THE LIBERALIZATION OF THE TURKISH ELECTRICITY SECTOR: A SIMULATION ANALYSIS

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ABSTRACT

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The Turkish Electricity System has gone through a liberalization process. This study aims to analyze the possible outcomes of this process by using a simulation framework. First, we look at the basics of new market design and focus on international evidence. Second, the theoretical and empirical literature about the liberalization of the electricity sector is reviewed. Then, the structure of our model, Turkish Electricity System Simulation Model (TESS), is summarized. In this model, it is assumed that a spot market is formed and all the agents in the sector operate in this market. Using this model, the effects of various factors, like industry structure, consumer participation and regulation, upon the performance of the spot market are analyzed. Moreover, in simulation case studies, uniform and a non-uniform pricing mechanisms are compared.

Keywords: Electricity Sector, Turkey, Liberalization, Simulation, Electricity Pricing, Spot Market, Regulation

ÖZ

TÜRKİYE ELEKTRİK SEKTÖRÜNÜN SERBESTLEŞTİRİLMESİ: BİR SİMÜLASYON ANALİZİ

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Türkiye elektrik sektörü bir serbestleştirme sürecinden geçmekte. Bu çalışma simülasyona dayalı bir çerçeve kullanarak bu süreci analiz etmeyi hedeflemektedir. Birinci olarak yeni piyasa yapısının temel özelliklerine bakıldı ve bir takım önemli sonuçları çıkarabilmek için bazı uluslararası örnekler üzerinde duruldu. İkinci olarak elektrik sektöründeki serbestleştirme hakkındaki teorik ve ampirik literatür özetlendi. Daha sonra bu çalışmada kullanılan simülasyon modelinin, Türkiye Elektrik Sistemi Simülasyon Modelinin, temel yapısı verildi. Bu modelde Türkiye'de bir spot piyasanın kurulduğu ve sektördeki bütün ajanların bu piyasada faaliyet gösterdikleri varsayılmıştır. Daha sonra bu model kullanılarak, endüstri yapısı, tüketici katılımı ve düzenleme gibi bir takım faktörlerin spot piyasanın performansı üzerindeki etkileri incelenmiştir. Ayrıca simülasyon örneklerinde bazı fiyatlama mekanizmaları karşılaştırılmıştır.

Anahtar Kelimeler: Elektrik Sektörü, Türkiye, Serbestleştirme, Simülasyon, Elektrik Fiyatlaması, Spot Piyasa, Düzenleme

To My Lovely Wife,

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I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

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INTRODUCTION

Beginning with the 1980s, liberalizing the sectors that provide basic utilities and that have been crucial in terms of guaranteeing social welfare has provided the basis for public sector retreat from economic life. Most importantly, these sectors have been opened up to **competition** and **private participation**. There has been considerable political and ideological support behind this transformation. Most governments have either taken important steps to liberalize these sectors or announced their intention to do so.

Main reasons that lead governments to liberalize such sectors are the inefficiency of public companies and insufficiency of public investment funds that can be directed to these sectors in order to overcome deficient supply. This transformation also receives a great deal of support from the Bretton-Woods institutions and specialized international institutions such as the International Energy Agency.

The liberalization of the electricity sector has been a more recent issue than the reform in other utility sectors. The delay in the liberalization of the electricity sector has been due to economic and technical complexities of the sector that the reformers should tackle with. As opposed to water or natural gas, electricity has some distinctive features such as non-storability. Moreover, there are strong externalities in the electricity network. In this context, the liberalization of the electricity supply industry becomes a complex issue on all political, economic and technical grounds. Such complexities create important discussions about which regulations to be adopted and which market structure to be imposed after the liberalization process. As we trace the history of the liberalization of the electricity sector in different countries, we observe some common tendencies among countries while there are also many discrepancies in the experiences. Since the structure of the electricity supply industry shows important variations among countries, the experiences differ very much. For a better understanding of the reform process, we can divide the transformation or reform process into two phases. In phase I, the "reformist" governments take the necessary legal and institutional steps to create a convenient environment. In this phase, they decide about market structures that will be formed at the end of phase II. In the second phase, they create the agents and device the market rules as a preparation to these market structures. As the international evidence shows, parallel markets like a spot market, a bilateral contracts market, and a balancing market may coexist. In some countries, which have a developed electricity market structure, a futures market may emerge as well. Turkey seems to have completed the first phase.

The objective of this study is to analyze the performance of the Turkish electricity sector in the post-liberalization period under the assumption of a spot market. We use the simulation approach to analyze four issues.

First, we discuss how different pricing mechanisms in the electricity sector affect social welfare created. Flows over electricity transmission lines create losses. In a system with loss, there may be range of pricing alternatives. Each pricing option affects profits or consumer surplus differently. We will use our model to compare the effects of different pricing mechanisms. In this context, we can digress upon the question that whether the non-uniform or uniform pricing scheme generates a higher level of social welfare.

Second, we will concentrate upon how the Turkish spot market may give response to external shocks under different pricing schemes. Third, we discuss whether gaming and bidding strategies can affect electricity price, quantity and social welfare. In the context of this question, we can extend the discussion to whether the spot market structure is prone to the exercise of the market power or not.

Another question that we focus on is that how distributional monopolies can affect social welfare at the regional level, that is, whether they decrease social welfare or not. Most of the international liberalization efforts aim to make all consumers free in the long run. How do output and prices respond when all consumers are free compared to a distributional monopoly case? We attempt to answer these questions in the simulation case studies section.

There is an important debate on the effects of bilateral contracts upon the spot market. We will use some simulation examples to find out such effects. Last, we will look at what impacts some regulatory measures like price caps or specific taxes may have. We will focus on environmental tax and price cap regulation.

In our analysis, we will use a simplified model that represents the Turkish electricity sector. We will use a simulation model since simulation analysis seems to be the most suitable analytical tool in this context. The electricity network is a complex network and it causes strong externalities. Moreover, any change in a part of the network affects the whole system. Hence, the best method in analyzing the electricity network is simulation analysis, since it provides a well-defined framework to focus upon complex interactions in the electricity network.

We designate this model as The Turkish Electricity Market Simulation Model (TESS) and it is written in Borland C++ v. 5.02. The model simulates a typical day of a spot market in which generators and consumers/distributors submit their offers/bids in the previous day just after the regulator announces its demand predictions.

In the spot market, sellers and buyers do not directly interact with each other. This market works as a stock exchange, sellers directly sell electricity to the market and buyers buy directly from the spot market. It is important to note that this market is a virtual market; regulator sells and buys all the electricity. The system operator, by solving a merit order problem or a non-linear optimization problem, allocates the generation among generators and the consumption among distributors/consumers.

In the modeling context, two types of spot markets could be defined. In the first one, generators or consumers submit discrete values. For example, generators submit output/price blocks as an offer to the regulator and consumers/distributors submit demand/price blocks (the case in which consumers/distributors submit their demand/price blocks is called flexible demand case). Regulator sums up the output/price blocks up to his demand prediction and determine the system prices. In the flexible demand case, the system operator adds up generation blocks as mentioned and also adds up demand blocks from the higher price to the lower one, he stops at the point at which demand and supply are equal. This type of spot market is called "merit order" spot market. In the second one, which we will use, generators submit their quadratic cost functions while consumers/distributors submit their quadratic total benefit/total revenue functions. Regulator solves a non-linear Social Optimal Power Flow problem and finds out optimum output and demand for each agent. After finding out optimum control variables, he should decide about the pricing scheme. Since there are losses in the system, prices of generators or consumers differ. This complicates the problem and paradoxically increases the pricing alternatives for the regulator. Profits and consumer surplus of the agents depend upon the pricing scheme selected by the regulator.

We will discuss various pricing alternatives. We look for the effects of different industry structures upon the performance of the spot market. It is a common belief that this market structure is the most efficient and transparent market structure, therefore, regulator can easily intervene and regulate. Moreover, the government in Turkey announced its will to form this market in the middle term and hence, such an analysis may bring some insights about policy alternatives and implications. There are some necessary steps to be taken in establishing the spot market. We make some restrictive assumptions and these assumptions may result in some over simplifications but this study aims to underline some important issues related with the spot market.

The thesis is organized as follows. In the second chapter, we will focus on the international experiences. Firstly, the UK experience, as an archetype in the liberalization of the electricity supply industry, will be reviewed. We should note that, the reform plan announced by the Turkish government seems to be highly influenced by the UK example. Then, we will focus on the liberalization attempts in the USA. We will also look at the experiences of other OECD countries and some developing countries. We conclude the second chapter by the historical and institutional development of the Turkish electricity system.

In the third chapter, we will review the theoretical and empirical literature concerning the spot market design and the liberalization in the electricity sector. The primal issue in the literature is the market power opportunities provided by the spot market design. The studies we will review indicate a considerable pessimism about the exercise of the market power. Some of the researchers indicate that, the basic source of the market power is asymmetric firm sizes that can settle in the sector after the transformation and offering/bidding mechanisms in the spot market may ease the exercise of such market power. Moreover, the structure of the transmission system may also create opportunities for local monopoly. These interrelated topics are reviewed in the third chapter.

In the fourth chapter, we define the analytical background of our model. We will use "DC Flow Approximation" approach that allows us work on a simplified version of the electricity system and escape from the technical details. Following a summary of "DC Flow Approximation" approach, we will introduce a standard Optimal Power Flow (OPF) problem and outline the basic solution algorithms. Then, we will give more detailed information about the Newton-Raphson method and we pass on to the details of our model and the software we use.

As indicated above, we will work on a simplified version of the Turkish Electricity System. Hence, we impose some restrictions about the data set. We estimate the cost functions of the generators in Turkey by using annual cost data provided by TEAŞ. For the flexible demand case, we use a parameter set for the coefficients of the benefit functions that will give very close estimates to actual demand levels. We calculate hourly demands for each region from aggregate hourly load schedule for Turkey. We get line data from TEAŞ sources.

We also model an individual welfare maximization procedure to show that a group of generators or consumers can apply mark-up pricing. Consumers use their corresponding optimum mark-up rates to obtain maximum consumer surplus. In this case, we show that the spot market mechanism is prone to the exercise of the market power. This procedure works as an upper layer of our social OPF solution procedure and also uses Newton-Raphson method to solve for maximum mark-up rates.

Since there may be the constraint violations in the system, there may be multiple equilibria for individual welfare maximization and our individual welfare maximization procedure with Newton-Raphson algorithm can not find multiple equilibria. In order to overcome this difficulty, we use Genetic Algorithm to find multiple equilibria. In the last section of Chapter IV, we will outline the Genetic Algorithm procedure. Chapter V is devoted to the simulation case studies. First, we outline each case separately. Then, we give summary statistics for the optimum estimated by the model and we concentrate on policy implications. The last section of this thesis summarizes main findings.

CHAPTER 2

ELECTRICITY MARKETS

2.1. The New Electricity Market Design

Although there are many dissimilarities among the experiences of electricity market liberalization, some major common patterns may be substantiated from these experiences: 1) Complete unbundling of traditional vertically integrated monopolies in the electricity supply industry. 2) Privatization of state-owned utilities and introducing competition firstly to the generation segment. 3) As a later step, allowing for wholesale competition. 4) Formation of Power Pool and an Independent System Operator (ISO) which is responsible from providing the system security, regulating Power Pool and the access to transmission grid (in some cases ISO owns the grid). 5) As a final stage, giving way to retail competition which includes introduction of "free consumer" category. The final stage aims to empower the end user and, by this way, to create a safe feedback mechanism for the electricity market (IEA, 2001:13). These are the main common steps towards a "fully competitive electricity market". International comparisons concerning new market design outline some basic features. We will underly these common features for each segment of the electricity system (generation, transmission and power pools).

2.1.1. Generation

Generation segment has been fully liberalized as a first stage. In most of the experiences, state-owned generation companies have divested a large share of their generation assets. In the new market design, these assets have been initially divested from transmission and distribution side and given to autonomous large state-owned companies. Then, these state owned companies sell these assets in pieces to private agents.

Generation segment has seemed to be the most unproblematic segment in the context of electricity market liberalization. The basic topic concerning generation segment is market concentration that may occur after the full-fledged electricity sector liberalization (This seems to be the most discouraging issue for the first-comers in the electricity market liberalization. For example, see Wolfram, 1999). Designers of market reforms generally have two kinds of precautionary steps in this context. One depends on the theoretical arguments of the proponents of this reform. According to these arguments, unbundling and lifting barriers to entry lead to the entry of new generators using more efficient technologies and having lower operation scales, thus to the lowering of entry deterrrence operational scale (Lai, 2001). Second one depends on the new institutional and legal structure of the generation segment. In most of the liberalization experiences, the relations between generators and distributors, or between generators and transmission companies are regulated. By this way, it is aimed to prevent the formation of privately-owned, vertically-integrated monopolies.

The variation in demand is another important issue for generation segment. In the new market design, a competitive generation segment coupled with a least cost economic dispatch should result in an efficient allocation of generators adjusting to the demand, that is, generators that have high start-up and capital costs should be dispatched for base loads and generators that have low fuel and start-up costs should produce in case of a peak demand. Therefore, this market design can bring the specialization of generators according to the fuel type and with respect to the level of load (Schmalense and Joskow, 1985). For example, hydro or nuclear plants may reserve their output for long-term base load contracts, fossil fuel type generators may specialize in meeting base and cyclic loads and gas fired plants may serve to meet peak loads.

It is assumed that enough number of entries and enough number of firms in the generation segment induce generation companies to perfectly inform about their true marginal costs which is very crucial for overcoming potential market power. There is a strong relationship between the number of firms and the firms' inducement to give information about their true marginal costs, and this holds for the concentration ratio in the electricity market. Hence, it can be deducted that unbundling in the electricity supply industry, if not supported by any pooling arrangement or by formation of any spot market that has a large number of generation companies, may not prevent any possible market power. It is argued that wholesale market competition in the form of spot market is the main dynamic force that drives generation segment to its efficiency locus. In contrast to these optimistic theoretical foresights, there are some pessimistic views about the performance of competitive pooling institutions. Rudkevich et al. indicate such a pessimistic belief; they stress that if there is not enough competitive pressure upon the firms in the pools, firms will have good opportunities to bid higher than their marginal costs (Rudkevich, Duckworth et al, 1998).

2.1.2. Transmission

Transmission is the transfer of electricity over lines having capacity equal to or greater than 66 Kv. Distribution is the electricity transfer over the lines, which has capacity less than 66 Kv.

Transmission segment is generally assumed to be a natural monopoly. There are important issues concerning transmission system in the liberalized electricity markets: transmission congestion, free access and operator/owner problem.

Transmisson congestion means the overloading of transmission lines by electricity transactions. Any overloading may cause an increase in price for final consumer and for also the supplier. Transmission pricing should reflect a possible congestion shadow price and such a reflection may be a signal for future expansion of the transmission system. As Hogan pointed out, “an essential feature of efficient, non-discriminatory transmission is a set of prices that reflect the cost of congestion when the transmission system is constrained” (Hogan, 1997a:3).

In a pooling mechanism, when the volume of electricity transactions on all lines generates no overloading, electricity prices among the busses become equalized (Such an equalization is valid only in a system where there is no loss). This is the most efficient outcome for the transmission system. Any overloading on a line will certainly result in price differentials, these differentials correspond to the shadow price of congestion. In reality, there is widespread range of transmission pricing schemes.

On the other hand, in a contract market, when a generator and supplier contract for electricity transaction, they bring this contract to ISO and ISO dispatches the volume of electricity determined by the contract as long as this volume generates no congestion (Yoon and Ilic, 2001:196). During this transaction, if ISO foresees any congestion, it may curtail the transaction. This market works without any transmission congestion pricing.

Any possible congestion is effective in exercising market power. For example, any generator that has a higher cost may have market power in the area in which it is located when the transmission capacity of lines connecting this area to the other areas at which lower cost generators are located is limited (Hogan gives a good illustration, see Hogan, 1997b). Proponents of the reform argue that, in order to prevent such a situation and increase the efficiency of transmission system, ISO may sell financial or physical tradeable rights concerning the transmission capacity in an auction (IEA,2001).

Other related issue is the transmission pricing. There are two kinds of transmission pricing. In the first one, embedded pricing, the embedded capital costs and average annual operation costs are evaluated and this evaluation results in a transmission price that can cover operation and capital costs. There are two main kinds of embedded cost based pricing: Postage stamp and MW-

Mile method. The first one depends on the relative transaction volume with respect to the system peak load and second one depends on the volume and the length of the line which carries that volume (Bhattacharya and others, 2001:128). The second type of transmission pricing is incremental cost pricing which includes short-run and long-run marginal cost pricing. Incremental transmission cost is the cost incurred in supplying incremental power of 1MW.

The other important topic about transmission system is the way of open access. This is related with the regulation of a transmission system owned by non-governmental utilities (especially a hot issue for USA). There are generally two ways for third-party access: Regulated third party access (RTPA), in which the open access is regulated by an independent system operator (ISO), and negotiated third party access (NPTA) in which owner and the third party demanding access to the transmission grid negotiate upon the conditions of access.

Another important topic is wheeling which means one-time transmission of power between seller and buyer by the owner of the transmission grid. Wholesale wheeling generally occurs between two isolated areas. Wheeling at the retail level is generally called transmission (IEA, 2001).

The distinction between the owner and the operator of the transmission grid is another problem concerning the transmission segment. In some cases, the owner and the operator of the transmission system are the same entity. In this case, the operator is at the same time the regulator for the power pool (as will be the case in Turkey). ISO has many responsibilities like power sytem scheduling, coordinating energy markets, determining available transfer capabilities, monitoring system security and system operations status, managing and regulating bilateral contracts, owning ancillary services and providing them to the end users and maintaining transmission network, providing transmission facilities to supplies and loads, and finally planning of transmission system expansion in this case.

In the second case, the owner and operator of transmission system are two distinct entities (as in the case of England/Wales). In this case, the responsibilities mentioned above are shared between the owner and the operator. For example, owner may be responsible from the transmission system maintenance, ancillary services and transmission system expansion under the guidance of the operator. On the other hand, operator may monitor system security, schedules power transactions and performs power system dispatch. It is also responsible from the type of regulation of transmission pricing in both cases.

2.1.3. Power Pools

The Power Pool is operated by an Independent System Operator. It makes economic dispatch of loads at different nodes. All the power transactions, except for those which are bilaterally contracted, must pass through power pool. In addition to making least cost load dispatching, it serves as a signal for prices of bilateral contracts.

There are two kinds of pools. The first one is mandatory pool in which all the generators are obliged to participate in power pool. England/Wales case is an example of this type of pool. On the other hand, in some cases, pooling is not mandatory for generators, meaning that power pools are operating like balancing markets. When any discrepancy between demand and supply for any entity occurs, this entity bids (offers) for buying (selling) power in the pool. In addition to this distinction, pools may be categorized under two headings according to their operational time domain. In the first case, real time pools, generators and distributors bid and offer for instantaneous demand, which is observed by ISO. In the second case, day-ahead power pool, ISO announces its next day load forecast and takes bids and offers for the next day. Pools are operating in hourly or half-hourly basis. In the pooling mechanisms, suppliers submit their output/price bids to ISO. In cases where consumer participation is allowed, distributor companies submit their demand/price offers and ISO sorts these bids and orders in a merit order, it adds up demand/price offers in a decreasing order, while adding up output/price bids in an increasing order and when demand is equated with supply, system marginal price (SMP) is found. We should note that the power pool is a special type of spot market.

The merit-order pricing is determined by the price offer of marginal generating utility. At this point, the problem is the efficiency of this mechanism and it is related to the discrepancy between cost structure and submitted prices of generators. If there is considerable market power; i.e. if some generators' market shares are high enough to affect the slope of the supply function given above in figures 2.2 and 2.3, then, market clearing price will be so much higher than true marginal cost-determined clearing price. Then, it is regulator's responsibility to regulate the market and prevent such an event.

The figures given above ilustrate a uniform-pricing pool but there are some other mechanisms as well. We give this figures since this mechanism is the mostly preferred pooling mechanism.

In the figures above, supply and demand offers are submitted as price/quantity blocks. As mentioned, this type of pools is called “merit order” pools. There is another type of pool in theoretical literature and we will use this type of pools. In this type, generators submit their continuous cost functions and consumers submit their continuous benefit functions. Again, regulator equates demand with supply by solving a non-linear optimization problem.

2.2. Electricity Sector Liberalisation and Regulation: International Evidence

Turkey, as a late-comer in the electricity sector liberalization, should substantiate the necessary conclusions from the international evidence in the electricity sector liberalization. In this section, we aim to focus on the several conclusions that can be derived from international evidence. We first look at the timing and the sequence of reforms concerning the electricity sector. Second, we look for how liberalization and introduction of competition have been handled in various countries. Third one is the possibility of the exercise of the market power that is created by new market design and the effects of the exercise of the market power. Fourth issue is the structure of pooling institutions and the operational rules of pools. Fifth issue is the modes of regulation in the countries reviewed. Sixth, how the relations between pools and other markets affect the electricity sector variables will be discussed.

Electricity supply industry has faced a liberalization wave in an innegligible number of countries for about two decades. This transformation has been reinforced by the strong support provided by international monetary and financial institutions. Although the country-specific motives behind this transfomation are crucial, a sytem-wide meta-discourse about electricity supply industry has emerged. This discource has been fed by the lessons substantiated from experiences and from the vast literature which has been constituted by scholars from experiencing countries. Liberalization and imposition of competition into electricity supply industry have resulted in a regrowing interest in energy economics.

Despite the importance of the re-occurrence of interest in energy economics, the academic attractiveness of liberalization experiences can not be solely accounted for this process. Robinson outlined a number of factors that lies behind the revival of interest in the form of “energy liberalism” such as the revival of market economics, the growing distrust against governmental and political institutions, and, most importantly, the perceived need of liberalization by governments (Robinson, 2000). The other main drive behind the revival of interest has been the intentions of private agents and capital to enter into electricity supply industry, these intentions has been publicised in the form of academic lobbying.

In this literature, introducing competition and privatization are not proposed only for electricity supply industry, all network industries and public utilities have been considered to be included in the liberalization plan (Klein and Gray, 1997). “Energy liberalism” argues that former public utilities have been major bottlenecks for competitive market mechanism and, thus, effective competition necessitates both privatization of and private agent participation in network industries. This two-sided proposal also includes electricity supply industry, but two-sidedness does not imply the simultaneity of opening industry to private agents and privatization. Joskow indicates that privatization of state-owned enterprizes should preceed the movement that will allow private firms to move into electricity supply industry (Joskow, 1998).

Privatization without introduction of competition may transform state-owned monopoly into privately-owned monopoly, thus, privatization without competition can generate inefficiency. For example, privatization in England could not prevent privatized companies from exercising market power (Newberry, 1999). Privatization-with-liberalization imposes market efficiency to the privatized incumbent firm. However, in some formerly public-owned network industries, minimum efficient scale deters new entrants although there have been no legal barriers to entry. Moreover, “network industries usually have a component that is non-competitive” (Gönenç, Maher and Nicoletti, 2000:13). In such a situation, the regulation of operations becomes inevitable.

Special structure of electricity industry, apart from other network industries, also necessitates a handful regulation both in pre-liberalization and post-liberalization stages. Compounding three different segments, electricity supply industry has been privatized and liberalized in a fragmented fashion. The first step in the process of liberalization is to unbundle generation, transmission and distribution (some authors accept retail supply as a different segment from distribution, i.e. Wolak, 1997:8). Then, second step was to privatize each separately, either by selling shares and keeping majority or golden share, or selling the whole assets in any segment.

Post-liberalization stage of electricity supply industry has been a major concern for a debate about regulation. A majority of scholars who are interested in this subject, because of the need for allowance of network access, believe that transmission grid should be regulated and operated under a monopoly structure. The main focal points in this context have been distribution and generation. Borenstein and Bushnell argue that liberalization of generation segment has been a major outcome of technological developments in electricity generation, these developments have decreased the minimum efficient scale of a electricity generating plant (Borenstein and Bushnell, 2000).

In this framework, it is very interesting to note that the proposal for opening of generation segment to private participation does not depend on the frequently repeated belief that public utilities generate electricity inefficiently. The liberalization and introduction of competition into generation and distribution segments aim at increasing allocative and productive efficiency in electricity supply industry. The secondary motives among countries those have experienced liberalization exhibit differences, however, the basic aim, as announced, is bringing about gains in efficiency. But this common aim does not prevent scholars from discussing the ways how to obtain these gains.

The most important issue in this debate is the role of regulation. Liberalized generation–controlled and monopolistic transmission–competitive distribution sequence seems to enforce a consistent regulation according to some scholars while others reject this thesis. This debate has been a natural outcome of the differences in experiences in the international agenda. Regulation-competition dichotomy can be discussed under the guidance of facts derived from different experiences and this chapter aim to make such an analysis.

This chapter will focus on the basic architecture of these reforms, timing, the mode of regulation and short and middle-run consequences of reforms. We select case studies according to the degree of effectiveness upon this literature.

As the first-comer in electricity sector liberalization, we firstly focus on the UK experience. Then, we pay attention to the transformation of the US electricity sector since it constitutes a specific example in terms of its diverging patterns from other experiences. A review over other OECD countries and developing countries follow and, lastly, we attempt to outline a brief discussion of issues obtained from these experiences.

2.2.1. UK: Privatization with Competition

Until the initiation of reforms in 1989 by Thatcher government, UK electricity sector was dominated by state-owned, vertically integrated utilities. In 1947, Electricity Supply Industry (ESI) was nationalized and ownership was given to Central Electricity Authority Board (CEA). In 1957, a new electricity act divided whole distribution network into 12 regional distribution state-owned companies and same act formed Central Electricity Generating Board (CEGB) which captured the ownership of generation and distribution segments. By this act, CEA obtained the regulative power and operated under the guidance of Mergers and Management Comission (MMC) (Armstrong, Cowan and Vickers, 1997: 291).

1983 Energy Act abolished the monopoly rights of CEGB over generation and opened it for private participation. Moreover, it allowed third party access over transmission (Vickers and Yarrow, 1993:292). Then, British conservativism won electoral victory and Thatcher government publicised its liberalization aims concerning the privatization of ESI in its famous White Paper. In 1989, Director General of Electricity Supply (DGES) and Office of Electricity Regulation (OFFER) were established as a premier to total liberalization.

1989 Energy Act divided CEGB into four parts; three for generation (National Power, PowerGen and Nuclear Electric) and the last for the transmission grid (National Grid Company, NGC). National Power and PowerGen hold the ownership of non-nuclear plants while Nuclear Electric got the ownership of nuclear plants. Government aimed at privatization of each company distinctly. In 1991, 60% of assets of National Electric and PowerGen was sold to shareholders and the remaining were sold in 1995 (Newberry, 1998:1)

In addition to the liberalization in generation, reform plan privatized 12 Regional Electricity Companies (RECs) in 1991 and franchised them to undertake regional distribution and supply. RECs jointly gained the ownership of transmission system, NGC (Newberry, 1995). However, the management of NGC was assigned to an independent executive committee instead of RECs. By this way, conservative government attempted to prevent any REC from exercising excessive power upon NGC. Moreover, RECs have been obliged to offer non-discriminatory access to 2^{nd} tier suppliers and this obligation have ensured third-party access to national grid (Reichman, 1998).

A spot market, targetting the introduction of competition into generation segment, was formed in order to balance half-hourly demand and supply, this spot market was called Pool and may be thought as a "day ahead" market (Newberry, 1995: 4). In addition to Pool, generators, distributors and retail supplier have been allowed to sign long-term contracts. These contracts are financial instruments, Contract for Differences (CfD), which help them to hedge risks incurred by Pool price. CfDs are calculated as addition of normal pool price with a sum equal to the number of contracted units times the difference between contracted strike price and pool price (Newberry, 1995). Since these contracts are financial instruments, generator firms have been allowed to buy or sell them in open market. The main target of these contracts are to share the hedged risks among buyers and sellers of electricity. For example, if pool price exceeds the contracted price, distributor pays a share of difference to the generator, but not the exact difference. The number of contracts determined the share of difference (Newberry, 1999). Green indicates that generators' attitudes have been sensitive to the Pool price. Although they might pay less attention to the Pool Price in the short term, they should have signed middle term contracts on the basis of Pool price (Green, 1998:6).

Pool, as mentioned above, operates in a "day ahead" manner, i.e. generator firms declare the price-generation level sets for the next day and Pool operator sorts these bids in an ascending order, this order is called "merit order" (it is important to note that Pool has been operated by NGC). Pool regularly estimates predicted demand for every half-hour and the grid operator (or as called "grid despatcher"), informed about bids, calculates the least cost of meeting the estimated demand. This least cost according to bids is set as System Marginal Price (SMP) which indicates the most expensive method of meeting predicted demand.

In order to impose competition upon consumption, reform package defined an "eligibility" level for consumers and consumers whose demand has exceeded this level obtained the right for entering into direct bargaining with suppliers. This type of consumers is called "free consumers". After 1990, this level was changed once in every four years and finally it was set to zero in 1998 (Littlechild, 1999:14).

All this liberalization steps have been combined with the development of a debated regulation. Transmission access, retail supply and distribution have been regulated via price-cap by OFFER (in 1998, OFFER was united with Office of Gas Regulation to constitute Office of Gas and Electricity Regulation, OFGEM) and DGES. Generation and Pool prices have not been in the operational domain of the regulative body. OFGEM applies price-cap to average revenue obtained from the “use of system charges” and charges for “existing connection”.

The results of this liberalization process are very crucial because it stands as a benchmark case for other experiences. Moreover, English/ Welsh experience may bring a great deal of insights into competition–regulation discussion. This dichotomy has been discussed in a distributional framework, and studies on electricity supply industry liberalization generally ask who benefit and who lose as a result of the reform in the electricity supply industry.

The most problematic result of the reform package has been in electricity prices. Newbery argues that the reduction in unit costs has not been reflected in final prices (Newberry, 1997:374). The unreflected cost reduction, in spite of a slight reduction in price, points to an unequal sharing of benefits. Thus, price movement after the reform has created a distributional dilemma. According to some authors, the main factor behind this dilemma is the post-reform market power of the two largest electricity generator; National Power and PowerGen (Newberry, 1997: 375 and Newberry, 1999). Wolfram argues that these two dominant generators generally submit high bids and their attitude has been reflected in higher mark-ups (Wolfram, 1999a: 9 and Wolfram, 1999b). Thus, they could reap the the largest share of benefits from the cost reduction.

Although they captured very high market shares just after the reform, the shares of National Power and PowerGen have declined over time. There have been two forces that have resulted in declining shares of the two largest firms. First of them has been that, after the initiation of the reform, regulatory bodies have distanced themselves from these firms and there occurred a systemic antypathy to these firms. Hence, many decisions of these firms were not verified by OFFER or MMC. Second was that liberalization and competition enforce these firms to divest some of their assets. As a result, their shares have fallen for about a decade (Littlechild, 1999: Table 1).

In conclusion, as can be seen from previous experiences, liberalization attempts seem to erode the market power for generators. However, same developments also result in mergers and acquisations among generators and RECs (since latest Energy Act does not prohibit this). Many RECs expanded their operations into generation sector (see, Newberry, 1999). In this sense, liberalization and competition, although one of the basic aims is to enforce an unbundling to former monopolies, have created a new type of privately-owned vertical integration. Secondly, by opening of internal electricity market to foreign investors and liberalizing external trade for electricity, England and Wales provide an incentive for domestic firms to merge with foreign firms and acquisation of domestic assets by foreign investors. EDF, France's state-owned electricity company, and Scottish Electric have acquired some firms after liberalization and they also began to export electricity to England and Wales.

As a conclusion, we should look at the beneficiaries and losers of reform after a decade. The most striking example was given by Newberry and Politt: They estimated that, between 1990 and 1997, government lost \$6 billion and final consumers lost \$16 billion while shareholders earned a profit of \$38 billion (Newberry and Politt, 1997). They also added that overall cost-reduction brought about by liberalization was about 5% and this was not a too much gain in productive efficiency.

Secondly, as mentioned, mark-ups has increased in electricity supply industry, since price-cost differential has widened in this era. This was a sign of allocative inefficiency. Thirdly, discrepancy between various types of consumers has been also increased because of the status of eligibility and bargaining power of some consumers. The gap between prices paid by domestic, commercial and industrial users has been levelled up. Lastly, although liberalization attmepted to abolish monopolistic conditions in electricity supply industry, the end results show that some distribution companies that have expanded their operations into generation segment could have transform into private oligopolies.

There have been many other criticisms concerning the new internal structure of English/Welsh electricity supply industry. We should outline some of them. Firstly, Wolfram notes that Reform of Electricity Trade Arrangements (RETA) proposed by new Labor Government asserted that a homogeneous binding System Marginal Price(SMP) determined by Pool has resulted in rents for some generators which have several plants with differential cost structures. In order to prevent these rents, government proposed an auction market in which generators, distributors and customers bid for discriminatory prices instead of a sytem-wide binding SMP (Wolfram, 1999).

Second criticism was that system-wide binding prices could not give necessary signals about investment and allocation decisions (Newberry, 1997:376). Hence, instead of a sytem-wide pricing, electricity supply industry should operate under nodal pricing. Node price differentials may indicate where to invest and where investors and consumers should locate. Newberry adds that a natural counterpart to nodal prices are nodal CfDs instead of system-wide CfDs.

2.2.2. USA: Non-Homogeneity and Conflict

Historically, the US electricity supply industry has expanded over a vast territory including 50 states which have different industry and market structures. The federal electricity structure has been based on three independent transmission grids, Interconnected Eastern, Western and Texas grids (EIA, 2000: 15). However, these grids were not controlled by a single entity. Rather, there were 140 points on grids in which utilities got involved in pooling operations (Joskow, 2000:6). At these points, locally-franchised utilities buy and sell electricity to their retail customers. This traditional industry structure was a major outcome of federal government's interventions to the legal framework concerning the electricity supply industry.

The first major intervention was the legislation of Public Utilities Holding Companies Act (PUHCA) in 1938 which required inter-state utilities to divest some of their holdings and put these utilities under direct regulation of Securities and Exchange Comission (EIA,1996: 6). In addition to this, PUHCA formed a Federal Energy Comission (FEC) which was later transformed into Federal Energy Regulation Comission (FERC).

In the 1950s, electricity demand grew at a rate of 20% and met with a supply whose cost was declining. This process continued until the end of the

1960s. At the end of the 1960s, problematic changes which put considerable burden upon supply cost occurred and regulatory bodies gave exclusive franchises to Investor-Owned-Utilities for selling electricity in restricted geographical areas (Doane, Williams, 1995:38). In the same decade, newly created power pools interconnected utilities across states and these pools provided the basis for the liberal reform in 1992 (Andrews, 1999:5)

In the 1970s, inflationary wave and two oil shocks increased the unit costs for generation plants. Since the US electricity industry was mainly depended upon fossil fuels, Carter administration prepared an emergency energy plan that aimed to decrease this dependency. In 1978, Public Utility Regulator Policies Act (PURPA) was legislated and this act firstly targetted the promotion of the entrance of non-fossil fuel using generators into generation segment (Moyer, 1996:14). In this way, PURPA defined a new producer type, Qualifiying non-utility (QN), in order to generate a basis for competition in generation segment. Then, a new classification of generators has been used in amendments and orders such as:

Utilities:

IOU: Privately owned, profit maximizing vertically integrated companies. In 1996 , there were 243 IOUs operating in US.

Federally Owned Utilities: Non-profit power marketting companies, mainly produce power for federal facilities.

Other Publicly Owned Utilities: State or local government agencies.

Cooperatively Owned Utilities: Utilities owned by rural communities

Non-utilities:

Cogenerators: Privately owned companies that sell power to utilities.

Since prices continued to be higher and many serious cricitisms were publicised, Republican governments aimed to deregulate and liberalize the US electricity supply industry further. In this context, in 1992, Energy Policy Act (EPACT) was passed. EPACT was more radical than PURPA.

The liberalization attempts in USA was parallysed by a shock in the Californian electricity market in 2000. The shock is the result of rapid and uncontrolled liberalization in the Californian electricity market. As Joskows points, the basic problem is that the distribution firms buy electricity from wholesale trade companies at a very high price and they can not reflect this high price on to their retail price (Joskow, 2001:365). As a result, the two largest utilities became insolvent and declared bankruptcy. The wholesale prices, because of the increasing excess demand originating from deficient investment levels and overgrowing of energy-intensive sectors, rose rapidly before the shock (Sevaioğlu, 2001). Joskow indicates that one of the basic reasons behind these shocks is the inconsistent interventions of regulatory body and market power problem especially in wholesale trade segment of the Californian electricity market (Joskow,2001).

In the first few months of the post-shock period, retail prices increased by fivefold and the Californian electricity market collapsed (Joskow,2001). This shock produced alarming signals and created important discussions about the awaiting reform packages in other states. Some of the states delayed the implementation of the reform.

Californian electricity crisis proved that any liberalization attempt in an electricity sector that has an underdeveloped infrastructure may result in a catastrophe. It is surprising that, apart from a very limited academic interest in USA, this catastrophe seems to produce very few discussions in the academic literature.

2.2.3. Other OECD Countries

Following the UK, in liberalizing the electricity supply industry in 1991, some OECD countries took quick steps to deregulate their electricity systems while remaining countries acted slowly or preferred to stay intact. In 1996, according to Steiner, OECD countries might be classified under six categories in terms of the extent to which OECD members have proceeded the reform (Steiner, 2000: 7). Apart from the UK, the most liberalized electricity systems could be found in Finland, New Zealand, Norway and Sweden while countries having the least liberalized electricity supply industry are Belgium, France, Canada, Greece, Ireland, Italy, Netherlands, Portugal and Spain.

Mostly liberalized countries in the list are Norway, Sweden, Australia, Finland and New Zealand. Although other countries in the list, like France, Italy and Germany, seem to show no effort for liberalization, they have taken necessary regulatory steps to open the electricity supply industry to competition.

Finland, Norway and Sweden deregulated their electricity supply industries to a great extent and these countries involved in an integrated power market, Nordpool, in which exchange of power has been performed via supply and demand bids (Tennbak, 2000: 863). Nordpool was formed through the combination of state-owned Norwegian and Swedish grid operators; Statneft SF and Svenska K (Wolak, 1997:17). Before accessing to Nordpool, Finland had its own electricity spot market (ELEX) which would later be dissolved after the unification (Amundsen, Bergman and Andersson, 1998: 2).

Although post-reform and post-unification structure have carried some similarities with English/Welsh Pool, the main driving force behind this reform was very different from that of English case. As Amundsen and others put the main target in the conservative attack upon former English electricity supply system was to privatize the electricity supply industry while Scandinavian countries aimed to reach efficiency gains through reform (Amundsen, Bergman and Andersson, 1998:3). Thus, post-reform national electricity systems in Scandinavia continued to be dominantly publicly owned. This pattern has created a number of systemic differences between the UK case and Scandinavian case.

The main difference between the English/Welsh Pool and Nordpool is that Nordpool is not a mandatory pool, i.e. Nordpool does not enforce generators to involuntarily get involved into exchange relations. Nordpool, in addition to bilateral contracts market, covers two other markets. Firstly, a futures market serves generator firms to trade financial instruments whose maturities have been ranging from a week to three years. Via these financial instruments, firms engaging in the electricity supply industry may arrange their short and long-run portfolios and by trading these instruments among themselves, they may finance their short-term operational costs. The second market, called Daily Power Market (DPM) is similar to English/Welsh Pool such that, in this market, agents buy or sell electricity at prices determined at a day-ahead basis. Sometimes, expected volume of day-ahead electricity consumption and actual consumption do not match, and unmatched excess demand should be met by additional dispatced electricity. The markets in which this additional electricity is traded are called Regulation Power Market (RPM) in Norway and Balancing Market in Sweden (Wolak, 1997:18).

We should outline market rules for Nordpool. Although the share of electricity traded in this market keeps a very small portion of total electricity traded, DPM has been the most important part of Nordpool. In DPM, as in Pool, generator firms submit their bids on day-ahead basis and system operator, by also holding demand bids, determines the price at the point of intersection of demand with supply. Since Nordpool is a bilateral contract pool, each firm is obliged to equate its announced supply with its own generation plus electricity purchased via bilateral contracts from other generators and DPM purchases. This is a very great difference between Pool and Nordpool, i.e. in Pool, generators submit their supply bids and only the system operator, NGC, determines how much electricity will be purchased from this generator without taking the level of generation of this generator into account. The price is determined by NGC as the intersection of supply bids and estimated demand rather than actual demand bids. In this context, Wolak argue that DPM may be considered as a physical forward market (Wolak, 1997: 21).

After the formation of Nordpool, transmission systems of these three countries are combined to form an integrated inter-state transmission system owned by an independent company. The first step towards the formation of a inter-state power market was to lift cross-border tariffs and special tariffs, independent transmission company began to apply nodal pricing (point tariffs) at each segment of inter-state grid. Nodal pricing cancels out the effects of the distance between the sellers and buyers; each point on the electricity supply system is assigned a different price. By this way, system ensures a system-wide competition on equal terms. On the other hand, although unification succeeded in the necessary environment for the future homogenization, there have still been variations in pricing mechanisms among countries. For example, variable cost part in tariffs in Norway also captures congestion costs, but in Swedish case, congestion costs are estimated independently. Such differences in pricing mechanisms have generated serious constraints upon the formation of homogeneous prices across the system.

In conclusion, Nordpool have pointed to an interesting example of liberalization and the formation of an integrated inter-state spot market. It is interesting because the reform movement has been proceeded without so much liberalization of domestic electricity supply industries. Moreover, the unification of Norwegian, Swedish and Finnish electricity grids under a Scandinavian grid and formation of inter-state spot market is not an closed-ended process. The unification and enlargement provides future opportunities to negihbouring countries like Denmark and Germany. However, it seems that enlargement without homogenization of regulation processes and pricing mechanisms will certainly create so much problems in the future. In contrast with English/Welsh experience, formation of Nordpool was not coupled with a bulk privatization, this is an indication of governments' future insistence on state direct/indirect regulation. This insistence may be due to the highly public-dominated tradition of Scandinavian countries.

As indicated above, neighbouring countries, it does not matter via direct unification or only mutual trade, have the aim of getting involved in transactions in Nordpool. The strongest intentions announced came from Denmark (see Ministry of Environment and Energy, 2000). Geographical advantage enforced Denmark to engage in trading activities with Nordpool members. Formerly, Danish electricity sector was marked by a strict regulation dominated by vertically integrated publicly-owned firms (Hauch, 2001:509). Then, by 1996 Act, government announced its intentions about the liberalization of Danish electricity supply industry. Government aimed to introduce competition in a gradual manner and 2003 will mark the beginning of a new competitive era. The most important step of the reform proposal was the article that enforce the new-comers to use renewable energy sources in order to decrease CO_2 emissions. The reform at the wholesale level allowed negotiated Third Party Access (TPA) in 1997. Denmark, in 1997, without giving any sign of forming a spot market, passed to wholesale wheeling (CRIEPI, 1998:19). Again, an eligibility level was defined for the consumers whose demand exceed 100 GWh/a and these consumers obtained the right for the negotiated TPA.

The other OECD member that has gone further in liberalizing its electricity supply industry is New Zealand. In the early 1980s, New Zealand electricity supply industry had a state-dominated structure in which local distribution was handled by about 60 Electricity Supply Authorities (ESAs). These authorities were owned by local or municipal bodies (Wolak, 1997:32, Gunn and Sharp, 1999:386). In 1987, Electricity Corporation of New Zealand (ECNZ) was formed from the former Electricity division of Ministry of Energy, this step was coupled with the abandonement of restrictions upon entry into generation and distribution segments (EMPG, 2001:2). In the following year, ECNZ was divided into four subsidiaries; one of them, TransPower, owned whole transmission grid. In 1992, New Zealand electricity market reform gained an additional spurt in the form of Energy Sector Reform Bill which trasformed ESAs into corporations and TransPower into fully independent state-owned enterprise. This bill also focused its attention upon about 40 local vertically-integrated companies and aimed to unbundle them (Small, 1998:2). In the same year, Wholesale Electricity Market Study (WEMS) was announced by the initiative of private sector (EMGP, 2001:5).

New Zealand's electricity system consists of two interconnected grids, one on the North, other on the south. The most important characteristic of this system is that, most of the population lives in the north while most of the installed capacity locates in the south. This structural property has been the origin of a serious transmission bottleneck.

In order to create the necessary environment for a spot market for electricity, a wholesale electricity market under the name Electricity Market Company (EMCO) was formed in 1996. The wholesale market's system operator has been TransPower and, as in Nordpool, the system is not mandatory (Wolak, 1997:34). Wolak argues that highly concentrated generation segment provides the necessary conditions for ECNZ and Contact to affect the formation of pool price to a great extent. In two distinct grids, two different prices prevail. In New Zealand's spot market, generator functions send their supply bids which cover the information about price offer for every half an hour of the following day. Again, EMCO provides a day-ahead basis market and, in this market, system operator uses a least cost approach. A market clearing model is used to determine the price for the following day using the bids submitted by generators.

Regulation in New Zealand's electricity system seems to be the most problematic area (Small, 1998), since regulation, as it is called in the literature as "light handed regulation", is not so strict and does not enforce or induce firms to handle specific tasks. The other problem in New Zealand's electricity system is, as mentioned, the discrepancy between the north and south of the system.

Apart from these difficulties in liberalizing New Zealand's electricity system, the transformation in New Zealand's electricity supply industry has been so much affected from the reform conducted by its neighbour, Australia. Australian electricity system was also mainly dominated by state-owned vertically integrated firms in most of its states. However, this picture began to change in 1990 when Commonwealth government announced its reform aims. In 1991, government transformed all state-owned firms into corporations and passed to light-handed regulation as in New Zealand (OECD, 1997:7). At the same time, transmission and distribution became fully independent and open accesss to transmission grid was permitted. The most important step at the initial stage of the reform period was the formation of National Grid Management Council (NGMC) whose main target is to provide the basis for the formation of a nation-wide electricity market which absorbs the state markets. Following these nation-wide steps, the main initiative passed on to the state-level and, at this stage, two of the states became prominent; New South Wales (NSW) and Victoria.

In NSW state government began to restructure its electricity supply industry. The code of restructuring was very alike the codes in other examles, i.e. government firstly divided its generation segment into two distinct independent companies and assigned the operation responsibility and ownership of transmission grid to a state-owned company, TransGrid. The distribution system was divided into six companies and new legislation ensured the formation of wholesale market at the end of the 20.Century.

On the other hand, Victorian government has gone too far in reform. In 1993, state electricity comission was separated into three companies and each became fully responsible from one segment. Later, Electricity Services Victoria (company for distribution) was disaggregated into five local distribution companies. Generation Victoria was divided into five companies. The most important transformation concerned National Electricity which operated and controlled transmission grid; it was divided into PowerNet Victoria (which became the owner of physical grid) and Victoria Power Exchange (VPX, became operator of the grid). VPX began to operate a spot market, or a "pool" in which generators began supply bidding (OECD, 1997:9). The pool in NSW began to operate in 1996 (Wolak, 1997:26). These two pools mediated and improved the trade between two states. The harmonization between two states' electricity supply industry seems to be non-problematic since the structural properties resemble each other such that the fuel mix in generation in both states has been very alike and the relative size of markets is nearly same. These properties will ease the integration of two most important states and the formation of a nation-wide market.

After the restructuring of the generation segment of Victorian electricity supply industry, a privatization plan at the plant level was initiated. This opened the generation segment to private agents to a great extent. Following liberalization, the market concentration was very low.

The most important part of the reform was the formation of Victorian Electricity spot market, or Vicpool. Initially, unlike other pooling examples, Vicpool enforced generator firms to bid for weekly periods. This scheme was replaced by daily bidding in 1996. The most important difference between English/Welsh Pool and Vicpool is, as Wolak indicates, that "Vicpool is an ex post market rather than ex ante market" (Wolak, 1997: 30). This indicates that price is determined with actual demand rather than estimated demand for each half-hour. Being an ex-post market, Vicpool does not require an additional balancing market. Vicpool has provided a lot of important lessons for future nation-wide electricity spot market.

As one can see above, some OECD members have insisted upon the reform of electricity supply industry and have proceeded very quickly. On the other hand, other OECD members have seemed to be very deliberate in reform process although some have been under EU jurisdiction of 1992/96 direction which enforced member countries to open and privatize their electricity supply industries in order to create the basis for future Europe-wide electricity market (Shuttleworth, 2000). 1992 directive advocated member states some common rules for electricity and gas markets. Its 1996 version gave a two-year preparatory period for each member state (exceptions were Belgium and Ireland which were allocated one more year, and Greece two years). It was important to note that EU focused upon this step very seriously, for example, European Comission informed Germany, France and Portugal for their failure in reforms and also initiated legal proceedings against France (Shuttleworth, 2000:3). However, such measures have proved to be ineffective in harmonizing the domestic electricity supply industries of member states.

Although the European Comission considered France as the most unsuccessfull member state, government took some steps towards reforming the French electricity supply industry. In 2000, France achieved the first step of the reform package which enabled third party access to network, allowed bilateral contracts among agents in a limited scope while keeping the dominancy of state-owned Electrité de France (EDF) intact (Finon, 2001:755).

The other slow EU member in reforms, Germany, has proceeded further than France. The basic difference between French and German electricity supply industries is that the latter allows private agents to participate in the sector. In spite of this fact, complete unbundling of activities and independent transmission grid operator is not on the agenda of government (Tennbakk, 2000:864). Transmission grid is owned and operated by large regional companies and these companies have resisted against the reforms. Like Germany, there has been a wide opposition to the liberalization attempts in Italy, although initial steps were taken under the guidance of 92/96 EU directive (Porrini, 1999). In 1999, Italian government passed an important decree to open generation segment to private participation and the monopoly position of state-owned company, ENEL. The decree will force ENEL to surrender 15,000 MW of its production capacity and state that no single agent may produce more than 50% of total production. The decree also give permission to private agents to enter freely into transmission grid. Italy, as France, has been on the eve of a full fledged liberalization and privatization process, thus, the outcome of the initial steps should not be so much exacerbated.

As a conclusion, we should say that, although there have been some minor differences, the experiences of OECD countries offer a standard model for the liberalization and reform in the electricity supply industry. This standard model, initialized with unbundling, proceeding with open access and privatization and ending with system-wide electricity market serves to the aims of global energy reform lobby in OECD countries. It is not certain whether this model will be proved be successful with future facts, up to now the balance sheet of reform policies has shown great variations among OECD countries.

2.2.4. Developing Countries

Developing countries have insisted upon reform because of the structural electricity shortages that have prevailed for a number of decades. The second motive behind the reform in developing countires has been the upsurge of interest in investment opportunities in the electricity supply industries of many developing countries and the inability of governments of these developing countries to finance these investment projects.

Apart from these motives, there have been a large number of developing countries that allow private participation in their electricity supply industries. The number of developing countries that entered into the reform process has not been so much low. The distribution of these countries points to an important fact that Latin America and South and East Asia have overstepped countries in Sub-Saharan Africa, Middle East and Nort Africa in the geographical and structural extent of the reform (Bacon, 1999). The main spurt of the reform came after 1990, as Izaguirre indicates, before 1990, only Chile allowed for the private participation in its electricity supply industry (Izaguirre, 1998:1). Throughout the 1990s, many developing countries had opened their electricity sectors to the entry of private agents.

As Izaguirre indicates, there have been some variations in the approach to the private participation and reform across regions (Izaguirre, 1998: 5). For example, Latin American countries have preferred private participation in projects which have been permanently owned by private agents while Asian countries have inclined to make Build-Operate-and-Transfer (BOT) or Built-and-Operate (BOO) contracts.

The most common feature among private investment projects in the electricity sector was that they mainly concentrated upon generation segment and the number of vertically integrated projects was very low for the period 1990-97. The 73% of total private investment was allocated in generation while vertically integrated projects (i.e. generation and distribution) held only 1%. This fact might be due to the higher profitability in the electricity shortage environment and the aims of governments that directed private investment funds to generation segment via formal or informal subsidies. The most prominent private investment projects have been owned by the Independent Power Producers (IPPs), that is, generation companies which are not directly controlled by the state.

The largest share of IPP investment was held by Asia by $54 billion and, unsurprisingly, the second place was held by Latin America by $6.6 billion (Albouy and Bousba, 1998:2). Although IPPs and private energy projects have raised the electricity producing capacity of developing countries, this process has been open to criticism as well. Firstly, the volatility in international capital markets certainly decreases the planning autonomy of the governments of the developing countries. Secondly, the electricity sector operates in such a manner that the price bid of highest cost generator determines the system-wide price. Hence, many inefficient small scale IPPs and privately-owned generators may increase the system-wide price.

It seems that developing countries' route in the development path of power markets has been unaffected by these criticisms. Many developing countries have been on the initial stage of reform, the most prominent figures in this context are Chile and Argentina.

Chilean electricity sector was liberalized at the end of the 1980s, the activities were unbundled and the electricity sector was opened to private participation. In 2001, generation segment has been dominated by three companies which together hold 93% of the installed capacity (Diaz V., 2001:4). The transmission grid is owned by Endesa (the largest generator company owned by state). Endesa also controls main distribution company. The regulatory structure is consisted of four different regulatory institutions. The particularization of regulation has created serious bottlenecks for the system. There are two markets; spot market and regulated market. The particularization of regulatory structure firstly generates certain problems in this context. The differential between spot price and regulated price has created misinformation. Secondly, particularized regulation has resulted in problematic dispatch of electricity. Thirdly, paradoxically, the structure of regulatory body, in combination with highly concentrated generation segment, produces an inflexible market. It can be said that Chilean reforms, inspite of the fact that they aimed to introduce competition into the electricity supply industry, have brought about a highly concentrated and a problematic electricity system.

On the other hand, Argentina, which initiated reforms in 1992, may be considered as a more successful example. The wholesale electricity market, MEM, is distinct from very small Patagonian system and in MEM, all consumers whose peak demand is equal to or greater than 30 kW are authorised to enter direct bargaining with generators. Transmission grid, as called SADI, is operated by an independent authority, CAMMESA. The regulatory body is ENRE and is responsible from ensuring compliance with the law, imposing necessary restrictions and preventing anti-competitive behavior. The first step in 1992 was again complete unbundling and opening generation and distribution segment to private participation. Although SADI is operated by CAMMESA, regional grids are operated by private transmission companies (Abdala and Chambouleyron, 1999). This last point is very important since there is no other example in which private agents are allowed to enter into transmission segment.

Compared to Latin American countries, Asian countries seem to be less liberal and less inclined to the reform at first sight, however, since the 1997 financial crisis, some East and South-East Asian countries have begun to outline the reform projects (Izaguirre, 2000:6). The initial and intermediate steps of the reform proposals are as mentioned in previous paragraphs, i.e. South Korea plans to liberalize its power system via firstly unbundling, segmentation and privatization. Thailand, the Philippines and Indonesia may be counted in the list.

The basic finding concerning the liberalization attempts that focus upon power systems in developing countries is that only upper strata of the developing world have engaged or is planning to engage in liberalization attempts. Secondly, remaining part of the developing world shows very weak signals about the reform in the electricity supply industry (for Sub-Saharan

Africa see, Turkson and Wohlgemuth, 2001). Lastly, international firms are interested in the reform projects in developing countries and they impose pressure on developing countries in order them to initiate the reforms .

2.3. The Turkish Electricity System

The first steps towards the formation of a nation-wide electricity system were taken in the first quarter of the 20th century. In 1913, Silahtarağa plant in İstanbul, first large scale plant, began generating electricity. At the beginning of the republican era, Turkey had an installed capacity of total 32.8 MW, annual generation was 44.5 GWh which was mainly supplied by concessionary firms. In 1923, there were 38 generation plants (TÜSİAD, 1998:243).

Between 1923 and 1930, Turkish infant electricity system was dominated by concessionary firms. This fact was consistent with the basic conlusions of 1923 İzmir Economic Congress which aimed to give private sector a pioneering role in economic development. In this era, electrification was succeeded by granting regional concessions to private companies. At the end of the era, which was marked by the domestic repercussions of 1929 global crisis, electricity prices peaked and policy regime shifted with the transformation of the developmental paradigm. In 1930, total installed capacity was 74.8 MW and annual production was 106.3 GWh.

After the outbreak of the 1929 crisis, government took necessary steps and initiated some institutional plans to provide the basis for state domination in the development of energy sector. Government's aim was reflected by First and Second Five Year Industrial Plans which stressed that the sustainability of a successful industrialization necessitates cheap and abundant energy. In 1935, the Electric Power Resources Survey and Development Administration was established and assigned the duty of conducting surveys and necessary inquiry about Turkey's hydro potential (IEA, 2001:87). Statist discourse of this era can easily be inferred from the fact that concessionary companies which dominated electricity generation in the previous era were bought by state between 1938-1944 (Soysal, 1994:9). In 1948, first regional generation plant, Çatalağzı Thermal plant, was opened. This plant, with Kandilli-Ereğli-Ümraniye transmission line through which Çatalağzı plant was connected to İstanbul, formed the first interconnected system, Northwest Anatolia Interconnected System.

The statist development policies proved to be more successful in the development of the electricity sector compared to the previous era. Between 1930 and 1950, total installed capacity showed about a sixfold increase and annual production increased by sevenfold. In 1950, total installed capacity was 407.8 MW and annual production was 789.5 GWh (TÜSİAD,1998:245).

The political transformation in 1950 changed the economic development policy regime –but not so much- and Democratic Party (DP) government allowed for more private participation. In the 1950-1960 period, government preferred to grant concessions to some firms for electricity production, for example, Çukurova Electric Company (ÇEAŞ) was granted the right for electricity production at Seyhan hydroelectric plant, this company still exists and is operarting. The other example is Kepez Electric Company which was authorised to supply electricity to Antalya region. Although these examples indicate a reversal in policy regime, the low private share in newly added capacity in this period showed that public sector continued to dominate electricity sector.

The increase in the number of hydroelectric plants in this period created a coordination problem. Thermal plants were mainly owned by municipal bodies. In 1953, State Hydolic Works (Devlet Su İşleri) was established and the ownership of all hydroelectric plants were transferred to DSİ. Then, Etibank took over these plants from DSİ. This was a major institutional reform since this move signalled the future centralization of management of electricity generation. The other major step in this period was the First Energy Congress in 1953, this congress, in its final resolution, stressed the need for a nation-wide institution to control whole electricity sector (Soysal,1994:10).

At the end of the 1950-1960 period, total installed capacity reached to 1274.4 MW, 860.5 MW of which was thermal and 411.9 was hydrolic. Annual production was 2815 GWH in 1960.

The coup in 1960 brought cadres that have planned-developmentalist vision to office. First (1963-67) and Second (1968-72) Five Year Development Plans indicated the need for the development of a nation-wide interconnected system and gave a priority to the utilization of hydro resources. Newly established Ministry of Energy and Natural Resources was assigned to implement the national energy policy in 1963. One of the most important institutional steps in the history of Turkish electricity system was the establishment of Turkish Electricity Authority (Türkiye Elektrik Kurumu) in

1970. TEK took over the ownership and management of all plants except the ones that were owned by municipalities and the Bank of Provinces (İller Bankası) (TEAŞ, 2001).

The development of the electricity sector was also hindered by macroeceonomic crises in the 1970s. Since the weight of fossil fuels in Turkish generation fuel mix was considerably high, the oil crises in the 1970s deteriorated the conditions for electricity sector development. Moreover, these crises, because of the foreign exchange scarcity, resulted in serious disequillibria between demand and supply. Only favourable development was the beginning of the rural electricification in the 1970s. At the end of the 1960-1980 planned development era, total installed capacity was 5118.7 MW (thermal installed capacity was 2987.9 MW and hydrolic installed capacity was 2130.8 MW). Annual production was about 23.5 thousand GWh (TEAŞ, 2001).

Another coup in 1980, again reversed the policy regime and Turkey entered into an export-oriented liberal development era. In the era that starts with the coup in 1980 and still lasts, succeeding governments have insisted upon the privatization of public utilities which includes electricity as well. However, the liberalization of electricity sector had been postponed till 2001 but until 2001, governments took some preparatory steps. In 1982, municipal bodies transferred their power generating assets to TEK. In 1984, one major step towards a competitive electricity sector was taken, the monopoly of TEK was lifted in electricity sector and private companies were granted the right to operate in generation, transmission or distribution segment of the electricity sector. Private participation in the form of Build Operate and Transfer (BOT) is allowed with Law no. 3096 (Atiyas and Dutz,2003:6). Between 1988 and 1992, 10 private companies were entitled to participate in generation, transmission and distribution activities within their authorised boundaries. In 1993, Decree in Force Law no.513 split TEK into two separate state-owned companies; Turkish Electricity Genaration Transmission Company (Türkiye Elektrik Üretim İletim Anonim Şirketi, TEAŞ) and Turkish Electricity Distribution Company (Türkiye Eelektrik Dağıtım Anonim Şirketi, TEDAŞ). In 1994, Law no. 3996 was enacted and this law provided tax concessions to BOT projects. Law no. 4283, which was enacted in 1997 aimed to induce private participation in investment in thermal plant projects under Build Operate and Own (BOO) contracts (Atiyas and Dutz, 2003:7).

Finally, Electricity Market Law, issued on 3rd March, 2001, fully liberalized legal framework for electricity sector. In 2000, Turkey's total installed capacity was 27264.1 MW and her annual electricity production was 124921 GWh.

2.3.1. Supply, Demand and Transmission in the Electricity Sector

In the earlier periods of the development of Turkey's electricity supply industry, nearly whole installed capacity was thermal as can be seen from Table 2.1. This pattern continued till 1950. Beginning with 1950s, the rural regions of the country were also integrated to the development process by way of some infrastructural investments and by the support of international agencies. Such a gradual ruralization of economic development with the international assistance was coupled with increased utilization of hydro resources. As a result, the share of hydro plants in electricity generation showed a sharp increase between 1950 and 1960. Between 1960 and 1970, it was stabilized around 30%. The 1970s gave another spurt to hydro electricity production under 3rd Five Year Development Plan which stressed the importance of the rural electrification for rural development. In the 1990-2000 period, the beginning of cheap natural gas import from Central Asia induced investment in thermal capacity, hence, the share of thermal capacity showed an upward trend in the 1990s. Table 2.2 shows this trend.

Table 2.1. The Development of Turkey's Installed Capacity (1913-2000)

Year	Thermal (MW)	Thermal (%)	Hydro (MW)	Hydro (%)	Geotherm. +Wind (MW)	Total (MW)
1913	17.2	99.4	0.1	0.6		17.3
1923	32.7	99.7	0.1	0.3		32.8
1930	74.8	95.9	3.2	4.1		78.0
1940	209.2	96.4	7.8	3.6		217
1950	389.9	95.6	17.9	4.4		407.8
1960	860.5	67.5	411.9	32.3		1274.2
1970	1509.5	67.5	725.4	32.4		2237.9
1980	2987.9	58.4	2130.8	41.6		5118.7
1985	5229.3	57.3	3874.8	42.5	17.5	9121.6
1990	9535.8	58.4	6764.5	41.5	17.5	16317.6
1995	11074.0	52.8	9862.8	47.1	17.5	20954.3
2000	16052.5	58.9	11175.2	41.0	36.4	27264.1

Source: TEAŞ

Table 2.2 shows that the share of natural gas fired plants in thermal capacity increased sharply between 1985 and 2000 because of the cheap natural gas import and the new efficient technology based on natural gas. There are many international examples facing the same change. According to the proponents of the reform, the main reason behind this transformation is the development of more efficient electricity production technologies (Borenstein and Bushnell, 2000:3).

Table 2.2. The Fuel Mix of Thermal Installed Capacity :1970-2000
(As a share of Total Thermal Capacity)

	Hardcoal	Lignite	Fuel-oil	Diesel	Natural Gas	Liquid+ N.Gas[a]
1975	14.6	24.6	36.3	19.5	0.0	0.0
1980	10.8	35.0	29.6	17.9	0.0	0.0
1985	4.2	54.8	21.0	12.0	1.9	0.0
1990	3.5	51.1	12.6	5.7	23.2	0.0
1995	2.9	54.6	10.4	1.8	26.0	0.4
2000	2.1	40.5	7.9	1.4	30.6	13.3

Source: TEAŞ
[a]: Multi Fuel Fired Plants

Table 2.3 shows the development of annual generation of electricity. As one can infer from the table, the share of the hydro plants in annual production fluctuated in a broader scale than its share in total installed capacity. This may be due to the insufficiency of rain drop in some years and insufficent pumped storage capacity of hydro plants located on dams. Thermal plants seem to dominate annual production.

Table 2.3. The Development of Electricity Generation in Turkey 1970-2000

Year	Thermal (GWh)	Thermal (%)	Hydro (GWh)	Hydro (%)	Geotherm + Wind (GWh)	Total (GWh)
1970	5590.2	64.8	3032.8	35.2	-	8623.0
1975	9719.2	62.2	5903.2	37.8	-	15622.8
1980	11927.2	51.2	11348.2	48.8	-	23275.4
1985	22168.0	64.8	12044.9	35.2	6	34218.9
1990	34314.1	59.6	23148.0	40.2	80	57543.0
1995	50620.5	58.7	35540.0	41.2	86	86274.0
2000	93934.2	75.2	30878.5	24.7	109	124921.6

Source: TEAŞ

Table 2.4 shows that, till the end of the 1990s, the weight of various utilities did not change too much, the share of TEAŞ (formerly TEK) showed a slight increase, but, in the second half of the 1990s, the share of non-public utilities, such as autoproducers, increased by a large amount. This was an outcome of a deregulatory interventions of governments. However, in 2000, public utilities have continued to supply about 60% of annual production.

Production companies are the private companies which have a generation company license. On the other hand, affliated partnership is a joint venture between TEAŞ and a private generation company. Previous and present governments announced their privatization targets which will radically change this picture. The legislation of Electricity Market Law in 2001 provided a greater maneouvre space for private utilities.

Table 2.4. Decomposition of Annual Electricity Production by Utilities (%)

Year	TEAŞ	Concess. Compnay	Auto-producers	Affiliated Partnership	Production Companies
1970	72.75	10.16	7.99	-	-
1975	82.22	11.07	5.85	-	-
1980	83.41	6.92	9.40	-	-
1985	88.40	4.65	6.95	-	-
1990	91.85	2.27	5.84	-	-
1995	82.95	2.67	6.52	7.71	0.15
2000	59.19	1.52	12.78	15.44	9.64

Source: TEAŞ

Table 2.5. The Development of Production, Consumption, Import and Export of Electricity

Year	Net Production (GWh)	Import (GWh)	Network Loss (GWh)	Net. Loss Rate[c]	Export (GWh)	Net Cons. (GWh)	Net Cons. Per Capita[b]
1970	8176.6	0	866.8	16.6	0	7307.8	207
1975	15030.7	96.2	1635.2	10.8	0	13491.7	334
1980	21881.5	1341.2	2824.5	12.2	0	20398.2	456
1985	31912.1	2142.4	4345.9	12.8	0	29708.6	586
1990	54231.6	175.5	6680.3	12.3	906.8	46820.0	829
1995	81858.6	0	13768.8	16.8	695.9	67393.9	1112
2000	118697.6	3791.3	[a]23325.6	19.0	437.3	98726.0	1512

Source: TEDAŞ [a]: Temporary [b]: in kWh
[c]:As a percent of (Net Production+Imports)

Increasing production has been coupled with increased consumption per capita for the last three decades. Rural electrification has been nearly completed in the 1990s and massive urbanization has resulted in a higher consumption of electricity. These trends can be observed from Table 2.5. As a result of the increased urbanization and rural electrification, the share of residential consumption in total consumption has shown an increasing trend since 1970. In 1970, it was 18% while it was 24% in 2000 (TEDAŞ, 2001).

2.3.2. The Transformation of Legal and Institutional Structure

The most important step towards a "competitive" electricity sector is taken on February 2, 2001 at which "Electricity Market Law" (Law no. 4628) was legislated. This law, which defines the framework, agents and boundaries of new market, draw the future path of the reform. It defined the basic types of the licenses which would be granted by regulatory authority, the basic types of agents are: production companies, transmission companies, distribution companies, autoproducer companies, wholesale and retail trade companies, and also "free" consumers.

Traditionally, in its first article, it defines the basic aim and scope. Its basic aim is to provide the necessary environment in which electricity can be produced and distributed at low cost, to create a strong and competitive electricity market and to form regulatory institutions. Its basic innovation is the formation of Electricity Market Regulation Board (EMRB) and Electricity Market Regulation Authority (EMRA). In article 2, the basic operations like generation, distribution and transmission are defined. Article 3 outlines the conditions of licenses to be granted. Articles from 4 to 10 determine the structure and duties of EMRB and EMRA. The members of EMRB are appointed by the cabinet and these members are also responsible for the management of the Authority. The board is also responsible for the monitoring of the operations in the market and taking necessary steps about the transition to the competitive market. Granting licenses is also in the operational domain of EMRB. Authority is assigned the duty of controlling daily operations.

Under the legal provisions supplied by the Law no. 4628[1], EMRA began to take preparatory measures in order to create the necessary framework. The first step was the publication of the Electricity Market Operations Brochure in the December, 2002. This brochure repeats some points that are referenced in the law. A summary of this brochure is given below.

According to the brochure, the basic targets of the reform are to introduce competition into electricity market in order to decrease costs and increase efficiency, to form the price level that provides the basis for financial sustainability and to support the participation of the private sector (EPDK, 2002:1).

Basic innovations of reform are Market Financial Settling Center (MFSC) and bilateral contracts. The other important one is the introduction of free consumer category which will be used for consumers whose annual consumption exceeds 9 million kWH before March 3rd, 2003. Although this level seems very high, reform package involves the reduction of this level with the introduction of automatic sensitive metering techniques in the future. In the long run, as in the Nordic Pool case, it is planned to make every consumer "free".

[1] www.tbmm.gov.tr/kanunlar/4628.htm

National Load Dispatching Center is responsible for overcoming instantenous imbalances in the system. Although any bilateral contract is designed for covering any unforeseen imbalances, MFSC takes the responsibility for instantenous imbalance and imposes extra cost for this imbalance to the costs of participants.

The reform will be implemented in four phases:

Phase 1: Phase I begins just after the publication of regulations and instructions and will end at the date when the board is ready to ratify the licenses of agents in market.

Phase2: This Phase ended at 3 March, 2003 which is the last day for approval of a free consumer.

Phase 3: This phase will end with MFSC's initiation of balancing and settling mechanisms.

Phase 4: This phase will last with the abandonement of all regulations upon bilateral contracts.

EPDK predicts that, at the initial phase, wholesale price of electricity may rise because of the transition costs (EPDK,2002:8). This may be firstly due to the so-called "stranded costs". These are the costs imputed by the inefficient pre-reform contracts whose imputed costs can not be matched after the implementation of the reform and by inefficient investment projects which were initiated before reform. The brochure seems to be unclear about the question "Who will pay these costs?". These commitments include high cost Build and Operate (BO) and Build-Operate-Transfer (BOT) contracts signed by governments. Although some of these contracts have been cancelled, they have continued to be a big legal problem for new market design. Brochure indicates that these costs may be recovered in one of the three ways: 1)They may be recovered from general budget. According to EPDK, this way may generate an important obstacle for privatization. 2)Consumers can pay these costs in the form of increased prices. 3)These costs may be recovered from more efficient and less costly projects. Electricity Market Law, amended in 4 August 2002, clearly ratifies this way (EPDK, 2002:17).

This is not a just way of recovering “stranded costs” since such a procurement will indirectly raise the electricity prices paid by consumers in the form of operational dispenses of these low cost projects embedded in their operational costs. The way of recovering these costs, as in USA and the UK, will be a focus of debate and also a matter of social antagonism.

The Brochure also defines the agents in different segments of the electricity sector. Agents are as follows:

* Generation

-EÜAŞ(Elektrik Üretim Anonim Şirketi)

-Private producers (each private producer’s generation is limited to at most 20% of the total installed capacity of the system in the previous year).

-Autoproducers (Any autoproducer’s marketable generation is limited to at most 20% of its annual production).

* Transmission

Transmission system is owned by TEİAŞ (Türkiye Elektrik İletim Anonim Şirketi). TEİAŞ is responsible for following: 1)Taking over all publicly owned transmission utilities. 2)Implementation and planning of all public investment into transmission facilities. 3)Operation and maintenance of national transmission system. 4)Servicing parties without assigning any priorities. 5)Providing third party access. 6)Operation of MFSC. 7)Preparation of transmission tariff lists. 8)Construction of the interconnection with international transmission systems.

* Distribution

-TEDAŞ and private distribution companies. They are responsible for demand forecasting, providing the basis for third party access, mandatory selling of electricity to the areas where no wholesale company is responsible for, operation and maintenance of the distribution system. On the other hand, a private distribution company can be authorised to have generating utility in the area it is authorised to distribute energy, but the generating capacity is limited to at most 20% of the electricity consumption of that area in previous year.

* Wholesale Trade

Wholesale companies: TETAŞ (Türkiye Elektrik Ticaret Anonim Şirketi) and private wholesale companies. TETAŞ is responsible for giving bids and offers to MFSC and participating in bilateral contracts with EÜAŞ and private generation companies and contracting bilaterally with retail companies.

* Retail Trade

Retail companies are privately owned and authorised to sell electricity to unfree consumers. They are also responsible for metering.

The brochure also defines the time dimension of the operations of the market. It is important to note that there are two parallel markets. The first one, bilateral contract market, at the initial phase of the implementation of the reform, is strictly monitored and regulated. In the future, the bilateral trades will be unregulated and will be immune from the control of the regulatory body. On the other hand, the second one, Balancing Market is strictly monitored and regulated. The brochure defines the time domain of this second market.

According to the brochure, there are three settling periods: 00:00-08:00 period, 08:00-17:00 period and 17:00-24:00 period. The operational time unit is 30 minutes in the new market mechanism. At the end of each settling periods, every agent in the market rearranges its trades in order to fulfill its own trade balance. In any imbalance case, for each agent, system operator accepts increment or decrements in both generation and distribution. Both increments and decrements are submitted to MFSC in the form of offers or bids.

Every generator that has the spinning reserve capacity supply their bids for increments that are to be processed during imbalance periods. On the other hand, generators, having faced diffuculty with meeting the demand that is enforced by a bilateral contract, offer for decrements in its capacity to MFSC. A wholesale or a retail company which faces an imbalance, again, offers for increments or decrements..

For the three settling periods, in case of any imbalance, MFSC accepts bids and offers form generators. The bid prices should be arranged as follows: Each generator’s output level is divided into two parts: Minimum Stable Production Capacity (MSPC) and Total Production Capacity (TPC). TPC is calculated as follows:

TPC = MSPC+SRC

where SRC is spinning reserve capacity. Then bids should be arranged as follows:

Inc1 (Incremen1): From 0 MW to MSPC.

Inc2 (Increment2): From MSPC to TPC.

Dec1 (Decrement1): From MSPC to 0 MW.

Dec2 (Decrement2): From TPC to MSPC.

The relation between these depends on the physical characteristics of the generation plant. For example, unit cost of thermal plants between 0 and MSPC is very high and greater than the unit cost above MSPC. In contrast, for hydrolic plants there is no such problem. However, for the sake of a logical pricing of increments and decrements, following relations should hold;

Inc2>=Inc1;

Dec2>=Dec1;

Inc1>=Dec1;

Inc2>=Dec2;

Which kind of increment or decrement bid a generator supplies depends on the Physical Condition Notification (PCN) of that generator. PCN is determined by the level of the production of that generator enforced by its bilateral contract.

MFSC estimates a balancing price in the case of an imbalance as follows;

BP= (Purchasing Cost + Selling Cost) / (Purchased Quantity + Sold Quantity)

On the other hand, the brochure indicates that a special type of the bilateral contract “Settling and Balancing Contract” signed between MSFC and any generator serves to overcome any imbalance. If an imbalance occurs, the generator that signed the contract is called to generate the necessary increment or decrement (we use the term “generate the decrement”, this means that the decrement value is bought by the generator which is the partner in the contract). This type of contract is a regulated contract (EPDK,2002:30).

The other issue adressed by the brochure is the ways of regulation. It seems that, in this issue, EMRA is not so much determined since, for some segments of the electricity network, the way of regulation is not explicitly defined. The types of regulations for different segments of the electricity network is given in Table 2.6.

Table 2.6. Types of Regulation for Different Activities

Activity	**Regulated Price**	**Regulation Type**
Transmission (TEİAŞ)	Connection Price	Projecting
	System Utilization Price	Income Ceiling
	System Operation Price	Income Ceiling
Distribution	Connection Price	Standard Connection Price
	System Utilization Price	Mixed (Income Ceiling and Price Ceiling
Retail Service	Retail Service Price	Price Ceiling
Retail	Average Retail Price	Price Ceiling
Wholesale (TETAŞ)	Average Wholesale Price	Cost

Generally, price cap regulation is the preferrred regulation type. The selection of such a regulation type may be a result of a view that any price ceiling could induce the firms in regulated segment to invest in technological innovations that can lower their prices and, hence, regulator can decrease this ceiling by the time and also increase total consumer surplus (for the discussion about this type of regulations see Armstrong, Cowan and Vickers, 1994). We will discuss the effectiveness of this type of regulations in our simulation case studies section.

The brochure is supported by Electricity Market Licence Statue, which was published in the Official Gazette prior to the publication of the brochure (Resmi Gazete, 4 August 2002, no: 24836). The statue began with the same definitions and continues with the definitions of conditions that an agent will be granted the license. There are some important precautionary measures against the exercise of the market power. For example, in article 17, in which the scope of the production licenses are defined, it is indicated that any generation firm’s total installed capacity can not be higher than 20% of the total capacity of Turkey for the previous year. This statue also prohibits any type of subsidy, for example, EÜAŞ can not subsidize its price. Article 21 indicates that all the transmission system will be operated by MFSC and the transmission company, TEİAŞ, is disallowed to engage in generation activity. The statue limits the maximum share of any wholesale company to 20% of the electricity consumed in the previous year. It also puts some limits for the generation of the autoproducers and shares of the distribution companies.

In addition to all these documents, some other statues are published in Official Gazette and became operational (for example “Free Consumer” Statue, Tariffs Statue etc.). All these documents aim to draw the planned path of the reform. This reform is also supported by the governmental organizations like Treasury.

CHAPTER 3

ECONOMICS OF ELECTRICITY MARKETS: THEORY AND EMPIRICAL STUDIES

In this chapter, we summarize the theoretical and empirical literature about the main issues debated in the context of the electricity sector liberalization. These issues will be adressed for the Turkish case in Chapter 5 in which we use the TESS model to simulate various forms of markets and regulations.

There are five main issues to be reviewed in this chapter. The first one is whether new market design gives way to the exercise of the market power or not. Most of the authors referenced in this chapter are pessimistic about the performance of the new market design in this context.

The second issue is the relation between the transmission bottlenecks and the market power. Which factors in new market design generate the possibility of the exercise of the market power is another important topic. The bidding mechanism in spot market seems to be a source for the market power. Fourth, the effects bilateral contracts in the context of market power will be discussed. Fifth issue is how different pricing mechanisms can affect the strategies of agents in the new market design. The theoretical and empricial literature is organized around these questions.

3.1. Theory

Economic theory, until full-fledged liberalization attempts, generally did not get so much interested in traditional public goods such as electricity. Liberalization attempts induce many economists to focus on energy sectors including the electricity sector. This recent interest have dealt with some new problems as a result of the new market design which were unfamiliar to the traditional public sector economics. Public sector economics mainly concentrated its efforts upon the regulation of formerly state-owned natural monopolies. In the context of the electricity supply industry, these new problems have provided a firm basis for the development of a new theoretical literature. The basic points of concern for this new theoretical literature may be summarized under a few headings such as market power, new forms of regulation, transmission congestion, strategic gaming etc.

Liberalization and introduction of competition into the electricity supply industry initiated an important theoretical discussion about the exercise of market power opportunities provided by the new market design. This discussion has been generally related to the discussion about the continuing monopoly over the transmission subsection of the electricity network and regulation issues. Full competition in the form of spot electricity market which has been proposed for many new comers in the liberalization of electricity sector have produced scepticism about the possible market power in the electricity supply industry. Empirical facts from the countries experienced such liberalization programmes verified this scepticism (for example see Wolfram, 1999 and Ocana and Arturo, 1998). Since electricity can not be stored, and can be produced and consumed in a geographically diverse area, possible locational or regional market power opportunities may occur. Agressive generation or distribution companies may want to exploit these opportunities in the post-liberalization market design. Hence, this kind of scepticism have produced an important literature concerning the exercise of market power issues in a liberalized electricity market.

In the context of market power discussion, David Newberry and Richard Green have made important contributions (Newberry and Green, 1992, Newberry, 1998 and Greeen 1999). These theoretical contributions were enriched by some empirical studies (see Wolfram, 1999).

Green and Newberry (1992), inspired by the initial phase of the liberalization of the British/Welsh electricity sector (initially all the generation assets of the English electricity supply industry is divided among four large private companies), benefiting from Klemperer-Meyer-type supply function equilibria (Klemperer nad Meyer, 1989), focus on non-cooperative Nash equilibria for a duopoly in the electricity spot market. They compare Cournot and competitive solutions and found out that large firms formed in the post-liberalization era may have considerable power and may affect the system sell price. They found a set of equilibria ranging between the full competitive solution and Cournot solution under capacity constraint assumption. The equilibrium is determined by the slope of the supply curves submitted by each of the duopolists. As will be indicated several times below, the exercise of market power opportunity mainly originates from the fact that any large firm or a coalition of firms may submit supply curves which are not close to their respective marginal cost curves. Green and Newberry find out that, in an asymmetric duopoly case, the larger firm can submit a supply curve very much steeper than the marginal cost curve (Green and Newberry, 1992:941).

Although they reached the same practical conclusion, Von der Fehr and Harbord put an important methodological counter argument against Green and Newberry (Von der Fehr and Harbord, 1993). They argue that supply function equilibria indicated by Newberry and Green can not be generalized. Moreover, they indicate that, by neglecting the role of the auctioneer in the newly liberalized market, Newberry and Green underestimated the effects of different bidding and pricing rules. Von der Fehr and Harbord use a sealed bid, multi-unit auction model (as opposed to Green and Newberry's model, which gives no role to the auctioning process). They search for multiple equilibria. They detect, as Green and Newberry do, a strong incentive to exercise market power in the liberalized electricity market. They conclude that:

> It therefore seems reasonable to conclude that for a given number of generating sets in the industry, system marginal price will be decreasing function of the number of owners or generators controlling the sets, i.e. the industry concentration ratio (Von der Fehr and Harbord, 1993:537).

They use the traditional concentration measures. Borenstein and Bushnell argue that such a conventional concentration measure is unable to cover the effects of the incentives of the generators, the price elasticity of demand and potential for the expansion of output by competitors and potential customers (Borenstein and Bushnell, 1999).

As market power has been the permanent problem for the UK electricity market, after the study of Green and Newberry, academic interest directed to the electricity supply industry continued to focus on this issue. Their main objective is to find out the ways to limit the exercise of market power. Two additional studies, one by Newberry and other by Green (Newberry, 1998 and Green, 1999) analysed the possible effects of contracts and entry upon the market power. The first one (Newberry, 1998) again uses a Klemperer-Meyer type supply function equilibria. It is important to note that in Klemperer-Meyer context variations in demand is unpredictable. Newberry concludes that contracts may have a dual role. In the first instance, with the threat of new entrants upon incumbents, contracts make the electricity spot market more competitive, and secondly, they may also be used to deter entry into the spot market. The second case is feasible only when incumbents have adequate capacity. In this case, when contract coverage is lower, contracts serve more to the role of entry deterring than inducing more competition. In Newberry's context, the amount of the electricity to be contracted is determined exogenously. In the UK electricity market, contracts are in the form of "Contracts for Differences" which is designed to cover the loss of consumer or generator when spot market price differs from the contract price. In this form, contracts may serve to increase the competition in the electricity market, i.e. they may be used to raise or reduce the spot market price to the competitive level. Newberry argues that sufficient level of contracting may decrease the opportunities for the exercise of market power.

On the other hand, Green (1999), moving from the same assumptions and using the same analytical framework, indicates that contracting a considerable share of output will decrease the short-run incentive to use market power (Green,1999:123). In Green's context, as opposed to Newberry's study mentioned above, the amount of the electricity to be contracted is determined by an optimization process instead of being determined arbitrarily. Again, Green states that sufficient level of contracts can result in the fact that submitted supply curves coincide with respective marginal cost curves. Despite these beneficial effects, contracting higher shares of output induce firms to demand higher prices for the contracted electricity.

As indicated earlier, generally, theoretical literature about the post-liberalization UK electricity market generally deals with market power issues related to a low number of large companies in the generation segment of the electricity supply industry and the entry-deterring strategies of these companies. In USA, the electricity sector has historically shown a geographically diversed structure, coverage is larger than in the UK. Moreover, we can observe the same type of diversity in the ownership structure of the generation and distribution segments. Studies about the electricity sector in USA generally focus on the topics like the relationship between the transmission network and the locational market power instead of the oligopolistic structures in the electricity supply industry.

W.W. Hogan makes a sizeable contribution to the literature in this framework (for example see, Hogan, 1997 and, Harvey and Hogan, 2001). Hogan indicates that transmission constraints mitigate market power, especially in locational form. He concludes that "ownership of geographically dispersed generation can create market power through interactions in the network" (Hogan, 1997:15). The transmission capacity constraints can result in the cases in which the lower cost generator's generation can be cut because of the transmission capacity constraint. Additionally, Hogan argues that the tradeable transmission rights (i.e. independent sytem operator gives some tradeable rights over the transmission system to some companies), as sometimes proposed as a solution to this problem, can generate extra profits for the firms which acquire these tradable rights. Hence, they can be an another source for the exercise of the market power.

Stoft analyzes the same topic (Stoft, 1997). With the help of a small model, he indicates that the transmission capacity constraints on the lines connecting geographically dispersed areas can result in multiple equilibria. The basic conclusion is that congested line can cut a geographically diversed market into several non-competing regions (Stoft, 1997). Stoft aims to analyse the origins of market power problem in USA. Including Stoft's, most of the studies in USA argue that the most feasible and effective solution to market power problem is the expansion of the electricity transmission grid. "Who will do this?" is a debatable question.

Most recent studies apply game-theoretic approach to the market power analysis for the electricity supply industry. For example, Cunningham et.al. use game theory to analyze the effects of the transmission constraints upon the opportunities for market power (Cunningham et.al. 2002). They distinguish between the effects of non-constrained and constrained transmission upon the competitive benchmark case and Cournot case. They conclude that generators having Cournot type behaviors, in the unconstrained case, can significantly change the transmission flows compared to the competitive benchmark case. On the other hand, in the constrained case, Cournot-type behaviors can result in locational price differences which can give way to locational monopolies. Interestingly, they argue that the exercise of market power generates serious difficulties for both transmission plannning and management of transmission congestion (Cunningham et. al., 2002:171). Hence, it can be said that the liberalization of the electricity supply industry discards any type of planning not only at the policy level but at the practical level as well.

Since new market design can generate informational asymmetry opportunities, firms which have higher shares can affect market price through some gaming strategies if the number of firms operating in the market is very low. As indicated above, gaming and optimal bidding have become important research areas. In the new market design, in the spot market portion, generation companies are mandated to submit price-quantity curves for each operational time unit. This process, naturally, can create potential for cheating as a result of informational asymmetry. Regulator/Independent System Operator's basic aim is to make generation companies to submit price-quantity curves close to their respective marginal cost curves. Horizontal market power or higher market shares can create considerable divergences from marginal costs and generate opportunities for mark-ups. Hence, bidding and gaming strategies can create productive ineffciency. This theoretical foresight creates an important subliterature (for example see, Kleindorfer et. al. 2000, Petrov et. al. 2001 and, Wen and David, 2001a).

Wen and David (2001a) use a Monte-Carlo-based method to find out the possible repercussions of strategic gaming among competitive generators and large consumers upon social welfare. In their modelling context, large consumers are also allowed to submit their demand curves and they can also play the game. This is consistent with the reality since new market design covers the participation of large consumers to bidding process. As a conclusion, they argue that informational asymmetries can create potential for strategic gaming which transforms the competitive market into an oligopolistic market. Gaming strategies have bias for strategic collusions and partnerships and these can induce firms or large consumers to submit demand or supply curves not so much close to their respective marginal benefit or marginal cost functions. In their second study (Wen and David, 2001b), they use the same methodology and, again, find out strong incentives for the exercise of the market power by competitive generators as a result of strategic gaming and bidding processes. Although competitive generators are inclined to act as oligopolists in this framework, their maneuver space will very limited if the load is elastic. This last conclusion will be shared with other studies but there is a basic weakness in this argument. These studies do not capture that although incorporating large consumers into the system may reduce the price paid by these consumers, price paid by households and small consumers will continue to exhibit the effects of the exercise of market power.

Apart from market share, there are some other factors, which influence the bidding strategies of the generation companies. Informational asymmetry is one of the most influential factors. The independency and autonomy of the system operator is strongly related to the informational asymmetry.

Petrov et.al. design an experiment in order to simulate an environment where one of the generators conduct a predatory gaming strategy, i.e. it aims to cut of one or more generators (Petrov, Richter and Sheble, 2000). They conclude that market power not only arise from market share but from informational asymmetries as well. In their experiment, the generator, which has predatory gaming strategy will have more information aboout congested lines or available transmission capacity. This informational asymmetry induce that generator to bid more agressively to capture the share of some other generators.

In the studies mentioned above, representative generator a priori knows how much to bid and which strategy to use, so there is no learning process. In theoretical framework, although this fact provides so much ease in the solution of models, neglecting learning process can direct analysis to give inconsistent results and, especially in the analysis for new-comers like Turkey, unrealistic solutions. Nicolaisen and others focus on this subject and design an experiment based on double-auction pricing in which agents learn by bidding (Nicolaisen et. al. 2001). In their model, they assume such a Walrasian tatonnement proces in which from inequalities between supply and demand, agents in the sector attain the maximizing bid by learning. Bidding process is bilateral i.e. both buyers and sellers submit their bids. The learning process is in Roth-Erev form, i.e. a particular actions's probability to be selected depends on the relative profit it gains. Agents which have Roth-Erev type learninig process solve a stimulus response problem at every stage of the game. At every round, as rivals' actions change, the selection probability of each action of the generator also changes. Authors' most important conclusion is that, the auction process, apart from other influential factors, is another source of the market power. Hence, Walrasian process in the electricity market gives an unanticipated outcome.

It is important to note that auction and bidding processes result in a system-wide marginal price which is mainly determined by the most expensive generator in a system with loss if regulator applies a uniform pricing mechanism. In the case when there is no loss, marginal cost among the busses is equal. Losses produce disparities among marginal costs of the generators at different busses. It does not matter marginal costs of different busses differ or not, generally, studies mentioned above assume that uniform price occurs after the bidding or auctioning process ended. Some studies abandon this assumption and generate a new discussion basis. For example, Giulio and Rahman (2000) compare the effects of the uniform price auction and discriminatory pricing under competitive and monopolistic supply cases. This study seems to be induced by the new market proposal in the UK known as New Electricity Trading Arrangement (NETA) which is designed to replace uniform pricing with non-uniform pricing. This new model is designed to overcome the market power of incumbent firms, since it is believed that uniform pricing mitigates their market power.

In this study, conclusions are very impressive. Firstly, they find that output under Pay-as-Bid (PAB) is always lower than that under System-Marginal-Price (SMP, unfiorm price) (Giulio and Rahman, 2001:9). Moreover, low-cost generators suffer more in a PAB auction. Low-cost generators, in PAB environment, are forced to bid more agressively to raise their prices and, thus, their supply curves diverge considerably from their marginal cost curves. This negative effect is somewhat balanced with the relative increase in consumer surplus under PAB regime, but this is positively correlated with the elasticity of demand. Moreover, under SMP, equilibrium is Cournot-like while it is Bertrand-like under PAB case. The most important conclusion is that uniform price induce generators to compete in supply functions as in the case of Green and Newberry's study (Green and Newberry, 1992), as non-uniform pricing induce generators to leave electricity spot market and compete in bilateral contracts (Giulio and Rahman, 2001: 31).

We will discuss this last point under the results of our simulation studies. This last study also assumes no loss and, as we indicated, in a lossless system productive efficiency enforces an equalization of marginal costs among generators and this provides a strong bias for uniform price. Taking losses into consideration changes the picture radically since in the case in which no loss assumption is abandoned, enforcing a uniform price over the whole system *de facto* generates productive inefficiency as the transmission loss itself has a cost and this cost is shared among the connected busses. The bus which has more connections will take the largest share of loss cost. This fact will result in cost differentials among busses.

Newberry and McDaniel discuss the possible benefits of nodal pricing compared to uniform pricing using the empirical results obtained form the UK experience (Newberry and McDaniel, 2002). Firstly, they criticize the new market design, NETA for the fact that it is not transparent in its pricing mechanism. Transparency is a very serious problem in such a market design, since the system does not operate under a uniform price and differences in prices paid to different generators is only known by the system operator. In new market design, central dispatch is abandoned and centrally-settling mechanism is replaced by a self-balancing mechanism (as in the case of Turkish experience). Newberry and McDaniel are very pessimistic about the outcomes of new market design, they argue that non-transparent pricing mechanism induce the exercise of market power. They add;

> Apart from the conditions of entry, it is far from clear that bilateral physical contracting combined with a discriminatory Balancing Mechanism mitigates market power more than bilateral financial contracting combined with a single price auction market of last resort (Newberry and McDaniel, 2002:10).

Newberry and McDaniel, despite their scepticism, argue that there is one beneficial outcome of NETA, i.e. it points out one basic weakness of uniform-pricing spot market such that it is difficult to pursue policies which are socially desirable but may have adverse effects upon the profits of one trading agent. Balancing mechanism (which is also a basic formation of New Turkish Electricity market) penalizes both trading partners in the form of imbalance prices and therefore trading agents are forced to innovate in their trading strategies and act less agressively.

All these important contributions to the literature indicate one important distinction between the experiences of the UK and USA as paragons for the late-comers in the liberalization electricity markets, as indicated above. In the UK, market power is the result of the presence of large oligopolistic firms especially in the generation segment of the electricity supply industry. Hence, the dominant theme in the theoretical literature in the UK is the search for the methods to prevent the exercise of the market power. On the other hand, market power in USA is generally assumed to be related to transmission bottlenecks to a greater degree and collusive behavior of generation firms to lesser degree. Geographically diversed electricity network can generate such problems and these problems increase the importance of the transmission segment of the electricity network. There are two important problems in this context: “Who should own it?” and “Who should operate it?”.

There is a commonly accepted answer to the first one; since the transmission segment has all the technical pre-conditions of a natural monpoly, state should own it. Although some proponents of liberalization carry this belief to the discussion area, the new methods, such as financial or physical tradable transmission rights, tradable transmission contracts, seem to be ineffective, or have adverse effects on the transmission expansion planning or transmission congestion management. As a result, the transmission grid will continue to be a natural monopoly in the middle run.

The operator, rather than the owner is more crucial for the market power issue. “Who should operate it?” is a much more debatable question than “Who should own it?”. This problem poses two related questions: “Should transmission system operator be independent from any public authority?” and “How should access to the transmission system be regulated?”. There is an important literature about the second question. Masiello (1998) adresses some basic points of debate in this contex and also covers some hints for the first one. A more coherent analysis is given by David and Wen (2001). They summarize the basic open access pricing rules such as nodal, zonal or allocation-based pricing schemes. Moreover, they also compare various transmission congestion management methods. A more detailed analysis can be found in the study of Shahidehpour, Yamin and Li (Shahidehpur, Yamin, and Li, 2002).

3.2. Empirical Studies

The theoretical literature implies its scepticism about the performance of the liberalized electricity sectors. It seems that this scepticism originates from the empirical facts observed rather than the basic findings of the economic theories about the liberalized electricity markets. The theoretical discussions about the ways to prevent the exercise of the market power seem to have a very slightly adverse effect upon the hope for the performance of the liberalized electricity markets. This hope is most likely to stem from the unshakened optimism for the future performance of the new market design. Theoretical contributions are mainly the result of the unanticipated outcomes of liberalization of the electricity supply industry. We can deduce some basic features of the new market design from the empirical literature concerning post-liberalization electricity markets.

In tandem with the theoretical literature, the most common topic in the empirical literature is the repercussions of the exercise of market power. A common conclusion of the studies, which contribute to the empirical literature is that, as in the theoretical literature, there is a potential for the exercise of the market power in the post-liberalization market.

Rudevich and Duckworth (1998) stress that, even in the markets with high number of generation companies, system price diverges significantly from short-run marginal costs (Rudkevich and Duckwort, 1998:19). They also use Klemperer-Meyer type framework and device a price-cost margin to express annual price mark-up. They find out that this index increases with the concentration in the electricity market. They add that measures taken in USA are ineffective in mitigating market power. They suggest some measures such as the divestiture of generation assets, changing the bidding and payment rules, promoting contracts against the exercise of market power. They indicate that demand-side bidding and real time metering on the consumer side may also be effective.

A second study, focused on the Swedish electricity market, indicates some pessimistic conclusions about the exercise of the market power (Andersson and Nergman, 1995). They wrote their paper prior to the deregulation of the Swedish Electricity Market. Their empirical conclusions derived from their experiments are impressive. They compare Nash-Cournot and competitive equilibria. They conclude that the relative size and the relative market share of the largest generator is very crucial for the equilibrium price and, more importantly, the number of the small generators do not affect the system-wide price. This last point is very important for our empirical case studies discussed below, since in our cases we find that, the system-wide price is determined by the definite generators and relative sizes of other firms do not affect the system-wide price. Their most pessimistic conclusion is that, in a market with high concentration ratio, as in the case of the Swedish electricity market, deregulation can be ineffective in reducing prices. They indicate that this tendency may be counter-balanced by consumer participation, or specificly a symmetric high concentration ratio on the consumer side, i.e. a large wholesale firm.

Empricial studies also highlight the possible ways of the exercise of the market power and posible ways to mitigate it. For example, Hudson looks for the possible effects of the non-uniform pricing upon the exercise of the market power. Despite the important critics made by Newberry and McDaniel (2002), he finds that, limiting the effects of *marginal* units (the units that determine the system-wide price and at the highest point of merit order and accepted as last bid) may mitigate the exercise of the market power. Moreover, this pricing scheme has the power to enhance system reliability.

Some empirical studies also apply game-theoretic approach to analyse country experiences. Moitre applies a game-theoretic approach to electric energy markets, and finds out that, in a competitive environment with a high number of generators, it is very hard to exercise market power (Moitre, 2002). On the other hand, decrease in the number of the generation companies increases the chance of exercise of the market power. The first part of the argument seems to be misleading unless we assume that the generators' relative sizes are very close to each other.

There are some studies that also append international electricity trade to modelling. Amundsen and et al. give an example of such studies (Amundsen, Bergman and Andersson, 1998). They use a simulation study to analyse the possible effects of the Nord Pool cosntructed by Sweden, Norway and Finland on the Swedish Electricity market. They note that, as opposed to the case of the British electricity sector deregulation which was implemented in order to open electricity market to private participation, Scandinavian countries deregulate in order to increase the efficiency. There are considerable differences among the countries which are covered by the Nord Pool in the context of fuel mix, for example about 90% of the Swedish installed capacity is hydro while Norwegian electricity sector has been dominated by thermal units. There is also a great difference in market concentration among countries, for example market share of the three largest firms in Sweden was 78.6% in 1994 while it was 43.1% in Norway and 55.8% in Finland (Amundsen, Bergman and Andersson, 1998:5). They use a model written in GAMS to find out possible efffects of Intra-Nordic trade upon the prices at the national level under the assumptions of competitive and Cournot behaviors. Under autarky assumption, they find that equilibrium prices differ significantly between competitive and Cournot cases. On the other hand, inter-country trade diminishes the difference between Cournot and competitive prices. Moreover, a high-price country (in their case, Sweden) can significantly benefit from the opening up of the electricity market to the international competition, while a low-price country (Norway) may face with sudden increase in price level.

There is another study concerning the exercise of the market power in the Nordic Market. Halseth, using again the Klemperer-Meyer framework, investigates the opportunities of the exercise of the market power (Halseth, 1998). He uses a linear optimization model and does not explicitly model contracts, concentrates upon the spot market. The basic finding of the author is that the new market design always induces large generators to collude with other generators and increase the price level. This is due to the fact that, in Halseth's system, regulator applies uniform pricing and any collusion can result in an increase in prices which is not offset by the decrease in output of generators that collude. Secondly, relieving the inter-country transmission system from bottlencks and abandoning border tariffs will reduce the prices in high price countries while these may increase the price in some low price countries. Most importantly, price level in the new market design is highly sensitive to the level of demand.

Another study, on the Spanish electricity sector, by Ocana and Romero, uses a simulation study to find out the possible effects of four-firm oligopoly in the Spanish electricity sector. They compare the outcome of Cournot-type oligopolistic structure and competitive market structure. They also look for the fuel mix of generation under different demand levels. They indicate that pool prices are higher and more volatile under the oligopolistic case and, in the competitive case, changing level of demand has a very low effect upon prices. Secondly, hydro generation shifts from low to high demand periods. This is very interesting, since, having the lowest marginal cost, hydro generation is generally dispatched to meet base load. Thirdly, they stress that pool performance is highly sensitive to market structure. As market structure deviates more from the competitive structure, pool tends to distort prices and hence reduce the consumer surplus.

There may be a methodological counter-argument against this and other studies mentioned previously. In a network production environment like electricity, the size of any firm which does not operate at the heart of the geographically diversed production space may have a little effect upon the performance of the electricity market. In other words, any small firm located at the point which has a large number of connections may have relatively high market power while a large firm operating near the border of the system may have only a slight locational market power. These studies, generally neglecting transmission system, can give misleading results.

The last important conclusion put by Ocana and Romeero is that, as Borenstein and Bushnell (Borenstein and Bushnell, 1999) argue, concentration indices such as Herfindahl are unable to capture the real movements of firms (Ocana and Romero, 1998:4). Most of the studies about the electricity sector are pessimistic about the conventional concentration measures since they are unable to capture some important dynamics of the electricity sector. All these measures are static measures, while trading of electricity is a very dynamic process. Moreover, static division between buyers and sellers is useless in an analytical framework for the electricity. In this sector, most of the buyers are also sellers and also most of the sellers are also buyers, this fact complicates the picture and conventional concentration measures depending on sales become doubtful in this context.

Secondly, parallel markets to the pool such as futures market, bilateral contract market or balancing market contribute to these complications. Any pool-based concentration measure can easily miscalculate the real concentration in the electricity market. There is another topic directly related to the first reason. Wheeling means wholesale electricity trade between first and third agent through the mediation of a second agent, which may also be a generation company. In the context of wheeling, traditional sales-based concentration measures also give misleading results.

Green, in his study, explores the repercussions of the transmission pricing upon the performance of the spot market (Green, 1998). He compares several different transmission pricing schemes. He also analyses the influence of transmission constraints and transmission losses; this last point is a very realistic assumption. Under these assumptions, he finds that prices rise with the number of nodes because of the losses, higher number of nodes mean higher number of connections, and hence higher loss level. It is important to note that, in Green's study, demand is flexible. Again, in his system, losses generate differences among the marginal costs at different nodes.

Apart from all of these, Green indicates that the most important conclusion is that, moving from uniform system-wide price to optimal nodal prices could increase the welfare but he adds that this option may be politically dangerous, since such a transformation enforces welfare transfers among the agents and may cause some of them to oppose politically (Green, 1998: 20).

Secondly, the imposition of transmission loss factors may generate a decrease in price in one region while raising it in the other. Most serious conclusion implies its criticism about bilateral contracts. Green indicates that bilateral contracts made by costly generators prevent the dispatch of the less costly generators. One solution may be, according to Green, the ban of the bilateral contracts. Bilateral contracts, by limiting the output of the less costly generators, may enforce a capacity payment to these generators, and, hence, increase the overall cost of the electricity system.

We return back to discussion about relative benefits of uniform pricing and non-uniform pricing. In our simulation case studies section, we also refer to this discussion. We will see that applying nodal pricing scheme limits the exercise of the market power in the price of widening differentials across bus level prices.

Makkonen and Lahdelma examine the nature of the contracts in the electricity market (Makkonen and Lahdelma, 2001). Makkkonen and Lahdelma call the contracts signed before the deregulation of the Finnish electricity sector as “old contracts” while the contracts made after that as “new contracts”. “Old contracts” are open long-term, multi-tariff contracts with capacity payments. “New contracts” do not include capacity fees and they are short-term contracts. They compare different pool types and stress that the information problem is very crucial for the performance of the pool. They discuss the possible benefits of the pool in the context of retail distribution. The benefets of pool should be allocated carefully. Any unfair allocation may induce firms to escape from the pool. Despite these warnings, they find that pool can operate more efficiently than the traditional vertically integrated monopolistic electricity sectors (Makkonen and Lahdelma, 2001:300).

Green and McDaniel estimate benefits of the introduction of competition in the British Electricity sector (Green and McDaniel, 1998). They look for the welfare effects and find out that large consumers gain more than small consumers. Reduction in prices paid by large consumers, as a result of the introduction of the competition, is far greater than that for small consumers. Secondly, net change in welfare is lower compared to the relative change in welfare shares. Hence, the introduction of competition into the electricity sector is more of a political economy issue than of a technical/economic issue. It is a political economy issue, since the change in the composition of total welfare generates political results and may create severe political opposition.

An important study on the perfomance of the long-term power markets is of Lee (Lee, 2001). His basic aim is to find out the factors that determine the volatility of the prices in the long-term electricity power markets. He makes projections using his simulation model. He uses a competition index and as this index rises, the social costs paid by the customers and total customer bill decrease. These social costs include environmental and other social costs. On the other hand, total environmental cost seems to be unaffected from the degree of the competition. Secondly, increasing price elasticity of demand reduces price volatility in the system. Moreover, increasing price elasticity of demand also reduces the social costs paid by consumers. Despite the pessimistic views of Green (Green, 1998 and Green, 1999), Lee determines a positive contribution of bilateral contracts because they reduce price volatility. Although they reduce price volatility, presence of bilateral contracts raises the average electricity prices.

CHAPTER 4

TURKISH ELECTRICITY SYSTEM SIMULATION MODEL (TESS)

4.1. Background

The technical and economic background of the Turkish Electricity System Simulation Model (TESS) is outlined in this chapter. First, we will give some definitions about the power systems. We will also outline the basic structure of a power flow problem. Then, we will summarize the solution techniques for the power flow problem and some recent approaches in the power systems theory that can ease the solution of a power flow problem. In this context, beginning with the basic power flow problem, we aim to proceed to obtain the basic structure and basic elements of the optimal power flow problem (OPF). We will look at diffferent approaches in the power systems theory and conclude with the approach that we will use in our model, the DC Flow Approximation Method.

4.1.1. Definitions

Before outlining the basics of a power system, we will define some basic concepts that are used frequently in the analysis of power systems. A power system is a network consisting of *busses*, *lines*, *transformers* and *electricity machines*. A *bus* is a node in a power system network at which voltage is measured. *Line* is the component of a power system network which connects busses. *Transformers* serve to regulate the voltage level while *electricity machines* are used to transform the electric power into some kind of energy like heat energy. TESS does not include transformers and electricity machines. Figure 4.1 shows a simple power network. The circles indicate busses. *V* indicates voltage of a bus and *I* indicates current flow from one bus to another.

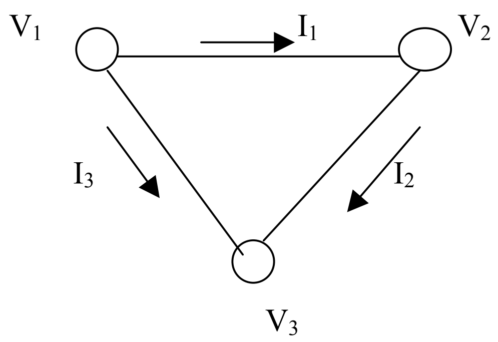


Figure 4.1. A Simple Power Network with Three Busses

-*Bus*: A bus is defined as the point of the system where voltages are calculated (IEEE, 1994:70). In power system analysis, bus is used interchangeably with the term "*node*". There is no strict rule for defining the boundaries of a bus. In fact, bus is the point where either generation or consumption, or both of them take place. Power network parameters are defined via buses. Distinct bus parameters are used to calculate *admittance* and *impedance* matrices.

-*Admittance Matrix*: Admittance matrix is used to determine currents (I) from nodal voltages; i.e. current injected at any bus is estimated from voltages injected to the overall system using the elements of the admittance matrix. Currents are calculated as below, for an n-bus system (Dhar, 1982):

(1) $I_1 = Y_{11}V_1 + Y_{12}V_2 + Y_{13}V_3 + \ldots + Y_{1n}V_n$

$I_2 = Y_{21}V_1 + Y_{22}V_2 + Y_{23}V_3 + \ldots + Y_{2n}V_n$

. . . . .

. . . . .

. . . . .

$I_n = Y_{n1}V_1 + Y_{n2}V_2 + Y_{n3}V_3 + \ldots + Y_{nn}V_n$

In general form we can write;

(2) $I_i = \sum_m^n Y_{im} V_m$ i=1,2,….n

where,

I_i = current injected to ith bus

V_m = voltage with reference to bus m

Y_{im} = admittance between busses i and m.

The elements of the admittance matrix are complex quantities. Since basic framework assumes alternative current (AC) environment, currents and voltages are complex quantities. They can be written in rectangular forms as following:

(3) $I = I_x + jI_y = I(\cos\text{Ø} + j\sin\text{Ø})$

(4) $V = V_x + jV_y = V(\cos\text{Ø} + j\sin\text{Ø})$

The elements of the admittance matrix are derived from bus conductance and susceptance as follows:

y_{ij} is an element of [Y] and $y_{ij} = g_{ij} + jb_{ij}$

g_{ij} is the conductance (real part of admittance) and b_{ij} is the susceptance (imaginary part of admittance) (Gross,1986:39).

Both conductance and susceptance depends on the physical characteristics of the lines connecting buses and active system elements such as transformers, synchronous motors or generators. Admittance matrix, indicating physical properties of the power network, is central to the power flow solutions.

-*Impedance Matrix*: Impedance matrix provides another way of looking upon power network. While admittance matrix is widely used in network flow solutions, the main application of impedance matrix is fault analysis (Bergen and Vittal, 2000:294). Impedance matrix can be easily derived from bus impedance matrix. It indicates the basic flow relation as follows:

(5) $V= Z_{bus} I$

Each element of impedance matrix Z_{bus} is also a complex magnitude whose real part is the resistance (r) and imaginary part is the reactance(x) ;

(6) $z_{ij}= r_{ij} + j\, x_{ij}$

The relation between impedance and admittance matrix is just straightforward i.e.;

(7) $Z=Y^{-1}$

The main difference between admittance and impedance matrices is that the admittance matrix can be directly constructed from given technical parameters of power network while the derivation of impedance matrix necessitates considerable amount of data, which should be calculated within more than one step. In the power flow solutions, admittance matrix representation has been used.

-Real and Reactive Power

Both bus voltages and bus currents are in complex forms. Calculated from bus voltages and currents, electric power is also in a complex form. Electric power is;

(8) $S_i = V_i\, I_i$

We combine equations (2) and (8), this gives;

(9) $S_i = V_i \sum_{k=1}^{n} Y_{ik}\, V_k$

in polar coordinates this becomes;

(10) $S_i = \sum_{k=1}^{n} |Vi|\, |Vk|\, (\cos Ø_{ik} + \sin Ø_{ik})\, (G_{ik} - j\, B_{ik})$

We can divide electric power into its real and reactive parts. Real power (P) is the real and reactive power (Q) is the imaginary part of complex power. Electric power can be written as;

(11) $S = P + j\, Q$

and the equation (11) can be divided into its real and and imaginary parts as;

(12) $P_i = \sum_{k=1}^{n} |V_i|\, |V_k|\, (G_{ik} \cos Ø_{ik} + B_{ik} \sin Ø_{ik}) \quad i=1,2,\ldots..n$

(13) $Qi = \sum_{k=1}^{n} |Vi|\, |Vk|\, (G_{ik} \sin Ø_{ik} + B_{ik} \cos Ø_{ik}) \quad i=1,2,\ldots..n$

$Ø_{ik}$ is the difference between the bus i angle and bus k angle, P_i and Q_i are real and reactive power injections to bus i, respectively.

4.1.2. Power Flow Problem

Since electricity networks consist of so many busses in real world, the estimation of power flows on each line and power injection to each bus becomes a hard problem. Power flow problem is the problem of finding real and reactive power injections to each bus in a large electricity network. Real and reactive power injections are indicated by equations (12) and (13).

As equations (12) and (13) show, there are n busses; there are 2*n non-linear equations to be solved. Power flow problem is the predecessor of optimal power flow problem. The system consisting of 2*n equations can be solved by either a sequential method called Gaussian Elimination method or a quadratic method called Newton-Raphson Algorithm. Gaussian Elimination, despite taking relatively less computational time, solves in large number of iterations. On the other hand, Newton-Raphson algorithm, solving in relatively few number of iterations, spends a considerable time in obtaining the solution (Dhar, 1982; 74). Although the Newton-Raphson method has a major drawback in solution time, most of the studies use this method.

For a Newton-Raphson solution, expanding equations (12) and (13) in Taylor's series around an initial estimate gives the following general form;

(14) $$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_1 & J_2 \\ J_3 & J_4 \end{bmatrix} \begin{bmatrix} \Delta\delta \\ \Delta|V| \end{bmatrix}$$

where

$$J_1 = \frac{\partial P}{\partial \delta}, J_2 = \frac{\partial P}{\partial |V|}, J_3 = \frac{\partial Q}{\partial \delta}, J_4 = \frac{\partial Q}{\partial |V|}$$

Equation (14) is a Newton-Raphson step function. δ is the bus angle. From an initial value, Newton Raphson method solves iteratively for the step function for the next iteration. Procedure is stopped when the step function value for all variables falls below a threshold value.

This procedure necessitates a few iterations but it takes a considerable operation time. In the power flow problem, one bus is taken as slack bus. Equation (14) forms a simultaneous equations model, the model is solved for real and reactive power flows. In a system with large number of busses, any iteration in the form of the equation (14) consumes a great deal of time. Some new approaches in the power systems theory about power flow problem like fast-decoupled power flow approach aim to simplify the solution procedures and decrease the solution time.

Fast-Decoupled Power Flow Solution

As power lines have high X/R ratios, ∂P's sensitivity to $\partial \delta$ is very high while its sensitivity to voltage magnitude is low. On the other hand, the change in reactive power (Q) is mainly determined by changes in voltage magnitudes. Hence, for a Newton-Raphson solution, equation (14) becomes (Saadat, 1999:240);

(15) $$\begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} = \begin{bmatrix} J_1 & 0 \\ 0 & J_4 \end{bmatrix} \begin{bmatrix} \Delta \delta \\ \Delta |V| \end{bmatrix}$$

Hence from equation (15);

(16) $\Delta P = J_1 \Delta \delta$

$$\Delta Q = J_4 \Delta |V|$$

Equation (16) shows that equation (14) is separated into two decoupled equations. Solution of the system becomes more simplified. Then, the derivative of real power with respect to the bus angle becomes;

$$\frac{\partial P_i}{\partial \delta_j} = -|V_i| B_{ij} \quad (17)$$

where B_{ij} is the imaginary element of the admittance matrix in row i and column j. Fast-decoupled power flow divides the power flow problem into real power flow and reactive power problems. This approach eases any type of solution method like Newton-Raphson method, since it reduces the number of derivatives to be estimated. Moreover, it may give way to further simplifications and may bring more simplified and efficient approaches in the power systems theory. One of them is Linearized (or Direct Current) Power-Flow Approximation Method.

Linearized (DC) Power-Flow Method

Transmission lines usually have small resistances compared to their reactances. Hence, from fast-decoupled flow approach, one can make another simplifying assumption in order to find a faster solution algorithm (Momoh, 2001:104). We assume that the differences between bus voltages are zero and hence, reactive power becomes zero (Gedra, 1999:242). By this way, we neglect the reactive side of the power generation, which is supposed to have no economic meaning. Flow from bus k to i, in this approach, is defined by;

$$P_{ik} = \frac{\delta_i - \delta_k}{X_{ik}} \quad (18)$$

where X_{ik} is the line reactance of the line connecting bus i to bus k. By assumption,

(19) $X_{ik} = -1/b_{ik}$

where b_{ik} is the susceptance of the line (imaginary part of the admittance matrix). Then,

(20) $P_{ik} = -b_{ik}\,\delta_{ik}$ where $\delta_{ik} = \delta_i - \delta_k$

Power at any bus is the sum of power flows on the lines connecting that bus;

(21) $P_i = \sum_k^M P_{ik} = \sum_k^M -b_{ik}\delta_{ik}$ and $k \in C$

where C is the set of the busses connected to bus i.

In this way, all the power flows are linear functions of the bus angle differences instead of non-linear functions of voltages and bus angles. This approach eases the solution of the real power problem. In this study, we will use this approach to solve the optimal real power flow problem.

4.1.3. Optimal Power Flow (OPF) Problem

Power flow problem's sole purpose is to determine power flow magnitudes that will ensure system stability and security of power system. Optimal power flow is a feasible level of power flow that optimizes a pre-determined objective such as economic load dispatch or transmission loss (Dhar, 1982:114). Most studies take generator cost minimization as the main objective (for example see Muchanyi and El-Hawary, 2000, Huang, 1994, Barrado.et.al, 2000). Transmission system loss is minimized in a few number of studies (see Lima et.al, 2001, Alves and Costa, 2002). Generation cost-minimizing OPF constructs an important link between technical and economic efficiency; and also guarantees the technical stability. The predecessor of cost minimizing optimal power flow is the economic dispatch of generators.

4.1.3.1. Economic Dispatch

The basic idea behind the economic dispatch is to minimize generation cost under the generator limit and transmission loss constraints. In a system constructed by n busses and m generators, basic constraints are as follows;

$$(22) \qquad P_D + P_L - \sum_{i}^{m} P_i = 0 \quad i=1,2\ldots m$$

where PD is total power demand in the system (summation of all bus demands) i.e;

$$(23) \qquad P_D = \sum_{i}^{n} P_{Di} \quad i=1,2,\ldots n$$

P_L is the total transmission loss. P_L is sometimes designated as function of generator outputs. P_i is the generation level for generator i. There are also generator limits such as;

$$(24) \qquad P_{im} - Pi \leqslant 0$$

$$Pi - P_{iM} \leqslant 0$$

where P_{im} is the minimum generation level for generator i and P_{iM} is the maximum generation for it.

The economic dispatch problem can be solved by Lagrangean-multiplier technique. The Lagrangean can be written as;

(25) $L = \Sigma F_i + \lambda(PD + PL - \Sigma Pi) + \Sigma\mu_{im} (P_{im}-Pi) + \Sigma \mu_{iM}(Pi-P_{iM})$

where Fi's are cost functions of generators, λ the Lagrange multiplier which indicates an equality constraint and, μ_{im} and μ_{iM} Kuhn-Tucker multipliers associated with inequality constraints.

The Lagrange multipliers in equation (25) denote the sensitivity of the objective function. For example, λ expresses the magnitude of the change in objective function against a 1 MW change in system demand.

In this context, the power system is represented without too many technical conditions. Moreover, reactive power generation is also neglected. This problem does not impose any transmission limit constraint and mainly it aims to equate power supply with power demand only at the system level (Dhar, 1982; 120). Without taking the transmission line limits into consideration, it is assumed that bus-level equilibrium is also constructed when system level equilibrium is reached.

Lagrangean function in (26) can be solved by any of the ways mentioned above (Gauss-Seidel or Newton-Raphson). It is important to note that the solution should satisfy Kuhn-Tucker conditions. More recent solution techniques may be introduced such as dynamic techniques which may be very useful when analyzing load variations and repercussions of instantaneous demands (Bhattacharya et.al., 2001).

4.1.3.2. Optimal Power Flow

We can write bus level power injections, by using equations (12) and (13), as below;

(26) $P_{in}=\sum_{k=1}^{n} |V_i|\,|V_k|\,(G_{ik}\cos \text{Ø}_{ik} + B_{ik}\sin \text{Ø}_{ik}) - P_i + PD_i = 0 \quad i=1,2,....n$

(27) $Q_{in}=\sum_{k=1}^{n} |Vi|\,|Vk|\,(G_{ik}\sin \text{Ø}_{ik} + B_{ik}\cos \text{Ø}_{ik}) - Q_i + QD_i = 0 \quad i=1,2,....n$

These 2*n equations constitute the basic constraints for optimal power flow (Weber, 1995:12). These constraints, which are neglected in economic dispatch problem, ensure not only the system level stability but also the bus-level stability. Moreover, these constraints impose demand-supply equality both at the bus level and the system level.

Another system level constraint is the transmission line constraint, which is imposed upon the branch flow. These constraints can be defined by;

(28) $|S_{ij}|^2-|S_{ijMAX}|^2 \leqslant 0$

Moreover, the generator limit constraints in equation (10) are also applied here. Upper and lower limits for reactive power are added ($Q_{imin} \leq Qi \leq Q_{imax}$). Some other constraints about the connected electrical equipment, like transformers or electrical motors, could be added to the list of the constraints (voltage bounds etc.).

Then, OPF can be defined as;

(29) $L= \Sigma\, C_i(P_i) + \Sigma\, \lambda i(P_{in}) + \Sigma\, \pi i\,(Q_{in}) + \Sigma\, \Sigma \mu_{im}\,(P_{im}-Pi) + \Sigma\, \mu_{iM}(Pi-P_{iM})$

$+ \Sigma\, \gamma j\,(|S^{ij}|^2-|S_{ijMAX}|^2) +$ *Other Constraints*

Since there are T lines, there will be T transmission constraints. For simplicity, a quadratic cost function is assumed for each generator;

(30) $C_i(P_i)= a_i + b_i P_i + c_i P_i^2 \qquad i=1,2,\ldots m$

The quadratic cost function assumption is a common feature for OPF studies. This assumption guarantees a unique solution to the problem.

Other Constraints may cover the rest of all technical constraints such as transformer tap ratios or voltage set points. In optimal power flow solution procedures, one bus is assumed to be the slack bus.

4.1.3.3. OPF Solution Methods

There are many techniques available to obtain a solution for equation (29). These can be classified into five groups: 1) Nonlinear programming and 2) Quadratic Programming, 3) Newton-based solution, 4) Linear programming, 5) Interior point methods (Momoh, El-Hawary and Adapa, 1999a). Each has some shortcomings and these shortcomings have made analysts to use genetic algorithms (GAs) in the last decade. We can accept GA-based methods as a sixth solution method.

Nonlinear programming method is the oldest one in the list and its origins may date back to the studies of Carpentier and, of Dommel and Tinney (Momoh et. al., 1999a). A large number of studies used this technique to solve the OPF (for example, see Taludakar, Giras and Kalyan, 1983, Momoh, 1986 and Contaxis, Delkis and Korres, 1986). Quadratic programming is a special form of non-linear programming. Although constraints in non-linear programming case are non-linear also, quadratic programming assumes linear constraints with a quadratic objective function (see Contaxis, Papadias and Delkis, 1983, Carvalho, Soares and Ohishi, 1988, and Huang, 1994).

In Newton-based methods, non-linear equations, which designate Kuhn-Tucker conditions for optimum, are obtained and these equations are solved iteratively. In this study, we will use Newton-Raphson method, which is a member of this group. Linear programming solution methods handle linear objective functions with linear constraints. In order to apply these methods, first, OPF should be linearized.

The latest development in OPF solution was Interior Point Method. Main invention in this method is the application of a logarithmic barrier function, which associates inequality constraints and Newton's method to solve Kuhn-Tucker equations (Momoh et. al, 1999b). Recent developments in this methodology have induced researchers to use new variants of the Interior Point Method. For example, Castronuovo, Campagnolo and Salgado compare five variants of the Interior Point Method (IPM) (Castronuovo, Campagnolo and Salgado, 2000). Almeida and Salgade introduced a continuation perspective to IPM (Almeida and Salgade, 2000). Interior Point Methods seem to overcome some problems created by inequality constraints. Moreover, empirical studies show that IPM takes less computational time compared to other methods.

GA-based methods are the most recent methods introduced to solve OPF. These methods do not necessitate derivatives or step functions, they are fast random search methods.

4.2. The Model

In this section, the basic structure of the model will be outlined. Beginning from the core fixed and flexible demand models, we will develop our model to incorporate consumer participation, distributors, individual welfare maximization in the form of mark-up pricing, contracts, various types of regulation etc. The basic tools that we use to build the model will be discussed below.

4.2.1. Fixed Demand

Optimal Power Flow (OPF) approach provides a wider framework than traditional Power Flow approach does by ensuring node-level supply-demand equilibrium. OPF supplies a good basis for a synthesis of economics and engineering. In economics, sector-specific models only deal with measures of allocative or productive efficiency; these abstract models do not take sector specific technical conditions into consideration. OPF approach can be used to find out the basic solutions, which are both allocative and productive efficient and, also do not violate technical conditions. Although the OPF approach necessitates a larger number of constraints and variables, efficient non-linear optimization algorithms like Newton–Raphson method, or most recent evolutionary techniques, overcome such a problem. Moreover, the OPF approach allows analyst to choose any type of objective function suitable for his analysis. One can choose social welfare maximization (which incorporates consumer and producer surplus), or loss minimization as a goal. The structure of the OPF problem allows for many opportunities.

One can write the basic form of OPF as follows;

(31) Min F(x) st. $h_i(Q_1, Q_2, ...)$ i=1,2….K

and $g_i(\theta_1, \theta_2, ...)$ i=1,2…T where h_i's are equality constraints and g_i's are inequality constraints. The equality constraints guarantee bus level supply-demand equilibrium in the lossless system. From now on, instead of designating reactive power as in previous sections, Q designates real power quantity. We assume that, at every transmission line, a part of flow is transformed from electrical energy into heat energy and, therefore, bus level equality constraint enforces the equality between supply and demand taking the losses on the lines through which that bus is connected into consideration. The inequality constraints incorporate both generator and transmission line limits. These inequality constraints are activated only when any limit is violated in the system.

Our model rests upon the DC Flow approximation approach in which reactive generation side is totally neglected. Bus voltage differences are assumed to be zero. Thus, the model can be specified as follows; (basic model assumes that demand is fixed, consumers participation will be added to the basic model later);

(32) Min $\sum_i C_i(Q_i)$

st. $h_j(D_j, Q_j, \theta) = 0$ j=1,2….n

$g^1_k(Q_k, \overline{Q_k}) = 0$ k=1,2….G

$g^2_l(\theta_m, \theta_n, \overline{T_l}) = 0$ l=1,2,…L

There are n busses, G generators and L lines in the system. $C_i(Q_i)$ is the cost function of generator i. For the sake of simplicity, we assume that it is a continuous quadratic function;

(33) $C_i(Q_i) = a_i + b_i Q_i + c_i Q_i^2$

Quadratic cost functions provide well-behaved first and second derivatives. We assume that, in a competitive environment, generators submit their cost curves to the Independent System Operator (ISO) and ISO implements the optimization procedure. $h_j(D_j, Q_j, \theta)$ is the equality constraint satisfying bus level equilibrium.

(34) $h_j(D_j, Q_j, \theta) = D_j - Q_j + netflw(\theta_j, \theta_{others}) + \frac{1}{2} totalloss_j = 0$

where D_j is the bus's fixed demand while Q_j is the generation level of the generator located at that bus. If there is no generation at this bus Q_j is zero. *netflw* denotes the net flow into this bus i.e. net of incoming and outgoing flows. θ_j is the bus's own angle while θ_{others} is the set of the angles of other busses directly connected to this bus. In DC Flow approximation approach, any line flow is calculated as follows;

(35) $flw_{ij} = \frac{(\theta_i - \theta_j)}{X_l}$

Line l connects busses i and j. θ_i is the angle of bus i and θ_j is the angle of bus j. X_l is the line reactance. In equation (34), the last term denotes the half of the total loss on lines connected to this bus. Loss allocation and loss estimation is a wide separate area of research (for example, see Conejo et.al., 2002, Conejo and Galiana, 2001 and Galiana, Conejo and Kockar, 2002). Researchers generally make simplifying assumptions about loss estimation and allocation. In DC Flow Approximation context, loss on any line k is estimated as follows;

(36) $$Loss_k = \frac{R_k X_k^2}{R_k^2 + X_k^2} flw_k^2$$

Hence, loss on any line is a quadratic function of the flow on that line, but a quadratic loss function increases the complexity of non-linear optimization problem and makes the second derivatives also a function of state and control variables. This makes the final solution sensitive to initial values and, hence, optimization procedure may give inconsistent results. Researchers whose aim is to analyze the topics other than loss allocation and loss estimation simplify the transmission loss formula. It is important to note that loss created by any flow is equally shared between the destination and terminal busses in our model. This is a simplification we have adapted here and, for simplicity, we assume that line loss linearly depends on the transmission flow such as;

(37) $$Loss_k = \frac{2R_k}{R_k^2 + X_k^2} flw_k$$

We choose the multiplier of resistance as 2 since, with this parameter value, the model gives very realistic estimate for the transmission loss in Turkey for 2000 (loss accounts for about 2% of the total transmission over 380 kV lines).

The inequality constraints are for the transmission or generator limits. Generator limits are in the following form;

(38) $$g_k^1(Q_k, \overline{Q_k}) = Q_k - \overline{Q_k}$$

where Q_k is the output of generator k and $\overline{Q_k}$ is the maximum generation capacity of this generator. Some researchers impose a positive minimum limit for generators; however, we assume that there is no minimum limit. Kuhn-Tucker (KT) conditions for this inequality constraint can be written as follows;

(39) $\mu_k^1 g_k^1(Q_k, \overline{Q_k}) = 0$ where;

$$Q_k - \overline{Q}_k \leq 0 \quad \mu_k^1 \geq 0$$

KT conditions of the generator minimum are as follows;

(40) $\mu_i^{\min} g_i^{\min}(Q_i, 0) = -\mu_i^{\min} Q_i = 0$

$$-Q_i \leq 0 \quad \mu_i^{\min} \geq 0$$

The inequality constraint for line flows is as follows;

(41) $g_l(\theta_k, \theta_m, \overline{T_l}) = flw_l(\theta_k, \theta_m) - \overline{T_l} \leq 0$

Line l connects the busses k and m and, hence, line flow function takes the angles of these busses as parameters. $\overline{T_l}$ is the maximum transmission capacity of line l. Again, KT conditions for this constraint;

(42) $\mu_l g_l(\theta_k, \theta_m, \overline{T_l}) = 0$ where;

$$flw_l(\theta_k, \theta_m) - \overline{T_l} \leq 0 \quad \mu_l \geq 0$$

Finally the Lagrangean for the basic model is as follows;

(43)

$$L = \sum_i^G C_i(Q_i) + \sum_j^n \lambda_j h_j(D_j, Q_j, \theta) + \sum_i^G \mu_i^1 g_i^1(Q_i, \overline{Q}_i) + \sum_l^L \mu_l g_l(\theta_k, \theta_m, \overline{T_l}) + \sum_i^G \mu_i^{\min} g_i^{\min}(Q_i, 0)$$

We use Newton-Raphson method to solve this Lagrangean.

4.2.2. Incorporation of Consumer Behavior

Before passing on to the solution method, we should expand our analysis and incorporate consumer participation to this model. This is very important since privatization of regional distribution companies and introduction of "free consumer" category make demand flexible and responsive to generators' supply curves.

In order to incorporate the consumer behavior into the basic model (equation 43), we should first define a representative benefit function for a consumer. This benefit function represents the behavior of the representative consumer at bus i. The benefit function for the ith consumer is assumed as follows;

(44) $B_i(D_i) = \beta_i D_i - \delta_i D_i^2$

Benefit function is a quadratic continuous function of demand. Variable demand has also minimum and maximum limits. The equality constraint for maximum limit and its KT conditions are as follows;

(45) $d_i^{\max}(D_i, \overline{D_i}) = D_i - \overline{D_i}$

where,

$$\eta_i^{\max} d_i^{\max}(D_i, \overline{D_i}) = 0$$
$$D_i - \overline{D_i} \leq 0 \quad \eta_i^{\max} \geq 0$$

For the minimum constraint, we assume that the minimum is zero for variable demand. Inequality constraints for the minimum of the variable demand and KT conditions;

(46) $d_i^{\min}(D_i, 0) = -D_i$ where;

$\eta_i^{\min} d_i^{\min}(D_i, 0) = 0$

$-D_i \leq 0 \quad \eta_i^{\min} \geq 0$

Then, we should add benefit functions and corresponding inequality constraints to the equation (43) and construct the new Lagrangean for flexible demand case. New Lagrangean is;

(47) $L^{flex} = L - \sum_i^F B_i(D_i) + \sum_i^F d_i^{\max}(D_i, \overline{D_i}) + \sum_i^F d_i^{\min}(D_i, 0)$

This is the non-linear function for the flexible demand case. In our analysis, operational time unit is an hour. Since, there is no data for hourly loads of regions for the Turkish electricity market, we approximate regional hourly loads by multiplying Turkey's hourly load duration curve for 2 February, 2000 with regions' yearly weights. We aim to find flexible demand curves for each region oscillating around their approximated values. In order to obtain these curves, we divide the demand for each region into two parts i.e. base demand–which is half of the approximated hourly demand– and variable demand, which will be found by the model. Then, the demand variable becomes;

(48) $D_i = bdem_i + dem_i$ and,

(49) $bdem_i = \dfrac{dem^*}{2}$

where dem^* is the calculated fixed demand for that hour. We will outline Newton-Raphson algorithm and the details of our software in appendix.

4.2.3. Properties of the Optimum

We should indicate some characteristics of the optimum solution. In a lossless system, marginal costs of generators are equal to system-wide price (which is equal to bus level equality lambda, λ_i's, all lambda's are equal) at the optimum. This rule does not hold under two conditions: First, if there is any transmission limit violation, there occur disparities in lambdas of busses. In such a situation, μ_i in equation (43) denotes the marginal cost of 1 MW power transmitted over the constrained line. At the optimum, the lambdas of the busses connected by the constrained line increase by the amount of μ_i. Hence, this results in variations among bus level prices.

Second, if the assumption that system is lossless is discarded, disparities among bus level lambdas will emerge. Transmission losses generate differences in bus level prices. In TESS, we take losses into consideration; hence, the results given by TESS show variations in bus-level prices. A model with losses is more realistic than that with the assumption of no losses.

4.2.4. Individual Welfare Maximization

In the previous sections, we assume that all the generators and distributors are addicted to the strategy that they should submit their true cost and benefit functions to the Independent System Operator (ISO). We abandon this assumption and assume that some of the generators and consumers decide to cheat the ISO and plan to use their market power to gain more profits.

We know that both cost and benefit functions are in the quadratic form. In a case in which generators and distributors do not plan to play the game, they submit their respective cost curves and benefit curves.

In a competitive environment, the ISO derives marginal cost from the cost function and use it as generator's marginal cost. At the optimum, the price paid to generator is equal to generator's marginal cost at the optimum output of generator i.e (such a marginal cost pricing does not cover fixed costs of generators).

(50) $MC_i(Q_i) = b_i + 2c_iQ_i^*$

This is equal to generator's sell price. Hence, we can find the slope of the bid curve for this generator as follows;

(51) $(\frac{C_i(Q_i)}{\partial Q_i}) = P_i^{sell}$

which can be graphically outlined as below;

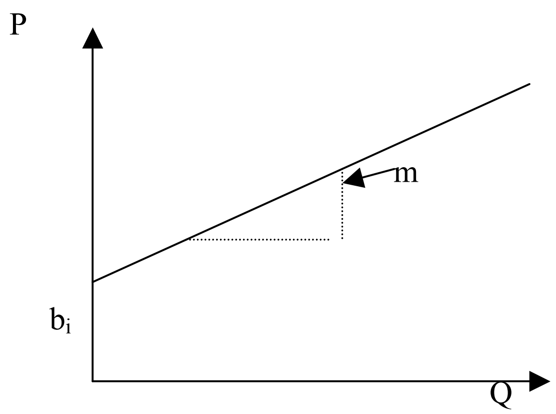


Figure 4.2. Bid curve of a Generator

where;

(52) $m_i = 2c_i$

This is the case in competitive environment. If a generator plans to play the game, it submits a cost curve multiplied by a mark-up instead of its original cost curve. Its new cost curve becomes;

(53) $C_i^k(Q_i) = k_i(a_i + b_iQ_i + c_iQ_i^2)$

where k_i is the mark-up rate. In the optimization procedure, then, marginal cost of the gaming generator becomes as follows;

(54) $MC_i = k_i(b_i + 2c_iQ_i)$

This is the corresponding linear supply curve for this generator compared to the case in which he is not gaming;

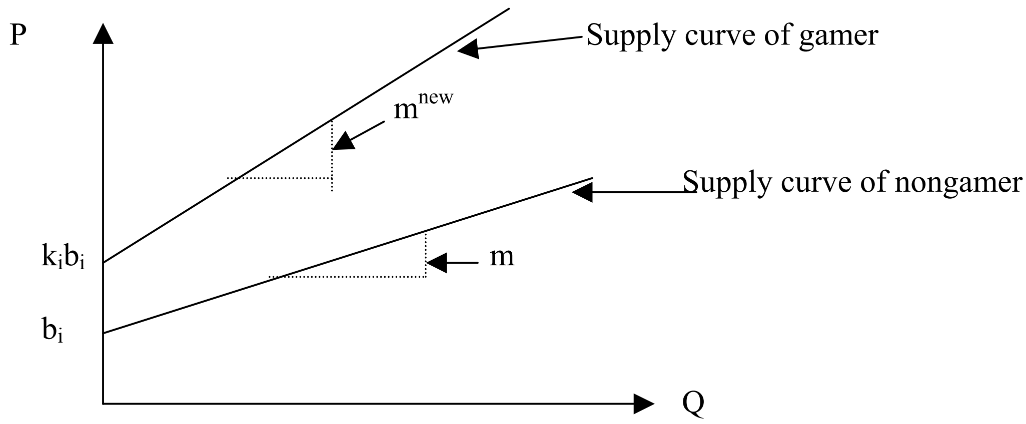


Figure 4.3. The Supply Curve of Gamer

The slope of new supply curve;

(55) $m^{new} = 2k_ic_i$

This fact gives way to extra profits for the generator although its output will decrease. This decrease will be offset by increase in its sell price.

For any consumer who wants to cheat, the same procedure should be followed. If the consumer's benefit function is as follows;

$$B_i(D_i) = \beta_i D_i - \delta_i D_i^2$$

As in the case of the generator, consumer multiplies its benefit function with a multiplier (a mark-up), i.e.

(56) $$B_i^{gm}(D_i) = k_i(\beta_i D_i - \delta_i D_i^2)$$

In the competitive case, we know that the marginal benefit gives the inverse demand function for this consumer (Figure 4.4);

(57) $$(\frac{\partial B_i(D_i)}{\partial D_i}) = P_i^{dem}$$

This relation is given in the figure below;

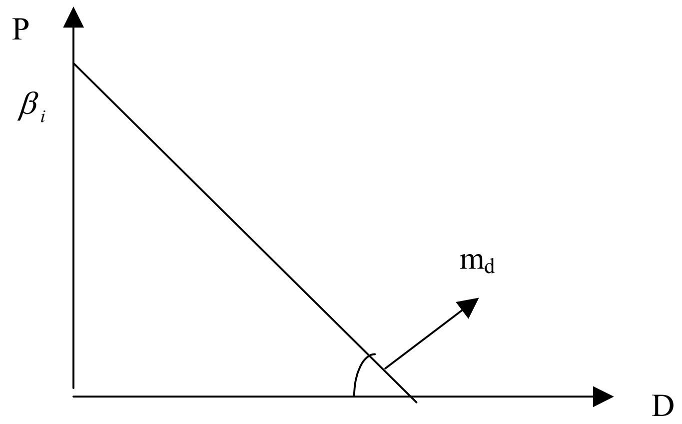


Figure 4.4. The Demand Function of Competitive Consumer

The slope of the demand curve m_d is;

(58) $$m_d^i = -2\delta_i$$

If the consumer aims to cheat, he will submit a new benefit function, which is the product of a mark-up and his actual benefit function. In this case, his new marginal benefit becomes;

(59) $$MB_i = k_i(\beta_i - 2\delta_i D_i)$$

The slope of new demand curve is as follows;

(60) $m_d^{new} = -2k_i\delta_i$

The new demand curve is steeper than the old one (Figure 4.5). Such a policy can generally affect the benefit of the consumer positively against a cost in the form of decreasing demand.

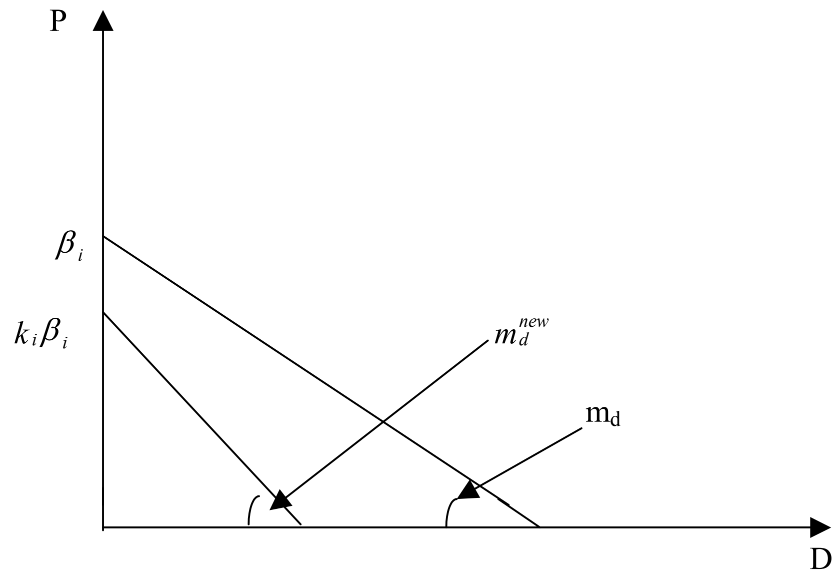


Figure 4.5. The Demand Curve for Gaming Consumer

After deciding to implement a gaming strategy, both generator and consumer should face an important problem; how large should be the mark-up to obtain the maximum profits and benefit? Any gaming strategy certainly results in a decrease in the dispatched output or dispatched demand. Hence, choosing the appropriate mark-up rate is crucial in gaming. Any inappropriate mark-up will result in a decrease in market share, which can not be offset by any increase in profits or benefits. Therefore, both the generator and the consumer should solve an individual welfare maximization problem (IWM), apart from the social welfare maximization problem solved by the regulator.

We should formulate the individual maximization problem of any agent controlling a set of generators and consumers. Assume that each agent controls *R* generators and *P* distributors. The agent's problem is as follows;

$$(61)\quad Max\ \ F(P^{sell},Q\ ,D\ ,P^{buy})=\sum_i^R(P_i^{sell}(k_i)Q_i(k_i)-C_i(Q_i(k_i))) \\ +\sum_j^P(B_j(D_j(k_i)-P_j^{buy}(k_j)D_j(k_i))\ \ st.\ \ \ Social\ OPF\ Problem$$

The constraint of this problem is either the solution of equation *(13)* (if demand is fixed, in this case agent's control set includes only generators) or *(17)* (in the case of flexible demand). As the objective function in equation (66) shows, demands and generations are implicit functions of mark-up rates as, for different levels of mark-up, agent is allocated different levels of generation output and demand by the Central Dispatcher (sometimes this duty is assigned to a different institution than ISO). Hence, for every round of operation, the agent looks for the maximum mark-up set for its utilities. This necessitates a dynamic learning process for each agent and requires more than one operation round; however, we assume that, in one operational round, he can find his optimum mark-up set. If there is more than one gaming agent in the electricity market, the problem in equation (66) will constitute a search for Nash-Equilibrium in a dynamic context. Therefore, there are two overlapping procedures for each agent in each operational round. In the first procedure, each agent maximizes equation (66) with his initial guess for the other agents' mark-up sets. This procedure is as follows (see Weber, 1999 for more detailed information):

Procedure for Setting Individual's maximum-markup

1. Make an initial guess for k
2. Solve OPF with individual's mark-up vector and individual's guess of competitors' markup rates.
3. Using data from OPF, obtain k^{new}
4. If $| k_{old} - k_{new} | < э$ exit;

   Otherwise, go to step 2.

This process necessitates an outer non-linear optimization of equation (66) over the core social OPF solution *(*equations *(43) or (47))*. In the outer optimization for individual welfare (step 3 above), we firstly need the first and second derivatives of generation output and demands with respect to mark-up set of the agent. We obtain these from the solution set of the core OPF solution. We estimate the vectors $\frac{\partial P^{sell}}{\partial k}$, $\frac{\partial^2 P^{sell}}{\partial k^2}$, $\frac{\partial Q}{\partial k}$, $\frac{\partial^2 Q}{\partial k^2}$, $\frac{\partial P^{buy}}{\partial k}$, $\frac{\partial^2 P^{buy}}{\partial k^2}$, $\frac{\partial D}{\partial k}$ and $\frac{\partial^2 D}{\partial k^2}$ from the solution of Lagrangeans (43) or (47). Then, we use these vectors to compute the vector $\frac{\partial F}{\partial k}$ and the matrix $\frac{\partial^2 F}{\partial k^2}$ in order to pursue NR method for the individual welfare maximization. We estimate six vectors outlined above (in the fixed demand case, since agent owns only generators, only the first three vectors should to be computed) as follows (this procedure is well defined in Weber, 1998): We should remind that $y(x_t)$ is the Jacobian matrix from the NR solution of OPF, then, if v=$[\,P^{sell} \;\; Q \;\; P^{buy} \;\; D\,]$;

(62) $\frac{\partial v}{\partial k} = -H^{-1} \frac{\partial y}{\partial k}$

where H is the Hessian matrix from the NR solution of OPF. We can also compute second derivative vector as follows;

(63) $$\frac{\partial^2 v}{\partial k^2} = -2H^{-1}\frac{\partial v}{\partial k}$$

Equations (62) and (63) are evaluated at the optimum solution of OPF. Then, we can compute $\frac{\partial F}{\partial k}$ and $\frac{\partial^2 F}{\partial k^2}$. We can estimate NR step function for the mark-up rate as follows;

(64) $$k_{new} = k_{old} - \left[\frac{\partial^2 F}{\partial k^2}\right]^{-1}\Bigg|_{v=v^*}\left[\frac{\partial F}{\partial k}\right]\Bigg|_{v=v^*}$$

where v^* is the solution of social welfare optimization problem (OPF).

Once these steps are finished and agent finds its maximum mark-up set, if there is more than one agent in the market, Search for Nash Equilibrium process begins. Every agent, after finishing his own welfare maximization process, begins to update its own guess of his rivals' bids. After updating its guesses, he begins his individual welfare maximization procedure again. Then, Search-For-Nash Equilibrium is an upward layer for the individual welfare maximization. This procedure is outlined below.

Search For Nash Equilibrium

1. Make an initial guess for all individuals.
2. Run **Individual's max-markup** for all individuals.
3. Update markup guesses for all individuals.
4. If individuals continue updating their bids, go to step 2, otherwise exit.

We write a separate program for finding Nash equilibrium in an electricity market in which there are multiple gaming agents. Figure 4.5 gives the algorithm of this program.

As Weber indicates (Weber, 1999), violation of any constraint makes the objective function in equation (61) non-differentiable and, hence, makes impossible to apply the NR method. Such a case may occur, if as Stoft (1997) indicates, some generators may aim to congest a line in order to raise their profits. A group of utilities either owned by the same agent or gather around an informal cartel may also behave in such a way that some constraints are violated. Violation of constraints generates multiple equilibria. The procedure we outline here can find an optimum of the objective function in equation (66) only for a non-constrained case. This procedure fails to find other optima for the constrained case but there are some recent techniques designed to do so. Genetic Algorithm is one of them and designed to find multiple equilbria. We will use genetic algorithm to find multiple equilibria for the individual welfare maximization.

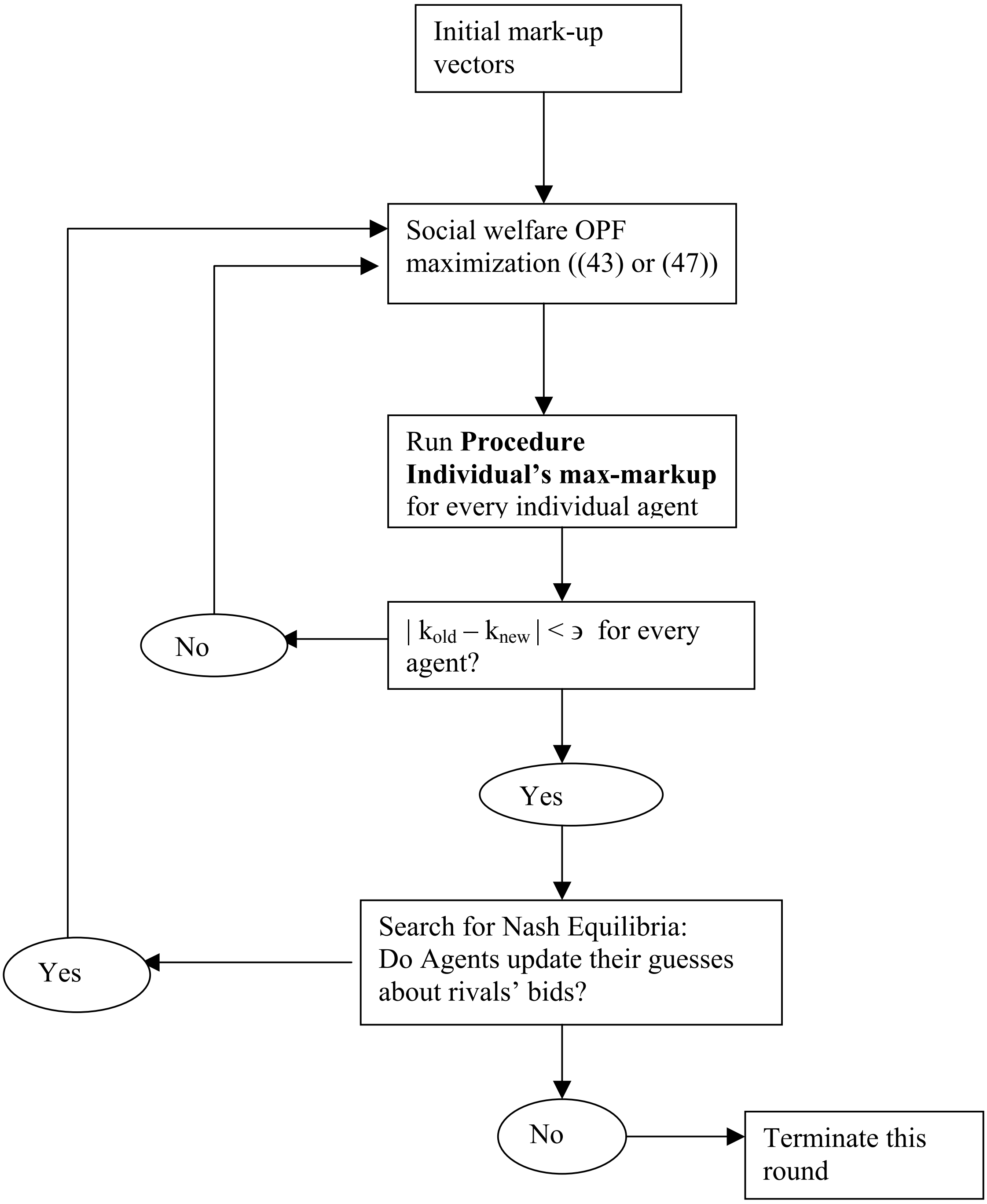


Figure 4.6. Algorithm for Finding Nash Equilibrium in a Multi-Gaming-Agent Environment

4.2.5. Pricing Schemes

Our model assumes a system with losses. This assumption brings the discussion about the pricing schemes that can be applied by the regulator. This discussion should be made, since social welfare depends upon the pricing scheme choice of the regulator. Since a system with loss generates disparities among bus-level prices, any regulator, in a uniform price system, should make this choice carefully and can face with some difficulty in finding a good reference price. "How can system level electricity sell and buy prices be estimated?" is an important question in the context of the social welfare maximization. System sell and buy prices directly determine producer and consumer surpluses.

For our simulation case studies, we assume that there are two different pricing schemes:

PS1: Each bus pays its bus lambda for its load while generators are paid at the lambda of bus at which it is located (Non-uniform Pricing).

PS2: Regulator accepts the most costly generator's marginal cost as the sell price (P_s) paid to all generators, while price paid by the consumers (P_b) is estimated as follows;

$$
\begin{aligned}
&P_b(G-L) - P_s G = 0 \\
&P_b = \frac{G}{(G-L)} P_s
\end{aligned}
\tag{65}
$$

where G is total generation and L is total loss.

Other pricing schemes may be devised. In the second one, regulator makes zero profits. Second pricing scheme is uniform pricing scheme such that unique system-wide sell and buy prices are settled.

4.2.6. Distributional Monopolies

In our basic fixed and flexible demand models, we assume that consumers at each node are free, that is, each consumer can directly buy electricity from the spot market; there is no intermediary institution. We, now, assume that regulator grants the distribution right at each node to a different company and these companies become distributional monopolies at busses at which they are authorized to sell electricity. Monopolist distribution companies know the benefit function of consumers in its distribution region and the inverse demand function is as follows;

(66) $P_j^B = \beta_j - 2\delta_j D_j$

Then distributor's total revenue is as follows;

(67) $TR_j = \beta_j D_j - 2\delta_j D_j^2$

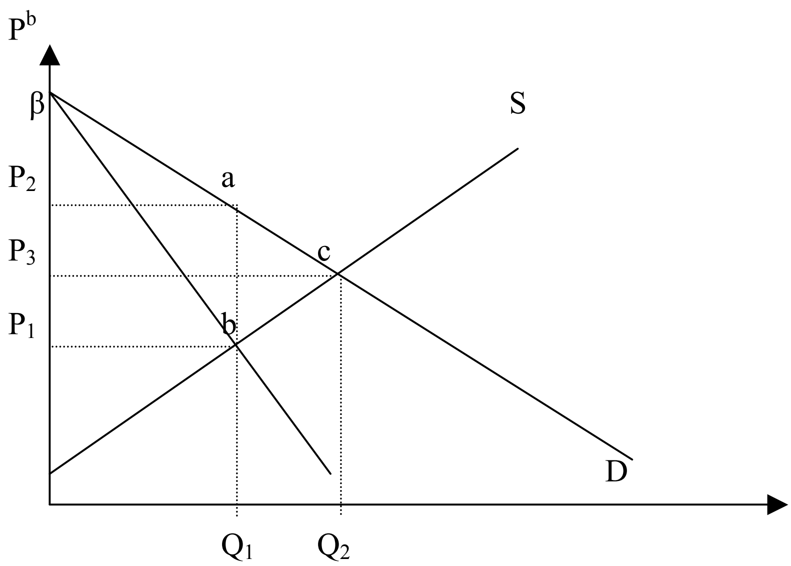


Figure 4.7. The Equilibrium Price and Quantity of Electricity under Distributional Monopoly

Marginal revenue of the distributor is;

(68) $$MR_j = \beta_j - 4\delta_j D_j$$

Figure 4.7 shows the optimum solution for this bus under distributional monopoly case.

In the figure, equilibrium at c is the optimum found by TESS when all the consumers are free. At this equilibrium, we can assume that, if there are distributor companies, distributors buy Q_2 from the spot market at P_3 and sell at this price to consumers. Hence, there are no distributional rents since distribution companies can not affect the price paid by consumers.

On the other hand, if regulator grants distributional monopolies, Q_1 is the new equilibrium output. Distributional monopolies buy this amount at price P_1 from the spot market and sell at P_2 to consumers. The difference between P1 and P2 is the distribution rent and the area P_1baP_2 shows total rent collected by the distributor. Therefore, as we can see from figure, granting distributional monopolies reduce total profits of the generators and total consumer surplus of the consumers (former decreases by the area P_2acP_3 and the latter is reduced by the area P_3cbP_1).

We will analyze such a situation in our simulation case studies. We will illustrate how our model works in a simple example in Appendix A.

4.2.7. Regulation

Apart from pricing schemes, regulator can take some regulatory measures consistent with its policy objectives. Regulation in the electricity markets is a very serious problem. In theoretical literature, sometimes it is assumed that, regulator gives unequal weights to consumer surplus and producer surplus maximization procedures. This can be summarized using the objective function in equation (47). The regulator/system operator's problem is as follows;

(68) Min $\psi(\sum_i C_i(Q_i)) - \phi(\sum_j B_j(D_j))$

st. constraints given above

In this case ψ and ϕ are the weights assigned to cost minimization and benefit maximization. In our case both are equal to 1, but in some studies regulator aims to protect consumers from possible exercise of market power and assumes that

ψ <1 and ϕ=1.

On the other hand, regulation may include price caps or income caps. The effects of a price cap will be discussed. Price cap is implemented after the solution of social welfare is obtained. This price cap may be lower than some of the prices found by the model and, hence, price cap may have profit-depressing effect upon some of the generators, which have sell prices over the price cap. It may be too high that all the prices found by the model can be less than it. In this case, producer surplus increases while consumer surplus decreases. There may be a positive effect of a price cap in the context of gaming and bidding algorithm outlined above. A good and effective price cap may limit the exercise of the market power i.e. it can limit the increase of maximum mark-ups found by the algorithm outlined above. Instead of putting upper limit to prices, regulator may choose to impose tax. The form of tax is again depends upon the priorities assigned by the regulator. For example, he can impose an environmental linear tax upon thermal generators. The linear environmental tax is as follows;

(69) $$T = T_0 + t_1 Q$$

where T_0 is the fixed amount of tax and $t_1 Q$ is the variable part. This tax changes the form of the Lagrangean in equation (43) as follows (there are H thermal generators);

(70) $$L = \sum_i^H (a_i + T_0 + (b_i + t_1)Q_i + c_i Q_i^2) + ...$$

The remaining part of the Lagrangean is the same as in equation (43). We will discuss the effects of such a tax later in the light of our simulation studies.

4.2.8. The Effects of Contracts

Actually, in the countries that liberalize their electricity markets, most of the electricity is traded in the form of contracts, although spot markets have shown a considerable development. The relatively high share of contracting poses some questions about the possible effects of contracts upon the electricity spot market. For example, the quantity and price of bilateral contracts may have effects upon spot market prices.

In our framework, the cost function of any contracting generator is as follows;

(71) $$C_i(Q_i) = a_i + b_i(Q_i + x_i) + c_i(Q_i + x_i)^2$$

where x_i is the contracted output while Q_i is the output traded in the electricity spot market.

On the other hand, contracts also change the structure of the benefit functions of the consumers who sign contracts as follows;

(77) $$B_j(D_j) = \beta_j(D_j + x_j) - \delta_j(D_j + x_j)^2$$

We will discuss the possible effects of contracts later; however, we should note that the presence of contracts somewhat reduce prices and also has a limiting effect upon the maximum mark-ups. Although we discuss the contracts, we do not model explicitly bilateral contract markets. This is a very simplifying assumption but bilateral contract market is not our main concern.

4.2.9. Genetic Algorithm

Traditional optimization methods have generally inelastic features that could not be easily adapted to an objective of finding multiple equilibria. In order to determine whether the local optimum is global or not, traditional optimization techniques, like Newton-Raphson, must apply several tests to the local optimum (for a brief discussion about the performance of traditional optimization techniques see, Goldberg, 1989). In the case of multiple equilibria, starting from an inadequate initial value, a traditional optimization process may direct us to an optimum which is not global and, hence, we can infer inconsistent results.

On the other hand, Genetic Algorithm seems to be more efficient than traditional optimization techniques. Accroding to Goldberg, the basic strength of Genetic Algorithm (GA) lies in the following factors:

> 1. GAs work with a coding of the parametere set, not the parameters themselves. 2. GAs search from a population of points, not a single point. 3 .GAs use payoff (objective function) information, not derivatives or other auxillary

knowledge. 4. GAs use probablistic transition rules not deterministic rules (Goldberg, 1989: 7).

GA has been used widely in the studies about the electricity market. Most of these studies are about unit commitment (UC) problem, although there are a few about the optimal power flow problem. For example, Bakirtzis et.al. use an GA-enhanced OPF algortihm to solve traditional OPF problem and find out both the solution of OPF and UC problems (Bakirtzis et. al. 2002). Numnonda and Annakkage also apply GA to OPF problem with consumer participation (Numnonda and Annakkage, 1999). The other example for the solution of economic dispatch is the study by Walters and Sheble (Walters and Sheble, 1993). They use a valve point technique appended GA algorithm to solve traditional economic dispatch problem.

Most of the studies using GA to analyse the electricity markets are about UC problem. For example, Rudolf and Bayrleithner apply GA solution of UC problem in a Hydro-Thermal system (Rudolf and Bayrleither, 1999). The number of examples may be increased (Chen et. al. 2000, Swarup and Yamashiro, 2002, Richter and Sheble, 2000, Juste et.al., 1999). Another area for which GA is used is the optimal bidding strategy. We will apply GA to optimal bidding strategy in our simulation case study section (for applications, see Richter and Sheble, 1998 and Richter, Sheble and Ashlock, 1999).

We will outline the basic structure and the modules of genetic algorithm in Appendix E. The basic structure for genetic algorithm software is given in figure E.1.

We use genetic algorithm to overcome a basic weakness in our individual welfare maximization procedure. Individual welfare maximization procedure can not find equilibrium when a line is congested or a generator becomes constrained. However, genetic algorithm can do this. In the parameter set for our cases, there are only mark-up rates of the generators that collude or those that are controlled by the same agent. Figure E.1 shows our genetic algorithm. GT is the predetermined number of generations.

4.3. Data

We use a simplified model that represents the Turkish electricity system. We make some simplifying assumptions in order to get rid of technical and geographical complexity of the electricity network.

First, the generators whose installed capacity are less than 250 MW are neglected. Moreover, we also neglect autoproducers since, except for a few of them, their installed capacities are less than our selection threshold and we can not obtain cost data about them.

Second, for the cost functions of generators we give in our data set, we are forced to make some assumptions. We estimate their cost functions by using annual data for the period 1984-2000. Since, the data set provided by TEAŞ is inconsistent and there are many outlier observations in this data set, we make some important restrictions and omit outliers. Moreover, as they are opened in recent years, there are not enough observations about some generators. Hence, we assume that they have similar cost functions with other generators using same fuel type and having nearly the same installed capacity.

There are also inconsistencies in annual data. As a result of these deficiencies in data set, we end up with cost functions that may not fully reflect the actual cost structures of the generators. Despite this insufficiency, these cost functions will provide us a good analytical framework. Since, we use the simulation model to understand how the spot electricity market may operate under various conditions, the problems in estimating cost functions may not constitute a major problem.

We do not explicitly model hydro generators and we do not take their distinctive characteristics like their reservoir utilities, pumped storages into consideration. Availability of water determines the performance of hydro generators. We assume that hydro generators have sufficient reservoir capacity and they are always working. This is not a weakness since the unit cost of the hydro generation is mostly determined by the cost of the fuel it uses (the machines in hydro generators necessitate a considerable amount of fuel). The factors that we do not take into consideration only determines the commitment tendency of hydro generators.

Table 4.1 gives the information about the cost functions (parameters of cost functions estimated), locations and basic characteristics of the 21 generators we will use in our simulation case studies. The Turkish electricity system is divided into 32 distribution regions. These distribution regions constitute our busses but we make some assumptions again. First, it is assumed that there is only one bus in İstanbul although it is covered by two distribution regions.

Table 4.1. Basic Information about Generators

Gen. No.	Gen. Name	Bus No.	Installed Capacity (MW)	A_i	B_i	C_i	Type	Fuel Type
0	Karakaya	1	1800	247	123	0.0180	Hydro	----
1	Atatürk	2	2405	106	116	0.0150	Hydro	----
2	Birecik	2	360	140	164	0.0261	Hydro	----
3	Keban	4	1330	744	130	0.0200	Hydro	----
4	A.Elbistan	6	1360	533	128	0.0200	Thermal	Lignite
5	Altınkaya	8	702	824	150	0.0240	Hydro	----
6	H.Uğurlu	8	500	582	162	0.0258	Hydro	----
7	Kangal	9	460	146	165	0.0262	Thermal	Lignite
8	Oymapınar	17	540	479	164	0.0254	Hydro	----
9	Ambarlı (DG)	21	1350	723	125	0.0210	Thermal	N.Gas
10	Ambarlı(FO)	21	630	550	152	0.0240	Thermal	Fuel Oil
11	Hamitabat	22	1200	723	132	0.0220	Thermal	N.Gas
12	Enron	22	500	737	165	0.0260	Thermal	N.Gas
13	Unimar	22	500	737	165	0.0260	Thermal	N.Gas
14	Bursa(DG)	24	1430	820	131	0.0194	Thermal	N.Gas
15	Seyitömer	26	600	200	157	0.0257	Thermal	Lignite
16	Tuçbilek	26	430	216	161	0.0260	Thermal	Lignite
17	Yatağan	27	630	324	158	0.0252	Thermal	Lignite
18	Yeniköy	27	420	407	162	0.0261	Thermal	Lignite
19	Kemerköy	27	630	381	158	0.0251	Thermal	Lignite
20	Soma	28	1040	221	135	0.0240	Thermal	Lignite

Source: TEAŞ
Not: $C_i(Q_i)=A_i+B_iQ_i+C_iQ_i^2$

Second, we combine Isparta distribution region to Afyon-Uşak-Burdur distribution region to form our bus no 17. Thus, we have 30 busses in our model representing the hypothetical distirbution regions. Table 4.2 outlines busses and corresponding distribution regions.

Our operational time unit is 1 hour. We can not find hourly loads at distribution region level and we use Turkey's hourly load schedule for February 2, 2000 in order to estimate hourly loads for busses. We multiply Turkey's hourly load for each hour with each region's weight in total annual demand in order to get hourly load of that region. By this way, we get hourly load schedules for each region that will be used in fixed demand analysis.

Table 4.2. Basic Information about Busses

Bus No	Regions
0	Batman, Siirt, Şırnak, Hakkari, Van,Bitlis, Muş
1	Diyarbakır, Mardin
2	Şanlıurfa
3	Erzincan, Bayburt, Erzurum, Ardahan, Kars, Iğdır,Ağrı
4	Maltya, Tunceli, Bingöl, Elazığ
5	Gaziantep
6	K.Maraş, Adıyaman
7	Giresun, Gümüşhane, Trabzon, Rize, Artvin
8	Sinop, Samsun, Ordu
9	Yozgat, Tokat, Sivas
10	İçel, Adana, Hatay, Osmaniye
11	Kayseri
12	Kırşehir, Aksaray, Nevşhir, Niğde
13	Kastamonu, Çorum, Amsya
14	Zonguldak, Bartın, Karabük, Çankırı
15	Ankara, Kırıkkkale
16	Konya, Karaman
17	Uşak, Afyon, Burdur, Isparta
18	Antalya
19	Sakarya, Bolu, Düzce
20	Kocaeli
21	İstanbul
22	Tekirdağ, Kırklareli, Edirne
23	Çanakkale, Balıkesir
24	Bursa
25	Bilecik, Eskişehir
26	Kütahya
27	Aydın, Denizli, Muğla
28	Manisa
29	İzmir

On the other hand, for flexible demand case, we should make assumptions about the parameters of demand function. As the benefit function of each bus is in the form as follows;

$$B_i(D_i)=\beta_i D_i - \alpha_i D_i^2$$

Inverse demand function becomes;

$P_i(D_i)= \beta_i - 2\alpha_i D_i$

where P_i is the price paid by bus i (the price paid by bus i in order to obtain D_i). We should make assumptions about β_i's and α_i's. They differ among busses. We aim to calibrate the demand fucntions for each bus for each hour in order to find bus level demands as close as possible to their estimated fixed demand levels mentioned above. For α_i , we divide the day into three intervals: 00-07, 08-15 and 16-23. α_i differs among intervals while it is equal for all hours in an interval. On the other hand, β_i differs among all hours, but the difference between β_i 's for two consequent hours is very low. For all busses, the lowest α_i is for the first interval since first interval includes the lowest demand hours. Since, α_i determines the price elasticity of demand, its lowest value should be for the first interval and it should attain its highest level in the third interval. Demand reaches its daily peak at third interval (hour 18:00). Table 4.3 shows α_i's for each bus for all intervals. We give the coefficient in positive values but all the values are negative.

In flexible demand analysis, we divide the demand variable into two parts; one is fixed base demand and the other is variable demand. Mainly, our model solves for the second one while first one is estimated from bus' demand calculated from Turkey's hourly load schedule. Fixed base demand is the half of the calculated hourly load of the bus. For modelling of the transmission system, we neglect all 154 kV and 66 kV transmission lines and use the data for only 380 kV lines. Table 4.4 gives the basic transmission line parameters. X is line reactance and R is line resistance.

Table 4.3. α_i Coefficients for Each Bus

	Interval		
Bus No	**I**	**II**	**II**
0	0.02421	0.02400	0.02378
1	0.02469	0.02448	0.02431
2	0.02520	0.02512	0.02500
3	0.02439	0.02380	0.02349
4	0.02432	0.02405	0.02380
5	0.02320	0.02305	0.02290
6	0.02335	0.02310	0.02285
7	0.02422	0.02403	0.02389
8	0.02445	0.02422	0.02400
9	0.02300	0.02284	0.02267
10	0.01990	0.01970	0.01950
11	0.02448	0.02438	0.02428
12	0.02498	0.02488	0.02478
13	0.02601	0.02590	0.02578
14	0.02353	0.02332	0.02310
15	0.02147	0.02124	0.02100
16	0.02371	0.02336	0.02300
17	0.02186	0.02143	0.02100
18	0.02285	0.02243	0.02200
19	0.02412	0.02380	0.02350
20	0.02489	0.02445	0.02400
21	0.01833	0.01816	0.01800
22	0.02154	0.02127	0.02100
23	0.02300	0.02290	0.02278
24	0.02010	0.02000	0.01980
25	0.02312	0.02300	0.02289
26	0.02824	0.02812	0.02800
27	0.02164	0.02132	0.02100
28	0.02472	0.02460	0.02450
29	0.02060	0.02030	0.02000

Table 4.4. Line Data

Line No	From	To	Tmax(MW)	R	X
0	0	1	1700	22.9	85
1	1	2	934	42.2	154.5
2	1	4	3040	11.0	47.5
3	2	5	3805	9.6	37.95
4	2	6	2445	10.0	59.1
5	3	4	711	50.0	203
6	4	9	1040	42.5	139.3
7	4	11	980	40.0	147.25
8	4	6	800	49.8	180.5
9	5	6	1750	30.1	129
10	5	10	1215	36.4	119.1
11	6	10	1915	20.8	75.4
12	6	11	3100	12.5	46.73
13	6	12	1430	30.7	100
14	7	8	752	60.0	192
15	8	13	2430	17.0	59.17
16	9	13	875	51.2	165
17	10	16	385	90.0	376.3
18	11	16	645	68.6	224.9
19	11	15	3360	12.9	42.9
20	12	15	1090	40.0	265.6
21	13	15	1000	89.0	291.7
22	13	14	670	65.8	215.5
23	14	19	3500	11.7	41.14
24	15	19	5020	5.0	18.43
25	15	25	815	47.3	177.3
26	16	18	1228	32.8	117.6
27	16	17	1600	22.9	90.3
28	18	26	740	54.4	193
29	19	25	1365	29.4	105.9
30	19	20	4187	4.7	28.7
31	19	21	915	48.0	158.1
32	19	24	970	41.1	148.9
33	20	21	9115	0.3	5.58
34	20	25	1980	5.9	24.86
35	21	22	8652	3.2	12.43
36	23	24	1245	32.0	166.1
37	23	28	2093	19.0	69
38	24	26	1800	25.0	92
39	25	26	1200	33.4	120.4
40	26	29	480	83.3	301.9
41	27	28	1000	20.2	74.9
42	27	29	3647	4.7	18.342
43	28	29	1755	24.3	82.3

Source: TEAŞ, 2001 * X and R are in Ohms

4.4. Calibration

We will discuss how model control variable estimates are close to their real values. We should remind some important characteristics of the data set we use. First, we neglect many generators whose installed capacities are very low. Second, our cost functions are estimated under some restrictions and they may not be very consistent with the real price variables. We should tackle with a trade-off between unit costs and output. Third, we assume that there is also a marginal cost of the water used by hydro generators.

Table 4.5. The Actual Contribution and Estimated Output of Generators at Hour18:00

Gen No.	Bus No.	Name	Actual[1] Contribution	Fixed Demand	Flexible Demand
0	1	Karakaya	1580	1415	1406
1	2	Atatürk	2300	1934	1924
2	2	Birecik	---	192	186
3	4	Keban	1280	1146	1138
4	6	A.Elbistan	1270	1183	1175
5	8	Altınkaya	700	588	581
6	8	H.Uğurlu	500	314	308
7	9	Kangal	470	244	237
8	17	Oymapınar	520	290	288
9	21	Ambarlı (DG)	1330	1334	1327
10	21	Ambarlı(FO)	624	605	598
11	22	Hamitabat	1130	957	949
12	22	Enron	----	175	169
13	22	Unimar	----	175	169
14	24	Bursa(DG)	1404	1285	1256
15	26	Seyitömer	610	449	453
16	26	Tuçbilek	390	367	371
17	27	Yatağan	630	393	383
18	27	Yeniköy	395	303	293
19	27	Kemerköy	580	393	383
20	28	Soma	1010	913	901

[1]: Source: TEAŞ, 2001* Actual Contribution and Generator Output are in MW

Therefore, our basic aim is to estimate our control varibles -generation of ecah generator and bus level demands in the flexible demand analysis- as close as to their real values. Table 4.5 shows the real contribution of each generator to peak demand calculated by TEDAŞ, and output of each generator estimated by TESS under fixed and flexible demand cases for the peak demand hour (18:00).

Table 4.6. Actual and Estimated Demands for Hour 18 (All in MW)

Bus No	Actual Demand	Est. Demand	Bus No	Actual Demand	Est. Demand
0	213.1	208.3	**15**	798.6	795.6
1	190.6	192.7	**16**	458.3	442.1
2	155.5	145.7	**17**	360.1	354.6
3	170.8	176.0	**18**	291.0	306.1
4	255.0	260.9	**19**	257.3	265.7
5	304.9	291.4	**20**	940.0	944.6
6	288.0	284.2	**21**	2636.4	2646.8
7	224.0	217.8	**22**	575.5	576.8
8	259.5	261.1	**23**	343.4	312.6
9	191.1	175.6	**24**	839.9	812.0
10	1188.6	1156.3	**25**	353.1	351.5
11	212.2	226.2	**26**	90.0	80.4
12	190.8	189.3	**27**	539.3	540.3
13	167.5	149.9	**28**	206.0	179.1
14	417.0	416.8	**29**	1351.6	1350.2

* Demand is in MW

As one can see from the table, there are some important disparities between actual contribution and estimated output of the generators. First, we should note that, our real demand data is calculated from the Turkey's hourly load schedule for February 2, 2000. However, actual contribution to peak demand data from TEAŞ may be for a day in January or December; TEAŞ does not clearly indicate the date of this calculation but it may be in these two peak demand months or a daily average of peak demand contributions. Despite these disparities, most of the estimates are very close to their actual contributions. The dashed lines in actual contribution column indicates that there is no data for the corresponding generators.

We should also look at how the estimated demands are close to their real calculated values. Table 4.6 shows the actual demand and model estimates for the hour 18:00. As table shows, estimated demands are very close to their real values. This provides us a well basis for making comparisons.

4.5. Sensitivity Analysis

In this section, we look for the sensitivity of the optimum solution to changes in parameter values. Our basic parameters are the cost parameters and benefit function parameters as shown in below.

$$B_i(D_i) = \alpha_i + \beta_i D_i - \delta_i D_i^2$$

$$C_i(Q_i) = a_i + b_i Q_i + c_i Q_i^2$$

We try to find out the effects of changes in β_i, δ_i, b_i and c_i upon the output, demand and prices. We look at the data for hour 18:00 as a representative hour. Table 4.7 gives the change in output, demand and average weighted price with respect to base case after the change in the corresponding parameter as given by the table. We should note that only weighted prices give response to change in parameters under the fixed demand case. Rates of change are in % with respect to base case.

In Table 4.7, SP and BP refer to average weighted sell and buy prices at hour 18:00. "Rnd" indicates a random rate of change between +10% and –10%. Q and D indicate total generation and total demand.

As Table shows, model variables are more sensitive to the changes in linear coefficients in cost and benefit functions (b and β). Prices are less sensitive to the parametric changes than quantities are.

Table 4.7. Sensitivity of Model

		Fixed Demand		Flexible Demand			
Parameter	**Rate Of Change**	**SP**	**BP**	**Q**	**D**	**SP**	**BP**
b_i	+10	7.97	8.01	-23.63	-23.89	4.31	3.47
	-10	-8.19	-8.20	24.38	24.46	-3.73	-3.06
	Rnd	-0.44	0.25	-1.00	-0.96	-0.41	0.15
c_i	+10	1.80	1.80	-5.61	-5.63	0.71	0.73
	-10	-2.03	-1.98	6.10	6.06	-0.79	-0.92
	Rnd	0.07	0.12	-0.24	-0.20	0.07	0.04
β	+10	-	-	28.60	28.58	5.09	7.66
	-10	-	-	-35.07	-35.20	-6.29	-6.09
	Rnd	-	-	4.49	4.45	0.75	0.85
α	+10	-	-	-4.89	-4.75	-0.33	-0.20
	-10	-	-	4.54	4.60	0.76	1.19
	Rnd	-	-	-0.33	-0.32	-0.06	-0.06

CHAPTER 5

REGULATION OF THE TURKISH ELECTRICITY SYSTEM: SIMULATION EXPERIMENTS

5.1. Introduction

We design this section as follows: First, we describe our base cases for fixed and flexible demand cases. In this section, we outline the solution of the base case and give the optimum values variables. In the fixed demand case, model estimates output of each generator, loss of each transmission flow, the value of each bus lambda, and if any constraint is activated, the value of the corresponding inequality multiplier. Then, the model estimates total generation and total loss for each hour. In flexible demand analysis, we append demand to the control variable list. The model estimates demand for each bus and, later, estimates the total demand for each hour. In fixed and flexible demand case, we assume that all the units in the system -generators and consumers– are controlled by the state and the basic problem of the public regulatory body is to maximize social welfare by minimizing total cost and maximizing total utility.

In the second section, we focus on the different pricing schemes mentioned above and total profits and total consumer surplus. We should remind that system prices depend upon the bus lambdas optimized by the model. Total profits and total consumer surplus, and also profits and consumer surplus at the bus level, depend upon the selected pricing scheme. It is more important to note that in a system with loss, as in our model, optimum bus level lambdas differ among busses and this fact provides a range of pricing alternatives for the regulator.

In the third section, we analyze the possible effects of external shocks such as a temporary removal of a major generator from the system or an accident, which damages the transmission lines and makes a major demand area inaccessible. In the fourth section, we try to find out the effects of an entry of a low cost generator to system.

In the fifth section, we look for the effects of mark-up pricing on both generators' and consumers' side in both flexible and fixed demand cases for different pricing schemes. In this section, we assume that some of the generators or consumers collude or gather under a same cooperative body and run the corresponding individual welfare maximization (IWM) problem and find out their respective maximum mark-up rates for each hour. In such a case, all the variables in the model are affected and we outline some of them. We also look for the effects of groups, which have different structures (such as a group consisting only of generators, only consumers or a mix of them).

In the sixth section, we assume that, at all busses, distribution companies are authorized to distribute electricity to whole distribution region and acquire monopoly position in those regions. We analyze the possible outcomes of such a situation. In all above cases, we assume that distribution companies are selling the electricity at a price equal to the price they pay to buy electricity from the spot market and, hence, they can not earn any profits. In this sense, we designate the demand side of the each bus as a single consumer. On the other hand, in this case, we assume that they can earn positive profits as a result of acting as a monopoly.

In the seventh section we focus on regulatory measures. First, we look for the effects of price cap regulation on both generation and consumption side. The repercussions of a price cap regulation on distribution side are also a matter of concern i.e. how would effective price caps affect distributors profits. The second measure we will concentrate on is the environmental tax, which is levied upon thermal generators. In the last section, we try two examples with genetic algorithm and try to find out multiple equilibria in individual welfare maximization.

Since there are many simulation cases, we will give the summary of these simulation case studies in Table 5.1. This table gives the definition, modeling environment and pricing scheme of each case. We should indicate that some cases outlined in table 5.1 are given in Appendix F.

Table 5.1. Summary of Simulation Case Studies

Case	Pricing Scheme	Definition	Modelling
Base Case, Fixed Demand	-	Optimizes the generation under fixed demand	Objective function is the sum of all cost functions
Base Case, Flexible Demand	-	Optimizes both demands and generation	Objective Function is the difference between the sum off all cost functions and the sum of all benefit functions
Pricing, PS1	PS1	Regulator applies PS1 for the base case	Profits and Consumer Surplus is estimated under PS1
Pricing, PS2	PS2	Regulator applies PS2 for the base case	Profits and Consumer Surplus is estimated under PS2

Table 5.1 (continued)

Case	Pricing Scheme	Definition	Modelling
EX1 (External Shock)	PS1	One major generator is cut off from the system for maintenance for the whole day.	Number of generators is reduced by 1. Corresponding cost function is deducted from the objective function
EX2 (External Shock)	PS1	One major demand area becomes inaccessible	Number of busses is reduced by 1 and the corresponding connections are discarded.
Entry	PS1	A low cost generator is opened.	Number of generators is increased by1 and its cost function is added to obj. func.
IWM-C1	PS1	An agent controls four generators and he aims to maximize his welfare	Agent runs his IWM procedure over OPF solution. Demand is fixed.
Distributional Monopoly-D1	PS1	Regulator grants the distribution right for each bus to different distribution companies.	Benefit functions in obj. function (under flexible demand) are replaced with total revenue functions of the distribution companies.
Regulation-R1	PS1	There are two agents; first controls three hydro generators and second controls three thermal generators.	Each agent runs his IWM procedure. Regulator imposes a linear environmental tax upon thermal generators.
Genetic Algorithm-G1	PS1	An agent controls three generators.	Agent use genetic algorithm to maximum mark-up rates for his generators (fixed demand).
Transmission Constraint Binding	PS1	Capacity of five lines reduced	Corresponding constraints are activated

5.2. Simulation Case Studies

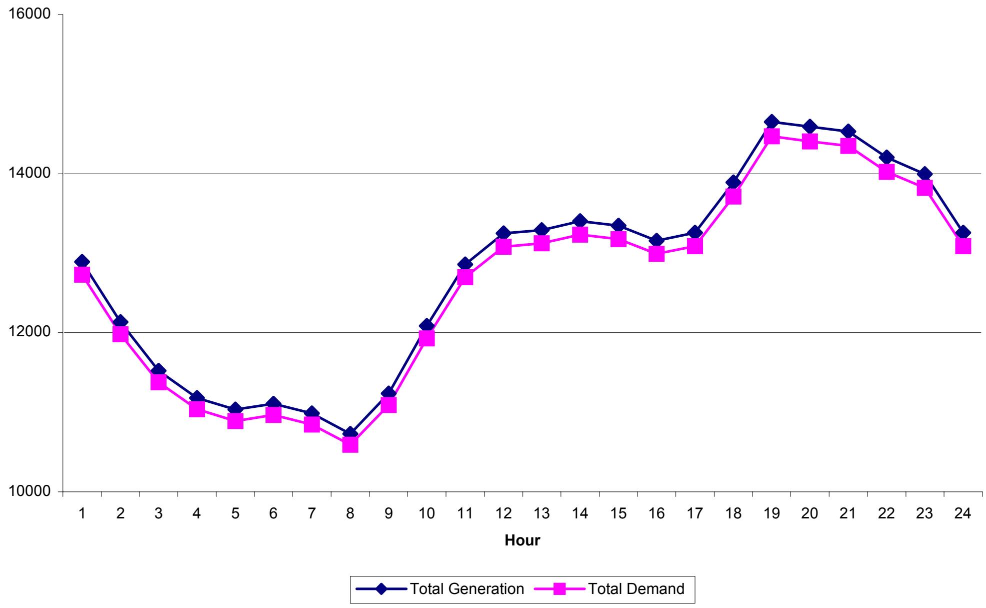
5.2.1. Base Case

As we mention above, in the fixed demand case, the model estimates the output of each generator, equality lambda of each bus, transmission flow on each line and the corresponding loss on each line. In flexible demand case, it estimates demand as well. After these, the model estimates macro variables like total generation, total demand and total loss.

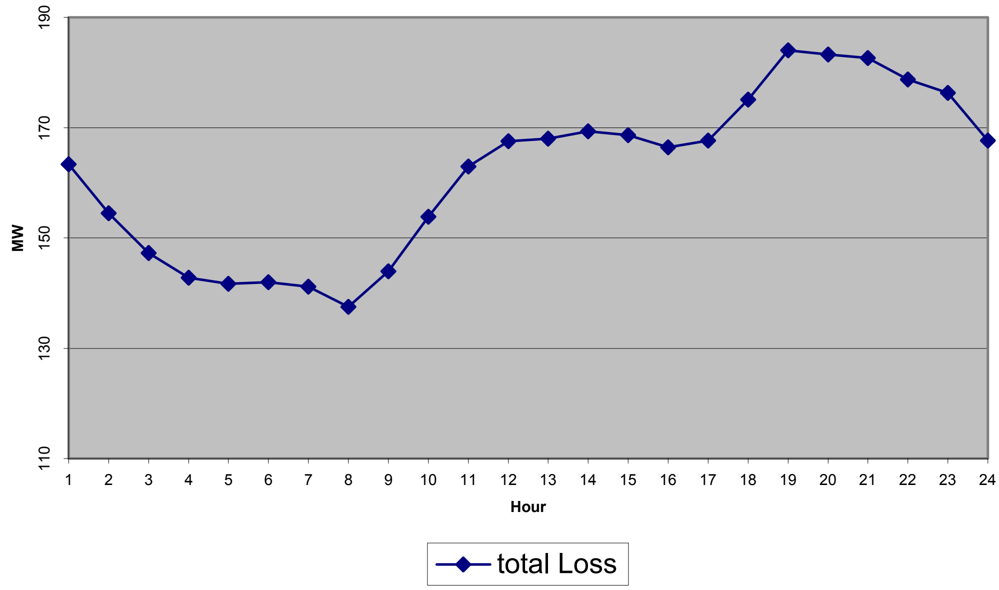
Fixed Demand Case:

In this case, demand is fixed for each hour and the model optimizes output such that total generation exceeds total demand. In a model without loss, they are found to be equal; however, in our case, generators are also over-producing to meet loss on every transmission line. Therefore, total generation exceeds total demand. Graph 5.1 shows the change in total generation and total demand over a whole day. As demand is predetermined, total generation adjusts itself to total demand, but exceeds it slightly as a result of the loss. As the graph indicates, peak demand hour is 18 and, at this hour, total generation reaches its maximum. The lowest demand hour is 07 and both total generation and total demand drop to their respective trough. Graph 5.2 shows total loss over the whole day. As the graph indicates, total loss moves in tandem with total demand and total generation. It is the difference between total generation and total demand. Table 5.2 gives total generation, total demand and total loss for some hours. As the table shows, total loss is the difference between total generation and total demand.

Graph 5.1. Base Case [Fixed Demand], Total Generation and Demand



Graph 5.2. Base Case [Fixed Demand], Total Loss



In order to look at the micro level data, we should look at the generator and bus level variables. The model optimizes bus level lambdas and generators' output, then, calculates the macro variables given above. We can not give the optimum output of each generator for 24 hours, hence, we select peak demand hour (18) as the reference hour.

Table 5.2. Total Generation, Total Demand and Total Demand under Fixed Demand Base case

Hour	Total Generation (MW)	Total Demand (MW)	Total Loss (MW)
0	12892	12729	163
7	10730	10593	137
12	13291	13123	168
16	13258	13090	168
18	14653	14469	184
22	13996	13820	176

Table 5.3 gives the optimum output, the number of bus at which the generator is located, marginal cost, average cost of the all generators for hour 18. As one can see, hydro plants' marginal and average cots are lower than those for thermal plants. The lowest electricity cost is of generator01, Atatürk Dam. Moreover, as the table shows, the generators having the highest marginal cost is located at bus no.21 (İstanbul region). This fact has important implications when we discuss the effects of different pricing schemes. There is an important note about the marginal costs and optimum equality lambdas: At the optimum, each generator's marginal cost is equal to the equality of the lambda of the bus at which it is located. This is shown as below. First order conditions of solution dictates for generator i that;

$$B_i + 2C_iQ_i - \lambda_i = 0$$

where the first two terms constitute the marginal cost of generator i while λ_i is the lambda of the bus at which it is located. Then, marginal cost of this generator is equal to its bus level lambda.

Table 5.3. Information about Generators at hour 18

Gen No.	Bus No.	Gen. Name	Optimum Generation (MW)	MC (10^5 TL)	Fuel Type	Av. Cost (10^5 TL)
0	1	Karakaya	1414.85	173.93	Hydro	148.64
1	2	Atatürk	1933.59	174.01	Hydro	145.06
2	2	Birecik	191.72	174.01	Hydro	169.73
3	4	Keban	1145.98	175.81	Hydro	153.57
4	6	A.Elbistan	1182.74	175.31	Thermal (Lignite)	152.11
5	8	Altınkaya	587.81	178.22	Hydro	165.51
6	8	H.Uğurlu	314.24	178.22	Hydro	171.96
7	9	Kangal	243.61	177.77	Hydro (Lignite)	171.98
8	17	Oymapınar	290.34	178.75	Hydro	173.03
9	21	Ambarlı (DG)	1334.36	181.04	Thermal (N. Gas)	153.56
10	21	Ambarlı(FO)	605.07	181.04	Thermal (F.Oil)	167.43
11	22	Hamitabat	956.56	174.09	Thermal (N. Gas)	153.80
12	22	Enron	174.78	174.09	Thermal (N. Gas)	173.76
13	22	Unimar	174.78	174.09	Thermal (N. Gas)	173.76
14	24	Bursa(DG)	1284.58	180.97	Thermal (N. Gas)	156.72
15	26	Seyitömer	449.38	180.10	Thermal (Lignite)	168.99
16	26	Tuçbilek	367.27	180.10	Thermal (Lignite)	171.14
17	27	Yatağan	392.96	177.81	Thermal (Lignite)	168.73
18	27	Yeniköy	302.78	177.81	Thermal (Hard Coal)	171.25
19	27	Kemerköy	392.54	177.81	Thermal (Hard Coal)	168.92
20	28	Soma	912.65	178.80	Thermal (Lignite)	157.15

In a system with loss, bus level lambdas differ because of the marginal costs of 1 MW loss on the lines connecting the busses. Since each bus is connected via different lines and different magnitude of electricity is transmitted on each line, the volume of loss allocated to a bus can be probably different from the volume allocated to other bus. We can observe this in table 5.4. It gives the bus level lambdas for each bus for hour 18.

Table 5.3 proves that optimum bus level lambdas differ among busses. The highest lambda is estimated for bus no 20. We can infer that bus level lambdas generally increase from the eastern regions to western regions. These lambdas are crucial for pricing. In this regard, we can simply indicate that the cost of buying electricity increase from east to west.

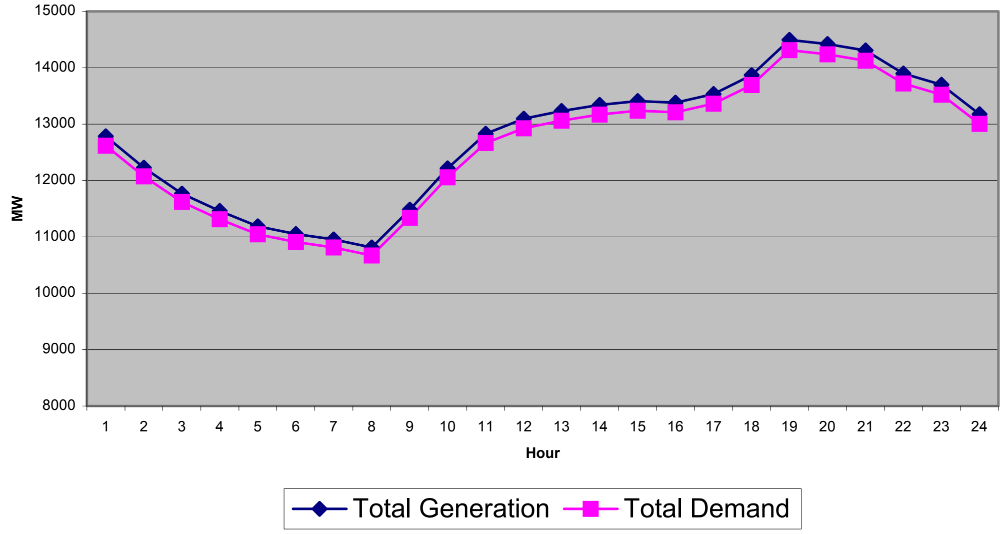
Table 5.4. Bus Lambdas for Hour 18

Bus No.	Bus Lambdas	Bus No	Bus Lambda
0	174.97	15	177.93
1	173.94	16	177.81
2	174.01	17	178.75
3	176.24	18	179.35
4	175.84	19	182.16
5	175.85	20	184.49
6	175.31	21	181.04
7	178.74	22	174.09
8	178.22	23	180.50
9	177.77	24	180.97
10	176.68	25	181.18
11	176.47	26	180.10
12	176.69	27	177.81
13	179.82	28	178.81
14	183.82	29	181.98

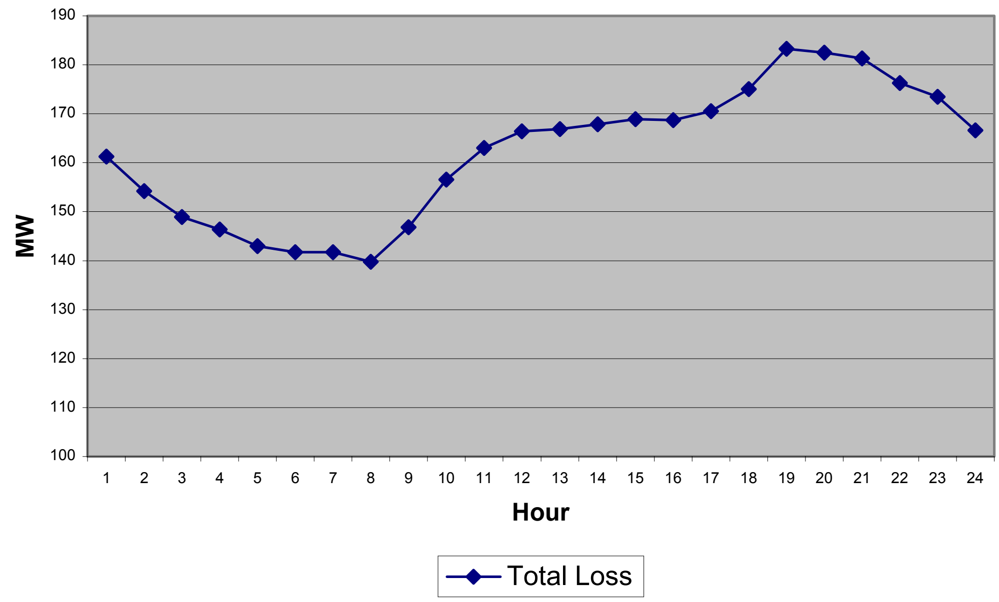
Flexible Demand Case:

In this case, bus level demands are not pre-determined; they are estimated within the model. Each consumer has a different benefit function, which designates his utility from consumption. From this benefit function, we can derive his demand function. Model minimizes the total costs and maximizes total benefit functions and finds optimum outputs and demands. Then, it calculates total demand, total generation and total loss. Graph 5.3 shows the total generation and total demand for flexible demand case. Graph 5.4 shows total loss over a whole day.

Graph 5.3. Total Generation and Total Demand under Flexible Demand Case



Graph 5.4. Total Loss under Flexible Demand case



The three curves exhibit the same pattern as in fixed demand case. This is due to our selection of demand parameters outlined in data section. We aim to find demands as close as possible to their estimated fixed levels that are used in fixed demand case. How close does the model estimate the demands can be seen from the Table 5.5. It gives the bus level actual demands and optimum demands estimated by the model.

Table 5.5. Actual and Estimated Demands for Hour 18 (All in MW)

Bus No	Actual Demand	Est. Demand	Bus No	Actual Demand	Est. Demand
0	213.1	208.3	**15**	798.6	795.6
1	190.6	192.7	**16**	458.3	442.1
2	155.5	145.7	**17**	360.1	354.6
3	170.8	176.0	**18**	291.0	306.1
4	255.0	260.9	**19**	257.3	265.7
5	304.9	291.4	**20**	940.0	944.6
6	288.0	284.2	**21**	2636.4	2646.8
7	224.0	217.8	**22**	575.5	576.8
8	259.5	261.1	**23**	343.4	312.6
9	191.1	175.6	**24**	839.9	812.0
10	1188.6	1156.3	**25**	353.1	351.5
11	212.2	226.2	**26**	90.0	80.4
12	190.8	189.3	**27**	539.3	540.3
13	167.5	149.9	**28**	206.0	179.1
14	417.0	416.8	**29**	1351.6	1350.2

Our model's estimates are very close to their corresponding actual levels. Few of the estimates differ above 15 MW from the actual levels. The highest demand is, again, of bus no.21. The demands for highly populated regions (like Ankara, İzmir and Adana) are very high. Table 5.6 shows total demand, total generation and total loss for various hours. Again, the difference between total generation and total demand is equal to total loss.

Table 5.6. Total Generation, Demand and Loss for Various Hours under Flexible Demand Case (All in MW)

Hour	Total Generation	Total Demand	Total Loss
0	12782	12621	161
7	10810	10670	140
12	13231	13064	167
16	13532	13361	171
18	14494	14311	183
20	14308	14126	181

Table 5.7. Bus Lambdas for Flexible Demand Case at Hour 18

Bus no	Bus Lambda	Bus no	Bus Lambda
0	174.66	**15**	177.58
1	173.63	**16**	177.67
2	173.71	**17**	178.61
3	175.93	**18**	179.33
4	175.53	**19**	181.78
5	175.56	**20**	184.16
6	175.01	**21**	180.72
7	178.40	**22**	173.77
8	177.87	**23**	179.76
9	177.44	**24**	179.84
10	176.40	**25**	180.91
11	176.17	**26**	180.30
12	176.38	**27**	177.31
13	179.47	**28**	178.23
14	183.44	**29**	181.49

In the fixed demand case, we know that marginal costs of the generators are equal to the equality bus lambdas at which they are located. This is also true for the flexible case. Moreover, in this case, marginal benefit of a consumer is also equal to the optimum bus lambda at which consumer lives. First order condition of the solution of flexible demand implies;

$$\beta_j - 2\alpha_j D_j - \lambda_j = 0$$

where the first two terms form the marginal benefit of consumer j, while λ_j is the lambda of the bus at which consumer j is located. Table 5.7 shows bus level lambdas.

Marginal benefits of consumers and marginal costs of generators are equal to the lambda of the bus at which they are located. Pricing under flexible demand case strictly depends upon these lambdas. Table 5.8 gives the marginal costs and output of generators at hour 18. The output of generators slightly differs from their levels in fixed demand case for the same hour. This is due to the minor differences between actual and estimated demand levels.

Table 5.8. Information About Generators at Hour 18

Gen No.	Bus No.	Name	Output(MW)	MC (10^5 TL)
0	1	Karakaya	1406	173.632
1	2	Atatürk	1924	173.713
2	2	Birecik	186	173.713
3	4	Keban	1138	175.531
4	6	A.Elbistan	1175	175.011
5	8	Altınkaya	581	177.868
6	8	H.Uğurlu	308	177.868
7	9	Kangal	237	177.438
8	17	Oymapınar	288	178.605
9	21	Ambarlı (DG)	1327	180.716
10	21	Ambarlı(FO)	598	180.716
11	22	Hamitabat	949	173.774
12	22	Enron	169	173.774
13	22	Unimar	169	173.774
14	24	Bursa(DG)	1256	179.844
15	26	Seyitömer	453	180.295
16	26	Tuçbilek	371	180.295
17	27	Yatağan	383	177.306
18	27	Yeniköy	293	177.306
19	27	Kemerköy	383	177.306
20	28	Soma	901	178.226

5.2.2. Pricing

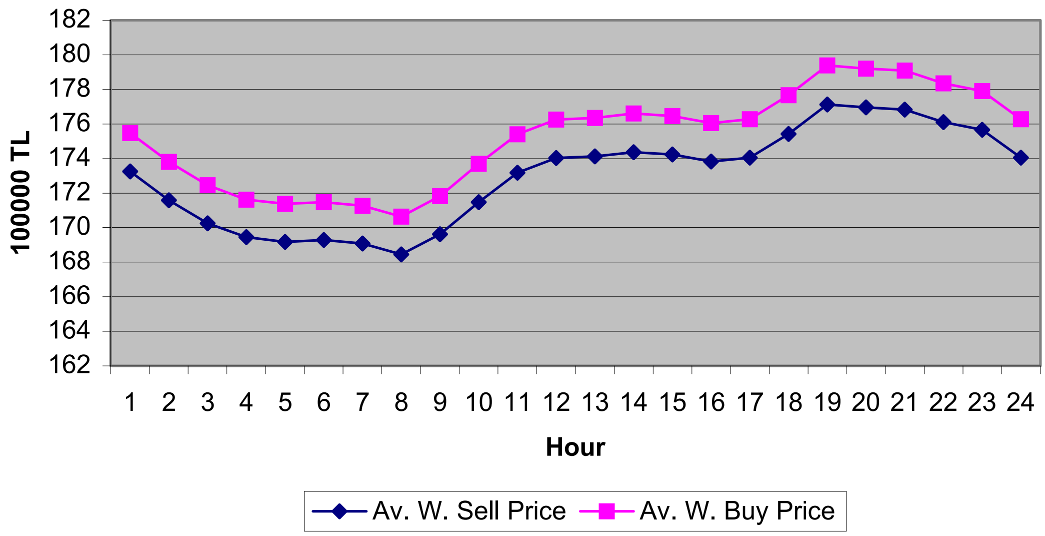
After giving the basic details about the base case, we can pass on to how this model works under different pricing schemes. In a competitive case, the basic concern for the regulator is how to price electricity since, as there are losses in the system, marginal costs and marginal benefits differ at the bus level. As opposed to the case with no losses for which such a model gives a unique sell and buy price (which are also equal to each other), our model gives different marginal costs and marginal benefits at the optimum. In a model without loss, it is very easy to determine the system-wide price, since, in such a case, all bus level lambdas are equal and, hence, uniform price is equal to bus level lambda. By this way, uniform price becomes equal to all marginal costs and all marginal benefits in the system.

For a system with losses, we outline two possible pricing schemes in the section in which we define our model. In the first pricing scheme (PS1), regulator buys electricity from generators at different prices, which are equal to respective generators' marginal costs (we call this price *sell price*). It sells electricity to each consumer at a price equal to its own lambda (this price is called *buy price*). This is a non-uniform pricing scheme, since, there is a range of sell and buy prices. In the second one (PS2), regulator accepts the highest marginal cost in the system as sell price and buys electricity from generators at this price. It determines buy price from this sell price and the difference between total demand and total generation such that the resulting buy price makes regulator's income zero. It is important to note that second pricing scheme is a uniform pricing scheme, unique sell and buy prices settle in the system.

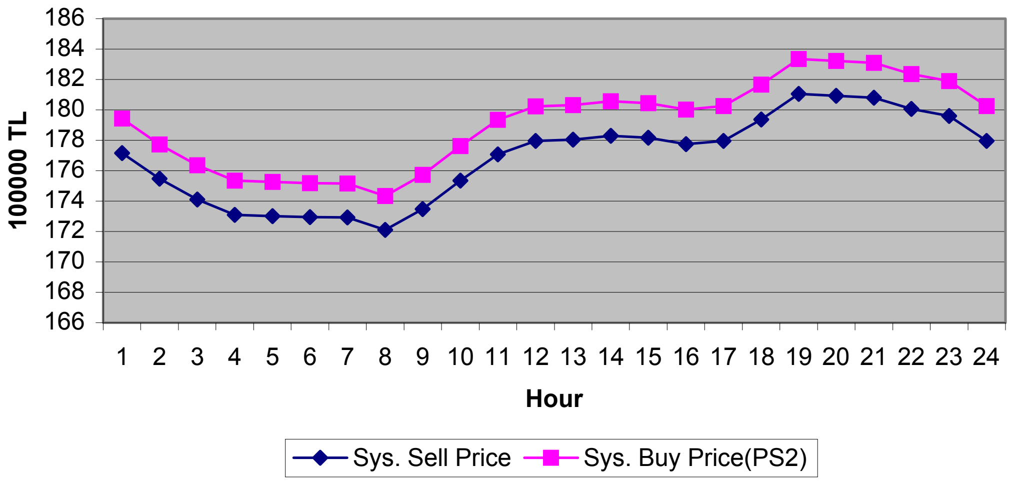
Fixed demand case

In the fixed demand case, we will outline, first, the average weighted prices in graph 5.5. As the graph shows, average weighted sell and buy prices show the same pattern with total generation and total demand. They show a peak at hour 18 while they exhibit trough at hour 07. The graph indicates that sell price of each generator (marginal cost) and bus level lambdas (buy price for each generator) move parallel to each other while sell prices generally are lower than buy prices. Under PS1, there is no uniform price. On the other hand, under PS2, ISO determines a uniform sell and buy price. Graph 5.6 shows the system sell and buy prices for PS2.

Graph 5.5. Average Weighted Sell And Buy prices under Fixed Demand Case



Graph 5.6. System Prices under PS2 in Fixed Demand Case



As one can see, system prices under PS2 exhibit the same pattern with average weighted prices as shown in graph 5.5. In both pricing schemes, system sell price is determined by the marginal costs of generators 09 and 10, which are located at bus 21. Since they are located at the same bus, they have equal marginal costs, as table 5.1 shows, their marginal costs are the highest in the system. Setting system sell price to their marginal cost, regulator guarantees that every generator in the system can cover its operational expenses. These generators are called *marginal generators*.

How will different pricing schemes affect generators' profits and ISO's income? Table 5.9 shows total profits for different pricing schemes. ISO's income is zero for all hours in both pricing schemes.

The lowest total profits are obtained under PS1 since each generator is paid at its marginal cost while, in the other two pricing schemes, generators other than *marginal* ones are paid higher than their respective marginal costs.

Table 5.9. Total Profits and Total Benefits under Different Pricing Schemes

Hour	Total Profits (PS1)	Total Profits (PS2)
0	244720	295080
7	188413	227583
12	256064	308176
16	255097	307060
18	297969	355260
20	293632	351296

* All in 10^5 TL

We should also look at generator level profits for each pricing scheme. Table 5.10 shows the generators' profits at hour 18 under PS1 and PS2. We do not give data about PS2 since under this pricing scheme sell price is equal to that for PS2 and generators' profits are not different from their level under PS2.

As the table outlines, for all generators, profits for PS1 are lower than those for PS2, except for generators 09 and 10. For these generators, profits are same under two pricing schemes since, under PS2; system sell price is equal to their marginal costs, which are also their sell prices under PS1. Therefore, we can conclude that, as long as a generator is not *marginal*, PS2 increase its profits.

Table 5.10. Profits of Generators at Hour 18 under PS1 and PS2

Gen No.	Profits(PS1)	Profits(PS2)	Gen No.	Profits(PS1)	Profits(PS2)
0	36033	46090	11	20130	26783
1	55834	69438	12	794	2010
2	819	2168	13	794	2010
3	26265	32229	14	31963	32064
4	27233	34015	15	5190	5615
5	8292	9955	16	3507	3854
6	2548	3436	17	3412	4684
7	1555	2353	18	2393	3373
8	1317	1983	19	3868	5138
9	37244	37244	20	19990	22031
10	8786	8786			

* All in 10^5 TL

We will give output for first two hours of model's solution of fixed demand base case under PS1 in Appendix B.

Flexible Demand Case:

In the flexible demand case, the selection of the pricing scheme also affects the consumer side, as opposed to fixed case in which consumers can not give any response to this procedure. Again, we firstly look at graph 5.7 for average weighted sell and buy prices over a whole day.

Average sell and buy prices show the same trend as the average prices under the fixed case. In PS1, every generator is paid at its corresponding marginal cost and every demand pays at its respective marginal benefit. Table 5.11 shows the system sell and buy prices under PS2.

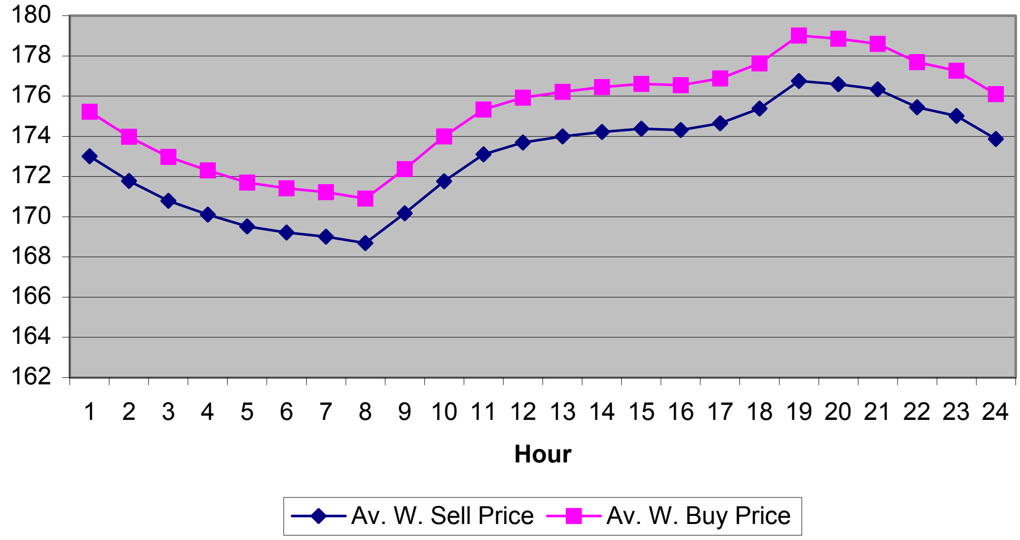
Table 5.11 shows that both system buy price and system sell prices reach their maximums at hour 18. If we look at the table 5.8, we can see that, again, generators 09 and 10 are *marginal* generators. Therefore, under PS2, their sell prices are system sell price although these prices are lower in flexible demand case than under fixed demand case (see table 5.1). Table 5.12 shows total profits under different pricing schemes at various hours.

Table 5.11. System Prices under Various Hours for PS2

Hour	Sys. Sell Price	Sys. Buy price
0	176.9	179.2
7	172.5	174.8
12	177.9	180.2
16	178.6	180.9
18	180.7	183.0
20	180.3	182.6

* All in 10^5 TL/MW

Graph 5.7. Average Sell and Buy Prices under Flexible Demand Case



In flexible case, as in fixed demand case, total profits under PS1 are lower than their levels under PS2. ISO's income is again zero for all hours for both pricing schemes. It seems that PS2 is more beneficial for generators.

Table 5.12. Total Profits under PS1 and PS2

Hour	Total Profits(PS1)	Total Profits(PS2)
0	244218	294096
7	193613	235063
12	256900	308745
16	265662	318838
18	295002	352492
20	289170	345818

* All in 10^5 TL

Table 5.13 shows sell prices (their marginal costs) and profits of generators at hour 18. As Table 5.13 proves, *marginal* generators are generators no. 9 and 10. They have the highest sell price. Since they determine the sell price under PS2 their profits do not differ from their respective levels under PS1 while other generators seem to gain extra profits under PS2. Under PS2, *non-marginal generators* are paid at a price higher than their sell prices and, hence, they earn extra profits under PS2. Especially for *non-marginal generators*, it is reasonable to press for PS2.

Table 5.13. Profits and Sell Prices of Generators under PS1 and PS2 at Hour 18

GenNo.	Sell Price (10^5 TL/MW)	Profits(PS1) (10^5 TL)	Profits(PS2) (10^5 TL)
0	173.6	35606	45569
1	173.7	55514	68986
2	173.7	904	2207
3	175.5	25914	31816
4	175.0	27626	34331
5	177.9	8090	9743
6	177.9	2440	3316
7	177.4	1476	2254
8	178.6	2100	2706
9	180.7	36956	36956
10	180.7	8590	8590
11	173.8	19831	26421
12	173.8	740	1912
13	173.8	740	1912
14	179.8	30541	31635
15	180.3	5279	5470
16	180.3	3580	3736
17	177.3	3698	5004
18	177.3	2244	3244
19	177.3	3674	4979
20	178.2	19463	21706

Consumer surplus for consumer i is calculated as follows;

$$CS_i = \beta_i D_i - \alpha_i D_i^2 - P_i^b D_i$$

where the first two terms on the right constitute to the benefit function of consumer i as mentioned above. P_i^b is the buy price of the consumer. Table 5.14

shows the total consumer surplus for various hours under two different pricing schemes.

Table 5.14. Total Consumer Surplus under PS1 and PS2

Hour	Total CS(PS1)	Total CS (PS2)
0	224370	174493
7	159141	117692
12	235505	183661
18	285181	227693
20	279243	222594

* All in 10^5 TL

As opposed to total profits, total consumer surplus is at its highest level when the regulator applies PS1. Therefore, for the consumer, it is reasonable to force the regulator to apply PS1. PS2 gives lower consumer surplus.

Table 5.15. Consumer Surplus and Buy Prices of Various Busses at Hour 18

Bus No.	Buy Price (10^5 TL/MW)	CS (PS1)	CS (PS2)
8	177.9	1636	288
10	176.4	26074	18410
13	179.5	579	46
15	177.6	13293	8960
20	184.2	21412	22481
21	180.7	126097	119973
24	179.8	13055	10468
29	181.5	36461	34384

* Consumer surplus is in 10^5 TL

As the table shows, the most beneficial pricing scheme for consumers is PS1. Under PS2, ISO determines a unique buy price, which makes ISO's income zero and this buy price is generally higher than the most of the buy prices across the system. Therefore, for most of the busses, consumer surplus decline.

5.2.3.External Shocks

In this section, we will analyze the system's sensitivity to external shocks. We design two experiments: In the first one (EX1), one of the *marginal* generators (Generator 09, Ambarlı DG) is cut off from the network for maintenance for a whole day. In the second one (EX2), an accident makes a major demand area inaccessible for a whole day. We design these examples in order to look at the sensitivity of the system under a spot market.

Fixed demand case

In EX1, the cutting of generator 09 results in a violation of constraint. In this case, after the removal of generator 09, generator 10 (the other *marginal* generator) becomes constrained for the whole day. Over the whole day, it produces at its maximum capacity. In such a case, the relation that every generator's marginal cost is equal to the lambda of the bus at which it is located does not hold any more. If generator i begins to produce more than its maximum, the model activates the corresponding constraint and the corresponding first order condition becomes;

$$B_i + 2C_iQ_i - \lambda_i + \mu_i = 0$$

where μ_i is the inequality Lagrangean multiplier of the constraint which imposes its maximum to generator i. Hence, marginal cost becomes less than its corresponding lambda.

Since demand is fixed in this case, total demand remains the same as the base case and the total generation is nearly the same as the base case. We use "nearly" since cutting of a generator from production network results in the shift of generation locus to the other areas and, in a system with loss, this has a slight effect on the total loss in the system. Therefore, total generation changes slightly as well. This small change has also affected bus level lambdas and generators' marginal costs.

On the other hand, for EX2, two generators, generators 09 and 10 (*marginal* generators) become constrained only at hour 18. In this case, total demand also falls below its base case level. This has an important impact upon marginal costs and bus level lambdas.

Table 5.16 gives the total demand, total generation and total loss with respect to fixed demand base case.

Table 5.16. Total Generation and Total Demand under External Shocks

Hour	Total Demand (Base Case)	Total Demand (EX2)	Total Generation (Base case)	Total Generation (EX1)	Total Generation (EX2)
0	12729	11540	12893	12946	11664
7	10593	9604	10730	10780	9717
12	13123	11897	13291	13346	12026
16	13090	11867	13258	13312	11995
18	14469	13117	14653	14715	13259
20	14350	13009	14532	14594	13156

* All in MW

As the table shows, total generation under EX1 is not so much different from base case level, while, the inaccessibility of a major demand are seems to reduce considerably the total generation. On the other hand, total demand under EX2 falls by the amount equal to the hourly demand of the inaccessible area (İzmir region). We do not give the change in total loss since it is a minor change.

Under EX1, all the generators generate higher outputs than their levels in base case. Under EX2, there is an interesting observation that should be underlined. Although total demand is reduced, at hour 18, two of the generators, generators 09 and 10 generate higher amount compared to their generation levels under base case while all other generators' output is declined. Two *marginal* generators reach their corresponding maximum. Therefore, it is likely to indicate that demand reduction in a region which is far from the bus at which *marginal* generators are located may be beneficial to these generators since the locus of generation shifts to them. Marginal costs are highest under EX1 and lowest under EX2 except for generators 09 and 10.

Table 5.17. Average Sell and Buy Prices for Various Hours

Hour	Av. W. Sell Price (Base Case)	Av. W. Sell Price (EX1)	Av. W. Sell Price (EX2)	Av. W. Buy Price (Base Case)	Av. W. Buy Price (EX1)	Av. W. Buy Price (EX2)
0	173.2	175.7	170.8	175.5	178.9	172.6
7	168.5	170.6	165.8	170.6	173.8	167.7
12	174.1	176.6	171.3	176.3	179.9	173.0
18	177.1	179.8	174.0	179.4	183.2	175.8
18	177.1	179.8	174.0	179.4	183.2	175.8

* All in 10^5 TL/MW

Table 5.17 gives the average weighted price for various hours and external shocks. Under EX1, sell prices generally increase while, under EX2, they decline (except for *marginal* generators). The same pattern can be observed for buy prices across the whole system. The selection of pricing scheme by the regulator is a complicated issue, because, under EX2 with PS2, the output of *marginal* generators increases. As a result, their sell prices also increase. Under this condition, if regulator chooses PS2, the demand reduction under EX2 will result in an increase in sell price as opposed to expectations. The system sell price -despite the fact that total demand falls below its base case level- exceeds its base case level under PS3. Such a fact proves that selection of pricing scheme is very crucial for social welfare optimization.

Table 5.18 shows the change in total profits and regulator's income under external shock cases for different pricing schemes for various hours. As one can observe from Table 5.18, the most important fact is that under EX2 with PS2, total profits at some hours increase because of the fact that the system sell price increases, although the total demand is reduced by nearly 10%. Table 5.22 shows the change in ISO's income under different pricing schemes. ISO's income is always negative under EX2 with the two different pricing schemes.

Table 5.18. Total Profits under Different Cases by Pricing Scheme

	PS1			PS2		
Hour	**Total Profits (Base)**	**Total Profits (EX1)**	**Total Profits (EX2)**	**Total Profits (Base)**	**Total Profits (EX1)**	**Total Profits (EX2)**
0	244720	247476	213222	295080	331920	308973
7	188413	188204	161668	227583	258224	197278
12	256064	259530	219344	308176	334279	316831
16	255097	258501	218551	307060	334095	315760
18	297969	303658	252943	355260	355270	362472
22	276986	281806	234762	332232	337505	306840

* All in 10^5 TL

Table 5.19. Profits of Some Generators at Hour 18 by Pricing Schemes

	PS1			PS2		
Gen no.	**Profit (Base)**	**Profit (EX1)**	**Profit (EX2)**	**Profit (Base)**	**Profit (EX1)**	**Profit (EX2)**
0	36033	39440	30067	46090	49844	46497
1	55834	60800	47667	69438	74509	70226
4	27233	30352	22241	34015	37136	34418
9	37244		38126	37244		38855
10	8786	9379	9526	8786	10058	9526
14	31963	34627	25123	32064	35055	33005
20	19990	22324	15549	22031	24275	22475

* All in 10^5 TL

Finally, in Table 5.19, we give the change in profits of some generators at hour 18 for different cases with different pricing schemes. As the table indicates, under PS1, profits of generators increase under EX1 while they decrease under EX2. On the other hand, profits of generators increase under both external shocks with PS2. This has an important policy related impact.

Flexible Demand Case

Under the flexible demand case, consumers can give response to price changes and it is possible that price changes are not so sharp as in fixed demand case. Table 5.24 gives the change in total demand and total generation under external shock cases with respect to the base case.

Table 5.20. Total generation and Total Demand under External Shocks

Hour	Total Generation	Total Generation (EX1)	Total Generation (EX2)	Total demand	Total Demand (EX1)	Total Demand (EX2)
0	12782	12284	12283	12621	12064	12148
7	10810	10592	10473	10670	10395	10376
12	13231	12608	12730	13064	12384	12597
16	13532	12844	12983	13361	12617	12847
18	14494	13659	13793	14311	13417	13646
20	14308	13508	13626	14126	13269	13482

* All in MW

As the table indicates, total generation falls in EX1 and EX2, as opposed to the fixed demand case in which total generation does not fall too much under EX1. On the other hand, under EX2, the fall in demand and total generation is not as much as in fixed demand case; since, in the flexible demand case, reduction in demand results in reduction buy prices and an increase in bus level demands. Thus the initial fall in demand is somewhat offset by the increase in demand, which is due to the decrease in buy prices. Under EX1, the removal of a major generator increases the output of all remaining generators. Generator 10 becomes constrained for all hours under EX1. On the other hand, under EX2, the removal of one major demand area results in the reduction of all generators' output, except *marginal* generators. Moreover, generators 12 and 13 become constrained from below i.e. they produce zero output, while generators 09 and 10 becomes constrained from above, they reach their maximum. This has important repercussions upon prices.

Marginal costs increase when a major generator is removed from the system. On the other hand, marginal costs decrease when a major demand area becomes inaccessible. The exceptions to this observation are *marginal* generators, which increase their marginal costs under EX2. Generators no 12 and 13 becomes constrained from below and their marginal costs are zero for hour 18 under EX2. This is shown in Table 5.21.

Table 5.21. Marginal Costs of Generators at Hour 18

Gen no.	MC(Base)	MC(EX1)	MC(EX2)
0	173.6	174.2	172.7
1	173.7	174.1	172.8
4	175.0	175.3	174.1
9	180.7	---	181.7
10	180.7	182.2	182.2
12	173.8	180.2	0.0
13	173.8	180.2	0.0
14	179.8	180.3	178.7
20	178.2	178.6	177.0

* All in 10^5 TL/MW

Since the system buy prices increase after the removal of a major generator, demands give negative response and fall under EX1. Moreover, variable part of demands at busses no 0,1,2,3 and 4 fall to their minimum, and consumers at these busses begin to consume only their fixed base demands (look at busses no. 0 and 1 at table 5.27). Since these busses' variable demand parts fall to zero, corresponding inequality constraint's multipliers are added to their bus lambdas. FOC condition dictates that;

$$-\beta_i + 2\alpha_i D_i + \lambda_i - \mu_i = 0$$

μ_i is the multiplier of demand minimum constraint and it is negative. Hence, bus level lambda increases for bus no 0 and 1. On the other hand, under EX2, bus demands increase since buy prices fall over the whole system as a result of the demand reduction. As the total demand decreases, bus level equality lambdas also decline. Table 5.22 gives average weighted sell and buy prices for three different cases.

Table 5.22. Average Weighted Sell and Buy Prices under Different Cases

Hour	Av. W. Sell Price (Base)	Av. W. Sell Price (EX1)	Av. W. Sell Price (EX2)	Av. W. Buy Price (Base)	Av. W. Buy Price (EX1)	Av. W. Buy Price (EX2)
0	173.0	174.5	171.9	175.2	176.5	173.9
7	168.7	171.2	168.6	170.9	171.5	170.2
12	174.0	175.1	173.7	176.2	177.7	174.8
16	174.6	175.6	174.3	176.9	178.4	175.4
18	176.8	177.4	176.1	179.0	180.9	177.6
20	176.3	177.1	175.7	178.6	180.4	177.2

* All in 10^5 TL/MW

Sell and buy prices rise relative to the base case under EX1, while both of them decline under case EX2. Under PS3, the same generators (generator 09 and 10) are *marginal* generators, while system buy price is determined by the buy price of the bus no.20 (Kocaeli region), since it has the highest buy price for the whole day under all cases.

Under EX1, generator 09 becomes constrained for the whole day and thus its sell price is fixed to 182.2 for the whole day. Since this sell price is the highest in the system, system sell price is also fixed at 182.2 for the whole day under PS2. On the other hand, under EX2, same generator again reaches its maximum after the hour 12 and we can observe the same pattern as in case EX1 after the hour12. Table 5.23 gives the total profits under each case by pricing scheme. Total profits under PS1 are generally lower than those under PS2. Moreover, under EX1, total profits reach their highest level with PS3 before the hour 12, while, after 12, generators 09 and 10 become constrained and total profits under EX2 exceed total profits under EX1. Table 5.23 shows the profits under different cases with different pricing schemes. Again, the most important observation is that total profits under EX2 are the highest under PS2 for some hours since both of the *marginal* generators become constrained. In a system without losses, we can not observe such a fact; a reduction of demand certainly reduces the level of total profits.

Table 5.23. Total Profits under Different Cases by Pricing Scheme

	PS1			PS2		
Hour	**Total Profits (Base)**	**Total Profits (EX1)**	**Total Profits (EX2)**	**Total Profits (Base)**	**Total Profits (EX1)**	**Total Profits (EX2)**
0	244218	234959	230906	294096	329844	278749
7	193613	195221	190973	235063	312384	276090
12	256900	242603	251079	308745	332271	359299
16	265662	248705	258363	318838	333831	361599
18	295002	271709	282856	352492	338080	367826
20	289170	267390	277668	345818	337452	366686

* All in 10^5 TL

Table 5.24. Total Profits under Different Cases at Hour 18

	PS1			PS2		
Gen no.	**Base Case**	**EX1**	**EX2**	**Base Case**	**EX1**	**EX2**
0	35606	36357	34287	45569	47835	47473
1	55514	56216	53738	68986	72019	71638
4	27626	28010	26530	34331	36179	35940
9	36956	0	38273	36956	0	39002
10	8590	9526	9526	8590	9526	9526
12	740	2233	0	1912	2819	0
13	740	2233	0	1912	2819	0
14	30541	31077	29135	31635	33573	33462
20	19463	19795	18370	21706	23107	22959

* Profits are 10^5 TL

Table 5.24 shows the profits for some generators under different cases by pricing scheme. Although one major demand area is removed from the system for a whole day, profits of generators increase under EX2 with PS2. This is due to the fact that the system sell price rises under this case. The lowest profit levels for generators are attained under EX2 with PS1.

How would these two shocks affect the consumer surplus when regulator applies different pricing schemes? First, we should look at bus level lambdas under different cases. Bus level demands decrease under EX1 but rise under EX2. Demands at busses no 0 and 1 becomes constrained from below and are zero under EX1. On the other hand, bus level lambdas increase under EX1 but decrease under EX2. This is a favorable development for EX2 if the regulator applies PS1. Table 5.25 shows the total consumer surplus under three cases.

Table 5.25. Total Consumer Surplus under Different Cases

	PS1		
Hour	**Total CS (Base)**	**Total CS (EX1)**	**Total CS (EX2)**
0	224370	209628	210125
7	159141	153394	141689
12	235505	218285	220751
18	285181	260393	263179
20	279243	255813	257258

* Consumer Surplus is in 10^5 TL

Total consumer surplus is at its lowest level under EX1. If we compare the system's sensitivity to external shocks under flexible and fixed demand cases, we can conclude that system with fixed demand respond to external shocks in wide price variations while system. Quantity is insensitive in fixed demand case. Therefore, price level is more volatile under fixed demand case. On the other hand, both price level and quantity changes against an external shock in a system with flexible demand case. Hence, price level is less volatile compared to fixed demand case.

5.2.4. Entry

In this case, a low cost generator is opened up at the bus at which *marginal* generators are located (Bus no. 21). This fact has important impacts upon marginal costs, since it has a lowering effect upon marginal costs over the whole system. As total demand is unchanged in the fixed demand case, total generation and total loss show minor changes. On the other hand, in the flexible demand case, since the entry of a low cost generator reduces output of the incumbent generators, sell prices generally decline and consequently bus level demands may increase. First, new generator's cost function is as follows;

$$C_i(Q_i) = 200 + 115Q_i + 0.018Q_i^2$$

Total generation and total demand increase, while total loss decreases. This is a result of the shift of the weight of generation from areas generating more loss to those incurring relatively less loss after the entry of a low cost generator.

Table 5.26. Output and Marginal Costs of Some Generators under Different Cases

		Fixed demand				Felxible Demand			
Gen No.	Bus No.	Output	%	MC (10^5 TL)	%	Output	%	MC (10^5TL)	%
0	1	1306.7	-7.6	170.0	-2.2	1367.5	-2.8	172.2	-0.8
1	2	1804.9	-6.7	170.1	-2.2	1877.0	-2.4	172.3	-0.8
9	21	1189.1	-10.9	174.9	-3.4	1287.8	-2.9	179.1	-0.9
10	21	478.0	-21.0	174.9	-3.4	564.4	-5.7	179.1	-0.9
12	22	119.7	-31.5	171.2	-1.6	0.0	-100.0	165.0	-5.0
13	22	119.7	-31.5	171.2	-1.6	0.0	-100.0	165.0	-5.0
14	24	1201.1	-6.5	177.7	-1.8	1217.6	-3.0	178.4	-0.8
20	28	851.6	-6.7	175.9	-1.6	869.9	-3.4	176.8	-0.8
New	21	1665.1		174.9		1780.3		179.1	

* Output in MW

Table 5.26 gives the output of some generators at hour 18 under both fixed and flexible demand cases. The table also gives the relative change with respect to the base case.

Outputs of the incumbent generators fall as a result of the entry of a low cost generator, but this fall is more sharply in the fixed demand case. There is an important reason why the fall in generators' output is less sharply in the flexible demand case. Two of the generators, 12 and 13, become constrained from below and they produce zero output for most of the hours in a day. As a result, the remaining generators' output increase despite an entry of low cost generator.

Table 5.27 shows the change in average weighted prices with PS3 with respect to base case under fixed and flexible demand cases. Average weighted prices fall following the entry of a low cost generator and the fall is higher in the fixed demand case. Table 5.28 shows the change in total profits relative to the base case under the fixed demand case with different pricing schemes.

Table 5.27. Average Weighted Prices After Entry at Various Hours

	Fixed Demand				**Flexible Demand**			
Hour	**Av. W Sell Price**	**%**	**Av. W. Buy Price**	**%**	**Av. W Sell Price**	**%**	**Av. W. Buy Price**	**% Change**
0	169.9	-1.9	171.6	-2.2	171.5	-0.9	173.0	-1.3
7	164.9	-2.1	166.7	-2.3	167.3	-0.8	169.0	-1.1
12	170.4	-2.1	172.2	-2.4	172.6	-0.8	174.4	-1.1
16	170.3	-2.1	172.1	-2.4	173.3	-0.8	175.0	-1.0
18	173.3	-2.1	175.1	-2.4	175.8	-0.6	177.5	-0.8

* All in 10^5 TL/MW

Table 5.28. Change in Total Profits after Entry

	Fixed Demand				Flexible Demand			
	PS1		PS2		PS1		PS2	
Hour	Total Profits	%	Total Profits	%	Total Profits	%	Total Profits	%
0	244340.0	-0.2	314316.0	6.5	267952.0	9.7	342217.0	0.2
7	187005.0	-0.7	242887.0	6.7	216985.0	12.1	271973.0	0.2
12	252263.0	-1.5	314301.0	2.0	284515.0	10.7	348243.0	0.1
16	251354.0	-1.5	313225.0	2.0	293854.0	10.6	359049.0	0.1
18	292555.0	-1.8	356922.0	0.5	330206.0	11.9	381064.0	0.1
22	272823.0	-1.5	339470.0	2.2	304548.0	12.6	354007.0	0.1

* Total Profits are in 10^5 TL

One can observe that an entry of a low cost generator lowers total profits only under the fixed demand case with PS1. The highest total profit increase under fixed demand case is under PS2 while PS1 provides the highest profit increase under flexible demand case. For the policy initiative of a regulator, this table points to an important question about pricing schemes. For the consumers, it seems that PS1 is more beneficial under fixed demand but under flexible demand case PS2 limits the increase in total profits. We should also look at generator level changes.

Profits of all generators decline under all conditions. The highest decrease is under fixed demand case with PS1, while the lowest one is under flexible demand case with PS2. Consumer surplus increases by entry under both pricing schemes but the increase under PS1 is higher. On the other hand ISO's income is raised by entry under flexible demand case while it is reduced under fixed demand case for both pricing schemes.

5.2.5. Individual Welfare Maximization (IWM)

In this case, we will look at the effects of the individual welfare maximization on the model variables. As we indicated earlier, agents controlling a set of generators or consumers and using the basic OPF solution, run their corresponding individual welfare maximization procedure and estimate their hourly maximum mark-ups. By multiplying the cost functions or benefit functions they control, they have the power of alternating system prices, output structures and their own profits.

We choose simple examples in order to give a brief summary of the effects of mark-up pricing. Some of them are given in Appendix F. In the example given here, we run three examples in order to show the impact of different pricing schemes upon the individual welfare maximization procedure. We assume that demand is fixed.

C1: One agent controls the following set of generators. Regulator applies PS1. The mark-ups for remaining generators are 1, i.e. they do not play strategically. They only submit their respective true cost functions. On the other hand, agent multiplies each generator's cost in its control set with his maximum mark-up rate and submits this product as the cost curve. The generators in agent's control set are as follows,

- Karakaya (Gen0)
- A. Elbistan (Gen4)
- Ambarlı (F.Oil) (Gen10)
- Soma (gen20)

Table 5.29 shows the maximum mark-up rate of the agent for various hours obtained by running his own individual welfare maximization procedure.

Table 5.29. Maximum mark-up Rates for the Generators in Agent's Control Set

Hour	Gen0	gen4	gen10	Gen20
0	1.05092	1.05092	1.05092	1.05092
7	1.04611	1.04611	1.04611	1.04611
12	1.05181	1.05181	1.05181	1.05181
16	1.05173	1.05173	1.05173	1.05173
18	1.05483	1.05483	1.05483	1.05483
20	1.05453	1.05453	1.05453	1.05453

Table 5.30. Average Weighted Prices under C1 Compared to Base Case under PS1

Hour	Av. W. Sell Price	%	Av. W. Buy Price	%
0	175.00	1.01	177.23	1.00
7	170.00	0.92	172.19	0.91
12	175.91	1.03	178.15	1.02
16	175.84	1.03	178.07	1.02
18	179.06	1.09	181.32	1.08
20	178.75	1.08	181.00	1.07

* All Prices are in 10^5 TL/MW

As the Table 5.29 shows, mark-up rate for each generator is the same. Maximum mark-up rates vary with the level of demand and they reach their maximum levels at the peak demand hour. One may argue that these mark-up rates are not so much high and, hence, individual welfare maximization process can not be a problematic issue in the new market design. Although these mark-up rates seem to be low, their effects are very considerable. The other reason that lies behind these low maximum mark-up rates is that each of the remaining generators is owned by different agent and these agents do not aim to exercise market power. The effects of this process upon the total generation and total loss is minor since demand is fixed and total generation always adjusts itself to total demand, however, its composition certainly changes. Table 5.30 shows the change in average weighted sell and buy prices with respect to base case under PS1. As the table indicates, the average weighted sell and buy prices increase. Table 5.31 shows the change in total profits compared to the base case.

Table 5.31. Total Profits under C1 Compared to Base Case

Hour	Total Profits	%
0	264429	8.1
7	202799	7.6
12	276852	8.1
16	275793	8.1
18	322680	8.3
20	317959	8.3

* All Profits are in 105 TL/MW

Total profits increase by about 8%. We should also look at the generator level changes. Table 5.32 shows the change in the output of generators in agents control sets, total output of agent under C1 and the rate of change in his total output with respect to the base case.

Table 5.32. Output of Agent and Rate of Change in Agent's Total Output

Hour	Gen0(C1)	Gen4(C1)	Gen10(C1)	Gen20(C1)	Total	%
0	1127	921.774	381.258	686.047	3116	-16.95
7	1014	819.172	292.759	628.09	2754	-16.96
12	1146	939.57	396.595	701.162	3184	-16.95
16	1145	938.073	395.305	699.891	3178	-16.95
18	1212	999.219	448.394	757.435	3417	-16.96
20	1207	995.022	444.393	748.268	3395	-16.95

* All output are in MW

Output of the agent falls by about 17% for all hours. This is the cost of mark-up pricing. The highest decline rate is for the output of generator 10 which is the smallest generator in the agent's control set, the decline in this generator's output is about 27%. Table 5.33 shows the change in sell prices relative to their base case values. As one can see from the table, sell prices of generators increase at about 1%. However, when this is coupled with a decrease in costs because of the decline in output, their profits and agent's combined profits increase. This can be seen from Table 5.34.

Table 5.33. Sell Price of Generators and Rates of Change with respect to Base Case

Hour	Gen0	%	Gen4	%	Gen10	%	Gen20	%
0	171.92	1.00	173.28	1.00	178.93	1.00	176.47	1.00
7	166.87	0.91	168.20	0.91	173.68	0.91	172.74	0.91
12	172.81	1.02	174.18	1.02	179.86	1.02	177.38	1.02
16	172.73	1.02	174.10	1.02	179.78	1.02	177.30	1.02
18	175.81	1.08	177.20	1.08	182.99	1.08	180.73	1.08
20	175.58	1.07	176.97	1.07	182.74	1.07	180.22	1.07

* Prices are in 10^5 TL/MW

Table 5.34. Profits of Generators, Total Profits of Agent and The Rate of Change in Total Profits

Hour	Gen0 (C1)	Gen4 (C1)	Gen10 (C1)	Gen20 (C1)	Total (C1)	Total (Base)	%
0	32265	24003	6779	17151	80198	76951	4.22
7	25973	18763	4289	14235	63260	60720	4.18
12	33440	24988	7273	17915	83615	80225	4.23
16	33340	24904	7231	17850	83325	79947	4.23
18	37564	28447	9072	20871	95953	92042	4.25
20	37238	28180	8920	20399	94738	90880	4.24

* Profits and Total Profits are in 10^5 TL

As the table shows, agent's combined profits increase by about 4.2%. A group consisting more generators or generators having higher market share can increase its combined profits at a higher rate. Regulator should design effective measures to limit the exercise of market power since such a market structure provide a firm basis for the exercise of the market power under these pricing schemes.

5.2.6. Distributional Monopolies

In this case, regulator grants the monopoly of distribution at all buses to different distribution companies. Consumer in the bus at which distribution rights are granted to a distribution company is not free to buy electricity directly from the spot market, only distribution monopolies have the right to access to spot market and buy electricity. They submit their marginal revenue curves as their bid curves. Since marginal revenue curves are lying under the demand curve for that bus, total demand and total generation become contracted. We use two experiments to look for the effects of distribution monopolies. In the experiments, regulator applies PS1.First experiment is given below and second is given in Appendix F.

D1: Regulator grants the distribution rights at every bus to a different distribution company and, hence, there are 30 separate distribution companies. In this case, output is contracted at a very higher rate. Table 5.35 shows the change in total demand and total generation, and their respective rates of change compared to the base case.

There are significant declines in total demand and total generation. Then, we can conclude that granting distributional monopolies at every bus is very detrimental to social welfare. This can be better understood from the change in sell and buy prices, and increase in the disparity between buy price of any bus (the price paid by corresponding distribution monopoly to regulator to buy electricity from the spot market) and *dprice* (price paid by consumer at any bus to corresponding distribution company authorized to sell electricity to every consumer on his bus). Table 5.36 shows the change in average weighted sell and buy prices, and also average weighted dprices.

Table 5.35. Change in Total Demand and Total Generation under Distributional Monopolies

Hour	Total Generation	%	Total Demand	%
0	9191.1	-28.1	9097.9	-27.9
7	7843.2	-27.4	7745.0	-27.4
12	9365.4	-29.2	9258.9	-29.1
16	9566.9	-29.3	9458.6	-29.2
18	10165.3	-29.9	10052.6	-29.8
20	10049.7	-29.8	9937.4	-29.7

* Total generation and Total Demand are in MW

Table 5.36. Average weighted System Prices under D1

Hour	Av. W. Sell Price	%	Av. W. Buy Price	%	Av. W. Dprice
0	164.3	-5.1	165.9	-5.3	185.9
7	161.1	-4.5	163.2	-4.5	179.7
12	165.4	-4.9	167.3	-5.0	187.4
16	166.0	-4.9	167.9	-5.1	188.1
18	167.8	-5.1	169.7	-5.2	191.6
20	167.5	-5.0	169.4	-5.2	191.1

* All prices are in 10^5 TL/MW

As the table proves, sell and buy prices fall at considerable rates since both generation and demand fall. On the other hand, the table shows that there is a great disparity between buy price and dprice. This disparity is reflected upon the profits of distributors.

Since the total demand falls because of the distributional monopolies, some of the generators become constrained form below and produce zero output. These generators are Gen02, Gen07, Gen12 and Gen13. Therefore, granting distributional monopolies also creates a distributional conflict between distribution and generation companies. Table 5.37 shows the change in total consumer surplus and total profits compared to flexible demand base case under

PS1 and total profits of distribution companies. As the table shows, the drop in total profits and total consumer surplus is highly drastic. On the other hand, total distributional profits are so much higher than total profits of generators and total consumer surplus.

Table 5.37. Total Profits, Total Consumer Surplus and Total Distributional Profits under D1 (All are in 10^5 TL)

Hour	Total Profits	%	Total CS	%	Total Dprofits
0	149567	-38.8	90815.2	-59.5	181630
7	125173	-35.3	64227.8	-59.6	128456
12	160686	-37.5	92963.4	-60.5	185927
16	166208	-37.4	95562.8	-60.5	191126
18	183307	-37.9	110330.2	-61.3	220660
20	179921	-37.8	108050.0	-61.3	216100

5.2.7. Regulation

In this section, regulator imposes two different regulatory measures in two sub-sections. In the first one, it imposes price cap on both sell and buy prices under the fixed and flexible demand cases. Moreover, we analyze the effects of environmental tax in the context of individual welfare maximization. The first experiment will be summarized in Appendix F while the second one is given below.

A. Environmental Tax

In this case, regulator imposes a linear environmental tax upon the thermal generators. Hence, the cost functions of thermal generators change. This changes the composition of output under the fixed demand case while it both changes the composition and the level of total generation under flexible case. We will look at only upon flexible demand case.

R1: In this case, we examine the effects of an environmental tax in the context of individual welfare maximization. There are two agents in the system. First one controls three hydro generators and second one controls three thermal generators. The control list is as follows:

Agent 1:

- Gen0
- Gen01
- Gen08

Agent 2

- Gen04
- Gen15
- Gen20

In this case, agents run their individual welfare maximization procedures and find their maximum mark-up rates. Then, regulator imposes a 1.2 per MW environmental tax upon the thermal generators. Regulator applies PS1. We will not give the change in macro variables in this case; we will only give how environmental tax affect maximum mark-up rates. Table 5.38 shows maximum mark-up rates before and after tax.

Table 5.38. Maximum mark-Up Rates for Agents Before and After Tax

	Before Tax		**After Tax**	
Hour	**Agent 1**	**Agent 2**	**Agent 1**	**Agent 2**
0	1.0449	1.0314	1.0455	1.0309
7	1.0417	1.0287	1.0424	1.0283
12	1.0459	1.0323	1.0464	1.0320
16	1.0467	1.0330	1.0461	1.0317
18	1.0480	1.0341	1.0486	1.0338
20	1.0479	1.0340	1.0485	1.0335

An environmental tax raises the maximum mark-up rate of a group covering only hydro generators while it reduces maximum mark-up rate of a group consisting only of thermal generators.

5.2.8. Genetic Algorithm

Our NR-based individual welfare maximization algorithm is unable to find multiple equilibria when a constraint is violated. In order to find multiple equilibria, we use genetic algorithm. For example if any transmission flow or generator limit constraint is violated, IWM procedure is unable to find the optimum mark-up rates in that case. In some cases, any informal cartel may aim to violate some of constraints in order to raise group profits or succeed other objective. We give one example in this context.

G1: In this case, one agent controls a set of three generators as follows:

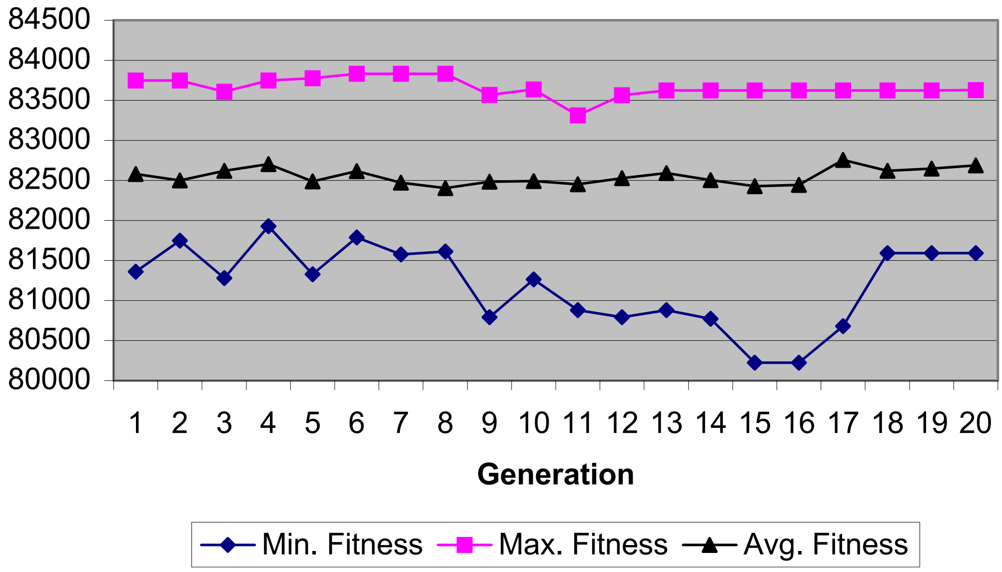
- Karakaya (gen0)
- A. Elbistan (Gen4)
- Soma (Gen20)

We make this experiment for only hour 18 since genetic algorithm takes a considerable time (even though we make it for only one hour in a day, it takes about an hour). Genetic Algorithm parameters are as follows:

- Population Size=30
- Generation Number=20
- Crossover Probability=0.7
- Mutation Probability=0.02
- Gene Inversion Probability=0.02

We run for 20 generations but this may increased. Graph 5.9 shows the maximum, minimum and average fitness of the agent. These fitness values are the summation of the profits of these three generators.

Graph 5.9. Average, Maximum and Minumum Fitness



As the graph shows, three macro variables show a fluctuating trend, this is due to the fitness scaling and fitness sharing. We can also increase the number of generations. Generally, in genetic algorithm examples, begining from the first generation, these values increase. However in our case, since scale of mark-ups are very narrow, we can increase the range. Table 5.39 and 5.40 show the mark-up rates and corresponding total fitness of the chromosomes after generation 20.

Genetic algotihm that we use aims to form niches under which mark-up sets that has close fitness values can be gathered and these mark-ups generate the same conditions. In this regard, our algorithm, as opposed to traditional simple genetic algorithms, prevents the decay of a chromosome from having low fitness. Hence, at some generations avereage fitness value declines. This provides genetic richness to our procedure but also cretes the fluctutaions as shown in Graph 5.9.

Our genetic algorithm finds two niches which means two negihborhoods around two possible multiple equilibria. Table 5.39 shows the first niche which is close neighborhood of the first local optimum (1.046, 1.046, 1.046). This is the maximum mark-up set found by NR-Base Individual Welfare Maximization algorithm for the C4. We try each mark-up at generation with our core OPF and find out that all these 15 chromosomes are in the neighborhood of this optimum, since they provide same conditions such that there is no constraint violation in the system with these mark-ups.

Table 5.39. Chromosomes in the Neighborhood of First Optima

Chromosome	Gen0	Gen04	Gen20	Fitness
0	1.051	1.049	1.060	84931
2	1.010	1.070	1.030	83097
7	1.054	1.075	1.093	83626
9	1.086	1.079	1.095	82658
11	1.072	1.070	1.030	83313
12	1.010	1.070	1.030	83097
13	1.010	1.070	1.030	83097
14	1.050	1.075	1.093	83628
17	1.086	1.095	1.041	82691
18	1.086	1.079	1.061	83129
19	1.074	1.070	1.030	83283
21	1.054	1.075	1.093	83165
22	1.074	1.070	1.030	83283
27	1.086	1.077	1.061	83057
29	1.010	1.070	1.030	83097

On the other hand, second set of chromosomes result in 2 constraint violations such that generators 09 and 10 (Ambarlı DG and Ambarlı FO) become constrained from above and they produce at their maximum. Fitness values for this set is lower than the first set and we try with core OPF program and find out that they are in the neighborhood of the maximum mark-up set (1.110, 1.073, 1. 032). This mark-up set provides a combined profit of 83218.

Table 5.40. Chromosomes in the Neighborhood of the Second Optima.

Chromosome	Gen0	Gen04	Gen20	Fitness
1	1.030	1.075	1.125	82582
3	1.057	1.124	1.034	82210
4	1.038	1.111	1.095	82672
5	1.030	1.075	1.125	82582
6	1.057	1.124	1.035	82116
8	1.030	1.075	1.125	82582
10	1.086	1.111	1.093	81902
15	1.038	1.111	1.095	82207
16	1.030	1.075	1.125	82582
20	1.104	1.070	1.027	82628
23	1.086	1.111	1.092	81923
24	1.104	1.070	1.027	82525
25	1.106	1.014	1.000	81592
26	1.038	1.111	1.095	82672
28	1.030	1.000	1.117	82250

There may be another optimum but our mark-up range allows us to find out two. One can make another experiment and may use mark-ups less than 1 and can find another optimum.

This shows an important characteristic of new market design. If a group of generators collude and if they find that a range of mark-up sets increase their total profit, they can try each of them and this may create volatility in the system. In our case, the second optimum gives a lower combined profit level but, in some cases, this group may prefer second niche. For example, if this group also takes the control of one of the constrained generators under the second set, total profits may be higher than the first set by setting the mark-up rate for the constrained generator to 1. We use genetic algorithm to show that collusion of a group of generators provides a range of alternatives and may result in mixed strategy Nash equilibrium.

5.2.9. Transmission Constraint Binding

In this section we will look at one experiment. In this experiment we reduce the transmission capacity of five lines as following: Line 3 (800 MW), Line 4(800 MW), Line 12 (1000 MW), Line 42 (500 MW) and Line 35(500MW). Therefore, these lines become constrained for the whole day. Demand is flexible. Table 5.41 shows the change in total demand and total generation with respect to base case.

As Table 5.41 shows, total demand and total generation fall after constraint becomes binding. The fall is highest in peak demand hour. Table 5.42 shows the change in average weighted prices with respect to base case with PS1.

Table 5.41. Change in Total Demand and Total Generation wrt. Base Case as a Result of Transmission Constraint Binding

Hour	Total Demand	%	Total Generation	%
0	12270	-2.78	12417	-2.9
7	10657	-0.13	10799	-0.1
12	12660	-3.09	12807	-3.2
16	12871	-3.67	13017	-3.8
18	13606	-4.93	13747	-5.2
20	13487	-4.52	13637	-4.7

* Total Demand and Total Generation are in MW

Table 5.42. Rate of Change in Average Prices (%)

Hour	Av. W. Sell Price	Av. W. Buy Price
0	-0.39	0.38
7	-0.12	-0.20
12	-0.40	0.45
16	-0.42	0.60
18	-0.56	1.37
20	-0.50	0.81

Table shows that sell and buy prices generally change in opposite directions. Sell prices decline and buy prices increase. Table 5.43 shows the rate of change in total profits and total consumer surplus when transmission constraint becomes binding.

Table 5.43. Rate of Change in Total Profits and Consumer Surplus (%)

Hour	Total Profits	Total CS
0	-4.4	-4.5
7	-1.2	2.0
12	-4.7	-5.3
16	-5.0	-7.0
18	-6.4	-13.9
20	-6.0	-8.8
Day Total	-4.1	-4.9

Both total profits and total consumer surplus decline as a result of transmission congestion. On the other hand, system operator acquires a high positive income. System operator may use this amount to invest in transmission expansion.

5.3. Summary & Policy Implications

First, we will give summarize the results obtained from simulation case studies. The results are summarized in Table 5.44.

Table 5.44. Summary of Results from Simulation Case Studies

Case	**Results**
Pricing PS1 and PS2	• Total Profits are higher under PS2 • Regulator earns zero income under PS1 and PS2 • PS1 provides the highest total consumer surplus • PS2 generates higher net social welfare.
External Shock EX1 and EX2	• Removal of a generator increases sell and buy prices in the system • Removal of a major demand area decreases both sell and buy prices • Removal of a major generator increases total profits. The increase is higher under PS2 (fixed demand). • Removal of a major generator reduce total profits under PS1 while it increase total profits under PS2 (flexible demand). • Removal of a major demand area decreases total profits under PS1 while it may increase total profits under PS2 (both flexible and fixed demand). Removal of a major generator increases ISO's income under PS1. Removal of a major demand area decreases it in all pricing schemes.
Entry	• Entry of a low cost generator increases both total generation and total demand under flexible demand case. • Entry reduces sell and buy prices across the system under both fixed and flexible demand cases. • Entry reduces total profits under PS1 but increases it under PS2 under fixed demand. • Entry increases total profits both under PS1 and PS2 under flexible demand. • Entry increases total consumer surplus under PS1
IWM - C1	• IWM raises both sell and buy prices across the system • IWM increases the profits of agents that apply IWM (fixed demand). • Applying maximum mark-ups reduces the total output for the agent (both fixed and flexible demand) • Applying maximum mark-ups reduces the total demand for the agent who controls a set consisting only of consumers (flexible demand)

Table 5.44 (Continued)

Case	Results
Distributional Monopolies- D1	• Distributional monopolies at bus level reduce both total generation and total demand. • Distributional monopolies reduce sell and buy prices. • Total consumer surplus and total profits decrease at large amounts while distributional monopolies obtain huge profits.
Regulation –R1	• Linear environmental tax increases maximum mark-up rates for the agent which controls a set consisting only of hydro generators while it reduces maximum mark-up rate for a group covering only thermal generators under PS1 (flexible demand).
Genetic Algorithm- G1	• There may be multiple equilibria when a group of generators collude or an agent controls more than one generator.

At the highest layer, regulator should make a choice about the market structure of both generation and distribution segments of the electricity sector. Firstly, he should decide whether the consumers participate or not. In all our cases, we see that consumer participation generally reduces the profits of generators. On the other hand, a market structure with consumer participation seems to be more prone to price volatility, since not only generation gives response, demands also respond to any change in the price level. We observe that, after entry or an external shock, bus level demands change at a rate about equal to the rate of change in output of generators. This fact increases the price volatility and may create unanticipated results.

However, consumer participation effectively reduces the maximum mark-up rates of groups consisting only of generators. Hence, flexibilization of demand seems to be beneficial for the consumers. Moreover, groups consisting of only consumers seem to reduce the system prices and increase consumer surplus while decreasing the total profits. Hybrid groups covering both generators and consumers seem to be an effective way of limiting the increase in the maximum mark-up rates of generators.

We can conclude that, in the context of social welfare optimization consumer, participation produces beneficial outcome for the consumers and regulator may induce policy makers to open the electricity market to consumer participation as soon as possible.

Regulator should also make choice about the distribution segment of the electricity system. We look for two extreme cases; in the first one, consumers at each bus are free to buy electricity directly from the spot market. In the second one, we assume that regulator grants distribution monopolies at each bus to private companies. We observe that consumer surplus and total profits of generators decrease at a very high rate in the latter compared to the former case. Hence, we can conclude that granting distributional monopolies is very harmful to social welfare, both consumer surplus and total profits decline while distribution monopolies derive huge amount of profits, the profits of distributional monopolies are higher than both consumer surplus and total profits of generators.

In the second layer, regulator should decide about the pricing scheme. We analyze two different pricing schemes. The first one is a non-uniform pricing scheme while the other two schemes are uniform pricing schemes. In the second pricing scheme, the sell prices of one or more generators determine the system sell and buy prices. These generators are called *marginal* generators. All other generators become passive price takers. Selecting the highest sell price as the system sell price, regulator ensures that all the generators can cover their operational expenses. The marginal costs of *marginal* generators, in these pricing schemes, are very crucial for these pricing schemes; they earn zero profits while the other low cost generators increase their profits with respect to their profits under the first pricing scheme. Therefore, we can conclude that PS2 decreases consumer surplus and increase total profits compared to PS1.

Under PS2, *marginal* generators increase the alternatives in front of them. In the context of mark-up pricing, they can select from a set of equilibrium mark-up rates under PS3. Under external shocks, PS2 gives very different results from PS1; for example, as we observe, reduction in demand certainly reduces system prices under PS1, while system sell price under PS2 may rise. Hence, consumer can not acquire the benefits of reduction in buy prices across the system. There are three important implications that can be derived from this comparison.

First, if regulator aims to apply PS2, he should strictly regulate the *marginal* generators. This is very crucial since the system prices strictly depend upon the marginal costs of *marginal* generators. The means of regulation depend upon the structure of the generation segment of the electricity system. For example, regulator should induce investors to open up a low cost generator, especially at the bus at which *marginal* generators are located.

Second, regulator should tackle with the information problem if he announces his will to apply PS2. He should not inform the generators about which generator is the *marginal* one. As we see, full information on the side of the generators, induce especially *marginal* generators to increase the mark-up alternatives.

Third, as another measure, regulator should prevent the privatization of marginal generator. A private company, if it acquires the ownership of the *marginal* generator, it can exploit the opportunities provided by the status of the *marginal* generator. This tendency is reinforced if this private company also owns a group of low cost generators.

Then regulator should device effective regulatory measures such as price caps or taxes. We saw that price caps over sell and price floor over buy prices reduce both the total profits and total consumer surplus while increasing regulator's income. In this way, he may increase his income and may use this amount to subsidize the buy prices. On other hand, regulator should be very careful about the environmental taxes. We see that any environmental tax increase the mark-up rate of a group consisting only of hydro generators while reducing maximum mark-up rate of a group covering the thermal generators.

Lastly, in the light of genetic algorithm case, we see that a group of generators may prefer a lower optimum. They may prefer maximum mark-up rates, which may result in constraint violations in the system. This example aims to show that the new market structure increases the range of alternatives for the agents in the market.

CHAPTER 6

CONCLUSION

Our study shows that the liberalization of the electricity sector is a complicated issue. Turkey's liberalization program is on the half way to a fully liberalized electricity market. In this context, our study aims to shed light upon this complicated issue. We make some restrictive assumptions in our model that prevent us to focus on all problems that the reformers could have to face with. However, our study and the conclusions that we derive may create a fruitful arena of discussion.

We can outline the basic conclusions that we substantiated from the results of our simulation studies as follows. We would first like to stress that the liberalized electricity markets, especially the spot market, needs to be strictly regulated. New electricity markets, as empirical and theoretical literature and our case studies show, are prone to the exercise of the market power and price volatility. A fully liberal market may strengthen these tendencies and may reduce social welfare. We should remind that the income and price elasticity of electricity in a modern society is very low, especially households can not decrease or increase their electricity consumption at large amounts as a response to an external shock or a price peak. Moreover, electricity network creates strong externalities (both negative and positive) and these externalities provide another *raison d'etre* for regulation.

In this context, a demand for "deregulation" decoupled with the liberalization attempts seems very unrealistic, especially for countries like Turkey, which has not yet completed the transformation of the electricity sectors.

Regulator should also be careful about the pricing scheme it applies. Although we focus on two different pricing schemes, there may be other alternatives. We can categorize two pricing schemes, PS1 and PS2 under more general headings as "non-uniform pricing" and "uniform pricing". According to our results, PS1 (pricing scheme 1) seems to be more advantageous in the context of social welfare optimization. Under PS2 (pricing scheme2), prices may be more volatile after an external shock, and also more unpredictable. Moreover, this pricing scheme creates an important information problem. As we have seen in our case about generator mark-ups, a *marginal* generator will have a range of alternatives and may affect system prices by altering its mark-up rate. Hence, under PS2, the regulator should not inform the generators about which of them is *marginal*. If the regulator ensures this informational safety, PS2 may prevent a group to run its own individual welfare maximization algorithm and to use mark-ups.

Marginality is crucial under PS2. At the extreme, we could argue that privatization of *marginal* generators should be prevented. If they are to be privatized, the regulator should impose strict regulations upon them. This pricing scheme, as our cases prove, is beneficial to low cost generators. They can earn extra profits under this pricing scheme. Hence, the regulator could impose income cap, instead of a price cap to these generators, since price caps strictly harm *marginal* generators and may reduce their profits so much.

The Turkish electricity system is divided into 33 distribution regions. The policy of granting distributional monopolies certainly reduces producer profits and consumer surplus. One can argue that distribution should remain as a public monopoly, or privatized under a strict public regulation, since distributional monopolies reduce both demand and supply. Another alternative would be to impose strict price caps upon distribution prices. Finally, municipalities or regional cooperative bodies could operate distributional monopolies with the aim of maximizing social welfare.

Although the new law puts a limit to the share of a private company in total generation, the regulator should device additional effective means to prevent the formation of informal groups of generators. Our simulation case studies prove that, as the empirical literature indicates, the spot market may provide opportunities to the exercise of the market power. Consumer participation effectively reduces the opportunities for the exercise of the market power. If some large generators are sold to cooperatives controlling the distribution in a group of regions, maximum mark-up rates of these generators are found to be very close to unity, and other generators also become less inclined to exercise the market power.

The regulator can also use bilateral contracts to limit the opportunities of the exercise of the market power. Low price contracts reduce the alternatives in front of the generator groups and force them to submit their true cost functions.

Moreover, as Newberry indicates (Newberry, 1999), contract prices may be at an entry-deterring level. Although we do not focus on this issue, we can say that low price contracts induce consumers to sign more contracts and this increase the output of the generators, which can bear low contract prices. High cost generators are driven away from the contract market and their share in total generation may fall. This picture may create pessimism on the side of the investors and may deter them from entry into the electricity sector.

If uniform pricing is applied, regulator should induce investors to open up low cost plants, especially at the busses at which *marginal* generators are located. This will effectively reduce the system prices. Hence, the regulator should continue to direct investments especially in the generation segment, although this is in a contradiction with the basic rationale behind the reform attempts. The regulator should also tackle with the problems created by the transmission system expansion.

As our simulations show, the high cost thermal generators determine the system prices under PS2. Therefore, the privatization of thermal generators should be handled very carefully. In all our simulations for PS2, two generators are always found to be *marginal*. These are Ambarlı DG (Gen09) and Ambarlı FO (Gen10); both of them are located in İstanbul region. These generators could remain under the public ownership if the regulator insists upon PS2.

There are numerous natural gas-fired plants that are expected to be operational by the end of 2005. Thus, the share of the natural-gas-fired plants will increase rapidly after 2005. Our estimates show that natural gas-fired plants do not have very low unit costs. Moreover, since most of them are built at the busses, which bear high level of losses, their costs are higher than the average cost in the electricity system. In other words, the unit cost of the electricity produced does not only depend upon the type of the fuel but on the geographical location. Therefore, the regulator should encourage the generators to be built in other regions, or should increase the capacity of high-voltage lines in the western regions to reduce losses.

Our simulation model allows us to analyze the effects of different regulatory measures upon the performance of the system. It is found that the caps on both buy and sell prices directly affect profits and consumer surplus. Moreover, we see that linear environmental taxes may be another source of volatility in price. Environmental taxes reduce the maximum mark –up rates for the thermal generators while increasing the maximum mark-ups for the hydro generators.

Finally, we should mention two main caveats of our model. First, our model does not cover investment decisions. Second, it assumes that there is not a deficient supply problem in the electricity sector. However, the model need extensions if it is to be used in analyzing the electricity markets with deficient supply, as in the case of many developing countries.

We should also indicate some general conclusions. First, our study indirectly points to an immediate need for further analytical studies about the issue. Since Turkey is on the half way of a full-fledged liberalization, these studies may pave the way for more concrete proposals and discussions about policies. Moreover, there is also a need for constructing an easily accessible and consistent database about the Turkish Electricity sector.

Second, we should note an important observation about the global interest on this subject. As long as the electricity system had been a public monopoly, economics discipline has not got much involved in the discussions about the electricity sector. However, liberalization has attracted a lot of scholars from OECD countries to this subject. It seems that, in Turkey, the engineering discipline monopolized the subject at policy and academic levels. Academic institutions, especially economics departments should encourage scholars to study this subject.

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APPENDICES

APPENDIX A

A SIMPLE EXAMPLE OF MODEL SOLUTION

We will use simple electricity network to illustrate how our model works. In our simple model we have five busses, three generators and five demands. This is shown in figure A.1. There are six lines.

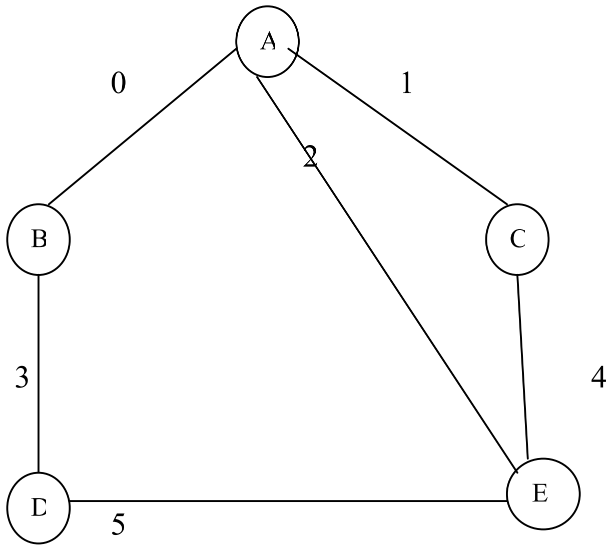


Figure A.1. The Structure of Example System

Table A.1 gives the basic information about three generators in the system. We assume that minimum for generators is 0 MW.

Table A.1. Cost Information About Generators

Gen. No	**Bus No**	a_i	b_i	c_i	**Gen Max. (MW)**
0	A	200	120	0.01	2000
1	C	200	130	0.012	2000
2	D	200	125	0.015	2000

In Table A.2 we give basic demand information. We should note that the second column gives the fixed demand levels, which will be used in fixed demand analysis and the remaining columns give the benefit function parameters, which will be used in flexible demand analysis.

Table A.2. Demand Parameters

Bus Name	Fixed Demand (MW)	β_i	δ_i	Dem. Max. (MW)
A	500	165.2	-0.020	2000
B	400	165.9	-0.022	2000
C	550	168.3	-0.019	2000
D	600	167.0	-0.018	2000
E	650	171.3	-0.017	2000

The minimum for demand is 0 MW. Table A.3 shows line data.

Table A.3. Line Data

Line No.	From	To	X	R	Tmax (MW)
0	A	B	28	7.5	1500
1	A	C	22	6.5	1500
2	A	E	30	10	1500
3	B	D	24	6.5	1500
4	C	E	26	8	1500
5	D	E	23	7	1500

* X and R are in Ohms

For the sake simplicity we simulate the system's operation in an hour. Firstly, we will show the results of the system without losses. Then we will look at the outcome of the system with losses. We firstly deal with the fixed demand case and we will pass on to flexible demand analysis.

A.1. Fixed Demand Case without Losses

In this case, we assume that there is no loss i.e. line resistances are equal to zero. In a lossless system, equality lambdas for each bus are the same.

This is also true for marginal costs of the generators. Table A.4 shows the optimal output and marginal cost of each generator.

Table A.4. Optimal Solution for Generators

Gen No.	Output (MW)	MC (10^5 TL/MW)
0	1313	146.267
1	678	146.267
2	709	146.267

At the optimum marginal costs are equal. Table A.5 shows the optimum flows on each line.

Table A.5. Optimum Flows

Line No.	From	To	Flow(MW)	Loss
0	A	B	348.7	0
1	A	C	136.1	0
2	A	E	328.5	0
3	B	D	-51.3	0
4	C	E	263.9	0
5	D	E	57.6	0

The negative flow value indicates reverse flow. These flows also guarantee bus level equilibria. Finally, table A.6 shows optimum bus angles and bus equality lambdas. We should note that first bus is selected as slack bus and we assume that the bus angle of the slack bus is zero.

Table A.6. Optimum Bus Angles and Lambdas

Bus No.	Bus Angle	Lambda
A	0	146.267
B	-9763	146.267
C	-2995	146.267
D	-8532	146.267
E	-9856	146.267

* Bus angles are in radiants.

A.2. Fixed Demand Case with Losses

In this case we assume that lines have positive resistances as shown in table A.3. In a system with losses marginal costs of any two generators are not same as far as they are not on the same bus, since the busses at which they are located possibly do not bear the same share in total loss in the system. The share of any bus in total loss increases with the number of connections and the volume of transmission from and to this bus. In this case, the optimum output of three generators is shown in Table A.7.

Table A.7. Optimum for Generators

Gen No.	Output (MW)	MC (10^5 TL/MW)
0	1279	145.58
1	749	147.99
2	695	145.86

Note that the optimum output under a system with losses is different from the optimum output set in the above case. In this case, total generation is no longer equal to total demand; it is greater than total demand. The difference between them is total loss in the system. In this case, total generation is 2723 MW, total demand is 2700 MW and total loss is 23 MW. This loss is very low. Although it is very low, it brings about the differences in marginal cost of generators as shown in table A.7. The highest marginal cost is of generator no 01 but, at optimum, it produces higher than generator 02 although generator 02 has a lower marginal cost. Table A.8 shows flow and loss on each line. As table shows, the highest loss is on line 2. The volume of loss on each line depends upon the amount of flow, the length of line and resistance of line. Table A.9 shows optimum bus equality lambdas and bus angles.

Table A.8. Optimum Flows and Losses

Line No.	From	To	Flow (MW)	Loss (MW)
0	A	B	353.1	6.3
1	A	C	95.9	2.4
2	A	E	322.4	6.4
3	B	D	-50.6	1.1
4	C	E	290.9	6.3
5	D	E	43.5	1.1

Table A.9. Optimum Bus Angles and Lambdas

Bus No.	Bus Angle	Lambda
A	0	145.58
B	-9887	148.61
C	-2109	147.99
D	-8673	145.86
E	-9673	149.77

* Angles are in radiants.

As the table exhibits, bus level lambdas differ in this case as a result of losses. We should note that marginal costs of generators at optimum are equal to the lambdas of the busses at which they are located.

A.3. Flexible Demand Case with Losses

In this case demands are flexible and demand parameters are given in A.2. The solution of flexible demand case shows that total generation is 2694 MW, total demand is 2671 Mw and total loss is 23 MW. The optimal output and marginal costs of generators are given in Table A.10.

Table A.10. Optimum Output for Generators

Gen No.	Output (MW)	MC (10^5 TL/MW)
0	1267.3	145.3
1	739.6	147.8
2	687.4	145.6

As the table shows, again, marginal costs differ. The optimal output of each generator does not differ so much from their levels in fixed demand case. Table A.11 shows the demand for each bus and corresponding marginal benefits.

Table A.11. Optimum Demand and Marginal Benefits

Bus	Demand (MW)	MB (10^5 TL/MW)
A	496.3	145.3
B	398.4	148.4
C	540.8	147.8
D	593.8	145.6
E	641.6	149.5

One can see that optimum demands are very close to their fixed levels. Again marginal benefits differ among busses. Table A.12 shows flows and losses.

Table A.12. Optimum Flows and Losses

Line No.	From	To	Flow (MW)	Loss (MW)
0	A	B	351.1	6.3
1	A	C	93.8	2.3
2	A	E	318.6	6.4
3	B	D	-51.0	1.1
4	C	E	288.3	6.2
5	D	E	41.5	1.0

A.4. Pricing Schemes

Pricing in a system with losses is a complex issue as we indicated. We outline three different pricing schemes. First one is uniform pricing, second is a non-uniform pricing scheme. Table A.13 shows profits of three generators and regulator's income under two pricing schemes under fixed demand case.

Table A.13. Profits of Generators under Different Pricing Schemes under Fixed Demand

Gen No.	PS1	PS2
0	16157	19236
1	6740	6740
2	7049	8530
ISO's Inc.	0	0

* Profits and Regulator's Income are in 10^5 TL

Hence, we can say that generator 01 is the marginal one. On the other hand, regulator's income is zero under PS1.

Table A.14. Profits of Generators under Different Pricing Schemes under Flexible Demand

Gen No.	PS1	PS2
0	16061.1	19106.8
1	6563.61	6563.61
2	7087.53	8550.37
ISO's Inc.	0	0

* Profits and Regulator's Income are in 10^5 TL

Table A.14 shows profit of each generator and regulator's income under three different pricing schemes. As in fixed demand case as shown in previous table, the highest profits for non-marginal generators are attained under PS2. Table A.15 shows consumer surplus of each bus under different pricing schemes. As table shows, PS1 provides a higher level of consumer surplus. Hence, we can say that the selection of pricing scheme may be an antagonistic issue between generators and consumers.

Table A.15. Consumer Surplus under Different Pricing Schemes

Bus	PS1	PS2
A	4927	3095
B	3492	3226
C	5557	4861
D	6348	4320
E	6998	7312

* Consumer Surplus are in 10^5 TL

A.5. Distributional Monopolies

In this case regulator grants the distribution rights at five busses to five distinct distribution companies. In this case, regulator applies PS1 and distribution companies buy electricity form the market at buy price and sell electricity to consumers at a price higher than buy price. The difference between buy price and distribution sell price is distribution company's rent. Table A.16 shows the total generation, total demand, total loss, total profits, total consumer surplus and total distribution rents under base case with PS1 and this case.

Table A.16. Basic Macro Variables under Base Case and Case with Monopolist Distributors

	Base Case with PS1	Case with Distr. Comp. With PS1
Total Generation[a]	2694	1817
Total Demand[a]	2671	1800
Total Loss[a]	23	17
Total Profits[b]	29712	13893
Total CS[b]	27322	12378
Total Dist. Rent[b]	0	24755
ISO's Inc[b] .	0	0

[a]: In MW [b]: In 10^5 TL

As the table shows, both total generation and total demand fall by a large amount under distributional monopoly case. Total profits and total consumer surplus fall sharply and it seems that the high level of distributional rents offset this fall. Hence, it can be indicated that granting distributional monopolies deteriorate social welfare.

A. 6. Individual Welfare Maximization

In this case one company owns generator 0 and 02 and he multiplies the cost functions of the generators with maximum mark-up rates found by individual welfare maximization algorithm. We assume that demand is fixed and regulator applies PS1. Individual welfare maximization for agent finds that maximum mark up rates set for the generators 0 and 2 is (1.236,1.236). Table A.17 shows the output and profit of each generator under base case and this case.

Table A.17. Output and Profit of Each Generator

	Base Case with PS1		Indiv. Wel. Max. Case	
Gen No.	**Output**	**Profit**	**Output**	**Profit**
0	1279	16157	817	32840
1	749	6740	1458	25496
2	695	7049	461	18151
Total	2724	29945	2736	76487

* Output is in MW and profit is in 10^5 TL

As the table shows, mark-up pricing of generators in agent's control set bring a reduction in output of these generators (about %30), at the same time the output of remaining generator, generator 1, increase at about %100. Looking at profit of each generator, one can see that, not only the profit of generators in agent's control set increase, profit of generator 1 increases as well. Profits of generators 0 and 2 increase at the cost of reduction in their output. The increase in profits of these generators is due to the increase in their sell prices. This can be understood from table A.18 which shows the change in sell prices of generators with respect to base case. As table shows, sell prices of three generators increase and as a result their profits are raised.

Table A.18. Generator Sell Prices under Different Cases

Gen No.	Base Case	Indiv. Wel. Max.
0	145.6	168.6
1	148.0	165.0
2	145.9	171.7

* Sell price is in 10^5 TL/MW

We can conclude that generally, mark-up pricing raise the sell prices and buy prices in the system. Generators, which apply mark-up pricing, should face a reduction in output but this reduction is offset by an increase in sell price. Therefore, profits of generators, which multiplies its cost function with maximum mark-up rates found by individual welfare maximization procedure increase at considerable amounts.

APPENDIX B

OUTPUT SAMPLE

hour :0

load profiles in hour 0

```
Bus no:0   Load:187.47
Bus no:1   Load:167.65
Bus no:2   Load:136.77
Bus no:3   Load:150.27
Bus no:4   Load:224.32
Bus no:5   Load:268.22
Bus no:6   Load:253.35
Bus no:7   Load:197.1
Bus no:8   Load:228.32
Bus no:9   Load:168.13
Bus no:10   Load:1045.71
Bus no:11   Load:186.65
Bus no:12   Load:167.84
Bus no:13   Load:147.35
Bus no:14   Load:366.83
Bus no:15   Load:702.56
Bus no:16   Load:403.17
Bus no:17   Load:316.81
Bus no:18   Load:256.01
Bus no:19   Load:226.41
Bus no:20   Load:827.02
Bus no:21   Load:2319.42
Bus no:22   Load:506.31
Bus no:23   Load:302.08
Bus no:24   Load:738.95
Bus no:25   Load:310.62
Bus no:26   Load:79.18
Bus no:27   Load:474.47
Bus no:28   Load:181.24
Bus no:29   Load:1189.11

No of Iteration: 4
time elapsed for matrix operations:3478
Number of line flow violations:0
Number of generator limit violations:0

OUTPUT
```

GENERATOR OUTPUT:

```
1311.39
```

1809.65
120.487
1051.78
1089.04
507.537
239.569
170.616
218.209
1241.77
524.048
871.57
102.867
102.867
1164.16
384.078
302.723
313.716
226.27
312.974
827.353

FLOWS:
-188.026
208.046
743.039
1015.04
976.987
-150.442
362.743
741.44
309.546
147.836
591.026
680.641
1150.2
426.143
-197.393
319.666
363.878
222.122
360.853
1327.75
256.963
192.021
341.489
-25.9494
895.861
156.955
79.9256
98.8614
-176.499
106.869
555.083
97.5798

-132.197
-91.9815
-185.577
-560.027
-262.881
-39.6398
29.5315
-235.033
224.607
-244.704
614.32
359.614

Loses:
1.11126
0.688676
7.46006
12.6284
5.4565
0.34419
1.45366
2.52839
0.879363
0.507193
2.77417
4.62824
12.2888
2.39373
0.585388
2.86765
1.24843
0.267077
0.895508
17.0588
0.28621
0.367485
0.885169
0.331199
24.5667
0.440951
0.351755
0.521732
0.47759
0.520226
6.11939
0.34354
0.454857
1.76738
3.35433
21.9342
0.587994
0.294087
0.162457
1.00567

0.38151
1.64273
16.1069
2.3734

BUS ANGLES:

```
bus angle 1   ;15982.2
bus angle 2   ;-16056.8
bus angle 3   ;-48365.9
bus angle 4   ;-17826.1
bus angle 5   ;-54628.2
bus angle 6   ;-73699.1
bus angle 7   ;-147381
bus angle 8   ;-109481
bus angle 9   ;-68356.2
bus angle 10   ;-125019
bus angle 11   ;-127448
bus angle 12   ;-116313
bus angle 13   ;-128396
bus angle 14   ;-201987
bus angle 15   ;-184409
bus angle 16   ;-208604
bus angle 17   ;-217531
bus angle 18   ;-218003
bus angle 19   ;-200919
bus angle 20   ;-216850
bus angle 21   ;-216337
bus angle 22   ;-209376
bus angle 23   ;-224886
bus angle 24   ;-181222
bus angle 25   ;-212237
bus angle 26   ;-183939
bus angle 27   ;-240480
bus angle 28   ;-222151
bus angle 29   ;-251748
```

EQUALITY LAMBDAS:

171.219
170.21
170.289
172.465
172.071
172.095
171.562
174.88
174.362
173.94
172.926
172.694
172.902
175.933
179.826
174.084
174.163

175.085
175.799
178.197
180.532
177.154
170.349
176.214
176.3
177.345
176.742
173.811
174.713
177.915

SELL PRICES
170.21
170.289
170.289
172.071
171.562
174.362
174.362
173.94
175.085
177.154
177.154
170.349
170.349
170.349
176.3
176.742
176.742
173.811
173.811
173.811
174.713

PROFITS FOR HOUR 0
30955.4
48874.9
238.897
22125
22976.2
6182.24
1480.75
762.676
385.431
32235.3
6591.03
16712
275.123
275.123
26251.7
3791.15

```
2382.67
2000.83
1336.27
2458.62
16428.3
```

---

hour :1

load profiles in hour 1

```
Bus no:0   Load:176.44
Bus no:1   Load:157.79
Bus no:2   Load:128.73
Bus no:3   Load:141.43
Bus no:4   Load:211.13
Bus no:5   Load:252.44
Bus no:6   Load:238.45
Bus no:7   Load:185.51
Bus no:8   Load:214.9
Bus no:9   Load:158.25
Bus no:10   Load:984.22
Bus no:11   Load:175.67
Bus no:12   Load:157.97
Bus no:13   Load:138.69
Bus no:14   Load:345.26
Bus no:15   Load:661.24
Bus no:16   Load:379.46
Bus no:17   Load:298.18
Bus no:18   Load:240.95
Bus no:19   Load:213.09
Bus no:20   Load:778.39
Bus no:21   Load:2183.02
Bus no:22   Load:476.54
Bus no:23   Load:284.31
Bus no:24   Load:695.49
Bus no:25   Load:292.35
Bus no:26   Load:74.52
Bus no:27   Load:446.56
Bus no:28   Load:170.59
Bus no:29   Load:1119.18

No of Iteration: 3
time elapsed for matrix operations:3113
Number of line flow violations:0
Number of generator limit violations:0
```

OUTPUT
GENERATOR OUTPUT:

```
1266.42
1755.66
89.457
1010.87
1048.25
472.984
207.427
```

139.041
185.426
1201.65
488.942
834.744
71.7067
71.7067
1120.88
351.371
270.393
280.913
194.598
280.041
792.731

FLOWS:
-176.963
199.825
727.335
968.395
938.836
-141.592
372.547
712.719
294.02
144.126
564.233
644.667
1119.3
410.203
-185.785
278.203
351.988
221.032
353.389
1287.06
250.941
173.522
315.552
-30.3101
875.644
153.841
80.8613
113.052
-160.484
105.174
533.208
93.9277
-115.825
-82.8853
-167.546
-491.983
-266.358
-18.3179

42.5887
-203.303
225.086
-250.681
551.6
351.075

Loses:
1.04587
0.661464
7.30239
12.0481
5.24343
0.323942
1.49295
2.43045
0.835259
0.494466
2.64841
4.38363
11.9586
2.30419
0.550965
2.49569
1.20763
0.265767
0.876986
16.5359
0.279503
0.332083
0.817939
0.386855
24.0123
0.432202
0.355873
0.596622
0.434254
0.511973
5.87825
0.330683
0.398523
1.5926
3.02842
19.2692
0.595771
0.1359
0.234287
0.869899
0.382324
1.68285
14.4624
2.31705

BUS ANGLES:

```
bus angle 1   ;15041.8
bus angle 2   ;-15731.2
bus angle 3   ;-46795.1
bus angle 4   ;-18051.9
bus angle 5   ;-52530.2
bus angle 6   ;-71122.5
bus angle 7   ;-147235
bus angle 8   ;-111564
bus angle 9   ;-69947.7
bus angle 10   ;-119730
bus angle 11   ;-123427
bus angle 12   ;-112143
bus angle 13   ;-128026
bus angle 14   ;-196027
bus angle 15   ;-178642
bus angle 16   ;-202905
bus angle 17   ;-213113
bus angle 18   ;-212414
bus angle 19   ;-194780
bus angle 20   ;-210083
bus angle 21   ;-209621
bus angle 22   ;-203506
bus angle 23   ;-221764
bus angle 24   ;-177522
bus angle 25   ;-205918
bus angle 26   ;-181441
bus angle 27   ;-239277
bus angle 28   ;-220501
bus angle 29   ;-249394
```

EQUALITY LAMBDAS:

```
169.59
168.591
168.67
170.825
170.435
170.458
169.93
173.216
172.703
172.286
171.281
171.051
171.257
174.26
178.116
172.428
172.507
173.42
174.127
176.502
178.815
175.469
168.729
```

174.538
174.623
175.658
175.06
172.158
173.051
176.223

PRICES:

168.591
168.67
168.67
170.435
169.93
172.703
172.703
172.286
173.42
175.469
175.469
168.729
168.729
168.729
174.623
175.06
175.06
172.158
172.158
172.158
173.051

PROFITS FOR HOUR 1
28868.7
45987.4
68.8666
20437
21232.3
5369.14
1110.07
506.512
49.3257
30176.6
5737.55
15329.6
133.688
133.688
24335.7
3172.96
1900.93
1509.29
988.369
1968.41
15082.1

APPENDIX C

NEWTON- RAPHSON METHOD

Equations (43) and (47) in Chapter 4 provide a well-defined environment for Newton-Raphson (NR) Method. Basically, for any function *f(x),* we need an initial guess for the vector x. From this initial value, we approximate the solution with a step function. For this step function, we need the first and second derivatives of f with respect to x such as;

$$y = \frac{\partial f}{\partial x}$$
$$z = \frac{\partial^2 f}{\partial x^2}$$

y is a vector of dimension of (n x 1) and z is a matrix of dimension (n x n). The step function is defined as follows;

$$\Delta x_t = (z(x_t))^{-1} y(x_t)$$

where $y(x_t)$ and $z(x_t)$ means y and z evaluated at x_t. The x vector at step t+1 becomes;

$$x_{t+1} = x_t - \Delta x_t$$

NR method provides a fast convergence to the optimum although it necessitates huge storage and operational space in computer programs. It provides highly robust estimates of the optimum. In our context, for NR solution, we need first and second derivatives of equations (43) and (47). First derivatives evaluated at x_t are;

(50) $y(x_t) = \frac{\partial L}{\partial x}|_{x=x_t}$

This vector constitutes the Jacobian matrix. x_t covers [Q_t θ_t] for fixed demand case while it covers [Q_t θ_t dem_t] for flexible demand case (for equation (47)). Second order derivatives;

(51) $z(x_t) = \frac{\partial^2 L}{\partial x^2}|_{x=x_t}$

$z(x_t)$ is our bordered Hessian matrix and we can write;

(52) $H = \frac{\partial^2 L}{\partial x^2}|_{x=x_t}$

Now, we can define our step function;

(53) $\Delta x_t = H^{-1} y(x_t)$

(54) $x_{t+1} = x_t - \Delta x_t$

APPENDIX D

SOFTWARE FOR NR-BASED OPTIMAL POWER FLOW

After outlining the basic details of our solution procedure, we can explain the basic structure of our program (or programs since we use two different programs for the OPF solution, one for fixed demand case and the other for flexible demand case). The program is written in Borland C++ version 5.02. Although this programming language's graphic utilities are weak, its strong support for object-oriented programming leads us to use it. Object-oriented programming (OOP) is a well-defined, coherent approach to bottom-up modeling of hierarchies such as electricity network It is very suitable for any analysis focused upon the electricity network since its basic features such as inheritance, overloading etc. can also be observed in the structure of electricity network. Hierarchical structure of the electricity network in the norms of object-oriented programming is given in the Figure D.1.

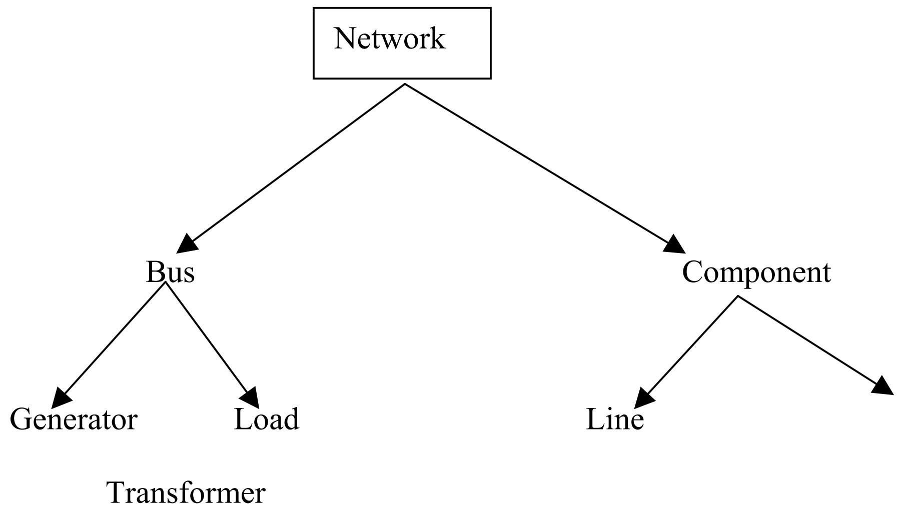


Figure D.1. Basic Structure of the Electricity Network

This structure can be very easily transformed into OOP using C++ language such as follows;

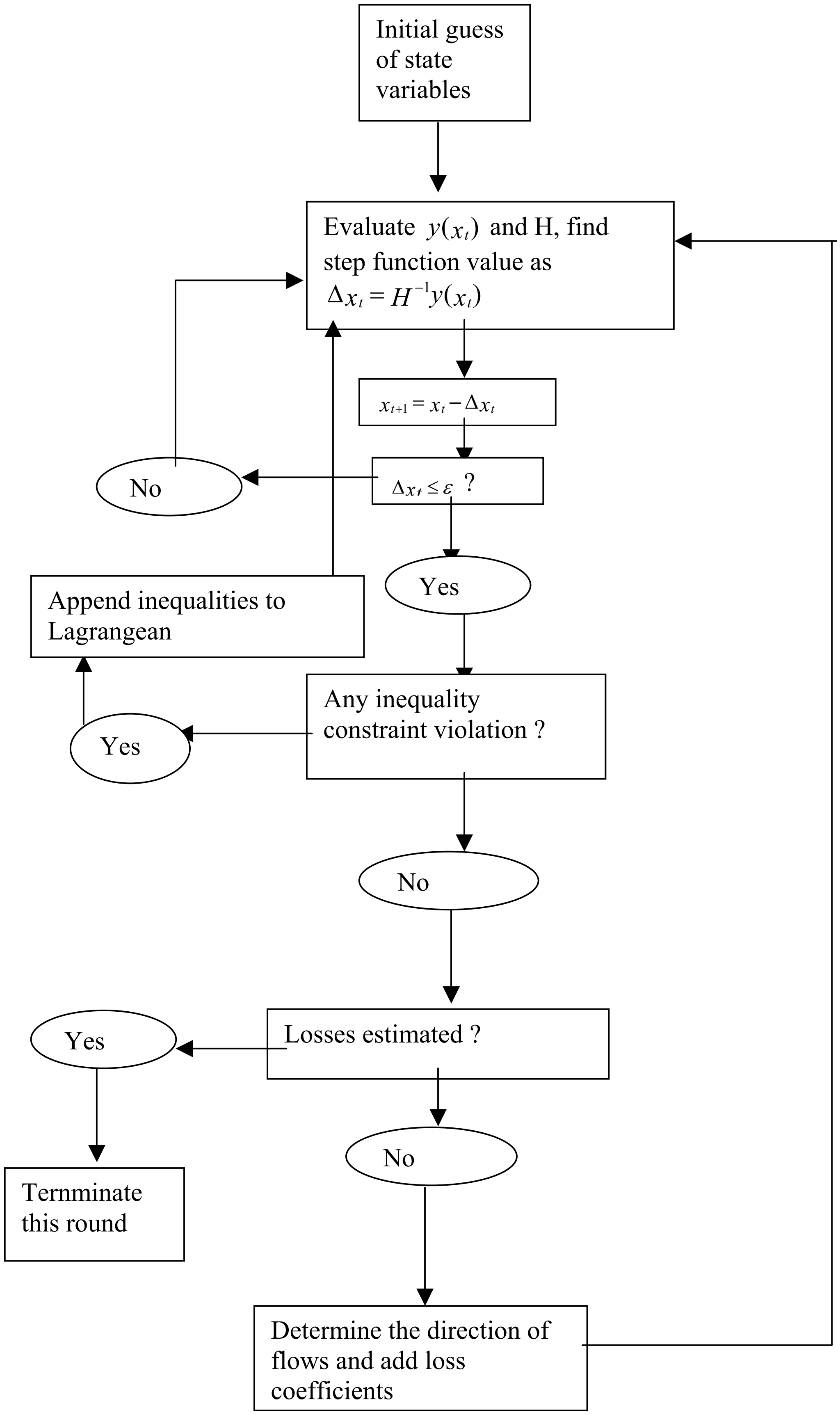
The Basic Structure of the Electricity Network in C++

```
class generator {
... }

class load {
....}

class bus {
generator gen1;
load load1;
....}

class transformer {
...}

class line {
...}

class component {
transformer trans1;
line line1;
}

class network {
bus sbus[20];
component comp[30];
}
```

Electricity network's hierarchical structure can be well outlined by C++. Inheritance and overloading features of OOP provides a good basis for the programming NR solution method. *Inheritance* means that any child, without giving explicit reference, can use its parent's data, functions etc. On the other hand, *overloading* implies that any parent can also use functions written for any one of its children. These two features abandon the need for any strict connotations in the program's structure.

As Figure D.2 indicates, there are three basic loops in the program. In the first one, it solves the model under the assumption that system is lossless and no inequality constraints are binding. When solutions are obtained, it checks for any violation of generator limit or transmission line flow limit. If so, it appends the corresponding inequality constraint to the Lagrangean and solves the model again (inequality constraint is activated). When this loop is terminated, it detects the direction of line flows. Since we assume that transmission line loss is a linear function of flow on it, we necessitate an additional loop to estimate and allocate line losses.

Figure D.2. Algorithm of Core OPF Program



APPENDIX E

ADDITIONAL SIMULATION EXAMPLES

E.1. Individual Welfare Maximization

C2: This case is a complementary case to two cases given above. In this case, two agents control two sets of generator each of which consists two generators, but no one of them is *marginal.* We only give maximum mark-up rates for different pricing schemes in order to show how different pricing schemes affect mark-up pricing behavior of agents. The agents' control sets:

Agent 1 – Gen 0 (Karakaya) and Gen04 (A. Elbistan)

Agent2 – Gen15 (Seyitömer) and Gen20 (Soma)

Table E.1. shows the maximum mark-up rates under both PS1 and PS2.

Table E.1. Maximum Mark-Up Rates under Different Pricing Schemes

	PS1		**PS2**			
			Agent1		**Agent2**	
Hour	**Agent1**	**Agent2**	**Gen0**	**Gen04**	**Gen15**	**Gen20**
0	1.031	1.016	0.994	1.002	1.014	1.002
7	1.029	1.014	0.992	1.001	1.013	1.001
12	1.032	1.016	0.995	1.003	1.015	1.003
16	1.032	1.017	0.995	1.003	1.015	1.003
18	1.033	1.018	0.996	1.004	1.016	1.004
20	1.032	1.017	0.996	1.004	1.015	1.004

Maximum mark-up rates for generators in the same control set are same under PS1 while they differ under PS2. On the other hand, under the full infomation assumption, generators, other than marginal generators, are less inclined to engage in mark-up pricing. Maximum mark-up rates under PS2 are very close to 1 except for the generator 15 which is located very near to marginal generators and has a very high cost. The agent that controls it may try to raise its price in order to make its sell price the system's sell price (for example, under base case, marginal generators' sell price is equal to 181.043 while generator 15's sell price is equal to 180.098 at hour 18). Therefore, except for the ones whose sell prices are very close to the sell prices of marginal generators, generators are induced to submit their true cost curves as offer curves. This is very crucial for the regulator.

C3 and C4: In this section, we examine the impacts of flexible demand upon the maximum mark-up rates of agents. We designate fixed demand case by C3 and flexible demand case by C4. Regulator applies PS1 in both cases. There is only one agent, which controls three generators. The control set of agent is as follows;

- Karakaya (gen0)
- A. Elbistan (Gen4)
- Soma (Gen20)

Table E.2 shows the maximum mark-up rates of the agent under both fixed and flexible demand cases.

Table E.2. Maximum Mark-Up Rate of Agent under Fixed and Flexible Demand Cases

Hour	Max. Mark-Up rate (C3)	Max. Mark-Up rate (C4)
0	1.043	1.017
7	1.039	1.016
12	1.043	1.017
16	1.043	1.017
18	1.046	1.018
20	1.045	1.018

As the table indicates, maximum mark-up rates under flexible demand case are lower than those under fixed demand case. Therefore, we can conclude that consumer participation effectively restricts the maximum mark-ups. We should also look at how would system prices be affected under both cases. Table E.3 shows the change in the average weighted sell and buy prices under C3 and C4 with respect to the base cases under PS1. As the table shows, sell and buy prices change at a higher rate under C3 than C4. Therefore, market power of generators is a more important problem under fixed demand than flexible demand.

Under C3, since demand is fixed, total generation and total loss do not change. On the other hand, under C4, consumers can give response and both total generation and total demand may change. However, in this case, since maximum mark-up rates are low, and since buy prices differ slightly from their base values, total demand, and total generation can not change very much. This may be observed in Table E.4. Table E.5 shows the change in total profits and total consumer surplus in flexible demand case.

Table E.3. Average Weighted Prices under C4 and C5

	C4				C5			
Hour	**Av. W.Sell Price**	**%**	**Av. W.Buy Price**	**%**	**Av. W.Sell Price**	**%**	**Av. W.Buy Price**	**%**
0	174.43	0.68	176.61	0.65	173.22	0.12	175.41	0.12
7	169.52	0.63	171.66	0.60	168.98	0.17	171.08	0.10
12	175.33	0.69	177.51	0.66	174.29	0.17	176.40	0.11
16	175.25	0.69	177.44	0.66	174.95	0.17	177.06	0.11
18	178.41	0.72	180.62	0.69	177.06	0.18	179.21	0.10
20	178.11	0.72	180.32	0.69	176.65	0.17	178.81	0.10

* All prices are in 10^5 TL/MW

Table E.4. Total Generation and Total Demand at Hours 12:00 and 18:00

Hour 12:00	Base	C5
Total Generation	13230.5	13146.0
Total Demand	13063.6	12981.3
Hour 18:00		
Total Generation	14493.9	14401.8
Total Demand	14310.6	14221.0

* All in MW

Table E.5. Change in Total Profits and Consumer Surplus under C4 and C5

	C4		C5			
Hour	Total Profits	%	Total Profits	%	Total CS	%
0	257663.0	5.3	243720.0	-0.2	179189.0	-1.0
7	198016.0	5.1	193633.0	0.0	124669.0	-0.5
12	269688.0	5.3	257720.0	0.3	184645.0	-1.5
16	268663.0	5.3	266566.0	0.3	188015.0	-1.5
18	314066.0	5.4	296272.0	0.4	222561.0	-1.4
20	309481.0	5.4	290367.0	0.4	216828.0	-1.4

* Total Profits and Total Consumer Surplus are in 10^5 TL

As Table E.5 shows, the increase in total profits in fixed demand case is so much higher than that under flexible demand case. As a conclusion, one can indicate that the consumer participation limits the exercise of the market power on the generation side.

Mark-Up pricing on the Consumer Side

In this section, any group of consumers combined under a cooperative agent can use mark-up pricing such that the group can multiply its bid curve (its benefit curve) with the corresponding maximum mark-up rate and thus changes the slope and the intercept of the marginal benefit curve. Therefore, this group reduces the buy price it pays to the regulator and, hence, increase group's combined consumer surplus. Although this result is beneficial for consumers, it is not an efficient result in economic terms. This procedure assumes that the consumers using this procedure act as monopsonists in their regions. We use two examples to analyze the effects of consumer side playing.

C5: In this case, there is only one cooperative agent, which controls the consumers at following busses. Regulator applies PS1. IWM finds minimum mark-up rates in this case.

- Bus 15
- Bus 19
- Bus 20
- Bus 21

Minimum mark-up rates are less than 1. Table E.6 shows the minimum mark-up rate for the cooperative agent. As the table shows, the minimum mark-up rate of a group consisting only of consumers moves in reverse direction with maximum mark-up rate of a group consisting only of generators. As β and α parameters increase, maximum mark-up rate of a group consisting of only consumers decline. This can be observed in table E.6.

Table E.6. Minimum Mark-Up Rates of Agent for Various Hours

Hour	Maximum Mark-up Rate
0	0.979
7	0.982
12	0.978
16	0.978
18	0.976
20	0.977

Since demand is flexible, such a mark-up will certainly affect total demand and total generation. Table E.7 shows the change in total generation and total demand compared to base case under, and also total loss.

Table E.7. Total generation, Demand and Loss under C5

Hour	Total Generation	%	Total Demand	%	Total Loss
0	12633.2	-1.2	12478.6	-1.1	154.6
7	10727.7	-0.8	10593.1	-0.7	135.5
12	13152.4	-0.6	12993.9	-0.5	159.9
16	13450.9	-0.6	13289.0	-0.5	163.4
18	14399.6	-0.7	14225.8	-0.6	175.4
20	14216.0	-0.6	14043.6	-0.6	173.6

* Total Generation, Total Demand and Total Loss in MW

As Table E.7 indicates, both total generation and total demand decrease as a result of mark-up pricing on the consumer side. Table E.8 shows how would this situation affect sell and buy prices across the system compared to the base case under PS1.

Table E.8. Average Weighted Sell and Buy Prices under C5

Hour	Av. W. Sell Price	%	Av. W. Buy Price	%
0	172.68	-0.19	174.82	-0.22
7	168.51	-0.11	170.56	-0.21
12	173.77	-0.13	175.79	-0.23
16	174.42	-0.13	176.45	-0.24
18	176.50	-0.14	178.57	-0.26
20	176.10	-0.14	178.17	-0.26

* Weighted Prices are in 10^5 TL/MW

As one can see, because of decline in generation and demand, sell and buy prices decline as well. Although the rate of decrease seems very low, the impact of such a decrease upon social welfare is considerable. Table E.9 shows the change in total profits and total consumer surplus under C5 with respect to the flexible demand base case with PS1.

As a consequence of mark-up pricing on the consumer side, total profits decline while total consumer surplus increases. The cost of this socially beneficial development is the foregone demand and generation. We should also look at the bus level changes. Table E.10 shows the change in welfare of the consumers living at the busses controlled by the cooperative agent.

Table E.9. Total profits and Total Consumer Surplus under C6 (&)

Hour	Total Profits	%	Total CS	%
0	237514.0	-2.7	227865.8	1.56
7	189099.0	-2.3	161336.4	1.38
12	251309.0	-2.2	239105.5	1.53
16	259944.0	-2.2	245653.8	1.56
18	288681.0	-2.1	289471.8	1.50
20	282966.0	-2.1	283358.2	1.47

* Total profits and Total Consumer Surplus are in 10^5 TL

Table E.10. Change in Demand and Surplus of Consumers in Agent's Control Set

Bus no.	Demand (Base)	Demand (C6)
15	796	705
19	266	183
20	945	862
21	2647	2539
Total	**4653**	**4289**
Bus no.	**CS (Base)**	**CS (C6)**
15	13293	13444
19	1660	1586
20	21412	21653
21	126097	127056
Total	**162462**	**163739**

* Demand in MW, Consumer Surplus in 10^5 TL

As the table indicates, the rate of increase in the combined consumer surplus extracted by cooperative agent is not as high as the rate of increase in total consumer surplus but there is a considerable increase in consumer surplus of the agent. Moreover, as we know that the general increase in consumer surplus is at a rate about 2.4%, we can conclude that groupings, as in our example, are beneficial for the social welfare. However, they are not Pareto efficient.

C6: In this case, we look for the effects of a mixed group i.e. a cooperative controls three generators and three consumers. Its basic aim is to maximize the sum of profits and consumer surplus of the units he controls. Regulator applies PS1. The control set of the agent is as follows:

- Gen 0 (Karakaya)
- Gen 04 (A. Elbistan)
- Gen 20 (Soma)
- Bus 15
- Bus 19
- Bus 20

In this case, agent should face a dilemma. If he chooses a maximum mark-up significantly higher than 1, the outputs of other generators increase and sell prices increase across the system. This adversely affects the consumer surplus of the consumers, which he controls. On the other hand, if he prefers a mark-up significantly lower than 1 for the consumers in his control set, then, total demand, and consequently total generation falls and the combined profits of the generators that he controls fall. Moreover, the structure of the control set is highly balanced (3 generators, 3 consumers). The maximum mark-up set is very sensitive to this structure. For our case, table E.11 shows maximum mark-up rates. As the table indicates, maximum mark-up rate for the agent is very close to 1. Hence, we can conclude that maximum mark-up rates of a group consisting of both generators and consumers can be very close to 1 and it is reasonable for an agent controlling such a set to offer and bid at true cost and true benefit curves. This example points to the important issues about privatization. It may be argued that if political authority is insistent upon the privatization of the electricity sector, it can sell a considerable part of the generation assets to cooperative bodies or municipalities which represent local consumers. By such a way, it may limit the exercise of market power by private companies holding generation assets.

Table E.11. Maximum Mark-up Rate of Agent

Hour	Maximum Mark-Up Rate
0	1.00717
7	1.0071
12	1.00723
16	1.00717
18	1.00714
20	1.00713

E.2. Distributional Monpolies

D2: In the second example, distribution price is regulated such that regulator applies a price cap of 175 to distribution price (dprice = 175). This is an effective price cap since it is higher than the buy prices of all distributors at every hour but less than the drpices of all distributors. We can observe the results in table E.12, which show buy prices and dprices for all distributors at hour 18 under D1.

There are great disparities between buy prices and dprices of distributors. The price cap selected by the regulator is less than most of the dprices and, hence, under price cap, distributors also make positive profits but most of them should face a decline in their profits. Table E.13 shows the change in total consumer surplus and total distributional profits with respect to case D1.

Table E.12. Buy Prices and Dprices for Distributors under D1 at Hour 18:00

Bus No	Buy Price	Dprice	Bus No	Buy Price	Dprice
0	165.8	175.2	15	168.5	189.8
1	164.8	173.9	16	169.2	183.6
2	165.0	173.0	17	170.1	181.8
3	167.0	175.6	18	171.2	182.0
4	166.6	177.3	19	172.1	183.2
5	166.7	177.8	20	172.9	201.2
6	166.2	177.1	21	169.7	222.9
7	169.2	179.0	22	163.2	180.6
8	168.7	179.5	23	170.8	182.4
9	168.4	176.9	24	171.4	191.7
10	167.6	194.5	25	174.6	185.8
11	167.3	177.2	26	172.8	178.8
12	167.4	176.6	27	170.7	185.4
13	170.2	178.7	28	171.7	179.4
14	173.7	188.2	29	174.7	205.1

* All prices are in 10^5 TL/MW

Table E.13. Change in Total Consumer Surplus and Total Distributional Profits after Price Cap on Distribution Price

Hour	Total CS	%	Total D. Profits	%
0	157370	110.6	76433	-57.9
7	93021	85.2	74510	-42.0
12	166446	121.3	67854	-63.5
16	173345	125.7	64811	-66.1
18	217797	145.4	52839	-76.1
20	209546	141.9	55349	-74.4

* Total Consumer Surplus and Total Distributional Profits are in 10^5 TL

Table E.13 proves that price cap on distribution price is very effective and total consumer surplus rises at about a rate more than 100% while total distributional profits fall by a large amount. Therefore, we can indicate that regulator should strictly regulate the distribution prices by means of price caps.

E.3. Bilateral Contracts

In this section, we attempt to find out the effects of bilateral contracts upon the model variables. Under the fixed demand case, the effects are limited only to monetary variables while under flexible demand case, since it affects both demand and generation, that is, the real variables are also affected. We review four experiments. In the first one, 11 generators make 150-MW contracts with various busses, which cover all the day under fixed demand case. We try experiment with PS1. In the second one, four generators make 4 250-MW contracts with four different busses with high base demands under the flexible demand case. In the third one, we look at the effects of contracts upon maximum mark-up rates under the fixed demand case, while in the fourth one; we do the same thing for the flexible demand case.

CT1: In this, case we make three different experiments. In the first one (CT11), eleven generators make 150-MW contracts with different busses at the contract price of 173. These contracts cover the whole daytime. In the second experiment (CT12), we raise the contract price to 177. In the last one (CT13), we raise the contract amount of ten generators to 200 MW but keep the contract price at 173.Regulator applies PS1. Table E.14 and E.15 show the average weighted sell and buy prices of three experiments and of fixed demand base case with PS1.

As Table E.14 and E.15 show, the largest decrease in average prices is under CT12. We should note that the selection of contract amount and price is very crucial. We should also look at the generator level sell prices in order to find out the effects of contracts.

Table E.14. Average Weighted Sell Prices under Different Cases

Hour	Av. W. Sell Price(Base)	Av. W. Sell Price(CT11)	Av. W. Sell Price(CT12)	Av. W. Sell Price(CT13)
0	173.25	173.18	173.69	173.17
7	168.46	169.02	169.63	169.20
12	174.12	173.87	174.36	173.79
16	174.05	173.80	174.30	173.73
18	177.13	176.56	177.01	176.39
20	176.83	176.33	176.78	176.16

Table E.15. Average Weighted Buy Prices under Different Cases

Hour	Av. W. Buy Price(Base)	Av. W. Buy Price(CT11)	Av. W. Buy Price(CT12)	Av. W. Buy Price(CT13)
0	175.47	175.28	175.80	175.24
7	170.64	171.05	171.67	171.21
12	176.35	175.94	176.44	175.84
16	176.28	175.87	176.38	175.78
18	179.38	178.65	179.11	178.46
20	179.08	178.41	178.87	178.23

Table E.16 shows the change in profits of all generators with respect to the base case with PS1. “X” indicates the contracting generator. As the table shows, since contract price under CT11 and CT13 is very low compared to the generators’ sell prices under the base case with PS1, most of the generators’ profits falls below their base case value. Some of them drop at very high amounts. Despite this feature, generators generally use contracts against the volatility in system prices. On the other hand, when contract price is raised to 177, most of the contracting generators increase their profits since this price is higher than their sell prices. Table E.17 shows the change in total profits under three cases compared to the base case with PS1.

Table E.16. Profits of Generators after Contracting at Hour 18

Gen No.	Bus No.	Contract	Profit (CT11)	%	Profit (CT12)	%	Profit (CT13)	%
0	1	X	35732	-0.8	36332	0.8	35732	-0.8
1	2	X	55456	-0.7	56056	0.4	55412	-0.8
2	2		795	-3.0	795	-3.0	795	-3.0
3	4	X	25712	-2.1	26312	0.2	25576	-2.6
4	6	X	26755	-1.8	27355	0.4	26645	-2.2
5	8	X	7453	-10.1	8053	-2.9	7199	-13.2
6	8		2507	-1.6	2507	-1.6	2507	-1.6
7	9		1523	-2.0	1523	-2.0	1523	-2.0
8	17	X	938	-28.8	1538	16.8	508	-61.5
9	21	X	35881	-3.7	36481	-2.0	35486	-4.7
10	21	X	7520	-14.4	8120	-7.6	7124	-18.9
11	22	X	19864	-1.3	20464	1.7	19816	-1.6
12	22		772	-2.8	772	-2.8	772	-2.8
13	22		772	-2.8	772	-2.8	772	-2.8
14	24	X	30619	-4.2	31219	-2.3	30227	-5.4
15	26		5131	-1.1	5131	-1.1	5131	-1.1
16	26		3459	-1.4	3459	-1.4	3459	-1.4
17	27		3361	-1.5	3361	-1.5	3361	-1.5
18	27		2354	-1.6	2354	-1.6	2354	-1.6
19	27		3817	-1.3	3817	-1.3	3817	-1.3
20	28	X	19020	-4.9	19620	-1.9	18736	-6.3

Table E.17. Total Profits under Contracting Compared to Base Case

Hour	Total Profits (CT11)	%	Total Profits (CT12)	%	Total Profits (CT13)	%
0	243782	-0.4	250382	2.3	243770	-0.4
7	194260	3.1	200860	6.6	196290	4.2
12	252526	-1.4	259126	1.2	251554	-1.8
16	251679	-1.3	258279	1.2	250744	-1.7
18	289439	-2.9	296039	-0.6	286951	-3.7
20	286045	-2.6	292645	-0.3	283688	-3.4

As the table indicates, since both of the contract prices are higher than sell prices of many generators at hour 07, contracting at these prices raises total profits at hour 07. On the other hand, since both contract prices are lower than sell prices at hours after 18, total profits decline in all the cases. The selection of the contract price is very important for generators and consumers. Any high contract price may induce firms to contract higher shares of output and as a result contract prices rise. Any lower price may deter generators to make contracts. Table E.18 shows the change in ISO's income under three different cases. We should remind that under base case with PS1, ISO makes zero profits.

Table E.18. ISO's Income After Contracting

Hour	ISO Inc(CT11)	ISO Inc(CT12)	ISO Inc(CT13)
0	-1534	-1534	-1995
7	-1549	-1549	-1938
12	-1966	-1966	-2279
16	-1961	-1961	-2274
18	-2139	-2139	-2454
20	-2121	-2121	-2436

The contracted output is traded outside the operational domain of the regulator. Therefore, as long as contracted output remains the same, the level of contract price does not affect the regulator's income. Since the share of contracted output to total output under CT11 and CT12 are same and not so much high (about 13%), sell and buy prices do not change among these cases so much. Regulator's income falls to negative under three cases. It is same under CT11 and CT12. On the other hand, since contracted output increase from 1650MW under CT11 and CT12 to 2150 MW under CT13, regulator's income falls further under CT13.

CT2: We assume that demand is flexible and four major generators make 300MW-contracts with four different busses as following:

- Gen0- Bus 20
- Gen01-Bus10

- Gen09-Bus21
- Gen20-Bus29

Again, regulator applies PS1 and the contract price is 173. Table E.19 shows the change in average weighted prices with respect to the flexible demand base case with PS1.

Table E.19. Average Weighted Sell and Buy Prices after Contracting

Hour	Av. W. Sell Price	%	Av. W. Buy Price	%
0	171.94	-0.62	173.55	-0.95
7	168.96	0.16	170.21	-0.40
12	173.70	-0.16	174.30	-1.09
16	174.21	-0.25	175.36	-0.86
18	175.96	-0.45	177.51	-0.84
20	175.61	-0.42	177.10	-0.84

As Table E.19 proves, the impact of contracting is more significant under the flexible demand case than under the fixed demand case. Both sell and buy prices fall. In this case, as opposed to the case under fixed demand, total generation, total demand and total loss also change. Table E.20 shows the change in these macro variables with respect base case.

Table E.20. Change in total Demand and Total Generation After Contracting

Hour	Total Generation	%	Total Demand	%
0	13422	5.01	13295	5.34
7	11622	7.51	11532	8.07
12	13997	5.80	13870	6.17
16	14219	5.08	14078	5.36
18	15070	3.97	14916	4.23
20	14905	4.18	14753	4.43

Total generation and total demand increase and this increase is due to the decrease in sell and buy prices. Since sell and buy prices decrease, consumers increase their demands and, by this way, they indirectly increase total generation. Table E.21 shows the change in total profits after contracting with respect to the base case with PS2.

Table E.21. Total profits and Total Consumer Surplus after Contracting

Hour	Total Profits	%
0	230352	-5.68
7	194989	0.71
12	249997	-2.69
16	257253	-3.17
18	281078	-4.72
20	276320	-4.44

As the table indicates, total profits fall and total consumer surplus increases after contracting. This is due to the low contract price; a higher price may result in a reverse situation. Table E.22 shows the effects of contracting on bus and generator level compared to the base case. The busses and generators in table are the sides of the contracts.

Table E.22. Profits and Consumer Surplus of Contractors at Hour 18

Gen No.	Profit	%	Bus No.	Consumer Surplus	%
0	34440	-3.3	**10**	27882	6.9
1	53863	-3.0	**20**	25380	18.5
9	35663	-3.5	**21**	130604	3.6
20	17354	-10.8	**29**	91899	5.1

As one can see, profits of contractor generators decline as consumer surplus of contractor consumers increase. We should again note that this depends on the contract price. Regulator should induce agents to make low-price contracts.

CT3: In this fixed demand case, there is one agent, which controls four generators and runs his individual welfare maximization algorithm to find maximum mark-up rates for the generators. Each generator makes 200MW contracts with four busses. Regulator applies PS1. Agent's control set and contract positions are as follows:

- Gen0 – Bus10
- Gen04- Bus20
- Gen10- Bus21
- Gen 20- Bus29

This control set is the same as in C1 under section 5 and contract price is 173.

Table E.23. Maximum Mark-Up Rate of Agent under C1 and CT3

Hour	Max. Mark-up Rate(C1)	Max. Mark-up Rate(CT3)
0	1.05092	1.03966
7	1.04611	1.03571
12	1.05181	1.04086
16	1.05173	1.04198
18	1.05483	1.04357
20	1.05453	1.04269

Table E.24. Average prices under CT3 and Rate of Changes with respect to C1

Hour	Av. W. Sell Price	% of C1	Av. W. Buy Price	% of C1
0	174.52	-0.28	176.57	-0.37
7	169.85	-0.09	171.87	-0.19
12	175.38	-0.31	177.44	-0.40
18	178.40	-0.37	180.48	-0.46
20	178.07	-0.38	180.16	-0.47

Table E.23 shows the maximum mark-up rates of agent under C1 and CT3. Contracting effectively reduces maximum mark-up rates. This is the most important feature of contracts. The maximum mark-up rate of any generator is reduced since contracted output limits the usable installed capacity of the generator. Table E.24 shows the change in average weighted prices with respect to C1. As the table shows, both sell and buy prices fall compared to C1. Table E.25 shows the change in total profits with respect to C1.

Table E.25. Total Profits under CT3 and The Rate of Change with respect to C1

Hour	Total Profits	%
0	259238	-1.96
7	202099	-0.35
12	270814	-2.18
16	269826	-2.16
18	314195	-2.63
20	309280	-2.73

Total profits, in this case, decrease compared to C1. Therefore, we can conclude that contracting may provide good means of limiting the exercise of market power. On the other hand, contracts may provide another source of market power as Newberry indicates (Newberry, 1999). Any generator holding a large share of contracted output may affect contract price.

C4: In this case, one agent controls four consumers at four different busses. Three of the busses make 300MW contracts with three generators. Regulator applies PS1. The set of busses and contracts are as follows:

- Bus 15- Gen04
- Bus19
- Bus 20-Gen14
- Bus21-Gen01

This control set is the same as control set in C6. Therefore, in order to find out the effects of contracting upon minimum mark-up rates, we should compare this case with C6. Table E.26 shows the agent's minimum mark-up rates under C6 and CT4.

Table E.26. Minimum Mark-up Rates under CT4 and C6

Hour	Maximum Mark-up Rate (C6)	Maximum Mark-up Rate(CT4)
0	0.9785	0.9842
7	0.9816	0.9874
12	0.9783	0.9839
16	0.9781	0.9837
18	0.9765	0.9820
20	0.9768	0.9823

Contracting increases the minimum mark-up rate of a group consisting of consumers. Consumers, making contracts at low prices, do not reduce their mark-up rates further. The change in total profits and total consumer surplus with respect to C6 is given in table E.27

Table E.27. Change in Total Consumer Surplus and Total Profits w.r.t. C5

Hour	Total CS	%	Total Profits	%
0	317681	39.4	239135	0.7
7	246597	52.8	194303	2.8
12	330069	38.0	251855	0.2
16	337336	37.3	259906	0.0
18	383469	32.5	286789	-0.7
20	376978	33.0	281428	-0.5

Total consumer surplus increases at a huge amount relative to case C1. Hence, we can conclude that contracts at large amounts at low contract prices increase the minimum mark-up rates for consumers and also more safe ways to increase consumer surplus.

E.4. Regulation

R1: In this case, regulator applies a price floor to buy prices and price cap to sell prices. It applies PS1. We make this experiment both under fixed

(R11) and flexible demand cases (R12). Table E.28 and E.29 give the change in average weighted sell and buy prices with respect to the base case with PS1 values. Price floor is 172.5 while price cap is 177.

Table E.28. Change in Average Prices under R11

Hour	Av. W. Sell Price(R11)	%	Av. W. Buy Price(R11)	%
0	173.23	-0.01	175.60	0.07
7	168.46	0.00	172.54	1.12
12	173.93	-0.11	176.40	0.03
16	173.88	-0.10	176.33	0.03
18	175.78	-0.76	179.38	0.00
20	175.67	-0.66	179.08	0.00

Table E.29. Change in Average Prices under R12

Hour	Av. W. Sell Price(R12)	%	Av. W. Buy Price(R12)	%
0	173.01	0.00	175.45	0.13
7	168.69	0.00	172.90	1.17
12	173.83	-0.09	176.32	0.06
16	174.31	-0.19	176.93	0.03
18	175.63	-0.63	179.01	0.00
20	175.43	-0.52	178.61	0.00

Price floor becomes effective especially at night hours since most of the buy prices are lower than 172.5. On the other hand, price cap becomes effective especially after hour 12, since most of the generators' sell price exceeds the price cap.

Price cap and price floor are effective means of restricting profits and consumer surplus. Table E.30 shows the change in total profits compared to the base cases with PS1. As the table indicates, when price cap becomes effective, total profits decrease at a considerable amount. Table E.31 shows the change in total consumer surplus with respect to the base case.

Table E.30. Total Profits under R11 and R12

Hour	Total Profits(R11)	%	Total Profits(R12)	%
0	244447	-0.11	244218	0
7	188413	0	193613	0
12	253520	-0.99	254862	-0.79
16	252833	-0.89	261064	-1.73
18	278189	-6.64	278798	-5.49
20	276761	-5.75	276046	-4.54

Table E.31. Change in Total Consumer Surplus

Hour	Total CS	%
0	221448	-1.3
7	137813	-13.4
12	234115	-0.6
16	241174	-0.3
18	285181	0
20	279242	0

Price cap becomes effective at daytime hours while price ceiling generally is activated at nighttime. Therefore, at daytime, total profits decline and, at nighttime, total consumer surplus declines. Regulator, keeping the disparities among nighttime and daytime sell prices in mind, should select effective price caps. Table E.32 shows ISO's income under R11 and R12. ISO's income under the base case is zero for all hours.

Table E.32. Regulator's Income under R11 and R12

Hour	ISO Inc(R11)	Iso Inc(R12)
0	900	2922
7	20213	21328
12	3245	3428
16	3022	5300
18	19780	16205
20	16872	13124

APPENDIX F

GENETIC ALGORITHM SOLUTION METHOD

In GA, all the parameters are encoded in binary code consisting 1's ans 0's. For example, any parameter x is encoded in binary string as follows;

1011101

in which every place in this string is called a *gene* and the value of that place is called an *allele.* This string is called a *chromosome*. The solution of the problem necessiattes a set of such chromosomes and this set is called a *population*. Beginning with an initial population, GA algorithm applies some operators to the chromosomes in a population and a new population is created. Each new poulation is called a *genearation*. We should note that, if the number of parameters is more than 1, then, any chromosome will consist of more than one encoded parameter like follows;

10…..01|01……1

in which the dashed line divides the places for two different parameters. All the encoded parameters are decoded and entered as inputs to the model. The value of the objective function obtained with a decoded parameter set is assigned as the fitness value of corresponding chromosome.

After each chromosome's fitness value is assigned, simple operators of GA are applied to this population. Simple operators are reproduction, crossover and mutation.

Reproduction: In the natural genetic evolution process, the most powerful genetic transmission mechanism is reproduction. In this mechanism, the chromosomes having highest probablity to live are transmitted to the next generation at a gretaer number while chromosomes with lowest probability are reproduced at lower numbers. Inspired from this process, GA's reproduction operator reproduces the chromosome which has higher fitness value (or lowest fitness value if the problem is a minimization problem) in next generation. We will use roulette wheel reproduction algorithm as follows;

Step 1: Sum up all fitnesses.

Step 2: Generate a random real number between 0 and 1.

Step 3: Multiply total fitness with random number.

Step 4: Begin to add up the fitnesses of chromosomes beginning from chromosome number 0. Add up until the sum exceeds the product of total fitness and the random number.

Step 5: Select the last added up chromosome and transfer it to next generation.

By this way, we can select the chromosomes having higher fitness values.

Crossover: In nature, a pair of species may crossover their genes and the result could be two new species that have higher living probablities. In GA, we select two chromosomes randomly and crossover some genes between them. The procedure is as follows:

Step 1: Randomly select two chromosomes.

Step 2: Determine a crossover probability between 0 and 1.

Step 3: Randomly generate a number between 0 and 100. Divide it by 100.

Step 4: If this number is greater than crossover probability, then, go to step 5. Else go to exit.

Step 5: Randomly select a crossover position. Crossover all genes up to crossover position between two chromosomes.

For example following are the two chromosomes chosen randomly and crossover position is 3.

101|1010

011|0001

Dashed line indicates the crossover position. After crossover, two new chromosomes will be as follows:

011|1010

101|0001

By this way, we can create chromosoemes having higher fitness values.

Mutation: Two operators explained above only transmits the genetic material to the next generation, they do not inject new genetic material to the population. In real natural evolution, sometimes, unanticipated external factors may change the gene in any chromosome and, although with a low probablity, this mutated gene is transmitted to the next generations. In GA, mutation operates as follows;

Step 1: Determine a mutation probability between 0 and 1 (generally this probability is very low i.e. 0.01 or 0.02).

Step 2: Select the gene in order (trace all the genes).

Step 3: Generate a random number between 0 and 100. Divide it by 100.

Step 4: If this number is less than or equal to the mutation probability go to step 5. Else go to step 2.

Step 5: If the allele of the gene is 0, change it to 1. Else change it to 0.

Step 6: If there are remaining genes, go to Step 2. Else exit.

All the genes are traced and a few of them may be mutated. This mechanism, as against to previous two operators, injects new genetic material into the population.

These are the simple operators applied in standard GA but there are some complex operators also. After all these operators are applied at generation T, new population at genartion T+1 is created. This process continues until a predetermined number of generations is attained. After a new population is created, the fitness value of each chromosome is assigned and same operators are applied.

There are some enhanced operators. We will use some of them. The first one is the linear scaling. Linear scaling is applied in order to prevent the early domination of a chromosome or chromosomes having high fitness values. The main objective of GA is to find multiple equilibria; however, any such domination may direct the search algorithm to one equilibrium. Hence, such high fitness values should be descaled while low fitness values are scaled up. We will use the fitness scaling applied by Numnonda and Annakkage (Numnonda and Annakkage, 1999:217) as follows:

(1) $F=aF^1+b$

where;

$F^1=(F_{max}-F)/(F_{max}-F_{min})$

$a=F_{avg}/ (F_{max}-F_{min})$

$b= F_{avg} (F_{max}-F_{avg})/ (F_{max}-F_{min})$

in which F_{avg} is the average fitness value for the population, F_{max} is the maximum fitness value and F_{min} is the minimum fitness value. This is applied to all the fitness values in the population.

The other enhanced GA operator is the fitness sharing algorithm. In this case, it is aimed to form niches in which chromosomes having close fitness values are gathered. This is done to obtain multiple equilibria. Traditional reproduction operator tend to discard the chromosomes having lower fitness values but these chromosomes may direct us to a lower local optimum. Hence, traditional reproduction operator may prevent us to reach that lower optimum.

We will first describe fitness sharing mecahnism (for more details, see Weber, 1999). The sharing parameter is:

(2) $$\sigma_{share} = \frac{\sqrt{\sum_{m=1} (k_m^{\max} - k_m^{\min})}}{2\sqrt[p]{q}}$$

where p is the number of the parameters estimated, q is the expected number of local maxima. k^{max} and k^{min} are the maximum and minimum values for parameters respectively. Then, phenotypic distance metric is:

(3) $$d(k_i, k_j) = \sqrt{\sum_{m}^{p} (k_j^m - k_i^m)^2}$$

This distance metric gives the distance between two parameter sets each consisting of p parameters.

Then, the sharing function for each d_{ij} is as follows;

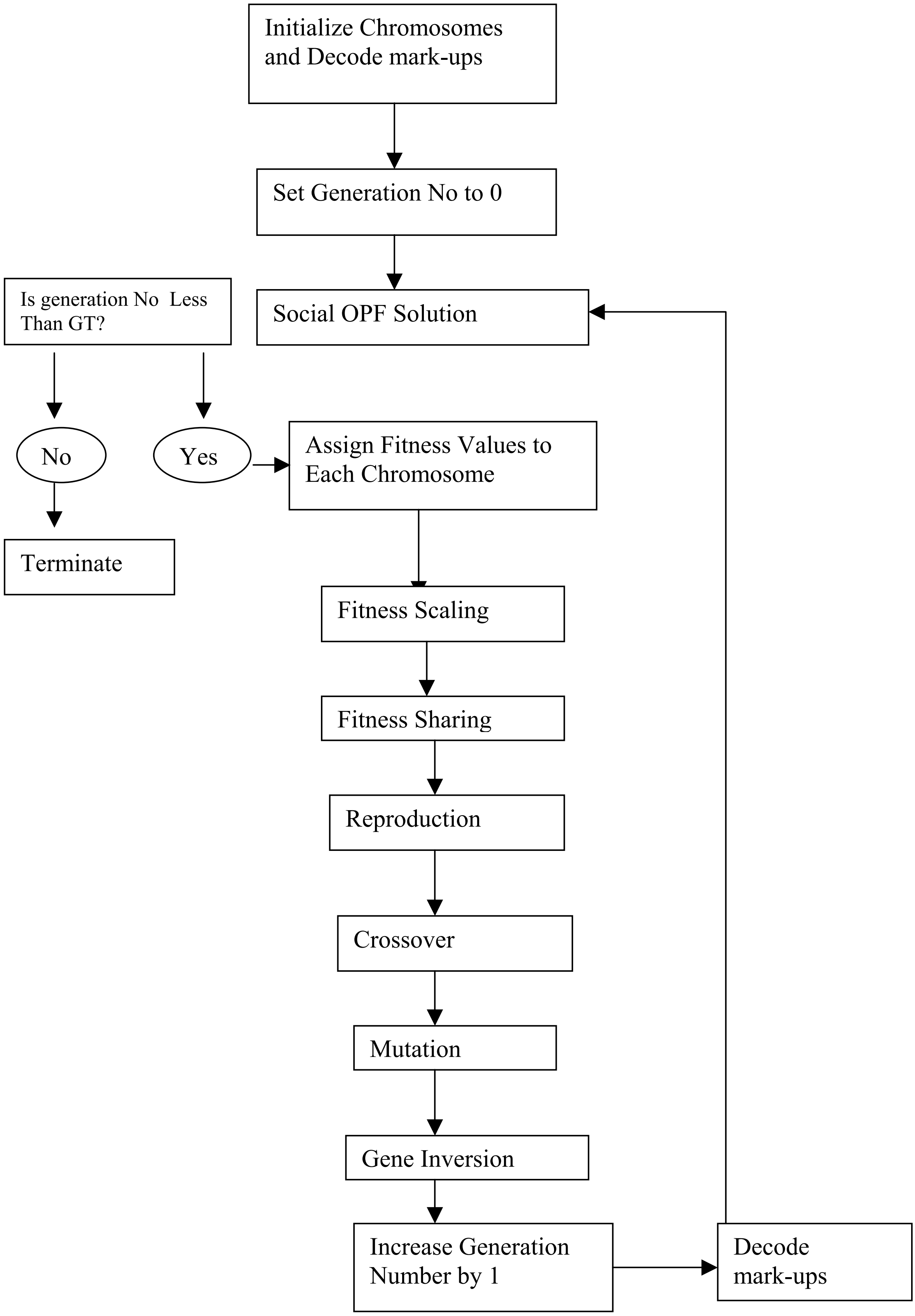
$$(4) \qquad Sh(d_{ij}) = \begin{cases} 1-\left(\dfrac{d_{ij}}{\sigma_{share}}\right)^{\alpha} ; d_{ij} < \sigma_{share} \\ \\ 0.................; d_{ij} \geq \sigma_{share} \end{cases}$$

Finally, shared fitness value is as follows;

$$(5) \qquad f_{shi} = \frac{f_i}{\sum_{j=1}^{n} Sh(d_{ij})}$$

We transform every fitness value to a shared fitness value and, then, apply reproduction procedure. We also use a gene inversion operator, such that, all the alleles in a gene can be changed with their inverses depending upon a gene inversion probability.

Figure F.1. Genetic Algorithm Enhanced Social Optimal Power Flow



APPENDIX G

TURKISH SUMMARY

Bu çalışmanın amacı Türkiye elektrik sektöründeki serbestleştirme sürecinin olası sonuçlarını incelemektir. Bu inceleme için simülasyon tekniği kullanılmıştır. Simülasyon tekniğinin kullanılma sebebi bu tekniğin elektrik gibi bir ağ (network) ortamında üretilen ve tüketilen, ve depolanamayan, malların kendine has özelliklerinin geleneksel analiz metodları aracılığıyla yeterince incelenebilme olanaklarının kısıtlı oluşudur. İkinici olarak, Türkiye elektrik sektörü serbestleştirme sürecini henüz tamamlamamıştır ve böyle tamamlanamamış süreçlerin incelenmesinde simülasyon teknikleri büyük avantajlar sağlamaktadır.

Pek çok gelişmiş ve gelimekte olan ülke elektrik sektörünü serbestleştirmistir ve pek çoğu da bu konuda ısrarlı olduklarını belirtmiştir. Bu konudaki deneyimler ve ısrar ayrıca uluslararası finans kurluşlarından ve International Energy Agency (IEA) gibi uluslarüstü uzmanlaşmış kuruluşlardan youğun destek görmektedir. Bu örgütlü ısrara kamu malları konusunda değişen akademik söylemin desteğini de eklemek gerekir. Geleneksel kamu mallarının özel ajanlar tarafından daha etkin bir şekilde üretilebileceğini öne süren liberal bir kuramsal çerçeve akademik kurumların pek çoğuna hakim olmuştur. Bu görüşe göre geleneksel kamu malları üzerindeki doğal devlet tekelinin pratik haklı sebepleri bu malların üretiminde kullanılan teknolojilerdeki gelişme tarafından geçersizleştirlimiştir. Bu sebepten özel ajanların bu malların üretimine ve dağıtımına katılabilmeleri ve bu katılımın yasal ve kurumsal temelllerinin atılabilmesi için adımlar atılması gerekmektedir.

Bu kurumsal ve kuramsal dönüşümden etkilenen pek çok ülke elektrik sektörlerini serbestleştirme işlemini tamalamıştır. Bu deneyimlerin ışığında, yeni elektrik piyasası kurgusunun temel özellikleri, ülkeler ararsı farklılıklar gözden kaçırılmadan, şöyle sıralanabilir: 1) Serbestleştirme ilk olarak üretimden başlatılmıştır. Yeni üretim teknolojileri üretimin işletim ve dağıtımdan çok daha önce ve çok daha kolyca serbestleştirilmesine izin vermektedir. Özelleştirme üretimdeki serbestleştirmenin mutlak bir koşulu değildir ancak pek çok ülke bu yolu tutmuştur. Daha önemlisi üretimin özel ajanların katılımına açılmasıdır. 2) İletim serbestleştirme sürecinin genel olarak dışında tutulmaktdır çünkü iletimin teknik altyapısı onun bir doğal olarak kalmasını zorunlu kılmaktadır. 3) Dağıtım kısmen serbestleştirilmekte ancak sıkı bir düzenlemeye tabi tutulmaktadır. 4) Elektriğin serbsetçe ve konrol altında pazarlanabilmesi için serbestleştirme deneyini yaşayan ülkelerin pek çoğunda bölgesel veya ulusal elektrik havuzları (Pool) oluşturulmaktadır. Bu bir çeşit spot piyasa tipidir ve daha çok yeni ve küçük olmasında rağmen gelişmektedir. Bunun yanı sıra fiziksel veya finansal kontrat piyasaları oluşturulmaktadır. 5) Bu kurgunun hiç kuşkusuz en önemli parçası bağımsız sistem işleticileri ve düzenleyici kurumlarıdır. Bu kurumlar politik ve sosyal müdahalelelri en aza indirgeyip, elektrik piyasalarının işleyişini ekeonomik etkinlik kriterlerine öre yönlendirmek ve sistemi kontrol etmek amacını gütmektedirler.

Bu deneyimi yaşayan ülkeler arasında hiç kuşkusuz en öze çarpanı nerdeyse bir serbestleştirme ikonu haline gelen Birleşik Krallık'dır. Bu deneyimde serbsetleştirme öncelikle üretimden başlamış, devletin elindeki üretim varlıklarının bölünerek satılması veya özerkleştirilmesi esası güdülmüştür. Bir elektrik havuzu kurularak bu havuza katılım zorunlu hale getirilmiştir. Ancak serbestleştime sonrası üretimde ortaya çıkan büyük özel firmalar piyasa gücü tartışmalarını gündeme getirmiştir. Diğer taraftan, ABD elektrik sisteminin kendine has özellikleriyle oldukça ayrık bir örnek gibi görünmektedir. Kaliforniya'daki kriz bu ülkedeki serbestleştirme çabalarını paralize etmiştir. İskandinav ülkeleri daha ilginç bir örnek sunmaktadırlar. Bu ülkeler bölgesel bir havuz oluşturmuşlardır. Bu havuz Danimarka'nın katılımıyla büyümüştür ve Almanya da yakın bir gelecekte bu bölgesel havuza katılmayı planlamaktadır. Ancak bu havuz Birleşik Krallık örneğinde olduğu gibi zorunlu bir havuz değildir; yani piyasadaki ajanlar istedikleri takdirde bu havuza katılabilmektedirler. Serbestleştirme konusundaki diğer göze çarpan örnekler Avusturalya ve Yeni Zellanda'dır.

Türkiye serbestleştirme sürecini aslında 1980'lerin başından itibaren başlatmıştır fakat özellikle 1994'e kadar bu süreç oldukça yavaş işlemiştir. 1984'de özel ajanların üretime katılımlarının önü açılmıştır. 1984'deki yasal düzenlemeyle Yap-İşlet ve Yap-İşlet-Devret yatırımlarının önü açılmıştır.

1994'de Türkiye Eelektrik Kurumu (TEK) iki kısıma bölünmüştür: Elektrik iletimi ve üretiminden sourmlu olan Türkiye Elektrik Üretim ve İletimi A.Ş. (TEAŞ) ve dağıtımdan sorumlu olan Türkiye Elektrik Dağıtım A.Ş. (TEDAŞ). Daha sonra TEDAŞ, TEÜİAŞ'a dönüşecektir. Ancak asıl radikal adım 2001 yılında elektrik piyasası yasasının meclis tarafından kabul edilmesiyle atılmıştır. Bu yasa en başta yeni piysadaki ajanları ve bu ajanların piyasada işlem yapabilmeleri için gerekli lisansların koşullarını tanımlamaktadır. Bu yasa ayrıca bu lisanslara ilişkin yasal yükümlülükleri de belirtmektedir.

Yasa bu arada yeni piyasa yapısına ilişkin düzenleyici kurumun yapısını ve yetkilerini tanımlamaktadır. Elektrik Piyasası Düzenleme Kurumu (EPDK) ve Elektrik Piyasası Düzenleme Kurulu yasa tarafından yetkilendirilerek göreve başlamışlardır. Kurul lisansların hangi şartlarda ve verileceklerini belirlemek, gerektiğinde bu lisansları iptal etmekle ve Kurumun faaliyetlerini kontrol etmekle yükümlüdür. Diğer taraftan, Kurum piyasaların günlük işleyişlerini kontrol etmek ve gerektiğinde müdahale etmekle görevlendirilmiştir. Yasanın ardından yayınlanan Elektrik Piyasası Elkitabı yasanın belirlediği çerçeve içinde piyasaların günlük işleyişlerinin nasıl olacağını ve piyasaların birbiriyle ilişkilerini belirlemiştir. Bu elkitabının işaret ettiği piyasa tipi bir kontrat piyasasısıdır. Bu piysada ortaya çıkabilecek olan arz talep dengesizliklerini gidermek için oluşturulan ikinci bir piyasa tipi Dengeleme piyasasısıdır. Birinic piyasada belirli bir kontrat üzerinde analaşan fakat bu kontratın öngördüğü miktardan fazla veya azını alabilecek veya satabilecek ajanlar ikinci piyasaya başvururlar. Her iki piyasa da Ulusal Yük

Merkezi tarafından işletilir. Bu Merkez her santralin üretimini ve her dağıtım şirketinin tüketimin belirler.

Elektrik sektörü serbestleştirmeleriyle ilgili teorik ve ampirik literatür hızla gelişmektedir. Özellikle gelişmiş ülkelerden araştırmacılar bu büyüyen literatüre oldukça sık ve önemli katkılarda bulunmaktadır. Bu literatür yeni piyasa yapısının yarattığı sorunlara cevap bulabilmek amacındadır. Bu sorunlar literatürde belirgin bir takım başlıkların öne çıkmasına yol açmıştır. Bunlardan ilki piyasa gücü sorunudur. Yeni piyasa yapıları bütün kurumsal ve yasal enegellere rağmen piyasa gücünün uygulanmasına yol açıyor gibi görünmektedir. Bu sourn özellikle Birleşik Krallık'da daha yakıcıdır. Piyasa gücü üretimde firmaların oldukça büyük olmasından, iletim hatlarının yam rekabeti sağlayamayacak ölçüde düşük kapasiteye sahip olmalarından ve spot piyasada orataya çıkan enformasyon probleminden kaynaklanmaktadır. Düzenleyici kurumların bunu önlemek için ne yapabilecekleri sorusu bu literatürdeki en temel sorudur. İngiltere ile ilgili çalışmalar ikili kontratların bu sorunu aşmada yardımcı olabilecekleri konusunda hemfikirdir. Ancak ikili kontratlar konusunda karamsar fikirler de vardır. Diğer taraftan spot piyasada tüketici katılımı da piyasa gücünün uygulanmasının enegellenmesi konusunda bir çare olarak öne sürülmektedir. Bütün tüketicilerin "özgür" olduğu bir piyasa ortamı, yani her tüketicin spot piyasada serbestçe, hiç bir aracıya ihtiyaç duymadan pazarlık yapabilecekleri bir piyasa ortamı bütün serbestleştirme deneyimlerinin sonal hedefidir. Tüketici katılım gerçekten ampirik çalışmaların ve bizim simülasyon örnelerimizin gösterdiği gibi üretici firmaların piyasa gücünü uygulamal kapasitelerini sınırlandırmaktadır.

Diğer taraftan iletim kısıtalrının yerel tekellere yol açabilecekleri hem teorik literatürde öngörülmüştür hem de ampirik literatür tarafından kanıtlamıştır. Bu sorunun çözümü ise iletim hatların sıkıca denetlenmesi ve üçüncü şahısların iletim sistemine erişiminin serbestçe sağlanabilmesidir. Ancak bu şartların sağlanabilmesi için işletim sistemine yatırım çok önemlidir ve kimin, nereye yatırım yapacağı sorusu devletin doğrudan müdahalesinin gerekliliğini göstermektedir.

Spot piyasalarda üretici ve dağıtıcı firmaların tekliflerini sistem ileticisine sunuş tarzları ve bu mekanizmanın yarattığı enformasyon problemi bir defa daha piysa gücü sorununu ortaya çıkarmaktadır. Bazı ajanların bu teklifleri sunarken önerdikleri fiyatların ajanların sahip oldukları marjinal maliyetleri veya marjinal getirileri yansıtmaktan uzak olabilecekleri ve bu marjinal büyüklüklerin bu mekanizmanın sağladığı bazı olanaklar sayeseinde mark-up fiyatlamasına tabi tutulabilecekleri bu literatür tarafından kabuıl edilen olgulardır. Bu anlamda sisteme daha fazla ajanın katılması bu türden bir soruna tek çözümmüş gibi görünmektedir. Ancak bu senaryonun gerçekleştiği durumlarda bile enformel kartellerin nasıl önlenebileceği bir sorun olarak ortada durmaktadır.

Bizim simülasyon modelimiz bir spot piyasa varsayımına dayanmaktadır; bir spot piyasa kurulmuştur ve sektördeki bütün ajanlar bu piyasada faaliyet göstermektedirler. Bu spot piyasada üreticiler kendi maaliyet fonksiyonlarını, tüketiciler hipotetik fayda fonksiyonlarını ve dağıtıcılar da kendi toplam getiri fornksiyonlarını teklif fonksiyonu olarak sistem işleticisine sunmaktadırlar. Burada işlem birimi bir saattir ve her ajan 24 saat için bu teklifleri sunar. Bizim hipotetik sistem işleticimiz bu tekliflerden her saat için bir doğrusal olmayan problem kurar ve bu problemi Newton-Raphson metoduyla çözer. Bu doğrusal olmayan problem aslında bir Sosyal Optimal Güç Akımı (Optimal Power Flow) problemidir. Sistem işleticisi bu problemi çözerek hem teknik hem de ekonomik kriterleri göz önünde bulundurmuş olur. Bu modelin her bir saat için çözümü o saatte her ajan için optimal miktarları verir. Bizim modelimiz iletim sisteminde kayıplar olduğunu varsayar. Kayıpların olmadığı bir sistemde optimal çözüm sistemdeki her bus için aynı alış ve satış fiyatını verir. Böylece bütün sistem için tek bir fiyat ortaya çıkmış olur. Ancak bizim sistemimizde her bus için ayrı fiyat ortaya çıkar. Dolayısıyla sistem işleticisi için bir fiyatlama problemi ortaya çıkar. Biziki tip fiyatlama varsaydık. Birincisinde her ajan kendi bulndupğu busın fiyatınıdan alış veya satış yapar. İkinicisindeyse sistem işleticisi elektiriği üretiilerden en yüksek marjinal maliyetten satın alır ve tüketiciye kendi gelirini sıfır yapan bir fiyattan satar. Biz bu iki fiyatlama meknazimasını karşılaştırdık.

Ayrıca piyasadaki herhangi bir ajanın gerçek fayda veya gerçek maliyet fonksiyonu yerine bu fonksiyonun belirli bir mark-up'la çarpılmış halini teklif ettiği durumda ne olacağını gösteren bir prosedür program tarafından çağrılır. Burada sorun optimum mark-up'ları asıl bulacağımızdır. Optimum mark-up'ları yine Newton-Raphson çözüm algoritmasını kullanan bu prosedür bulmaktadır.

Bu modeli programlarken Borland C++ kullandık ve nesne yönelimli programlama metodunu tercih ettik.

Simülasyon örneklerinden çıkna sonuçları genelde özetlersek:

1) Birinci tip fiyatlama ikinciden daha fazla tüketici artığı yatatırken, ikinci tip fiyatlama birinciden daha fazla net sosyal hasıla yaratır.

2) Dışsal şoklar durumunda esnek olmayan talep durumunda sistem fiyatları daha çok oynatarak karşılık verirken, esnek talep duurmunda fiyat ve miktar neredeyse aynı oranda oynar.

3) Üretim segmentine yeni bir santral girişi net sosyal refahı ve tüketici artığını arttırırken, birinci fiyatlama durumunda karlar azalırken ikincisinde artar. Ayrıca bu giriş bazı santralların sıfır üretmesine yol açar.

4) Bazı santralların veya tüketicilerin biraraya gelmesinden doğan enformel birleşmeler bu gruba ait toplam miktarı azaltırken, bu grubun satış fiyatlarını arttırır. Böylece gruba ait toplam kar artmış olur. Ayrıca eğer bu grup sadece tüketicilerden oluşuyorsa gruba ait toplam tüketici artığının artmasına sebep olur. Tüketicilerden ve santrallardan oluşan bir grubun optimum mark-upları bire yakın olur. Ayrıca, talebin esnekleşmesi sadece üretim santrallarından oluşan bir gruba ait optimum mark-upları düşürür.

5) Burslarda bulunan her tüketicinin özgür olması yerine, düzenleyici kurumun her busdaki dağıtım hakkını ayrı bir firmaya verdiği durumda hem toplam üretim hem de toplam tüketim düşer. Ayrıca üretici ve tüketici artığı düşerken dağıtıcal büyük dağıtıcı rantlarına sahip olurlar. Bu anlamda dağtıcı tekelleri sosyal refah açısından zararlıdır.

Sonuç olarak TESS yeni simülasyon çerçevelerine ve uyarlamalara olanak verecek bir simülasyon modeli. Biz bu modeli kullanarak serbestleştirme sonrası Türkiye'de düzenleyici kurumun önüne gelebilecek bazı sorunları irdelemeye çalıştık.

VITA

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