY_B (£)
3600	-12000

Tables 4.10 and 4.11 show the SMP under two methods. It shows that the SMP resulting from Table A/B method is higher than or equal to the SMP resulting from uniform allocation method during the periods classified as Table A, and is lower than the SMP resulting from the uniform allocation method during the periods classified as Table B.

Because of the uniform pricing, every winning bidder receives the highest system incremental price and the NS cost allocation. The gensets whose marginal price plus NS cost allocation is lower than the SMP can be jestingly considered as "free loaders." The Table A /B method excludes the chances for "free loaders" during Table B periods while the uniform allocation method does not. That is another explanation that the Table A/B method results in lower total pool payment compared with the uniform allocation method.

Chapter 5. Marginal Versus Average Cost Pricing

Basically, the EWPP employs a marginal cost pricing policy. It was shown in the last chapter that paying the system average price (SAP) instead of the SMP to all winning bidders will decrease the total pool payment if bidders use same bidding strategies under the two different rules. In other words, adopting the average cost pricing policy will result in a lower pool payment. In this chapter, it will be shown that under these two different methods, bidders will tend to use different bidding strategies so that the total pool payment under average cost pricing may in fact be higher than that under marginal cost pricing.

This chapter is arranged as follows. In section 5.1, the term "bidding strategy" is defined and the objective of bidders is formulated. Then in section 5.2, the bidding behaviour under marginal and average cost pricing policies are analysed and compared. The reason for using marginal cost pricing policy is also presented in this section. It will be shown that under average policy, bidders tend to restrict their offered generation availabilities when compared with the marginal cost pricing. The restriction of the availability offer will increase the Capacity Element (CE) payment and facilitate the gaming behaviour of those who have notable market power. In section 5.3, the discussion is extended beyond the poolco model to the bilateral contract negotiation model. We use an example to show that by setting the price between the average and the marginal cost, a genset can make more profit by gaining more market shares. On the other hand, decrease in price by one genset will induce a price decrease by the others, leading to a price war. In section 5.4, we use Game theory to analyse the price war phenomenon. We also apply our conclusion obtained from the bilateral negotiation model to the poolco model to show that the gensets who make zero or very small profit under average cost pricing will increase their bids, and finally increase the total pool payment.

5.1 Bidding Strategies and the Objective of Bidders

The bidding strategy is the particular plan of one bidder to make maximum profit from the auctions. There are many possible bidding strategies. For example, one bidder may offer a price according to his / her cost, or he or she may bid according to his / her experience in previous auctions. In the EWPP, a bidder, that is a genset, has two weapons to compete with other pool participants, bidding prices and the amount of power he or she wishes to sell. Bidding strategy refers to the strategic use of these two weapons. In other words, a bidding strategy helps the bidder decide how to offer prices and generation availability.

Normally, there are two criteria that a bidder must comply within selecting the bidding strategies. First, a bidder must maximize his / her profit. Second, if a bidder wins the auction (one or a series auctions), that is, if a genset is selected to supply the load, the generation cost must be recovered by the revenue. It is possible to approximately formulate the above criteria as follows. Ignoring the Capacity Element (CE) as well as the uplift and using uniform pricing, the bidding strategy selection problem for bidder I become:

$$\underset{GA_j,\ BP_j(P)}{Max} \quad \sum_j U_{i,j}\ [MCP_j\ P_{i,j} - C_i(P_{i,j})] \tag{5.1}$$

subject to,

$$\sum_{j} U_{i,j} \, [SMP_j \, P_{i,j} - C(P_{i,j})] \geq 0 \qquad (5.2)$$

where subscript i and j refer to bidder i and period j respectively; GA representes the Genset Availability optimization variable; BP, the Bidding Price, is a function of the output power P and can be specified by eight parameters in the EWPP (see section 2.4; U and P are the unit commitment and generation variables which can be obtained from the preliminary generation schedule made by the EWPP according to the load forecasting and all bids; MCP is the market clearing price, that is, the uniform price each winning bidder receives from the pool; MCP can be the system marginal price (SMP) or the System Average Price (SAP), depending on which pricing policy is adopted; Finally, $C(P)$ is the cost function of bidder I.

An auction system like the EWPP's is a competitive system, therefore, a bidder cannot completely control his / her profit. Every bidder faces two kind of restraints, physical and economic restraints. The physical restraints refer to the firm's maximum output level and other power system constraints. The economic ones mean that amount of power a bidder can sell to the pool is not determined by bidder himself / herself, but the pool. How the pool selects the winning bidder and how it calculates the MCP will definitely affect the bidders' choice of bidding strategies.

5.2 Bidding Strategy Under Average and Marginal Cost Pricing for Pure Competitive Environment

In this section, the average and marginal cost pricing are defined and their properties presented. Finally, the bidding strategies likely adopted by bidders under these two policies are analysed. In this section, we only consider the case of a pure competitive market in where all market participants are so small that their individual influence on the MCP can be neglected. We conclude that under average cost pricing, the bidders may restrain their maximum generation availability, that is, the gensets may not offer their maximum generation.

5.2.1 Definition of Average and Marginal Cost Pricing

If the cost function of genset i is $C_i(P_i)$, under the average cost pricing the genset is paid at the rate of SAP, $\sum_i C_i(P_i)\ /\ \sum_i P_i$, while under the marginal cost pricing the genset is paid at the rate of $d\,C_i(P_i)\ /\ dP_i$ or SMP, $d\sum_i C_i(P_i)/d\sum_i P_i$. In the uniform auction systems, every winning bidder receives SAP under the average cost pricing, in contrast to receiving SMP under the marginal cost pricing (see section 4.5).

5.5.2 Properties of Average and Marginal Cost Pricing

Property 1. Average cost pricing guarantees that the generation cost is covered through the price. This property is obvious.

Property 2. For the EWPP, Marginal cost pricing also guarantees that the generation cost is covered through the price. Since in the EWPP, winning bidders who are selected to supply the load only work at the status where the average cost is less than the marginal cost, receiving the marginal cost price ensures that the winning bidders can make profit.

Property 3. Marginal cost pricing also guarantees that the greater the output, the greater the profit. Proof of the above property is as follows.

Supposing Π is the profit, under marginal cost pricing,

$$\Pi = \frac{dC_i(P_i)}{dP_i} \times P_i - C_i(P_i) \tag{5.3}$$

The first derivative of Π over P_i is:

$$\frac{d\Pi}{dP_i} = \frac{d^2C(P_i)}{d^2P_i} \tag{5.4}$$

If the first derivative of profit is greater than zero, the more a genset produces, the more profit it gains. When the cost function is a convex curve, equation 5.4 is always greater than zero. The Willans' Line defined in section 2.4 is an example of a convex cost curve.

5.2.3 Bidding Strategies Under the Two Pricing Policies in a Pure Competitive Environment

We first define a "pure competitive environment" as one where all market participants are sufficiently small so that their influences on the market clearing price (MCP) can be neglected, that is, any individual bid change does not affect the MCP. Another expression to describe this environment is that each player is a pure MCP taker.

It has been proved by David Finley and George Gross in [5-1] that under uniform marginal cost pricing rules and in a pure competitive environment the optimal bidding strategy for an individual bidder is to bid at its generation cost and at its maximum availability.

Here is proven that under uniform average cost pricing rules and a pure competitive environment, the optimal bidding strategy is also to bid at generation cost. This result can be proved simply by the contradiction.

First, suppose that the bidder bids higher than its cost. Since bidding higher than cost does not affect its generation cost and the MCP, the profit is also not increased compared to bidding at cost. Thus, bidding higher than cost only increases the risk of not being successful in the auction, that is, bidding higher than the generation cost only increases the probability of not being selected to supply load or being selected to supply less than desired. Alternatively, suppose the bidder bids lower than its cost. Since the MCP and generation cost is fixed, bidding lower than cost will not result in higher profit compared to bidding at cost. Thus, bidding lower than cost only increases the risk of losing money. Consequently, since either bidding higher or lower than cost both result in a negative impact on profit, the optimum bidding strategy is to bid at cost.

Under the uniform marginal cost pricing rules the optimal bidding strategy for an individual bidder is to bid at its maximum availability. However, under the average cost pricing policy, the optimal bidding strategy is not to bid at its maximum generation availability. The reason is that with marginal cost pricing the greater the output the greater the profit, while under average pricing the above property does not hold. To prove this statement, suppose the cost function of genset i is formulated as a piece-wise linear equation, and the minimal average price coincides with P_l, which is a value not equal to the maximum output, P^{max} (see figure 5.1). In the case that the MCP is lower than the average price corresponding to the maximum output level, AP^{max}, genset i is selected to supply the load at the output level of P^* if it bids at its maximum availability, P^{max}. Thus, since MCP equals the average cost at its output level P^*, genset i makes zero profit. However, if the genset offers an

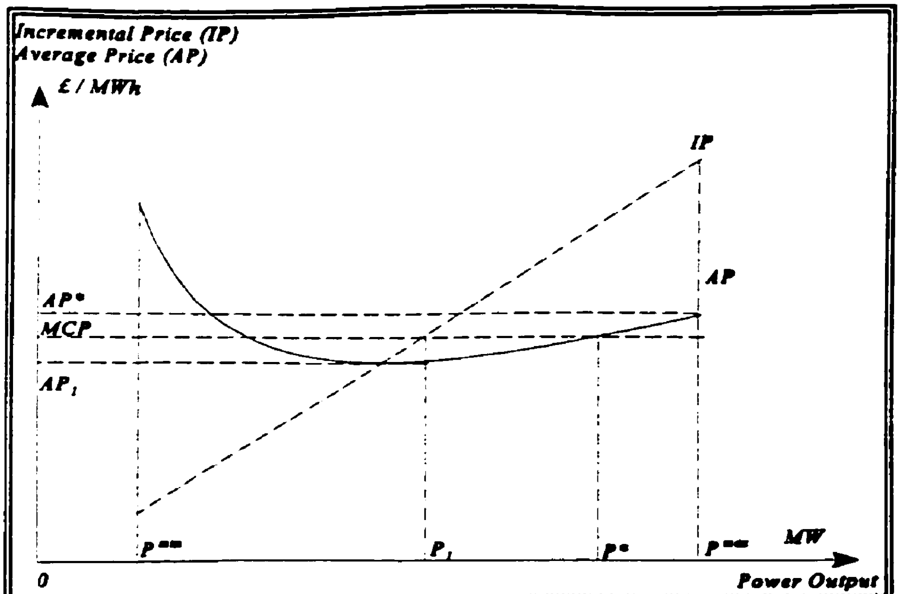

Figure 5.1 Bidding Strategy under the Average Cost Pricing (Quadratic Cost Function)

availability of P_l instead of P^{max}, it can still make a profit equal to $P_l \times (MCP - AP_l)$ as shown in figure 5.1. If the cost function is formulated as a piece-wise linear equation with zero NS cost allocation or as a quadratic, the bidder also does not bid its maximum availability in the circumstances mentioned above. Figure 5.2 and 5.3 illustrate the above statement. All legends in figures 5.2 and 5.3 are the same as 5.1.

The immediate impact of this optimum bidding strategy is that the total system available generation capacity is decreased, and therefore, system realizability deteriorates. The indirect impact is that prices will increase. As shown in section 2.7, the EWPP electricity price consists of four elements, namely, system marginal price (SMP), Capacity Element (CE), uplift, and transmission losses price. The CE is worked out by the NGC through a complex formula (see section 2.7). The basic idea is to pay more while the spare capacity, i.e. the system capacity less the demand, is

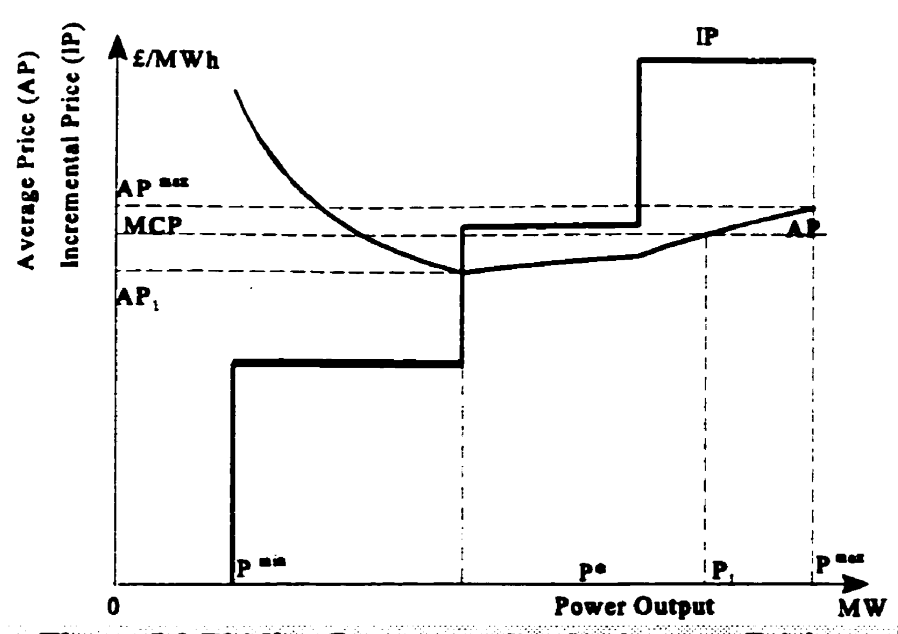

Figure 5.2 Bidding Strategy under the Average Pricing (Piece-wise Linear Cost Function with NS cost)

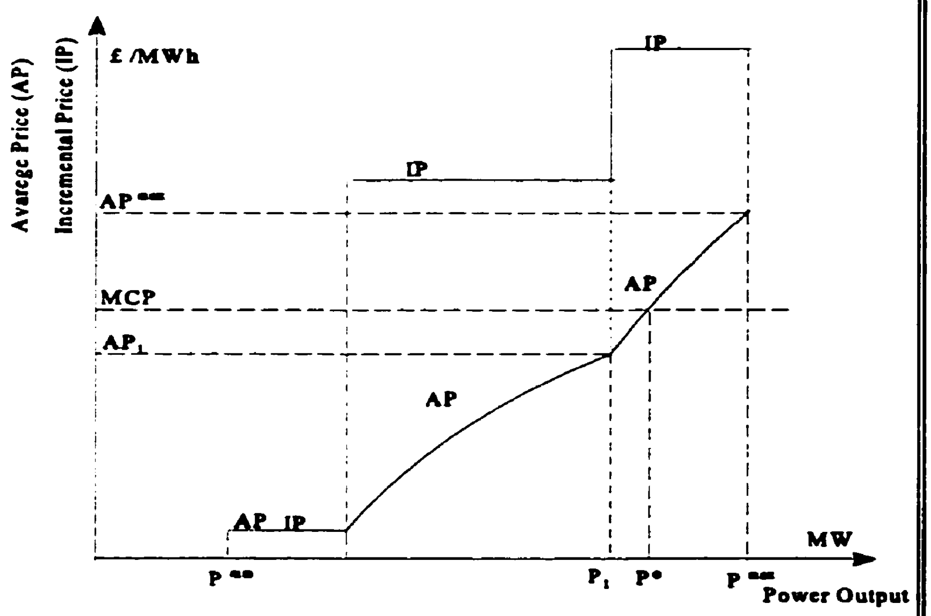

Figure 5.3 Bidding Strategy under the Average Pricing (Piece-wise Linear Cost function with Zero NS Allocation)

small and pay less when the spare capacity is large. Clearly, the less the system available generation capacity, the larger the CE

Hence, under uniform average cost pricing in a pure competitive environment, the system operates under a less reliable condition compared to uniform marginal cost pricing. In addition, because of the lower availability, the pool pays more CE prices to the bidders. In a duopoly environment where two market players have notable market power, things are even worse. Since bidders tend not to bid their maximum availabilities, duopolists have an even greater market share compared to the case under marginal cost pricing. Thus, gaming behaviour and collusion are more likely to take place.

In conclusion, the average pricing is not an appropriate method for the EWPP auction system. For example, the average cost pricing method proposed by Hao in [5-2] is not a realistic approach for the EWPP.

5.3 Bilateral Negotiation Contract Model

In this section, we extend our discussion to the bilateral contract negotiation model. It is well known that the marginal cost pricing is commonly used in the bilateral contract model. What is the logic behind it? If one market player decreases his / her price below the marginal cost, is it possible for him / her to get more profit? If he or she can make more profit by decreasing the price, what will the other players do? What is the market equilibrium? All these questions will be answered in this section, and the result will be applied to the poolco model in section 5.4.

5.3.1 The Logic behind the Marginal Cost Pricing

In a competitive market, the MCP usually is relatively stable for a certain period in a certain area. It is possible that some contracts are signed at the price below or above the MCP. However, if the market is transparent enough, the contract price will converge to the MCP in a long run. The MCP is the market price equilibrium. Ideally, each market player can be treated as an MCP price taker. What is left for each player to decide is the quantity of the contract. For example, in the electricity market, each genset must decide the amount of power it wishes to sell.

The objective of each individual player is to maximize his / her own profit, and can be approximately formulated as:

$$\underset{P_i}{Max}\,[MCP \times P_i - C(P_i)] \tag{5.5}$$

where MCP is the market clearing price, P_i is the quantity variable, and $C(P_i)$ is the cost function.

If MCP is fixed, the optimal output level P_i^* happens at:

$$MCP = \frac{d\,C(P_i)}{dP_i} \tag{5.6}$$

It means that the maximum profit can be gained when the genset produces P_i^* at where the marginal cost equals the MCP. That is the theoretical base of marginal cost pricing.

5.3.2 Gain More Profit by Decreasing the Price

If a genset charges the price between its average and marginal generation cost, it still can make a profit since the average cost pricing guarantees that all costs are recovered by the price. However, the only incentive for a genset to do so is to obtain more market shares so that it can make more profit. In this section, we give an example to show that a genset can gain more profit by decreasing its price. Nonetheless, this kind of behaviour will usually cause a price war and eventually punish the genset itself. This will be shown in section 5.3.3.

To illustrate that a genset can make more profit by decreasing its price, we use a small system consisting of one load, L1, and two gensets, G1 and G2, as an example. G1 and G2 have same generation cost function: $C(P_i) = a + bP_i + 0.5\,cP_i^2$. Suppose the load of L1 is fixed: $P_d = 2\,P_0$, and therefore, G1 and G2 both sell P_0 to L1 at the price $MC_0 = b + cP_0$. MC_0 is high enough to satisfy payment adequacy constraint (see section 4.2).

Suppose G1 is not satisfied with the profit it makes. It decreases its price between the average cost and marginal cost. Suppose it select to sell $P0 + \Delta P$ at the rate of PR_1. The marginal and the average cost at $P_0 + \Delta P$ are MC_1 and AC_1. The profit change of G1 resulting from the price change is (see figure 5.5):

$$\begin{aligned} \Delta Profit &= (PR_1 - MC_1)P_0 + PR_1\Delta P - \frac{MC_0\Delta P}{2} - \frac{MC_1\Delta P}{2} \\ &= (P_0 + \Delta P)(PR_1 - MC_0) - \frac{c}{2}(\Delta P)^2 \end{aligned} \tag{5.7}$$

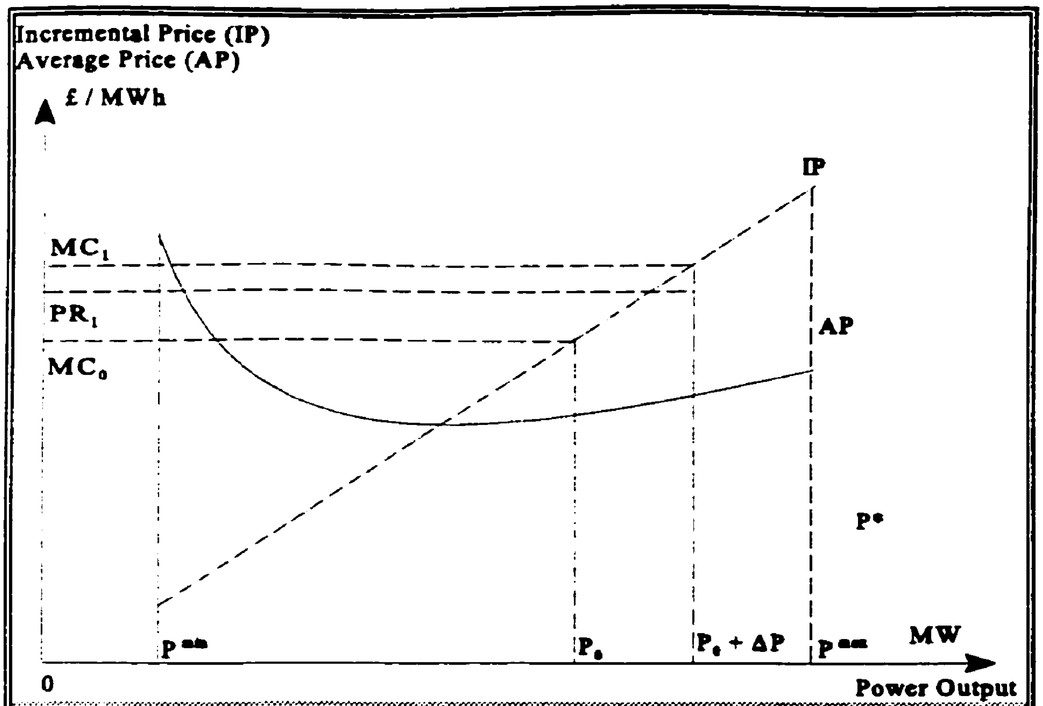

Figure 5.4 Making More Profit by Decreasing the Price

To make *ΔProfit* greater than zero, the following must hold.

$$PR_1 \geq PR_1^* = \frac{c(\Delta P)^2}{2(P_0 + \Delta P)} + MC_0 \tag{5.8}$$

It can be easily shown that PR_1^* is greater than AC_1, since the profit is greater than zero. It can be also proved that when $2P_0 + \Delta P \geq 0$, $PR_1^* \leq MC_1$.

The above shows that G1 can make more profit if it can sell $P0 + \Delta P$ at the price of PR_1 to L1. Now the problem is whether L1 wishes to buy ΔP more from G1 at that price. Based on the cost minimization theory, L1 will buy $P0 + \Delta P$ from G1 if it can save money. Since the load of L1 is fixed, if L1 buys $P0 + \Delta P$ from G1, it will buy $P0$ - ΔP from G2. The cost change, $\Delta\Pi$, for L1 is:

$$\Delta\Pi = [MC_0 + \frac{c(\Delta P)^2}{2(P_0+\Delta P)}][P_0+\Delta P] + [MC_0 - c\Delta P][P_0 - \Delta P] - 2MC_0P_0 \quad (5.9)$$

If $\Delta P \leq 2P_0/3$, $\Delta\Pi$ is less than zero, which means that L1 will buy more from G1. The above result is shown in figure 5.6. In the figure, P_0 equals 100 MW; in the shaded area, G1 can find a price and quantity which bring more profit to itself and L1. The shaded area is called beneficial area for L1 and G1.

However, the problem is not so simple. Please note that the profit of G2 decreases while L1 and G1 make more profit. Will G2 be satisfied? What will G2 do next? Is above status stable? Is there any mechanism preventing L1 from decreasing its price below the marginal cost?

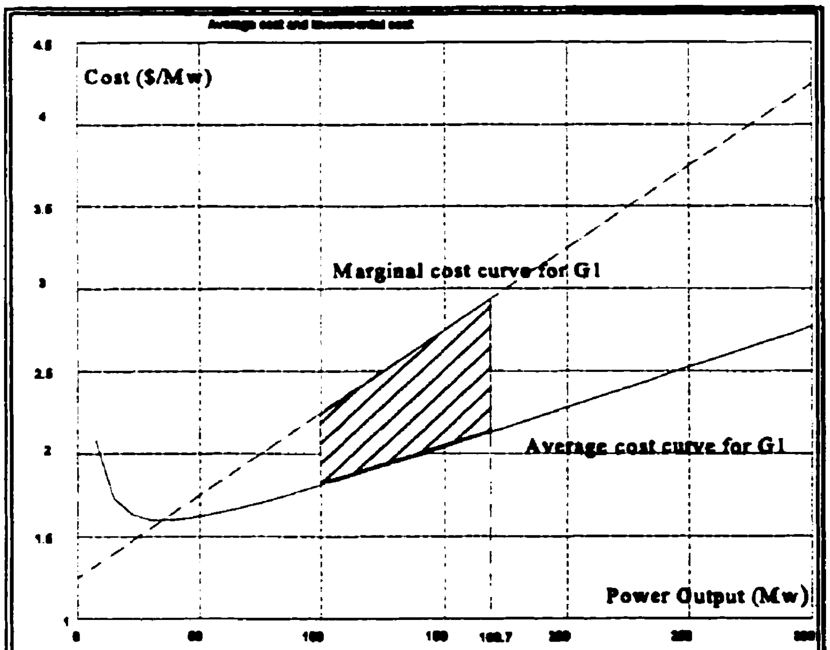

Figure 5.5 Beneficial Area

It is clear that G2 will not be satisfied with the condition when G1 decreases its price. Most likely G2 will also decrease its price. Consequently, both G1 and G2 make less profit compared to the initial condition. This situation is known as price war. In next subsections, we are going to use game theory to analyse price war, and answer the questions in last paragraph. Game theory is introduced in section 5.3.4, and applied to the bilateral contract model in section 5.3.5.

5.3.3. Can a Genset Gain More Profit by Increasing its Price above the Marginal Cost?

Alternatively, can G1 gain more profit by increasing price above the marginal cost? Suppose G1 increase its price to PR_2 and sell P_0 - ΔP to L1. The profit change of G1 compared to the initial condition is:

$$\begin{aligned} \Delta Profit &= (PR_2 - MC_1)P_0 - PR_2\Delta P + \frac{MC_0\Delta P}{2} + \frac{MC_1\Delta P}{2} \\ &= (P_0 - \Delta P)(PR_2 - MC_0) - \frac{c}{2}(\Delta P)^2 \end{aligned} \tag{5.9}$$

To make sure that $\Delta profit$ is greater than zero, the following must hold.

$$PR_2 \geq PR_2^* = \frac{c(\Delta P)^2}{2(P_0 - \Delta P)} + MC_0 \tag{5.10}$$

Equation 5.10 shows that to make more profit, the genset should increase its price not only above the marginal cost at P_0 - ΔP, but also above the marginal cost at P_0. Now the question is that whether L1 wishes to accept the price change.

Based on the cost minimization theory, L1 will buy P_0 - ΔP from G1 if it can save money. Since the load of L1 is fixed, if L1 buy P_0 - ΔP from G1, it will buy P_0 + ΔP from G2. The cost change, $\Delta\Pi$, for L1 is:

$$\Delta\Pi = [MC_0 + \frac{c(\Delta P)^2}{2(P_0 - \Delta P)}][P_0 - \Delta P] + [MC_0 + c\Delta P][P_0 + \Delta P] - 2MC_0 P_0 \quad (5.11)$$

$\Delta\Pi$ is always greater than zero, which means that L1 will not accept the price change. If the market is competitive, that is, L1 has other choices, L1 will likely buy electricity from other suppliers.

Therefore, in a competitive environment, increasing the price above the marginal cost usually will not bring more profit unless a genset have a very low cost curve. If a genset's generation cost is very low, the genset does not face a competitive market any more since there is no price competitor for the genset. Therefore, this genset can increase its price above marginal cost.

5.3.4 Game Theory

Game theory is a theory of rational behaviour of people with nonidentical interests. The term "game" refers to a situation defined by several "rules", and the term "play" refers to the particular occurrence of a game [5-3]. The term "strategy" refers to how a rational player behaves under a specific rule. In another word, the game theory can be defined as a theory concerned with the general analysis of strategic interaction. The area of game theory application extends considerably beyond games in usual sense; it includes, for example, economics, politics, and war. The EWPP auction system can be considered as a game under a rule, the Settlement Agreement, and the electricity generation utilities can be treated as players of the game.

Strategic interaction can involve many players and many strategies. For simplicity, we study the case with finite number of players and strategies, so that we can get a payoff matrix. It is the easiest way to depict a game.

Assume that there are only two players, player A and player B, and each play only has two strategies, strategy 1 and strategy 2. There are four possible outcomes. Player A and player B can each get a payoff matrix. For example,

$$Payoff_A = \begin{bmatrix} 100 & 0 \\ 200 & 100 \end{bmatrix} \qquad Payoff_B = \begin{bmatrix} 200 & 100 \\ 100 & 0 \end{bmatrix} \tag{5.12}$$

The indices of the matrix refer to the strategy the players employed. For example, in equation 5.12, $Payoff_A(2,1) = 200$ means that player A gets 200 if player A uses strategy 2 and player B uses strategy 1; $Payoff_B(2,1) = 100$ means that player B gets 200 if player A uses strategy 2 and player B uses strategy 1.

If the sum of all payoff matrices is a all zero matrix, the game is called zero sum game, which means that the interests of players strictly conflict each other, in other words, there are no common interests among players. If the sum of all payoff matrices is a non-zero matrix, the game is a non-zero sum game, which means that the players' profits can coexist somehow. The EWPP auction system can be considered as a non-zero sum game since the sum of the payoff matrices is a non-zero matrix. One of the objectives of game theory is to find an equilibrium, which is a stable status acceptable to all players.

In the above example, we can find a dominant strategy. Player A finds that he can always get more if he plays strategy 2, and play B finds that he will get more if he always plays strategy 1. So that the game has an equilibrium, in which player A gets 200 and player B gets 100.

However, not all the games have an equilibrium like the above example. Suppose the payoff matrix is:

$$Payoff_A = \begin{bmatrix} 300 & 0 \\ 0 & 100 \end{bmatrix} \qquad Payoff_B = \begin{bmatrix} 100 & 0 \\ 0 & 200 \end{bmatrix} \tag{5.13}$$

There is no dominant strategy. The optimal choice of player A depends on player B's choice, and vice versa. This kind of situation is defined as Nash equilibrium, which means if A's choice is optimal given B's choice, B's choice is optimal given A's choice. In equation 5.13, if player A selects strategy 1, player B will select strategy 1; if player B select strategy 1, player A will select strategy 1. Nash equilibrium can be interpreted as a pair of expectations about each player's choice, such that, when the other player's choice is revealed, neither individual will change his choice. [5-2] However, not all games have Nash equilibrium and some games have more than one Nash equilibrium.

Another problem with the Nash Equilibrium is that it does not necessary lead to a Pareto efficient result. Pareto efficiency is an economic term which means that there is no way to change a deal to make all parties better off. Following is a famous example. It is well known as "Prisoner's dilemma." The payoff matrix is:

$$Payoff_A = \begin{bmatrix} -3 & 0 \\ -6 & -1 \end{bmatrix} \qquad Payoff_B = \begin{bmatrix} -3 & -6 \\ 0 & -1 \end{bmatrix} \tag{5.14}$$

The origin of the game is to describe the situation that A and B committed a crime together and were caught. The two players are questioned in two separate rooms. If one confesses the crime and another denies, the one who confessed will be set free and another will be sentenced 6 years in jail; if they both confess, they will all be sentenced for 1 year; if they both deny, they will all be sentenced for 3 years. The Nash equilibrium of the game is that A and B confess and both get -3, but the payoff is not the optimal outcome for them. The strategy (confess, confess) is not Pareto efficient.

If player A and B can coordinate with each other, the problem is easy to solve. If each of them could trust each other, they will also get better off. If the game is only play for one time, there is no way for the two players to build credit on each other. The game will be most probably ended at Nash equilibrium.

However, if the game is played for many times, that is, it is a repeated game, the players have time to build trust on each other. The "bad" behaviour from the other player will be "punished" and the "good" behaviour will be "rewarded", so that the players have enough time to establish the bilateral loyalty and end the game in the strategy of (deny, deny).

It had been demonstrated in a convincing experiment run by Robert Axelrod [5-2]. He asked a dozen game theory experts to submit a strategy for prisoner's dilemma, and ran a "tournament" to test the strategies. The winning strategy, the one that gets the highest payoff, is a simple strategy. It is called "tit-for-tat"; it starts with denying, on every round after, it simply copies the other player's choice in the last round. When player A adopts the strategy, if B selects confess in one round, A will punish B immediately in next round. Simply speaking, "good" and "bad" actions are "rewarded" or "punished" immediately. Finally, if both player play reasonably, the game will continue at (deny, deny) to the end.

5.3.5 Applying the Game Theory

The prisoner's dilemma applies to a wide range of economic and political phenomena. In the example in section 5.3.4, "decreasing price" can be interpreted as confess, and "keeping the same price" can be interpreted as deny. If G1 decreases its price to get more profit, most likely G2 will follow the action, and finally G1 and G2 will get lower payoff. In a long run, both G1 and G2 will realize that the genset which decreases price will finally hurt itself as well as hurt the other, and keeping the marginal cost pricing is best strategy for them. That explains that why the bilateral contract model adopts the marginal cost pricing instead of average pricing.

5.4 Bidding Strategy Under Average and Marginal Cost Pricing for Competitive Environment

In this section, we are going to analyse the bidding strategy under competitive environment. Like the pure competitive environment, under the competitive environment, there are no players who have notable market shares so that he or she can manipulate the CMP. The difference between the competitive environment and the pure competitive environment is that an individual bid change may alter the CMP under the competitive environment.

5.4.1 Bidder Classification

Based on the cost curve, gensets can be classified into three categories. 1. Those very cheap ones which have high probability to be selected to serve the load. These gensets are not MCP setter. 2. Those relatively expensive ones which set the MCP. These gensets face tough competition. 3. Those very expensive ones which are seldom called on. The above classification changes depend on the load change. The gensets in the second category face a competitive environment while the gensets in the first and the third do not.

5.4.2 Bidding Strategy under Average Cost Pricing

Under the competitive environment and average cost pricing, there is no incentive for a genset to decrease the bidding price under its generation cost. Since bidding lower than cost does not increase the MCP, it will not result in higher profit compared to bidding at cost. Thus, bidding lower than cost only increases the risk of losing money.

Alternatively, there is a big incentive for a genset to bid higher than its cost. Those gensets which set the MCP, that is, those gensets in the second category, make zero or very low profit if they bid at generation cost. These gensets are definitely not satisfied with the profit they make. Increasing the bid will increase their profit.

However, one can argue that one genset may not be chosen to supply the load if it increases the price while the others stick on bidding at cost. One can say that increasing the bid also increases the risk of not being successful in the auction. These arguments do not hold when we take into game theory consideration. In this case, bidding at cost can be considered as confessing while increasing the price is denying.

Denial from all competitors will bring benefit to all bidders.

As shown in 5.2.3, under the pure competitive environment and average pricing, gensets tend to restrain the bidding capacity. This statement holds for the competitive environment.

5.4.3 Bidding Strategy under Marginal Cost Pricing

Under the competitive environment and marginal cost pricing, there is no incentive for a genset to increase the bidding price above its generation cost. 1) Gensets in the first category will not get more profit unless it increases the bidding price and sets the MCP. Since these gensets already make a good profit, increasing price to set the MCP is high risk and low benefit. 2) Gensets in the third category still are not selected if they increase the bid. 3) Gensets in the second category face tough competition. As shown in section 5.3.3, a genset which faces a competitive environment should not increase the price above the marginal cost. Increasing the price probably results in not being selected to supply the load. Summarising the above ideas, we conclude that under a competitive environment and marginal cost pricing policy, gensets tend not to bid higher than the generation cost.

Similarly, there is no incentive for a bidder to bid lower than the cost. 1) If a genset is called on to generate at the maximum capacity when it bids at cost, why should it decrease the bid? 2) If a genset is called on to generate less than its maximum capacity when it bids at cost, its output level coincides with the maximum profit (see section 4.3.1). Decreasing the bidding price to increase the output level only decreases the profit. 3) If a genset is not selected to supply the load, its minimum average price is higher than the MCP (see chapter 2), decreasing the bidding price only increases the risk of losing money. Therefore, the optimum bidding strategy is to bid at generation cost.

5.4.4 Conclusions

Comparing the bidding strategies under the two different pricing policies, we conclude that marginal pricing is a more appropriate method for the EWPP. Under the uniform marginal cost pricing and competitive environment, the optimum bidding strategy is to bid at cost and maximum capacity. The bidding strategy is simple and transparent. Average pricing policy under the competitive environment induces bidders to increase bids above generation cost, and to restrain the availability. This biding strategy leads to a high Capacity Element payment and a low system reliability. Furthermore, the complexity of the bidding strategy needs more manpower to figure out the bids.

Chapter 6. Uniform Pricing Versus Discriminatory Pricing

The EWPP pays all winning bidders one price, the system marginal price. This rule, at first glance, is counterintuitive. Why does the EWPP not pay the winning bidders according to what they bid? Paying all winning bidders one price is known as uniform pricing, and paying different prices to different bidders is known as discriminatory pricing. Will discriminatory pricing result in lower total pool payment compared with the uniform pricing? What are the advantages and disadvantages of these two pricing policies? What are advantages of using auction systems in the power industry? These questions will be answered in this chapter.

This chapter is organized as follows. In section 6.1, the reasons for applying the auction system in the electricity industry are presented. In section 6.2, in addition to introducing the theory of auctions, we present and compare different kinds of auctions. The difference between uniform pricing and discriminatory pricing is formulated in section 6.3. Then, in section 6.4, uniform pricing and discriminatory pricing are compared via Bayesian analysis. Finally, in section 6.5, we summarize the advantages and disadvantages of the two pricing policies.

6.1 Reasons for Applying the Auction System in the Power Industry

The objective of power industry deregulation is to encourage competition, and therefore, to increase the running efficiency of the system. Auctions, by their nature, provide a fair competitive environment. Since electricity is a merchandise with variable prices, auctions are therefore a good mechanism for the trading of electricity. In principle, as an alternative method, negotiation is also appropriate in this case, but its high transaction costs and the possibility of an impasse are serious disadvantages [6-1]. Auctions have an advantage over negotiations since the former provides fewer opportunities for kickbacks or under-the-table agreements [6-1].

In addition, the power system is physically interconnected, and requires a system operator to coordinate generation, load, transmission, losses, and so on. To handle the auction process, auctions also need a centralized operator, known as an auctioneer. Therefore, using an auction system in power pools is an easy, natural and efficient way to introduce competition to the power industry.

Besides providing a competitive environment, auctions have the following advantages: First, auctions provide fairness and full transparency in trading. Second, they induce significant reductions in transaction costs and result in faster processing in trading compared with bilateral negotiations. Third, they permit price discovery for goods which lack adequate reference rates [6-1]. However, auctions are also vulnerable to collusive activities [6-1].

6.2 Theory of Auction

6.2.1 Types of Auctions

There exist many types of auctions. The two main categories are sell auctions and buy auctions. In this section, we study the sell auction, which is more common in the economic world. The same theories that apply to sell auctions also hold for buy auctions with minor modifications.

Auctions can be conducted orally or by sealed bid. There can be a single or multiple winners; the goods can be allocated in one round (simultaneous auctions) or in several rounds (repetitive auction); all winners pay one price (uniform pricing) or pay different prices (discriminatory pricing); winners pay the best bidding price (first price auction) or the second best price (second price auction) [6-2].

■ **Oral Auctions**

To clarify the incentives facing bidders under various types of sealed auctions, it is helpful to analyse the oral auction first. Two basic oral auctions are the English and the Dutch auctions. Both of these occur in "real time [6-1]."

In an English sell auction, there is a bidding price initially set at a relatively low level that rises continuously. Bidders who wish to remain in the auction simply continue to bid, otherwise when the price is too high, they stop submitting bids. When only one bidder remains in the auction, the goods are allocated in order from the remaining bidder down to the point where either the goods are exhausted or the floor price is reached[1]. Each bidder pays the price at which his immediately preceding bidder leaves the auction [6-1].

In a Dutch sell auction, the bidding price is initially set at a very high level that continuously decreases with time. Bidders are allowed to submit only one bid which they exercise when the dropping price reaches their desired rate. The goods are allocated to successful bidders until all goods are allocated or the floor price is reached. Each winner pays exactly the amount that she bids [6-1].

In oral English auctions, it is important for bidders to monitor all other bids during the auction process. Here, bidders drop out of the auction when the price

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[1] The floor price is the lowest price that the auctioneer can accept.

exceeds the maximum price they wish to pay, that is, a reserve price. Here we suppose that every bidder has a reserve price. Since a winning bidder will pay the price offered by the bidder who dropped out immediately before her, which is lower than her reserve price, generally the dominant bidding strategy is to bid at the reserve price [6-1]. However, in oral Dutch auctions, bidders cannot receive information from competitors during the auction process. Bidders want to win the bid, but do not want to pay too much to outbid the competitors. A bidder might not submit the bid when the price reaches her reserve price if she expects that other bidders will bid a lower price [6-1].

■ Sealed Bid Auctions

In a sealed bid auction, such as in the EWPP, bidders offer concealed bids, and goods are allocated in decreasing order from the highest bid down to the point where either the goods are exhausted or the bid is less than the floor price. There are two types of sealed auctions: discriminatory pricing and uniform pricing auctions. In discriminatory auctions, each bidder pays the submitted bidding price while in uniform auctions all winning bidders pay the same rate, which can be the lowest accepted bid (first price auction), the highest rejected bid (second price auction) if it is greater than the floor price, or the floor price [6-1].

In a sense, Dutch auctions are closer to sealed bid discriminatory auctions while English and sealed uniform second price auctions are equivalent when bidders are certain about their reserve price [6-1]. The dominant strategy for uniform second price auctions is similar to that for oral English auctions, which is to bid at the reserve price [6-1]. Here, there is no incentive for an individual bidder to bid higher or lower than her reserve price since the submitted bidding price only determines whether a bidder wins the auction, but does not determine the price she will pay.

6.2.2 The Auction System in the EWPP

In the EWPP, more than one genset is needed to satisfy the load, hence, the auction system is designed as a multiple-winner system. Empirical analysis indicates that a sealed auction is less vulnerable to collusion than oral auctions since oral auctions provide more information [6-2]. For this reason as well as for operational simplicity, the EWPP uses a sealed bid system.

The EWPP auction system, therefore, can be summarised as a (1) multiple-winner, (2) sealed bid, (3) marginal and (4) uniform pricing system. So what is the logic of this system and what are the advantages and disadvantages of this system?

The reasons for adopting multiple-winner, and sealed bid system are presented in this section while the reasons for using marginal cost pricing are discussed in chapter 5. The question that remains to be explored is why the EWPP employs uniform pricing instead of discriminatory pricing. This problem, which is the initial motivation of this thesis research, will be solved in the next two sections.

6.3 Difference between Discriminatory Pricing and Uniform Pricing

In this section, we analyse the possible difference in the total pool payments resulting from uniform pricing versus discriminatory pricing auctions. First, we present the optimum bidding strategy under the EWPP rules, that is, uniform pricing. Then we analyse the bidding behaviour under the hypothetical discriminatory pricing rules.

6.3.1 The Optimum Bidding strategy under the EWPP Rules

It has been shown in chapter 5 that, under a pure competitive environment and the EWPP rules, the optimum bidding strategy for a genset is to bid at its generation cost. Bidding higher or lower than generation cost will not lead to more profit for the bidder under any circumstances.

It has also been shown in chapter 5 that under an oligopoly environment and the EWPP rules, gensets also should bid at generation cost. This result, proven in chapter 5 by contradiction, can also be shown to be true by the auction theory as follows.

The EWPP auction is a buy auction, and the reserve price for each genset (bidder) is the generation cost. According to the theory shown in section 6.2.1, the optimum strategy for a genset under the uniform second price auction is to bid at generation cost. If auctions have many bidders and the bid price range is relatively narrow, the highest accepted bid price and the lowest rejected price usually are quite close to each other. Therefore, the optimum strategy of bidding at generation cost also applies under the first pricing rules, which are the EWPP rules.

In a duopoly environment, where there are two or more players who have notable market power, gaming activities will likely happen. Detailed discussion of such activities will be presented in chapter 7.

6.3.2 Differences in the Total Pool Payment under Uniform and Discriminatory Pricing

If bidders also bid at generation cost in a discriminatory pricing auction, it can be easily seen that the total pool payment in a uniform pricing auction is higher than that in a discriminatory pricing auction. However, in a discriminatory pricing buy auction system, gensets tend to bid higher than generation cost in order to achieve their expected profits. This phenomenon is illustrated in figure 6.1.

Figure 6.1 is used to illustrate the total pool payment difference under uniform pricing and discriminatory pricing auctions. Consider the discriminatory and uniform pricing auctions with the same bidders and the same load level. In figure 6.1, curve D is the merit-order-list curve obtained from the bidder's offer files in a discriminatory auction, and curve U is the merit-order-list curve obtained from the bidders' offer files in a uniform auction.

Generally, curve D is higher than U. The total pool payment in a uniform auction is the rectangle area O-A-B-E, and the pool payment in a discriminatory auction is the area O-A-C-K-J-I-H-G-F-D1. It can be seen that if shaded area A is greater than shaded area B, then, uniform pricing auction results in a higher total pool payment than under discriminatory pricing.

If the auction is repeated several times, and if the load (Line A-B-C in figure 6.1) is fixed, in a discriminatory auction the bidder who failed to win in last round will decrease its bid, (although the new bid will still be greater than the generation cost), while the bidder who won, but was unsatisfied with the profit earned in the last round will increase the bid. If this auction runs enough large times, both areas A and B will decrease, and eventually approach zero. Hence, uniform and discriminatory pricing will converge to the same total pool payment [6-3].

Since power system conditions are periodic, the EWPP can be considered as a repeated auction system. Thus, if discriminatory pricing were adopted in the EWPP, bidders would anticipate the SMP and bid as close to it as possible. Since the

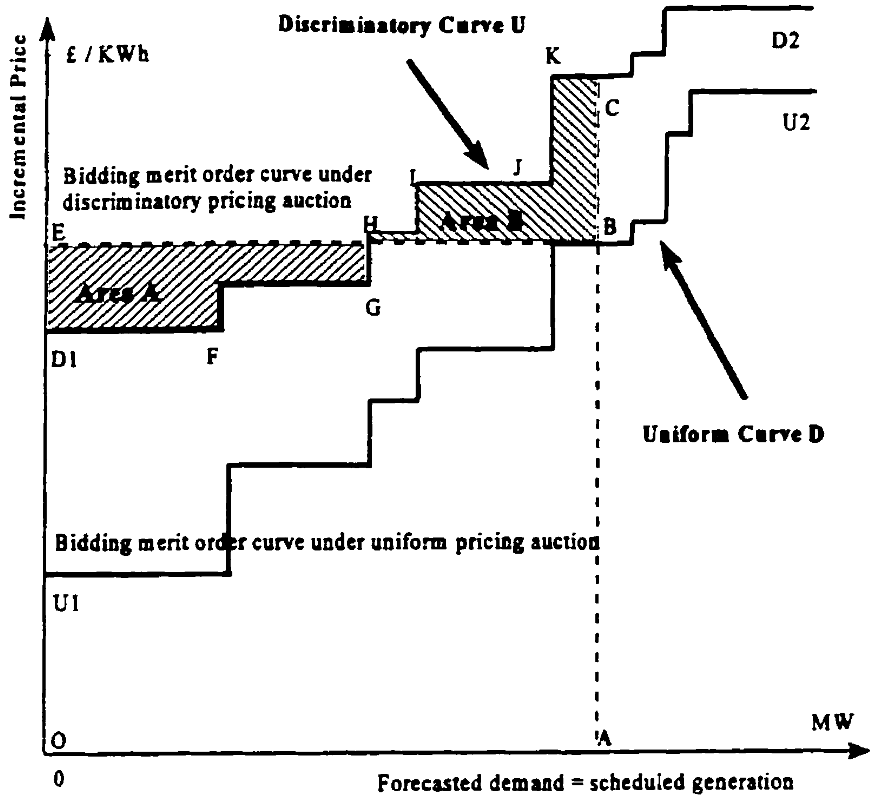

Figure 6.1 Uniform Pricing VS Discriminatory Pricing

bidders would anticipate the SMP and bid as close to it as possible. Since the forecasted load is broadcast, and the previous SMPs under different load levels are also exposed to all bidders, the difference between area A and area B, that is, the difference in pool payment resulted from the uniform and discriminatory pricing auctions are small.

In the next section, it will be shown through Bayesian analysis that if bidders are risk neutral, discriminatory second pricing and uniform pricing auctions result in the same expected total pool payment.

6.4 Comparison between Uniform and Discriminatory Pricing Auctions Via Bayesian Analysis

The total pool payment difference resulting from the uniform and discriminatory pricing auctions has been illustrated in figure 6.1 in section 6.3. In this section, we use Bayesian analysis, which is a statistical method, to analyse the problem.

6.4.1 Bayesian Analysis

Game theory is an effective weapon to analyse auctions and bidding, however, it has some shortcomings [6-4]. Firstly, game equilibrium is of minimal profitability for all bidders, accordingly, there is no big incentive for a risky bidder to adopt an equilibrium strategy even though this bidder knows he will face a big risk if he adopts a non-equilibrium strategy. Secondly, game theory supposes that all bidders are rational players. This assumption, however, does not simulate the real world perfectly. Finally, the underlying assumption of game theory, the payoff matrix, is not easily obtained in the real world. To overcome these disadvantages, a new analysis technique is needed [6-4].

Instead of treating the auction problem as a game between bidders, or as a game between bidders and the auctioneer, we consider an auction as an individual bidder decision-making problem under uncertainty [6-4]. Then, Bayesian statistical theory can be used to study the auction problem [6-7].

It has been proved by Milton Harris and Artur Raviv that the total gain in a sell auction is the same under two pricing rules [6-7]. A similar approach can be applied to the buy auction.

To prove that the total payment in a buy auction is the same under two pricing rules, two theorems are introduced first [6-5].

Theorem 1.

Let $Y_1 \le Y_2 \le \ldots \le Y_n$ represent the order statistics from a cumulative distribution function *F(.)*. The marginal cumulative distribution function of Y_α (α = 1, 2, ..., n) is given by,

$$F_{Y_\alpha}(y) = \sum_{j=\alpha}^{n} \binom{n}{j} [F(y)]^j [1 - F(y)]^{n-j} \tag{6.1}$$

Theorem 2.

Let $X_1, X_2, \ldots X_n$ be a random sample from the probability density function *f(.)* with cumulative distribution function *F(.)*. Let $Y_1 \le Y_2 \le \ldots \le Y_n$ denote the corresponding order statistics; then

$$f_{y_\alpha}(y) = \frac{n!}{(\alpha - 1)!\,(n - \alpha)!}[F(y)]^{\alpha-1}[1 - F(y)]^{n-\alpha}f(y) \tag{6.2}$$

6.4.2 Total Pool Payment under Uniform Second Pricing

Suppose that there is an electricity auction system whose demand, *D*, is inelastic. There are *N* gensets whose generation capacity for each genset equal *D* / *S* (*S* < *N*) where *S* is an arbitrary positive integer. In addition, suppose that each genset bids at its maximum capacity, therefore, the number of winning bidders is S. Each genset i has its own generation cost function, and the cost at output level of D / S equals C_i. The bid price for genset i can be formulated as a function of cost, that is, $B_i(C_i)$.

Under the uniform second pricing environment, the dominant bidding strategy, according to section 6.3, is to bid at cost, that is, $B_i\ (C_i) = C_i$. Each bidder does not know the cost function of other bidders, and therefore, it assumes that all other bidders draw their cost function independently from a distribution density function $f(.)$, whose corresponding cumulative distribution function is $F(.)$.

According to all bids, a cost merit-order list can be formed from the lowest to the highest, indexed $C_1 \le C_2 \le ... \le C_S ... \le C_N$. Hence, the market clearing price, the MCP, equals to C_{S+1} if the second pricing is adopted, that is, if the lowest rejected price is assigned as the MCP.

The total pool total payment, PAY_U, is S times the MCP. According to Theorem 2, the formula can be further expanded.

$$\begin{aligned} PAY_U &= SC_{S+1} \\ &= S \int_0^\infty x\, f_{S+1}(x)\ dx \\ &= S \int_0^\infty x \frac{N!}{S!\,(N-S-1)!} F(x)^S\,[1-F(x)]^{N-S-1} f(x)\,dx \\ &= \frac{N!}{(S-1)!\,(N-S-1)!} \int_0^\infty x\,F(x)^S[1-F(x)]^{N-S-1} f(x)\,dx \end{aligned} \tag{6.3}$$

where $f_{S+1}(.)$ is the density function of $S+1$ order statistic among N competitors.

6.4.3 Discriminatory Pricing

Now we analyse the discriminatory pricing auction. Again, suppose that there is an electricity auction system with an inelastic demand, *D*, and *N* bidders whose generation capacity for each genset equals D / S ($S < N$), and each one bid at its maximum capacity.

Genset *I* has its own generation cost function which equals C_i at the output level of D / S . Suppose that the bid for genset *i* is a function of cost, that is, $B_i(C_i)$, and $D_i(B_i)$ is the inverse function of $B_i(C_i)$, that is, $D_i[B_i(C_i)] = C_i$.

■ **The Cumulative Distribution Function for Bidder *i*'s Success in the Auction**

The probability that bid B_i will be accepted is equivalent to the probability that $D_i\ (B_i)$ will be less than an *S* order statistic among the $N - 1$ competitive bids. Therefore,

$$Pr[Accept\quad B_i] = Pr[\,C_i = D_i(B_i) < C_S\,] = 1 - L(D_i(B_i)) \qquad (6.4)$$

where C_S is the *S* order statistic among $N - 1$ generation costs of other gensets, and where $L(.)$ denotes the cumulative distribution of the S order statistic among $N - 1$ random variables. $L(.)$ can be explained as the expected probability of $C_i = D_i(B_i) \geq C_S$.

Then, according to Theorem 1, $L(.)$ is:

$$L(x) = \sum_{j=S}^{N-1} \binom{N-1}{j} F(x)^j [1 - F(x)]^{N-1-j} \tag{6.5}$$

The density function $l(.)$ corresponding to the distribution function $L(.)$ is then, according to Theorem 2,

$$l(x) = \frac{(N-1)!}{(S-1)!(N-S-1)!} F(x)^{S-1} [1 - F(x)]^{N-S-1} f(x) \tag{6.6}$$

■ **Dominant Bidding Strategy under Discriminatory Pricing**

The objective of bidder i is to maximize its expected profit over B_i, that is,

$$\max_{B_i} (B_i - C_i) \times \frac{D}{S} [1 - L(D_i(B_i))] \tag{6.7}$$

The maximum value of equation 6.7 happens at:

$$\frac{D}{S} - \frac{D}{S} L(D(B_i)) - \frac{D}{S} \frac{(B_i - C_i)\, l(C_i)}{B'(C_i)} = 0 \tag{6.8}$$

Equation 6.8 can be rewritten as,

$$\frac{dB_i(C_i)}{dC_i} (1 - L(C_i)) + \frac{d(1 - L(C_i))}{dC_i} B(C_i) = -C_i\, l(C_i) \tag{6.9}$$

$$\frac{d}{dC_i} [(1 - L(C_i))\, B(C_i)] = - C_i\, l(C_i) \qquad \textit{for all } C_i \tag{6.10}$$

Therefore,

$$B(C_i) = \frac{1}{(1 - L(C_i))} \int_{C_i}^{\infty} x\, l(x)\, dx + D \tag{6.11}$$

where D is a constant.

To determine the value of D, an initial condition is needed. Suppose C_i equals 0, we obtain,

$$\begin{aligned} B(0) &= \frac{1}{1 - L(0)} \int_{0}^{\infty} x\ l(x)\ dx + D \\ &= \int_{0}^{\infty} x\ l(x)\ dx + D \end{aligned} \tag{6.12}$$

In the above equation, $\int_0^{\infty} x\ l(x)\ dx$ can be explained as the expected value of the S order statistic, which is the bidding price edge between being selected and rejected. As shown in last section, the optimal bidding strategy under discriminatory pricing is to bid as closely as possible to SMP, which is $\int_0^{\infty} x\ l(x)\ dx$. Therefore, in equation 6.11, D equals zero, and the optimum bidding strategy becomes,

$$B(C_i) = \frac{1}{(1 - L(C_i))} \int_{C_i}^{\infty} x\, l(x)\, dx \tag{6.13}$$

■ **Total Pool Payment under the Discriminatory Pricing**

The total pool payment PAY_D under discriminatory pricing is,

$$PAY_D = \sum_{j=1}^{S} \int_0^{\infty} B(x) f_j(x)\, dx \tag{6.14}$$

where $f_j(x)$ is the density function of a j order statistic in a sample of size N.

From Theorem 2, we get,

$$\begin{aligned} PAY_D &= \sum_{j=1}^{S} \int_0^{\infty} B(x) \frac{N!}{(j-1)!(N-j)!} F(x)^{j-1}[1-F(x)]^{N-j} f(x)\, dx \\ &= \int_0^{\infty} N B(x) f(x) \sum_{j=1}^{S} \frac{(N-1)!}{(j-1)!(N-j)!} F(x)^{j-1}[1-F(x)]^{N-j} dx \\ &= \int_0^{\infty} N B(x) f(x) \sum_{j=0}^{S-1} \frac{(N-1)!}{j!(N-1-j)!} F(x)^{j}[1-F(x)]^{N-1-j} dx \end{aligned} \tag{6.15}$$

If the bidding strategy shown in equation 6.13 is adopted by all bidders, applying equation 6.5 to 6.15, we get,

$$PAY_D = N \int_0^{\infty} B(x)\, f(x)\, (1 - L(x))\, dx \tag{6.16}$$

Because from equation 6.5, we get,

$$1 - L(x) = 1 - \sum_{j=S}^{N-1} \binom{N-1}{j} F(x)^j [1 - F(x)]^{N-1-j}$$
$$= \sum_{j=0}^{S-1} \binom{N-1}{j} F(x)^j [1 - F(x)]^{N-1-j} \qquad (6.17)$$

Then, if all bidders adopted the bidding strategy shown in equation 6.13, we obtain

Apply equation 6.6 to 6.18, we obtain:

$$PAY_D = \int_0^{\infty} N\ y\ l(y) \int_0^{y} f(x)\ dx\ dy \qquad (6.18)$$

The equation can be further expanded as:

$$\begin{aligned} PAY_D &= \int_0^{\infty} N\ y\ (l(y)) \int_0^{y} f(x)\ dx\ dy \\ &= \int_0^{\infty} N\ y\ (l(y))\ F(y)\ dy \\ &= \int_0^{\infty} N\ y\ F(y) \frac{(N-1)!}{(S-1)!(N-S-1)!} F(y)^{s-1} [1 - F(y)]^{N-S-1} f(y)\ dy \\ &= \frac{N!}{(S-1)!\,(N-S-1)!} \int_0^{\infty} y\, F(y)^S [1 - F(y)]^{N-S-1} f(y) dy \end{aligned} \qquad (6.19)$$

6.4.4 Compare the Total Pool Payments under the Uniform and Discriminatory Pricing

Compare equations 6.19 with 6.3, we see

$$PAY_U = PAY_D \tag{6.20}$$

Please note that the above conclusion is based on the assumption that all bidders adopt the bidding strategy formulated in equation 6.11, and every one is able to precisely predict the SMP, in other words, to accurately estimate the edge bidding value between been rejected and selected, and bid as closely to it as possible. This assumption holds for fully diversified competitive power pool auctions system because the auction is a repeated system. Thus, bidders can precisely anticipate the SMP from former experiences since the forecasted load is broadcast, and the previous SMPs under different load levels are also exposed to all bidders.

However, in the EWPP where notable market power exists, the above conclusion does not hold because it is very difficult for individual small bidders to predict the SMP, which is under the influence of National Power and PowerGen's market force. More discussion will be presented in next section.

6.5 Advantages and Drawbacks

From the above analysis, we conclude that the total pool payments are equal under uniform and discriminatory pricing rules in competitive environment. Thus, why does the EWPP choose one pricing method over the other? In this section, we answer this question by analysing the advantages and disadvantages for applying these two pricing policies to the EWPP.

6.5.1. Compression of the Merit-order List under Discriminatory Pricing

It was shown in section 6.3 that under discriminatory pricing, bidders tend to bid as closely to the expected SMP as possible. Therefore, the bidding prices from different gensets are much closer to each other than those under uniform pricing. Consequently, the merit-order list is compressed.

The compressed merit-order list resulting from discriminatory pricing brings on some difficulties in generation scheduling. Since the EWPP uses several heuristics to make the preliminary schedule, from which the electricity prices are determined, if the merit-order list is compressed, the heuristics employed by the EWPP are more likely to yield sub-optimal solutions, for example, units may be turned on and off in a sub-optimal sequence. Moreover, the compressed merit-order list makes generation scheduling more sensitive to load forecasting errors.

In addition, since each genset only bids one set of prices every day, the compressed merit-order list resulting from the discriminatory pricing will result in less price differentiation between peak and off-peak periods [6-6], leading to distorted market price signals, which decrease incentives for load management. This problem can be solved by allowing gensets to bid more than one set of prices, one for each load level, however, this change increases the complexity of the EWPP rules, which are already very complicated.

6.5.2. Bidding Strategy Simplicity

Under the uniform bidding policy and competitive environment, the optimal bidding strategy for every genset is very simple, that is to bid at cost. Under duopoly or oligopoly environments, the optimal bidding strategy for those relatively efficient gensets is still to bid at cost. The bidding strategies for those who have market power are however more complex.

In contrast, under discriminatory pricing, the bidding strategy for all gensets also becomes complex since every genset must predict the SMP and bid as closely to it as possible. This complexity may put small generation utilities at a great disadvantage because they may not have enough manpower to figure out the bids, or they may misjudge the bidding strategies of large utilities and the SMP. Consequently, a discriminatory pricing policy might discourage new entrants from emerging into the generation market [6-6].

6.5.3 Sharpen Awareness of Competition

Under discriminatory pricing, every genset must bid more actively compared with the case under uniform pricing because what a winning bidder receives is what it bids. In the EWPP there are many zero bidders which always bid at zero. These gensets usually are very efficient and hold contracts for difference. Such contracts are great stimulus for gensets to get into the pool, and to be able to fulfill their contracts.

Some gensets bid at zero because they predict that they will be ordered not to generate because of the transmission constraints. According to the EWPP rules described in section 2.8, these gensets will be paid at the rate of SMP. This kind of gaming strategy is called "constrained off," and a more detailed discussion will be presented in section 7.4. If the EWPP adopted a discriminatory pricing policy, these zero bidders would disappear since winning bidders get what they bid.

Generally speaking, the bidding strategy is passive under uniform pricing, while active under discriminatory pricing because bidders must forecast the future market and future prices. This active bidding strategy will increase of the awareness of the competition, and therefore, may potentially increase the operational efficiency.

6.5.4. Avoid "Free-loaders"

In the EWPP, if the companies National Power and PowerGen exercise their market power to increase the SMP, all winning bidders receive the extra payment caused by the gaming behaviour. If the discriminatory pricing policy were adopted, these "free-loaders" will not receive any extra payment, thus, the total pool payment would be decreased.

However, discriminatory pricing again puts the small generation utilities at a big disadvantage since small utilities do not have enough market power to manipulate the SMP, and cannot get any benefits from the gaming behaviour of other companies. Therefore, in this sense, the uniform pricing policy provides a more fair environment than the discriminatory pricing policy.

From the above analysis, we see the advantages of uniform pricing outweighs those of discriminatory pricing, therefore, we reach the conclusion that the uniform pricing is an appropriate pricing policy for the EWPP.

Chapter 7 Gaming Strategies in the EWPP

In the last few chapters, we analysed the theoretical base behind the EWPP rules. In this chapter, we come back to the real world and discuss the market structure, the rules governing the EWPP, the potential profit-making opportunities as well as the various gaming strategies.

In a competitive environment, the impetus for profit drives private companies to seek all possible opportunities to use the market rules for their own advantages. In the EWPP, like in other markets, no matter how tightly the market rules are set by the regulating body (OFFER in England and Wales), players will find a way to game. This occurs not only because of the weakness in the rules, but also due to the duopoly nature of the EWPP generation market structure. Typical gaming strategy includes withholding generation availabilities, increasing bidding prices to manipulate the SMP, and manipulating the uplift by taking advantage of the transmission constraints.

This chapter is organized as follows. In section 7.1, the EWPP market structure is presented. The duopoly nature of the EWPP generation market is described and the generation market shares of the major companies in England and Wales are illustrated. Also in this section, the trend in the fuel share since Vesting Day is presented. Then, in section 7.2, the four price elements of the pool sale price are analysed and examples of historical statistical data of the pool prices are presented. In section 7.3, some gaming strategies are analysed to demonstrate how bidders can increase profits by manipulating the CE, SMP and the Uplift. Finally, in section 7.4, we discuss the some related issues in the EWPP operation, namely, transmission and losses management.

7.1 Market Structure of the EWPP

In England and Wales, generation, transmission, distribution and retail supply of electricity were divided into different businesses and largely privatized since Vesting Day. The generation capacities of the CEGB were split into three companies, the public-owned National Power and PowerGen, as well as the state-owned Nuclear Electric. Besides the three large companies mentioned above, Electricity de France, Scottish Hydro-Electric, and Scottish Power, plus several other companies also supply power to the EWPP. Since Vesting Day, a number of new independent power producers (IPPs) also joined the electricity market.

7.1.1 The Duopoly Nature of the Generation Market in the EWPP

Following the policies of the conservative government, the UK rapidly restructured its power industry and privatized the electricity generation utilities in 1989. Initially nuclear capacities were scheduled to be privatized, but it turned out that the nuclear plants would not be competitive under the deregulated environment and were then withdrawn from the privatization. However, the size of National Power and PowerGen was not reconsidered. Therefore, privatization yielded an essentially duopoly electricity market.

Initially, the National Power and PowerGen possessed nearly 80% of the total capacity. Since Vesting Day, both of these companies reduced their capacity steadily while several independent power producers (IPPs) entered the market. However, today these two companies still have notable market power to manipulate the clearing price. Tables 7.1 and 7.2 show the market share of the major companies in the EWPP. From tables 7.1, 7.2 and 7.3, we see that the market shares of the National Power and the PowerGen continuously declined primarily due to the closure of a number of plants and the facts that the Nuclear Electric increased output because of newly committed plants, and some new IPPs entered the market. This trend, as shown in figure 7.1 and 7.2, is likely to continue although these two companies still hold significant market shares today [7-3].

Table 7.1 Generation Utility Overall Market Share [7-1]

	89 -- 90	90 -- 91	91 -- 92	92 -- 93	Apr-Jun 93
National Power	48.04	45.46	43.57	40.99	34.02
Power Gen	29.69	28.40	28.18	27.04	26.70
Nuclear Electric	16.49	17.43	12.65	21.29	23.74
Others	5.78	8.79	9.63	10.67	15.54

Table 7.2 Generation Utility Overall Market Share, March 1996 [7-2]

	Capacity (MW)	Market Share (%)
National Power	19,269	30
PowerGen	15,282	24
Nuclear Electric	7,128	11

Table 7.3 Shares of the Electricity Generation (1990 - 2001) [7-2]

	1990 / 1991	1995 / 1996	2000 / 2001
National Power	46%	31%	21%
PowerGen	28%	23%	17%
Nuclear Electric	17%	22%	24%
IPPs	1%	14%	21%
Others	8%	10%	17%

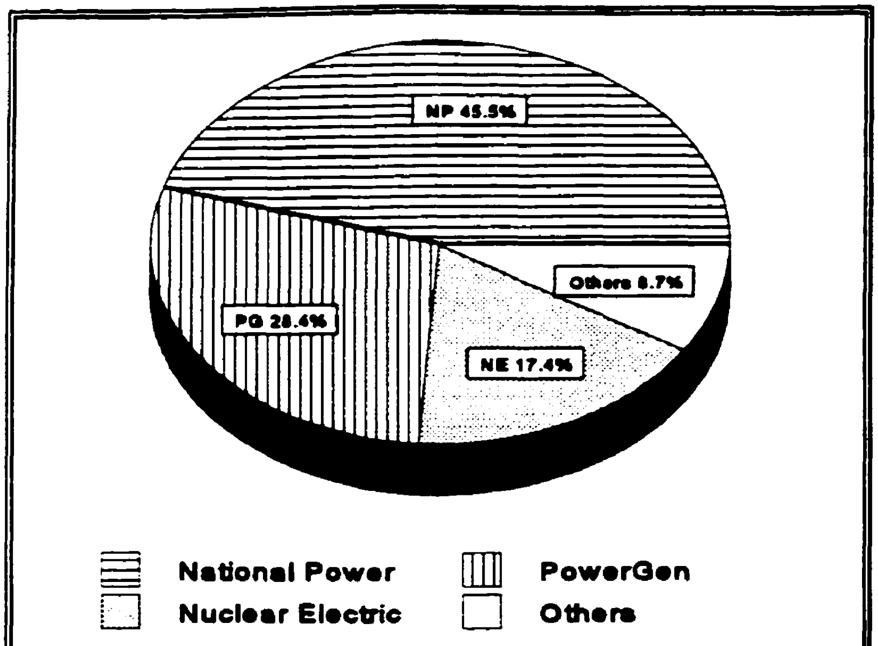

Figure 7.1 Market Share in 1990 / 1991

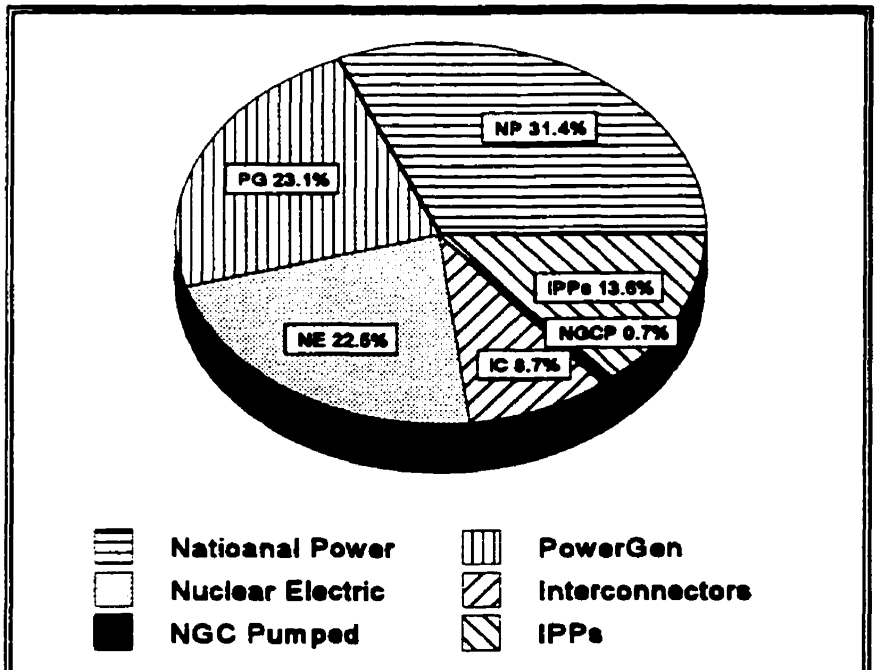

Figure 7.2 Market Share in 1995 / 1996

7.1.2 New Entrants into the Electricity Market

Because of low investment, short construction time, modular design, and some environmental advantages, gas-fired plants have gained favour among both existing utilities and new entrants in the UK. By March 1996, 9,505 MW of additional capacity from new gas-fired plants had been commissioned in England and Wales, while 15,000 MW more was either under construction or planned [7-1]. Meanwhile, some coal-fired and oil-fired plants were also shut down.

Among the extra capacities mentioned above, new entrants have commissioned 6,000 MW and 2,900 MW more is under construction [7-2]. In total, in 1996 there were more than 20 independent power schemes under consideration. By the year 2000 the new entrants, which in 1996 already account for nearly 14% of the generation market share, could rise up to 20% [7-2]. The UK electricity demand is forecast to rise very slowly (around 1% increase per year over the next decade), therefore, new entrants seriously challenge the existing generation utilities.

The trend in generation fuel is shown in figures 7.3 and 7.4 while a breakdown in the new gas-fired plants commissioned in England and Wales from March 1989 to March 1996 is shown in table 7.4.

Table 7.4 New capacity commissioned up to March 1996 [7-1]	
Independent generators	6,061 MW
PowerGen	1,640 MW
National Power	1,804 MW

Note that both oil and coal have decreased significantly while gas has increased dramatically.

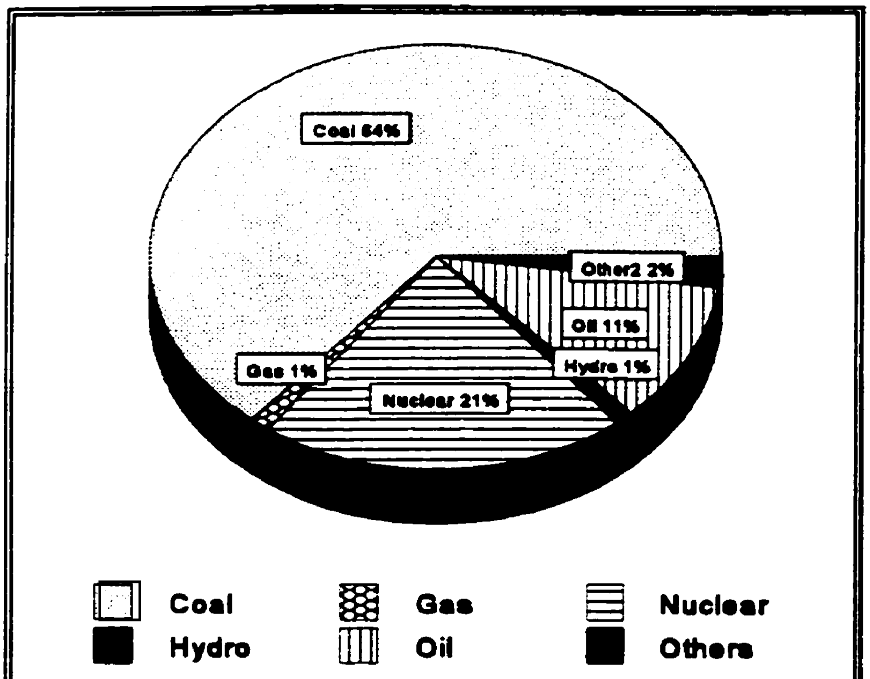

Figure 7.3 Fuel Share in 1990 / 1991

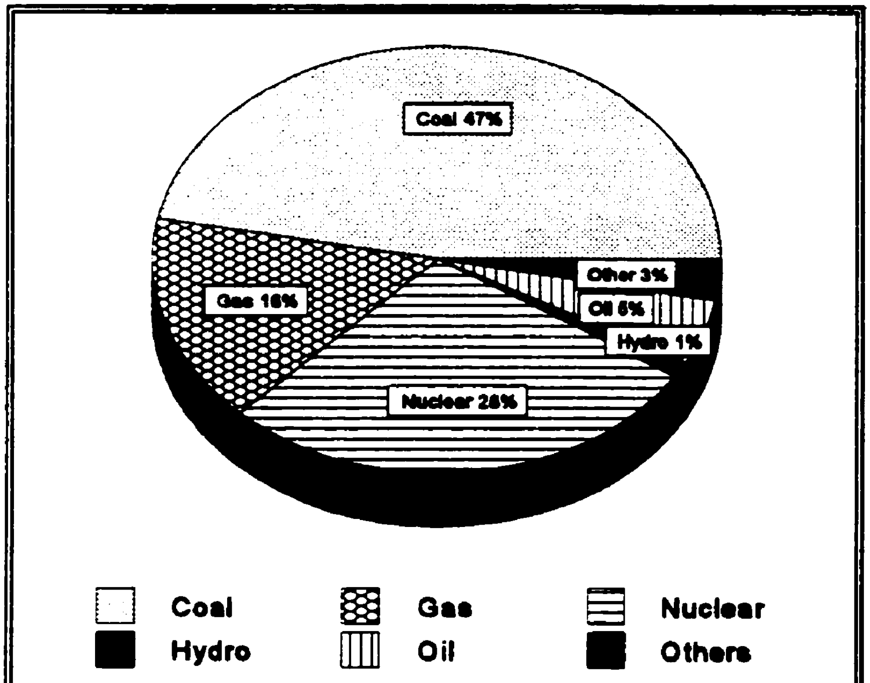

Figure 7.4 Fuel Share in 1995 / 1996

7.1.3 Fossil Fuel Levy on Nuclear and Renewable Capacities

Before privatization, the costs of the nuclear plants were embedded in the CEGB's total portfolio. Analysts discovered that this cost was too high to attract investors, hence, the nuclear section was withdrawn from privatization. However, the government still insisted on the diversity of generation, thus, remaining the nuclear plants in the power pool auction. In order to make the nuclear plants competitive, a Fossil Fuel Levy was introduced in the system to cover to the stranded cost (see section 1.2.4). As a result, the nuclear plants receive substantial extra revenue from the government which amounts up to 80% over and above the pool prices [7-4]. A similar levy is applied to renewable resources such as wind and geothermal.

The nuclear capacities have a contract for this levy which lasts from 1990 to 1998. In 1993, about 95% of the total Levy supported the nuclear plants and 5% supported the renewable capacities while in 1998, the levy for nuclear capacities is scheduled to stop, while the support for renewable capacities will likely continue.

7.2 Pool Prices

In a competitive environment, the market clearing price is a signal that indicates whether the market runs efficiently and competitively. Therefore, studying the pool price variations since Vesting Day helps to understand the market structure, the EWPP rules, and various gaming activities.

In this section, the four elements in the pool price described in section 2.7 are analysed first, followed by examples of statistical data of the pool prices after Vesting Day. From this data, in section 7.2.3, we determine that which company usually sets the system marginal price known as the SMP. This analysis demonstrates that the National Power and the PowerGen have enough market power to manipulate the pool price.

7.2.1 Four Price Elements

The price at which electricity is bought and sold under the pool trading arrangements is determined for every half-hour. As described in section 2.7, this price consists of four elements, namely, system marginal price (SMP), capacity element (CE), uplift, and transmission losses price. The average value of the SMP on a typical scheduled day is much greater than that of the other elements, however, during peak-load periods when the PSP is very high, the CE dominates other elements.

The SMP is the energy element of the pool price, and is mainly related to the bidding prices. On the other hand, CE is based on the idea that the pool should pay more while the spare capacity[1] is low while paying less when the spare capacity is high. Clearly, CE is mainly related to the load level and the bidding generation availabilities. Finally, the Uplift is the price component mainly related to the power system constraints.

7.2.2 Pool Prices Historical Statistics

Ever since Vesting Day, the pool prices have increased continuously. Initially, the pool prices were relatively low due to the facts that generation utilities relied on contracts for differences instead of the pool prices to purchase electricity (see section 8.4), but they soon began an upward trend. From 1991 to 1993, the pool prices

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1 Spare capacity is the margin between the total system bidding availability and the system demand.

experienced some unusual increases due to the gaming behaviour of some generation companies, mainly PowerGen and National Power. The Office of Regulation (OFFER) made several rule changes and established an agreement with these two companies to prevent the unusual price hikes from happening. From 1994 to 1996, the pool prices declined continuously.

The main reason for the recent price decrease is the drop in generation cost due to the replacement of expensive coal and oil fired plants by gas fired plants which are cheap to build and efficient to operate. Meanwhile, almost all generation utilities reduced their manpower significantly [7-8]. For example, National Power and PowerGen cut their staff by half, while the NGC also decreased their personnel significantly [7-8].

The pool prices were initially artificially low due to the existence of the government contracts (CFDs) holding by National Power and PowerGen. These contracts were enforced by the government and signed with the RECs at a rate which is high enough to cover the expensive UK coal purchase cost and other operational cost. Therefore, these two companies did not rely on the pool prices to meet their financial targets. The IPPs had complained to the OFFER that the price gave a wrong market signal.

Then in summer / autumn 1991, the EWPP experienced a substantial CE increase primarily due to the strategic use of the bidding availabilities by PowerGen, which will be discussed in detail in section 7.3. Following an investigation, the OFFER declared a set of new rules to prevent the above gaming behaviour from happening. However, as we will argue later, the new rules are not good enough to achieve their objective.

Later in the summer of 1992, the SMP began to increase significantly and this was attributed to abuses in bid prices by National Power and PowerGen which OFFER found to have enough market power to manipulate the SMP [7-1]. Following an investigation, the OFFER required the two major generation utilities to restrict their bidding prices by threatening with referring them to the Monopolies and Mergers Commission (MMC). Meanwhile, the OFFER also forced the two companies to lease 6,000 MW of their capacity (4,000 MW from National Power and 2,000 MW from PowerGen) to another company called Eastern Electric.

The Uplift element also experienced some unusual increases which were caused mainly by gensets taking advantage of the transmission constraints and the fact that most generation plants are in the north while most loads are in the south. This special load-generation pattern leads to a potential transmission congestion problem. As shown in section 2.7, gensets which are not in the preliminary generation schedule, but are ordered to run, receive what they bid, while gensets which are in the preliminary schedule, but are ordered not to generate or to a lower generation level, also receive payment for the difference between the schedule and real generation. The strategic abuse of the above two rules increases the Uplift. Again, detail will be presented in section 7.3.

The average pool prices from 1990 to 1994 are shown by components in tables 7.5, 7.6 and figure 7.6. In table 7.7, the minimum, average, and maximum prices of the financial year from December 1995 to December 1996 are presented.

Table 7.5 Average Demand Weighted Pool Prices (£ / MWh) [7-5]

	90 -- 91	91 -- 92	92 -- 93	93 -- 94 (April -- Jan)
SMP	18.1	19.9	23.1	25.9
CE	0.1	1.7	0.2	0.4
Uplift	1.0	1.8	1.5	2.3
PSP	19.2	23.4	24.8	28.6

Table 7.6 Average Time Weighted Pool Prices (£ / MWh) [7-5]

	90 -- 91	91 -- 92	92 -- 93	93 -- 94 (April -- Jan)
SMP	17.4	19.5	22.6	25.4
CE	0.0	1.3	0.2	0.3
Uplift	1.0.	1.6	1.4	2.3
PSP	18.4	22.4	24.2	28.0

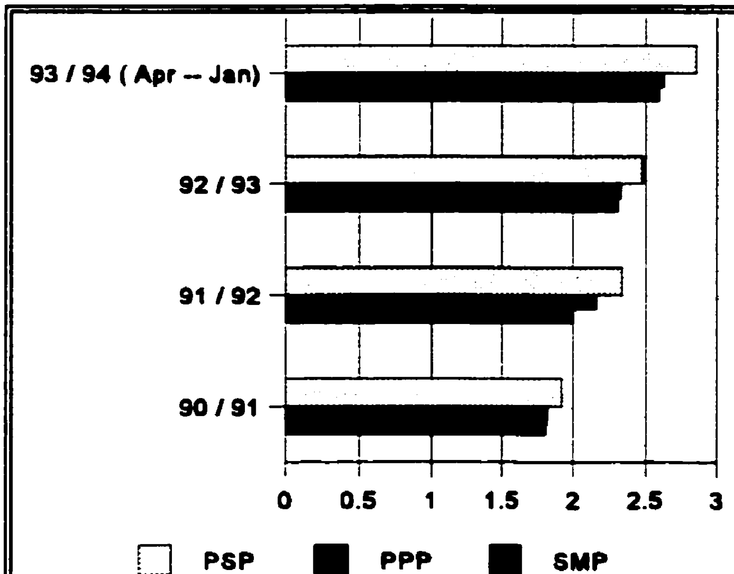

Figure 7.5 Price Variation between 1990 -- 1994

Table 7.7 Prices of the Final Year (December 1995 – December 1996)			
	MIN	AVERAGE	MAX
SMP (£/ MWh)	5.56	18.46	80.35
PPP (£/ MWh)	5.56	22.02	515.56
PSP (£/ MWh)	6.44	23.99	586.87
Pool Bill (£M)	7.04	19.17	73.21

7.2.3 Who Sets the SMP?

It was shown in section 7.1.1 that the EWPP basically created a duopoly environment where National Power and PowerGen initially owned 80% of the total generation at Vesting Day. Since then, the two giants have closed some plants while the nuclear plants and inter-connectors[2] have increased their output, in addition to the entry of several IPPs. Until 1996, National Power and PowerGen owned 54.5% market share, while Nuclear Electric owns 22.5% and IPPs 13.6% [7-3].

It seems that although far from ideal, the EWPP basically has a competitive environment. However, this statement is problematic. The costs of new gas fired, and nuclear plants (which receive Fuel Levy from the government) are very low, and therefore these plants primarily serve the base load. They bid into the pool at a very low price so that they are called on first. The remaining gensets, the coal and oil fired gensets, which mainly belong to National Power and PowerGen, form the middle and high-level of the merit-order list. Therefore, National Power and PowerGen have a low load-factor and usually set the SMP. Figure 7.6 shows the SMP setter in November 1997 [7-6].

2

Inter-connectors refer to the electricity trade between France, Scotland and England and Wales.

7.3 Gaming Behaviours

In a competitive environment, the desire of making maximum profits drives private companies to seek any profitable opportunities existing in the market rules and market structure to increase profits. In this sense, whether a set of market rules is successful can be judged by whether the rules delete all potential profit-making gaming opportunities [7-8]. Since the rules are made by humans, initially they inevitably contain weaknesses, and it is the regulator's responsibility to investigate the abuse of the market rules, and to alter the rules when necessary.

The EWPP rules, like all other market rules, are far from perfection. The duopoly market structure of the EWPP generation market makes the rules even easier to abuse.

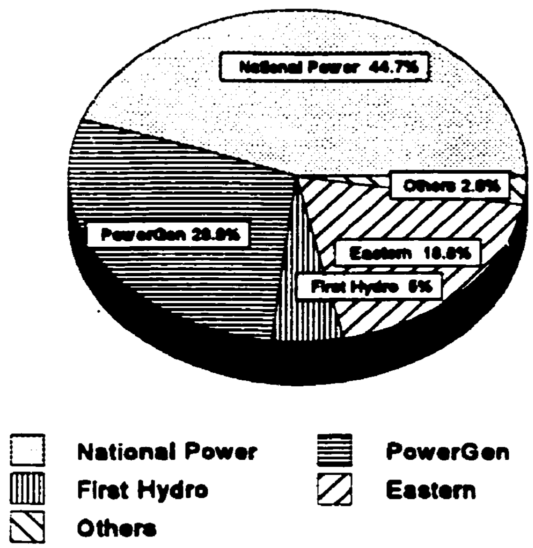

Figure 7.6 Generator setting SMP in Nov. 1996

In this section, we analyse four gaming strategies existing in the EWPP, namely, gaming over CE, gaming over SMP, constrained on, and constrained off.

7.3.1 Gaming over the Capacity Element

If a genset is not used to serve load frequently, it might not receive enough payment through SMP to cover its cost and investment. In the long run, generators must have a reasonable return for their investments, otherwise nobody will build new plants. For these reasons, the capacity element (CE) is included in the PSP which, in the long term, is expected to reflect the cost of building new power stations needed to meet peak demands. The CE is worked out by NGC through a complex formula as follows

$$CE_j = LOLP_j \times (VLL - SMP_j) \tag{7.1}$$

where subscript j refers to period j; $LOLP_j$ is the loss of load probability and VLL is value of lost load. The LOLP is calculated by the NGC, and is a convex function of the expected reserve which is the margin between the total bidding generation availabilities and the system load. The VLL, which was initially set at 2000 $£/MWh$, is a fixed value and changes annually according to the RPI.

The convexity of the LOLP function indicates that when the expected reserve is small, the LOLP becomes large and sensitive to changes in the expected reserve. Moreover, because of the large difference between the VLL and the typical SMP, a small change in the LOLP has a large impact on the CE [7-7]. Therefore, the CE element is very volatile and sensitive to small change in bids due to its calculation method.

The CE element is introduced into the pool prices in order to provide an economic signal for investments of new generation capacity. However, the characteristics of the CE calculation method open a door for gaming behaviour since the value of the CE depends on the value of LOLP, which in turn depends on the total bidding generation availabilities. Therefore, generation utilities could declare some plants unavailable and later, after the CE had been determined, re-declare these plants available.

In the late summer of 1991, PowerGen exercised the above-mentioned gaming strategy by withholding its generation substantially. As a result, the CE element increased significantly. Followed an investigation, the OFFER changed the generator licence condition by requiring all generators provide half-year statements of their expected available capacities, and explanations if their real bidding availabilities violate their statements, which will be judged by an independent assessor appointed by the OFFER. In addition, the OFFER required generators declare unavailability eight days in advance.

The above-mentioned rule change impedes the gaming behaviour over the CE, but does not completely delete the gaming opportunity. Because of the substantial market shares National Power and Powergen hold, it is easy for them to affect the CE element significantly, and therefore, to gain substantial high profits sometimes. Withholding availability is subtle and elusive to be detected by the OFFER, and it is not very difficult for companies to find explanations for the discrepancy between their actual bidding availability and half-year plan, therefore, it is believed that this gaming strategy has still been exercised in the EWPP [7-8].

7.3.2 Gaming over the System Marginal Price

As it has been shown in section 7.2.3, the coal and oil fired gensets that mainly belong to National Power and PowerGen form the middle and high-level of the merit-order list. In other words, approximately only National Power and PowerGen compete each other to serve the peak load while the relatively cheap gensets serve the base laod[3]. As it has been shown in figure 7.6, usually the genset which sets the SMP is either from National Power or PowerGen.

Every day, the NGC broadcasts the forecasted demand for the next scheduled day, therefore, both National Power and PowerGen can approximately predict the residual expected demand which is defined as the forecasted demand less the availability of other gensets [7-8]. This residual expected demand will be served jointly by these two companies no matter what prices they bid, hence, the only risk for them is to bid too high to loose market shares to the other company and take a small portion of the residual demand [7-8].

However, compared with the strategy of withholding availability, increasing bids to manipulate the SMP is obvious and easy to detect. In 1993, the high SMP in the EWPP drew the attention of the OFFER, which later threatened to refer these two companies to the Monopolies and Mergers Commission after an investigation. Finally, in 1994, National Power and Powergen undertook the responsibility of keeping the average pool prices (PSPs) below 25 $£/MWh$ by restraining their bids for the next two years, and leased 6000 MW (4000 from National Power and 2000 from PowerGen) of their oil and coal fired generators to another company [7-7].

3

Since 1996, Eastern Electric, which leased 4,000 MW and 2000 MW of capacity from National Power and Powergen respectively in 1996 joined the competition.

The strategy of increasing bids can be combined with the strategy of withholding availability to build a more subtle and elusive strategy, which withholds relatively cheap gensets and declares relatively expensive gensets available. Because of the diverse mix of generation capacity owned by National Power and PowerGen, this combined strategy becomes powerful [7-8].

7.3.3 Gaming over the Uplift

As it has been shown in sections 2.7.3 and 2.8, the uplift payment is a mixture of many elements. Generally, it can be divided into four categories, namely, generation outturn, ancillary services, scheduled reserve, and unscheduled availability payments. The generation outturn payment refers to money paid to gensets to compensate the discrepancy between the preliminary schedule and actual dispatch; the ancillary services payment refers to the money paid to various parties which provide ancillary services; the scheduled reserve payment refers to the money paid for the spinning reserve; finally, the unscheduled availability payment refers to the money paid to gensets for bidding. The total uplift payments from 1990 to 1993 are broken down by the above-mentioned categories, and show in table 7.8.

Table 7.8 Uplift Payment by Component (£ million) [7-9]

	90 - 91	91 -92	92 - 93
Operational Outturn	121.1	216.4	205.2
Ancillary Services	106.0	121.4	119.0
Scheduled Reserve	35.9	35.1	45.9
Unscheduled Availability	3.7	102.2	12.7
Other	0.2	0.1	0.1
Total	266.9	475.2	382.9

From table 7.8, we learn that the payments for operational outturn and ancillary services are dominant components in the total uplift payment. One may notice that the payment for unconstrained availability in 91 - 92 is very high compared with that in other years. The main reason is that this payment is proportional to LOLP (see section 2.8.3) and in late summer 1992, the LOLP increased substantially due to the gaming behaviour by PowerGen. Table 7.9 shows the payment for unconstrained availability in 1991 by month.

Table 7.9 The Payments for Unscheduled Availability in 1991 [7-9]

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0.27	0.38	0.14	1.52	1.25	5.19	0.46	1.20	23.7	24.6	9.73	25.5

The payment for generation turnover which compensates gensets for the out-of-merit operations provides two potential gaming opportunities, which are known as constrained-on and constrained-off.

- **Constrained-on**

Suppose that genset i is scheduled to generate P_1 in the unconstrained schedule, but actually generate P_2 due to transmission constraints. If $P_2 > P_1$, that is, genset i is constrained on, it must sell the extra energy, $(P_2 - P_1) \times SPD$, to the market at the rate of offer bidding price. The total payment genset i receives is, then,

$$P_1 \times SPD \times SMP + (P_2 - P_1) \times SPD \times Price_{bid} \qquad (7.2)$$

where $Price_{bid}$ is the bidding price of genset i, and SPD is the scheduled period, which is a half hour in the EWPP.

If one genset can predict that it will be called on to generate because of the transmission constraints, it tends to bid high because according to equation 7.2, the higher it bids, the higher payment it receives.

■ **Constrained-off**

On the other hand, if $P_2 < P_1$, that is, genset i is constrained off, it must buy back the energy it should have produced, $(P_2 - P_1) \times SPD$, from the market at its bidding price, and the total payment for energy is, then,

$$P_1 \times SPD \times SMP - (P_1 - P_2) \times SPD \times Price_{bid} \quad (7.3)$$

If one genset can predict that it will be turned off or generate less than scheduled in preliminary schedule because of the transmission constraints, it tends to bid low, even to zero, because according to equation 7.3, the lower it bids, the higher payment it receives.

Table 7.10 breaks the payment for generation outturn into four categories, high-voltage constrained-on, high-voltage constrained-off, low-voltage constrained-on, as well as low-voltage constrained-off.

Table 7.10 Operational Outturn Payment by Component (£ million) [7-9]			
	90 - 91	91 -92	92 - 93
High-voltage Constrained-on	2.7	3.5	5.6
High-voltage Constrained-off	0.7	1.7	5.2
Low-voltage Constrained-on	3.4	5.2	10.8
Low-voltage Constrained-off	2.4	2.3	4.8
Total	5.8	7.5	15.6

7.4 Uplift and Losses Management

As was shown in section 2.8, the SMP and CE elements are predetermined, and are announced one-day ahead of the spot market trading, while the Uplift element and losses payment are calculated after the trading, and therefore are affected heavily by the operational efficiency of the pool and transmission services.

Basically, the Uplift payment is caused by out-of-merit generation, reserves, ancillary services, load forecast errors, generator failures, and unscheduled availability. Some of the above-mentioned components and transmission losses are closely related to pool operation and transmission services and therefore can be managed by the NGC, which operates the pool and transmission network [7-10]. Hence, the NGC is able to decrease the Uplift and losses payment by improving the transmission availability, producing more accurate load forecasting, making proper investment in transmission lines, and so on [7-10]. For example, the NGC can call on more reactive power to relieve a transmission voltage violation instead of run an out-of-merit generator.

However, unfortunately, initially since Vesting Day, the NGC has no economic incentive to operate the transmission network and the pool efficiently, and therefore, as shown in figure 7.7, the uplift element increased over time until 1994 [7-10]. Please note that the unscheduled availability payment is excluded from the Uplift payment in figure 7.7 since the NGC has no control over it.

In April 1994, the Uplift Management Incentive Scheme (UMIS), which allows the NGC and pool buyers split the cost-savings in the Uplift and losses, was implemented in the EWPP [7-10]. Equation 7.1 shows how the UMIS worked in 1994 / 1995, indicating that the extra profits the NGC would obtain was a piecewise linear function of the value of Uplift payment less the unscheduled availability payment. For example, if the Uplift excluding unscheduled availability payment was less than 490 million£, the NGC would receive 25 million£, while if it exceeds 660 million £, the NGC would have to pay 20 million £ back to customers where X refers to the total Uplift payment less the unscheduled availability payment and Y refers to the extra profits or fines assigned on the NGC. The unit of both X and Y is million £.

$$Y = \begin{cases} 25, & X \le 450 \\ 25 - \frac{25}{180} \times (X - 490), & 490 \le X \le 570 \\ 0, & 570 \le X \le 580 \\ -\frac{10}{70}(X - 580), & 590 \le X \le 660 \\ -10, & X \ge 660 \end{cases} \tag{7.1}$$

The UMIS worked for 18 months and then in 1995 was replaced by Transmission Service Scheme (TSS), which was a refinement of the UMIS [7-10]. The TTS split the Uplift into several components and designed cost-saving shares between the NGC and customers for each component and transmission losses. Both plans, especially the TTS, successfully achieved their goals, which are to minimize the Uplift payment and losses payment, as was shown in figure 7.7.

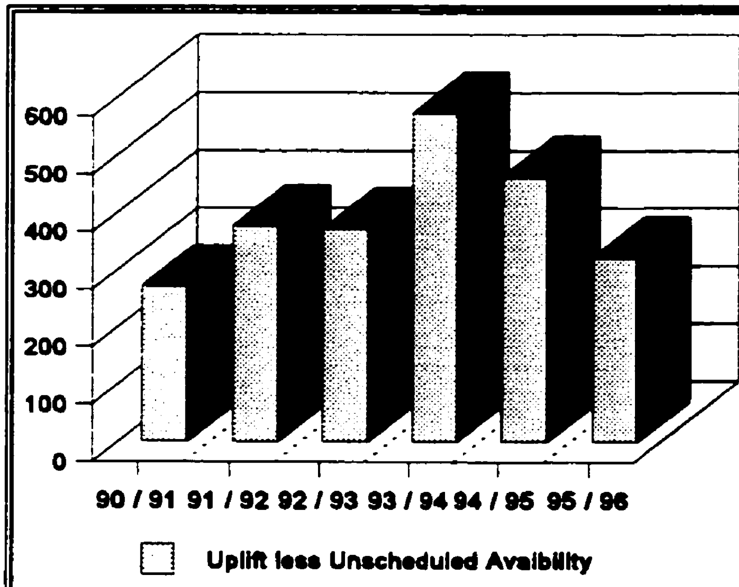

Figure 7.7 Uplift Payment (excluding unscheduled availaibility) [7-10]

Chapter 8 Various Issues in England and Wales Power Industry

To provide a broader view of the England and Wales power industry reform, in this chapter we present an extensive review regarding the operation of the transmission, distribution and supply businesses. Price-caps control, and contracts for differences (CFDs) which are heavily used in England and Wales are also discussed together with the implementation of retail competition scheduled to appear in 1998.

8.1 The Transmission Business

The National Grid Company (NGC), which operates the 175 kV and 400 kV high voltage transmission system, owns 7,000 km of transmission lines and over 200 substations [8-1]. Initially, after Vesting Day, the NGC was owned by twelve RECs, but it was sold off to the public, and is currently listed in the London Stock Exchange [8-3]. Being the only service provider in the transmission business and regulated by OFFER, the NGC is responsible for the efficient, coordinated, and economic transfer of electricity as well as for the provision of open access to the grid [8-1].

Generation utilities and supply companies which meet the requirements of the Grid Code are allowed to connect and use the grid. The Grid Code defines technical requirement for access, and specifies many items related to transmission services such as planning and safety coordination [8-1]. Every year, the NGC is also required to publish a *Seven-year Statement*, on which the future development of the transmission system is based [8-1].

8.1.1 Charges for Transmission Services

The rate charged by the NGC for transmission services has two components, one is for maintenance and construction, the other for grid operation. The maintenance and construction of the national grid prices are under a cap regulation, thus, are not included in the pool prices. The grid operation (reactive power provision, transmission constraint coordination, etc.) is under EWPP management.

The costs associated with the operation of the grid are directly passed through the pool to the customers via the Uplift component of the pool sell price (PSP) [8-2]. On the other hand, the charges for transmission system maintenance and construction are paid to the NGC by the gensets, RECs, and large customers outside the pool. These charges are, of course, indirectly passed down to the end consumers through the genset bids and contracts for difference (CFDs), on the one hand, and through the supplier pass-though factors (see section 8.2.4), on the other. The charges for transmission system maintenance and construction consist of two parts, namely, (i) the connection to and (ii) the use of the transmission network. The charge for connection is imposed on all users which directly connect to the grid according to the user's size [8-1]. Alternatively, the charge for the use of the network is paid by the generators and suppliers in proportion to the amount of power transferred by the grid. This charge, in turn, has two rate components, one fixed, the other variable. The fixed rate is paid equally by all generators and suppliers, while the variable rate depends on the location of the network user.

The location-based variable rate for the use of the transmission grid differentiates among fourteen areas in England and Wales [8-1]. Generally, there is a negative charge for generation in the south where the load is the heaviest, and a positive charge in the north where there is an excess of generation [8-2]. However, when combined with the fixed rate component, the charge for the use of transmission network is always positive [8-3]. The logic behind the variable element charge is that the generation in the south alleviates potential transmission congestion while the generation in the north aggravates it.

The charge for the transmission system maintenance and construction described above, C_{MC}, is summarised in equation 8.1.

$$C_{MC} = C_{CON} + C_{USEC} + C_{USEV} \quad \textbf{(8.1)}$$

where C_{CON} refers to the charges for connection to the grid which are independent of the amount of power transferred, while C_{USEC} and C_{USEV} respectively refer to the constant and variable network use charge component.

8.1.2 Regulation of the Transmission Maintenance and Construction Rates

Since the transmission business is a monopoly, regulation of its rates becomes necessary. The regulating body, OFFER, has adopted a price cap regulation to control the transmission system maintenance and construction charges by limiting the annual rate increase based on the so-called RPI - X formula. In this formula, RPI is the retail price index, while X is a potential productivity gain by the transmission business as estimated by the regulating body, OFFER. The factor X was set at 3% until April 1997 [8-1]. Since significant profits were gained initially by the NGC, the price controls from April 1997 to March 2001 entailed an initial one-time reduction in the transmission service rate in the first year of 20%, followed by RPI minus 4%

in each of the following years [8-1]. Detailed discussion regarding the above reduction will be presented in section 8.3.

8.2 Distribution and Supply Businesses

Before Vesting Day, there were twelve state owned Area Boards responsible for distributing and supplying electricity to customers in England and Wales. Since Vesting Day, the direct successors of these twelve Area Boards, that is, twelve Regional Electricity Companies (RECs), have assumed responsibility. Moreover, the responsibilities of Area Boards have been divided into two specific business, distribution and supply. The distribution business refers to the operation of the distribution network, while the supply refers to the business of facilitating trade of electricity from the EWPP to customers.

RECs are the only entities involved in the distribution business. On the other hand, the supply business, which refers to the trading of electricity with final customers, large or small, is handled by both RECs and other players, called second-tier suppliers in England and Wales. The nature of second-tier suppliers is discussed in more detail in section 8.2.3.

8.2.1 The Distribution Business

The distribution business, operated and maintained by the RECs as a monopoly, uses the distribution network to deliver electricity from the high voltage grid to individual customers. To facilitate competition, RECs are required to provide open access of their distribution networks to second-tier suppliers.

The charge for the use of the distribution network is also controlled by a price increase regulation which supervises the annual price increase based on the so-called RPI - X formula discussed in 8.1.2. Since Vesting Day, the factor X was initially set in the range from 0 to -2.5% depending on the RECs [8-1]. In August 1994, the regulating body, OFFER, required that distribution charges be reduced by an amount ranging from 11% to 17% (depending on the RECs) commencing in April 1995 [8-1]. This price reduction was to be followed by a further 2% per year in the subsequent four years [8-1]. Later, OFFER proposed further reductions of between 10% and 13%, starting from April 1996, followed by a further 3% per year for the subsequent three years [8-1]. The reason of these deduction will be discussed in section 8.3.

Typically, the distribution business produces most of the profits in the RECs. A typical REC with an annual revenue of about £330 million has profits of around £ 120 million [8-1].

8.2.2 The Supply Business

In general, to create competition, it is necessary to split the electricity industry into four distinct businesses, namely, generation, transmission, distribution, and supply. The transmission and distribution businesses, by their nature, have only limited scope for competition, and therefore, are monopoly operated and regulated in England and Wales. The emphasis of competition, therefore, lies in electricity generation and supply.

In England and Wales, competition in generation was implemented abruptly in 1989, while competition in the supply was introduced gradually over several years. Jestingly, the deregulation of the UK power industry was known as a "half-market" since, until the writing of this thesis, only generation competition had been fully implemented. However, competition in supply improved over time and is expected to be completely implemented by 1998. Table 8.1 and figure 8.1 show the evolution of the expanding scope in the competitive electricity supply market of England and Wales [8-8, 8-9].

Table 8.1 The Scope of Competition in Supply Market [8-8]

	Size (MW)	Date of Deregulation	Numbers of Customers	Percent of Demand
Large Customers	> 1	April 1989	5,000	30
Medium Customers	> 0.1 and < 1	April 1994	45,000	20
Small Customers	<0.1	April 1998	22,000,000	5

8.2.3 The Supply Market Structure

In the EWPP, two types of electricity supply companies are allowed to sell electricity to end consumers, namely, RECs and second-tier suppliers. RECs have a monopoly within their approved area to supply end customers, while second tier suppliers are allowed to sell to any customer with a peak demand over 100 KW in any area. RECs can also act as a second-tier supplier within the authorized area of other RECs. In addition, some generation utilities also play the role of second-tier suppliers. It is the presence of the second-tier suppliers that introduced a degree of competition into the electricity supply market.

Until 1998, customers in the England and Wales are also classified into two types: (1) Consumers with peak load less than 1 MW are franchise customers who must buy from their local REC, (2) Consumers with peak load exceeding 1 MW are non-franchise customers who can buy either from their local REC or from second-tier suppliers. In other words, non-franchise consumers are allowed to shop around for the best prices.

The above limit of 1 MW was reduced to 100 kW in 1994 and will expire in 1998. In 1996, the 100 KW and above market contained about 55,000 customers [8-1]. After 1998, all customers, regardless of the size, will be free to choose suppliers.

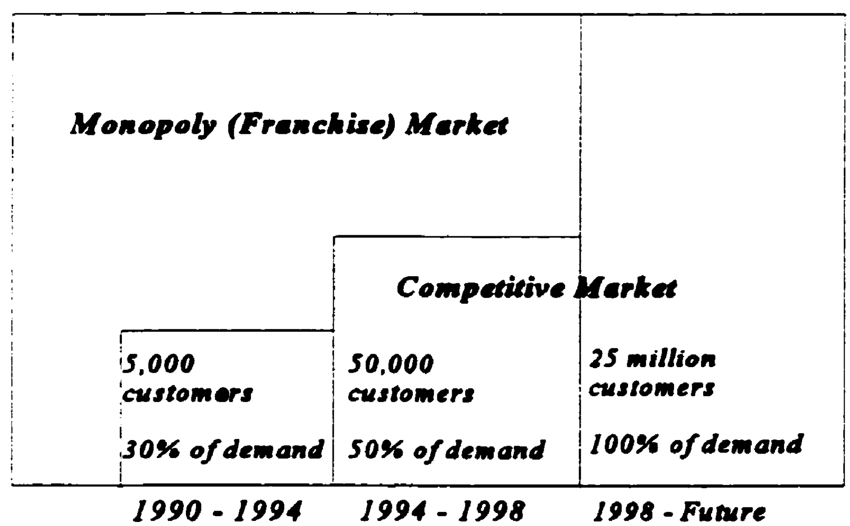

Figure 8.1 Approximation of the Expanding Scope in the Competitive Electricity Supply Market [8-9]

8.2.4 Supply Price Regulation of RECs

Since RECs have a monopoly and a responsibility to sell electricity to their franchise customers, price controls become necessary. Thus, prices are controlled on the basis of the so called RPI - X + Y formula [8-4]. In this formula, RPI is the supply price index, that is, the rate of inflation, while X is a potential productivity gain by the REC as estimated by the regulating body, OFFER. The purpose of this enforced reduction is to encourage the REC to improve its operational efficiency. The factor Y is a so-called pass-through factor which lumps the cost increase in transmission, distribution, and electricity purchase costs as well as the Fossil Fuel Levy [8-2, 8-4]. The factor X is included to force the electricity supply price to decrease over time and the factor Y is included to ensure that the electricity purchase price, plus the transmission and distribution costs are passed on to the end consumers.

The price control of the supply business is also referred as RPI - X in some references [8-1, 8-2]. One essence of this formula is that the uncontrollable elements, such as electricity purchase price and transmission and distribution charges, are passed down to the customers. These uncontrollable elements, can be regarded as the Y factor of the formula in the last paragraph.

8.2.5. Competition in England and Wales Power Supply Business

As it turned out, competition for the supply of non-franchise (large) customers has become very high. Thus, around 43% (demand-weighted) of the customers with peak load from 100 kW to 1 MW buy electricity from second-tier suppliers. All RECs, National Power, PowerGen, Nuclear Electric, the Scottish companies and some new companies have also become second-tier suppliers, therefore, the prices charged to non-franchise customers have undergone significant downward pressure [8-1].

8.2.6 Historical Data of Supply Prices

Tables 8.2 and 8.3 show the supply prices in England and Wales in 1994 and 1995, and the price variations from 1989 to 1996. In table 8.2, customers are classified into five categories, namely, industrial, domestic, commercial and public administration, transport and agricultural sectors, while in table 8.3, customers are classified into three categories according to their assumed capacity. From table 8.3, we see that the electricity supply prices in England and Wales decreased for all categories since Vesting Day when the inflation rate is taken into consideration.

Table 8.2 The Supply Prices in 1994 and 1995 (£/MWh) [8-1]

	1994	1995
Average Price	61	59
Industrial Sector	45	44
Domestic Sector	74	73
Commercial and Public Administration	62	59
Transport Sector	56	45
Agricultural Sector	68	66

Table 8.3 The Supply Price Variation From 1989 to 1996 [8-5]

	I	II	III	RPI
Maximum demand (KW)	500	2,500	10,000	
Maximum consumption (MWh/year)	1,752	8,760	52,560	
Annual load factor	40%	40%	60%	
Price in 1989 / 1990 (£ /MWh)	46.7	45.2	39.2	117.4
Price in 1993 / 1994 (£ /MWh)	56.7	n/a	n/a	141.5
Price in 1995 / 1996 (£ /MWh)	51.2	45.1	40.3	150.1
Price in April, 1996 (£ /MWh)	48.6	43.6	39.8	152.6
Price in July, 1996 (£ /MWh)	48.7	43.9	39.7	152.4
Price in Oct, 1996 (£ /MWh)	47.6	42.7	38.9	153.8
Price Change Ratio 89/90 --- 96/97 (including inflation rate)	-24.5%	-30.1%	-26.5%	+53.8%

Compared with the pool prices shown in tables 7.4, 7.5, and 7.6, the electricity supply prices shown in tables 8.2 and 8.3 are relatively high as the PSP only accounts for less than 40% of the supply price. However, since most suppliers rely on contracts for difference (CFDs) instead of on the pool sell prices (PSP) to purchase electricity, the above comparison does not always reflect the reality.

Generally, about two thirds of the final supply price is associated with generation cost, approximately 5% transmission, roughly 25% distribution, and between 1% to 7% supply charge [8-1]. Figures 8.2, 8.3 and 8.4 show the price breakdown components and their typical percentage of the final prices for different-sized customers [8-6].

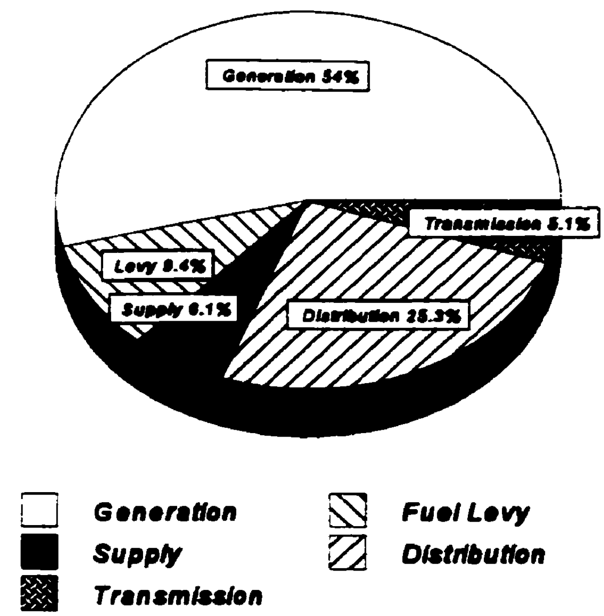

Figure 8.2 Supply Price Breakdown for Customers below 100 KW [8-6]

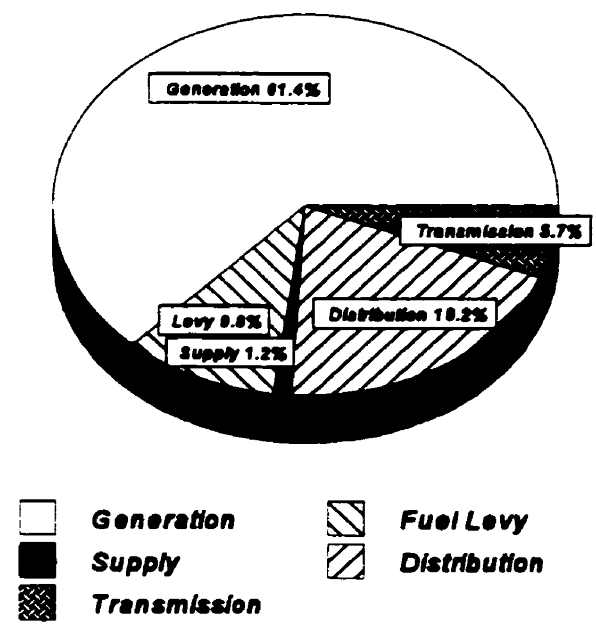

Figure 8.3 Supply Price Breakdown for Customers Between 100 KW and 1 MW [8-6]

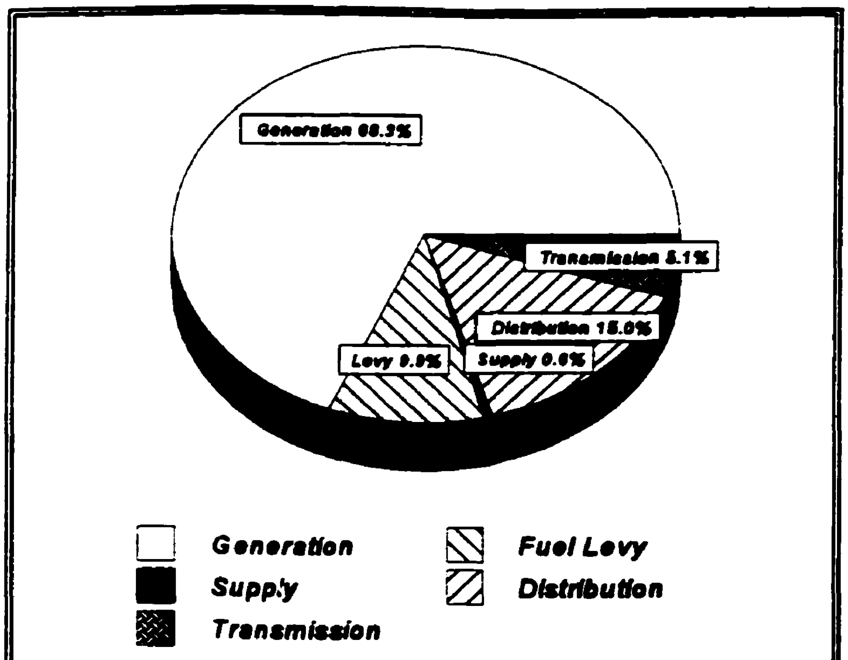

Figure 8.4 Supply Price Breakdown for Customers above 1 MW [8-6]

8.2.7 International Electricity Prices Comparison

Tables 8.4, 8.5 and 8.6 compare electricity prices in the European Union and in the world. In table 8.4, prices are classified into three categories according to the customer consumption capacity.

From these tables, we can see that the UK ranks as the fifth cheapest out of the 15 European Union member countries in the domestic supply market, and fourth cheapest in the industrial supply market. In world terms, the UK electricity prices remain competitive, failing midway in both domestic and industrial price comparisons [8-5].

Table 8.4 European Prices Comparison (£/MWh) [8-5]			
Customer Classification	I	II	III
Maximum demand (KW)	500	2,500	10,000
Maximum consumption (MWh/year)	1,752	8,760	52,560
Annual load factor	40%	40%	60%
Germany	84.7	79.1	63.7
Italy	74.7	68.9	45.9
Austria	73.0	72.3	60.4
Belgium	68.7	64.6	47.3
Spain	65.9	60.8	53.0
Luxembourg	65.9	54.3	44.0
Portugal	65.0	64.0	53.0
Ireland	54.6	50.6	41.3
Netherlands	54.2	52.6	44.2
France	52.5	52.1	41.0
UK	50.9	45.3	40.3
Greece	48.6	48.6	35.9
Denmark	46.0	44.8	41.1
Finland	43.6	42.9	n/a
Sweden	39.6	31.2	25.6

Table 8.5 World Electricity Domestic Price Comparison(£/MWh) [8-5]

Czech Republic	Canada	South Africa	USA	New Zealand	Taiwan	Australia
29.2	45.9	47.4	48.9	54.7	56.7	57.7
Norway	Argentina	Singapore	Israel	Finland	Greece	Sweden
58.4	59.9	64.4	65.9	75.8	79.0	85.6
Ireland	UK	South Korea	Nether lands	Luxemb ourger	Italy	Portugal
86.7	93.3	95.9	104.9	110.8	114.6	118.1
Austria	Spain	France	Germany	Denmark	Japan	Belgium
114.4	126.6	131.4	137.0	137.6	142.4	150.1

Table 8.6 World Electricity Industrial Price Comparison (£/MWh) [8-5]

South Africa	Norway	Canada	Sweden	New Zealand	Czech Republic	Australia
27.9	29.0	29.9	31.2	35.2	38.9	39.4
Argentina	South Korea	Finland	USA	Israel	Demark	UK
41.7	42.5	42.9	44.1	44.6	44.8	45.1
Taiwan	Singapore	Greece	Iceland	France	Nether lands	Luxem bourg
46.7	47.3	49.6	50.8	52.2	52.8	54.1
Spain	Portugal	Belgium	Italy	Austria	Germany	Japan
60.8	64.0	64.6	68.0	72.8	76.9	83.0

8.2.8 The Profit of the Regional Electricity Companies

In 1994 and 1995, RECs were fiercely attacked because of their continuing high profits, fat salary packages for CEOs and, soaring stock prices [8-7]. From Table 8-7, which shows the profits and revenues of the major electric companies in England and Wales in 1992 / 1993, we see that the profit-revenue ratio of the RECs' distribution business, 27.8%, was relatively high. The distribution business accounts for a large proportion of the total profits earned by RECs [8-6].

Table 8.7 Pretax Profit and Revenue of the Major Electric Companies in England and Wales 1992 / 1993 (million £) [8-4]

Company	Profit	Revenue	Profit / Revenue
National Power	580	4,348	13.3%
PowerGen	425	3,188	13.3%
Nuclear Electric	661	1,400	47.1%
NGC	350	1,396	25.1%
RECs Distribution	1,042	3,751	27.8%
RECs Supply	n.a	13,921	2% (Approximation)

The high profits listed in table 8.7 can be attributed to the improvement in running efficiency, staff reduction, as well as insufficient regulation. One may notice that both generation utilities, the NGC and RECs obtained high profits, however, generation profits, although high, have not been criticized as excessive since the generation market is operated competitively. The regulation over the NGC's transmission services was tightened on April 1996 as shown in section 8.1.2.

The RECs' high profit, as well as their high salaries and soaring stock prices brought on regulation changes in 1995. After the first scheduled review of the price cap for distribution in 1994, the regulating body, OFFER, forced RECs to reduce their charges by 11 to 17% in 1995-96, and, thereafter, an RPI - 2 price cap was to be imposed until 1999-2000 [8-4].

These regulation changes shocked the RECs. The Midlands Electricity, a REC, said, "We thought everything was settled and sorted out. We were quite surprised that OFFER planned to reopen the whole thing [8-7]." As a result of the change, in 1995 shares in RECs lost nearly 23% of their value [8-7].

8.3 The RPI - X Price Caps Regulation

The RPI - X price-cap regulation,also known as performance-based regulation [8-8], is a method adopted by England and Wales for the purpose of restraining the NGC and RECs' monopoly power over prices. Compared with the commonly used rate-of return regulation, it is very new. The main reason for introducing price-cap regulation is to provide the regulated companies with a financial incentive to reduce their operational cost, and therefore, to increase the running efficiency.

In sections 8.1.2, 8.2.1 and 8.2.4, we have discussed the application of the price-cap regulation in transmission, distribution and supply businesses in England and Wales. In this section, we analyse the advantages and shortcomings of this method.

8.3.1 How RPI - X Works?

The general form of price-cap RPI - X regulation is RPI - X + Y, where Y refers to all costs over which the regulated companies have no control. Supposing PR_t is the electricity price for year t, we can derive the price for the next year as:

$$PR_{t+1} = PR_t \times (1 + RPI - X + Y) \qquad \textbf{(8.2)}$$

The factor X is set by the regulating body, and should be reviewed every few years. In England and Wales, the review timing ranges from three to five years [8-8].

8.3.2 The Practice of Price-cap Regulation in England and Wales

The RPI - X regulation is designed to provide a strong economic incentive for regulated companies to decrease cost and to increase efficiency since companies which achieve savings greater than factor X will profit more. In this sense, the RPI - X regulation has worked very successfully in England and Wales, where NGC and RECs have substantially reduced their operational costs [8-8].

However, the RPI - X regulation proved problematic in allocating the cost-saving gains among electricity companies, shareholders and customers. The England and Wales experience shows clearly that the regulating body has an inclination to underestimate the companies' potential to reduce costs, and therefore, sets the factor X lower than it should be. When the factor X is under-set, most of benefits brought by the efficiency gain are allocated to regulated companies rather than to the customers. The initial failure to set an appropriate factor X in England and Wales has proved expensive for customers [8-8]. Moreover, subsequent experiences have shown the difficulty of correctly setting the factor X.

From table 8.8, which shows the price regulation over the transmission, distribution and supply businesses in England and Wales since Vesting Day, we see two major regulation changes, one in the transmission business in 1997, and the other in the distribution business in 1995. As discussed earlier, the main reason for these regulatory changes was the high profits initially gained by the NGC and RECs. These regulatory changes have raised concerns that the regulating body, OFFER, lacks a sense of commitment to its previous decisions, and therefore, brings on financial uncertainty for new investments in the England and Wales electricity industry.

Table 8.8 Regulation Over Transmission, Distribution, and Supply in E&W		
Regulatory Area	**Regulatory period**	**Regulatory method**
Transmission (1)	04/90 - 04/93	RPI - 0
Transmission (2)	04/93 - 04/97	RPI - 3
Transmission (3)	04/97 - 04/98	One-time 20% Deduction
Transmission (4)	04/98 - 04/01	RPI - 4
Distribution (1)	04/90 - 04/95	RPI + X ($0 \geq X \geq -2.5\%$)
Distribution (2)	04/95 - 04/96	One-time 11 - 17% Deduction
Supply (1)	04/90 - 04/94	RPI -0
Supply (2)	04/94 - 04/98	RPI - 2

8.4 Contracts for Differences

It turns out that the pool purchase price (PPP) fluctuates very sharply, with the difference being almost 100 times between the highest and the lowest PPPs. For example, in December 1996, the lowest PPP was $6.44£/MWh$ while the highest one was $586.87£/MWh$, while the load during highest PPP period is only about 3 times the load during the lowest PPP period [8-9].

To hedge against price volatility, a hedging market evolved over times, and most suppliers and large customers purchase contracts for differences (CFDs). Initially since Vesting Day, CFDs were imposed on RECs, National Power and PowerGen in order to protect the UK coal industry [8-8]. At that time, the two privatized successors of the CEGB were constrained by the fuel contracts signed with the highly priced British coal industry. Thus, OFFER decided that RECs must buy a certain amount of electricity from these two companies to limit the impact of these contracts and, therefore, to create a fair competitive environment. Therefore, CFDs played an important role to protect the UK coal industry at the beginning of the restructuring of the electricity industry [8-10]. Then, later, many other generation utilities also entered into the CFD market to hedge against volatility.

CFDs are purely financial contracts, therefore, are not contracts to physically deliver electricity, but to transfer funds. Typically, there are one-way CFDs and two-way CFDs, both of which have a predetermined price called the strike price, which is the price both sellers and buyers agree on to trade electricity. One-way CFD provide payment to the buyers (usually RECs) when the PPP exceeds the strike price, while two-way CFDs also provide payment to the sellers (usually generators) when the PPP falls below a strike price.

The following gives a hypothetical example to show how two-way CFDs work. Suppose that the strike price of the contract is $30£/MWh$, and the quantity of electricity traded is 1,200 MWh daily. If the PPP average demand-weighted PPP during that day is $24£/MWh$, the buyer should pay the seller $1200 \times (30 - 24) = 7200£$. Alternatively, if the average demand-weighted PPP is $35£/MWh$, the buyer pays 6000 £ to the seller.

Almost all generation utilities are covered by CFDs to hedge against risks. In the first two years following Vesting Day, it was estimated that CFDs covered 84.3% and 89.1% respectively of National Power and PowerGen's generation [8-11]. The OFFER report [8-12] shows that in 1994, about 80% of total demand are covered by some form of CFDs, and another reference [1-1] indicates that only 10% of electricity is traded at the pool prices, the rest being covered by CFDs.

8.5 Future Picture

As originally planned, full competition will be introduced into the supply business in 1998, after which all customers will be able to choose suppliers other than their local RECs. The implementation of supply competition is planned in three steps [8-11]. In step 1, which starts in April 1st 1998, 10% of all sub 100 kW customers in each REC area, plus all maximum demand customers and those taking supply through a half hourly metre are allowed to choose suppliers. In step 2, which follows 13 weeks after step 1, all remaining business customers and a further third of domestic customers are free to choose. Then in step 3, all remaining domestic customers are allowed to choose. The timing of the third step depends on the progress in steps 1 and 2.

There are more than 30 licensed suppliers in England and Wales, from which every customer can purchase power after 1998. It is estimated that there are 25.6 million customers in England and Wales below 100 kW [8-11].

To facilitate supply competition, metering becomes very important. OFFER is likely to adopt different approaches for above and sub 100 KW customers.

For customers above 100 KW which wish to buy electricity from suppliers other than their local RECs, a half-hourly metre must be installed and a metre operator from one of the RECs must be appointed. In addition, a suitable communication link to each metre is also required to allow remote reading. Meters can be purchased or leased, with the budget cost for a typical five year lease and operation agreement being £200 per metre per annum [8-14].

For sub 100 KW customers, it has been proposed that after April 1998 everyone will be assigned one of eight standard load profiles. The standard profiles specify a means of assessing the average consumption in each half-hour, throughout the year. This will enable sub 100 KW customers to change supplier without incurring extra metering costs. As an alternative approach, half hourly metering may be installed.

The readiness of suppliers and customers for full competition as well as the necessity to install half-hour meters for all customers is still uncertain. What is certain is that the impact of full competition on electricity supply will be huge. However, only time can tell whether the full supply competition in England and Wales will be successful. Nevertheless, some predictions can be made at this time.

1. New suppliers will enter the market, therefore, increasing the competition, then decreasing the supply price.

2. Suppliers will provide more electricity service options to match the various customers' needs. For example, customers might buy a contract consisting of a trade-off between price and reliability.

3. Load management will likely be exercised more frequently since customers will be more sensitive to price variations.

4. Small size customers in rural areas will have to pay higher prices than urban customers.

Chapter 9 Conclusions

This thesis studies the electricity industry reform carried out in England and Wales with emphasis on the England and Wales Power Pool (EWPP). In particular, the rules which govern the operation of the EWPP are studied and rigorous analytic explanations for these rules are provided. Four particular questions are targeted, namely, (1) the theoretical base behind the EWPP scheduling program which is known as GOAL, (2) the purpose for using the Table A/B method in pool payment calculations, (3) the reason for adopting marginal cost pricing instead of average cost pricing, and (4) the logic for choosing uniform pricing auction over discriminatory pricing. In addition to the above-mentioned four problems, an extensive review of the entire deregulated electricity industry in England and Wales is presented which helps to understand the electricity industry reform, in particular, the poolco model operation.

9.1 The England and Wales Power Pool Operation

The EWPP, which is operated by the NGC and governed by a set of complicated rules, is the heart of the deregulated electricity industry in England and Wales. Essentially, the pool is operated as a sealed-bid, multiple-winner electricity auction system. However, electricity is a merchandise which cannot be stored, and its generation cost is not a linear function of the output level, therefore, an electricity auction is much more complex than ordinary auction systems.

The EWPP Pool rules presented in chapter 2 are analysed and discussed in chapters 3, 4, 5, and 6. The following conclusions can be drawn from this thesis research:

- The GOAL program employed by the EWPP to produce a preliminary generation schedule for the purpose of determining the pool price has a solid theoretical basis. Essentially, the GOAL algorithm is a heuristic derived from Lagrangian Relaxation and the Switching Curve Law.

- The pool price calculation method should be designed to ensure that generators receive enough payment to cover their long and short-run costs, while protecting customers from overcharges. The Table A/B method is such an approach. It satisfies the payment adequacy constraint[1] and, meanwhile, decreases the total pool payment charged to the pool electricity buyers.

- The pool price is based on marginal rather than average cost pricing policy. This thesis concludes that the marginal cost pricing is an appropriate method for the EWPP. Under uniform marginal cost pricing and a competitive environment, the optimum bidding strategy is to bid at cost and at maximum capacity. The bidding strategy is therefore simple and transparent. However, an average pricing policy under a competitive environment induces bidders to increase bids above their generation cost, and to restrain their availability. The biding strategies normally lead to a higher Capacity Element payment and a lower system reliability compared to marginal pricing. Furthermore, the complexity of the average cost pricing bidding strategy would need more manpower to figure out the bids.

- The EWPP uses uniform pricing rules which mean that all winning bidders

---

[1] Payment adequacy constraint guarantees that winning bidders (gensets) receive a total payment at least as high as specified in their offer files over the whole scheduled horizon.

receive the same price for energy production, the SMP. This thesis concludes that, under a competitive environment, if bidders are neither risk-averse nor conservative, the total pool payment under uniform and discriminatory pricing are equal. The discriminatory pricing policy has some advantages over the uniform pricing policy, such as sharpening the bidders' awareness of competition, and limiting "free-loader" (see sections 6.5.3 and 6.5.4), but it also has some disadvantages such as compressing the merit-order list and complicating the bidding strategy. It is apparent that the disadvantages outweigh the advantages, and therefore, discriminatory pricing was not considered appropriate for the EWPP.

- Basically, the EWPP bidding rules are suitable for electricity auctions. However, the rules are very complex, and not transparent enough. In addition, the special market structure in the England and Wales generation market makes the rules vulnerable to be abused by the National Power and the PowerGen which have notable market power. In particular, the design of the Capacity Element calculation is problematic (see chapter 7).

9.2 The Entire Deregulated Power Industry in England and Wales

The England and Wales experiences provide a precious case study for electricity industry reform. Its experiences, whether successful or not, are valuable for those who are planning to undertake or are undertaking electricity industry reform.

- Generally speaking, the England and Wales electricity industry reform is a clear success because the financial efficiency in many electricity utilities has been improved while the reliability has not been hurt. The England and Wales model shows that wholesale competition is possible by divestiture, privatization, restructuring and regulatory changes, and that the poolco model is a practical and easy approach to introduce competition. In addition, in the UK, the environmental effects of electricity reform have turned out to be positive because of the replacement of the coal plants by gas plants.

However, the England and Wales template is not perfect and some problems, as discussed later, still exist in the newly deregulated system.

- Basically, the England and Wales generation market is dominated by two generation companies, National Power and PowerGen, which in 1996 owned more than 50% of the total generation capacity. This duopoly market structure, together with the weakness in the EWPP pool price calculation method, open gaming opportunities for generation companies to game. Essentially, National Power and PowerGen have control over the system marginal price (SMP) and the capacity element (CE) by increasing bids or withholding bidding generation availability. The Uplift element is also a gaming object because of the discrepancy between the preliminary generation schedule and actual generation. To protect customers, the regulating body, OFFER, made several rule changes, however, these changes did not solve the problem completely.

- The transmission, distribution, and supply businesses in England and Wales are regulated by so-called RPI - X price-caps regulation, which is designed to provide the regulated companies with an economic incentive to improve running efficiency. However, the difficulty of setting a proper factor X caused several problems. Generally, in the England and Wales electricity industry, the factor X was set too low, so that the efficiency improvement was not allocated evenly among the regulated companies and customers.

- As of 1998, retail competition is only partially implemented. Wholesale competition, by itself, can only improve the economic efficiency of electricity companies, but does not necessarily bring benefits to customers. As it turns out in England and Wales, almost all electricity companies have increased their profits since Vesting Day, some doubling their profits. However, although the supply price decreased, this drop was not substantial.

- The EWPP, which is operated by the NGC, is a centralized entity which handles the electricity auction process. There is no natural economic incentive for the NGC to operate efficiently, and therefore, to decrease the Uplift price element.

9.3 The Electricity Industry Reform

Some general ideas regarding electricity industry reform can be extracted from the England and Wales experience.

- To create a fair competitive environment in the wholesale market, it is necessary to control the market shares of generation companies to prevent a group of companies from dominating the market and manipulating the price. In this sense, the England and Wales electricity industry reform is not a good example.

- The competitive electricity market is operated under some market rules, whose success can be judged by the extent to which they can effectively compress all potential excessive-profit-making opportunities. In a deregulated environment, competition will prompt players to seek all possible opportunities to increase profits, and it is impossible to make market rules perfect at the beginning. Therefore, it is the regulator's responsibility to identify all gaming opportunities and to modify the rules to limit these opportunities.

- Wholesale competition, by itself, does not necessarily decrease the retail prices because in the absence of retail competition final customers do not have a choice. Therefore, the typical problems found in a regulated monopoly still exist without the introduction of retail competition.

- The price-caps "RPI - X" regulation is designed to provide the regulated companies with an incentive to increase their operational efficiency, and it can be successfully introduced into the electricity industry reform if a proper value of the factor X can be found. Essentially, the factor X determines the allocation of the improvement in efficiency among regulated companies and customers.

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