A STOCHASTIC EVALUATION ON THE PROSPECTS FOR THE DIFFUSION OF WIND POWER TECHNOLOGIES AT ALTERNATIVE SITES IN TURKEY

by
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ABSTRACT

A STOCHASTIC EVALUATION ON THE PROSPECTS FOR THE DIFFUSION OF WIND POWER TECHNOLOGIES AT ALTERNATIVE SITES IN TURKEY

The objective of this thesis is to explore wind energy projects under competitive electricity market conditions by performing financial and economic analyses for alternative sites and projects in Turkey. The competitive electricity market model is determined according to the EPSIM model (Kleindorfer *et al.*[12]) with some modifications to reflect Turkish conditions. A Wind Energy Project Evaluation tool (WEPE) has been developed to provide a comprehensive evaluation integrating wind speed data analysis, wind power engineering analysis, financial and economic analyses of wind energy projects, production cost calculation of alternative power generation technologies and simulation of the Turkish competitive electricity market model.

First, wind speed data analysis is performed based on the Weibull distribution by analyzing wind speed data of potentially suitable sixteen sites obtained from the State Meteorological Service. Seven sites with high wind energy potential have been identified through this analysis. Then, the corresponding regional load distribution centers are determined and the load data has been obtained from the National Load Distribution Center. Stochastic time-series techniques based upon ARIMA are used for forecasting the five different regions' loads over a twenty-five year period from 2005 to 2030. Load scheduling and dispatching in the power pool is captured by EPSIM. The model includes generation companies, load management entities and a system operator as involved actors. By making assumptions regarding functioning of the model for the Turkish case, results are obtained through WEPE for a base case reference scenario and eight additional scenarios based on the draft renewable energy law. Economically viable sites are determined, and impacts of a competitive market and of various purchase price guarantees on wind power sale revenues are explored.

ÖZET

TÜRKİYE'DE RÜZGAR GÜCÜ TEKNOLOJİLERİNİN FARKLI BÖLGELERDE UYGULANABİLİRLİĞİ ÜZERİNE STOKASTİK BİR DEĞERLENDİRME

Bu çalışmanın amacı, rüzgar enerjisi projelerinin Türkiye'de alternatif bölge ve projeler için, rekabetçi elektrik piyasası şartlarında finansal ve ekonomik analizlerinin gerçekleştirilerek, incelenmesidir. Rekabetçi elektrik piyasası modeli Türkiye şartlarını sağlaması için bir takım değişikliklerle birlikte EPSIM (Kleindorfer *et al.*[12]) modeline göre belirlenmiştir. Rüzgar veri analizi, rüzgar gücü mühendisliği analizi, rüzgar enerjisi projelerinin finansal ve ekonomik analizi, alternatif elektrik üretim teknolojilerinin üretim maliyetinin hesaplanması ve modelin simülasyonu ile bütünleşik ayrıntılı değerlendirme sağlaması için Rüzgar Enerjisi Proje Değerlendiricisi (WEPE) geliştirilmiştir.

İlk olarak, Devlet Meteoroloji İşleri'nden elde edilen oldukça uygun onaltı bölgenin verileri analiz edilerek, Weibull dağılımına bağlı olarak rüzgar hızı veri analizi gerçekleştirilmiş ve yüksek rüzgar enerjisi potensiyeline sahip yedi yer analiz sonunda belirlenmiştir. Daha sonra, uygun bölgesel yük dağıtım merkezleri belirlenmiş ve yük verileri Milli Yük Tevzi Merkezinden alınmıştır. ARIMA yöntemine bağlı stokastik zaman serileri teknikleri 2005 ile 2030'a kadar ki yirmi beş senelik zaman aralığında beş farklı bölgenin yükünü tahmin etmede kullanılmıştır. Yük çizelgelemesi ve dağıtımı elektrik havuzunda EPSIM dahilinde ele alınmıştır. Model oyuncular olarak, üretim şirketlerini, yük yönetim birimlerini ve sistem operatörünü içermektedir. Modelin Türkiye durumu için çalışması ile ilgili varsayımlar yapılarak ve temel durum referans senaryosunu ve yenilenebilir enerji kanun taslağına dayanan sekiz ek senaryoyu uygulayarak, sonuçlar WEPE aracılığı ile elde edilmiştir. Ekonomik olarak uygun bölgeler belirlenerek, rekabetçi pazarın ve birçok satınalma fiyat garantisinin rüzgar gücü satış gelirleri üzerindeki etkileri araştırılmıştır.

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LIST OF ABBREVIATIONS

ACF	Autocorrelation Function
ANN	Artificial neural networks
AR	Auto-regressive
ARIMA	Auto regressive integrated moving average
AWEA	The American Wind Energy Association
BCR	Benefit-cost ratio
BOT	Built-Operate-Transfer
CRW	Combustible renewables and waste
DEWI	The German Wind Energy Institute
DG TREN	The European Comission's Directorate General for Transport and Energy
DSI	State Hydraulic Works
DWIA	The Danish Wind Industry Association
EIEI	The Electrical Power Resources Survey and Development Administration
EMRA	Energy Market Regulatory Authority
EPSIM	Electric Power Strategy Simulation Model
EWEA	The European Wind Energy Association
G-DUY	Balancing and settlement regulation
IEA	International Energy Agency
IRR	Internal rate of return
LMO	Load management options
MA	Moving average
MAPE	Mean Absolute Percentage Error
MTA	Mineral Research and Exploration Institution
NLDC	National Load Distribution Center
NPV	Net present value
NWCC	The United States National Wind Coordinating Committee
O&M	Operating maintanence

PACF	Partial Autocorrelation Function
PMUM	Market Financial Reconciliation Center
PPA	The power purchase agreement
RMSE	Root Mean Square Error
SIS	State Institute of Statistics
SMA	Seasonal moving average
SMO	Turkish State Meteorological Service
SMP	System marginal price
TEAS	Turkish Electricity and Transmission Company
TEDAS	Turkish Electricity Distribution Company
TEIAS	Turkish Electricity Transmission Corporation
TEK	The Vertically Integrated Public Authority
TFC	Total final energy consumption
TOE	Tons of oil equivalent
TOOR	Transfer of operating rights
TPA	Third party access
TPES	Total primary energy supply
USAID	The United States Agency for International Development
WCF	Wind plant capacity factor
WEPE	Wind Energy Project Evaluation Tool
WPC	Wind plant capacity
WT	Wind turbine

1. INTRODUCTION

The demand for energy is increasing by 1,7 % per year due to the exponential growth of world population, industrialization, technological developments and modern life [1]. All countries have been making an effort to meet the demand of energy since the 20th century particularly focusing on the conventional energy sources. Due to the facts that fossil energy sources are limited and lead to pollutant emissions, there has been a considerable interest in alternative energy sources especially after the two subsequent oil crises in 1971 and 1973. The utilization of renewable energy sources such as solar,wind, biomass and geothermal seemed to be promosing in achieving sustainable clean development. Wind power as a commercial energy source has grown by nearly 29 % annually over the last decade in the world [2,3]. The rapid expansion in recent years is mainly a result of cost, due to the technological improvements, industry maturation and an increasing concern with the emissions associated with burning fossil fuels.

Renewable energy sources play an important role for an ecologically sustainable development as they are free of pollutant emissions. Renewable energy increases the diversity of power generation and over the long run, may replace diminishing fossil fuel resources. According to the IEA (International Energy Agency), the share of renewables in world total primary energy supply (TPES) accounts for between 13 % and 14 %. The annual increase of renewable technologies between 1971 and 2000 is given in Figure 1.1. Conventional renewables supply experienced an annual growth of 2 % over the 30 year period, almost identical to the annual growth in TPES. Nevertheless, the other category in the figure below recorded a much higher annual growth of 9 %. It refers to new renewables including wind, geothermal, solar, tide and others as demonstrated in Figure 1.1.

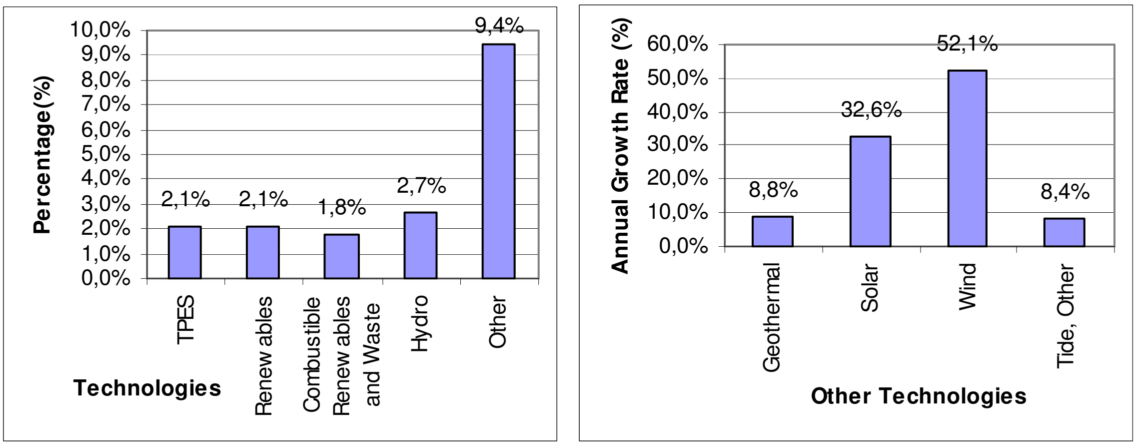


Figure 1.1.Annual growth of renewables and new renewables supply from 1971 to 2000[4]

Wind experienced the highest growth (52 % p.a.) followed by solar (32 % p.a.). According to the IEA's reference scenario, assuming the continuation of present policies and no major breakthrough in technologies, renewables would grow by 1.3 % per year over the next 25 years. With respect to this scenario, the world share of renewable energy would decline from 13.8 % in 2000 to 12.5 % in 2030. This is principally due to a slowdown in the growth of Combustible Renewables and Waste (CRW), caused by the shift from traditional biomass to modern forms of energy in developing countries, and some reduction in the growth of hydropower (to 1.6 % p. a.). New renewables will grow at the fastest rates (4.1 % p. a.), but they will still remain to be the smallest component of renewable energy in 2030 [4].

The last decade was described by a rapid development of wind power engineering all over the world. The global installed capacity of wind power has reached 47,3 GW with a 20% annual increase in total installed generating capacity in 2004 [3]. The countries with the highest total installed wind power capacity are Germany (16,629 MW), Spain (8,263 MW), the United States (6,740 MW), Denmark (3,117 MW) and India (3,000 MW). The top five countries account for over 67% of 2004 installation and nearly 80% of total wind energy installation worldwide [3]. Europe (74 %) and the USA (16 %) account for 90 % of installed wind power capacity.

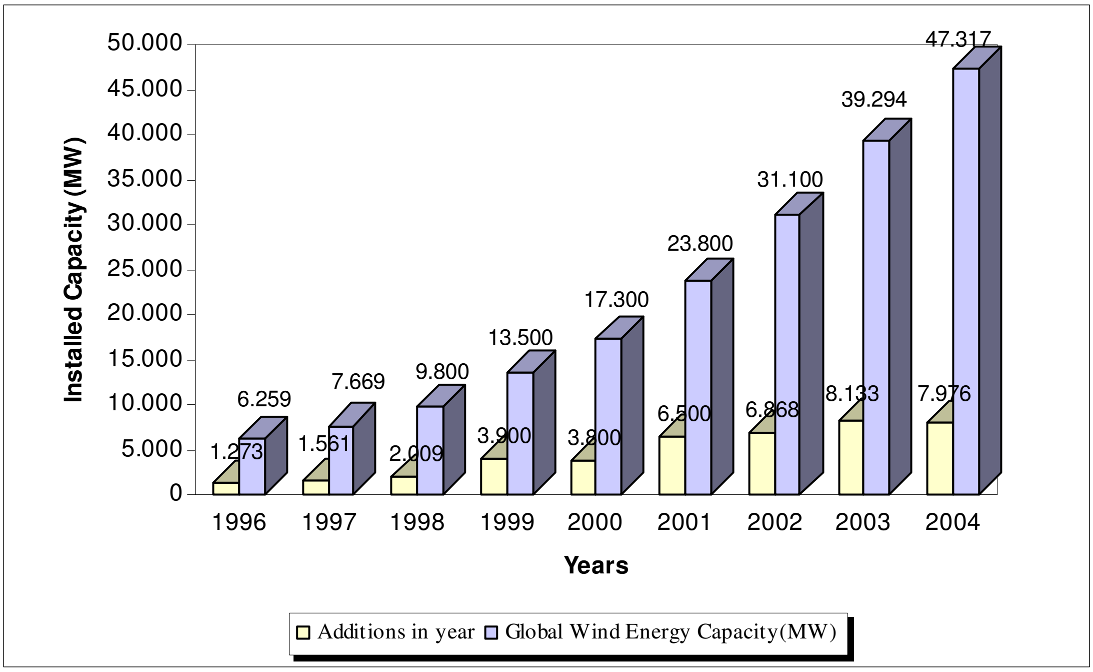
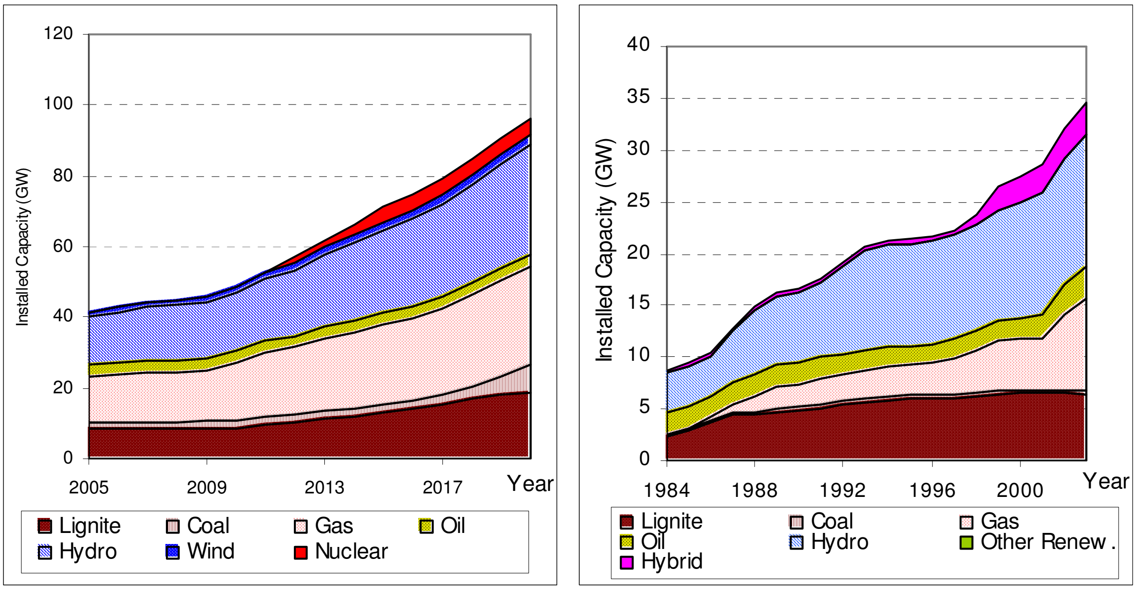


Figure 1.2. Global cumulative wind power capacity and additions (MW) [2,3]

In Turkey, total installed capacity of wind power is only about 20 MW which is far below the annual theoretical potential that is estimated to be in the range 50 GWh - 88 GWh [5,6]. Wind energy licences approved by the Energy Market Regulatory Authority (EMRA) until July 2004 1269 MW, which indicates that Turkey might have a promising future in wind power generation.

Turkey's electricity energy sources include lignite (18,9 %), hard coal (0,9 %), imported coal (4 %), oil (6,7 %), natural gas (29,7 %), hydroelectricity (33,7 %), geothermal (0,05 %), wastes (0,1 %), LPG (0,1 %), naphta (0,4 %), multi-fuels (5,5 %), solar and wind (0,1 %). Thermal resources meet approximately 60% of total installed capacity for electric power generation, while 75% of total electricity is generated from thermal power plants. On the other hand, Turkey imports nearly two thirds of its energy supply. Turkey's domestic energy production in TPES is nearly between 30-40 % [5,7,8].



(a) (b)

Figure 1.3. (a) Development of electricity generating capacity in Turkey, (b) Capacity projections of Turkey 2005-2020 by primary energy source [9]

Turkey has significant renewable energy potentials, which could be interpreted as the second-largest domestic energy source after coal. In electricity generation, renewables accounted for 20 % in 2001, 26 % in 2002 and 25 % in 2003 of which hydroelectric energy is absolutely dominating (99 %). The economically feasible renewable energy potential in Turkey is estimated to be 495,4 TWh/year, including 196,7 TWh/year for biomass energy, 124 TWh/year for hydropower, 102,3 TWh/year for solar energy, 50 TWh/year for wind power, and 22,4 TWh for geothermal energy [5,8].

Turkey's total final energy consumption (TFC) grew at an average annual rate of 9,6 % over the last three decades and is projected to result in a 3,1 times increase from 159,6 TWh in 2005 to 499,5 TWh in 2020 according to TEIAS (Turkish Electricity Transmission Corporation) projection. The development of Turkey's installed capacity by primary energy sources between 2005 and 2020 is given in Figure 1.3. As can be seen from Figure 1.3, renewable energy installed capacity is expected to reach around 37.000 MW in 2020, which corresponds to 35 % of total installed capacity.

The wind energy potential in various parts of Turkey seems to be very favourable due to high annual average wind speed records. Turkey's total theoretically available potential for wind power may be around 88,000 MW annual, with particularly attractive areas for wind located along Turkey's west coast and in southeastern Anatolia [6]. Wind electricity was first obtained from a wind turbine with a nominal 55 kW power built in Çeşme in 1986. Nevertheless, the utilization of wind energy in Turkey has increased since 1998 when the first wind power plant with a total capacity of 1,5 MW was installed in Çeşme. The biggest availabe wind power plant is the BORES (Bozcada Wind Energy Plant) which is a Built-Operate-Transfer (BOT) plant with 10.2 MW power. Turkey has 18,9 MW of wind power installed capacity by the end of the 2004 [10].

The Turkey Wind Atlas, which shows statistical data on regional mean wind speeds and power densities was prepared by Dundar et al.(Figure 1.4). It includes power potentials at height of 50m above the ground level for five various windy regimes.

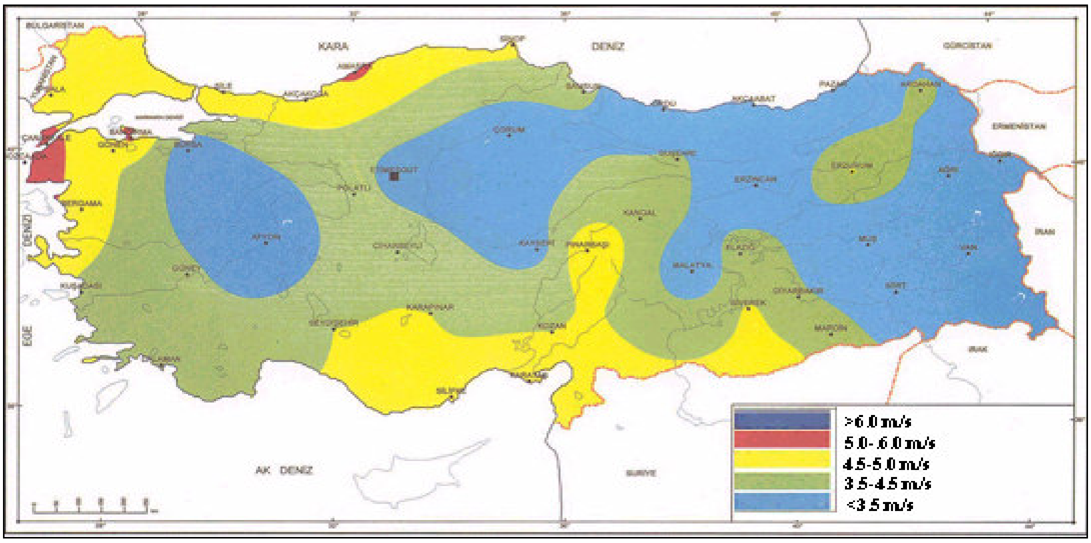


Figure 1.4. The Turkey Wind Atlas for unopened areas [11]

Progress in wind energy technology in recent years has drawn private sector attention to wind power. Numerous companies have submitted their applications to EMRA for licensing and 1269 MW of wind power capacity was approved by EMRA at the end of July 2004. Turkey current wind power installations are given in Table 1.1. According to the TEIAS projection given in Figure 1.3, there will be very large increase in electric generation capacity over the next 20 years and therefore, the total installed wind power capacity in 2020 will be 3018 MW which 160,7-times increases from 18,9 MW in 2004. As a concequence, Turkey seems to have a promising future for wind power.

Table 1.1. Distribution of wind power installations in Turkey [6]

Place	Region	Capacity of Each Turbine(kW)	Number of Turbines	Installed Capacity(MW)	Type of Turbine
Cesme	Aegean	500	3	1,5	Enercon-40
Cesme	Aegean	600	12	7,2	Vestas-V44
Bozcada	Marmara	600	17	10,2	Enercon-40

Throughout the thesis, the wind energy projects evaluation process is scrutinized under competitive electricity market conditions by performing financial and economical analyses for alternative sites and projects in Turkey. Cashflows of the selected wind projects are compared according to scenarios defined. The competitive electricity market conditions are satisfied using the Electric Power Strategy Simulation Model EPSIM (Kleindorfer *et al.*[12]). The data used in the study is obtained from various sources including TEIAS, Turkish Meteorological Service, National Load Distribution Center, NASA, Ministry of Environment Canada and Demirer Holding.

The thesis organized as follows: Chapter 2 includes a comprehensive literature survey about wind energy basic, wind speed data analysis, electricity load forecasting, electricity markets and wind energy project evaluation. Firstly, wind energy information sources are presented and afterwards studies conducted on wind speed data analysis are reviewed. Then, a literature survey regarding the electricity load forecasting is given. In the following subsection electricity market structures are briefly explained and afterwards the wind energy projects evaluation process is overviewed.

The third chapter reviews wind energy basics concerning history, technology, trends, developments, costs and prices, investment structure, operating maintanence costs, cost of energy and future aspect and experience curves in detail.

Chapter 4 describes the competitive electricity markets in detail. Firstly, market fundamentals of competitive electricity markets are explained involving basic liberalisation reform models. Later, price determination process in the deregulated power markets is studied. Afterwards, examples of the competitive electricity markets in the world are reviewed and main features of the England and Wales power market are presented including the price determination process.

The fifth chapter focuses on the wind energy projects evaluation process. In this respect, economic and financial analyses of the wind power projects are investigated. In addition, barriers for wind power projects and also the risk of the investment are outlined in this chapter.

The sixth chapter is concerned with the Turkish electricity market structure involving historical development, characteristics of the system, pricing approaches and future prospects. Firstly, the evolution of the Turkish electricity system is summarized and then main characteristics of the current system are described particularly focusing on the law of 2001 and liberalisation process. Next, methods of price regulation are presented and system prices are compared with OECD countries. Afterwards, electricity sector reforms and privatization process within the next seven years are described in order to see the future market structure.

Chapter 7 analyzes the hourly wind speed records of sixteen sites over a five year period from 1999 to 2003 obtained from Turkish Meteorological Service by applying the Weibull distibution. The wind energy potential of those locations is studied based on Weibull Models. Seven sites with high wind energy potential have been determined after performing the statistical analyses using the statistical analysis program, StatGraphics.

The eight chapter contains the load forecating analyses of the five regions which are Western Antolia, Central Anatolia, Northwestern Anatolia, Southeastern Anatolia and Others. The hourly load data for the regions are obtained from the National Load Distribution Center. ARIMA models are used for forecasting five different regions' load over a time period from 2005 to 2029. Based on sectional data, i.e. hourly loads studied separately as a single series, 24 different models are estimated for each region.

Chapter 9 elaborates details of the analysis on wind energy projects in the Turkish Competitive Electricity Market Model. The competitive electricity market model is determined according to the EPSIM model (Kleindorfer *et al.*[12]). A comprehensive program (Wind Energy Project Evaluation - WEPE) has been developed integrating load forecasts, projections of wind energy potentials based on statistical and economic analyses, and alternative power generation technology evaluations. The competitive electricity market is modeled by adopting the power market and pool rules from the U.K.

Chapter 10 analyzes the base case scenario which comprise a twenty-five year horizon from 2005 to 2029 and other scenarios based on the model so as to determine the feasibility of wind power projects for the seven sites. Generated and dispatched capacities of the projects for the base case scenario and other scenarios are given. Also cashflows of the projects and financial parameters such as NPV, IRR and benefit-cost ratio are explored in detail and relevant graphics are presented.

The last chapter concludes the research and points out future studies that may be conducted in this area.

2. LITERATURE SURVEY

Starting with an introduction of main information sources, this chapter includes a review of the literature about wind energy with particular focus on history, technology and cost & prices. Wind speed data analysis methods, load forecasting techniques and wind energy project evaluation processes and applications are reviewed. Furthermore, competitive electricity market conditions are explored due to the essential impact on wind energy investment decisions.

2.1. Research on Wind Energy Technology, Siting and Cost

Progressing of engineering and scientific skills is a main part of the evolution of wind turbine technology. In the last 20 years, turbines have increased in power by a factor of 100, the cost of energy has reduced and the industry has moved from an idealistic fringe activity to the edge of conventional power generation [13]. From the begining of 1980 many different design styles of wind turbines have been introduced. The dominant wind turbine design is the up-wind, three bladed, **stall controlled**, constant speed machine. The next most common design is similar, but is **pitch controlled**. Modern wind turbine structure involves rotor, generator, directional system, protection system and tower.

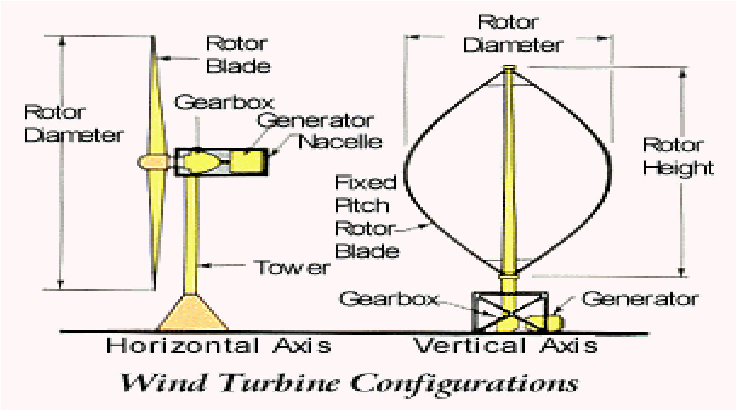


Figure 2.1. Main parts of a wind turbine [14]

Improvements in WT technology continue to make turbines cheaper and more efficient. Diameter in relation to power rating has generally increased in recent years. A remarkable increase has taken place, the average diameter of a 15 MW turbine being from 65 m, 69 m and almost 74 m in the years 1997, 2000 and 2003 respectively. Direct drive transmission systems for WTs are of increasing interest. The removal of gearboxes has presented challenges and the direct drive concept seems to be more desirable. The WT blade technology has became automation involved in the process and labour intensive. Most of the WT blades are made from glass polyester or glass epoxy [15].

The cost of a wind power plant has fallen substantially during the last twenty years, and this trend is continuing. Selection of a suitable site is key to the economics of wind energy. The power available from the wind is a function of the cube of the wind speed, which means that, all other things being equal, a turbine at a site with 5 meters/second (m/s) winds will produce nearly twice as much power as a turbine at a location where the wind averages 4 m/s. Capital costs of wind energy projects are dominated by the cost of the WT itself. Wind Turbines share of total cost is typically a little less than 80% but there are considerable variations ranging from 74% to 82%. Dominant ones of other components are grid-connection, electrical installation and foundation, but other auxiliary costs such as road construction could represent a substantial proportion of total costs. The price of modern turbines around the 70-80 m diameter mark is around 900 to 1100 €/kW [16].

Operating and maintanence costs form a considerable share of the total annual costs of a WT. These costs are nearly 20%-25% of total levelised cost per kW produced. O&M costs consist ot the following components:Insurance, Regular Maintanence, Repair, Spare Parts and Administration. The development of O&M costs appears to be strongly correlated with turbine age. The total cost of wind energy per produced kWh is computed by discounting and levelising investment and O&M costs over the lifetime of the WT, divided by the annual electricity production.

A key element of wind turbine siting is the turbine spacing used. The appropriate spacing for turbines is strongly dependent on the nature of the terrain and the wind rose at the site. Optimising layout of the wind farm based on the constrained defined is called “micrositing”[15]. Some of the issues regarding wind turbine siting that should be considered are mentioned below:

Turbulence: In areas with a very uneven terrain surface, and behind obstacles such as buildings there is similarly created a lot of turbulence, with very irregular wind flows.

Wind Obstacles: Obstacles to the wind such as buildings, trees, rocks etc. can decrease wind speeds significantly, and they often create turbulence in their neighbourhood.

Wake Effect: Since a wind turbine generates electricity from the energy in the wind, the wind leaving the turbine must have a lower energy content than the wind arriving in front of the turbine. A wind turbine will always cast a wind shade in the downwind direction.

Park Effect: Wind turbines in wind parks are usually spaced somewhere between 5 and 9 rotor diameters apart in the prevailing wind direction, and between 3 and 5 diameters apart in the direction perpendicular to the prevailing winds.

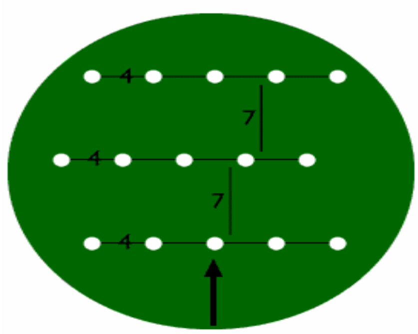


Figure 2.2. Illustration of park layout [17]

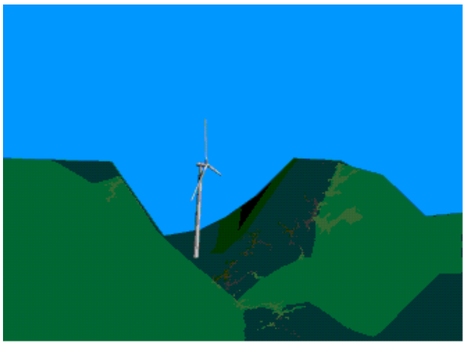


Figure 2.3. Illustration of tunnel effect [17]

Tunnel effect: The air becomes compressed on the windy side of the buildings or mountains, and its speed increases considerably between the obstacles to the wind.

Hill Effect: A common way of siting wind turbines is to place them on hills or ridges overlooking the surrounding landscape [17].

Since the wind doesn't blow continuously, wind generation is often described as intermittent. Wind power generation is variable and not completely predictable so the electricity system operator must provide additional reserves for balancing supply and demand. There is a growing awareness, particularly in the United States, that the penalties for wind are not cost-reflective and a growing trend towards excepting wind from balancing market penalties and providing system operators with good forecasting tools. The extra reserve capacity required due to the wind variations accounts for 5 % of the wind capacity and 5 % on an energy basis at modest wind penetrations. The extra costs of this reserve ranges between CA $ 0,12-0,24 / MWh of generation with 5 % wind, rising to CA $ 0,40-0,6 / MWh with 10 % wind [18]. Improvements in wind forecasting and using demand-side management techniques are likely to reduce the extra costs. There are no technical limits and very high wind energy penetrations appear achievable on the European electricity systems without affecting the quality of supply. Variability remains a major disadvantage that becomes more important at high penetrations because it increases the amount of reserve that an operator must cary on the system. Also, the unpredictability of wind generation requires system operators to carry additional reserve or possibly force curtailment of wind generation [15].

An experience curve theory same as the so-called learning curve or progress curve is generally used for forecasting the future cost development of wind turbines and wind electricity. According to Junginger *et al.*[19], costs may actually decline faster than anticipated in most scenarios and models. They propose a simple scenario based on the following assumptions: current average wind farm investment prices lie around 1000 €/kW and global installed cumulative capacity will double four times by 2020. Under these assumptions and using the average progress ratio of 92%, they found that prices would drop to 716 €/kW by 2020. In the case of a progress ratio of 86 % (computed as an average ratio from [20,21]), prices will drop to 547 €/kW by 2020. Consequently, it seems that large scale wind farms may have lower investment cost when we analyze the future cost reductions and studies employing experience curves.

2.2. Wind Speed Data Analysis

There are three basic methods in wind energy assessments: (i) statistical analysis of the existing wind energy potential and other meteorological data, and topographical information; (ii) qualitive indicators of long term wind speed levels; and (iii) application of boundary layer similarity theory and the use of surface pressure observations [22].

In literature, many efforts to construct an adequate statistical model for describing the wind speed frequency are reported. Over the last decade, a number of studies have been carried out in order to assess the wind power of various regions around the world [23,24,25,26,27].

In many cases, the Weibull distribution allows to model the availability of wind energy for a specific region by means of the probability of occurrence of the wind speed. Because of its greater flexibility, simplicity and good aggreement with experimental data for fitting wind speed data, Spera [22], Mayhoub and Azam [24], Lun and Lam [26], Ulgen and Hepbasli [28] and Jaramillo and Borja [27] proposed Weibull Distribution for energy assessment analyses and wind load studies.

Based on studies carried out in Turkey, some researchers have performed the assessments of wind power on the basis of particular locations. Incecik and Erdogmus [29] investigated the variability of the wind power on the western coast of Anatolia, considering the Weibull distribution. In their study, routinely measured hourly wind speeds from eight stations operated by the Turkish Meteorological Service are used. These locations have been chosen to cover the whole Western Anatolia coast. These locations are Ayvalık, Bodrum, Bozcaada, Çanakkale, Dikili, Edremit, Gökçeada and İzmir. The wind data used in their calculations cover the period of 5 years between 1979 and 1983.

Karslı and Gecit [30] performed a study on the determination of wind power potential of the Nurdağı/Gaziantep district situated in the south of Turkey. Wind data used in this study are taken from the The Electrical Power Resources Survey and Development Administration (EIEI) at Nurdağı. It was demonstrated that the district has a mean wind speed of 7.3 m/s at 10 m height above the ground level (with an observed high 23.3 m/s).

They state that the site encourages investment and represents a promising area for the production of electricity.

The wind power potential in the İskenderun and Antakya regions which are situated in the East Mediterranean region of Turkey was investigated using computer package program called WASP by Bilgili *et al.* [31]. In their study, hourly mean wind speed for the period of 10 years between 1992 and 2001 was used, the data being taken from the State Meteorological Institute of Turkey. They found out that mean wind speeds, in the south and east regions of İskenderun, are between 5 and 7 m/s and in many areas of the Antakya region are greater than 5 m/s at 10 m height above the ground level.

Durak and Sen [32] investigated the wind power potential of Akhisar in Turkey as a case study. According to the results of their analysis, the average wind speed was 5.8 m/s in the Akhisar area. They calculated that the annual wind energy output in this region varies between 31.416 and 41.560 MWh.

Ülgen and Hepbaşlı [28] analyzed wind characterstics in İzmir using the Weibull two-parameter function to describe the wind speed frequency distribution over a 5-year period during 1995-1999. In their study, they found that the average wind speeds for the Bornova region of İzmir are to range between 3 and 4 m/s.

In these studies, much consideration has been given to the Weibull two-parameter (k, shape parameter and c, scale parameter) function because it has been found to fit a wide collection of wind data. Different from above mentioned studies also special case of the Weibull distribution (named a bimodal Weibull&Weibull probability distribution function) has been developed to analyze the wind speed frequency distribution by Jaramillo and Borja [27] for the case of La Ventosa in Mexico.

2.3. Electricity Load Forecasting

Most forecasting models and methods have already been tried out on load forecasting, with varying degrees of success. Accurate models for electric power load forecasting are essential to the operation and planning of a utility company. Weron and Misiorek [33] classified forecasting methods into two broad categories: artificial intelligence based techniques and classical (or statistical) approaches. The former include expert systems, fuzzy inference, fuzzy neural models, and artificial neural networks (ANN). The statistical methods forecast the current value of a variable by using an explicit mathematical combination of the previous values of that variable and, possibly, previous values of exogenous factors (specially weather and social variables). Models that have been applied recently include autoregressive (AR) models, linear regression models, dynamic linear or nonlinear models, ARIMA and ARMAX models, threshold AR models, methods based on Kalman filtering, optimization techniques, and curve fitting procedures [33].

Ramanathan *et al.*[34], who won a load forecast competition at Puget Sound Power and Light Company, presented hour by hour approach using variable segmentation and multiple modelling for hourly load forecasting. In their study, they used separate multiple regression models for each hour. The idea of variable segmentation (framing the problem as 24 separate hourly models) renders each model rather more simple but altogether involves more parameters and is computationally more intensive. The main advantage of this approach is clearly that it allows different variables to have different response functions for each hour [35,36].

Another computationally intensive methodolgy is the use of multiple modeling and combining. Smith [37] described the minute by minute approach of the National Grid Company in the United Kingdom, using combinations of two Box Jenkins models and a spectral method, where the linear combining weights are not only adaptive to previous errors but also lead time dependent.

Much research has also been carried out using artificial neural networks(ANN) for forecasting, especially during the last decade. Nevertheless, the reports on the performance of ANNs in forecasting have not entirely convinced the researchers. Recent reviews and textbooks on forecasting argue that there is little evidence as yet that ANNs might outperform standard forecasting methods [33].

Hamzaçebi and Kutay [38] have performed an analysis of the long-term Turkish electricity load using ANN. The results obtained by ANN are compared to those obtained by Box-Jenkins models and regression technique. They found minimum Mean Absolute Percentage Error (MAPE) values using ANNs. However, ANNs have so-called *black box* properties so that they may yield undesirable results. Therefore when using ANNs as a forecasting tool, other methods should also be used to complement the analysis.

ARIMA techniques have been mainly used for load forecasting due to their accuracy and mathematical soundness. Gross and Galaina [39] and Hagan and Behr [40] obtained relatively good performance. Also, in many of the countries with ongoing electricity market restructuring process, ARIMA models are being used to predict prices (e.g. the case of Norway; reforms) [41]. Moreover, this methodolgy has been used for forecasting electricity prices in the electricity market of mainland Spain and California [42].

2.4. Electricity Markets

The electricity industry worldwide undergoes a process of fundamental restructuring transforming the electricity sector from (publicly owned) vertically integrated monopolies to more competitive structures. Wilson (1998) [43] considered that the design of competitive wholesale electricity markets began with the implementation of structural conditions that aim at creating enough competitors and avoiding any monopoly power in generation and any local monopoly due to transmission constraints.

Hunt [44] determined several key components for restructuring and the development of competitive electricity markets. Briefly, these can be summarized as the privatization of state-owned utilities, vertical separation of competitive segments, horizontal integration of transmission and network operations, the creation of public wholesale spot energy and operating reserve market institutions, the application of regulatory rules and supporting network institutions, and the unbundling of retail tariffs and independent regulatory agencies.

Wolak and Patrick [45] stated that market institutions were precisely designed so as to mitigate the ability of firms to exercise market power. They provide a description of the market structure and rules governing the operation of the England and Wales electricity market, emphasizing aspects that are important to the success of the strategy believing the two generators use to exercise market power.

Hepbasli [46] reviewed the development of and restructuring activities in Turkey’s electricity sector, including the historical development, and exploring energy related emissions, and energy utilization efficiencies. He investigated the importance of restructing the Turkish electricity market separating five different periods.

Özkıvrak [47] has studied the Turkish electricity sector reform and elaborated some problems affecting the reform process. The study is mainly based on the electricty market law of 2001 and its structures. Important problems which prevent competition are identified to be high losses in the distribution, lack of access supply and metering-communication-control infastructure. Also, the structural and institutional features of Turkey are not fully integrated with the new competitive structure. For instance, positions of independent regulatory bodies is controversial in the Turkish Law System.

2.4.1. EPSIM Model

The EPSIM model is used to simulate the payoffs to each player for a ten-year time horizon given the bids from generators and load management entities and the investment and operating strategies of the grid operator in the England and Wales power pool. The actual power pool rules and strategies aren’t reflected in the implemantation of EPSIM (Kleindorfer *et al.*[12]). The model is performed over ten planning periods and the duration of the periods are chosen one year. Furthermore, each planning period is comprised of six periods in which capacity is scheduled and dispatched to meet demand at each node also bids and contracts are assumed to hold for a single year. There are five key players in the model: the first two players are generating companies Power Gen and National Power which provide considerable proportion of the generation in England, the third one is all other generators, the fourth player is the grid operator or system operator and the last player is the master of the game. The master of the game is responsible for managing all parameters such as demand, scenarios, regulatory restricitions and etc.

The essential features of the model are presented as follows. Generators and load management entities in the power pool submit bids to the Power Pool Administrator for the entire planning period. These bids specify a bid capacity (MWh) at a bid price ($/kWh). For each of the six periods in each planning period, the model first determines the unconstrained Schedule and SMP by sorting plants in increasing order of bid price and scheduling until the system demand is met. After completion of the unconstrained schedule, then the model schedules and dispatches capacity to minimize system costs using the linear programming formulation.

3. COMPETITIVE ELECTRICITY MARKETS

In the last twenty years, there has been considerable change in the utility sector of various countries due to deregulation and introduction of competition. There is over a decade of experience with the privatization, restructuring, regulatory reform, and wholesale and retail competition in electricity markets around the world.

During the 1990s, many countries restructured their electric power sectors to increase economic efficieny. The restructuring programs have included privatization of state-owned enterprises, the separation of potentially competitive segments (generation and retail supply) from natural monopoly segments (distribution and transmission), the creation of competitive wholesale and retail markets, and the application of performance-based regulatory mechanisms (PBR) to the remaining regulated segments [48].

In nearly all industrial and developing countries that are committed to economic reform the trend goes universally in the direction of widening the scope for competition. Under a perfect competition, neither suppliers nor consumers exercise market power and suppliers stil earn a normal rate of return on their investment [49].

In many developing countries, the sectors were characterized by low labor productivity, poor service quality, high system losses, inadequate investment in power supply facilities, unavailability of service to large portions of the population, and prices that were too low to cover costs and support new investment [48].

In this section the basic structure of competitive electricity markets and the process of price determination will be discussed.

3.1. Market Fundamentals

Basic liberalisation reform models are bidding competition, wheling (third party access) and Pool models.

Competitive Bidding: Competitive Bidding in Generation and Franchise Bidding are differentiated in this category.

Under competitive bidding, certain supply rights are opened to public tender. Under bidding competition for generation, new generation capacities are opened for competitive bids in order to replace retired capacity or to account for load growth. Under the bidding for new capacity, existing generation capacity is not exposed to direct competition. Once the tender is closed the newly contracted generator is not exposed to competition with its generation output as it supplies according to a long-term contract.

Under franchise bidding the right to supply final customers in a certain area is opened for competitive bids. Franchise bidding only induces competition for an interim period. Frequently repeated bidding is not viable due to high transaction cost of passing over (distribution) assets to new operators [50].

Wheeling (Third Party Access - TPA): Under a wheeling regime (or equivalently, third party access) competition is constituted by the access of electricity generators, traders or their customers who access existing grids. Within this framework competitors have to sign bilateral contracts with incumbent grid (transmission and distribution) owners for connection to and use of the grid and with their customers for the supply of energy [50].

The TPA model can potentially open the generation/wholesale and retail market to competition. In fact, the TPA model links competition in generation with competition in supply, since firms will only generate output for which they have gained supply contracts. As opposed to bidding model, competition is not limited to new generation capacities. Old generation facilities are also exposed to competition for sales [50].

Pool Models: Pools (power exchanges) are organised, anonymous short-term markets for electricity. (Pools are sometimes referred to as spot markets). Typically generators make supply bids in a standardised format, usually one day in advance of production. Bids or generation units behind the bids are ranked in ascending order of bid prices (merit order) and only the units with lowest bid prices are included in the economic dispatch.

Market clearing takes place for short time intervals (half hour or one hour) and the market clearing bid typically determines the market or spot price. The Pool is usually co-ordinated by an institution that works in close co-operation with the company operating the high voltage grid as short-run generation dispatch must be in accordance with capacity availability for transmission.

The Pool model is therefore a model for organising a generation/wholesale market. In contrast to the TPA model, generation and supply competition are disintegrated in Pool models. Electricity generated can be sold to the Pool (provided the generator is included in the merit order) even if the generator does not hold a supply sales contract. Unlike TPA at the wholesale level, Pool competition allows for permanent short-run competition for plant dispatch. It is usually considered that Pool models (in conjunction with TPA for retail sales) bring about a higher degree of competition than models with an unorganised wholesale market (TPA) [50].

3.2. Price Determination

Efficient pricing is a central feature of a competitive electricity market. It is essential if the benefits of a competitive market are to flow through to customers and other market participants. Pricing that is inefficient will fail to signal and encourage appropriate levels of consumption and supply or the appropriate levels and locations of new generation and transmission investment.

The standard determinant of competitive market pricing is system marginal cost. This is the simple definition of the market-clearing price where supply equals demand. This production level just balances the marginal benefit of additional consumption with the marginal cost of production [51].

In the pool based competitive market, power producers submit generation bids and their corresponding bidding prices, and consumers do the same with consumption bids. The market operator uses a market-clearing tool to clear the market. This tool is based on one-sided auctions [52] and considers the hours of the market horizon one at a time. An one-sided auction is performed every hour to determine the resulting market clearing price in that hour and also the accepted production and consumption bids.

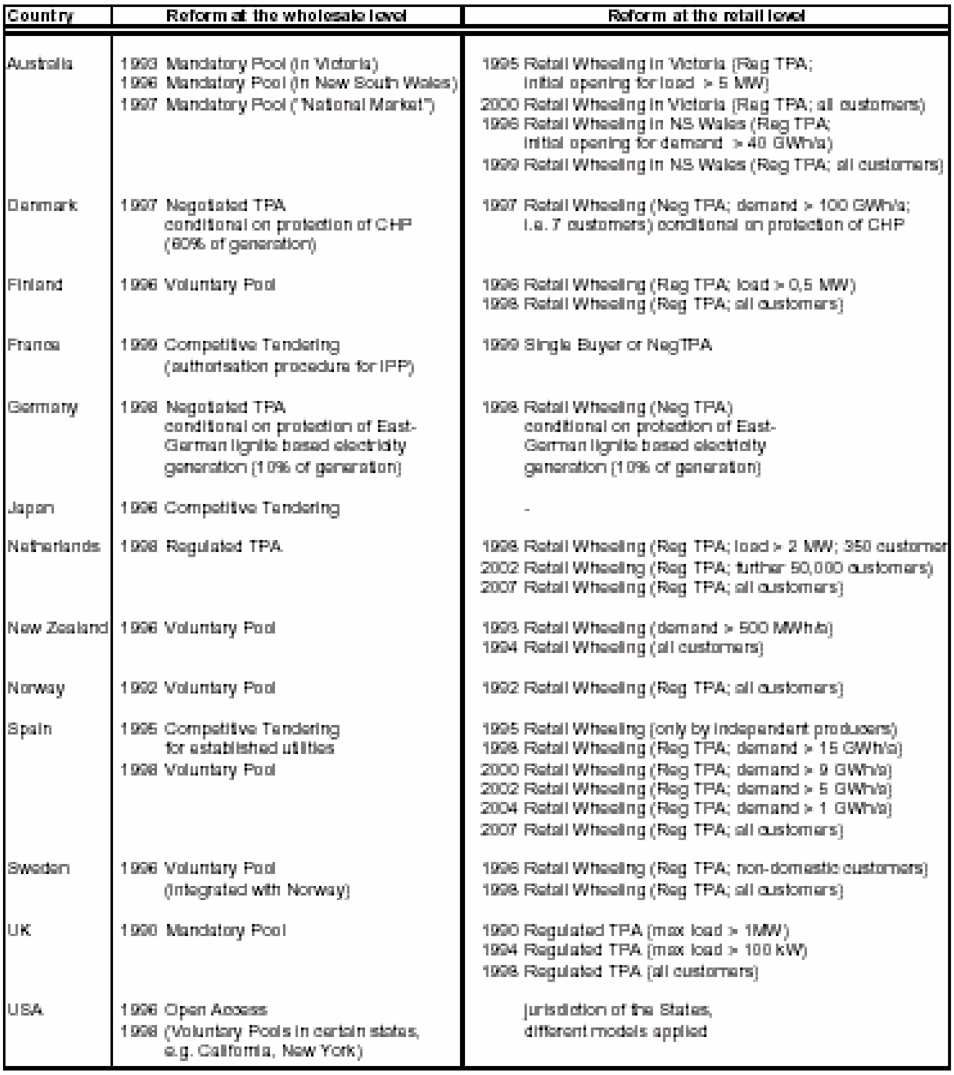
3.3. Electricity Markets Deregulation Examples

The electricity market is moving towards greater reliance on competition in the world. Changing technology, new entrants in the generation market, and a legislative mandate to provide access to the essential transmission facility have accelerated a process of competition that will require major changes in the institutions and operations of the electricity market [53].

Reorganization of the electricity sector has been taking place in the last decade in several European countries. The main issue raised by this deregulation is the establishment of spot-markets which allow for efficient pricing in response to the nature of the demand and supply of this commodity. At present Austria, Belgium, Denmark, Finland, Germany, Norway, Spain,Sweden and the UK have undertaken succesfully the deregulation process [54].

On the other hand Australia, New Zealand and the US have shown a great effort on the way to competitive electricity markets. However, Californian electricity market reforms unravealed the worst electricity restructuring policy failure ever seen with price spike implications that reached 10-times higher rates [51].

In this section, example of the important pool based electricity markets England and Wales are explored. The structure of the market is discussed in details and pool rules are identified.



Country	Reform at the wholesale level	Reform at the retail level
Australia	1993 Mandatory Pool (in Victoria) 1996 Mandatory Pool (in New South Wales) 1997 Mandatory Pool ("National Market")	1995 Retail Wheeling in Victoria (Reg TPA; initial opening for load > 5 MW) 2000 Retail Wheeling in Victoria (Reg TPA; all customers) 1996 Retail Wheeling in NS Wales (Reg TPA; initial opening for demand > 40 GWh/a) 1999 Retail Wheeling in NS Wales (Reg TPA; all customers)
Denmark	1997 Negotiated TPA conditional on protection of CHP (60% of generation)	1997 Retail Wheeling (Neg TPA; demand > 100 GWh/a; i.e. 7 customers) conditional on protection of CHP
Finland	1996 Voluntary Pool	1996 Retail Wheeling (Reg TPA; load > 0,5 MW) 1998 Retail Wheeling (Reg TPA; all customers)
France	1999 Competitive Tendering (authorisation procedure for IPP)	1999 Single Buyer or NegTPA
Germany	1998 Negotiated TPA conditional on protection of East-German lignite based electricity generation (10% of generation)	1998 Retail Wheeling (Neg TPA) conditional on protection of East-German lignite based electricity generation (10% of generation)
Japan	1996 Competitive Tendering	-
Netherlands	1998 Regulated TPA	1998 Retail Wheeling (Reg TPA; load > 2 MW; 350 customer 2002 Retail Wheeling (Reg TPA; further 50,000 customers) 2007 Retail Wheeling (Reg TPA; all customers)
New Zealand	1996 Voluntary Pool	1993 Retail Wheeling (demand > 500 MWh/a) 1994 Retail Wheeling (all customers)
Norway	1992 Voluntary Pool	1992 Retail Wheeling (Reg TPA; all customers)
Spain	1995 Competitive Tendering for established utilities 1998 Voluntary Pool	1995 Retail Wheeling (only by independent producers) 1998 Retail Wheeling (Reg TPA; demand > 15 GWh/a) 2000 Retail Wheeling (Reg TPA; demand > 9 GWh/a) 2002 Retail Wheeling (Reg TPA; demand > 5 GWh/a) 2004 Retail Wheeling (Reg TPA; demand > 1 GWh/a) 2007 Retail Wheeling (Reg TPA; all customers)
Sweden	1996 Voluntary Pool (integrated with Norway)	1996 Retail Wheeling (Reg TPA; non-domestic customers) 1998 Retail Wheeling (Reg TPA; all customers)
UK	1990 Mandatory Pool	1990 Regulated TPA (max load > 1MW) 1994 Regulated TPA (max load > 100 kW) 1998 Regulated TPA (all customers)
USA	1996 Open Access 1998 (Voluntary Pools in certain states, e.g. California, New York)	jurisdiction of the States, different models applied

Figure 3.1. Reform models and timing of implementation selected OECD countries [50]

3.3.1. The Case of England and Wales

The initial reforms in England and Wales in 1990 were highly influential to subsequent developments in electricity restructuring around the world. Generation, transmission, and distribution (suppliers to end-users) of electricity were divided into separate companies and largely privatized. The signature element of the model is the introduction of the "Pool” as a centralized entity that controls the scheduling and dispatch of generation [55].

3.3.2. The Pool Price Determination Process

A generator submits day-ahead bids to supply power to the system at half-hourly intervals. For each generating plant, generators make ‘capacity offers’ and ‘price offers’ respectively equivalent to a willingness to produce (in MW) and a price at which they would like to do so. Capacity offers have three components whereas price offers have five components. Altogether they provide the dispatcher with all the information required to efficiently dispatch the generating units, i.e. at the minimum costs. Pool rules define the dispatch that determines which generating plants will produce, how much and when, while minimising the operating costs of the system. They provide the merit order according to which cheapest generating plants are dispatched first so as to minimise total supply costs.

The merit order results in a schedule determining, for a given period, which plants will be committed to produce and which will not. At this stage, transmission constraints, initial running conditions and most of the operating characteristics are not taken into account (the resulting Schedule is therefore called “unconstrained “Schedule). The market-clearing price, also called System Marginal Price (SMP), of electricity results from this unconstrained schedule. It is set by the offer price of the marginal plant required to meet the forecasted level of demand. Transmission constraints, operational characteristics and actual availability are then taken into consideration to technically coordinate the generation. It results in a modification of the unconstrained schedule. Plants not included in the unconstrained schedule may be asked to produce (they are called constrained-on) whereas some scheduled plants may be asked not to produce (they are called constrained-off). This revised production plan determines the constrained schedule (also called operational schedule) which gives the quantities to be actually generated.

4. TURKISH ELECTRICITY MARKET STRUCTURE

The Turkish electricity industry has been dominated by a state-owned enterprise TEK (the Turkish Electricity Authority) until 1993 when it was separated into the Turkish Electricity and Transmission Company (TEAS) and the Turkish Electricity Distribution Company (TEDAS).

Restructuring of the Turkish Electricity Market was initiated with the approval of Electricity market law no:4628 in February 2001. According to this law the Energy Market Regulatory Authority (EMRA) has been established. The Turkish electricity reform includes generation, transmission and distribution segments, introduction of competition into genaration and retail sale, establishment of an independent regulatory authority and privatization of public generation and distribution entities [47].

Deep crises at the late of 1990s and serious supply shortfall (resulting in some supply restrictions and energy saving measures) in the begining of 2000s, triggered the Turkish reforms, and helped improving the efficiency of electrcity system.

In this section, firstly historical developments in the Turkish electricity market are reviewed and considerable changes are remarked. Afterwards, three main interrelated segments of the electricity system are clarified. Then, the pricing process of the Turkish electricity market is discussed. The last part comprises the Turkish electricity sector reforms, restructuring of the market and future prospects.

4.1. Historical Developments

A historical development of the Turkish Electricity Market can be classified into five periods [46]: a foreign investment period (1923-1930), a nationalization (1930-1950), a period of development plans and back to a monopolistic market (1960-1980), a period of investment Models (1980-2000), and the restructuring period (2000-present).

Foreign investment period (1923-1930): During this period, the electricity industry was heavily dependent on foreign investment. Mostly, German, Belgium, Italian and Hungarian companies joined in providing electricity.

Nationalization (1930-1950): During the 1930s goverments played an active role in the electricity industry all over the world. In Turkey, a legislation that allowed the municipalities to build and operate power plants came into force in 1933. In 1935 Mineral Research and Exploration Institution (MTA) and The Electrical Power Resources Survey and Development Administration (EIEI) were founded; later State Hydraulic Works (DSI) were established.

Development plans and back to a monopolistic market (1960–1980): The Ministry of Energy and Natural Resources of Turkey (MENR) was established in December 1963, being responsible for Turkey's energy policy and planning. Then the law creating TEK was passed and this has caused monopoly in the Turkish electricity sector at all stages. The transmission and distribution business, which was managed by the municipalities, has been left to local governments. During this period, the goverment invested in hydro and thermal power plants and at the end of 1980 electricity generation was 23,275 GW/h and nearly 80% of the population was electrified [56].

Investment models (1980–2000): Beginning in the 1980s, liberalization in economy dominated the country and, the government sought to attract private participation various sector including electricity. As a first step, all assets have been given to TEK taken from the municipalities to centralize the industry and facilitate the infrastructure for private companies. Secondly, the 2705th law in 1982 took over TEK and DSI's oligopoly on building power plants and allowed the private sector to build an operate power plant and sell their electricity to TEK. In 1984, the monopoly of TEK came an end and the private entities were also given the opportunity to intervene generation, transmission and distribution of electricity.

The first law setting up this framework for private participation in electricity was enacted (Law No. 3096). This Law formed the legal basis for private participation through Build Operate and Transfer (BOT) contracts for new generation facilities, Transfer of

Operating Rights (TOOR) contracts for existing generation and distribution assets, and the autoproducer system for companies to produce their own electricity [57].

About 10 private entities were entitled to do the generation, transmission, distribution and trade of electricity within their legal district boundaries between 1988 and 1992. TEK was restructured as two separate state owned enterprises by the Decision of the Council of Ministers no. 93/4789 in August 1993: TEAS and TEDAS as already mentioned.

Restructuring the electricity market (2000–present): Electricity sector restructuring in Turkey has gained momentum with the Electricity Market Law no.4628 in February 2001. The aim of the Law was to establish financially strong, stable and transparent electricity market under competitive and special law provisions for a sufficient, high-quality, continuous, low-cost and environment friendly supply of electricity to the disposal of consumers as well as the maintaining of an independent regulatory and supervisory framework [58]. The law established the independent Energy Market Regulatory Authority (EMRA). The law called for the unbundling of the state owned electricity assets, opening the market for consumers above a certain level of electricity consumption and allowing third party access to the grid. In response, the state unbundled TEAS into three separate state-owned entities: EUAS (generation), TETAS (wholesale trading and contracting), and TEIAS (transmission). TEDAS continues to be in charge of distribution [59]. Key feature of Law no: 4628 are described in the following section.

4.2. Characteristics of the Current System

The main drivers for liberalisation in Turkey were quite different from leaders of electricity liberalisation such as the UK. The EU was primarily concerned with creating an internal market. Countries such as the UK were motivated by inefficiency of public enterprises and the opportunities generated by technological changes that made competition possible in generation. In Turkey, the main driver was rapid growth in demand combined with the inability of the goverment to meet that demand through public investments or Treasury-guaranteed private investments, given the deteriorating fiscal situation.

The Law no. 4628 was designed to establish a competitive electricity market, to promote private participation and to improve efficiency of generation and distribution. The key features of the law are depicted below.

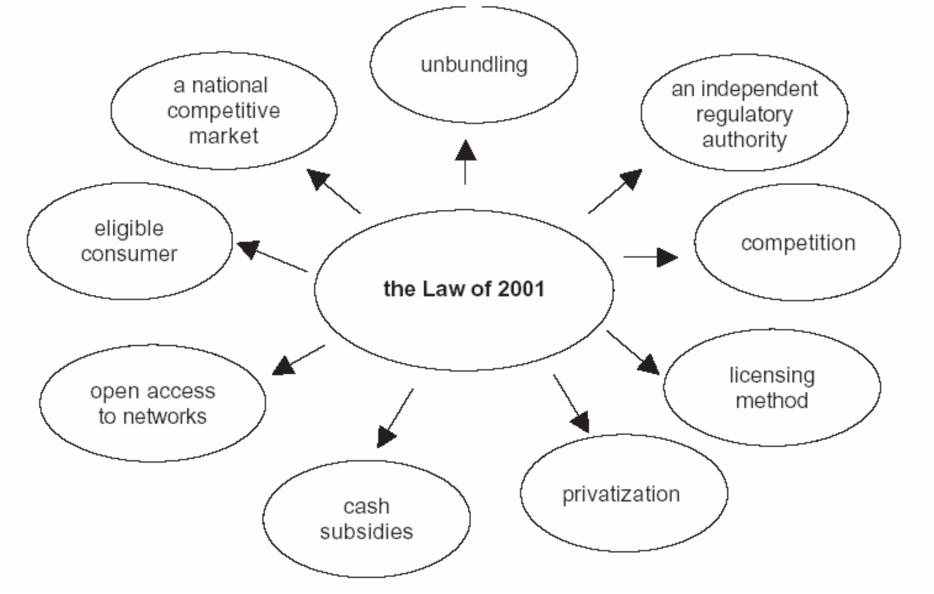


Figure 4.1. Features of electricity market law no:4628 [47]

Market Opening: On the demand side, customers that consume more than 9 GWh per annum have been designated as eligible consumers free to choose their suppliers.

On the supply side, an authorisation-type licensing framework was established providing entry opportunities into generation (Independent Power Producers, and autoproducers have been allowed to sell up to a maximum of 20% of their annual production to consumers other than their shareholders), wholesale trade, distribution, retail trade, import and export of electricity. Transmission remained a state monopoly but private generators have been allowed to establish private direct transmission lines. The granting of generation licenses by EMRA has been conditional on no congestion in the transmission-distribution link connecting the new plant to the grid or directly to customers [57].

Unbundling: As mentioned before, the vertically integrated public authority (TEK) was disaggregated into TEAS and TEDAS in 1993 and, after the approval of the Law no.4628 in 2001, TEAS was restructed into EUAS, TEIAS and TETAS. EUAS takes over all of the generation capacity of TEAS (hydro and thermal) and DSI plants that are not transferred to the private sector. TETAS, established to carry out wholesale operations, takes over all existing energy sale and purchase agreements from TEAS and TEDAS (distribution) and is responsible for transmission assets, for system operation and maintenance, planning of new transmission investments and building of new transmission facilities, and critically for the Balancing and Settlement Procedure [60].

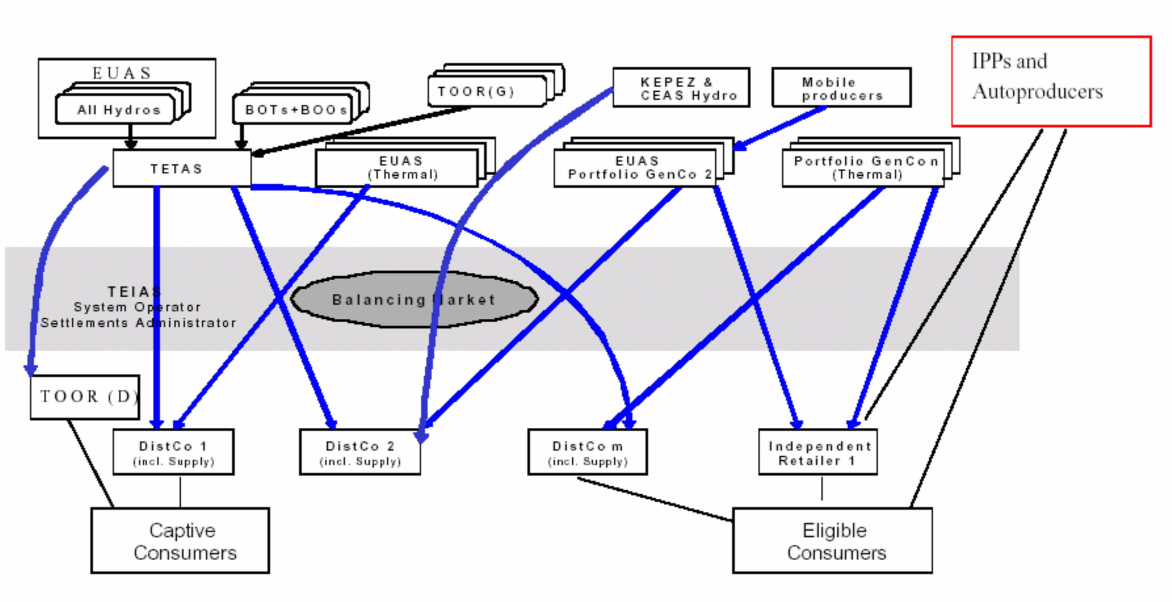


Figure 4.2. The new structure of Turkish electricity market [57]

Introducing competition in non-monopoly segments: Competition is introduced into generation and retail of electricity. Some restrictions have been placed on private generation companies in order to avoid market concentration. For instance, total market share of a particular private generation company may not exceed 20% of the published figure for the total installed capacity in Turkey in the preceding year. Besides, generation companies can not enter into affiliate relationships with distribution companies as to have controlling power over them.

Licensing through an independent regulatory authority: All participants engaging electricity activities are required to be licensed. Important issues like how prices are set, how long the license terms are, which conditions cause the cancelling of licenses, and which disagreements are to be solved by the regulator, are addressed in licenses, which are granted by an independent regulatory authority.

As mentioned earlier, EMRA has been established in 2001 as an independent to ensure transparency and independent regulation over the sector. EMRA is resposible for issuing licences which set out the rights and obligations of industry participants; approving, amending and enforcing performance standards and the grid, distribution and customer service codes and the balancing and settlement code; setting pricing principles and regulation for wholesale prices and transmission tariffs, distribution tariffs and retail tariffs; market monitoring; ensuring conformity of market behavior with the Law and licence conditions.

Constituting a national competitive electricity market: The new Turkish electricity market, like the new electricity trading agreements of England and Wales, is based on bilateral contracts between generators, distribution companies, whosale companies, retail sale companies, eligible consumers and a balancing settlement mechanism. The current market design is a bilateral contracting model, which means that dispatch and wholesale market operation are not integrated into the same organization so there is not a centralized pool in the new market design. The actual real-time equality of demand and supply, given the bilateral contracts, will be carried out by the system operator through purchases and sales in a balancing market. For this purpose, a market System Balancing and Settlement Center is to be established within TEIAS [47].

4.2.1. The Balancing-Settlement Mechanism

TEIAS has the responsibilty for transmission system and market operations. A National Load Distribution Center (MYTM), established under TEIAS, performs system operations including load dispatch and real-time balancing. A Market Financial Reconciliation Center (PMUM) carries out settlement. The balancing-settlement mechanism and bilateral contracts run as follows. Bilateral contracts, which are one of the major components of the market model, are agreements whose terms and duration are freely determined by parties. These are subject to the provisions of private law. The purpose of the bilateral contracts is for the customer's entire electric energy needs to be met by the supplier.

According to EMRA, until the balancing and settlement mechanism becomes fully operational, those bilateral contracts that state-owned entities are a party to will be subject to regulation. This will enable market participants gain experience in carrying out bilateral contracts and ensure that they will not be subject to excessive extra costs arising from system imbalance.

Bilateral markets are supported by a balancing mechanism, suppliers have to meet the power requirements of their customers and this needs to be done in real time. The market rules have two purposes:

i. *To allow the system operator:* MYTM to perform the residual balancing of the National Power System in a technically and commercially efficient manner.(i.e.based on a least-cost order compatible with genset dynamic parameters)

Residual Balancing means: After generators have scheduled their gensets to meet the contracts they have sold, following the orders of MYTM for increasing or decreasing their output to ensure real time balancing of demand and supply in
the system.

ii. *To ensure that:* Parties that are short of supply pay a fair and cost reflective price for their energy shortfall. Parties that are in excess supply get paid a fair and cost reflective price for their spill energy

Supply shortage occurs when either:

- A generator has sold more contract energy in a settlement period than it generates and it therefore has a shortfall; or
- A distribution company or retailer has bought less contract energy than its customers' energy consumption in a settlement period, or

- A wholesaler has sold more contract energy than it has bought.

Excess supply occues when either:

- A generating company has sold less contract energy in a settlement period than it generates (it is ‘spilling’ energy into the balancing mechanism); or
- A distribution company or retailer has bought more contract energy than its customers energy consumption in a settlement period; or
- A wholesaler has sold less contract energy than it has bought.

Fair and cost reflective price means a price that reflects the system operator’s cost in balancing the system while not unfairly penalizing participants with long or short positions. In particular, it should allow the balancing mechanism to generate a soft balancing [61].

Settlement periods are time periods over which participants can reasonably be expected to contractually balance in the Turkish electricity market. Currently, there are three settlement periods (06:00-17:00, 17:00-22:00, 22:00-06:00), as the competition and required metering and communications infrastructure of the market improves, the number of settlement periods shall also increase. By the end of July 2006, settlement periods will be arranged on a hourly basis accoding to EMRA action plans.

4.3. Pricing Approaches

In Turkey, electricity prices include a substantial cross-subsidization from consumers in eastern regions and also from industrial users to households. With due regard to the operational problems as a result of the geographical structure, the size of the region (as compared to energy purchased) and technical/ financial characteristics, the “High Planning Council” decided to shift from the national tariff structure to a regional tariff structure. But this decision hasn’t been applied due to political pressure by consumer in the eastern regions.

Industrial prices in Turkey are comparable to household prices, unlike the position in various liberalised markets where industrial prices are often around half that for households. Lower industrial prices reflect the lower unit cost of delivery of large amounts of electricity to industrial customers. Therefore, the present tariff structure in Turkey can be said to include cross subsidy from industry to the household sector [60].

According to Atiyas *et al.* [57], electricity prices will increase in short term as due to tariff rebalancing towards cost-reflective tariffs which considers cross-subsidization, stranded costs, high distribution losses and financial deficits of EUAS and TEDAS, it is expected that electricity prices will increase. The cross subsidy to households will not survive with liberalisation as eligible consumers are entitled to switch to lower-cost sources under bilateral agreements, and as less efficient and/or higher cost regional distribution systems reflect these costs in user tariffs [61].

Figure 4.3 shows residential electricity prices as a percentage of industrial prices in selected OECD countries.

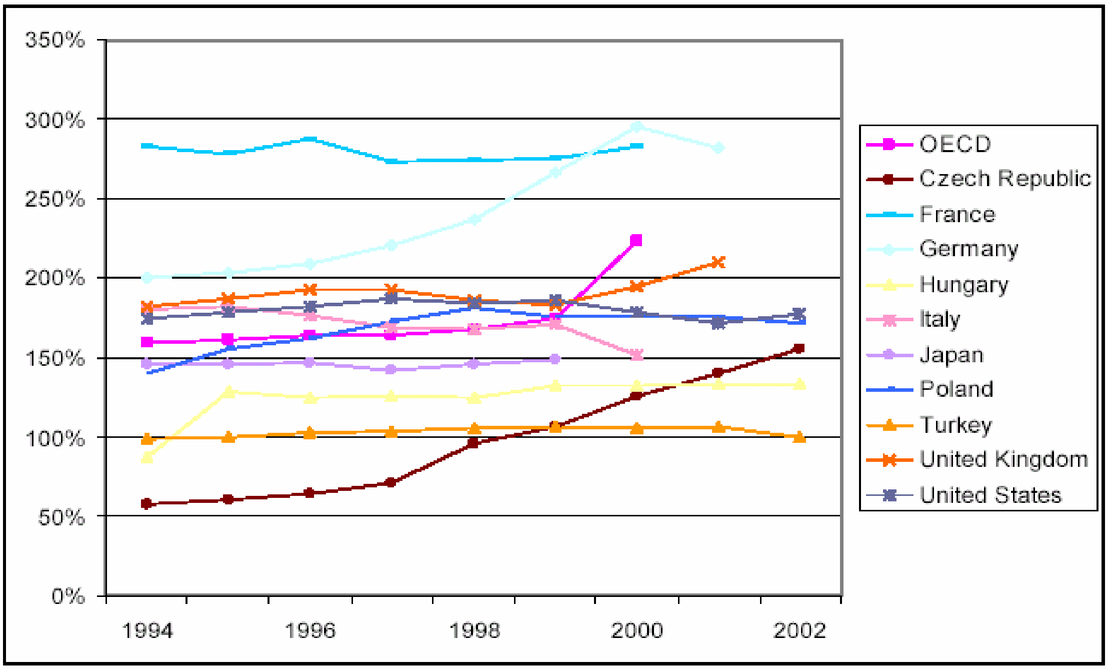


Figure 4.3. 1994-2002 Residential electricity prices as a percentage of industrial prices in selected OECD countries [62]

Figure 4.4 depicts industrial electricity prices in select OECD countries 1994-2002. Obviously, Turkey has much higher prices for industrial consumers than in all other major OECD countries except Japan.

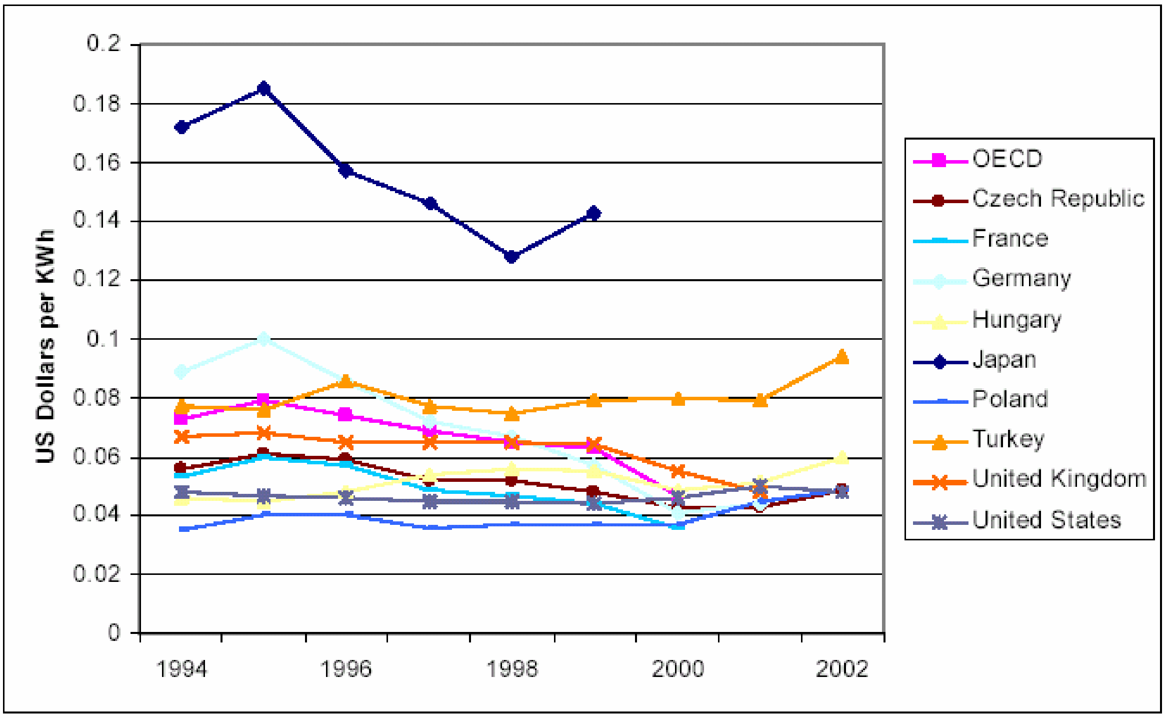


Figure 4.4. 1994-2002 Industrial electricity prices in selected OECD countries [62]

In the new market model, transmission and distribution activities which possess natural monopoly characteristics will be subject to retail sales and retail sales service price regulation that are provided to non-eligible consumers, as well as TETAS' wholesale price regulation.

The basic purpose of price regulation is to provide minimization of costs by increasing efficiency in the electricity market and emergence of prices reflecting costs. The responsibilities of EMRA regarding tariffs may be summarized as follows:

- To balance interests of consumers and suppliers,
- To encourage competition,
- To encourage economic efficiency,
- To ensure the financial viability of the sector.

4.3.1. Methods of Price Regulation

Generally, there are two options for price regulation:

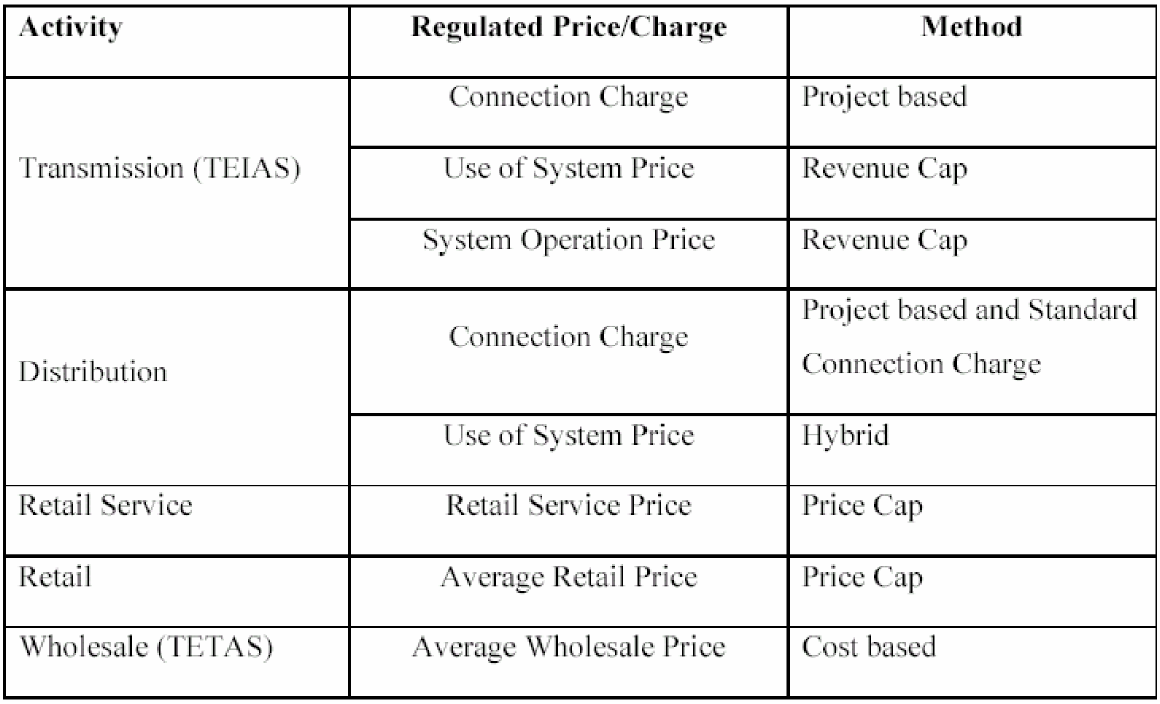
- Cost plus pricing (regulation based on actual turn out of costs)
- Price/revenue cap (regulation based on forecasts and targets of costs)

4.3.1.1. Cost Plus Pricing. In this pricing method, regulated prices are determined based on the results of the test year. In time, the prices are revised and reset to reflect actual costs in line with the increasing costs upon the request of the licensee, or they can be revised in line with the increasing profitability upon the initiative of the regulator. Prices change parallel to cost changes, however there are no strong incentives directed towards cost minimizing. This method has widely been used in the US where private companies usually are responsible for financing of infrastructure investments. This method is employed in the determination of an average wholesale price by TETAS [61].

4.3.1.2. Price Cap / Revenue Cap Regulation. Price and/or revenue cap regulation implies that price and/or revenue cap is fixed for a given period of time. In this way, company benefit from any savings in costs achieved over that period. During the period when the price cap is applied, prices are reduced every year at a predetermined rate [61].

The price control methods applicable in the electricity market as per the provisions of the Electricity Market Tariffs Regulations are summarized in Table 4.1.

Table 4.1. The price control methods applicable in the Turkish electricity market [61]



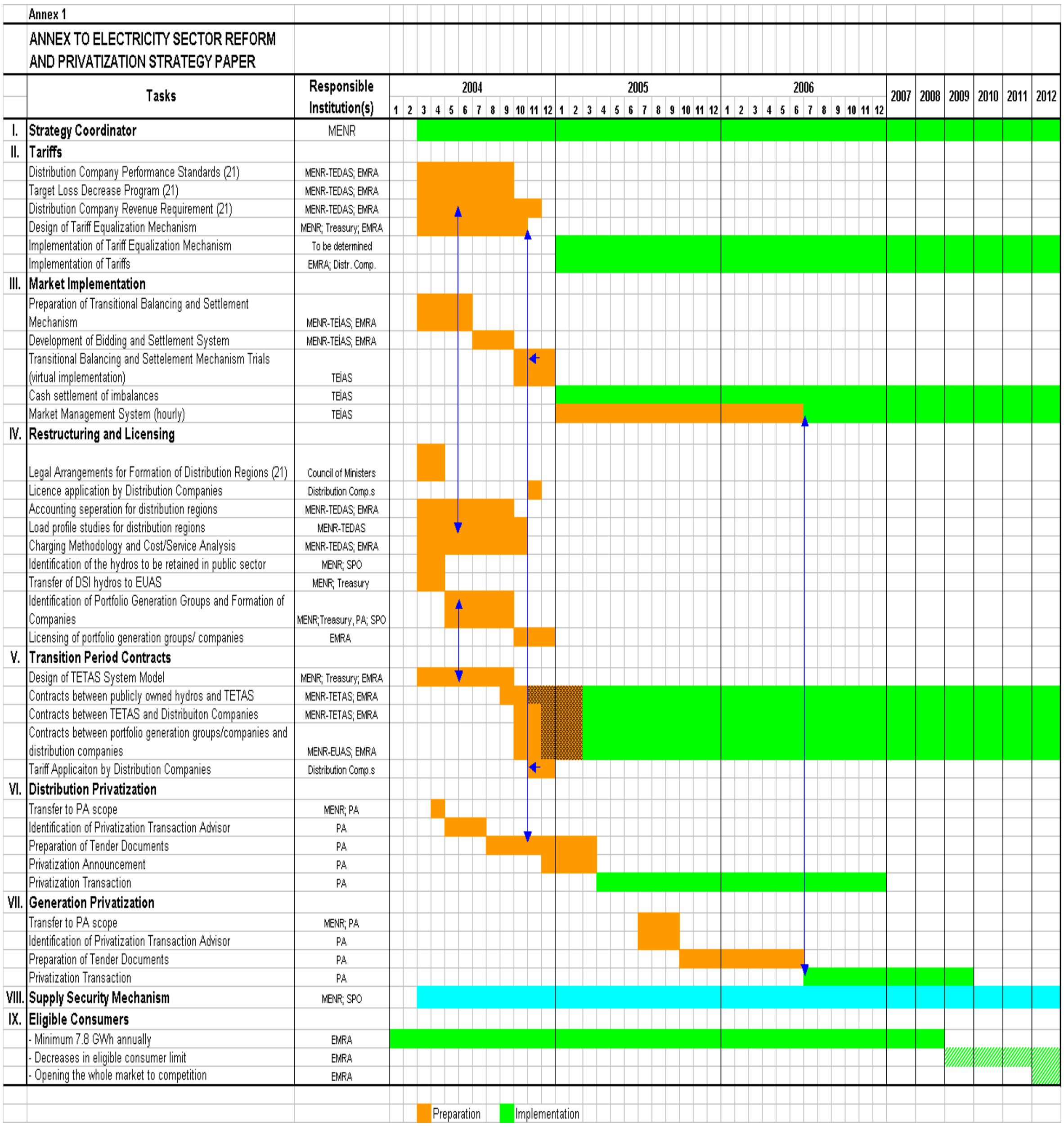
Activity	**Regulated Price/Charge**	**Method**
Transmission (TEIAS)	Connection Charge	Project based
	Use of System Price	Revenue Cap
	System Operation Price	Revenue Cap
Distribution	Connection Charge	Project based and Standard Connection Charge
	Use of System Price	Hybrid
Retail Service	Retail Service Price	Price Cap
Retail	Average Retail Price	Price Cap
Wholesale (TETAS)	Average Wholesale Price	Cost based

4.4. Future Prospects

Turkey adopted the bilateral contracting model which is less susceptible to market power problems than the alternative of a compulsory wholesale pool. The new system doesn’t include demand side participation since it involves an extra degree of complexity. In the future, demand side participation will be allowed because it could help to reduce the market power of generators in the balancing market.

The liberal market structure with a balancing and settlement regime will enhance security of supply because it facilitates participation of independent and relatively small generators. The transition contracts will initially cover about 85% of the total demand of non-eligible consumers in the related distribution region. These transition contracts will be set at regulated prices and will last for a maximum of 5 years, except for TETAS contracts. As they run out such contracts will be replaced by market priced bilateral contracts and thus, will ensure a smooth transition to liberal market. The balancing and settlement mechanism will be in compliance with the objective of creating a spot market and will include price signals to attract new investments.

In order to ensure that TEIAS performs its responsibilities arising from Electricity Market Law no. 4628 and related legislation and its system/ market operator roles in a sound manner, TEIAS' human resources and technical infrastructure will be strengthened [63].



Annex 1

ANNEX TO ELECTRICITY SECTOR REFORM AND PRIVATIZATION STRATEGY PAPER

	Tasks	Responsible Institution(s)
I.	**Strategy Coordinator**	MENR
II.	**Tariffs**	
	Distribution Company Performance Standards (21)	MENR-TEDAS; EMRA
	Target Loss Decrease Program (21)	MENR-TEDAS; EMRA
	Distribution Company Revenue Requirement (21)	MENR-TEDAS; EMRA
	Design of Tariff Equalization Mechanism	MENR; Treasury; EMRA
	Implementation of Tariff Equalization Mechanism	To be determined
	Implementation of Tariffs	EMRA; Distr. Comp.
III.	**Market Implementation**	
	Preparation of Transitional Balancing and Settlement Mechanism	MENR-TEİAS; EMRA
	Development of Bidding and Settlement System	MENR-TEİAS; EMRA
	Transitional Balancing and Settelement Mechanism Trials (virtual implementation)	TEİAS
	Cash settlement of imbalances	TEİAS
	Market Management System (hourly)	TEİAS
IV.	**Restructuring and Licensing**	
	Legal Arrangements for Formation of Distribution Regions (21)	Council of Ministers
	Licence application by Distribution Companies	Distribution Comp.s
	Accounting seperation for distribution regions	MENR-TEDAS; EMRA
	Load profile studies for distribution regions	MENR-TEDAS
	Charging Methodology and Cost/Service Analysis	MENR-TEDAS; EMRA
	Identification of the hydros to be retained in public sector	MENR; SPO
	Transfer of DSI hydros to EUAS	MENR; Treasury
	Identification of Portfolio Generation Groups and Formation of Companies	MENR;Treasury, PA; SPO
	Licensing of portfolio generation groups/ companies	EMRA
V.	**Transition Period Contracts**	
	Design of TETAS System Model	MENR; Treasury; EMRA
	Contracts between publicly owned hydros and TETAS	MENR-TETAS; EMRA
	Contracts between TETAS and Distribuiton Companies	MENR-TETAS; EMRA
	Contracts between portfolio generation groups/companies and distribution companies	MENR-EUAS; EMRA
	Tariff Applicaiton by Distribution Companies	Distribution Comp.s
VI.	**Distribution Privatization**	
	Transfer to PA scope	MENR; PA
	Identification of Privatization Transaction Advisor	PA
	Preparation of Tender Documents	PA
	Privatization Announcement	PA
	Privatization Transaction	PA
VII.	**Generation Privatization**	
	Transfer to PA scope	MENR; PA
	Identification of Privatization Transaction Advisor	PA
	Preparation of Tender Documents	PA
	Privatization Transaction	PA
VIII.	**Supply Security Mechanism**	MENR; SPO
IX.	**Eligible Consumers**	
	- Minimum 7.8 GWh annually	EMRA
	- Decreases in eligible consumer limit	EMRA
	- Opening the whole market to competition	EMRA

Figure 4.5. Electricity sector reform and privatization strategy plan [63]

Working plan of the establishing Balancing and Settlement Mechanism is shown in Figure 4.6. In this figure transition periods of the Balancing and Settlement Regulation (G-DUY) are defined. As of now, transition period DUY, study of the implementation of G-

DUY and market administration system design process was prepared. Preparation of the final DUY and purchasing of the market administration system have partially completed. The virtual implementation and operation of the G-DUY has started by November 2004 and according to EMRA plan at the end of the virtual implentation period, system will be evaluated and required regulation changes will be made. Then real implementation period will be passed.

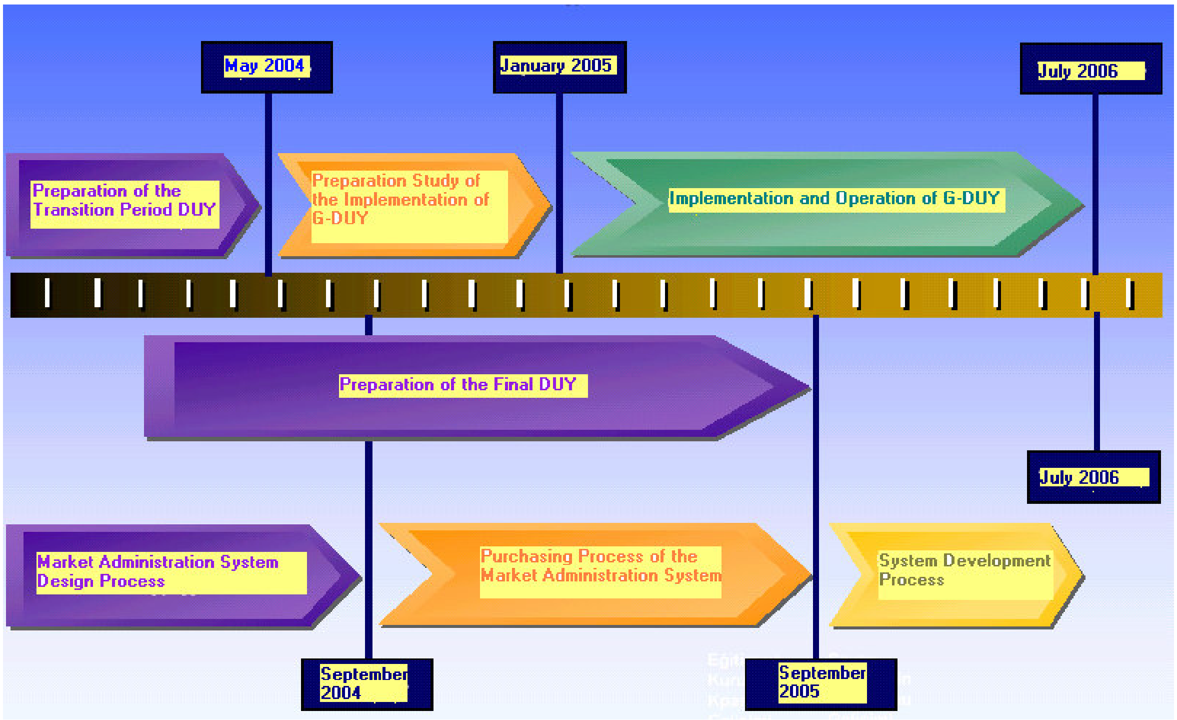


Figure 4.6. Working plan of the establishing balancing and settlement mechanism [64]

5. WIND SPEED DATA ANALYSIS

One of the analyses part of the study is wind speed data analysis for separate regions of Turkey. The statistical characteristics of the wind speed in 16 sites, have been analyzed by using wind speed data of the specified sites, consisting of hourly records over a five year period (1999-2003), recorded by the Turkish State Meteorological Service. The wind speed distribution is represented by a typical two parameter Weibull function. The analysis is based on two estimation methods: maximumlikelihood and linear regression. The analysis of wind data is mainly focused on the maximumlikelihood estimation method and the results are presented in terms of the method. A linear regression is also carried out in order to validate results. Finally, the sites that have high wind energy potential are selected as inputs to WEPE according to average wind speeds.

The wind direction data is required to determine maximum frequency of occurance for all sites. For this purpose, wind direction frequency distributions are prepared and given in Appendix A.

5.1. Data Collection

In Turkey, wind measurements are generally performed by two governmental institutions; The Turkish State Meteorological Service (SMO) and EIEI. In June 2002, Turkey's Wind Atlas was assembled and published by these two institutions. Observation results of 45 meteorology stations of Turkey are summarized in Table 5.1.

The wind speed data in the table below are not suitable for wind power planning since the related meteorology stations are mostly in or around villages, which is a high distorting factor. However, still many researchers used data from such meteorology stations to assess wind potentials in various regions of Turkey, because of lack of the research funding that would allow own measurements.

Table 5.1. Average wind speeds of some SMO stations in Turkey [11]

No	Station Name	Observation Period	Average Wind Speed	No	Station Name	Observation Period	Average Wind Speed
1	Afyon	1989-98	1,8				
2	Ağrı	1989-98	1,7	24	Kangal	1989-98	2,6
3	Akçabat	1989-98	1,9	25	Karapınar	1989-98	2,3
4	Akçakoca	1989-98	1,8	26	Karataş	1989-98	3,1
5	Amasra	1989-98	5,2	27	Kayseri	1989-98	1,8
6	Ardahan	1989-98	1,9	28	Kozan	1992-98	2,1
7	Bandırma	1989-98	4	29	Kuşadası	1989-98	2,2
8	Bergama	1989-98	3	30	Malatya	1991-98	1,9
9	Bozcada	1989-98	5,8	31	Mardin	1989-98	3,9
10	Bursa	1990-98	1,8	32	Muş	1989-98	1,1
11	Cihanbeyli	1989-98	2,9	33	Ordu	1989-98	1,5
12	Çanakkale	1989-98	3,7	34	Pazar	1989-98	2
13	Çorum	1989-98	1,8	35	Pınarbaşı	1989-98	3,9
14	Dalaman	1989-98	2,6	36	Polatlı	1989-98	2,5
15	Diyarbakır	1989-98	2,8	37	Samsun	1989-98	2,4
16	Elazığ	1989-98	2,7	38	Seydişehir	1989-98	1,9
17	Erzincan	1989-98	1,7	39	Siirt	1989-98	1,3
18	Erzurum	1989-98	2,8	40	Silifke	1989-98	2,1
19	Etimesgut	1989-98	2,2	41	Sinop	1989-98	2,9
20	Gönen	1989-98	2,4	42	Siverek	1989-98	2,9
21	Güney	1989-98	4,3	43	Suşehri	1989-98	3,2
22	Iğdır	1989-98	1	44	Şile	1989-98	3,4
23	İpsala	1989-98	2,9	45	Van	1989-98	2,5

EIE stations have good performance measuring wind speed data because they are generally located on hills far from urban life. Wind speed data fee of the EIE stations is very high and only 25 stations' data is available. Currently, there are only 6 EIE wind monitoring stations in operation. As compared to 229 meteorological stations of SMO, this is very small. The following table shows wind speeds registered at EIE stations.

Table 5.2. Annual wind speeds of all EIEI wind monitoring stations [65]

No	Station Name	Average Annual Wind Speed
1	Akhisar (Manisa)	6,3
2	Bababurnu (Zonguldak)	5,5
3	Bandırma-I	5,2
4	Bandırma-II	7,3
5	Belen (Hatay)	6,8
6	Bergama (İzmir)	6,3
7	Datça (Muğla)	5,7
8	Didim I (Aydın)	4,7
9	Didim II (Aydın)	4,1
10	Fethiye (İzmir)	3,1
11	Foça (İzmir)	5,3
12	Gelendost (Isparta)	4,8
13	Gelibolu (Çanakkale)	6,5
14	Gökçeada (Çanakkale)	6,8
15	Göktepe (Muğla)	5,5
16	Karabiga (Çanakkale)	6,6
17	Karaburun (İzmir)	6,6
18	Keles Bursa)	2,1
19	Kocadağ (Çeşme)	8,3
20	Nurdağı (Gaziantep)	6,9
21	Şenköy (Hatay)	7,6
22	Sinop	4,4
23	Söke (Aydın)	4,1
24	Yumurtalık (Adana)	4,0
25	Zengen (Konya)	3,4

For the data handling process, firstly observation results of 45 meteorology stations from Turkey's Wind Atlas (Figure 1.4.) are obtained and 16 stations which are suitable for the analysis are determined according to average wind speed and geographical locations. These locations characteristics are shown in Table 5.3.

In order to determine the wind power potential and project feasibility, at least a one year long measurement from an observation station is required. On the other hand, it is preferable to have wind speed data for five years, if the case is applicable [28,66]. In the present study, the five year wind speed data between 1999 and 2003 in hourly time series and the direction of the wind data for these 16 stations, measured by anemometers located at 10 m height on the mast are obtained from SMO. The data gathering process has been tedious, time consuming and governed by bureaucratic formalities.

Table 5.3. Locations of the selected SMO stations for analysis [67]

No	Station Name	Latitude (degree)	Longitude (degree)	Altitude (m)
1	Afşin	38°14′45′′	36°54′55′′	1221
2	Akhisar	38°55′19′′	27°50′15′′	113
4	Amasra	41°45′02′′	32°23′03′′	73
4	Bandırma	40°19′54′′	27°59′56′′	58
5	Bozcada	39°50′00′′	26°04′25′′	28
6	Çanakkale	40°08′33′′	26°24′00′′	6
7	Çeşme	41°7′0′′	37°46′60′′	0
8	Datça	36°45′20′′	27°39′55′′	24
9	Elbistan	38°12′7′′	37°11′34′′	1139
10	Güney	38°09′07′′	29°03′34′′	805
11	İskenderun	36°34′54′′	36°9′54′′	8
12	Mardin	37°18′50′′	40°43′37′′	1050
13	Pınarbaşı	38°43′33′′	36°23′30′′	1500
14	Sivas	37°02′32′′	39°45′20′′	1275
15	Şile	41°10′13′′	29°36′05′′	31
16	Yatağan	37°20′52′′	28°8′16′′	487

Some of the wind speed values in the regional data set are missing but they amount to less then 5 %. The missing values are estimated according to the remaining wind speed data of that particular day. That is, the average of the wind speed data for that particular day in other years has been assumed instead of the missing value.

5.2. Methodology

While deciding on a suitable location for a specified wind turbine, it's rather important to evaluate several essential properties of the site such as wind behavior, probability and availability. In order to find out statistical and dynamic wind characteristics of the proposed site, wind observations and statistical wind data analysis should be performed.

In order to estimate the wind energy output for a particular site, measurements of wind speed distribution are used according to the observations. The most commonly used functions for fitting a measured wind speed probability distribution in a given location over a certain period of time are the Weibull and Rayleigh distributions.

5.2.1. Weibull Distribution

The Weibull probability distribution function allows to model the availability of wind energy for a specific region by means of the probability of occurence of the wind speed. It is known that the Weibull distribution yields smaller root-mean-square error than the square-root-normal distribution when fitting actual distributions of observed wind speeds [30].

The two parameter probability density function of of the Weibull distribution is given by,

$$f(v) = \left(\frac{k}{c}\right)\left(\frac{v}{c}\right)^{k-1} \exp\left[-\left(\frac{v}{c}\right)^{k}\right] \tag{5.1.}$$

where $f(v)$ is the probability of observing wind speed v, k is the dimensionless Weibull shape parameter, and c is the Weibull scale parameter. The cumulative distibution function is given as:

$$F(v) = 1 - \exp\left[-\left(\frac{v}{c}\right)^{k}\right] \tag{5.2.}$$

Taking the natural logarithm of both sides of equation (6.2.) yields

$$\ln[1 - F(v)] = -\left(\frac{v}{c}\right)^{k} \tag{5.3.}$$

And taking the logarithms of equation (6.3.) yields

$$\ln\{-\ln[1 - F(v)]\} = k \ln\left(\frac{v}{c}\right) \tag{5.4.}$$

or,

$$\ln\{-\ln[1-F(v)]\} = k\ln(v) - k\ln(c) \qquad (5.5.)$$

Obviously, a plot of $\ln\{-\ln[1-F(v)]\}$ versus $\ln v$ presents a straight line. The gradient of the line is k and the intercept with the y-axis is $-k\ln c$. Thus, the Weibull parameters k and c can easily be estimated by the application of a linear regression.

The two significant parameters k and c are closely related to the mean value of the wind speed v_m as [28]

$$v_m = c\Gamma\left(1+\frac{1}{k}\right) \qquad (5.6.)$$

where $\Gamma(\ )$ is the gamma function of $(\ )$.

Once the scale and shape parameters have been computed, the most probable wind speed, v_{MP} and and the wind speed carrying maximum energy, v_{MaxE}, can be easily obtained [68]. The most probable wind speed shows the most frequent wind speed for a given wind probability distribution and is expressed by,

$$v_{MP} = c\left(\frac{k-1}{k}\right)^{1/k} \qquad (5.7.)$$

The wind speed that carries the maximum amount of wind energy can be written as follows:

$$v_{MaxE} = c\left(\frac{k+2}{k}\right)^{1/k} \qquad (5.8.)$$

The Weibull-based wind power density *P* per unit area of a site can be determined as [69],

$$P = \frac{1}{2}\rho c^3 \left(1 + \frac{3}{k}\right)$$

where ρ is the air density of the site.

5.2.2. Rayleigh Distribution

The Rayleigh distribution is a special case of the Weibull distribution and the difference between the Weibull distribution is the value of the shape parameter. If the value of the shape parameter is 2.0 then the Weibull distribution is named as Rayleigh distribution. The probability density function for the Rayleigh distribution can be simplified as:

$$f(v) = \frac{2v}{c^2} \exp\left[\left(-\frac{v}{c}\right)^k\right] \tag{5.9.}$$

5.2.3. Statistical Analysis

The coefficient of determination (COD) is used to evaluate the performance of the Weibull and Rayleigh distributions. This coefficient indicates how much of the total variation in the dependent variable can be accounted for by the fitted distribution. A higher COD represents a better fit using the theoretical or empirical function. Normally, a value higher than 70% of COD is acceptable. The COD is defined as:

$$COD = R^2 = 1 - \frac{\sigma_{y,x}^2}{\sigma^2{}_y} \tag{5.10}$$

where R is the correlation coefficient and σ_y is the standart deviation of the measured data y from its own mean value y_m.

$$\sigma_y = \left[\frac{\sum_{i=1}^{N} \left(y_i - ym\right)^2}{N-1} \right]^{1/2} \tag{5.11}$$

Where N is the total number of measurements and,

$$\sigma_{y,x} = \left[\frac{\sum_{i=1}^{N} (y_i - y_{ic})^2}{N-2} \right]^{1/2} \tag{5.12}$$

where the y_i are the actual values of y and y_{ic} are the values computed from the correlation equation for the same value of x.

Other goodness-of-fit parameters, the Chi-square (χ^2) error and root mean square error (RMSE), are also used for evaluating the performance of the Weibull and Rayleigh distributions. These are expressed as,

$$\chi^2 = \sum_{i=1}^{n} \frac{\left(y_i - y_{ic}\right)^2}{N-n} \tag{5.13}$$

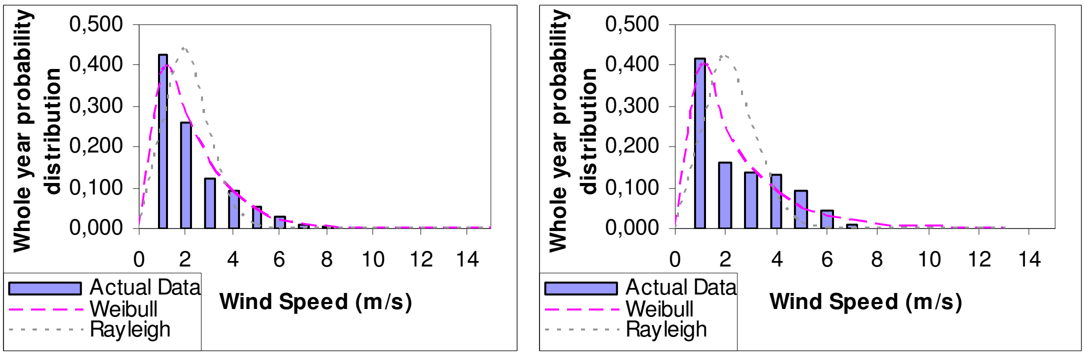
$$RMSE = \left[\frac{1}{N} \sum_{i=1}^{N} \left(y_i - y_{ic}\right)^2 \right]^{1/2} \tag{5.14.}$$

where n is the number of constants. The smaller the values of χ^2 and $RMSE$ are, the better the proposed distribution function approximates the measured data.

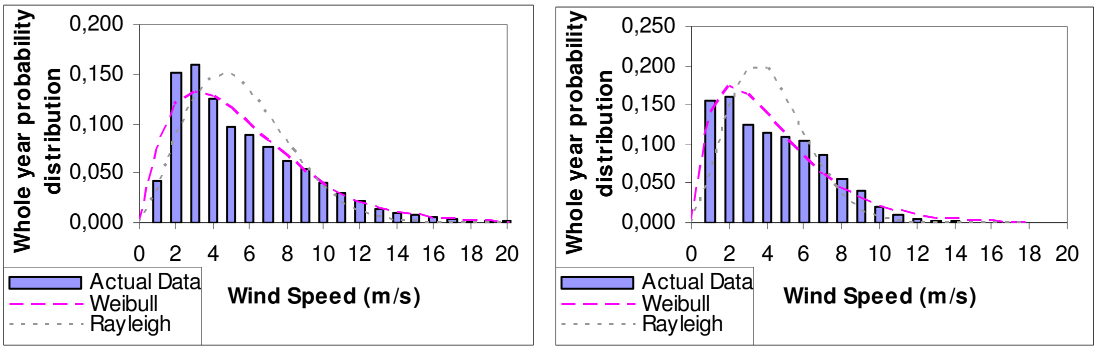
5.3. Results and Discussion

Throughout the wind speed data analysis, wind speed data for 16 stations over a five year period from 1999 to 2003 are analyzed based on the Weibull distribution. Two estimation methods, maximum likelihood and linear regression are used in order to fit a Weibull distribution to the data values. The preferred method in Weibull analysis is maximum likelihood estimation, this section therefore mainly includes the results with this methodology. Linear regression analysis results are also presented for comparison. The linear regression analysis is done in MS Excel and the maximum likelihood estimation is implemented in StatGraphics.

The main results obtained from the StatGraphics using maximumlikehood method are illustrated below for all sites. The frequency histogram and overall wind speed probability density fuctions for each site are given in the following figures.



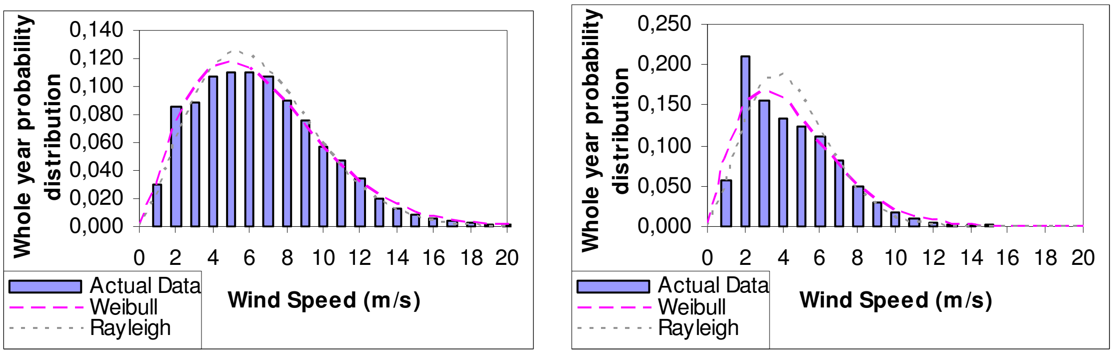
(a) Afşin (b) Akhisar



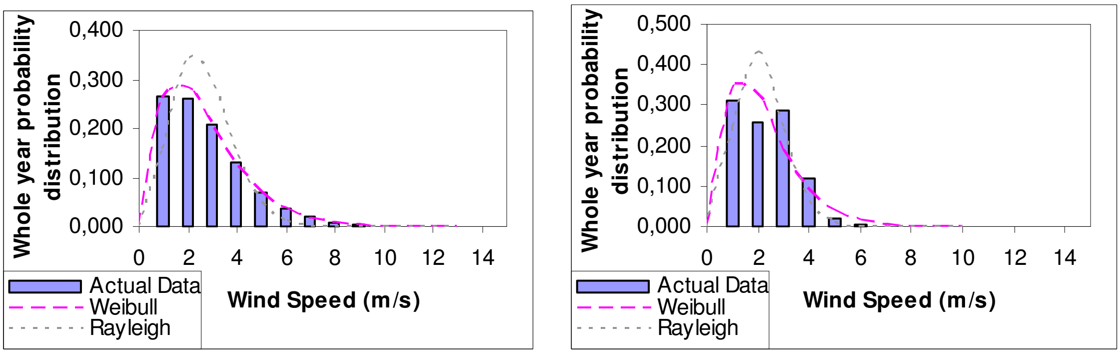
(c) Amasra (d) Bandırma

Figure 5.1. Fitted Weibull and Rayleigh distributions for Afşin, Akhisar,Amasra, Bandırma

As can be seen from Figure 5.1, for about 40 % of the time the wind blows, the wind speed ranges between 0 and 1 m/s, while for 28 % of time it ranges from 1 to 2 m/s in Afşin, and the Weibull probability density function shows peak at a wind speed of 1 m/s where as Rayleigh probability density function is around 2 m/s. Figure 5.1 reflects that for approximately 40 % of the time the wind speed ranges between 0 and 1 m/s and 15 % of the time it ranges from 1 to 2 m/s and there is a peak around 1 m/s. The frequency histogram for Amasra depicts that for nearly 16 % of the time the wind blows between 2 and 3 m/s. The Weibull probability density function for Amasra represents a peak at nearly 3 m/s. Figure 5.1 illustrates that wind speed ranges from 0 to 1 m/s for about 15 % of the time and for 16 % of time it ranges from 1 to 2 m/s in Bandırma. There is a slightly narrow peak around 2 m/s at the Weibull probability density function for Bandırma.



(a) Bozcada (b) Çanakkale

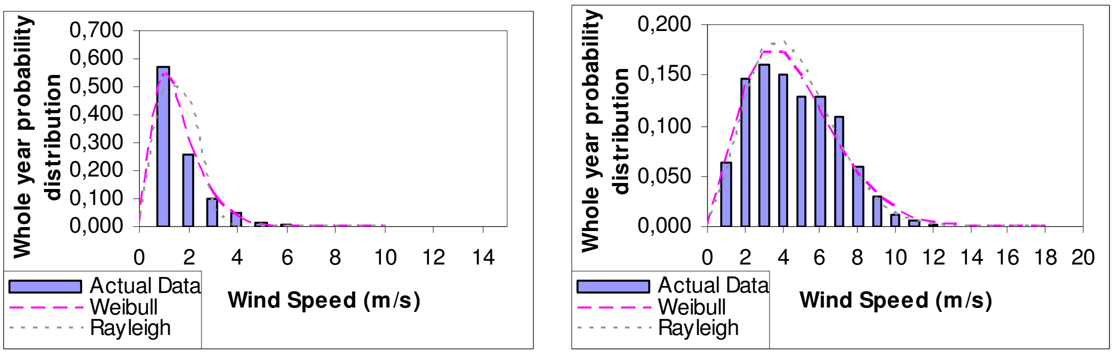


(c) Çeşme (d) Datça

Figure 5.2. Fitted Weibull and Rayleigh distributions for Bozcada, Çanakkale, Çeşme and Datça

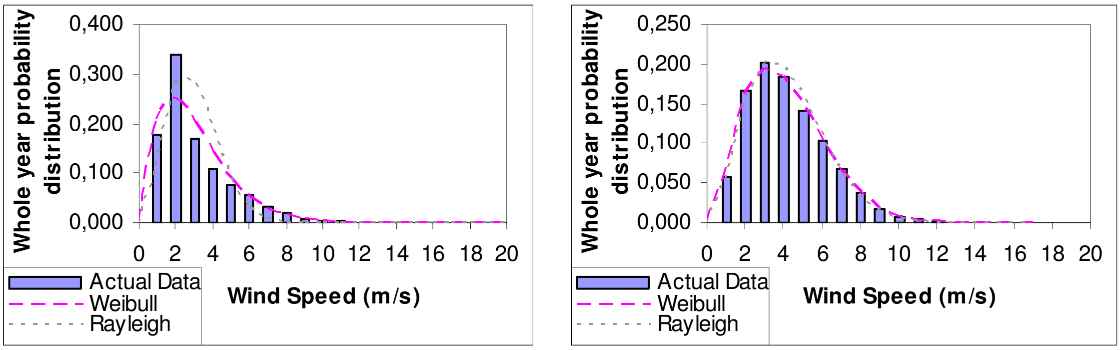
Figure 5.2 shows that for nearly 11 % of time the wind speed ranges between 6 and 7 m/s and for about 8 % time it ranges from 2 to 3 m/s in Bozcada also the weibull probability density distribution represents a peak at a wind speed of around 5 m/s. The frequency histogram for Çanakkale describes that the wind speed ranges from 1 to 2 m/s for about 21 % of the time, while for approximately 15 % of time it is between 2 and 3 m/s. As can be seen from Figure 5.2., the wind blows, the wind speed ranges from 0 to 1 m/s for about 26 % of the time and it is nearly between 1 and 2 m/s for 25 % of the time in Çeşme and there is a peak between 1 m/s and 2 m/s in the probability density function. Figure 5.2

indicates that for nearly 30 % of the time, the wind speed in Datça ranges from 0 to 1 m/s and for about 27 % of the time it ranges between 1 and 2 m/s. The Weibull probability distribution has a peak at around 1 m/s for the case of Datça.



(a) Elbistan

(b) Güney



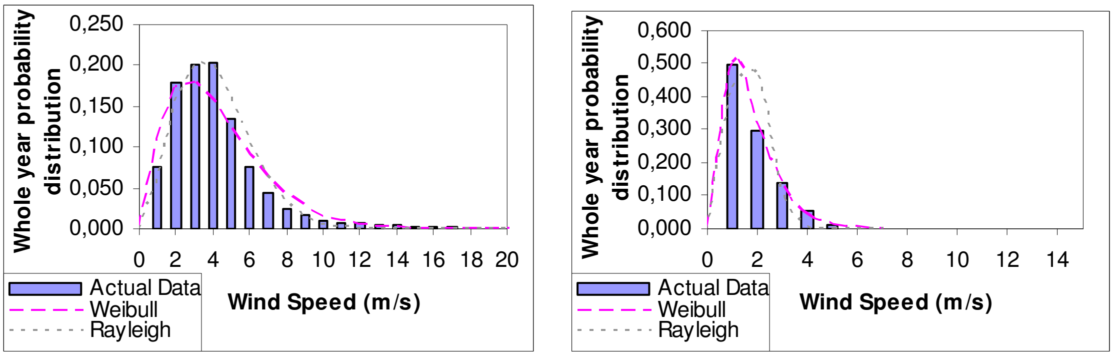
(c) İskenderun

(d) Mardin

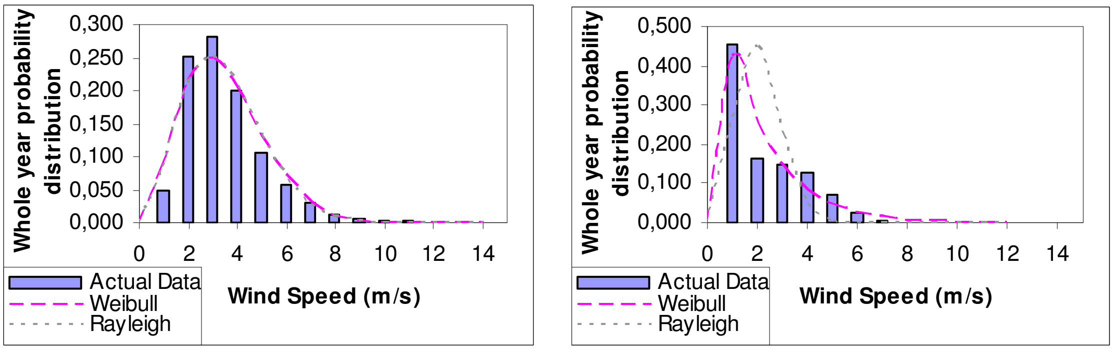
Figure 5.3. Fitted Weibull and Rayleigh distributions for Elbistan, Güney, İskenderun and Mardin

As presented in Figure 5.3, for approximately 56 % of the time the wind speed is between 0and 1 m/s and about 25 % percent of the time it ranges from 1 to 2 m/s in Elbistan also there is a peak at a wind speed of approximately1 m/s in the Weibull density fuction. Figure 5.3 reflects that the wind speed ranges from 2 to 3 m/s for about 16 % of the time and for 15 % of time it is between 1 and 2 m/s in Güney. The Weibull probability density distribution for Güney represents a peak near 3 m/s. The frequency histogram for İskenderun indicates that for nearly 34% of the time the wind blows between 1 and 2 m/s and for 18% of time the wind speed is from 1 to 2 m/s besides there is a peak at around 2 m/s. As can be seen from Figure 5.3, the wind speed ranges between 2 and 3 m/s for about

20% of the time and it is from 3 to 4 m/s for 17% of the time in Mardin. The Weibull probability density distribution for Mardin shows a peak at around 3 m/s.



(a) Pınarbaşı (b) Sivas



(c) Şile (d) Yatağan

Figure 5.4. Fitted Weibull and Rayleigh distributions for Pınarbaşı, Sivas, Şile and Yatağan

Figure 5.4 represents that the wind speed ranges from 3 to 4 m/s for about 21% of the time, while for 20 % of the time it is between 2 and 3 m/s in Pınarbaşı also there is a slightly wide peak at around 2 m/s in the weibull probability function. As shown in Figure 5.4., for approximately 50% of the time the wind blows between 0 and 1 m/s and it ranges from 1 to 2 for nearly 16% of the time in Sivas. The weibull probability density distribution has a peak at around 1 m/s for the case of Sivas. The frequency histogram for Şile depicts that for about 28% of the time the wind speed ranges from 2 to 3 m/s and for nearly 25% of the time the wind speed varies from 1 to 2 m/s also the weibull probability density distribution indicates a peak at around 3 m/s. Lastly, Figure 5.4 shows that for approximately 45% of the time the wind speed ranges from 0 to 1 m/s and for nearly 16%

of the time it is between 1 and 2 m/s. In addition there is a peak at around 1 m/s in the weibull probability density fuction.

The maximumlikelihood estimation method is applied in the Weibull analysis using StatGraphics and the results are presented in Table 5.4.

Table 5.4. Results of the Weibull analysis based on maximumlikelihood estimation

Site	Shape Parameter [*k*]	Scale Parameter [*c*]	Average Wind Speed (m/s)	Median Wind Speed (m/s)	Most Prob. Wind Speed (m/s)	Max. Energy Wind Speed (m/s)	Wind Power Density (W/m^2)
Afşin	1,179	1,830	1,73	1,34	0,24	4,19	11,58
Akhisar	1,025	1,938	1,92	1,36	0,00	5,58	17,31
Amasra	1,481	5,657	5,11	4,42	1,24	8,98	336,14
Bandırma	1,345	4,206	3,86	3,20	0,80	7,78	147,38
Bozcada	1,797	6,821	6,07	5,56	1,68	8,02	518,34
Çanakkale	1,617	4,479	4,01	3,57	1,06	6,20	158,03
Çeşme	1,366	2,389	2,19	1,83	0,47	4,31	26,98
Datça	1,378	1,875	1,71	1,44	0,37	3,33	12,70
Elbistan	1,238	1,236	1,15	0,92	0,19	2,61	3,48
Güney	1,816	4,577	4,07	3,74	1,13	5,30	141,90
İskenderun	1,403	2,820	2,57	2,17	0,58	4,87	43,19
Mardin	1,842	4,123	3,66	3,38	1,02	4,67	99,81
Pınarbasi	1,530	4,086	3,68	3,22	0,93	6,16	103,89
Sivas	1,280	1,329	1,23	1,00	0,23	2,66	4,13
Şile	1,957	3,354	2,97	2,78	0,84	3,47	58,84
Yatağan	1,039	1,775	1,75	1,25	0,06	5,00	12,53

As can be seen from Table 5.4, the five year values of the two Weibull parameters, the scale parameter c (m/s) and the shape parameter k (dimensionless) are determined using the maximumlikelihood estimation method. The average mean speed, median wind speed, most probable wind speed, wind speed carrying maximum energy and wind power densities are calculated according to the weibull parameters.

The shape parameter, k, tells how peaked the distibution is, i.e. if the wind speeds always tend to be very close to a certain value, the distibution will have a high k value, and lead to a peak. The five year values of k range between 1,025 and 1,957 with an average value of 1,446 for all sites. Şile, Mardin, Güney, Bozcada and Çanakkale have high k values which indicate certain wind speed values. On the other hand, Akhisar, Yatağan, Afşin, Sivas and Elbistan have lower shape parametes so the wind speeds at those sites are scattered. Other sites have average k values and there are slightly peaked wind speeds available.

The scale parameter is used to indicate on the average how windy the site is. Table 5.4 shows that the highest scale parameter estimated is 6,821 m/s in Bozcada and the lowest one is 1,208 m/s in Elbistan. Therefore, the most windy site is Bozcada and the least windy site is Elbistan. The sites with high scale parameters are Bozcada, Amasra, Güney, Pınarbaşı, Çanakkale, Bandırma and Mardin.

As we look at the average wind speed values, the highest average wind speed is found for Bozcada with 6,07 m/s and the lowest average wind speed calculated as 1,15 m/s for Elbistan. In that case the most attractive site for wind energy utilization is Bozcada due to the highest average wind speed. The results obtained using linear regression method are given in Table 5.5. The linear regression method is not prefered in practice (compared to other statistical methods such as maximumlikelihood estimation) method but it gives highly accurate results. A Weibull analysis based on this method yields the following results.

Table 5.5. Results of the Weibull analysis based on linear regression

Site	Shape Parameter (k)	Scale Parameter (c)	Average Wind Speed (m/s)	Median Wind Speed (m/s)	Most Probable Wind Speed (m/s)	Maximum Energy Wind Speed(m/s)	Wind Power Density (W/m^2)
Afşin	1,307	1,787	1,65	1,35	0,32	3,46	10,02
Akhisar	0,994	1,939	1,94	1,34	0,00	5,88	17,74
Amasra	1,631	5,555	4,97	4,44	1,32	7,58	298,69
Bandırma	1,254	4,245	3,95	3,17	0,69	8,78	159,11
Bozcada	1,798	6,862	6,10	5,60	1,69	8,06	527,56
Çanakkale	1,740	4,416	3,93	3,58	1,08	5,46	144,49
Çeşme	1,395	2,370	2,16	1,82	0,48	4,14	25,96
Datça	1,187	1,925	1,82	1,41	0,26	4,35	15,25
Elbistan	1,411	1,208	1,10	0,93	0,25	2,07	2,97
Güney	1,718	4,611	4,11	3,73	1,12	5,81	150,24
İskenderun	1,615	2,757	2,47	2,20	0,65	3,82	36,75
Mardin	1,910	4,100	3,64	3,38	1,02	4,39	95,99
Pınarbasi	1,779	4,016	3,57	3,27	0,99	4,80	89,50
Sivas	1,336	1,313	1,21	1,00	0,25	2,46	3,87
Şile	2,255	3,305	2,93	2,81	0,82	2,77	51,80
Yatağan	1,037	1,764	1,74	1,24	0,06	4,98	12,32

It is observed that the results based on maximumlikelihood estimation are very close to the linear regression results. Differences of the two methods are show in Table 5.6.

Table 5.6. Comparison of maximumlikelihood linear regression methods

Site	Difference		
	Shape Parameter (k)	Scale Parameter (c)	Average Wind Speed(m/s)
Afşin	-0,128	0,043	0,08
Akhisar	0,031	-0,001	-0,02
Amasra	-0,15	0,102	0,14
Bandırma	0,091	-0,039	-0,09
Bozcada	-0,001	-0,041	-0,03
Çanakkale	-0,123	0,063	0,08
Çeşme	-0,029	0,019	0,03
Datça	0,191	-0,05	-0,11
Elbistan	-0,173	0,028	0,05
Güney	0,098	-0,034	-0,04
İskenderun	-0,212	0,063	0,1
Mardin	-0,068	0,023	0,02
Pınarbasi	-0,249	0,07	0,11
Sivas	-0,056	0,016	0,02
Şile	-0,298	0,049	0,04
Yatağan	0,002	0,011	0,01

In terms of the linear regression method, the lowest shape parameter estimated is 0,994 and the highest shape parameter is 2,255. The highest scale parameter given in Table 5.5 is 6,862 m/ s and the lowest one is 1,208 m/s. The highest and the lowest estimated average wind speeds are 6,10 m/s and 1,10 m/s respectively.

Table 5.6 depicts the differences in the shape parameter, scale parameter, and average wind speed obtained from the maximumlikelihood and linear regression methods. Differences exceeding over 0,1 between shape parameters are found in Amasra, Şile, Pınarbaşı, İskenderun, Çanakkale, Elbistan, Datça and Afşin. On the other hand, there is only one location with difference over 0,1 between scale parameters, which is Amasra. Since the big differences between the shape parameters, the sites which have considerable differences concerning the average wind speed values are Amasra, Datça and Pınarbaşı.

As mentioned earlier, the results based on maximumlikelihood estimation method will be used in the remaining parts of the study.

The sites which present high wind characteristics are selected as inputs to the WEPE in terms of the average wind speed value that is higher than 3.5 m/s. The selected sites for the model are given in Table 5.7.

Table 5.7. Selected sites for the model

Site	Average Wind Speed (m/s)
Amasra	5,11
Bandırma	3,86
Bozcada	6,07
Çanakkale	4,01
Güney	4,07
Mardin	3,66
Pınarbasi	3,68

5.3.1. Statistical Analysis

The parameters for the statistical analysis, COD, RMSE and Chi-square error, are given in Table 5.8 for whole year wind speed distributions in all sites. As can be seen in Table 5.8, the highest R^2 values are usually obtained by using the Weibull distribution. Also, RMSE and χ^2 values of the Weibull distribution for many sites are lower than the values obtained from by the Rayleigh distribution.

Table 5.8. The statistical analysis parameters for whole-year wind speed distributions

	Weibull			Rayleigh		
Site	R^2	RMSE	Chi-Square	R^2	RMSE	Chi-Square
Afşin	98,1319	0,017297	0,000301	69,8304	0,069513	0,005942
Akhisar	93,3200	0,032222	0,001072	47,5086	0,090326	0,011448
Amasra	94,6195	0,011593	0,000136	83,1096	0,020539	0,000493
Bandırma	94,0067	0,014911	0,000242	71,1198	0,032731	0,001657
Bozcada	98,9828	0,004416	0,000020	97,9762	0,006229	0,000052
Çanakale	93,7969	0,016197	0,000263	87,3707	0,023111	0,000602
Çeşme	99,6710	0,006184	0,000043	85,3834	0,041220	0,002387
Datça	90,2244	0,044155	0,002047	81,0627	0,061456	0,005034
Elbistan	98,7222	0,022156	0,000503	85,4444	0,074777	0,006145
Güney	97,0037	0,011275	0,000135	95,2795	0,014152	0,000249
İskenderun	92,6664	0,024656	0,000616	83,3050	0,037201	0,001547
Mardin	99,6449	0,004488	0,000021	99,0792	0,007227	0,000061
Pınarbasi	95,9486	0,013497	0,000199	97,2634	0,011093	0,000129
Sivas	99,7552	0,010236	0,000133	86,6949	0,075470	0,007232
Şile	96,7932	0,018532	0,000387	96,9421	0,013090	0,000359
Yatağan	93,6569	0,035012	0,001239	49,6361	0,098657	0,013095

The results show that the Weibull approximation in many sites is found to be the most accurate distribution according to the highest value of R^2 and lowest values of RMSE and χ^2. The correlation coefficient values range between 90.2244 and 99.7552 for the Weibull distribution, while they vary from 47.5086 to 99.0792 for the Rayleigh distribution. As a result, the Weibull distribution returns higher correlation coefficient values and lower RMSE and Chi-square error values for most of the sites than the Rayleigh distribution and this indicates a better fit to the measured probability density distributions. Therefore, the Weibull distribution is used for wind speed data fitting at all sites.

6. ELECTRICITY LOAD FORECASTING

Load forecasting is very important for the electric industry especially in the deregulated market. The advent of electricity markets, widespread and significant computing power, real-time weather information and forecasts and load metering coupled with advances in various types of forecasting techniques have lead to an increasingly sophisticated use of load forecasting tools [70]. Studies aimed at forecasting electricity load can be divided into three categories:

i. Short-term forecasts: one hour to one week
ii. Medium Forecasts: one week to one year
iii. Long-term Forecasts: longer than a year

Due to the deregulation of the energy industries, supply and demand fluctuations, the changes of weather conditions and energy prices increasing by a factor of ten or more during peak usage, load forecasting is vitally important for utilities [71].

This chapter involves time series analysis of Turkish electricity consumption over a 5 year period between 1999 and 2003 based on the ARIMA methodology. ARIMA techniques are generally used to analyze time series for load forecasting particularly because of the accuracy and powerful approach to the solution of many forecasting problems. The data handling process, methodology of forecasting including a detailed explanation of ARIMA models and results from load data gathered from the Turkish Load Distribution Center are presented throughout the chapter.

6.1. Data Collection

In order to predict the electricity loads over a twenty-five year period starting from 2005, historical data is required to apply ARIMA models. The data obtaining process lasted nearly one month due to the bureaucratic issues. The load data for regional electricity consumptions between 1999 and 2003 is obtained in an hourly format from the National Load Distribution Center. Electricity consumptions of five predetermined regions, Western Anatolia, Central Anatolia, Northwestern Anatolia, Southeastern Anatolia and Others including Northeastern region, KEPEZ region and ÇEAŞ region and Thrace region, are modeled. Load distribution regions are presented in Figure 6.1.

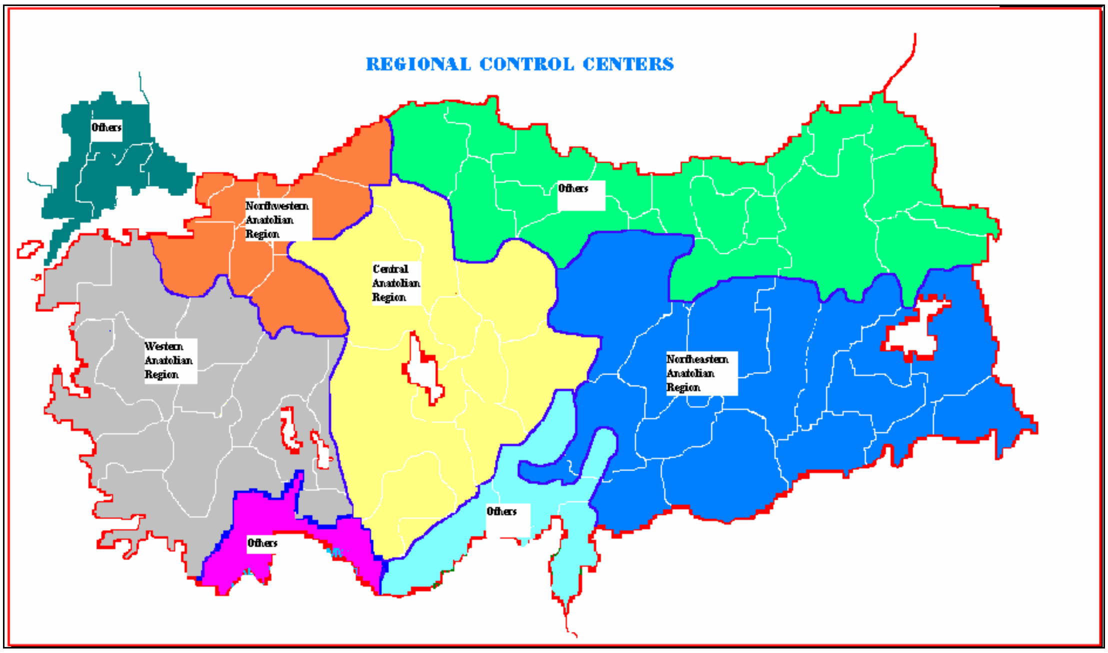


Figure 6.1. Regional load distribution centers in Turkey [72]

The hourly load data for five regions are presented in Figure 6.2. The data generally exhibits a clear linear trend and seasonality. However, there exists some peak values for Region 4 especially at the end of the observation period. For Northwestern Anatolia and Others only three years of data exists between 2001 and 2003 due to insufficient readings. Other regions' data consist of hourly data over a five year period. All raw data is processed to fit in the hourly data format using an Excel macro.

There are two methods for modeling the electricity load data: the first one is the parallel approach which includes partitioning the data and using a separate model for each hour of the day while the second one is a sequential approach which utilizes a single model for the day. In the sequential approach interdependence for the hours of the day is ignored. The partitioned series $X_t, t = 1,...,24$ represents the data partitioned by the hour of the day. In this study, we assume that there exists interdependence between the hours of the day and this interdependence remains unchanged in the forecasts.

The data set is separated into 24 subsets each containing the load for a specific hour of the day for all regions. Each of the subsets is treated as a single time series, and estimates are given accordingly. Using sectional data allows us to avoid modeling complicated intra-day patterns in the hourly load and enables us to observe the distinct pattern for each hour of the day.

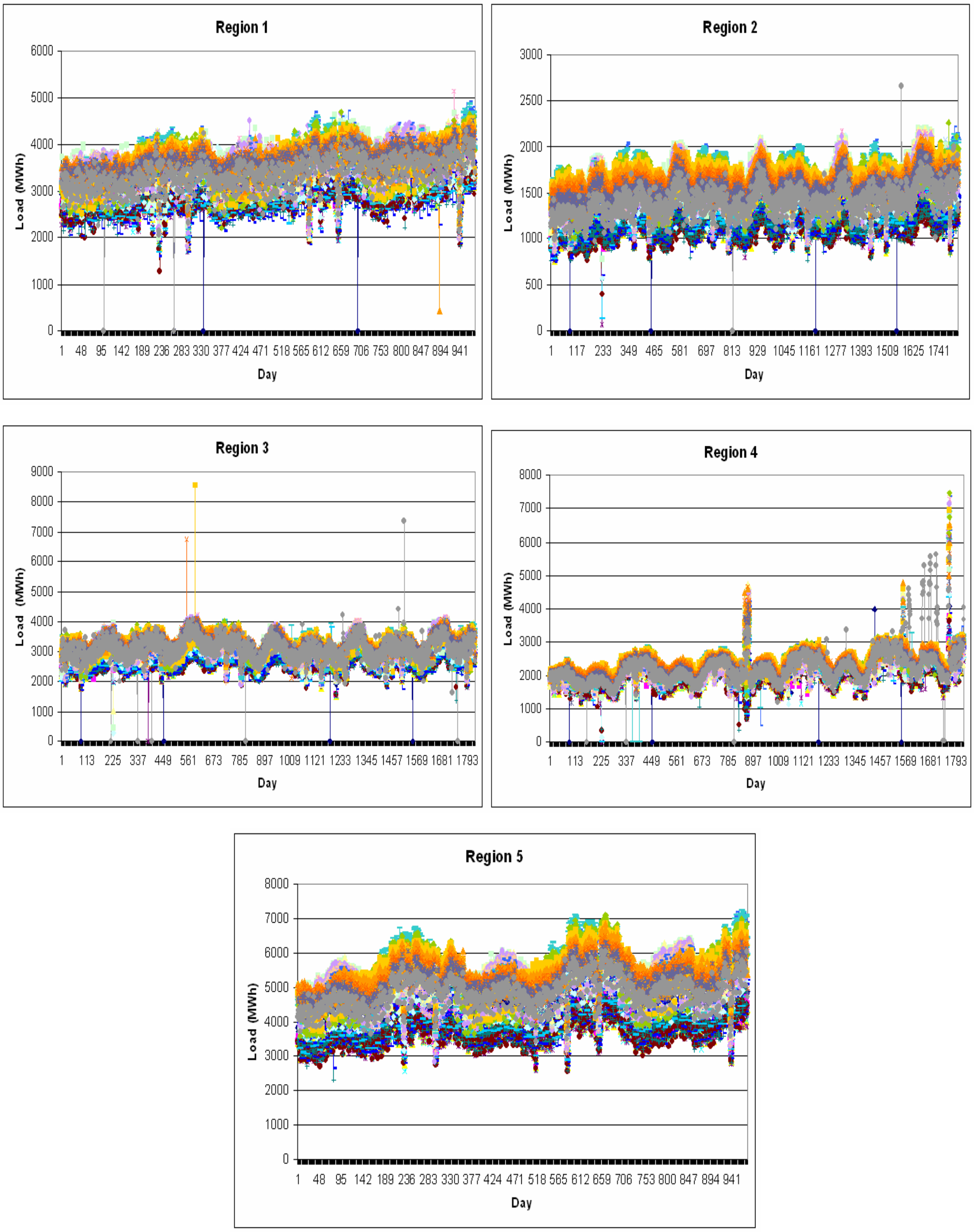


Figure 6.2. Hourly load data plots for regions

6.2. Methodology

6.2.1. Methods of Forecasting

Many of the load forecasting methods use statistical techniques or artificial intelligence algorithms such as regression, neural networks, fuzzy logic, and expert systems. The development and improvement of appropriate mathematical tools will lead to the development of more accurate load forecasting techniques.

For short-term load forecasting several factors should be considered, such as time factors, weather data, and possible customer classes. The medium and long-term forecasts take into account the historical load data.

Statistical approaches usually require a mathematical model that represents load as function of different factors such as time, weather, and customer class. The two important categories of such mathematical models are: additive models and multiplicative models. They differ in whether the forecast load is the sum (additive) of a number of components or the product (multiplicative) of a number of factors. Models that are used in the literature include autoregressive (AR) models, linear regression models, dynamic linear or nonlinear models, ARMAX models, methods based on optimization techniques, and curve fitting procedures [36]. The statistical models are attractive because some physical interpretation may be attached to their components, allowing engineers and system operators to understand their behavior. At the same time they offer relatively good performance [33].

6.2.2. Time Series Models

A time series is a time-ordered sequence of observations of a variable. The variable is observed at discrete time points, usually equally spaced. Time series analysis uses only the time series history of the variable being forecasted in order to develop a model for predicting future values [73].

Most time series patterns can be described in terms of two basic classes of components: trend and seasonality. There are no proven "automatic" techniques to identify trend components in the time series data; however, as long as the trend is monotonous (consistently increasing or decreasing) that part of data analysis is typically not very difficult. If the time series data contain considerable error, then the first step in the process of trend identification is smoothing. Smoothing always involves some form of local averaging of data. The most common technique is *moving average* smoothing which replaces each element of the series by either the simple or weighted average of n surrounding elements, where n is the width of the smoothing "window" [73].

Seasonality is another general component of the time series pattern. It can be defined as a pattern of a time series, which repeats at regular intervals every year. Seasonal patterns of time series can be examined via Autocorrelation Functions (ACF) and Partial Autocorrelation Functions. (PACF)

6.2.3. ARIMA Models

ARIMA processes are a class of stochastic processes used to analyze time series. The application of ARIMA methodology for the study or time series analysis is due to Box and Jenkins [42]. The acronym ARIMA stands for “Autoregressive-Integrated Moving Average”. There are many names encountered in the literature for the class, for example ARMA models, ARIMA models, Box-Jenkins method, linear time series models, etc.

Because of its power and flexibility, ARIMA is a complex technique; it is not easy to use, it requires a great deal of experience, and although it often produces satisfactory results, those results depend on the researcher's level of expertise (Bails & Peppers, 1982). Random-walk and random-trend models, autoregressive models, and exponential smoothing models (i.e., exponential weighted moving averages) are all special cases of ARIMA models [74].

A nonseasonal ARIMA model is classified as an "ARIMA(p,d,q)" model, where:

- p is the number of autoregressive terms,
- d is the number of nonseasonal differences, and

- *q* is the number of lagged forecast errors in the prediction equation.

In order to identify the appropriate ARIMA model for a time series, the order of differencing is identified and then the features of seasonality is removed.

6.2.3.1. Two Common Processes of ARIMA. *Autoregressive process:* Most time series consist of elements that are serially dependent in the sense that one can estimate a coefficient or a set of coefficients that describe consecutive elements of the series from specific, previous elements. This can be summarized in the equation:

$$x_t = \gamma + \phi_1 * x_{(t-1)} + \phi_2 * x_{(t-2)} + \phi_3 * x_{(t-3)} + ... + \phi_p * x_{(t-p)} + \varepsilon_t \qquad (6.1.)$$

Where

γ	constant (intercept)
$\phi_1, \phi_2, \phi_3 ... \phi_p$	the autoregressive model parameters.
ε_t	random error component

As can be seen from Equation 6.1, the process is an autoregressive process because the current observation x_t is regressed on previous realizations $x_{(t-1)}, x_{(t-2)}, x_{(t-3)} ... x_{(t-p)}$ of the same time series. Equation 6.1.is referred to an autoregressive process of order p, shortly AR(p).

Moving average process: Independent from the autoregressive process, each element in the series can also be affected by the past error (or random shock) that cannot be accounted for by the autoregressive component, that is:

$$x_t = \mu + \varepsilon_t - \theta_1 * \varepsilon_{(t-1)} - \theta_2 * \varepsilon_{(t-2)} - \theta_3 * \varepsilon_{(t-3)} - .... - \theta_p * \varepsilon_{(t-p)} \qquad (6.2.)$$

Where:

µ	constant
$\theta_1, \theta_2, \theta_3 ... \theta_p$	the moving average model parameters.
ε_t	random error component

The model above is called a moving average process of order q, abbreviated as MA(q). Each observation in the model depends on the random error component (ε_t) and a linear combination of prior random shocks.

6.2.3.2. Non-stationary Processes. Time series usually have no constant mean in that case if the parameters are not within a certain range then such time series are called non-stationary. In order to reduce a non-stationary stochastic time series to a stationary time series successive differencing is required. A non-stationary time series which can be reduced to a stationary series by applying a suitable degree of differencing is named as homogeneously non-stationary. A general model capable of representing a wide class of non-stationary time series is the autoregressive integrated moving average process of order (*p*,*d*,*q*), abbreviated *ARIMA (p,d,q)* [73].

6.2.3.3 Seasonal Processes. Seasonal ARIMA is a generalization and extension of the method introduced in the previous paragraphs to series in which a pattern repeats seasonally over time. In addition to the non-seasonal parameters, seasonal parameters need to be estimated. A seasonal ARIMA model is classified as an *ARIMA(p,d,q)x(P,D,Q)* model, where P is the number of seasonal autoregressive (SAR) terms, D is the number of seasonal differences, Q is the number of seasonal moving average (SMA) terms.

6.2.3.4 Steps in ARIMA Modeling. Box and Jenkins introduced a general methodology for developing an appropriate ARIMA time series model for use in forecasting in 1970. According to their approach, first the experimental model of the ARIMA class is identified through analysis of historical data. Then the estimation of the unknown parameters of the model is performed. Finally, diagnostic checks are performed to determine the adequacy of the model [73].

Identification: First, the appropriate order of differencing required to stationarize the series and removing of the seasonality is done. The number of times the series needs to be differenced to achieve stationarity is reflected in the *d* parameter. At this stage, whether or not to include a constant term in the model is determined. If the total differencing is higher than 1 then a constant term is not included in the model. In addition, parameters are adjusted and determined to eliminate any autocorrelation that remains in the residuals of the model.

Estimation: This step involves estimation of the parameters. The estimation process is performed on differenced data, before the forecasts are generated. The estimation procedure requires that the sums of squares of the ARIMA residuals be minimized.

Diagnostic Checking: After the experimental model has been fitted to the data, the adequacy of the model is examined. The major measure of the reliability of the model is the analysis of residuals. If the residuals contain some serial dependency then the selected ARIMA model is inadequate. Another quality measure of the model is the accuracy of the forecasts it generates. This is measured with respect to the past data set aside for this goal. The data which are not withheld are used to estimate the parameters of the model, the model is then tested on the data in the validation period, and forecasts are then generated. For the validation of the all ARIMA models, 200 data points are held out and data which are not held out are used to estimate the parameters of the model. A sample validation for ARIMA model at hour 1 p.m. (13:00) in Central Anatolia region is presented in Figures 6.3 and 6.4 and in Table 6.1.

We have 1826 data points covering a 5-year time horizon and of these, 200 are withheld for validation and as mentioned before, 9490 forecasts are generated into the future. The statistics of the forecast errors in both estimation and validation period are prepared and using the Analysis Summary report, all ARIMA models are compared and tested. Analysis Summary result for each of the model is given in load forecasting section of the accompanied CD.

Table 6.1. Validation period results for the sample model

Actual	Estimation	MAPE	Actual	Estimation	MAPE	Actual	Estimation	MAPE	Actual	Estimation	MAPE
1585	1541,99	2.7135	2004	2019,52	11.635	1995	2227,12	4.2843	1982	1990,62	1.8969
1944	1850,51	4.8091	1905	1961,58	1.9889	2084	2042,55	1.3017	1873	1957,9	3.5372
1956	1888,49	3.4514	2007	1933,05	0.7756	2077	2060,89	0.0461	1657	1714,76	2.4757
1881	1941,89	3.2371	1703	1786,29	2.3262	2078	2029,66	0.8206	2041	1836,19	1.9843
1899	1861,81	1.9583	2076	1986,59	1.4125	1995	2023,18	7.2844	2094	2041,47	2.3463
1830	1855,38	1.3868	2098	2011,06	0.5360	1983	1993,63	9.2644	2088	2116,01	0.2300
1815	1799,37	0.8611	2036	2089,75	1.5318	1713	1739,24	4.2875	2016	2088,12	1.7822
1524	1561,9	2.4868	2038	2050,04	0.3787	2049	2041,24	0.0308	1664	1975,79	3.1466
1790	1751,42	2.1553	1945	1999,03	0.9081	2046	2027,42	1.7628	1623	1726,3	5.1189
1910	1760,49	7.8277	2007	1943,52	0.3986	2072	2063,74	4.2399	1514	1400,78	7.9652
1954	1827,84	6.4564	1664	1772,05	0.2538	2060	2054,77	7.8344	1802	1793,01	2.5779
1952	1939,9	0.6198	2090	1966,99	3.3933	1927	1992,39	5.8154	1874	1883,74	2.9362
1835	1866,47	1.7149	2074	2094,35	2.1712	1892	1933,08	3.5822	1834	1887,39	30.1313
1909	1821,94	4.5605	2026	2091,75	3.8355	1745	1678,07	0.0598	1882	1893,65	36.0073
1634	1699,79	4.0263	2088	2028,45	2.4459	2074	2023,27	2.7430	1700	1786,04	20.9192
1945	1877,72	3.4591	2008	2031,37	3.9309	1999	2077,58	2.6257	1759	1730,38	1.5735
1978	1955,68	1.1284	1991	2016,93	4.2957	2083	1993,52	27.002	1577	1549,22	13.7975
2018	1996,64	1.0584	1698	1781,34	0.7774	2031	2046,79	9.5241	1779	1855,02	3.0831
2068	1992,4	3.6557	1997	1985,84	0.8561	1953	1969,72	4.9953	1810	1806,89	2.7190
1995	1997,72	0.1363	2040	2014,52	0.1742	1940	1943,38	1.9888	1771	1845,66	7.3123
2084	1938	7.0057	2018	2027,32	0.3406	1688	1693,75	2.2225	1746	1813,75	3.2053
1722	1861,39	8.0946	2048	2059,78	3.7114	2010	1935,4	3.6539	1666	1766,85	6.2636
2064	1979,72	4.0833	1978	2003,97	2.8258	2067	2008,59	0.8191	1656	1697,22	1.7938
2091	2053,88	1.7752	2018	1968,48	2.0445	2042	2000,25	1.4117	1462	1476,5	3.9308
2037	2057,29	0.9960	2068	1798,76	1.1647	2045	2068,82	3.4188	1712	1699,62	0.5767
1790	1713,31	0.7744	1686	1651,7	0.4349	1766	1799,5	2.0344	1511	1500,61	0.6876
1760	1737,09	2.9700	1450	1483,94	4.5328	1813	1748,87	2.3406	1787	1739,52	2.6569
1798	1797,17	3.6846	1705	1700,39	3.4858	1770	1726,18	0.2703	1861	1754,85	5.7039
1728	1742,18	4.8907	1688	1733,39	10.034	1794	1758,4	2.6889	1784	1804,98	1.1760
1870	1733,78	4.3068	1711	1735,64	2.5085	1533	1568,97	1.4400	1833	1807,55	1.3884
1524	1665,19	4.1439	1705	1696,55	1.3414	1813	1808,83	0.4956	1801	1725,48	4.1932
1711	1784,36	2.6399	1617	1677,52	3.5773	1860	1826,85	3.7427	1825	1766,67	3.1961
1749	1748,46	0.5907	1684	1649,21	18.737	1861	1802,44	2.0659	1540	1561,76	1.4129
1750	1780,85	2.7778	1483	1478,46	6.3647	1933	1834,05	0.3061	1841	1805,91	1.9060
1684	1755,4	3.1629	1755	1732,43	7.4782	1698	1833,25	1.2860	1797	1806,73	0.5414
1558	1680,06	6.4933	1767	1766,4	0.4988	1770	1724,37	0.0339	1730	1805,07	4.3393
1658	1561,58	5.8856	1615	1752,99	0.5197	1537	1491,87	8.5442	1726	1759,56	1.9443
1453	1505,05	0.9811	1914	1662,94	2.9111	1355	1763,28	13.117	1829	1729,49	5.4406
1721	1722,03	3.2453	1841	1793,1	0.6190	1086	1477,04	2.6018	1848	1792	3.0303
1728	1775,4	2.8520	1701	1829,87	5.0611	953	1152,36	7.5761	1556	1624,09	4.3759
1782	1735,21	1.1638	1424	1489,2	1.6270	1121	1103,36	4.5786	1811	1783,95	1.4936
1390	1765,34	1.3023	1681	1669,21	1.7615	1403	1209,42	0.7013	1791	1766,58	1.3634
1616	1462,09	4.9081	1679	1657,7	4.2731	1444	1488,52	1.2686	1823	1721,38	5.5743
1718	1632,18	0.5588	2077	1706,8	0.1718	1420	1381,39	17.823	1793	1807,65	0.8170
1520	1550,23	1.249	1735	1977,49	4.2156	1684	1560,86	13.976	1832	1749,88	4.4825
1748	1786,85	0.4618	1652	1743,54	3.8802	1724	1668,74	5.5411	1795	1809,55	0.8105
1786	1720,74	0.5751	1663	1642,21	6.0534	1790	1677,88	1.2501	1552	1639,2	5.6185
1758	1772,4	1.3129	1496	1399,49	2.4891	1756	1724,5	6.4512	1816	1782,07	1.8683
1729	1753,41	2.4539	1866	1790,48	0.9917	1794	1723,48	4.0471	1797	1824,9	1.5525
1645	1701,24	13.019	1775	1847,17	0.7231	1779	1768,74	4.0659	1792	1811,07	1.0641

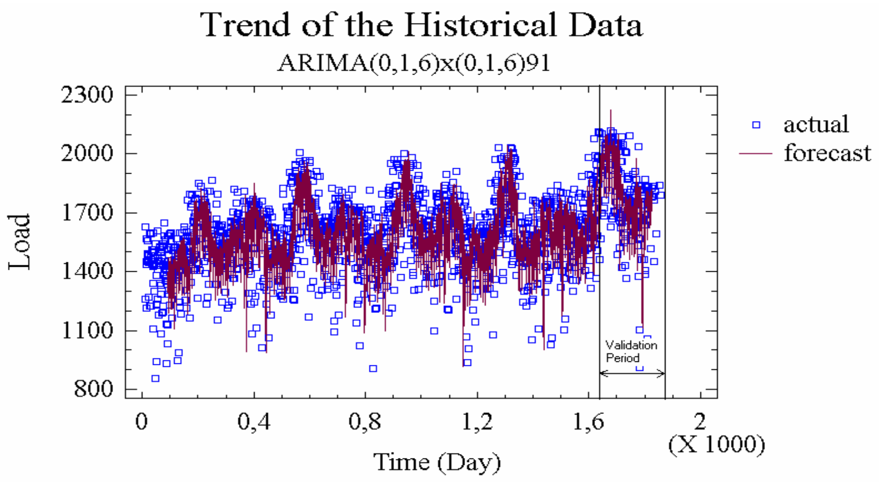


Figure 6.3.llustration of the validation period for the sample model

As can be seen from Table 6.1, actual data and forecasts are compared and corresponding MAPE values for each data point are estimated in the validation period. The MAPE value for the validation period is found as 3,7885 and in the estimation period it is estimated as 3,3411 which is similar. Also, Figure 6.4 shows the fitted values and actual data in the validation period.

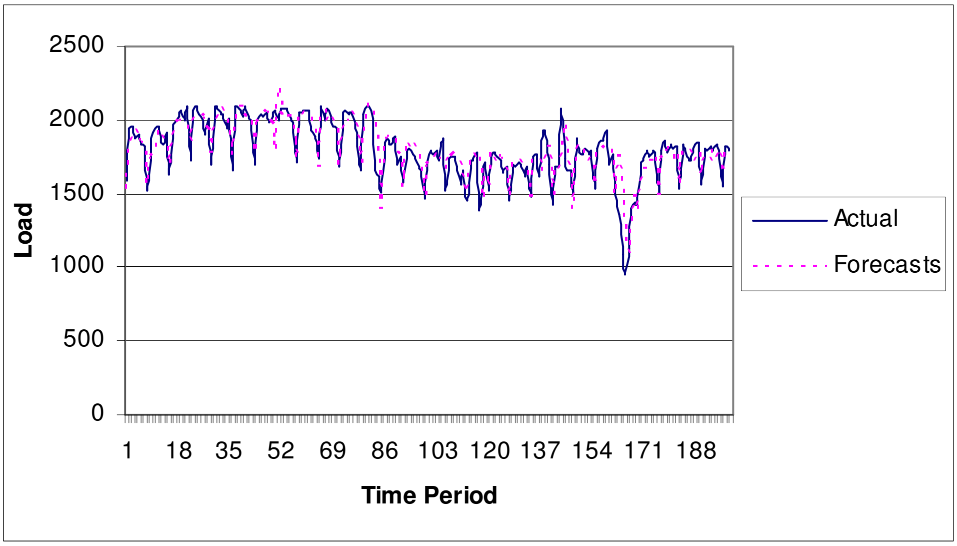


Figure 6.4. Comparison of the forecasts with the actual data of the validation period for the sample model

6.3. Model Results

Load predictions in an hourly format over a twenty-five year time horizon are prepared using proposed ARIMA models for all regions in Turkey. By analyzing hourly loads separately as a single series, twenty-four models are estimated for each node. The period is used for evaluating the forecasting performance between January 1, 1999 and December 31, 2003 for Western Anatolia, Central Anatolia and Southeastern Anatolia. The period for Northwestern Anatolia and Others spans from May 1,2001 to December 31,2003.

All the cases are computed on a machine equipped with Pentium IV with 512 Kb of RAM at 2.6 Ghz using StatGraphics. Each of the statistics in StatGraphics is based on the one-ahead forecast errors, which are the differences between the data value at time t and the forecast of that value made at time t-1. Running time including estimation and forecasting is about five minutes for each of the ARIMA models.

The Mean Absolute Percentage Error (MAPE) and Root Mean Square Error (RMSE) are used in order to evaluate forecast errors. The MAPE is defined as follows:

$$\text{MAPE}_t = \frac{1}{n}\sum_{i=1}^{n}\frac{\left|\hat{X}_{ti} - X_{ti}\right|}{X_{ti}} \qquad (6.3.)$$

Where

t hour of the day t=1,2,3...24

X_{ti} load at time i in hour t

$\hat{X}_{ti}$ estimate of X_i in hour t

n size of the sample

The MAPE measures the proportionality between error and load and is the most frequently used measure of forecasting accuracy in the load forecasting literature [34,35] As another measure, RMSE are used to evaluate forecast errors but the standart measure is selected as MAPE according to the load forecasting literature.

The root mean square error (RMSE) formula is given below:

$$\mathrm{RMSE}_t = \frac{1}{n}\sqrt{\sum_{i=1}^{n}(\hat{X}_{ti} - X_{ti})^2} \qquad (6.4.)$$

Where

t	hour of the day	$t = 1,2,3...24$
X_{ti}	load at time i in hour t	
$\hat{X}_{ti}$	estimate of the load at time i in hour t	
n	size of the sample	

The RMSE is the most commonly used measure of success of numerical prediction.

6.3.1. Identification

As mentioned before, time series analysis based on ARIMA is applied to sectional data where the load for each hour of the day is treated separately as a series. The first step of fitting the ARIMA model is the determination of the order of differencing to stationarize the series. For each region, load data series have strong positive autocorrelations thus, they need a higher order of differencing. First, a non-seasonal differencing is applied to selected the initial representative model ARIMA (0,0,0) a with constant. The procedure is displayed via an example for Region 1 in hour one in Figure 6.5.

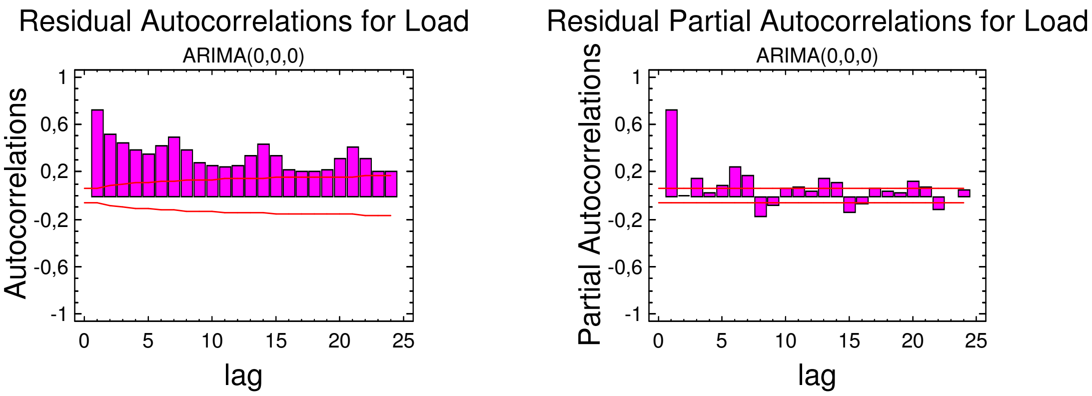


Figure 6.5. Residual autocorrelations of ARIMA (0,0,0)

After taking one non-seasonal difference the residual plot and the autocorrelations are presented in representative ARIMA(0,1,0) with constant model in Figure 6.6.

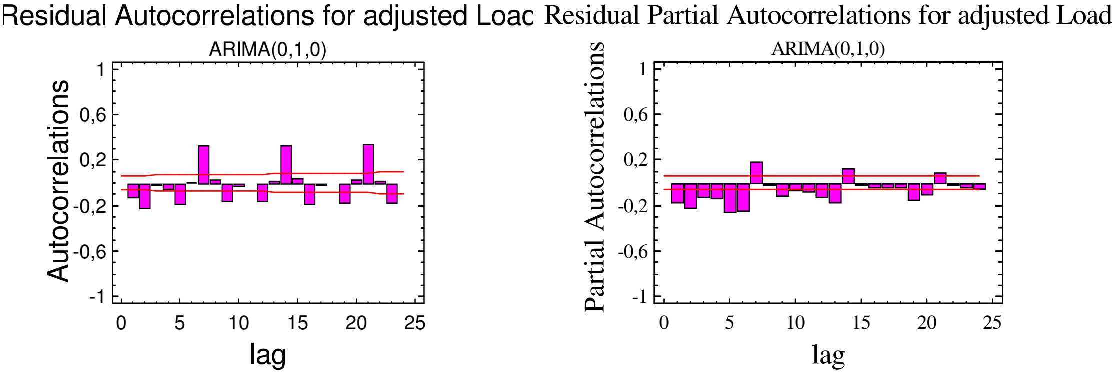


Figure 6.6. Residual autocorrelations of ARIMA (0,1,0)

The differenced series looks more stationary but there is still very strong autocorrelation at the seasonal period. Due to the strong and stable seasonal pattern, one order of seasonal differencing is used. After a seasonal difference the representative model, ARIMA (0,1,0)*(0,1,0)91, looks like in Figure 6.7.

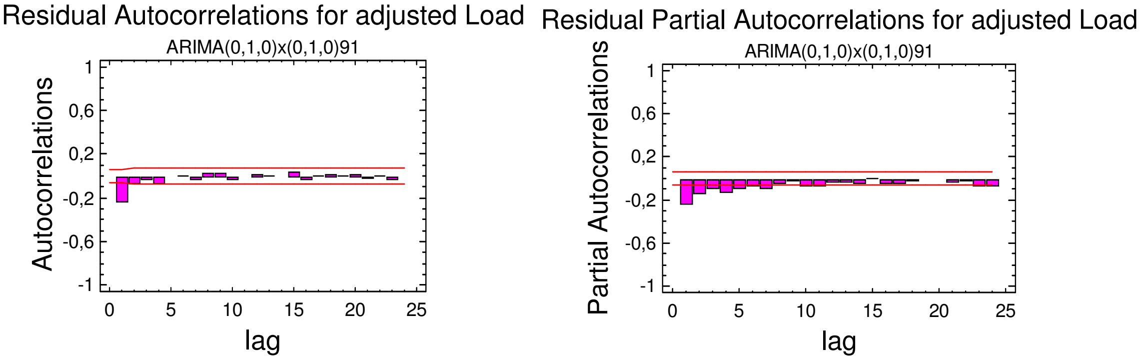


Figure 6.7. Residual autocorrelations of ARIMA (0,1,0)*(0,1,0)91

As can be seen from the last Figure, autocorrelation is mostly removed from the representative model.

Since there is a dip in the ACF with one difference of each type, the next step is to add non-seasonal and seasonal moving average terms to the model. Also, there is no constant term because two orders of differencing are involved. First by adding one moving average (MA(1)) and one seasonal moving average (SMA(1)) term to the model, we start improving the model step by step. Then for each step we increase one moving average term and seasonal moving average term in order to find the best suitable ARIMA model. Experimental ARIMA models are presented in Figure 6.8.

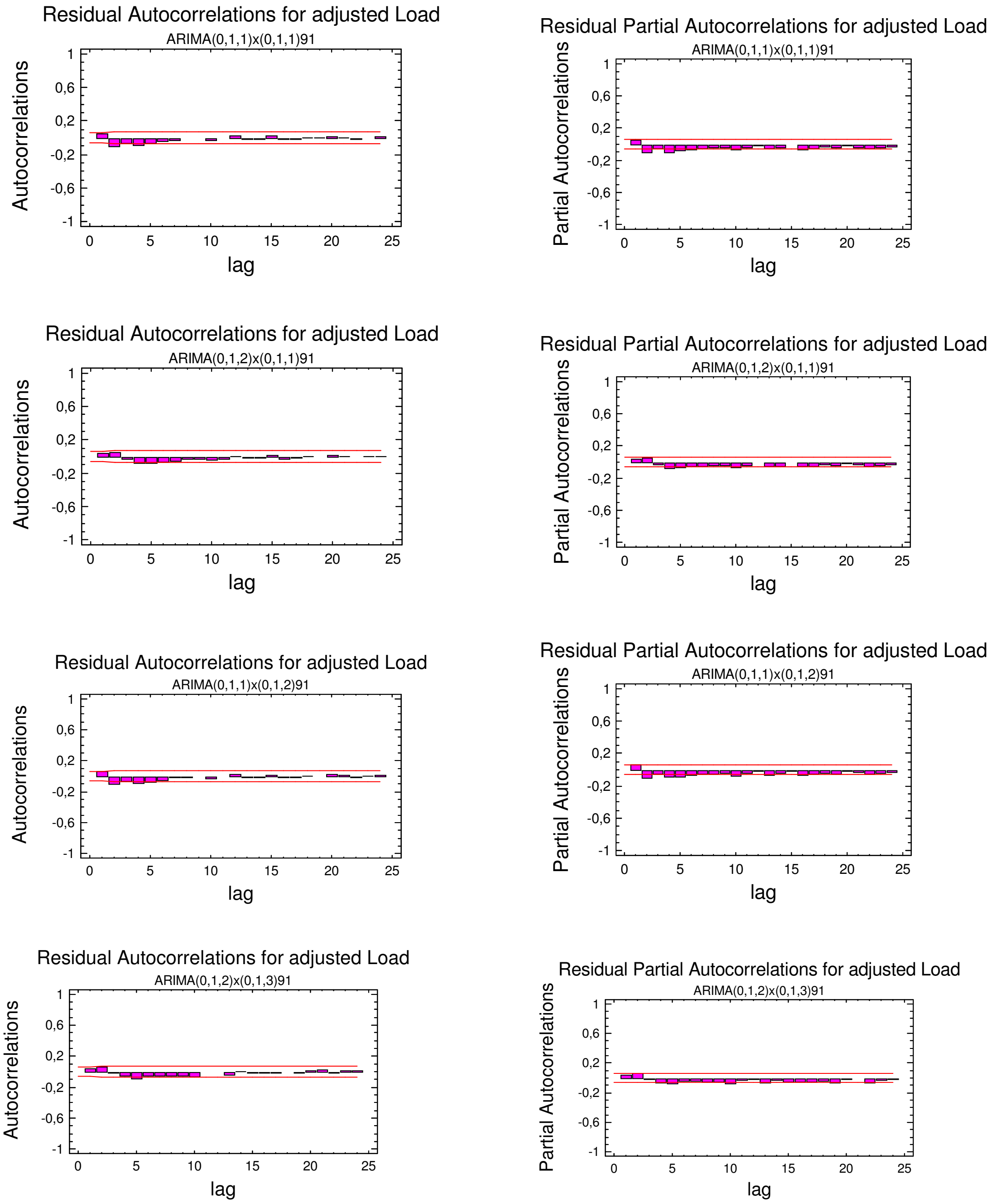


Figure 6.8. Autocorrelations of the experimental ARIMA models

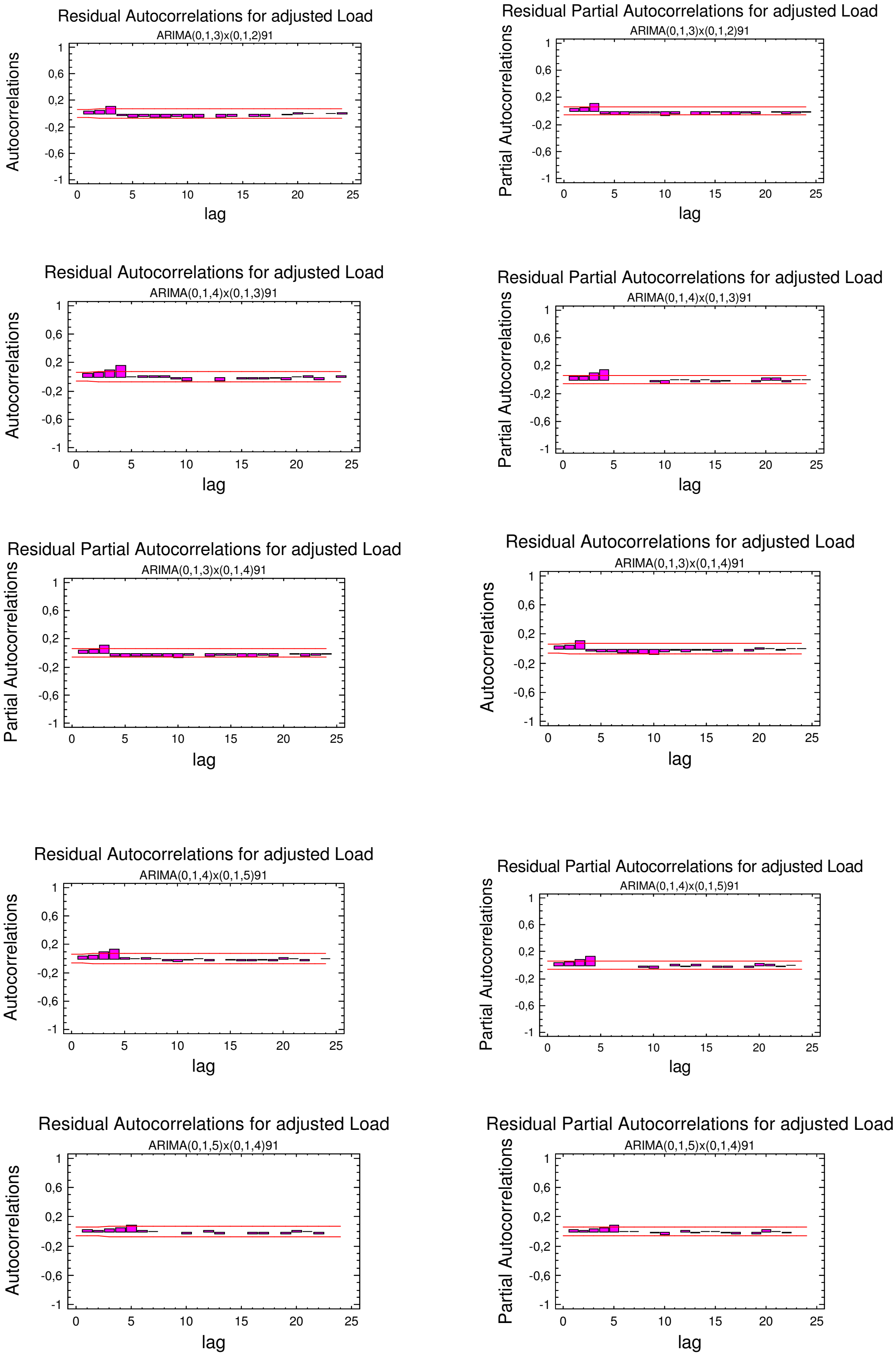


Figure 6.8. Autocorrelations of the experimental ARIMA models (Continued)

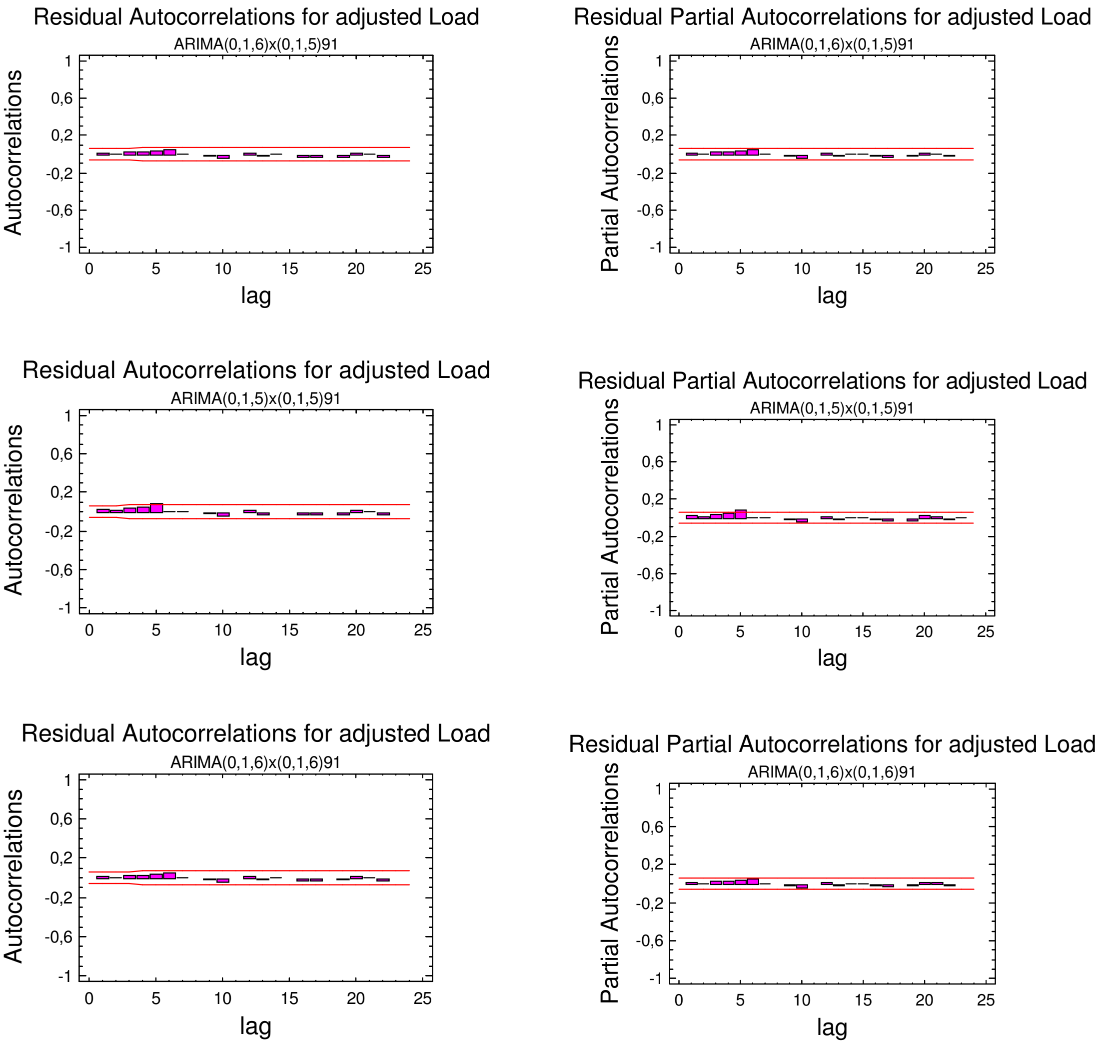


Figure 6.8. Autocorrelations of the experimental ARIMA models (Continued)

For each data set an appropriate ARIMA model is fitted such that the autocorrelation is eliminated and the MAPE and RMSE are minimized. The autocorrelation plots for the models are displayed in Figure 6.8. Proposed ARIMA models that correspond to the autocorrelation plots above are given in Table 6.2.

Table 6.2. ARIMA models by regions

Hour/ Region	**Region 1**	**Region 2**	**Region 3**	**Region 4**	**Region 5**
1	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91
2	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91
3	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,5)91
4	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6* ARIMA(0,1,5)91
5	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6* ARIMA(0,1,5)91
6	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6* ARIMA(0,1,5)91
7	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,5)91
8	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,4)91
9	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6* ARIMA(0,1,5)91
10	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,4)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91
11	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6* ARIMA(0,1,5)91
12	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91
13	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6* ARIMA(0,1,5)91
14	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6* ARIMA(0,1,5)91
15	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,5)91
16	ARIMA(0,1,5)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,5)91
17	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,5)91
18	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,5)91
19	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,5)91
20	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,5)91
21	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91
22	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91
23	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,4)* ARIMA(0,1,5)91
24	ARIMA(0,1,6)* ARIMA(0,1,5)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,5)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91	ARIMA(0,1,6)* ARIMA(0,1,6)91

6.3.2. Estimation

In terms of the selected appropriate ARIMA models which have minimized MAPE and RMSE, parameter estimation is performed and standart errors and t-values of the models are obtained. The ARIMA models have usually more than five moving average and five seasonal moving average terms. The general ARIMA model is ARIMA (0,1,6)*ARIMA(0,1,6)91. For all regions, t-values of the models are significant and any parameters in the model can't be removed. The estimated parameters of the proposed ARIMA models for each hour by regions appear in the CD accompanied with the Thesis.

6.3.3. Forecasts

Forecasting results for the proposed ARIMA models are presented. Figure 6.9 shows the trends of the forecasted loads over a twenty-five year time horizon for the proposed ARIMA models. As can be seen from the Figure 6.9, the forecasted values have a linear pattern over the time period.

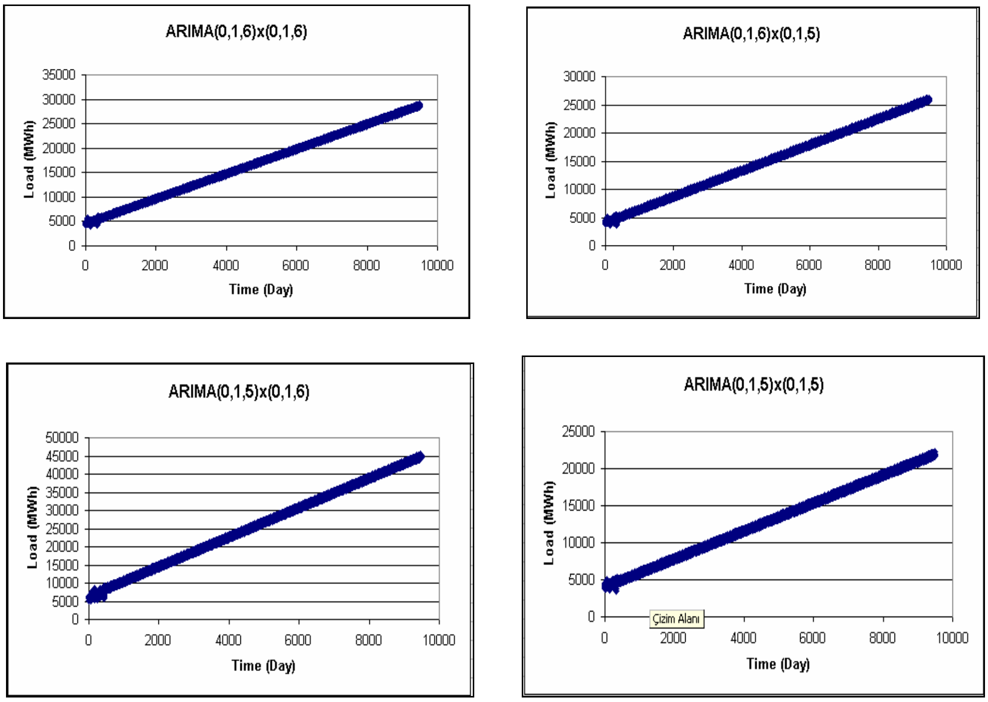


Figure 6.9. Representative forecast plots for ARIMA models in Others region

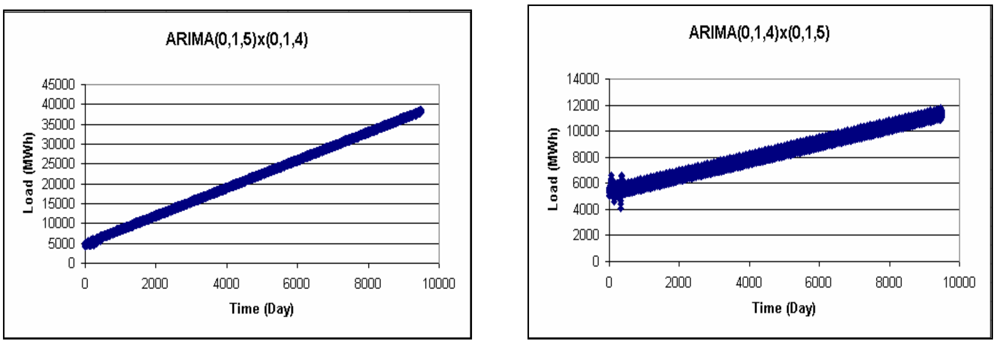


Figure 6.9. Representative forecast plots for ARIMA models in Others region (Continued)

6.3.4. Diagnostic Check

In order to evaluate prediction accuracy of the proposed ARIMA models, the MAPE and RMSE values are checked. The first statistical measure of forecasting accuracy is MAPE and the second one is RMSE. For all regions except region five ARIMA models have no autocorrelation like the representative model explained above. There is a slight positive autocorrelation for the ARIMA models of Region 5. However, all adequate alternatives are tested in order to find the best fit model. Table 6.3 shows the estimated MAPEs for each hour by regions. The RMSEs are given in Appendix B.

Analysis Summary reports for all models indicate that all error measures in the validation period are similar to those in the estimation period. The MAPE values range between 2,3536 % (for Region 1 at hour 21) and 5,1568 % (for Region 4 at hour 10).

Table 6.3. Mean absolute percentage errors for all models

Hour/ Region	Region 1	Region 2	Region 3	Region 4	Region 5
1	2,75409	2,87395	3,2549	3,95167	2,94636
2	3,54918	3,00234	3,27528	3,75301	2,7818
3	3,03128	3,05634	3,14091	3,65499	3,00173
4	2,98887	4,07018	3,14061	3,89154	2,99108
5	2,97098	4,02208	3,21395	3,92631	3,01355
6	2,93914	3,35161	3,25944	4,71816	2,91733
7	3,13372	3,48808	3,37592	4,85027	3,06745
8	3,76282	3,75133	3,65966	4,31	3,9967
9	3,52642	4,50977	3,82699	4,35338	4,44709
10	3,51065	3,71617	4,48276	5,15678	4,16824
11	3,01582	3,45762	4,15425	4,30748	4,15089
12	2,93011	3,3602	4,20265	4,37107	3,97946
13	2,96385	3,3411	3,54996	4,27396	3,93172
14	3,11335	3,42657	3,74012	4,48377	4,00521
15	3,4952	3,44534	3,71408	4,66713	4,11378
16	3,41634	3,44534	3,75019	4,5204	4,22272
17	3,39119	3,47368	3,83183	4,53856	4,0786
18	2,93463	3,09091	3,55702	4,05561	3,71897
19	2,7889	2,95038	3,43361	3,60543	3,33853
20	2,62674	2,5869	3,45445	3,36644	2,87652
21	2,35357	2,43984	2,94519	3,22385	2,63811
22	2,45823	2,5012	3,09977	3,29656	2,36498
23	2,49483	2,90462	2,97635	3,52817	2,5966
24	3,56943	4,21156	5,13614	4,25572	2,92707

7 . ANALYSIS WIND ENERGY PROJECTS IN THE TURKISH COMPETITIVE ELECTRICITY MARKET MODEL

In this study, wind energy projects at alternative sites are evaluated by performing economical and financial analyses under competitive electricity market conditions for alternative sites in Turkey. A comprehensive program (Wind Energy Project Evaluation - WEPE) has been developed integrating load forecasts, projections of wind energy potentials based on statistical and economic analyses, and alternative power generation technology evaluations.

Modelling of the deregulated electricity market is a difficult task to establish due to great uncertainties surrounding the market environment. The Electric Power Strategy Simulation Model EPSIM by Kleindorfer *et al.*[12] to evaluate alternative regulatory and contracting scenarios in the England and Wales power market, has been integrated into WEPE. EPSIM allows investors and stakeholders involved to appraise wind energy projects under a deregulated market structure simulating an hourly day-ahead power exchange market.

The WEPE Model including EPSIM involves the following main features: Wind speed data distribution fitting, energy curve calculation, wind energy related parameters calculations, calculation of wind energy delivered to the system, economic calculations, wind energy initial production cost calculation, other technologies production cost calculations, determination of unconstrained schedule, electricity market simulation model and overall results section. The algorithm of the WEPE model is outlined in the following figure. Throughout this chapter the features of WEPE Model are presented. Section 7.1 covers the wind energy project basic assessment model which comprises power calculations, modelling energy, economic analysis and production cost calculation. Other technologies; hard coal,lignite,natural gas, geothermal, hydro, fuel-oil, diesel-oil and biomass production cost estimations are described in section 7.2. Section 7.3 includes the competitive electricity market simulation model involving the assumptions and load management options. WEPE Program designed in Excel is explained in the last section including detailed descriptions of the algorithms and formulas.

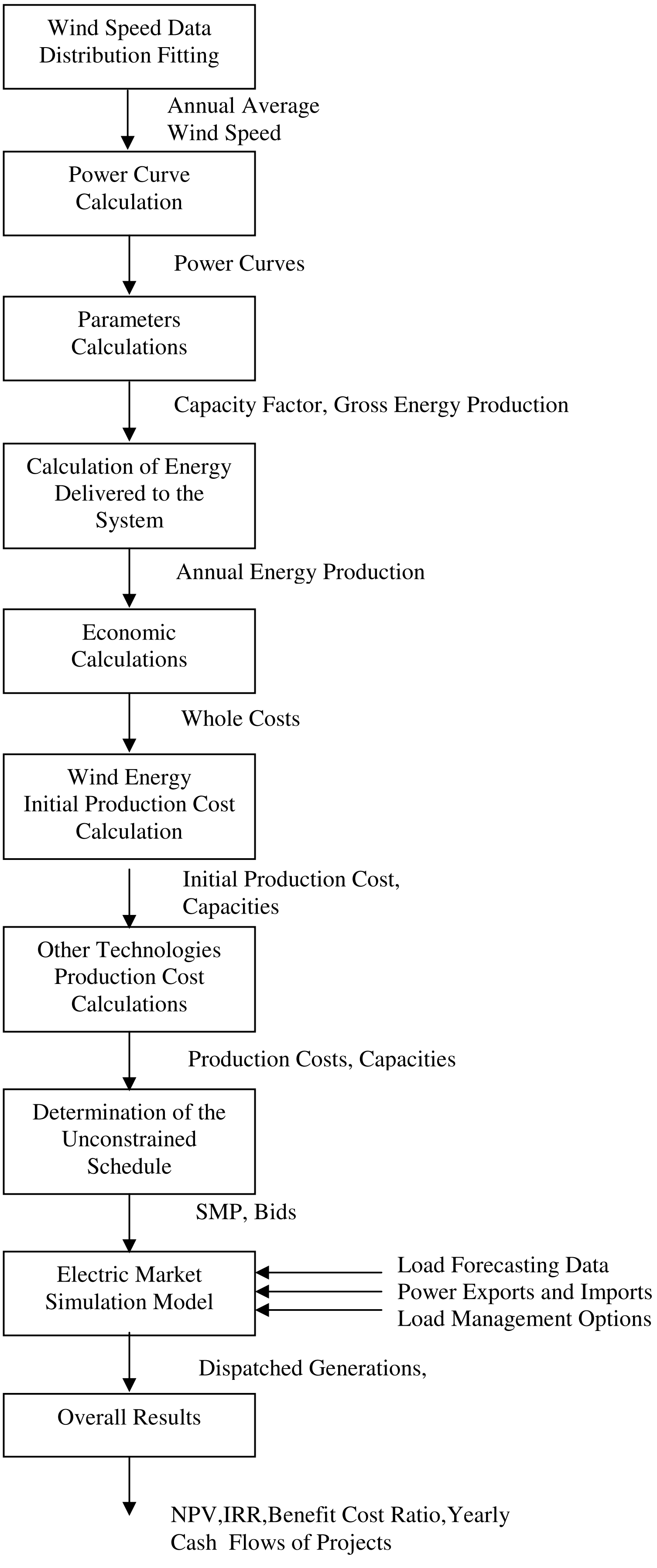


Figure 7.1. Basic steps of the wind energy project evaluation model

7.1. Wind Energy Project Basic Assessment Model

A basic assessment model of wind energy projects has been developed in order to calculate initial production cost and energy generation from the wind turbines. This submodel consists of four modules: power curve determination, estimation of wind energy parameters and energy curve, economical analysis and production cost calculation.

7.1.1. Power Curves

The power curve for each of the wind turbine is obtained from the wind turbine database. The power curve data as shown in Figure 7.2 is instantaneous energy delivered by the wind turbine, measured over its operating range of wind speeds at hub height. This performance characteristic is usually provided by the wind turbine manufacturer. The model assumes that the power output is rated at 15 °C and 101,3 kPa. The database is taken from RETScreen, which is established under the Ministry of Natural Resources in Canada.

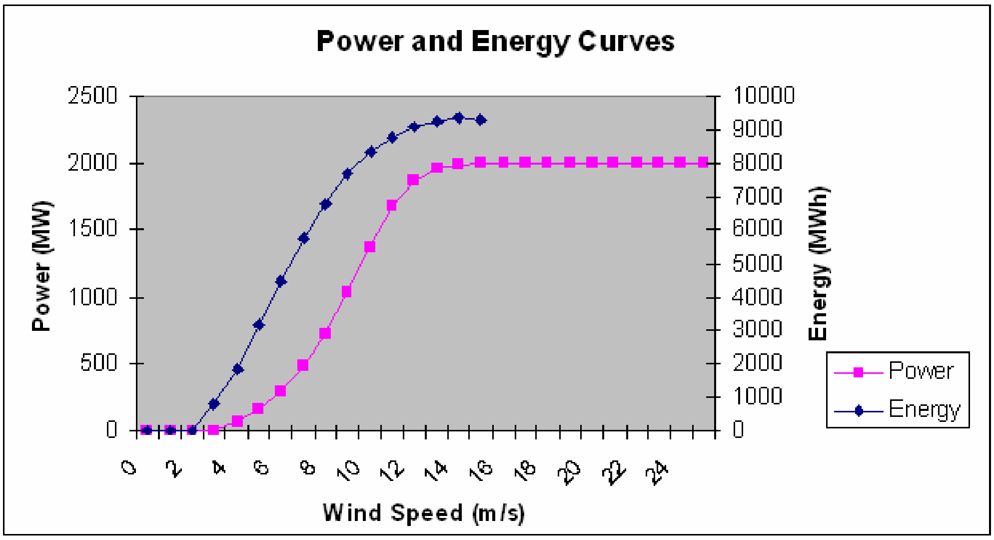


Figure 7.2. Power curve illustration for a representative wind turbine

7.1.2. Energy Production

The energy production calculations are based on parameters related to site characteristics from the selected wind turbines. The calculation is based on the energy curve of the selected wind turbine and on the average wind speed at hub height for the site. The energy curve is the total amount of energy a wind turbine produces over a range of annual average wind speeds. The user enters the wind turbine power curve data as a function of wind speed in increments of 1 m/s from 0 m/s to 25 m/s and Weibull probability function for the proposed site [75].

Each point on the energy curve is calculated as follows:

$$E_{\hat{v}} = 8760 \sum_{x=0}^{25} P_x \, p(x) \qquad (7.1.)$$

Where $\hat{v}$ is the mean wind speed, P_x is the turbine power at wind speed x and $p(x)$ is the Weibull probability density function for wind speed x, calculated for an average wind speed $\hat{v}$.

The unadjusted energy production is firstly calculated at standart conditions of temperature and atmospheric pressure. The calculation involves the average wind speed at hub height for the specified site. As mentioned in the wind speed data analysis chapter, using wind power law, average wind speed at hub height is obtained. After calculating average wind speed, by interpolating the energy curve at the value $\bar{v}$, the unadjusted energy production is computed easily [75].

Gross energy production (E_G) is the total annual energy produced by the wind energy equipment before any losses at wind speed atmospheric pressure and temperature conditions at the site.

$$E_G = E_U c_P c_T \qquad (7.2.)$$

Where c_P is the pressure adjustment coefficient, is the temperature adjustment coefficient, E_U is the unadjusted energy production. c_P is calculated as follow:

$$c_P = \frac{P}{P_0} \tag{7.3.}$$

Where P is the annual average atmospheric pressure at the site, P_0 is the standart atmospheric pressure of 101.3 kPa.
c_T is given by,

$$c_T = \frac{T_0}{T} \tag{7.4.}$$

Where T is the annual average absolute temperature at the site and T_0 is the standart absolute temperature of $15.1\ ^{\circ}C$ [75].

Wind energy delivered is equal to the net amount of energy produced by the wind turbines. In this model all wind energy applications are assumed to be central-grid so all the energy produced by the wind energy project is delivered to the central electricity system. Wind energy collected is calculated as below: [75]

$$E_c = E_G c_L \tag{7.5.}$$

Where E_G is gross energy production, c_L is the losses coefficient, formulated by:

$$c_L = (1-\lambda_a)(1-\lambda_{a\&i})(1-\lambda_d)(1-\lambda_m) \tag{7.6.}$$

Where λ_a is the array losses, $\lambda_{a\&i}$ is the airfoil soiling and icing losses, λ_d is the downtime losses, and λ_m is the miscellaneous losses.

The model calculates the specific yield of the wind turbines, which is a common criteria to evaluate and compare the performance of a wind turbine in conjunction with the wind regime at the site. The specific yield is obtained by dividing the wind energy delivered by a wind turbine by the swept area of the rotor [75].

$$Y = \frac{E_D}{NA} \tag{7.7.}$$

Where A is the area swept by the rotor of a single wind turbine and N is the number of turbines.

The wind plant capacity factor (WCF) is the ratio of the average power produced by the plant over a year to its rated power capacity.

$$WCF = \left(\frac{E_c}{WPCh_Y} \right) * 100 \tag{7.8.}$$

Where E_D is wind energy delivered, WPC is the wind plant capacity, h_Y is the number of hours in a year [75].

7.1.3. Economic Analysis

Economic analysis of a wind energy project is presented in detail including all costs related to wind energy, differentiating mainly three categories: initial costs, annual costs and other costs.

7.1.3.1. Initial Costs. Initial costs are comprised of the six categories which are feasibility study, development, engineering, energy equipment, balance of plant and miscellaneous. The energy equipment and balance of the plant amount to a considerable proportion of the initial costs. The categories are explained in the following [76].

Feasibility Study: In order to prepare a proper feasibility study, accuracy of wind resource data is very important. Installation of meteorological towers at the site is required to collect and anlysis of the wind resource data. At least one year of measurement is recommended. In addition to the assessment of the annual average wind speed, other weather characteristics like temperature, wind speed frequency distribution, turbulence intensity, icing occurance etc. can be considered to evaluate the performance of a wind energy project.

The feasibility study includes a preliminary design which is performed to determine the optimum plant capacity, the size and layout of the structures and equipment and the estimated construction quantities. Detailed cost estimate and project management costs are included in the preliminary design [76].

Development: There are number of possible project developers for wind energy projects. In Turkey, private power developers can install their wind farms and sell energy to the customers by making bilateral contracts with eligible customers or distribution companies. Power Purchase Agreement (PPA) negotiation is a crucial step of the project development stage. It depends on whether or not conditions for sale of power already exist, and the licence application to the EMRA. The development stage includes costs related to regulation and licensing [76].

Land rights are required for the land on which the wind energy project is located including the service road, substation, transmission and collection lines and O&M building. The land required for the project can be leased or purchased. Legal and accounting costs include development cost items including the establishment of a company to develop the project fees and devices for load acquisition preparation of monthly and annual financial statements for project accounting, etc. The project development stage contains expenses of managing all phases of the development of the project [76].

Engineering: The engineering stage consists of the following cost items: wind turbines micro-siting, mechanical design, electrical design, civil design, and tenders and contracting. Wind turbines micro-siting includes investigating site specific variations in wind because of topography, obstructions and and the like. The mechanical design step involves planning assembly and erection of the wind turbines. Electrical design task is performed to design and plan the construction of the electrical control system and the electrical interconnection with the existing power grid. The civil design stage is associated with design and planning of construction of necesssary foundations, roads, etc [76].

Energy Equipment: This category includes the cost of wind turbines, spare parts and their transportation. A wind turbine's all components (including tower which is considerable part of the wind turbine and control system) are included under wind turbine costs. Spare parts required depend on the reliabity of the wind turbine, warranty, transportation difficulty and number of machines at the site. Transportation costs for wind turbines components are influenced by the location of the site and transport mode.

Balance of Plant: This category includes the costs of wind turbine foundations, wind turbines erection, road construction, transmission line, substation, control and O&M building and transportation. Wind tubines foundations contains the costs of labour and material such as concrete, steel frames and forms. Wind turbines erection includes the cost of labour and purchase of equipment. The equipment required differs according to the size of the wind turbine and its characteristics. It's hard to find skilled labour in many of the project locations and also the cost of labour in isolated areas is typically twice the rate found in populated areas. Road construction is necessary, especially large scale wind farms necessitate an access roads and on-going service roads. Transmission line task involves construction of the transmission lines, which depends on the type, length, voltage, location of the line and the installed capacity of the power plant to be constructed. In general for connecting the wind turbines underground lines are preferred. Substation cost is site specific and depends mainly on the voltage and the installed capacity of the power plant being developed. This cost also covers auxiliary electrical equipment such as monitoring equipment, banks of capacitors and control system. Transportation task consists of the transportation of the equipment and construction materials [76].

Annual Costs: Annual Costs include land lease, insurance premium, transmission line maintenance, parts and labour and general and administrative. Land lease costs contain the use of the land cost where the project is being implemented. In general, project developer pays compensation to the landowner for use of the site for a fixed period of time. Insurance

Premium covers the annual insurance Premium cost. Insurance is required for public liability, property damage and equipment failure. Transmission line maintanence includes periodic clearing of trees and replacement of parts. Parts and labour consist of annual cost of spare parts and annual labour required for routine and emergency maintenance and operation of wind turbines. Operaiton contains monitoring, regular inspection of the equipment, snow, ice and dirt removal, scheduled maintenance and etc. General and Administrative covers the costs of bookkeeping, preparation of annual statements, bank charges, communication etc.

Other Costs: Other costs stage contain periodic costs which represent recurrent costs that must be incurred at regular intervals to maintain the project in working condition. Periodic costs are defined as blades costs of wind turbines [76].

7.1.4. Production Cost Calculation

Production Cost Calculation module involves initial financial analysis of wind enery projects to determine the production cost. Wind power plants with different combinations of selected wind turbines are evaluated according to defined financial parameters. This section includes the following items: general and financial terms, financial analysis, annual costs and debt, periodic costs, initial costs and initial results.

General and Financial Terms : Project id, site and annual energy generation are defined as general terms. Financial terms include energy cost escalation rate, inflation rate, discount rate, project life, debt ratio, debt interest rate and debt duration. The energy cost escalation rate is the projected annual average rate of increase for the cost of energy over the life of the project. This cost rate is different from the general inflation rate. Inflation rate is the projected annual average rate of inflation over the life of the project. The discount rate is used to determine the present value of a stream of future earnings. The rate is an organization’s weighted average cost of capital. Cost of capital is a broad concept involving a blending of the costs of all sources of investment funds, both debt and equity. The discount rate is sometimes called the hurdle rate, the cut-off rate, or the required rate of return.

Debt ratio is the ratio of debt over the sum of the debt and the equity of a project. It is used to estimate equity investment that is required to finance the project. Debt interest rate is the annual rate of interest paid to the debt holder at the end of each year of the term of the debt. Debt payments are estimated using this rate. Debt duration which consists of the number of years over which the debt is repaid. The debt term is usually shorter than the project life. This term is used to calculate debt payments and the yearly cash flows [76].

Annual Costs and Debt: The total annual costs which cover sum of the O&M costs and debt payments are estimated by the model. Debt payments are not a cost but rather an outflow of cash. Debt payments which is the sum of the principal and interest paid yearly to service the debt. The principal portion increases and the interest portion decreases with time. Using the debt interest rate, the debt term and project debt payments are estimated.

Financial Analysis: Financial analysis section of the production cost model consists of the NPV, project equity, project debt and debt payments. NPV is calculated using the total cash flows. The project equity is the portion of the total investment required to finance the project which is funded by the project owners. Project debt which is financed by the loan covers the portion of total investment. Debt payments is the sum of the principal and interest paid yearly to service the debt [76].

Periodic and Initial Costs: The periodic costs and initial costs estimated in the economic analysis model are transferred to these stages as a sum of each cost item. The periodic costs include the costs of the blades that should be changed during the project life. The total initial costs are the sum of the estimated feasibility study, development, engineering, energy equipment and balance of plant.

Initial Results: The initial results task involves the wind plant capacity factor(WCF), hourly energy delivered and energy production cost. The WCF, which is the ratio of the average power produced by the plant over a year to its rated power capacity is calculated by the model. Hourly energy data transferred from the energy production module. The energy production cost can be calculated per kWh by clicking calculate button. The model computes energy production cost, which is a value that results in a NPV of zero (i.e. the value which makes the NPV zero is the energy production cost)

The model escalates the periodic costs and O&M costs yearly according to the inflation rate starting from 1 and throughout the project life. As well the model escalates energy income yearly according to the energy escalation rate throughout the project life [78].

7.2. Other Technologies Cost Estimation

In order to assess wind energy projects in a competitive matket with other technologies, a cost estimation module for other technologies model has been developed. The module includes ; hard coal, natural gas, fuel-oil, lignite, and diesel oil as fossil fuel based technologies, hydro, geothermal, biomass as renewable. The electricity production cost for each technology is calculated using defined parameters. This model contains five sections: general, basic costs, fuel cost, financial parameters and result.

General: General task contains technology type, capacity, capacity factor, fuel conversion efficiency and electricity generation. Technology type presents which technology type of the electricity generation is chosen. There are nine technology types defined in the model. Capacities of the power plants per MW are described in the capacity task. Capacity factor of each technology type can be written as a percantage after defining capacity. Fuel conversion efficiency is the ratio of the heating value of the selected fuel type to the quantity of fuel used in the power plant. Heating values of the fuel types are obtained from the State Institute of Statistics (SIS,2004). Electricity generation calculates the annual electricity production per MWh by the power plant using capacity and capacity factor.

Basic Costs: Costs are classified into five categories: investment cost, total investment cost, annual fixed O&M cost, annual variable O&M cost and total annual O&M cost. Investment cost is defined $ per kW. Total investment cost is calculated using installed capacity and investment cost. Annual fixed O&M cost is a cost which does not depend on the production and this cost item is defined $ per kW. Annual variable O&M cost is written $ per MWh in the model and calculated using annual electricity production. Total annual O&M cost is the sum of the annual fixed O&M cost and annual variable O&M cost.

Fuel Cost: Fuel cost consists of the folowing items: annual fuel consumption, cost unit, cost per unit and annual fuel cost. Annual fuel consumption covers the total annula fuel consumption which is calculated by multiplying annual electricity production and unit fuel consumption per MWh. Cost unit represents the cost unit of the technology type such as $/kg or $\$/m^3$. Cost per unit is defined as $ for a unit cost of the fuel type. Annual fuel cost is calculated using unit cost of the fuel type and fuel consumption.

Financial Parameters: Financial parameters are calculated same as mentioned in the production cost calculation section. These parameters are discount rate, inflation rate, energy cost escalation rate, project life, debt ratio, debt interest rate, debt duration, project equity, project debt, debt payments and NPV of all costs. NPV of all costs are the sum of the O&M costs, fuel cost, debt payments and project equity.

Result: The result section involves the calculations of the production cost for each technology type using NPV of the investments. The value of production cost makes the NPV zero is assigned to the production cost for each technology. The model escalates the fuel costs and O&M costs yearly for each technology type according to the inflation rate starting from 1 and throughout the project life. As well the model escalates energy income yearly for each technology type according to the energy escalation rate throughout the project life.

7.3. Turkish Competitive Electricity Market Simulation Model

As indicated in the begining of the chapter nine, The Electric Power Strategy Simulation Model EPSIM (Kleindorfer *et al.*[12]) has been chosen to simulate power dispatching under competitive electricity market conditions in Turkey.

EPSIM was initially used in the England and Wales power market, which has been a pioneering example in electricity sector liberalization implementious. EPSIM was developed to capture the effects on network performance for the stakeholders involved of alternative investment, pricing and contracting strategies at a sufficent level of detail to allow meaningful assessment of these strategies. Stakeholders can make strategic decisions easily on network size, new investments and contracting terms using EPSIM outputs which are formed after day-to day trading, scheduling and dispatching in a power pool.

Figure 7.3. Basic structure of the model

The Turkish competitive electricity market simulation model is investigated in three subsections: the model, assumptions and load management options. The model section provides the basic EPSIM model and paramaters of this model. Assumptions include the modifications of the model and adoption of wind energy plants. Load management options are reductions in the obligations to schedule and dispatch power that are bid into system by various wholesale demand points. On the other hand, load management options can be thought as demand side bidding. Load management options are explained in detail in subsection 8.3.3.

7.3.1. The Basic Model

The EPSIM model and its parameters are as follows:

$$MIN_{q_{ik}LM_{im}F_{if}O_i}\left[\begin{array}{l}\sum_i(\sum_k(SMP*q_{ik}+(\overline{p}_{ik}-SMP)(q_{ik}-q^U_{ik})-R_{ik}(\overline{p}_{ik},\hat{p}_{ik},q^U_{ik},q_{ik})+\\ \sum_m(\overline{p}_{im}+SMP)*LM_{im}+(p_{io}+SMP)*O_i)\end{array}\right] \qquad (7.8.)$$

Subject to generation and load management capacity constraints;

$$0\leq q_{ik}\leq \overline{q}_{ik}\ ,\ 0\leq LM_{im}\leq \overline{LM}_{im}\quad \forall ik,im \qquad (7.9.)$$

Line capacity constraints;

$$F_{ij}\leq L_{ij}\ ,\ F_{ji}\leq L_{ji}\ \ \forall ij \qquad (7.10.)$$

Maximum forced outage constraints;

$$0 \leq O_i \leq D_i , \forall i \tag{7.11.}$$

The node balancing condition;

$$\sum_{k} q_{ik} + \sum_{m} LM_{im} - \sum_{j \neq i} F_{ij} + \sum (1 - \alpha_{ji}) * F_{ji} + O_i - D_i \geq 0 \quad \forall i \tag{7.12.}$$

Refund;

$$R_{ik} = (\overline{p}_{ik} - \hat{p}_{ik}).(q_{ik} - q^{U}{}_{ik}) \tag{7.13.}$$

Where

i	number of nodes
D_i	demand at node i
k	number of generation plants
R_{ik}	refund to the system operator
$\overline{q}_{ik}$	non-negative bid capacity for node i at plant k
$q^{U}{}_{ik}$	unconstrained schedule
$\overline{p}_{ik}$	non-negative bid price for node i at plant k
$\hat{p}_{ik}$	exercise price specified in the contract
m	multiple contracted outage options
$L\overline{M}_{im}$	non-negative bid capacity for node i at outage opt. m
$\overline{p}_{im}$	non-negative bid price for node i at outage opt. m
O_i	forced outage for node i (unfilled demand)
p_{io}	forced outage cost for node i
q_{ik}	scheduled and dispatched capacity
F_{ij}	power exports from node i to j

L_{ij}	line capacity
α_{ij}	losses coefficient
SMP	system marginal price

Primary decision variables in the model are scheduled and dispatched capacities (q_{ik}) and (LM_{im}) and resulting forced outage (O_i). Power imports to node i from node j, $(1-\alpha_{ij}).F_{ij}$, are limited by line capacity, $L_{ji} = L_{ij}$ but incur linear line losses $\alpha_{ji}F_{ji}$ proportional to power flow [12].

The objective function of the model involves a minimization of the scheduled and dispatched capacities at a cost equal to SMP per unit, plus constraint payments, minus refunds for consraint management contracts, plus payments to load management entities, and payments for forced outages. Load management options are required in order to meet electricity demand by implementing demand side bidding. As can be seen from eq.(7.12.) these options are net against aggregate demand D_i at node i.

The decision variables of the model are scheduled and dispatched capacity (q_{ik}), load management options (LM_{im}), unfilled demand not covered by load management options (O_i), line flows (F_{ij}). The first term in the objective function $SMP.q_{ik}$ indicates energy payment from the system operator or grid operator to plant k for scheduled and dispatched electricity at node i; the second term $(\overline{p}_{ik} - SMP).(q_{ik} - q^{U}{}_{ik})$ indicates constraint payment from the system operator. The third term $R_{ik} = (\overline{p}_{ik} - \hat{p}_{ik}).(q_{ik} - q^{U}{}_{ik})$ reflects payments to the system operator by generators for power scheduled and dispatched covered by constraint management contracts. A contracted plant has to refund this payment to the system operator when q_{ik} is scheduled and dispatched, where $\hat{p}_{ik}$ is an exercise price specified in the contract. The fourth term $\sum_{m}(\overline{p}_{im} + SMP) * LM_{im}$ indicates the constraint payment from the system operator at their bid price plus SMP for load management options payments which are paid to load management entities. The last term of the objective function $(p_{io} + SMP) * O_i)$ reflects the forced payments in each node [12] .

Contracts in the Model: Congestion costs are the crucial issue in the England and Wales power pool and these costs are calculated through the constraint payments. The EPSIM focuses on the grid operator which is responsible for minimizing the total costs including the congestion costs, investing in network expansion and generators strategic behaviours. The system operator has the right to negotiate with individual generating facilities and manage them via contracts for preventing strategic bidding. There two types of the contracts offered by the grid operator in the model: constrained-on and constrained off contracts. Constrained-on means capacity that is not in the unconstrained schedule but is dispatched on the other hand capacity that is in the unconstrained Schedule but is not dispatched is called constraint-off. The contracted plant has to refund the following payment to the system operator whenever the plant is constrained on or off. The refund depends on the running price, $\hat{p}_{ik}$, specified in the contract.

$$R_{ik} = (\overline{p}_{ik} - \hat{p}_{ik}).(q_{ik} - q^{U}{}_{ik}) \tag{8.14.}$$

Constrained-on contracts: When capacity is constrained-on, $(q_{ik} - q^{U}{}_{ik}) > 0$, this type of contracts are valid. There are three forms of constrained-on contracts available in the EPSIM. The first one is under a pure SMP consrained-on contract in which the contract refund is specified with: $\hat{p}_{ik}$ =SMP.

The second one is under a max(running price,SMP) constrained-on contract in which the contract refund is specified with: $\hat{p}_{ik}$ =Max(Running Price,SMP). The last type of constraint-on contract is under a pure running price constrained-on contract in which the contract refund is specified with: $\hat{p}_{ik}$ =Running Price.

Constrained-off contracts: When capacity is constrained-off, $(q_{ik} - q^{U}{}_{ik}) < 0$, this type of contract is performed by the system operator. There are two types of constrained-off contracts exist in the model. The first one is under a pure SMP constrained-off contracts in which the contract refund is specified with $\hat{p}_{ik}$ =SMP. The other is under a min(running price,SMP) constrained-off contract in which the contract refund is specified with $\hat{p}_{ik}$ =Min(Running Price,SMP) [12].

7.3.2. Load Management Options

Load management options have been a topic in discussion for several years in countries with deregulated electricity markets, due to growing shortage of power generation capacity. These options are pre-arranged methods of cutting demand (load). If the load exceeds the limit of available power generation capacity, then load management options can be implemented to solve this problem. The best example of explaning load management options is interruptible tariff. This is a tarif for industrial consumers in which the consumer agrees that, with some notification, the consumer will curtail demand by some specified amount and reduce overall consumption. Load management options can be thought as load bidding programs in that case the consumers can bid the load that they would normally consume in a given hour and sell the load. Declining consumption of electricity by the consumer is the same as dispatching a generator to produce same amount of power. Electricity-meters are required to operate load bidding programs in the day-ahead markets.

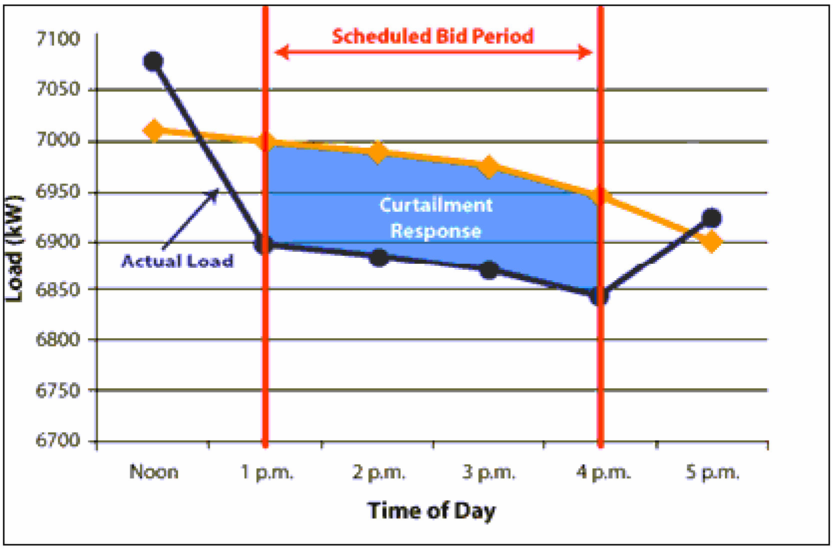


Figure 7.4. Implementation of LMO [77]

The benefit of the load management options is that when energy is very expensive, e.g. on a hot-hot day at peak hours, then being able to curtail any demand will have a huge benefit for the system and for the distribution company serving customers. For instance consider the marginal cost curve presented below for electricity in a given hour. You can see that if consumption is lowered from point A to point B that the market-clearing price drops dramatically (savings are indicated by the shaded area; all consumers save on price). Sometimes during peak consumption periods a reduction in demand of a only three percent can cut the cost of electricity by as much as 20 percent. As such, the general welfare benefits of these programs are significant.

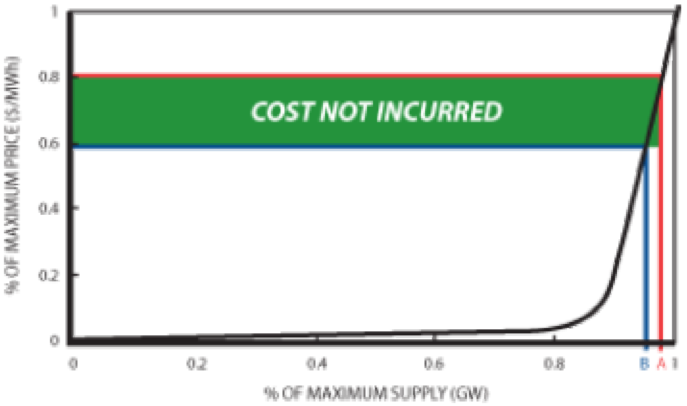


Figure 7.5. An example of the benefit of load bidding programs [77]

In the model, load management options are implemented for industrial consumers due to the high consumption of electricity from these consumers and available data source. Load management entities,industrial consumers, submit bids for each period in the model and these bids specify a bid capacity (MWh) consumers will curtail and bid price ($/kWh). There is no capacity limit for bidding in the model and all participants are assumed to be able to bid all of their capacities. The system operator makes schedules of load management entities with the lowest bid prices and when the load exceeds available total power generation capacity, system operator dispatches needed capacity to these industrial consumers using the scedule.

7.3.3. Implemented Model Version

Both constrained-on and constrained-off contracts are assumed to be a pure SMP contracts in that case the contract refund is determined with $\hat{p}_{ik}$ = SMP. Contracting prices are made equal to SMP because the purpose of the thesis is not to evaluate power pool and strategic behaviours of the participants. Utilizing the basic structure of EPSIM as a testbed, alternative investment opportunities for wind power projects are analyzed and cashflows of the projects are obtained from the WEPE.

After $\hat{p}_{ik}$ is replaced with SMP then the refund payment of the model changes as follow:

The refund payment is $R_{ik} = (\overline{p}_{ik} - SMP).(q_{ik} - q^{U}{}_{ik})$ so the objective function of the current model is given as below:

$$MIN_{q_{ik} LM_{im} F_{if} O_i} \left[\sum_{i} (\sum_{k} (SMP * q_{ik}) + \sum_{m} (\overline{p}_{im} + SMP) * LM_{im} + (p_{io} + SMP) * O_i) \right] \quad (8.15.)$$

Subject to generation and load management capacity constraints (2)-(5) as specified in EPSIM.

7.3.4. Model Assumptions

The main assumption, which are common to all scenarios are as follows: The model differentiates between five regions, Western Antolia, Central Anatolia, Northwestern Anatolia, Southeastern Anatolia and Others (including northeastern region, KEPEZ region and ÇEAŞ region and Thrace region) as mentioned in sections six and seven. These regions cover all of Turkey’s electricity consumption. The regional data is obtained from the Central Load Distribution Center in Ankara where all the regional data coming from the other load distribution centers is gathered. The reason of summing four regions to others is having none of wind energy projects for these regions.

Table 7.1. Regional structure of the model

Node ID	Region(s)
1	Northwestern Anatolian
2	Central Anatolian
3	Western Anatolian
4	Southeastern Anatolian
5	Northeastern Anatolian,KEPEZ,ÇEAŞ and Thrace

Generation entities, load management entities and a system operator are presented in the model. Generation entities are power producer groups that represent different technologies for each node, i.e. the installed capacity for each node is separated with respect to the technology type and each technology, in the model is represented by a generation entity (except wind power plants). Naphta and LPG technologies are included in the natural gas technology. Imported coal technology is assumed to fall into the hard coal technology.

Table 7.2. Total installed capacity of regions according to the technology type [10]

Unit:MW

Region Technology Type	**Node1**	**Node2**	**Node3**	**Node4**	**Node5**	**TOTAL**
Fuel Oil	246	226,198	517,494	519,529	1030,7	2539,921
Hydro	74,146	1105,711	901,468	7235,567	3328,5	12645,39
Diesel Oil			120	20,63		140,63
Lignite	575	626	3327,985	1812	188,1	6529,085
Natural Gas	8114,122	972,874	433,612	3,6	2385,2	11909,41
Hard Coal	648,4				1430,4	2078,8
Waste	6,6	3,2	13,8		4	27,6
Geothermal			15			15

Load management options are arranged for industrial customers whose electricity consumption have a great proportion over the total national consumption. The offer prices and bid capacities for industry goups and regions are calculated using the energy consumptions in the manufacturing industry between 1999 and 2001. The data differentiated by industry groups and geographical regions and value added tables are obtained from SIS. As given in the CD Table 1 contains energy consumptions by industry groups and regions as tons of oil equivalent (TOE). The TOE values are converted to mega watts using the following conversion factor: 1 MW of electricity equals 0,086 tons of oil consumption. Table 2 in the CD includes the value added of the energy consumption by industry groups. The value added values are defined as TL so the average rate of US $ exchange is calculated for every years between 1999 and 2001. Firstly, energy consumption for industry groups and regions are estimated then value added values are calculated as US $. Lastly, by dividing value added to energy consumption, the unit value added per consumption of electricity (kWh/$) for each industry group and region is estimated.

It's assumed that the energy consumption values by industry groups are the bidding capacities for each of the region and also the unit value added values are the offer price for the industry groups. The industry groups taken from SIS are truncated to the main industry groups shown in Table 7.3 due to solver limitations in WEPE.

Table 7.3. Industry groups capacities and bid prices used in the model for time period

Industry Groups	**Offer Price($)**	**Region 1 Capacity (MWh)**	**Region 2 Capacity (MWh)**	**Region 3 Capacity (MWh)**	**Region 4 Capacity (MWh)**	**Region 5 Capacity (MWh)**
Manufacture of Food (except sugar industry)	1,83	40,43	14,42	19,7	1,05	32,34
Sugar Industry	5,72	5,73	3,29	0,57	-	3,44
Beverage Industry	3,91	3,76	6,77	6,26	-	1,99
Tobacco Industry	15,58	1,93	0,00	0,34	-	3,99
Textile Industry	0,66	219,29	32,65	36,00	49,85	109,71
Wearing Apparel	2,09	9,28	0,15	2,41	0,35	2,82
Manufacture of Wood	0,61	8,17	1,02	2,73	0,43	18,39
Manufacture of paper,printing and publishing industry	0,55	58,75	3,89	19,61	0,07	20,41
Manufacture of chemicals and of chemical petroleum coal, rubber and plastic products	2,75	126,42	9,62	57,64	6,65	76,04
Manufacture of non-metallic mineral products except products of petroleum cool and cement	0,82	71,19	4,79	32,81	0,07	30,12
Manufacture of cement	0,27	119,82	57,00	65,31	34,87	135,78
Iron and steel basic industries	0,24	226,13	10,16	234,89	-	230,03
Non-ferrous metal basic industries	0,21	23,02	131,58	4,14	-	8,16
Manufacture of fabricated metal products expect machinery and equipment	1,24	40,20	4,32	3,01	-	0,14
Manufacture of fabricated machinery	3,72	37,30	18,14	9,35	-	3,75
Manufacture of transport equipment	3,08	54,02	3,36	3,11	-	0,73
Manufacture of professional, scientific measuring and controlling equipment, not elsewhere classified	0,87	-	-	0,15	-	0,46

The model performs the simulation for a twenty-five year time horizon and provides dispatched capacities for each period. The periods are assumed to be comprised of eight hours each:

a) $00.^{00} – 08.^{00}$
b) $08.^{00} – 16.^{00}$
c) $16.^{00} – 00.^{00}$

WEPE covers a planing horizon of 25 years including fifty planning periods which have a half-year duration each. Capacity is scheduled and dispatched to meet demand at each node and period. Initially, generators and load management entities in the model submit bids to the Power Pool for each planning period. These bids specify a bid capacity (MWh) at a bid price ($/kWh). In each planning period, the model first determines the unconstrained Schedule and SMP by sorting plants in increasing order of bid price and scheduling until the average demand is met. The average demand is calculated by taking average of all periodic forecasted loads which include all regions' load forecasting data for the planning period. Then the model schedules and dispatches generators capacities taking into account constraints and decision variables using the linear programming formulation. The offered capacities in the unconstrained schedule by generators (except wind power plants) don't change while sheduling and dispatching. The wind power plants use estimated energy generation over the twenty-five year time horizon.

The loads (or, equivalently) demand are obtained from the load forecasting section in a hourly format for each node in the model. The estimated hourly loads for each region are converted to a periodic format which contains total of the eight hours' loads. In the model, forced outages costs are determined as thirty times of SMP based on the EPSIM Model (Kleindorfer *et al.*[12])

Load Projections and Capacity Additions: In chapter eight, the load projections over a twenty-five year time horizon were prepared using ARIMA models for all nodes. In that case, twenty-four models were estimated analyzing hourly loads seperately as a single series for each node. The forecasted loads' graphic for all regions in a periodic format are given in Figure 7.6. As can be seen from Figure 7.6., demand for node 5 is much more higher than other regions. The reason for the growing pattern of the load 5 is due to the consisting of the four load distribution regions which are Thrace, northeastern, KEPEZ and ÇEAŞ. Also the ARIMA models for load 5 have sharp pattern as compared to other patterns of load.

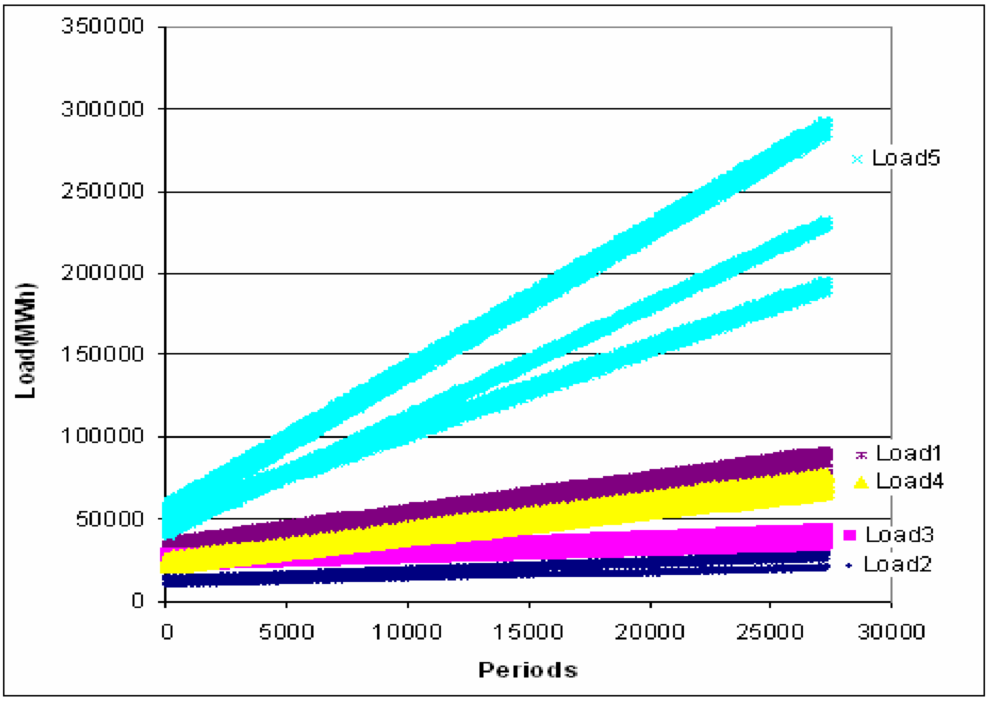


Figure 7.6. Load projections of all regions over 25 year period

Installation of new power plant capacities starting from year 2006 is determined according to the TEIAS capacity projections between 2005 and 2020. The current installed capacity percentage of each technology type for each region is kept constant up to year 2020 and annual capacity additions were calculated in terms of the increments by TEIAS projection. New capacity additions after 2020 are projected using ARIMA models for each technology type and forecasted capacities by regions are obtained.

Table 7.4. TEIAS capacity projections 2005-2020 [9]

Unit:MW

YEARS	LIGNITE	HARD COAL	NATURAL GAS	F.OIL+ DIESSEL	WIND	HYDRO	TOTAL
2005	8301	2038	13137	3307	879	13681	41343
2006	8301	2157	13307	3307	1288	14400	42760
2007	8301	2157	13697	3307	1413	15521	44396
2008	8301	2157	13697	3307	1538	15855	44855
2009	8621	2157	14397	3307	1663	15889	46034
2010	8621	2157	16497	3307	1788	16446	48816
2011	9661	2157	18447	3307	1913	17177	52662
2012	10181	2157	19147	3307	2038	18655	55485
2013	11221	2157	20822	3307	2163	20253	59923
2014	12101	2157	21522	3307	2288	21811	63186
2015	13141	2157	22497	3307	2413	23257	66772
2016	14181	2157	23472	3307	2538	24740	70395
2017	15381	2657	24447	3307	2663	26299	74754
2018	16941	3657	25847	3307	2788	27717	80257
2019	17981	5257	27247	3307	2913	29307	86012
2020	18661	7857	27947	3307	3038	31038	91848

Table 7.5. Current capacity installation according to region and technology [10]

Region Technology Type	**Region 1** (%)	**Region 2** (%)	**Region 3** (%)	**Region 4** (%)	**Region 5** (%)
Fuel Oil	9,69	8,91	20,37	20,45	40,58
Hydro	0,59	8,74	7,13	57,22	26,32
Diesel Oil	0,00	0,00	85,33	14,67	0,00
Lignite	8,81	9,59	50,97	27,75	2,88
Natural Gas	68,13	8,17	3,64	0,03	20,03
Hard Coal	31,19	0,00	0,00	0,00	68,81
Waste	23,91	11,59	50,00	0,00	14,49
Geothermal	0,00	0,00	100,00	0,00	0,00
Wind	92,06	0,00	7,94	0,00	0,00

The estimated installed cumulative capacity up to year 2020 based on TEIAS data, is given in the following Figure 7.7.

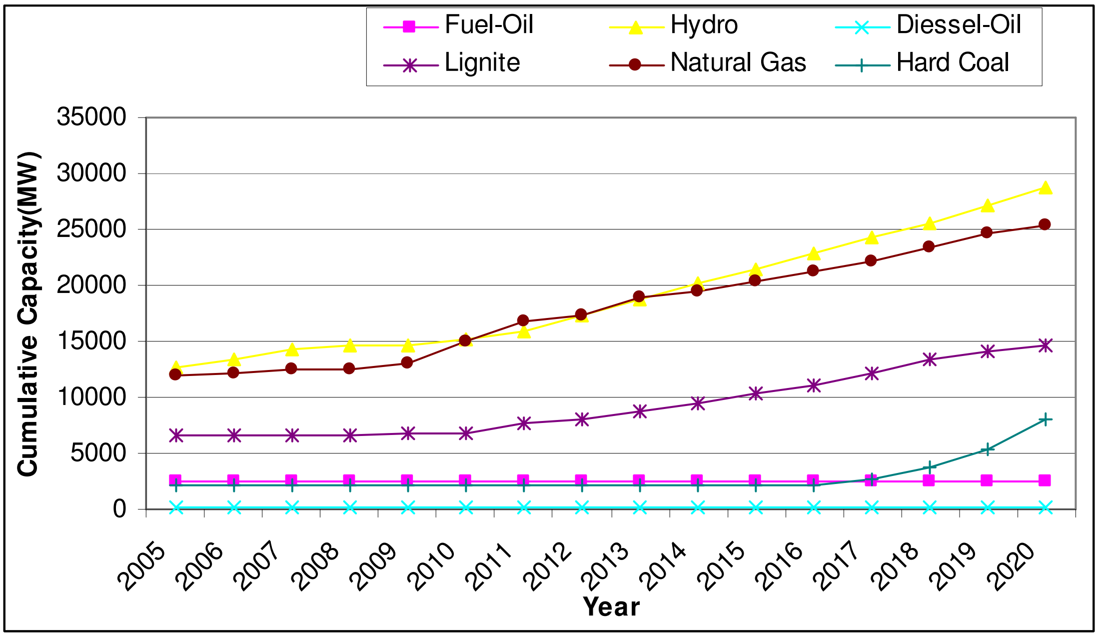


Figure 7.7. Cumulative installed capacity by technology type, 2005-2020

Biomass Model: Biomass capacity projection doesn't exist in the TEIAS study, therefore installed capacity for biomass technology is modeled by employing ARIMA technique and the results are given below.

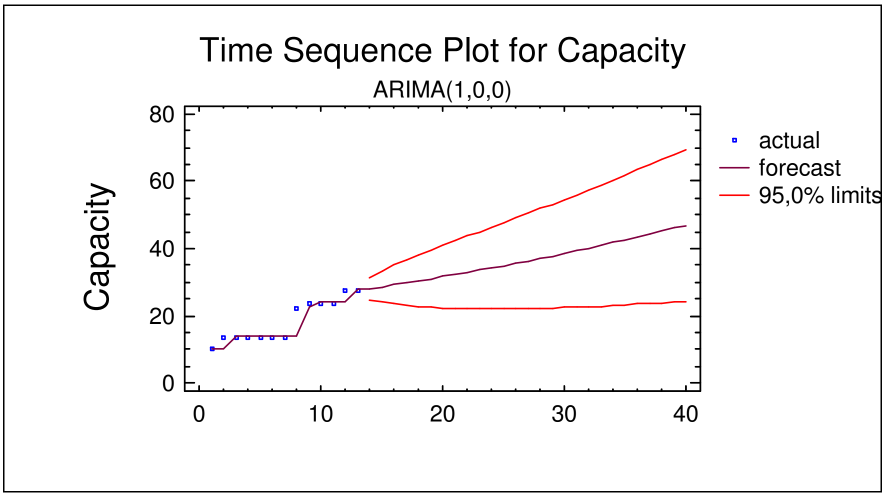


Figure 7.8. Biomass time sequene plot for ARIMA model

ARIMA forecasting technique for analyzing pattern of biomass installed capacity over the twenty-seven time period is performed and ARIMA(1,0,0) model, which results in the most satisfactory RMSE, has been chosen from among others in order to forecast capacities.

The installed capacity data up to year 2002 is obtained from WEC report [78] and using ARIMA (1,0,0) model the future projection of total biomass capacity is estimated. The regional capacities are distributed according to the current percentage of installed capacity.

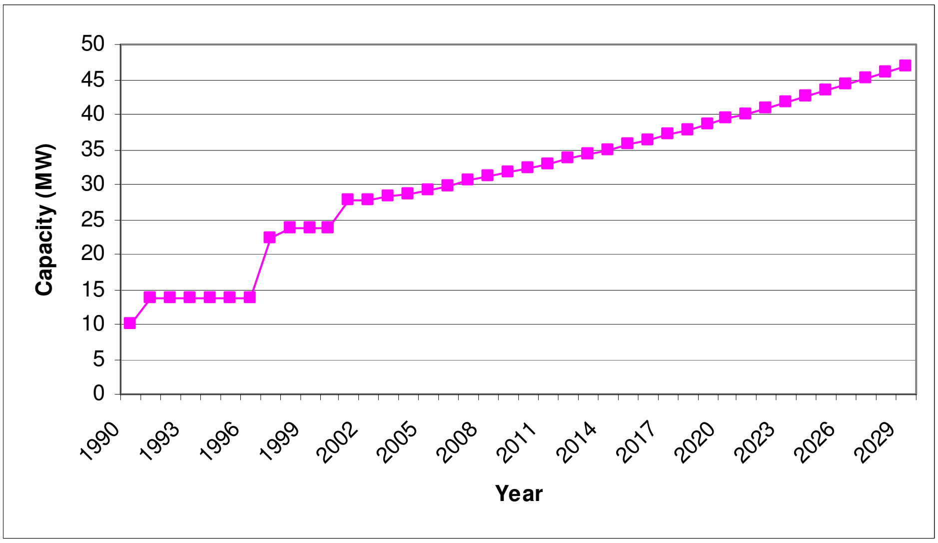


Figure 7.9. Biomass installed capacity projections, 2003-2029

The future projections of the technologies after year 2020 are obtained by using ARIMA models. Fuel-oil and diessel-oil installed capacities are kept constant so as to comply with official projections. The ARIMA model results for the natural gas, lignite, hard coal and hydro are given in the following.

Natural Gas Model: In order to determine the capacity projection of natural gas between 2021 and 2029, ARIMA technique is used and time sequence plot for capacity is obtained as follows:

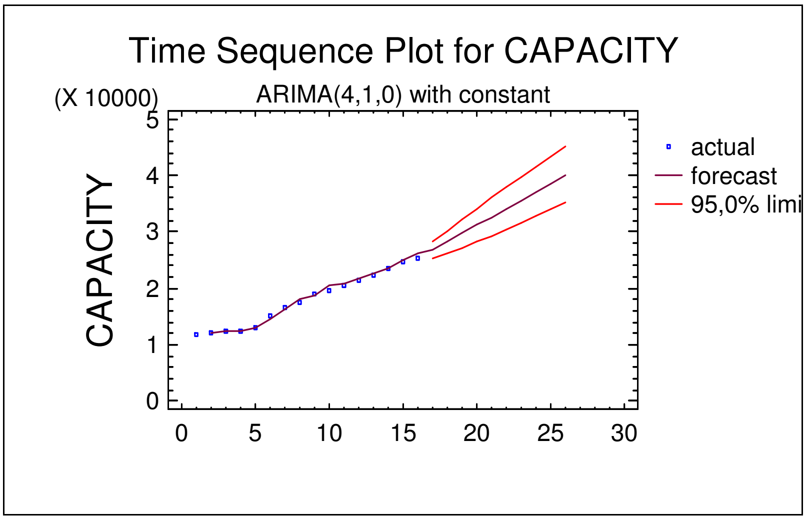


Figure 7.10. Natural gas time sequence plot for ARIMA model

Lignite Model: Lignite capacity projection is performed by using ARIMA(4,1,0) with constant model given in the following.

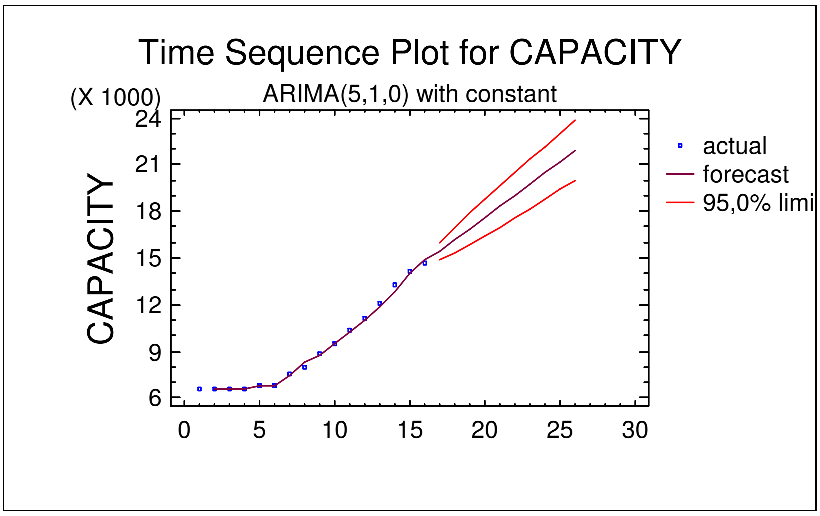


Figure 7.11. Lignite time sequence plot for ARIMA model

Hydro Model: ARIMA(5,2,0) model is chosen in order to forecast future values of installed capacity of hydro technology. The time horizon covers years from 2021 to 2029. The model includes five auto-regressive terms and two times of differencing. The model result including time sequence plot is given as follows:

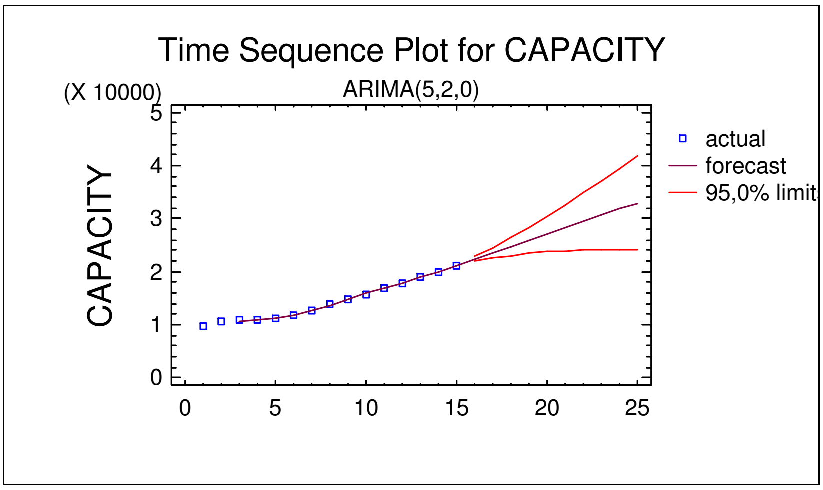


Figure 7.12. Hydro time sequence plot for ARIMA model

At the end of the capacity forecasting analyses of technology types, the cumlative installed capacity projections are prepared and according to the percentage of installed capacity for each region in 2005, the capacities are distributed to each region over a twenty-five year time horizon.

Hard Coal Model: As mentioned before hard coal technology is assumed to involve imported coal. Since the trend of the hard coal data is mostly constant over time, none of ARIMA models that has been applied to fit data give satisfactory results. Therefore, the generation capacity of hard coal technology is assumed to constant after the year 2020.

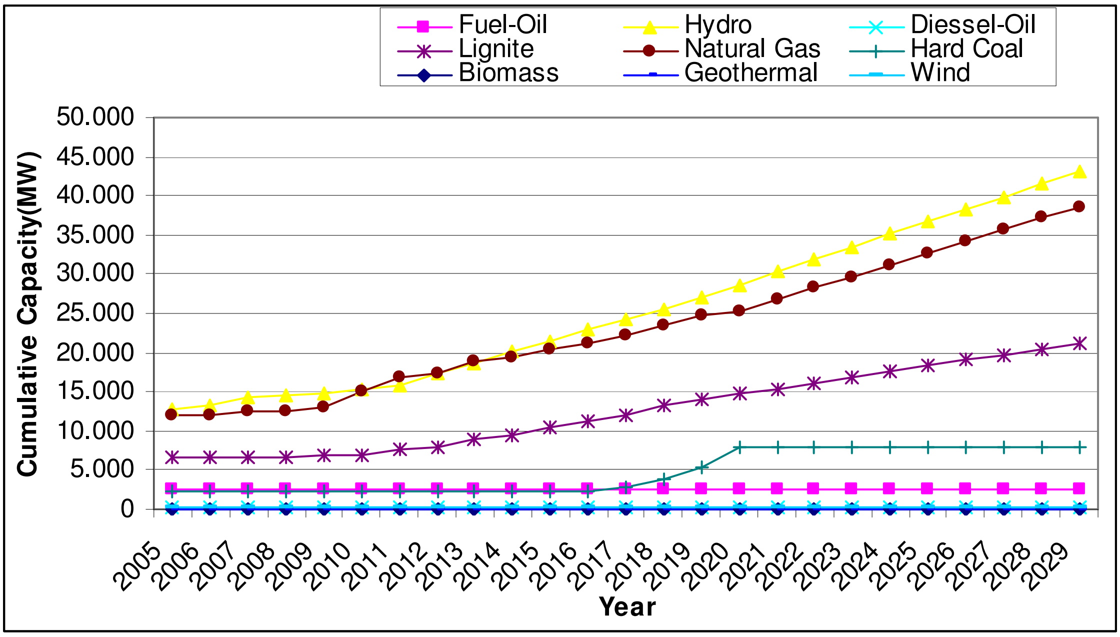


Figure 7.13. Cumulative installed capacity by all technology types, 2005-2029

7.3.4.1. Historical Simulation of the Average Wind Speeds. As explained in the wind speed data analysis chapter, seven sites with high wind energy potential are determined after performing the statistical analyses. These sites are *Amasra* located in Region 1 , *Bandırma* located in Region 1, *Bozcaada* located in Region 3, *Çanakkale* located in Region 3, *Güney* located in Region 3 , *Mardin* located in Region 4 and *Pınarbası* located in Region 2.

Average hourly wind speed records over a five year period from 1999 to 2003 are used in order to perform historical simulation as inputs to WEPE. Historical simulation is appropriate due to the huge amount of data available over a five year period in a hourly format, which is hard to fit to any statistical distribution. The historical simulation lasts up to year 2029 and hourly average wind speed values are determined in terms of the algorithm of the simulation. For each of the sites, ten historical simulations are run and the results of the them are obtained. The average hourly wind speeds of ten historical simulations are used as inputs to WEPE in order to calculate hourly energy generation of the sites with the selected wind turbines over a twenty-five year time period.

The algorithm of the historical simulation is based on a randomly selecting feature through five year wind speed records for each site. A flow diagram of the algorithm is depicted in the following figure.

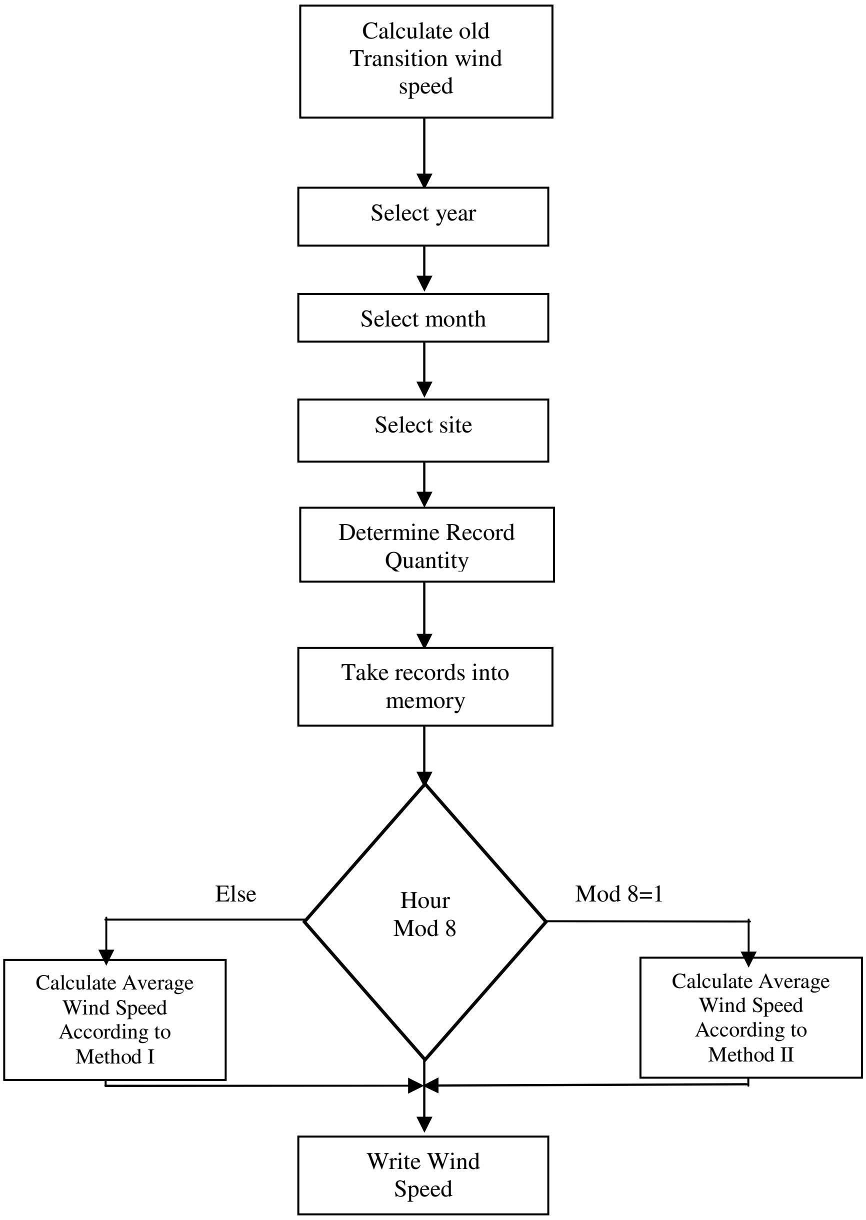


Figure 7.14. Flow diagram of the simulation algorithm

Firstly, the transition wind speed is calculated by the model and at the begining this value is equal to the sum of the five year average wind speed and the range between zero and minus or plus five. Then the model selects year and month randomly up to year 2029. After determination of the date, the model reads the data file and records hourly wind speeds. For the determined time, the model takes the wind speed data into memory. Within the next step, initially the model randomly selects the one of the row available in the memory and if the *mod* of the hour of the simulation is different from one, then wind speed is estimated using the selected value in the data file and the range between zero and minus or plus five. If the *mod* of the hour of the simulation is one then wind speed is estimated according to half of the sum of the old wind speed value plus windspeed calculated, and if the *mod* of the hour of the simulation is zero then old wind speed is equal to the wind speed calculated. The reason of using old wind speed value and mod eight is to make soft transitions between data blocks, each of which consists of the eight hourly wind speeds. In that case, it is hindered that the wind speeds during the transitions between the data blocks involve a significant difference.

The results of the ten historical simulations for each of the sites are given below. The parameters calculated in every simulation analysis are average of hourly wind speeds, standard deviation, minimum and maximum values, lower and upper quantile, 10% quantile, 90% quantile, median, confidence intervals and probability of no wind.

Table 7.6. Simulation results of the selected sites

Site/Parameters	**Amasra**		**Bandırma**		**Bozcada**		**Çanakkale**		**Güney**		**Mardin**		**Pınarbaşı**	
Average(m/s)	5,03		3,68		6,01		3,94		4,02		3,61		3,61	
Standart Deviation	2,09		1,64		2,20		1,56		1,37		1,13		1,59	
Minimum	0,33		0,15		0,48		0,47		0,23		0,29		0,25	
10% quantile	2,61		1,62		3,24		2,05		2,36		2,26		1,91	
lower quartile	3,47		2,45		4,39		2,71		3,0		2,81		2,51	
Median	4,74		3,57		5,86		3,75		3,88		3,49		3,30	
upper quartile	6,29		4,77		7,44		4,99		4,94		4,30		4,41	
90 % quantile	7,87		5,85		8,91		6,07		5,94		5,14		5,71	
Maximum	20,48		14,67		18,26		13,58		12,53		10,47		17,17	
Probability of no wind	0,00001		0,00366		0		0		0,00005		0,00001		0,00013	
Low and High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
90 % quantile 95 %C.I.	7,81	7,93	5,79	5,91	8,85	8,97	6,01	6,13	5,88	6,0	5,08	5,20	5,65	5,77
95% C.I.	5,02	5,04	3,67	3,69	6,00	6,02	3,93	3,94	4,02	4,03	3,60	3,61	3,60	3,62

Generation Technologies Cost Estimation: In order to provide inputs to the WEPE, generators' bidding prices by technology type and region are estimated based on TEIAS data. As mentioned earlier, bidding prices are assumed to equal marginal production costs for all generators in the model. The production costs of the technologies for each region are based on the current power plant data of TEIAS, the only exception being wind and biomass power plants. The production costs of wind power plants are calculated using the wind turbine info, power calculations, energy model, economic analysis and production cost parts of the WEPE. The Other technologies cost estimation model of WEPE is used to find electricty production costs of other technologies.

Production Cost Calculation for Wind Power Plants: In terms of the parameters chosen in the power calculations, energy model, economic analysis and production cost parts, thirty-eight production cost calculations for the selected wind energy projects are performed and the lowest production cost with the most appropriate wind turbines for each of the project is determined. The accurate combinations of the wind turbines are satisfied by chosing the wind turbines whose total capacities make 50 MW.

Table 7.7. The lowest production costs with the selected wind turbines for the projects

Projects	**Turbine ID**	**Manufacturer**	**Wind Turbine Rated Power**	**Hub height (m)**	**Rotor Diameter**	**Number of Turbines**	**Estimated Production Cost**
Amasra	105	A	2000	100	83	25	0,0571
Çanakkale	105	A	2000	100	83	25	0,0848
Bandırma	105	A	2000	100	83	25	0,0873
Güney	105	A	2000	100	83	25	0,0898
Pınarbaşı	105	A	2000	100	83	25	0,1088
Mardin	105	A	2000	100	83	25	0,1208
Bozcada	92	B	1000	70	62	50	0,0426

The calculations regarding for production cost determination are given in Table 7.8. As can be seen from the table, the combinations of wind turbines usually don’t reduce production costs.

Table 7.8. Production cost calculations of the selected wind power projects

Number	Turbine ID	Number of Turbines	Production Costs for the Selected Sites ($)						
			Amasra	**Çanakkale**	**Bandırma**	**Güney**	**Pınarbaşı**	**Mardin**	**Bozcada**
1	102	25	0,06370	0,09890	0,09970	0,10620	0,12720	0,14420	0,04700
2	101 88	25 5	0,06024	0,09000	0,09260	0,09552	0,11581	0,12887	0,04490
3	97	25	0,05900	0,08850	0,09070	0,10180	0,11380	0,12710	0,04390
4	94	25	0,06590	0,10360	0,10390	0,12070	0,13330	0,15200	0,04850
5	95	25	0,06430	0,10000	0,10080	0,11620	0,12870	0,14620	0,04740
6	96	25	0,06220	0,09540	0,09680	0,11040	0,12280	0,13860	0,04600
7	93	25	0,06150	0,09450	0,09600	0,10940	0,12200	0,13810	0,04540
8	103	25	0,06210	0,09560	0,09680	0,11070	0,12290	0,13870	0,04590
9	104	25	0,06010	0,09120	0,09300	0,10530	0,11730	0,13160	0,04450
10	105	25	0,05710	0,08480	0,08730	0,08980	0,10880	0,12080	0,04262
11	132	25	0,07570	0,12570	0,12340	0,14880	0,16280	0,19220	0,05520
12	139	25	0,08380	0,14360	0,13890	0,17140	0,18610	0,22280	0,06100
13	140	25	0,08150	0,13790	0,13430	0,16410	0,17920	0,21360	0,05930
14	141	25	0,07840	0,13060	0,12820	0,15490	0,17030	0,20190	0,05720
15	142	25	0,06710	0,10690	0,10680	0,12510	0,13800	0,15910	0,04920
16	143	25	0,06540	0,10310	0,10350	0,12020	0,13320	0,15270	0,04800
17	144	25	0,06320	0,09820	0,09930	0,11400	0,12690	0,14460	0,04660
18	145	25	0,05990	0,09090	0,09290	0,10490	0,11740	0,13230	0,04440
19	89	40	0,07470	0,11900	0,11860	0,12930	0,15360	0,17860	0,05450
20	90	40	0,07210	0,11310	0,11360	0,12220	0,14610	0,16880	0,05270
21	85	50	0,08260	0,13520	0,13330	0,14760	0,17440	0,20260	0,06060
22	86	50	0,08060	0,13070	0,12930	0,14190	0,16830	0,19450	0,05920
23	87	50	0,07730	0,12300	0,12280	0,13280	0,15850	0,18170	0,05680
24	88	50	0,07460	0,11700	0,11770	0,12580	0,15090	0,17190	0,05490
25	91	50	0,06010	0,09430	0,09460	0,10200	0,12150	0,14010	0,04400
26	92	50	0,05820	0,08970	0,09070	0,09650	0,11570	0,13250	0,04262
27	108 97	40 4	0,07551	0,11750	0,11864	0,12661	0,15206	0,17520	0,05508
28	110 92	30 5	0,06517	0,10141	0,10270	0,10877	0,13134	0,15012	0,04769
29	111 92	30 5	0,06346	0,09763	0,09937	0,10436	0,12639	0,14364	0,04670
30	138 92	28 1	0,07307	0,11873	0,11778	0,12919	0,15436	0,18084	0,05338
31	78 110	50 5	0,08006	0,12817	0,12770	0,13907	0,16528	0,19006	0,05882
32	55 90	50 10	0,07818	0,12388	0,12410	0,13405	0,16040	0,18593	0,05720
33	37 105	40 3	0,06433	0,11425	0,09663	0,09789	0,11876	0,13042	0,04802
34	32 105	30 8	0,06706	0,10154	0,10390	0,10816	0,13098	0,14724	0,04972
35	42 105	40 7	0,07238	0,11090	0,11266	0,11853	0,14269	0,16040	0,05352
36	92 105	30 10	0,05906	0,08972	0,09140	0,09592	0,11548	0,13062	0,04356
37	92 110	20 20	0,06300	0,09784	0,09900	0,10502	0,12654	0,14472	0,04614
38	149 105	40 13	0,07241	0,11294	0,11372	0,12155	0,14546	0,16582	0,05343

Other Technologies Cost Estimation: As mentioned in section 7.2, other technologies cost estimation model consists of the following energy technologies ; hard coal, natural gas, fuel-oil, lignite, diessel oil, hydro, geothermal, biomass. For each region, the production cost of each technology is calculated according to the financial parameters as given in assumptions of the parameters, MARKAL-MATTER (ECN, 2004) and TEIAS data. Some of the capacity factors and investment costs of each technology are based on MARKAL-MATTER data as presented in Table 7.9.

Table 7.9. MARKAL-MATTER data used in the model

Technology	Technology Type in the Model	Investment Cost($/kW)	Capacity Factor (%)
Pulverized coal power plant	Coal	1488	80
Oil fired power plant	Fuel-Oil and Diessel-Oil	1032	80
Natural Gas CC power plant	Natural Gas	972	65
Lignite fired power plant	Lignite	1728	75
Medium and high head hydro	Hydro	2280	34
Geothermal power plant	Geothermal	1236	90
Biomass gas turbine CHP	Biomass	2040	80

Annual fixed and variable O&M costs, fuel consumptions per kWh and unit cost of the fuel are gathered from TEIAS data given in Table 7.10 for technology types by regions except hydro and biomass technologies. Table 7.10 presents data concerning only the available thermal power plants and geothermal power plant. Fuel consumptions by generation technologies are calculated using the weighted average of all available power plants.

Table 7.10. Existing thermal power plants: fuel and O&M costs in Turkey [9]

	FUEL COST		OPERATING and MAINTENANCE COST			
Power Plant	($/TON)	(cent/106kcal)	Fixed ($/kW-month)	Fixed ($/kW-year)	Variable($/MWh)	FuelType
ÇATALAĞZI B	38,6	1205	2,86	34,32	1,2	Hard Coal
ELBİSTAN A 1-4	10,4	995	1,94	23,28	0,93	Lignite
ÇAYIRHAN	14	1181	4,77	57,24	4,11	Lignite
KANGAL	10,3	789	3,46	41,52	0,99	Lignite
KEMERKÖY	9,6	566	1,36	16,32	1,11	Lignite
ORHANELİ	28,7	1221	3,26	39,12	3,28	Lignite
SEYİTÖMER	10,4	592	2,28	27,36	0,77	Lignite
SOMA B	22,4	975	1,17	14,04	0,5	Lignite
TUNÇBİLEK	34,3	1459	3,63	43,56	1	Lignite
YATAĞAN	14,6	766	2,92	35,04	0,88	Lignite
YENİKÖY	10,5	639	2,57	30,84	0,69	Lignite
AMBARLI DG	166,3	1984	0,35	4,2	2,33	Natural Gas
HAMİTABAT	171,7	2115	0,65	7,8	0,07	Natural Gas
BURSA	171	2049	0,47	5,64	0	Natural Gas
AMBARLI+HOPA	218	2271	0,77	9,24	0,11	Fuel Oil
ALİAĞA GT	427,4	4452	2,54	30,48	0,11	Diessel Oil
BO Nat.Gas	171	2049	0,47	5,64	0	Natural Gas
OTOP	218	2271	0,77	9,24	0,11	Fuel Oil
New OTOP	171	2049	0,47	5,64	0	Natural Gas
BOT	171	2049	0,47	5,64	0	Natural Gas
EÜAŞ Others	458,6	4452	2,54	30,48	0,11	Diessel Oil
BO Imported Coal	50	833	4,98	59,76	2,38	Imported Coal
CAN	49,3	1896	3	36	1	Lignite
ELBİSTAN B	10,4	995	3,31	39,72	5,06	Lignite
MOBIL	218	2271	1,53	18,36	0,29	Fuel Oil
GEOTHERMAL-İZMİR	-	-	-	-	27,99	-

TEIAS capacity factor assumptions for the capacity projections between years from 2005 to 2020 are taken into consideration and some of the technology types and generators are analyzed under TEIAS assumptions. All autoproducers are assumed to have 50% capacity factor and mobil power plants are assumed to operate with 18 % capacity factor. In addition, EUAS fuel-oil power plants are assumed to have 13 % capacity factor according to Figure 7.15 given below. Other power plants are analyzed under the MARKAL-MATTER model.

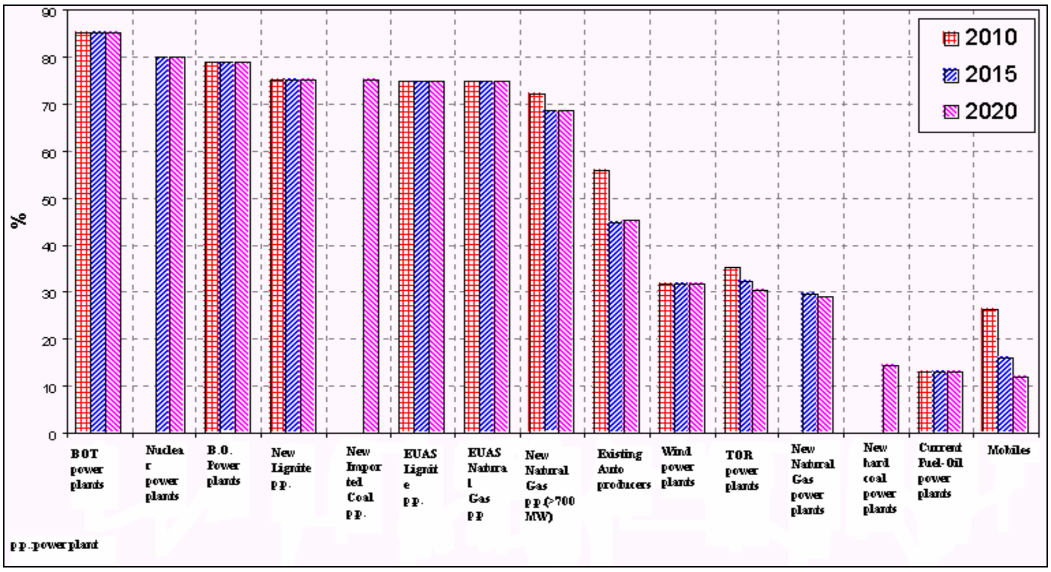


Figure 7.15. Capacity factors of power plants, 2005-2020 [9]

The hydro power plants are modeled using TEIAS Statistics published in 2000 to find production costs for the regions. The available hydro power plants are given in Table 7.11.

Table 7.11. Statistics of available hydro power plants [79]

Plant	Region	Capacity (MW)	Unit O&M Cost (ct-$/kWh)	Plant	Region	Capacity (MW)	Unit O&M Cost (ct-$/kWh)
Adıgüzel	Region 3	62	0,552	Kovada1	Region 3	8,3	2,265
Atatürk	Region 4	2405	0,059	Kovada2	Region 3	51,2	1,197
Demirköprü	Region 3	69	1,185	Göksu	Region 2	10,8	0,272
Dicle	Region 4	110	0,094	Kayaköy	Region 1	2,6	0,917
Gezende	Region 2	159,4	0,285	Almus	Region 5	27	0,956
Gökçekaya	Region 2	278,4	0,551	Altınkaya	Region 5	702	0,179
Hirfanlı	Region 2	128	0,749	Aslantaş	Region 5	138	0,384
Kapulukaya	Region 2	54	0,376	Ataköy	Region 5	4,8	4,337
Karakaya	Region 4	1800	0,082	Çamlıgöze	Region 5	16	0,243
Karkamış	Region 4	189	0,041	Çatalan	Region 5	168,9	0,196
Keban	Region 4	1330	0,189	Derbent	Region 5	56,4	0,145
Kemer	Region 3	48	1,295	H.uğurlu	Region 5	500	0,134
Kesikköprü	Region 2	76	0,269	Karacaören	Region 5	32	0,859
Koçköprü	Region 4	8,8	1,196	Kılıçkaya	Region 5	120	0,366
Kralkızı	Region 4	94,4	0,225	Köklüce	Region 5	90	0,137
Menzelet	Region 4	124	0,269	Kuzgun	Region 5	21,3	0,545
Oymapınar	Region 3	540	0,315	H.polatkan	Region 5	160	0,721
Özlüce	Region 4	170	0,03	S.uğurlu	Region 5	69	0,241
Zernek	Region 4	3,5	3,105	Tercan	Region 5	15	1,284

The production costs for natural gas technology by regions have been calculated as given in Table 7.12. Offered prices are comprised of the weighted average of the production costs and capacities and used as inputs to the unconstrained schedule. The conversion factor to convert tons of liquid natural gas in cubic metres of gaseous natural gas is taken as follows: 1 tonnes of liquid natural gas is equal to the 1400 m^3 gaseous natural gas [80]. Lignite production cost calculations by regions are given in Table 7.13.

Table 7.12. Natural gas parameters by regions

Region	Fuel Consumption m^3 /kWh	Unit Fuel Cost \$/ m^3	Unit Fixed O&M Cost \$/kW-year	Unit VaribleO&M Cost \$/MWh-year	Production Cost (\$)	Offered Price in the Model (\$)
Region 4	0,2088	0,122225	6,18	**-**	0,02897	0,02897
Region 3	0,227	0,1221	5,64	-	0,03051	0,03051
Region 1	0,1959	0,1221	5,64	-	0,02773	0,02804
Adapazarı-Hamitabat	0,23	0,1226	7,8	0,07	0,03119	
Region 2	0,1823	0,1221	5,64	-	0,02657	0,02657
Region 5						0,02853
Ambarlı	0,21	0,1162	4,2	2,33	0,02961	
Others	0,198	0,1221	5,64	-	0,02792	

Table 7.13. Lignite parameters by regions

Region	Fuel Consumption gr/kWh	Unit Fuel Cost \$/kg	Unit O&M Cost \$/kW-year	Unit VaribleO&M Cost \$/MWh-year	Production Cost	Offered Price in the Model (\$)
Region 4						0,03750
Kangal	2507	0,0103	41,52	0,99	0,03888	
Elbistan	2194	0,0104	31,5	2,995	0,03704	
Region 3						0,04021
Kemerköy	1543	0,0096	16,32	1,11	0,02811	
Seyitömer	1478	0,0104	27,36	0,77	0,0295	
Soma B	1419	0,0224	14,04	0,5	0,03983	
Yatağan	1401	0,03504	35,04	0,88	0,05512	
Yeniköy	1572	0,03084	30,84	0,69	0,05406	
Others	549,66	0,021656	24,72	0,79	0,02667	
Region 1						0,04162
Orhaneli	963	0,0287	39,12	3,28	0,04162	
Region 2						0,03511
Park Termik	1116	0,0199262	28,94	1,334	0,03511	
Region 5						0,03462
Autoproducers	470,5	0,0199262	28,94	1,3338889	0,03462	

Table 7.14. Fuel-Oil parameters by regions

Region/Generator	Fuel Consumption gr/kWh	Unit Fuel Cost $/kg	Unit Fixed O&M Cost $/kW-year	Unit VaribleO&M Cost $/MWh-year	Production Cost($)	Offered Price in the Model ($)
Region 4						0,07447
Mobil	220,61	0,218	18,36	0,29	0,08035	
Autoproducers	261,6	0,218	9,24	0,11	0,05648	
Region 3	178	0,218	9,24	0,11	0,04314	0,04314
Region 1	177	0,218	9,24	0,11	0,04298	0,04298
Region 2						0,04187
Otoproducers	149	0,218	9,24	0,11	0,03851	
Mobil	215	0,218	18,36	0,29	0,07945	
Region 5						0,09155
EUAS	288,5	0,218	9,24	0,11	0,10247	
Mobil	221	0,218	18,36	0,29	0,08041	
Autoproducers	161,5	0,218	9,24	0,11	0,0405	

Table 7.15. Hard coal parameters by regions

Region/Generator	Fuel Consumption gr/kWh	Unit Fuel Cost $/kg	Unit Fixed O&M Cost $/kW-year	Unit VaribleO&M Cost $/MWh-year	Production Cost	Offered Price in the Model ($)
Region1	-	-	-	-		0,04289
Çatalağzı	827	0,0386	34,32	1,2	0,04645	
Çolakoğlu	352	0,05	59,76	2,38	0,03949	
Region 5						0,04464
İskenderun	390	0,05	59,76	2,38	0,04088	
Autoproducers	1024	0,0386	34,32	1,2	0,06534	

Table 7.16. Diessel oil parameters by regions

Region/Generator	Fuel Consumption gr/kWh	Unit Fuel Cost $/kg	Unit Fixed O&M Cost $/kW-year	Unit VaribleO&M Cost $/MWh-year	Production Cost($)	Offered Price in the Model ($)
Region 4	234,5	0,4586	30,48	0,11	0,09701	0,09701
Region 3						0,09625
Aliağa.	271	0,4274	30,48	0,11	0,09625	

Table 7.17. Hydro power parameters by regions

Region	Fuel Consumption gr/kWh	Unit Fuel Cost $/kg	Unit Fixed O&M Cost $/kW-year	Unit VaribleO&M Cost $/MWh-year	Production Cost($)	Offered Price in the Model ($)
Region 4	-	-	-	1,0265	0,04333	0,04333
Region 3	-	-	-	5,502	0,04661	0,04661
Region 1	-	-	-	9,17	0,04929	0,04929
Region 2	-	-	-	4,7889	0,04609	0,04609
Region 5	-	-	-	2,754	0,0446	0,0446

Biomass data is obtained from Environment Canada and National Renewable Energy Laboratory. It has been assumed that there is no difference between regions in the production costs of biomass.

Table 7.18 Biomass power parameters

Region	Fuel Consumption m3/kWh	Unit Fuel Cost $/m3	Unit Fixed O&M Cost $/kW-year	Unit VaribleO&M Cost $/MWh-year	Production Cost($)	Offered Price in the Model ($)
Region 3	0,416	0,05056	36,56	11,3	0,05569	0,05569
Region 1	0,416	0,05056	36,56	11,3	0,05569	0,05569
Region 2	0,416	0,05056	36,56	11,3	0,05569	0,05569
Region 5	0,416	0,05056	36,56	11,3	0,05569	0,05569

Table 7.19 Geothermal power parameters

Region	Fuel Consumption gr/kWh	Unit Fuel Cost $/kg	Unit Fixed O&M Cost $/kW-year	Unit VaribleO&M Cost $/MWh-year	Production Cost($)	Offered Price in the Model ($)
Region 3	-	-	-	27,99	0,02921	0,02921

Energy Model: Parameters to be determined as inputs to energy model in the WEPE include wind shear exponent, annual average temperatures, annual average pressures, shape factors for the sites and losses coefficients which includes array losses, airfoil soiling/icing losses, other downtime losses and miscellaneous losses. These parameters are summarized in Table 7.20.

Table 7.20. Illustration of the parameters of the energy model [75,81,82]

Parameters/Site	**Amasra**	**Bandırma**	**Bozcada**	**Çanakale**	**Güney**	**Mardin**	**Pınarbasi**
Wind shear exponent	0,14	0,14	0,14	0,14	0,14	0,14	0,14
Annual average temperature(°C)	11,9	12,7	14,4	13,3	12,3	11,8	10,2
Average atmospheric pressure (kPa)	95,5	97,9	97,9	97,9	93,7	89,7	89,2
Shape Factor	1,481	1,345	1,797	1,617	1,816	1,842	1,530
Array losses (%)	3%	3%	3%	3%	3%	3%	3%
Airfoil soiling and/or icing losses (%)	2%	2%	2%	2%	2%	2%	2%
Other downtime losses (%)	2%	2%	2%	2%	2%	2%	2%
Miscellaneous losses (%)	3%	3%	3%	3%	3%	3%	3%

Wind shear exponent is assumed to a value of 0,14 which is a first good approximation according to the literature (due to the lack of the available sites characteristics such as topographic data) [75]. Annual average temperature and annual average pressure data which cover ten year average values is obtained from NASA for the sites. Shape factors for the selected sites are gathered from wind speed data analysis. Losses coefficients are determined in terms of the interview with Demirer Holding which is a leading wind energy company in Turkey. As to site characteristics these values can be changed so the average of the values are taken into consideration and all losses coefficients are assumed to be the same for all available wind energy projects.

Economic Analysis: All values of the parameters concerning the economic analysis section of WEPE is based on Demirer Holding data. Generally, the values of the economic parameters of a wind energy project differ slightly between countries due to economices of scale. The labour costs and wind turbine parts that are manufactured by Turkish firms are cheaper as compared to the price in developed countries. Therefore, some of the values defined in this section are peculiar to the Turkish economic situation. The formulas and the values of the parameters used as inputs in the economic analysis section are given in Table 7.21.

Table 7.21. Parameters of the WEPE economic analysis module

INITIAL COSTS			
Feasibility Study	**Number**	**Unit Cost ($)**	**Amount ($)**
Site investigation	x	-	If x ≤ 10 500 else 1000
Wind resource assessment	1	10.000	10.000
Preliminary design,cost estimation and project management	x	90.000	90.000*x
Report preparation	x	1.000	If x ≤ 10 1.000*x or 10.000
Travel and accommodation	x	1.000	If x ≤ 10 1.000 else 5000
Development			
PPA negotiation	x	1.200	1.200*x
Land rights	x	10.000	10.000*x
Legal and accounting	x	5.000	5.000*x
Project management	x	15.000	15.000*x
Engineering			
Wind turbine(s) micro-siting	x	10.000	If x ≤ 10 10.000*x else 5000*x
Mechanical design	x	1.000	If x ≤ 10 1000*x else 500*x
Electrical design	x	1.000	If x ≤ 10 1000*x else 500*x
Civil design	x	1.000	If x ≤ 10 1000*x else 500*x
Tenders and contracting	x	30.000	If x ≤ 10 30.000*x else 20.000*x
Energy Equipment			
Wind turbine(s)	x	1.125*y	1.125*x*y
Spare parts	x	16.000	16.000*x
Transportation	x	20.000	20.000*x
Balance of Plants			
Wind turbine(s) foundation(s)	x	15.000	15.000*x
Wind turbine(s) erection	x	5.000	5.000*x
Road construction	x	5.000	5.000*x
Transmission line	x	40.000	If x ≤ 10 40.000*x else 15.000*x
Substation	x	60.000	If x ≤ 16 60.000*x else 50.000*x
Control and O&M building(s)	1	50.000	50.000
Transportation	1	68.000	68.000
ANNUAL COSTS			
Operating and Maintenance Costs			
Land lease	x	2.500	2.500*x
Insurance premium	0,05	z*0,05 / x	z*0,05
Transmission line maintenance	x	25.000/x or 125.000/x	If x ≤ 5 25 .000 else 125.000
Parts and labour	0,02	z*0,02 / x	z*0,02
General and administrative	0,05	t*0,05 / x	t*0,05
OTHER COSTS			
Blades	x	50.000	50.000*x

x: number of wind turbines y: wind turbine rated power z:total initial costs t:Total O&M costs up to general and administrative

Initial costs of the wind energy projects include estimation of the parameters of the feasibility study, development, engineering, energy equipment,and balance of plant. The amount of costs regarding the economic analysis usually depend on the number of wind turbines defined in the energy model.

In feasibility section, the amount of site investigation is assumed to be $ 500 if number of turbines smaller than 11 else the cost item is $ 1.000. Wind resource assessment item is defined as $ 10.000 for all projects. Preliminary design,cost estimation and project management costs are assumed to equal $ 90.000 per turbine. The amount of the report preparation is given according to the number of the turbines that is if there are more than 10 turbines, then $ 10.000 else 1.000*number of wind turbines. Travel and accommodation costs are assumed to be $ 5.000 if the number of the turbines greater than 10 else $ 1.000 in this section.

PPA negotiation costs are equal to $ 1.200 per turbine and the amount of the land rights are calculated by multiplying $ 10.000 with number of turbines. It is assumed that legal and accounting costs are $ 5.000 per turbine. The amount of project management is determined as $ 15.000*number of turbines in the development phase.

All cost items of the engineering section are defined using if then else statements in the WEPE. Wind turbines micro siting costs are computed as follows: a) if number of turbines is greater than 10 then costs = $ 5.000*number of turbines. b) if there are 10 turbines or less, then costs = $ 10.000*number of turbines. Mechanical, electrical and civil design costs of the wind turbines are calculated by multiplying $ 1.000 if there are less then 11 turbines, else by multiplying $ 500 with number of turbines. The amount of tenders and contracting is estimated by multiplying number of wind turbines with $ 20.000 if the number is greater than 10, else $ 30.000.

The unit cost of the selected wind turbine is calculated according to the wind turbine rated power. The value of $ 1125 per kW is determined by Enercon E-40 wind turbine data obtained from Demirer Holding. The amount of the wind turbines are estimated by multiplying rated power, unit cost of wind turbine, and number of wind turbines. Spare part cost per turbine is assumed to be \$ 16.000 and transportation cost per turbine is given as \$ 20.000.

The cost of the installation of wind turbines is given \$ 15.000 per turbine and wind turbines erection and road construction costs are assumed to be \$ 5.000 per turbine in balance of plants section. The amount of transmission and substation costs are related the number of wind turbines. The amount of transmission cost is determined by multiplying \$ 40.000 per turbine if the number of the turbines smaller than 11 else \$ 15.000 per turbine. On the other hand, the amount of substation cost is assumed to be equal \$ 50.000 per turbine if the number of the turbines is greater than 16 else \$ 60.000 per turbine. Control and O&M building cost is given as \$ 50.000 and transportation cost is assumed to equal \$ 68.000.

In O&M costs section of the WEPE, all cost items are determined on a yearly basis. Land lease cost is calculated by multiplying \$ 2.500 with number of turbines. The amount of insurance premium cost is determined by estimating 5 % of the total initial costs and the unit cost iss calculated by dividing number of wind turbines. Transmission line maintanence cost is assumed that if the number of wind turbines smaller than 6 than \$ 25.000 else \$ 125.000. The amount of parts and labour costs accounts for 2 % of the total initial costs and by dividing number of turbines unit cost of parts and labour is obtained. General and administrative cost is given as % 5 of the yearly total O&M costs up to this cost item and the unit cost of general and administrative is defined as per turbine.

Lastly, the amount of the periodic cost of blades is calculated by multiplying \$ 50.000 per turbine.

Financial Parameters: The input items of the financial parameters include energy cost escalation rate, inflation rate, discount rate, debt ratio, debt interest rate, debt duration as given in Table 8.22. Project life of the all wind energy projects are assumed to 25 years since the economic life of the well designed wind energy projects is between 20 and 30 years.

Table 7.22. Financial parameters of the WEPE

Parameters	Value	Reference
Energy cost escalation rate (%)	4,91 %	USA Energy Cost Escalation Rates
Inflation rate (%)	1,64 %	USA Inflation Rates
Discount rate (%)	10 %	SPO
Project life (year)	25	Environment Canada
Debt Ratio (%)	70 %	Demirer Holding, EUAS
Debt Interest Rate (%)	4,5 %	EUAS
Debt Duration (year)	15	Environment Canada

Financial terms are defined as inputs in production cost calculation section, other technologies cost calculation section and the results section of the WEPE in order to estimate production cost of technologies and financial ouput items such as project equity, IRR, NPV and benefit-cost ratio. Since the currency of the WEPE is defined in US dollars and the structure of Turkish economy involves high inflation rate, energy cost escalation rate and inflation rate are based on the USA data. Inflation rate and energy cost escalation rate defined in the model comprise average of the values between 1984 and 2000 years as shown in Table 7.23.

Table 7.23. Energy cost escalation and inflation rates of USA, 1984-2000 [83]

Year	**Energy cost escalation rate**	**Inflation rate**
1984	5,45	2,4
1985	5,46	-0,5
1986	5,23	-2,9
1987	5,12	2,6
1988	5,38	4
1989	6,46	5
1990	6,46	3,7
1991	7,36	0,2
1992	7,62	0,6
1993	4,41	1,5
1994	4,01	1,3
1995	3,41	3,6
1996	3,25	2,4
1997	3,05	-0,1
1998	3,27	-2,5
1999	3,65	0,9
2000	3,87	5,7
Average	4,91	1,64

It is assumed that the discount rate is 10 % according to the expected value of DPT in 2003. Debt ratio and debt interest rate are defined as 70 % and 4,5 % respectively in the model in terms of the EUAS project evaluation document for one of the thermal power plant and Demirer Holding data. The value of debt duration is taken into consideration as 15 years which is typically used to assess energy projects in practice [78].

Line Capacities: The Turkish electric power transmission system is assumed to have 5 nodes and each of the node can import energy from other nodes or export energy to other nodes depending on the line capacities. The line capacities are given as in Table 7.24 for each of the node. The determination of line capacity of each region is based on the sum of the 380 kV lines due to the much of the energy delivered by these lines.

Table 7.24. Line capacities

Line Capacities for Nodes(MW)			
L12	44000	L34	35200
L13	44000	L35	35200
L14	52800	L41	52800
L15	88000	L42	61600
L21	44000	L43	35200
L23	35200	L45	79200
L24	61600	L51	88000
L25	79200	L52	79200
L31	35200	L53	35200
L32	35200	L54	79200

There are no line losses which occur while exporting power from one node to another node. On the other hand, power imports from node i to node j are limited by the line capacities and there exists line losses in that case. The line losses coefficient with power exports determines the amount of power imported from node i to node j. The line losses coefficient is assumed to equal 0,02 according to TEIAS data. The power imports from node i to j is calculated as (0,98) * F_{ji} .

8. MODEL RESULTS

In this chapter, scenarios defined in WEPE are explored and their results are discussed from the perspective of the stakeholders. Nine scenarios are examined: base case scenario and eight additional scenarios which are mainly defined in accordance with the draft renewable energy law.

These scenarios are defined as follows. Six year guaranteed purchase price with SMP scenario: Scenario 1 , six year guaranteed purchase price with weighted average scenario: Scenario 2, fixed six year five Euro/cent guranteed purchase price scenario: Scenario 3 , fixed six year six Euro/cent guranteed purchase price scenario: Scenario 4, all years guaranteed purchase price with SMP scenario: Scenario 5, all years guaranteed purchase price with weighted average scenario: Scenario 6, fixed all years five Euro/cent guaranteed purchase price scenario: Scenario 7, fixed all years six Euro/cent guaranteed purchase price scenario: Scenario 8.

There are thirty-eight players which include nine key players in the scenarios. The twenty-nine players are represented as technology types for each region in the model such as natural gas, lignite, hard coal, hydro,geothermal,biomass, fuel-oil and diessel oil. The seven wind power plants are the first seven key players; the eighth player represents the system operator and nineth player represents the "master of the scenarios" who set the scenarios in place including demand growth patterns, bidding prices, bidding capacities, load management options and other parameters. For each of scenario, an unconstrained Schedule is first constituted and SMP is determined according to forecasted load for each planning period . The simulation model is then run and results of the all twenty-five years of performance simulation for wind power plants including load management and forced outage results, as provided by WEPE, are obtained. The cash inflows of the wind energy projects are obtained from dispatched generation and SMPs for each planning period. Besides, the dispatced energy and payments from the System Operator to generators (for wind power plants) are presented. At the end of the simulation, the cash flows of the wind power projects are prepared and financial parameters such as NPV, IRR and benefit-cost ratio are evaluated.

8.1. Base Case Scenario

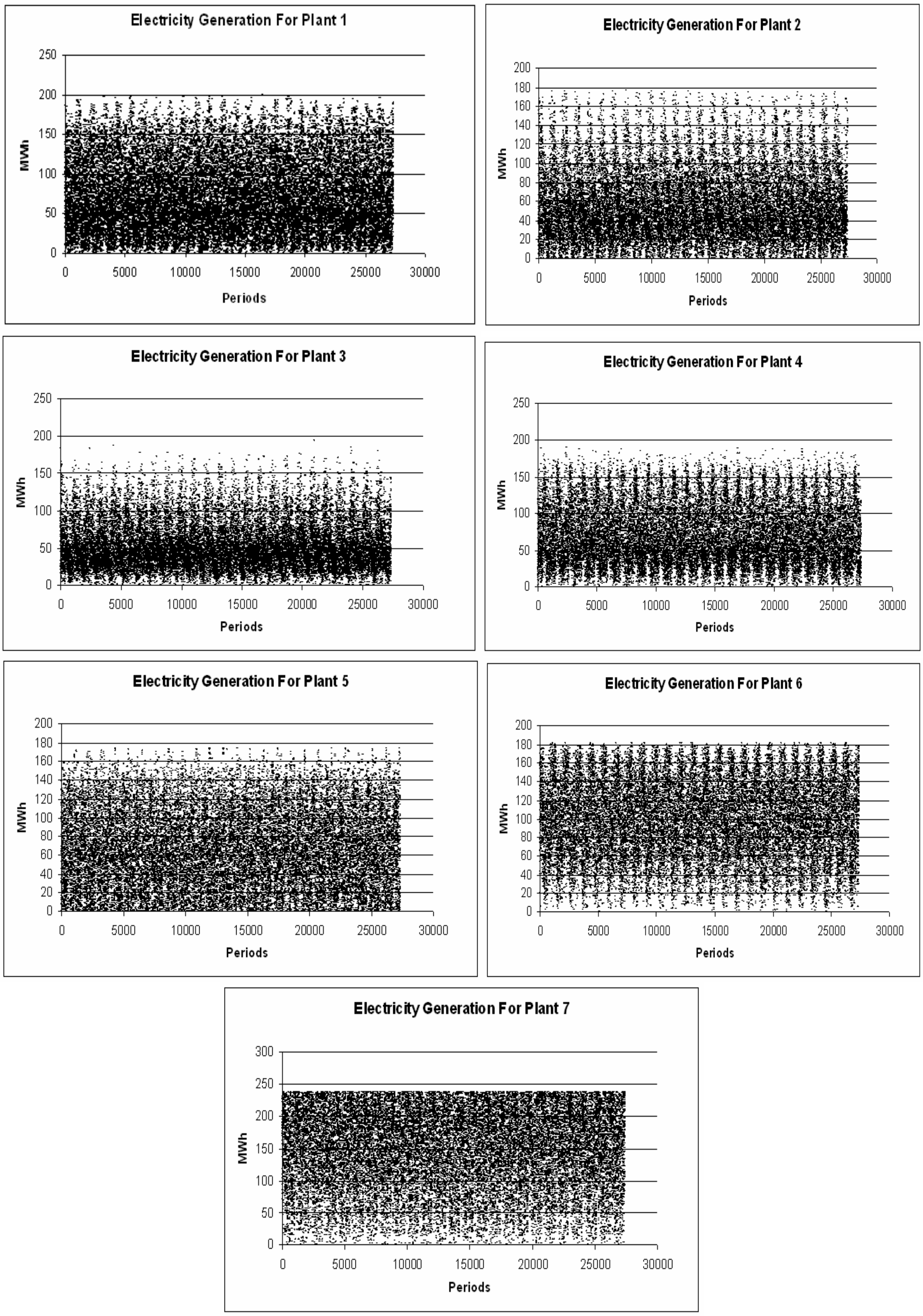
The base case scenario involves analyzing the model under defined assumptions within a 25-year time horizon. The model for evaluating the wind energy projects, described in Section 7, is implemented for simulation in MS Excel. There are 145 variables, 60 constraints and 290 bounds in the model. As mentioned before, all generators including wind power plants submit bids that specify bid price and bid capacity to the power pool for each planning period. Then, system operator prepares unconstrained schedule according to load data and determines the SMP which is the last offered bid price by the generator until the average of the total demand of the period is met.

Firstly, historical simulation is performed to calculate average hourly wind speeds for wind energy generation using average hourly wind speed records over a five year period from 1999 to 2003. Afterwards, electricity generation estimates for the alternative wind energy projects are obtained based on the historical simulation results. Wind energy generation is calculated in a periodic format comprising eight hour time intervals as described in the model assumptions. Lastly, the electricity market model based on the defined assumptions is simulated over a 25 year time horizon in the program in order to evaluate wind power plant viability in a competitive electricity market. After performing historical simulation, using the parameters defined in the assumptions and historical simulation results, electricity generation for each of the power plant is estimated in WEPE. The corresponding sites for the wind power plants defined in WEPE are presented in Table 8.1.

Table 8.1. The corresponding sites for the wind power plants

Plant ID	Site
Plant 1	Çanakkale
Plant 2	Pınarbaşı
Plant 3	Mardin
Plant 4	Güney
Plant 5	Bandırma
Plant 6	Amasra
Plant 7	Bozcada

The generated amount of electricity for all power plants over the twenty-five year time horizon are illustrated in Figure 8.1. It takes nearly 150 hours to simulate the model on a Pentium IV PC with 512 MB Ram 2.6 GHz machines. Each planning period lasts three hours and approximately each period is completed in 20 seconds.


Electricity Generation For Plant 1

Electricity Generation For Plant 2

Electricity Generation For Plant 3

Electricity Generation For Plant 4

Electricity Generation For Plant 5

Electricity Generation For Plant 6

Electricity Generation For Plant 7

Figure 8.1. Electricity generation for wind power plants (MWh)

There are seven graphics in Figure 8.1 which indicate the electricity generation per power plant over all periods. The simulation results for electricity generation, on which the reults are based are given in Table 8.2. The graphics which have more concentrated and scattered points belong to the sites that have high wind speeds. Electricity generation for plant 1 shows that the wind turbines produce electricity up to 200 MWh and the overall generation is slightly intensive but it seems to decline especially after 100 MWh.

Table 8.2. Simulation results for energy generation of wind power plants

Site/Parameters	**Wind Power Plant 1 (MWh)**		**Wind Power Plant 2 (MWh)**		**Wind Power Plant 3 (MWh)**		**Wind Power Plant 4 (MWh)**		**Wind Power Plant 5 (MWh)**		**Wind Power Plant 6 (MWh)**		**Wind Power Plant 7 (MWh)**	
Average	73,86		57,22		55,23		72,11		67,14		98,28		146,80	
Standart Deviation	44,58		35,36		31,75		39,85		41,53		41,35		60,70	
Minimum	0		0		0		0,19		0		0		0	
10% quantile	19,09		16,37		20,25		24,10		11,91		42,32		57,74	
lower quartile	37,52		30,84		31,66		40,01		32,64		66,83		101,85	
Median	67,33		50,67		48,21		65,95		64,78		98,90		154,3	
upper quartile	106,05		78,22		73,62		100,72		98,71		130,92		197,64	
90 % quantile	139,12		107,66		101,48		131,18		125,57		154,35		223,50	
Maximum	200,93		176,89		194,30		190,54		174,76		182,04		239,76	
Probability of no energy	0,00004		0,00095		0,00007		0,0		0,01235		0,00066		0,00073	
Low and High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
90 % quantile 95 % Confidence Interval	139,06	139,18	107,61	107,72	101,42	101,54	131,12	131,24	125,51	125,63	154,29	154,41	223,44	223,56
95% Confidence Interval	73,74	74,39	56,81	57,64	54,86	55,61	71,64	72,58	66,65	67,63	97,79	98,77	146,09	147,52

The average electricity generation is 73,86 MWh with a standart deviation of 44,58 for Plant 1, as can be seen from Table 8.2. The reason of the high standart deviation is high variation in wind speed for the particular site and since the power available in the wind is proportional to the cube of its speed, even slight variations in wind speed have significant effect on generated power. The minimum value for Plant 1 is zero which indicates that the wind turbines don’t generate electricity because of the lack of a minimal sufficient wind speed. The tenth percentile of the electricity generation value of the Plant 1 is 19,09 and the lower quartile is 37,52. The median is 67,33 , the seventy-fiveth percentile of the generation values is 106,05 and the ninetieth percentile of the values is 139,12 for Plant 1. The maximum energy produced by Plant 1 is 200,93 MWh over the twenty five year simulation time. The probability of not to generate electricity for Plant 1 is 0,004 % which can be ignored. The ninetieth percentile of the values with 95 % confidence interval range from 139,06 to 139,18 and with 95 % probability, the average generated electricity is between 73,74 and 74,39.

The wind power plant 2 electricity generation graphic represents sparse generation as can be seen from blank fields and the intensive generation ranges between 20 and 60 MWh. The electricity generation doesn't exceed the 180 MWh boundary and sometimes variates from 100 to 180 MWh. Wind Power Plant 2 generates 57,22 MWh electricity in an average for a period and this changes with a standart deviation of 35,36. The minimum generation is zero and 10% quantile is 16,37 which is 40,85 MWh less than the average. The lower quartile, median and upper quartile are 30,84, 50,67, and 78,22 respectively. The plant 2 works without producing any power with a probabilty of 0,095 % for a period. The average electricity generation quantity ranges from 56,81 to 57,64 with 95 % probability and with 95 % probability, 90 % quantile is between 107,61 and 107,72

It is seen from Figure 8.1 that the electricity generation for wind power plant 3 demonstrates that the generation is highly concentrated at around 50 MWh and it rarely surpasses 150 MWh due to insufficient wind speed. Also between 0 and 15 MWh level there isn't much generation in terms of the blank points. The average generation for plant 3 is 55,23 MWh with a standart deviation of 31,75. The minimum generation is zero and 10% quantile, lower quartile and median are 20,25, 31,66 and 48,21 respectively. The seventy-fiveth percentile of the generation values is 73,62. The 90% quantile is 101,48 and maximum energy generated by plant 3 is 194,30. The probability of not to generate electricity is 0,007 % for each of the period. The confidence interval of the generated electricity with 95 % of probability is between 101,42 and 101,54 and for 90% quantile the generated electricity ranges from 101,42 to 101,54.

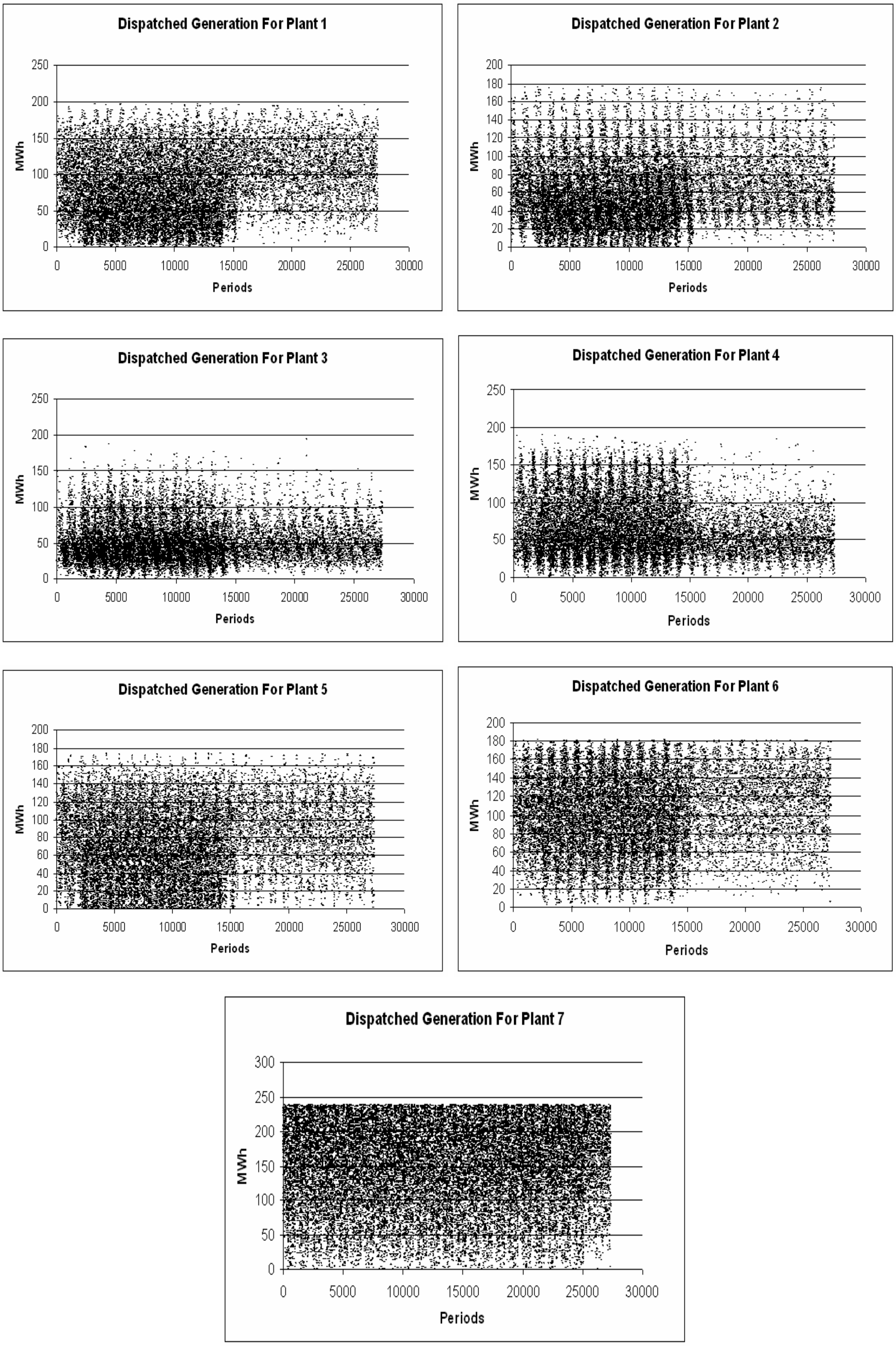
The electricity generation figure for wind power plant 4 points out the intensive generation between 25 and 100 MWh. Above 100 MWh there are small black points pointing out that generation reaches peak values in these periods. Also, wind turbines occasionally generate electricity up to 25 MWh so this results in blank points around that level. Plant 4 generates electricity at an average of 72,11 MWh with a standart deviation of 39,85. Different from other plants, the minumum generated energy is 0,19 thus, wind turbines always generate electricity for each of the period. The 10% quantile, lower quartile, median, and upper quartile are 24,10, 40,01, 65,95 and 100,72 respectively. The 90 % quantile is 131,18 and the maximum value of the generation is 190,54. Since all turbines generate electricity for every periods, the probability of no wind power production is zero. The wind power plant 4 produces average electricity with 95 % probability ranging from 71,64 to 72,58 and the 90 % quantile with 95 % probability is between 131,12 and 131,24.

As shown in Figure 8.1, wind power plant 5 electricity generation is one of the most scattered one over the periods. Wind turbines produce electricity up to 180 MWh and the dispersion of generation is not intensive at around a specific range. Interestingly, between 0 and 50 MWh, the generation is dispersed very well separate from the other plants. Thus, plant 5 generates more electricity than others in this range. The average generation for plant 5 is 67,14 MWh with a standart deviation of 41,35. The tenth percentile of the electricity generation value of the Plant 5 is 11,91 and lower quartile is 32,64. Median, upper quartile, 90 % quantile and maximum energy are 64,78, 98,71, 125,57 and 174,76 respectively. The probability of not to generate electricity is 1,235 % which is the highest ratio over the all plants. The confidence interval of the average generation with 95 % probability is between 66,65 and 67,63. The ninetieth percentile of the values with 95 % confidence interval range from 125,51 to 125,63.

The graphic for wind power plant 6 shows that the electricity generation is slightly intensive between 80 and 140 MWh and it seldomly reaches maximum level of 180 MWh. Also, due to the wind speed and wind turbine characteristics, the blank points cover up to 20 MWh over the periods. The average electricity generation is 98,21 MWh which is the second highest generation with a standart deviation of 41,35. 10% quantile, lower quartile, median and upper quartile are 42,32 , 66,83 , 98,90 and 130,92 respectively. The maximum generated energy is 182,04 and the probability of not to generate electricity for each of the period is 0,066 % that is one of smallest value among other values. With 95 % probability, the electricity generation in average ranges from 97,79 to 98,77 and the confidence interval of the 90 % quantile with 95 % probability is between 154,29 and 154,41.

As illustrated in Figure 8.1, the electricity generation for wind power plant 7 is rather intensive especially between 100 and 240 MWh, and it produces most of the electricity above 150 MWh. Because of the high speed wind potential in Bozcaada, the suitable type of wind turbines do not turn much up to 50 MWh and this causes blank points below that level as can be seen from the graphic. Table 9.2. shows that plant 7 has the highest average electricity generation value which is 146,8 with a standart deviation of 60,7. As we compare with other plants, the plant 7 average generation is nearly three times higher than plant 2 value because the difference of the average wind speed values of these plants is 2,39. Also, the standart deviation is the highest one which arises from the high variation in wind speeds. The minimum generation is zero although Bozcada is the most windy sites. The tenth percentile of the electricity generation value of the Plant 7 is 57,74 and lower quartile is 101,85. The values of the median, upper quartile and 90 % quantile are given as 154,3 , 197,64 and 223,5 respectively. The maximum energy generated by wind turbines of plant 7 is recorded as 239,76. The probability of not to generate electricity is 0,073 % which is the third highest value in the set. The confidence interval of the average generation changes from 146,09 to 147,52 with 95 % probability and the ninetieth percentile of the values ranges between 223,44 and 223,56 with 95 % probability.

Once the electricity generation process is completed which includes twenty-five year time horizon for wind power plants, the simulation is run under the general asumptions comprising fifty planning periods and the following results are obtained: Firstly, the dispatched energy over the twenty-five year time for each of the power plant is demonstrated in Figure 8.2.



Dispatched Generation For Plant 1

Dispatched Generation For Plant 2

Dispatched Generation For Plant 3

Dispatched Generation For Plant 4

Dispatched Generation For Plant 5

Dispatched Generation For Plant 6

Dispatched Generation For Plant 7

Figure 8.2. Dispatched generation for wind power plant

The graphics in Figure 8.2 represent dispatched electricity generation by the system operator for each of the plants over the simulation period. The more concentrated and dispersed black points indicate higher dispatched electricity generation of wind power plants. As can be seen from the graphics, all power plants except plant 7 have much generation dispatched by the system operator until around the 15.000 period and after this level the dispatched generation for each of the plant falls to a quite small portion. The reason of declining the dispatched generation is excess available electricity generation capacities (except wind power plants) so the wind power plant capacities are not included in the unconstrained schedule due to the high offered prices to the power pool. The dispatched energy wind power plant 7 is almost same with the generated energy only, at the end of the simulation for some periods there are slightly differences. The generation capacities having lower prices than plant 7 meet the electricity demand for the periods therefore, plant 7 is not dispatched in the unconstrained schedule and over the periods when demand covers its capacity then wind power plant 7 can sell energy to the power pool.

The simulation result of the dispatched generation for each of the wind power plant is given in Table 8.3. According to the dispatched generation graphics and the results table, the following issues are summarized:

The dispatched electricity graphic of plant 1 illustrates rather intensive dispatched generation between 0 and 100 MWh level until approximately 15.000th period which is corresponds to the year 2018. After 2018, especially from 0 to 50 MWh, there is no much dispatched generation as can be seen from the blank points in this range. The average dispatched generation over the periods is 53,86 with a standart deviation of 53,51. If we compare with electricity generation results, the difference of the generated energy and dispatched energy is 20,35. Therefore, in an average 28 % percent of the generated electricity is not sold to the power pool due to high offerings and electricity market characteristics. In addition, the standard deviation is nearly equal to the average dispatched energy and the difference from the generated case is 8,93. This can be explained by the high variations in dispatched generation which mainly arises from the periodic demand pattern. In the time period between 00.00 and 08:00 electricity demand is growing slowly but in other time periods from 08:00 to16:00 and from 16:00 to 24:00, the demand is growing rapidly so in that case for the first time period, most of the wind power plants are not dispatched. On the other hand, for the second and third time periods, most of the wind power plants are dispatched. Thus, these variations in dispatched generation cause high variation and small average dispatched generation values. The minimum, 10 % quantile and lower quantile are zero which indicate that zero values are higher and nearly 34 % of the dispatched generation is zero. The difference between the medians is 23,67 and the upper quartile, 90 % quantile and maximum dispatched energy are 96,66 , 133,93 and 198,98 respectively. The average dispatched capacity ranges between 53,22 and 54,49 with probability of 95 % and the confidence interval of the 90 % quantile is from 133,87 and 133,99 with probability of 95 %.

Table 8.3. Simulation results for dispatched energy of wind power plants

Site/Parameters	**Wind Power Plant 1**		**Wind Power Plant 2**		**Wind Power Plant 3**		**Wind Power Plant 4**		**Wind Power Plant 5**		**Wind Power Plant 6**		**Wind Power Plant 7**	
Average(MWh)	53,86		40,55		32,45		44,27		47,70		66,92		143,29	
Standart Deviation	53,51		40,87		34,85		44,89		48,19		58,26		64,42	
Minimum	0		0		0		0		0		0		0	
10% quantile	0		0		0		0		0		0		48,79	
lower quartile	0		0		0		0		0		0		96,86	
Median	43,66		34,63		27,33		36,74		37,67		69,79		152,31	
upper quartile	96,66		67,94		53,34		74,08		87,09		117,49		196,92	
90 % quantile	133,93		99,12		82,34		111,84		119,52		147,07		223,23	
Maximum	199,98		176,89		194,30		190,54		174,41		181,98		239,76	
Probability of not to sell energy (%)	34,83		34,33		39,62		35,51		35,39		34,20		2,80	
Low and High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
90 % quantile 95 % Confidence Interval	133,87	133,99	99,07	99,18	82,28	82,40	111,78	111,90	119,47	119,58	147,01	147,13	223,17	223,29
95 % Confidence Interval	53,22	54,49	40,06	41,03	32,04	32,86	43,73	44,80	47,12	48,57	66,23	67,61	142,53	144,06

The dispatched electricity figure for wind power plant 2 shows that the dispatched capacity is only concentrated in between 0 and 80 MWh up to 2018 and the shape of the black points appear like vertical lines in the overall graphic 2 due to the demand variance in time periods. Like all other plants except plant 7, plant 2 dispatched energy decreases after the year of 2018. The average dispatched capacity for plant 2 is 40,55 which reflects 29 % decrease in terms of the electricity generation. The standart deviation is 40,87 and the difference between the standart deviations is 5,51. As others except plant 7, the minimum, 10 % quantile and lower quartile have zero values. The median, the seventy-fiveth percentile and the ninetieth percentile of the dispatched generation are 34,63, 67,94 and 99,12 respectively. The maximum dispatched energy is 176,89 which is same as with maximum generated energy. Wind power plant 2 sells its generated energy with a probability of 65,67 % which is the second highest ratio among the plants. The confidence interval of the average dispatched energy for plant 2 is between 40,06 and 41,03 with a probability of 95 % and the ninetieth percentile of the dispatched energy ranges from 99,07 to 99,18 with probability 95 %.

As can be seen from Figure 8.2, the dispatched electricity graphic for wind power plant 3 describes that only a small portion of the generated energy is sold to the power pool since there are not many black points dispersed around the graphic 3. The black points cover up to 150 MWh and after approximately 15.000th period there is sparse dispatched capacity for plant 3 as it is seen from the blank fields in graphic 3. The wind power generation for plant 3 is dispatched with an average of 32,45 which is the smallest value among all wind power plants. The difference between average generated energy and average dispatched energy is 22,78 that is equivalent to nearly 41 % decrease in average electricity generation. Therefore, the plant 3 electricity generation is dispatched approximately in proportion of 59 % which is the lowest ratio as comparing with other plants. The standart deviation is obtained as 34,85 and also this is the lowest value. The minimum, 10 % quantile and lower quartile values are again zero. The median, upper quartile and 90 % quantile are 27,33, 53,34 and 82,34 respectively. The probability of not to sell energy for wind power plant 3 is 39,62 % and this ratio is the highest ratio as the average dispatched generation is the lowest one. The average wind turbines electricity generation for plant 3 is dispatched between 32,04 and 32,86 with 95 % probability and the 90 % quantile of the dispatched energy with 95 % probability ranges from 82,28 and 82,40.

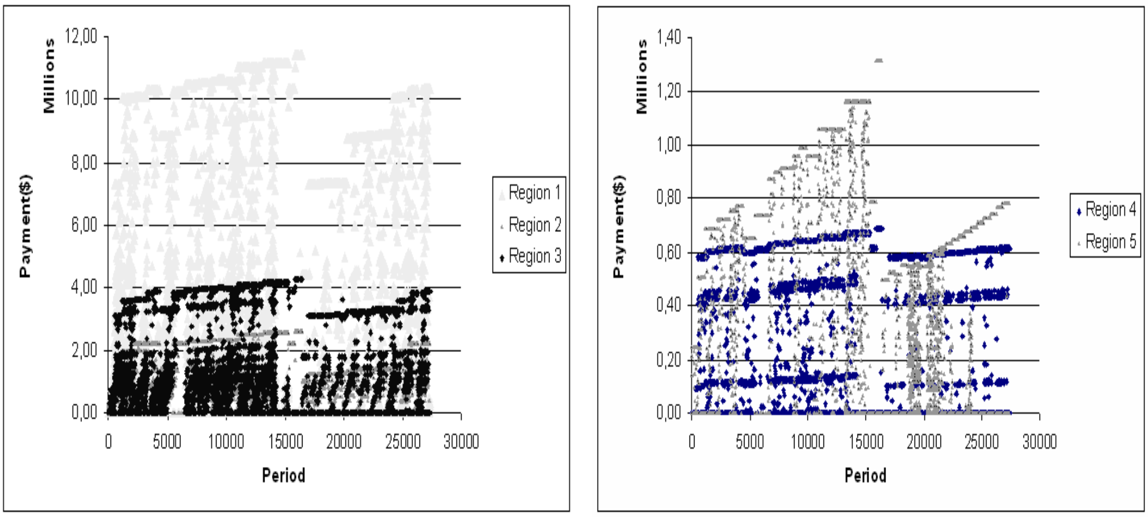
The dispatched capacity graphic for plant 4 indicates that the dispatched energy is quite intensive in the interval between 50 and 100 MWh. The vertical lines comprising of the black points can be easily seen from graphic 4 and begining from 2018, there is a considerable decrease for the dispatched energy which rarely exceeds 100 MWh level. The average dispatched energy is 44,27 with standart deviation of 44,89. The ratio of the generation that is not sold to the power pool includes 39 % of the total electricity generation for plant 4. The difference of standart deviations between generation and dispatched energy is 5,04. The minimum, 10 % quantile and lower quartile values are zero. The median, the seventy-fiveth percentile and the ninetieth percentile of the dispatched generation are 36,74, 74,08 and 111,84 respectively. The probability of not to sell energy to the power pool is 35,51 % that is the second highest ratio among other ratios. The confidence interval for the ninetieth percentile of dispatched energy is between 111,78 and 111,90 with 95 % probability and the average dispatched energy is between 43,73 and 44,80 with 95 % probability.

As it is demonstrated in Figure 8.2, graphic 5 involves rather scattered dispatched electricity generation until around the 15.000th period and the generation that is sold to the pool reaches nearly 180 MWh. Since total generation capacities exceed the total demand and high offer prices by wind power plant 5, the dispatched generation falls rapidly and this creates more blank points in graphic 5 after 2018. The average dispatched electricity generation is 47,70 and this means that nearly average generation of 19 MWh is not sold to the power pool for each of the period as we compare with the electricity generation for plant 5. The standart deviation is calculated as 48,19 which shows 16 % increase in the standart deviation of generated electricity for plant 5. The minimum, 10 % quantile and lower quartile values are again zero. The median, upper quartile and 90 % quantile are obtained as 37,67, 87,09 and 119,52 respectively. The wind power plant 5 sells its generated energy with probability of 64,61 % and the maximum energy dispatched is 174,41. The average dispatched generation ranges from 47,12 to 48,57 with probability of 95 % and the 90 % quantile with 95 % probability is between 119,47 and 119,58.

Graphic 6 in Figure 8.2 represents the slightly intensive dispatched generation until the year of 2018 and there are some vertical lines stating the variance in time periods. The intensive part of the generation is between 80 and 140 MWh. After nearly the 15.000th period like other graphics except graphic 7, the dispatched generation decreases very much and the rest of the graphic 6 includes only small portion of black points. Wind power plant 6 generates electricity with an average of 98,28 and it sells approximately 68 % of its generation that is equivalent to 66,92 to the power pool. The standart deviation of the dispatched energy for plant 6 is 58,26 which reflects nearly 41 % increase in the standart deviation of generated electricity for plant 6. As others except plant 7, the minimum, 10 % quantile and lower quartile have zero values. The median, the seventy-fiveth percentile and the ninetieth percentile of the dispatched generation are 69,79, 117,49 and 147,07 respectively. The probability of not to sell energy to the power pool is 34,20 % that is the second lowest ratio among others. The confidence interval for the ninetieth percentile of dispatched energy is between 147,01 and 147,13 with 95 % probability and the average dispatched energy is between 66,23 and 67,61 with 95 % probability.

The dispatched electricity graphic for wind power plant 7 describes that the overall dispatched generation is rather dispersed until the 25.000th period and between 100 and 240 MWh it is more concentrated as can be seen from Figure 8.2. The reason of the highly concentrated dispatched generation is explained by the fact that the offer price of plant 7 is the lowest one among all wind power plants also over the unconstrained schedule it lies in the middle of the offered prices so this makes plant 7 more likely to be dispatched. Due to the high wind speed characteristics, only small portion of the dispatched generation ranges from 0 and 50 MWh. Interestingly, after the 25.000th period, the wind power plant 7 doesn’t sell much energy to the power pool especially between 0 and 50 MWh. The average dispatched electricity generation is 143,29 with a standart deviation of 64,42. The difference of the average generation and dispatched values is only 3,52 which is equivalent to 2 % decrease in generated energy. The standart deviation of dispatched electricity increases about 6 % as compared to the case of electricity generation: The minimum value of the dispatched capacity for plant 7 is 0 as others but 10 % quantile and lower quartile are different from other plants. The tenth percentile of the dispatched energy is 48,79 and the lower quartile is 96,86. The median, upper quartile and 90 % quantile are 152,31, 196,92 and 223,23 respectively. The maximum energy sold to the power pool is 239,76 and wind power plant 7 sells its generated energy with probability of % 97,2 which is the highest ratio among the plants. The average dispatched generation ranges from 142,53 to 144,06 with probability of 95 % and the 90 % quantile with 95 % probability is between 223,17 and 223,29.

The load management options (LMO) results with the basic assumptions defined in the previous chapter are illustrated in Figure 8.3 for the first three regions and in Figure 8.4 for region 4 and region 5. As mentioned before, the load management options are implemented in the simulation if the load exceeds the limit of available power generation capacity. The spaces between the points in the figures reflect the load variations in time periods, that is to say especially in the second (08:00-16:00) and third time period (16:00-24:00) the electricity load usally exceeds the available generation capacity so the LMO payments variate when the time period is changed.



(a) (b)

Figure 8.3. The payments of LMO for (a) Region 1, Region 2 and Region 3 (b) Region 4 and Region 5

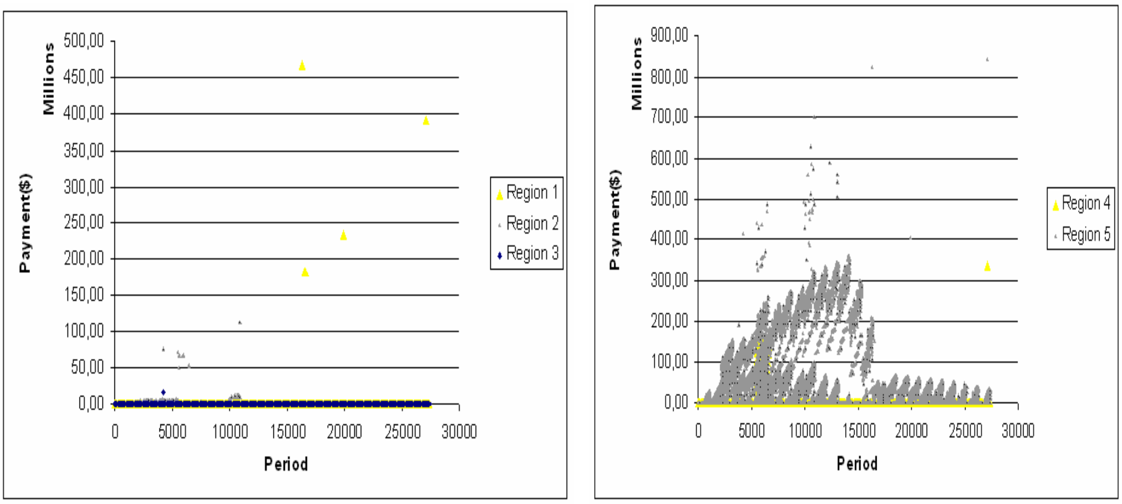
As can be seen from Figure 8.3, the highest amount of load mangement options is paid to the industry groups which submit bids to the power pool with a bid capacity and bid price by the system operator for Region 1. The LMO payments for Region 1 reach peak values of nearly twelve million dolar in some periods (especially after about the 15.000th period since total available generation capacity exceeds total load for some periods). The payments are cut down very quickly and then, they start to grow rapidly till the end of the simulation. The reason of the highest value of the LMO in Region 1 is expressed by the fact that the generation capacity for Region 1 doesn't fill the total electricity demand of this region and LMO bidding capacity is bigger than others, so in that case the system operator exercises the LMO. Because the difference between electricity load and available generation capacity for Region 1 is considerable, the amount of the LMO paid to the industry consumers is very high.

The LMO exercised for Region 2 covers only a small portion of Figure 8.3 demonstrated as a triangular point. The payments of the LMO by the system operator range from 0 to nearly $ 2,5 million for each of the periods and these payments are more intensive at around $ 2 million up to approximately the year of 2018. The small amount of LMO for Region 2 shows that most of the time available generation capacity is sufficient to meet the electricity demand for this region.

The shape of the LMO for Region 3 illustrates that the payments are quite concentrated between 0 and $ 2 million until nearly 15.000th period and after this period the LMO payments become slightly concentrated. The amount of the LMO for this region, depending on the balance between load and generation capacity, sometimes exceeds $ 4 million.

Also, Figure 8.3 describes the LMO payments paid to industry groups by the system operator in Region 4 and Region 5. As we compare with the other regions, Region 4 and Region 5 don’t have sufficient generation capacity that is dispatched to meet industrial consumers’ demand. As can be seen from Figure 8.3, there exists a gap at around the 15.000th period. The graphic can be investigated in two parts. The left side of the gap for Region 4 shows that the maximum LMO payment is below 800.000 $ which indicates the lowest amount among the regions. Also, there appears to be three thick lines that are formed by the points in Figure 8.3 for Region 4. The amount of LMO decreases at a considerable rate in the right side of the gap whereas it increases in the other part. The shape of the LMO points in the left side of the graphic constitutes like a trapazoid for the Region 5 and the maximum LMO payment is between $ 1,2 million and $ 1,4 million. Begining with approximately the 15.000th period, the amount of LMO for Region 5 is diminished considerably since the available generation capacity limit fills the electricity load. However, it starts to rise after nearly the 20.000th period.

The forced outages are explained as unfilled demand which is not covered by load management options. As it hs been mentioned in the model assumptions section, the cost of forced outage is set very high in each region; thirty times of the system marginal price referred from (Kleindorfer *et al.*[12]). The payments of the forced outages by regions are shown in Figure 8.4.



(a) (b)

Figure 8.4. The Payments of forced outages for (a) Region 1, Region 2 and Region 3 (b) Region 4 and Region 5

As can be seen from the Figures, since the LMO don’t cover total demand, in some periods and regions forced outages occur with a very high payments by the system operator. Figure 8.4 represents that forced outage payments assigned to the system operator for Region 1 have incredible high values which nearly reach $ 500 million. For the case where the cost of forced outages are paid for Region 2, the payment values are grouped nearly at the range between $ 50 and $ 100 million. The payments for Region 3 have only one high value that is between $ 150 and $ 200 million, and others are at around zero level. As it is shown in Figure 8.4, the forced outage payments for Region 5 are so much that the points in the graphic form a very intensive shape especially until the 15.000th period. The maximum value of forced outage payment assigned to the system operator for Region 5 exceeds $ 800 million limit that is, total system demand is so high that available generation capacity and the LMO cover only small portion of it for the particular period. After the 15.000th period, the forced outage payments usually range from 0 and $ 100 million and exhibit decreasing pattern which is still quite intensive. The extraordinary cases where forced outages are greater than $ 400 million occur rarely. On the other hand the system may collapse due to electricity shortage and the huge amount of forced outage payments. In order to avoid high forced outages in some periods, the system operator might give more incentives to the generators for installing more power generation capacity and extending load mangement options to the residential consumers.

8.1.1. Financial Analysis

This section involves detailed financial analysis of the wind power plants based on the base scenario results obtained from WEPE. In order to evaluate wind energy investments, the following economic measures are used: Net Present Value (NPV), Internal Rate of Return (IRR), Benefit-Cost Ratio (BCR) and Simple Payback Period (SPP). NPV, IRR and BCR are estimated in WEPE for each of the project. The first performance measure generally used for evaluating whether a wind energy project is promising or not is NPV.

IRR is also used widely for project evaluation, however there are methodological difficulties when nonconventional projects are evaluated. Only for the case where the projects are conventional, IRR is calculated in the WEPE. For nonconventional wind energy projects, IRR is not calculated and in that cases NPV is used to evaluate project feasibility. Conventional and nonconventional investments are defined as follows:

According to Bussey [84], the interpretation of the IRR depends on the two factors. The first one is the form of the cash flow stream of the industrial project and the last one is the form of uncovered investment balance stream. He separates the industrial pojects as conventional and nonconventional investments in terms of the cash flow stream. A conventional investment has one or more negative-sided cash outflows followed by one or more positively-signed cash inflows. A nonconventional investment has one or more negative-sided cash outflows mixed with positive-signed cash inflows. Furthermore, depending on the form of the unrecovered investment balance stream he classifies investments as pure and mixed investments. A pure investment is a project which has negative or zero project investment balances calculated at the IRR of the project. On the other hand, a mixed investment is the one which has some positive investment balances. Thus, all conventional investments are also pure investments.

Figure 8.5 shows SMPs obtained from unconstrained schedules, each of which is prepared at the begining of the planing period over a twenty-five year time horizon. First value of SMP is around 5 cent/$ and then in the second planning period of 2005 it rises to nearly 10 cent/$. From 2006 to 2018, due to the lack of available generation capacity in the electricity market, the last price which has the highest value in the unconstrained schedules is always determined as SMP. Based on the energy cost escalation rate, this price increases over the planning periods. The linear trend of SMP between 2006 and 2018 is explained in terms of the increments of the last price that is selected as SMP.

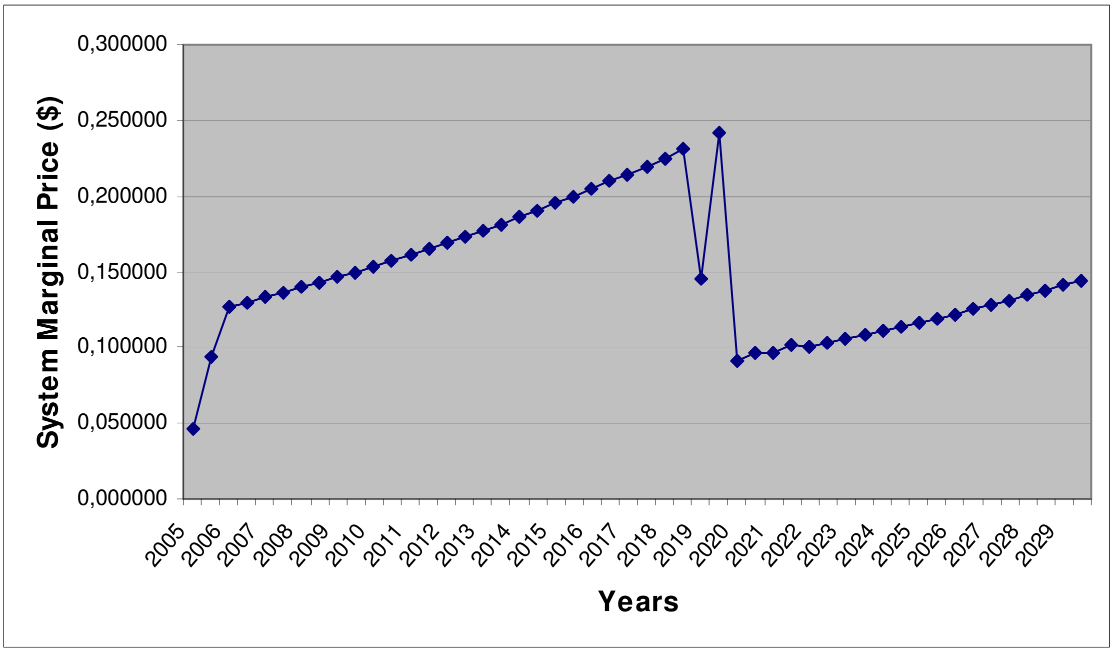


Figure 8.5. System marginal prices for the base case scenario

After the year of 2018, SMP falls dramatically to nearly 15 cent/$ due to the excess generation capacity in the market. In order to find SMP, system operator determines the unconstrained schedule by descending order of the generator bids until the system demand is met. In the first planing period of 2019 system demand doesn't exceed available generation capacity limit so SMP is selected from the last accepted generator' offered price which is lower than the previous SMPs. SMP of the second planning period in 2019 presents peak value that is about 25 cent/$ and this means that in the second period of 2019 available generation capacity in the market doesn't fill all demand. Therefore, SMP increases and has the highest value over the simulation period. Between 2020 and 2029, SMP has almost a linear trend depending on the energy cost escalation rate. The average of the SMPs is 14,75 cent/$ over the time horizon between 2005 and 2029.

The financial results of the base case scenario based on the general assumptions are summarized in Table 8.4. Here, financial parameters: NPV, IRR, BCR, capacity factor, utilization rate, project equity, project debt, project debt payments, levelized energy income and intial costs for each of the wind power plants are estimated. Utilization rate reflects how much generated energy of the wind power plant is dispatched in the competitive market. Levelized energy income shows the levelized yearly savings of the project calculated from the overall project savings discounted at the discount rate.

Table 8.4. Financial results of the base case scenario

Plants/ Parameters	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7
NPV	$ -7.957.712	$ -29.764.657	$ -41.717.355	$ -16.722.477	$ -16.969.913	$ 19.031.442	$ 99.070.889
IRR	-	-	-	-	-	20%	44%
BCR	0,58	-0,57	-1,20	0,12	0,11	2,00	5,71
Capacity Factor	18,47%	14,31%	13,81%	18,03%	16,79%	24,57%	36,70%
Utilization Rate	72,91%	70,86%	58,75%	61,39%	71,04%	68,09%	97,61%
Equity	$ 18.970.950	$ 18.970.950	$ 18.970.950	$ 18.970.950	$ 18.970.950	$ 18.970.950	$ 21.023.700
Debt	$ 44.265.550	$ 44.265.550	$ 44.265.550	$ 44.265.550	$ 44.265.550	$ 44.265.550	$ 49.055.300
Debt Payments	$ 4.121.734	$ 4.121.734	$ 4.121.734	$ 4.121.734	$ 4.121.734	$ 4.121.734	$ 4.567.726
Levelized Energy Income	$ 3.739.318	$ 2.867.041	$ 2.388.933	$ 3.388.728	$ 3.378.830	$ 4.818.885	$ 8.491.709
Initial Costs	$ 63.236.500	$ 63.236.500	$ 63.236.500	$ 63.236.500	$ 63.236.500	$ 63.236.500	$ 70.079.000

As it can be seen in Table 8.4, Plant 1, Plant 2, Plant 3, Plant 4 and Plant 5 have negative NPV values which indicate that the wind power projects are not feasible. Also IRRs are not estimated due to the negative NPVs. Plant 6 and Plant 7 yield nearly a NPV of $ 19 million and $ 99 million respectively. Furthermore, IRR for Plant 6 is 20 %, while it is 44 % which is the highest rate among the plants since Plant 7 has approximately five times higher NPV. This rate of return, being positive, indicates that the wind power plant's savings preserve their value against inflation. Also IRR for both Plant 6 and Plant 7 is substantially higher than the assumed real rate of return named as discount rate on electricity energy projects. BCR values lead to the same conclusion as the NPV indicator that is for Plant 2 and Plant 3 BCR values are negative which means that these projects are the worst ones. Although Plant 1, Plant 4 and Plant 5 have positive BCR values, these values are smaller than one and ratios greater than one are indicative of profitable projects.

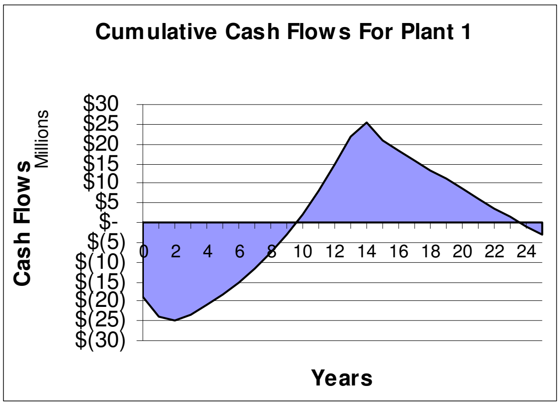
Plant 6 has rather higher value of BCR that is 2 and Plant 7 has the highest benefit cost ratio which is nearly 6 and this means Plant 7 is the most profitable one. One of the important performance measure of the wind power plant is capacity factor which is the ratio of the average power produced by the plant over a year to its rated power capacity. As expected, Plant 7 has the highest capacity factor (36,7 %) among the plants due to the high average wind speed potential in Bozcaada. The second highest capacity factor is found in Plant 6 (26,57 %). Interestingly, although the average wind speed of Guney, where Plant 4 is installed, is higher than the average wind speed of Çanakkale where Plant 1 is installed, the capacity factor of Plant 1 is slightly higher than the capacity factor of Plant 4. The difference of these two capacity factors is 0,44 % and this means that Plant 1 generates 48.000 MWh more electricity than Plant 4 over the simulation. This difference is explained by the low shape parameter, high average temperature and high average pressure in Çanakkale. This makes Plant 1 generating more electricity than Plant 4 in Güney where Plant 4 has a high shape parameter, low average temperature and low average pressure.

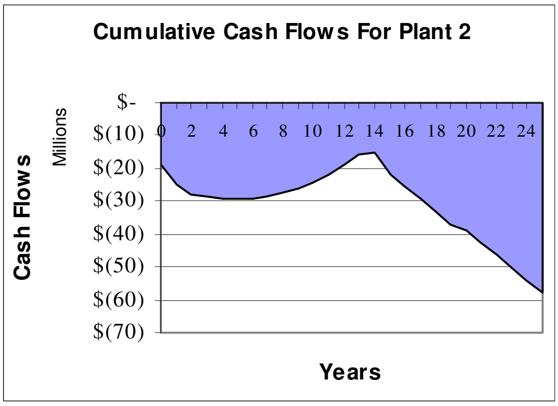
In order to find how much wind power plants are utilized over the twenty-five year time, capacity factors and utilization rates are used. The utilization rate of Plant 7 describes that nearly 98% of the generated energy is dispatched and sold to the electricity market. This rate is the highest one whereas others don't even exceed the 75 % limit. Since Plant 7 has the lowest production cost, namely the lowest bid price among the wind power plants, the system operator is likely to select Plant 7 in the unconstrained schedule. Though the capacity factor for Plant 6 is higher than Plant 1, Plant 5 and Plant 2 , the utilization rates of these plants surpass slightly the utilization rate of Plant 6 due to the variation in wind energy. That is, especially in time period 2 and time period 3, most of the generated energy is dispatched by the system operator because of excess load: Plant 1, Plant 2 and Plant 5 generate much energy for these time periods, therefore a high utilization rate is achieved in these power plants. The project equity for all power plants except Plant 7 is nearly $ 19 million and for Plant 7 it is about $ 21 million; as mentioned before, the debt ratio is assumed to be 70 %. The reason of the same project equity for six power plants is that installed wind turbines in these plants are selected from the same manufacturer and cost items depend only on the type of the wind turbines. Total debt of each of the first six plants is nearly $ 44 million, and it is approximately $ 49 million for Plant 7. Debt payments for each of the first six power plants and Plant 7 are respectively, nearly $ 4 million and $ 4,5 million for fifteen years.

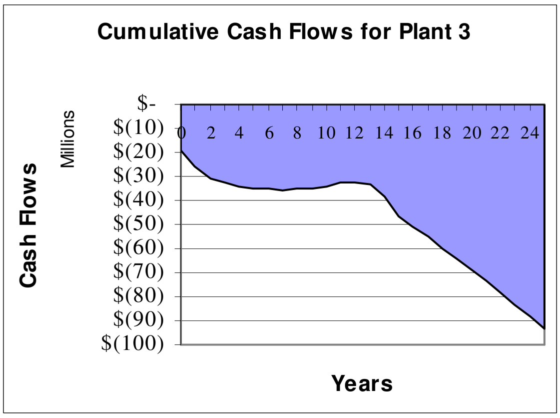
As can be seen from Table 8.4, Plant 7 has the highest levelized energy income with about $ 8,5 million per year whereas others are under $ 5 million. Plant 6 is the second one with $ 4,8 million. As would be expected, the lowest levelized revenue is obtained by the Plant 3. Initial cost of the power plants except Plant 7 is about $ 63,2 million and for the case where Plant 7 it is nearly $ 70 million. The difference of the initial costs arises from the number of wind turbines that are installed. For the first six wind power plants twenty-five wind turbines are used and for Plant 7 fifty wind turbines are used to generate electricity. Since initial costs mainly depend on the type and number of the wind turbines, Plant 7 has the highest initial cost value.

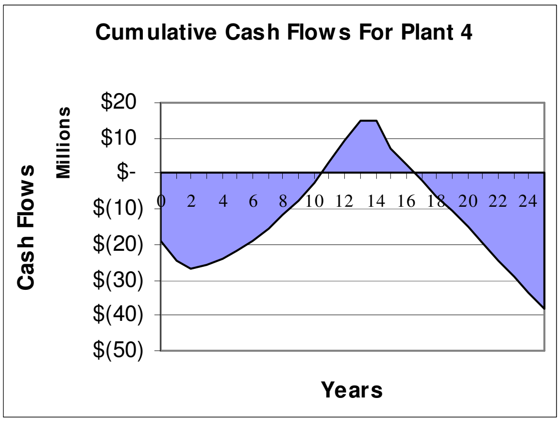
Cumulative Cash Flow is the compounded sum of each year's Cash Flow added to the previous year's. Cumulative cash flows are prepared below for each wind power plant in order to see cash flow implications and project earnings. As presented in Figure 8.8., Graphic (a) shows that after the year of 2012 cash flow turns positive and profits that are realized. On the other hand, we can say that the simple payback period is nearly nine years if we don’t see the negative cash flow between 2024 and 2025 that indicates the amount of additional cash required to sustain the project. There is a cumulative negative cash flow for Plant 2 and Plant 3 and the projects need additional financing to continue. Especially, at the end of the simulation, cumulative cash flow of Plant 3 exceeds negative $ 90 million level which is the worst value. Graphic (d) for Plant 4 points out that cumulative cash flow turns positive after the eleventh year of the project but again it turns negative starting from the nineteenth year of the project. The payback begins to occur in the twelfth year of the project where the cumulative cash flow equals total expenses but after the nineteenth year, additional amount of cash is required due to the negative cash flow.

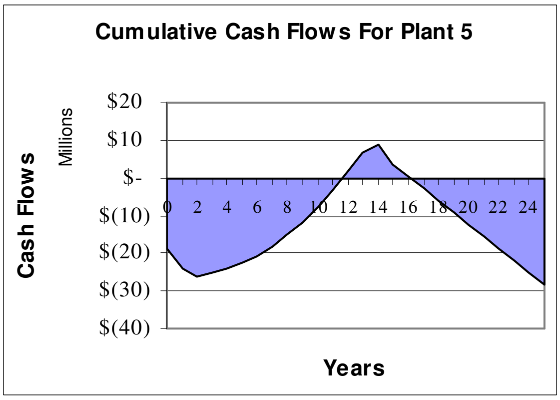
Figure 8.6, presents cumulative cash flows of Plant 1, Plant 2, Plant 3, Plant 4, Plant 5, Plant 6 and Plant 7. Plant 5 graphic is nearly same with Plant 4. Cash Flow only turns positive between year 12 and year 16. Although between year 12 and 13 the project covers its investment, after year of 16, cumulative cash flow becomes negative.

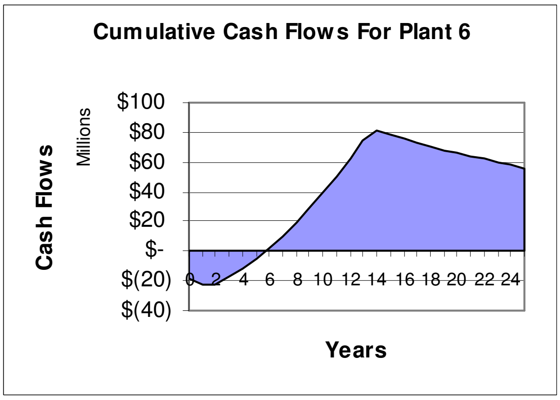












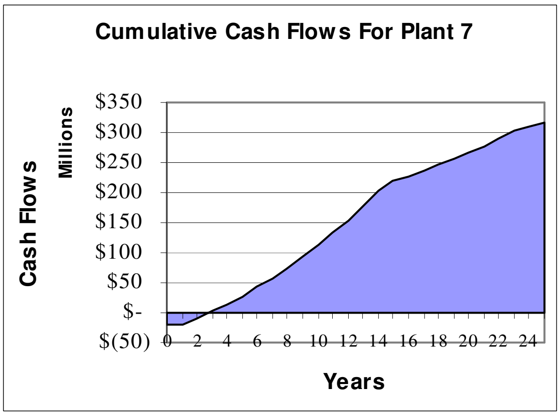


Figure 8.6. Cumulative cash flows of the base case scenario

As can be seen from Graphic (b) in Figure 8.6, only between 0 and 6 years cumulative cash flow is negative and the simple payback period is nearly 6 where the project covers all expenses. Cumulative positive cash flow reaches a peak value ($ 80 million) at around year 2020. Graphic (c) shows that Plant 7 is the most profitable project among the others. The year when cumulative cash flow equals total expenses is the third year of the project and after this year cumulative positive cash flow increases substantially and at the end of the lifetime of the Plant 7 cash flow exceeds $ 300 million limit.

8.2. Other Scenarios

The results of the simulation varies depending on the changes in the model assumptions. This section aims to examine different scenarios based on the guaranteed purchase price of wind energy in the competitive electricity market. In that case, in terms of a draft renewable energy law, eight scenarios are driven and results are obtained.

After all scenarios are run and corresponding results are obtained, the renewable energy law which will provide feed-in tariffs for electricity from renewable energy sources is approved by the Turkish Parliament (with some modifications on the draft law) in the second week of May and entered into force on May 18, 2005. There are two differences of the renewable energy law from the draft one: determination of the purchase price and guarantee period. The renewable energy law supports wind power by setting up a purchase guarantee of the *average wholesale electricity price* for a period of *seven years* for electricity generated from wind power plants. The draft law on the other hand included a *fixed wholesale electricity price* for a period of *six years*. Scenarios defined in this study already include average wholesale electricity price scenarios. The only difference remains to be the guarantee period. Since scenarios based on weighted average prices already satisfy the renewable law conditions (based on average wholesale electricity prices) and there exists only one year diffence in the guarantee period between the draft law and approved law, it can be said that the findings of the study generally reflect the possible results of the renewable energy law.

The scenarios are are defined as follows: Scenario 1 involves guaranteed purchase price for a period of six years, assumed to be fixed for all electricity generated from wind power plants. After six years, the wind power plants are included in the unconstrained schedule with bid prices. SMP is determined according to the weighted average of the bid capacity and bid price for the first six years in Scenario 2 and rest of the years SMP is determined same as with the base case scenario. Scenario 3 is based on the fixed five euro cent guranteed purchase price for a period of six years and afterwards the wind power plants bid price into the market. Wind power plants sell electricity to the market with six euro cent guranteed price for the first six years in Scenario 4. Scenario 5 provides twenty-five year guaranteed purchase price for electricity generated from wind power plants which is determined by the unconstrained schedule. SMP is calculated by taking weighted average of bid price and bid capacity for the case where Scenario 6 is performed. Wind energy is sold to the market with fixed five euro cent purchase price for twenty-five year time horizon in Scenario 6. The last scenario (Scenario 7) is all years fixed six euro cent guranteed purchase price where the system operator pays six euro cent per kWh for all electricity generated from wind power plants during the simulation time.

The results of the Scenario 1 are given in Table 8.5. Since project equity, project debt, debt payments, levelized energy income and initial costs are same as with base scenario, these items aren’t included in other scenarios’ results.

Table 8.5. Financial results of scenario 1

Plants/ Parameters	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7
NPV	$ -12.006.973	$ -32.968.365	$ -41.368.520	$ -19.154.353	$ -20.604.758	$ 14.770.320	$ 83.817.004
IRR	-	-	-	-	-	18%	36%
BCR	0,37	-0,74	-1,18	-0,01	-0,09	1,78	4,99
Capacity Factor	18,47%	14,31%	13,81%	18,03%	16,79%	24,57%	36,70%
Utilization Rate	75,32%	73,13%	63,80%	64,63%	73,45%	70,90%	97,63%

As can be seen from Table 8.4, all wind power plants between Plant 1 and Plant 5 have negative NPV values which indicate that these projects are not profitable and therefore not feasible. Plant 6 and Plant 7 have positive NPVs that are $ 14,7 million and $ 83,8 million respectively. IRRs of the first five power plants aren't estimated due to the negative NPVs. IRR of Plant 6 is calculated as 18 % whereas Plant 7 has two times higher IRR than Plant 6. BCRs which are greater than one are found for Plant 6 and Plant 7. Capacity factors are same as with the base scenario but on the other hand utilization rates are different. As it is expected, all utilization rates for this scenario increase as we compare them with the base case scenario. The highest difference between the utilization rates is 5,05 %, which is found for plant 3.

Figure 8.7 illustrates the cumulative cash flow analysis of the Scenario 1. Cumulative cash flows of Plant 2 and Plant 3 are all the time negative on the other hand cash flows of the Plant 1, Plant 4 and Plant 5 turn positive in some years, but then cumulative cash flows become negative at the end. After six and a half years cumulative cash flow equals total expenses for Plant 6 whereas it takes only three years covering all expenses for Plant 7. Therefore, the simple payback period for Plant 6 and Plant 7 is 6,5 and 3 years respectively.

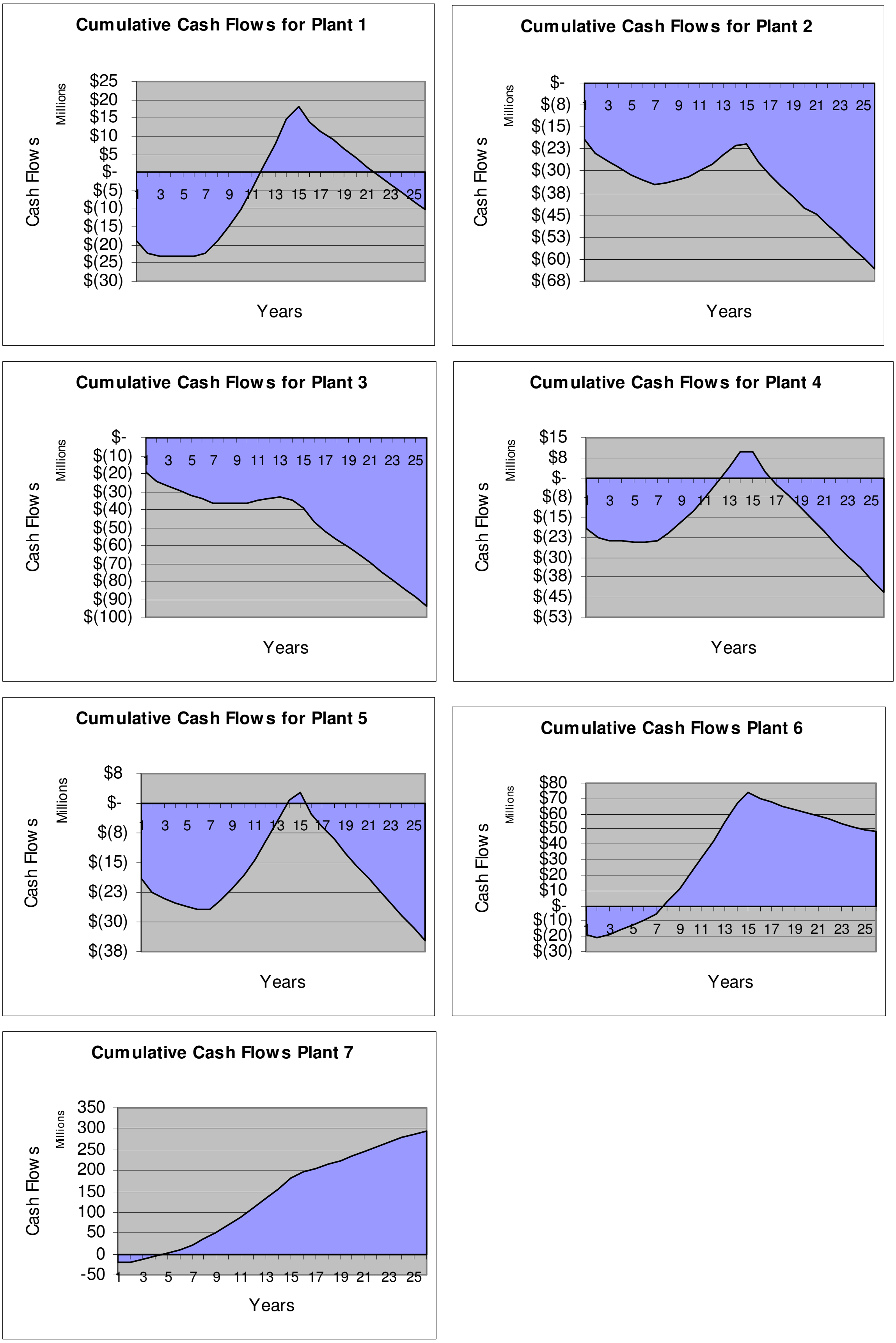


Figure 8.7. Cumulative cash flows of scenario 1

The following table shows the financial results of the Scenario 2. In this scenario, only Plant 7 has a positive NPV value that is nearly $ 40 million and all other power plants have negative NPVs. IRR of Plant 7 is about 18 % which is greater than the discount rate.

Table 8.6. Financial results of scenario 2

Plants/ Parameters	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7
NPV	$ -33.967.682	$ -49.614.875	$ -57.451.901	$ -40.457.947	$ -40.687.770	$ -14.208.057	$ 40.493.927
IRR	-	-	-	-	-	-	18,07%
BCR	-0,79	-1,62	-2,03	-1,13	-1,14	0,25	2,93
Capacity Factor	18,47%	14,31%	13,81%	18,03%	16,79%	24,57%	36,70%
Utilization Rate	75,32%	73,13%	63,80%	64,63%	73,45%	70,90%	97,63%

As can be seen from Figure 8.8, all plants except Plant 6 and Plant 7 have cumulative negative cash flows so this means that these plants don’t recover the investment expenditures. Although, it seems that after the eleventh year of the project 6 whereas simple payback period is eleven, cumulative cash flow turns into positive, NPV is negative so also Plant 6 isn’t profitable. Plant 7 is again the profitable one whose payback period is nearly eight years.

The results of the Scenario 3 are summarized in Table 8.7. As it is seen in Table 8.7, all power plants except Plant 7 again have negative NPV values that range between $ - 2,9 million to $ -51,1 million. NPV of the wind power plant 7 is nearly $ 57,2 million. IRR of the project 7 is 24 % which is 6 % higher than the former scenario. The acceptable BCR is 3,72 for plant 7, as it is expected.

Table 8.7. Financial results of scenario 3

Plants/ Parameters	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7
NPV	$ -25.506.036	$ -43.099.248	$ -51.149.910	$ -32.243.431	$ -32.989.941	$ -2.997.959	$ 57.287.644
IRR	-	-	-	-	-	-	24%
BCR	-0,34	-1,27	-1,70	-0,70	-0,74	0,84	3,72
Capacity Factor	18,47%	14,31%	13,81%	18,03%	16,79%	24,57%	36,70%
Utilization Rate	75,32%	73,13%	63,80%	64,63%	73,45%	70,90%	97,63%

Figure 8.9 depicts the cumulative cash flows of the all wind power plants for the case where Scenario 3 is chosen. It seems that the time when the cumulative cash flow equal total costs of Plant 1 is at around 2020 but then negative cash flows occur and this makes the project 1 nonprofitable. Plant 2, Plant 3, Plant 4 and Plant 5 have always cumulative negative cash flows so the amount of additional cash is required for these projects. Simple payback period of Plant 6 is nearly 9 years and even though cumulative cash flow is positive at the end of the simulation time, since NPV is negative, it is more likely not to invest in this project. As we compare this scenario with the previous one, simple payback period of the Plant 7 is reduced to seven years from eight years. At the end of the lifetime of the wind turbines cumulative cash flow reaches approximately $ 250 million.

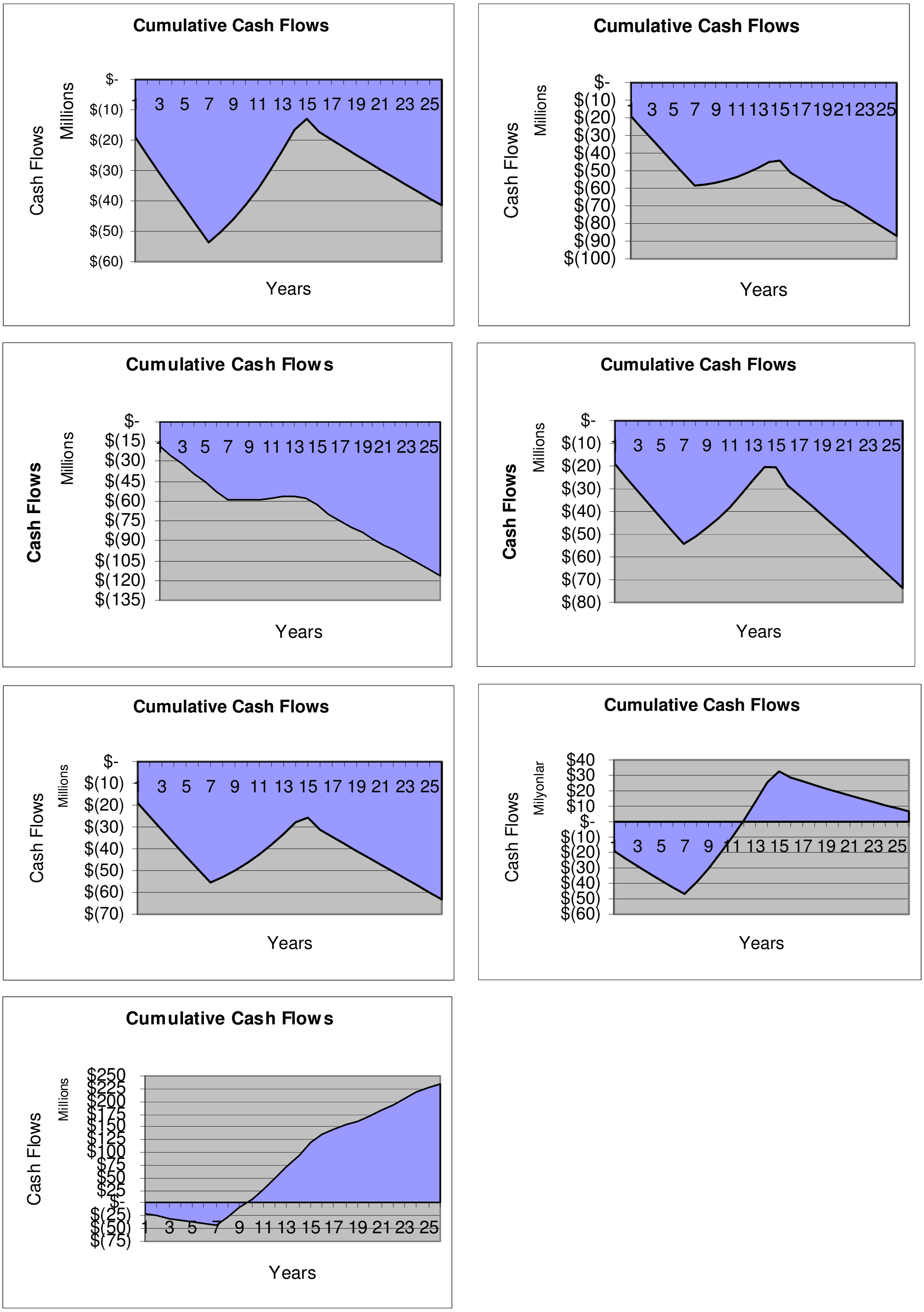


Figure 8.8. Cumulative cash flows of scenario 2

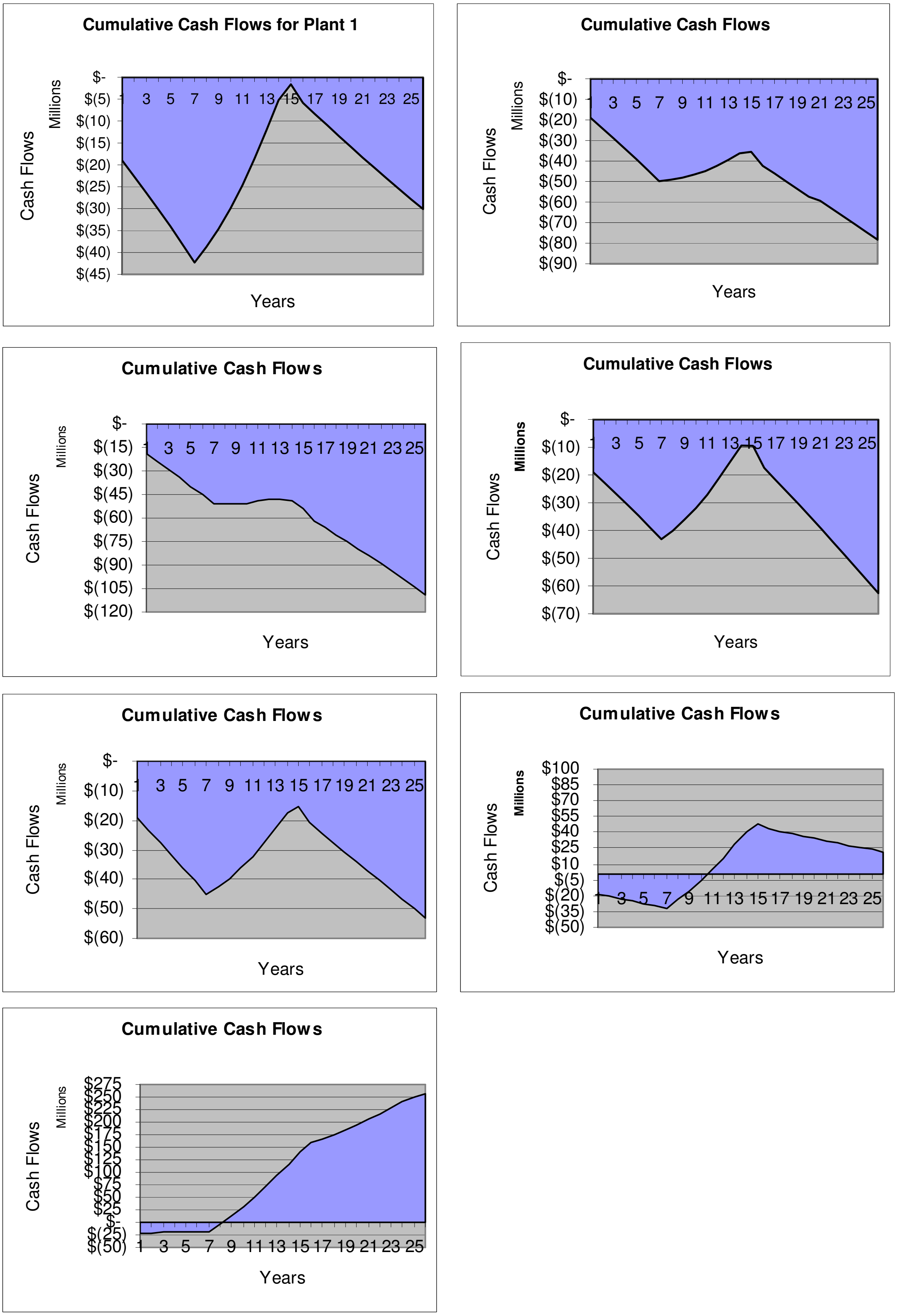


Figure 8.9. Cumulative cash flows of scenario 3

Table 8.8 displays financial results of Scenario 4. Different from the previous scenario, in this scenario NPV of Plant 6 is positive and this makes Plant 6 profitable. Again Plant 7 has the highest NPV value that is about $ 66.5 million and IRR is more than two times higher than the IRR of the Plant 6. Also BCR value of the Plant 6 is 1,17 whereas for Plant 7 it is 4,17. The first five plants have still negative NPVs between nearly $ 20 million and $ 47 million. Thus, these plants don't gain much money.

Table 8.8. Financial results of scenario 4

Plants/ Parameters	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7
NPV	$ -20.829.520	$ -39.510.054	$ -47.677.270	$ -27.702.153	$ -28.729.892	$ 3.195.121	$ 66.557.232
IRR	-	-	-	-	-	12%	28%
BCR	-0,10	-1,08	-1,51	-0,46	-0,51	1,17	4,17
Capacity Factor	18,47%	14,31%	13,81%	18,03%	16,79%	24,57%	36,70%
Utilization Rate	75,32%	73,13%	63,80%	64,63%	73,45%	70,90%	97,63%

Figure 8.10 represents cumulative cash flows of the Scenario 4 explained above. Plant 1 has two negative signed cumulative cash flows and one positive signed cumulative cash flow. There is completely cumulative negative cash flow for the case where Plant 2, Plant 3, Plant 4 and Plant 5 are considered. Wind power plant 6 recovers its investment at around the ninth year of the project. However, there exists a decreasing trend in the graphic due to the lack of the enough annual income. Simple payback period for Plant 7 is nearly 6 years and also again Plant 7 is the most profitable one.

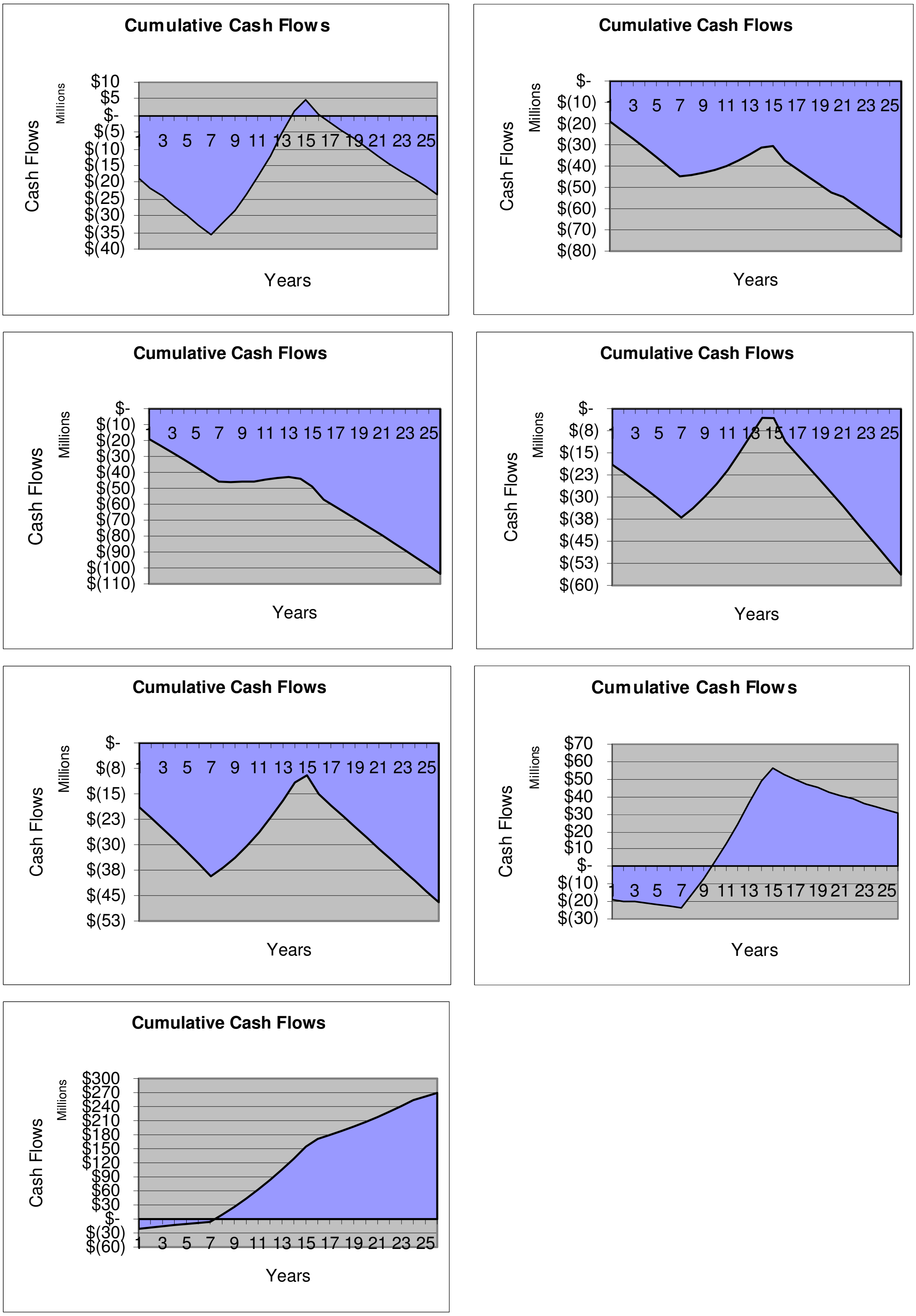


Figure 8.10. Cumulative cash flows of scenario 4

The financial results of the Scenario 5 is summarized in Table 8.9. As it is seen from Table 8.9, utilization rates are 100 % for all wind power plants since all years guranteed scenarios assume that electricity generated from wind power plants is purchased by the system operator over the lifetime of the wind power plants.

Table 8.9. Financial results of scenario 5

Plants/ Parameters	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7
NPV	$ -11.436.183	$ -31.673.457	$ -34.623.684	$ -13.598.482	$ -19.426.117	$ 17.983.947	$ 65.299.599
IRR	5%	-	-	4%	0%	17%	33%
BCR	0,40	-0,67	-0,83	0,28	-0,02	1,95	4,11
Capacity Factor	18,47%	14,31%	13,81%	18,03%	16,79%	24,57%	36,70%
Utilization Rate	100,00%	100,00%	100,00%	100,00%	100,00%	100,00%	100,00%

Interestingly, IRR of the Plant 1 is 5 %, although NPV has negative value that is nearly $ 11,4 million. In that case as the first economic measure for evaluating wind power investments is NPV, Project 1 is not feasible one to invest. On the other hand, same as with Plant 1, Plant 2 has negative NPV, whereas IRR is 4 %. Therefore Project 4 is also not acceptable one. The case where IRR is 0 % for Plant 5 may be the most interesting one among the others because IRR is at around zero value that indicates that there is no average annual percent return on money invested over the lifetime of the project. As it is expected, Plant 6 and Plant 7 have positive NPVs which are $ 17,9 million and $ 65,2 million respectively. IIR of the Plant 6 is 17 % whereas for Plant 7 IRR is nearly two times higher than the first one.

Cumulative cash flows of the wind power projects are given in Figure 8.11 for this scenario. The simple payback period of the Plant 1 is nearly 15 years but as mentioned before since this project has negative NPV, this is not a good choice to invest. As can be seen from the cumulative cash flows of Plant 4 and Plant 5, these are the same with the case of Plant 1 that is although, the cumulative cash flow turns positive after the year of seventeenth for Project 4 and it turns positive at around year 2028 for Project 5, NPVs of these projects are negative. The simple payback period of Plant 6 and Plant 7 is three and six years respectively. Cumulative positive cash flows of Plant 6 and Plant 7 over several periods highlight the capacity of the projects to generate surplus cash.

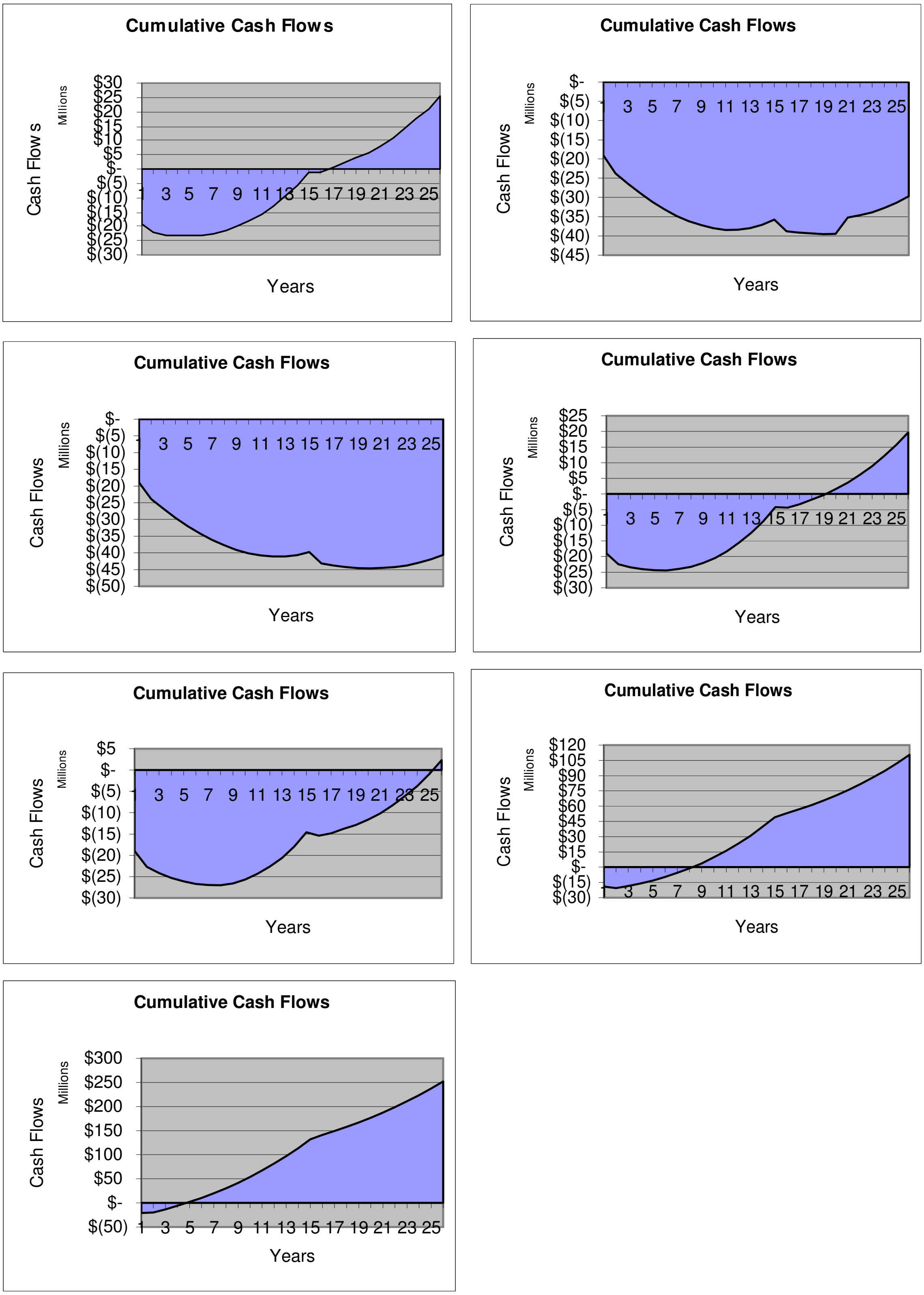


Figure 8.11. Cumulative cash flows of scenario 5

The following table summarizes the financial results of Scenario 6. As given in Table 8.10, this scenario based on the weighted average is similar with the scenario based on the five euro cent.

Table 8.10. Financial results of scenario 6

Plants/ Parameters	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7
NPV	$ -60.463.239	$ -69.343.233	$ -70.883.783	$ -61.440.743	$ -64.155.990	$ -47.005.414	$ -31.840.617
IRR	-	-	-	-	-	-	2%
BCR	-2,19	-2,66	-2,74	-2,24	-2,38	-1,48	-0,51
Capacity Factor	18,47%	14,31%	13,81%	18,03%	16,79%	24,57%	36,70%
Utilization Rate	100,00%	100,00%	100,00%	100,00%	100,00%	100,00%	100,00%

All NPV results are still negative and only IRR of Plant 7 is estimated. Interestingly, although NPV of the this scenario is lower than the previous one, IRR is found 2 % which is 1 % higher than the previous one. This can be explained in terms of the amount of positive cash flow as can be seen in Figure 8.12, in this scenario especially between 2027 and 2029 that is, the amount of positive cash flow in this scenario is higher than the amount of positive cash flow in the scenario based on five euro cent guranteed purchase price. Moreover, BCRs are negative for all plants (even for Plant 7). Consequently, in this scenario none of the wind power projects are profitable.

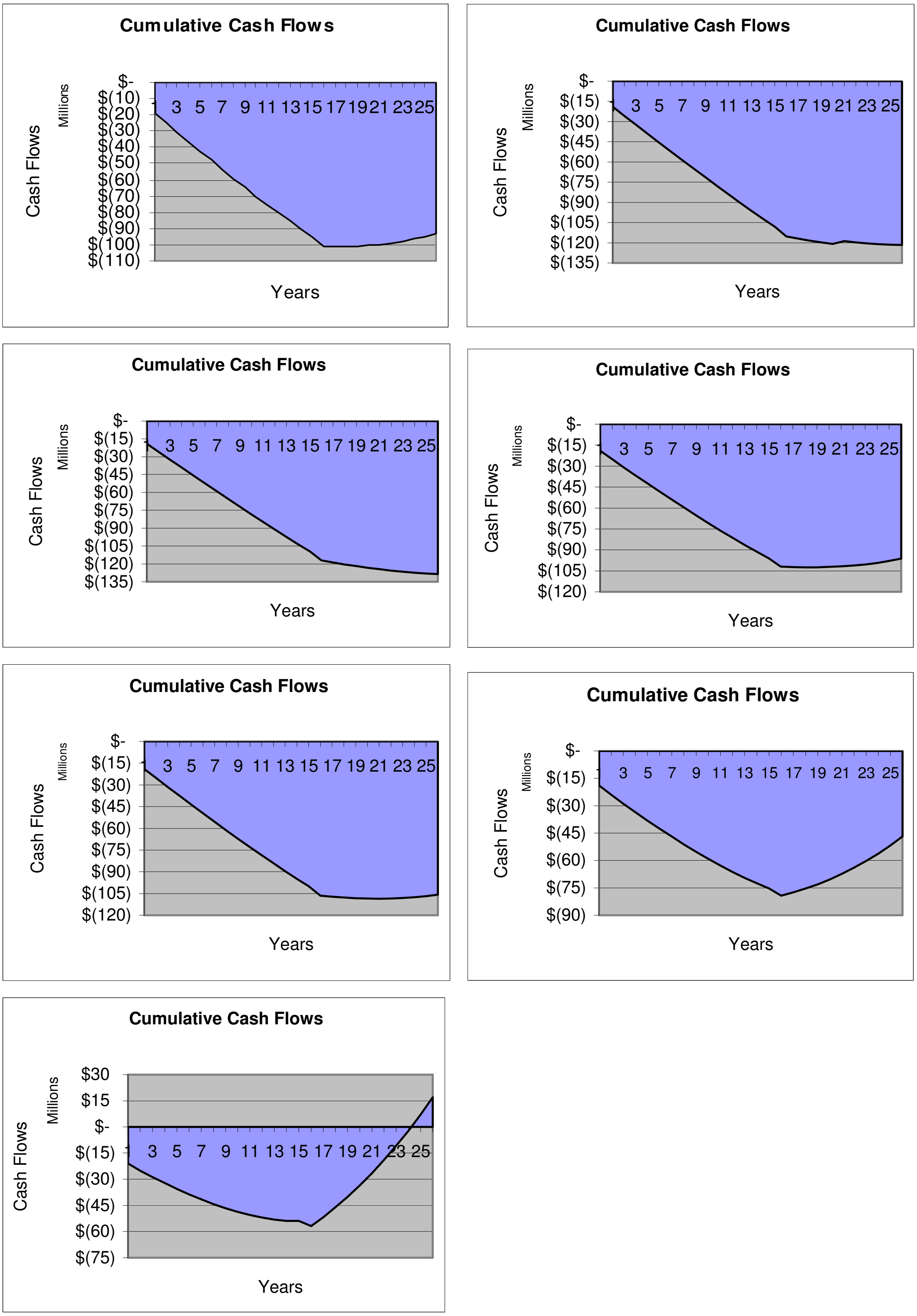


Figure 8.12. Cumulative cash flows of scenario 6

Table 8.11 shows the financial results of the Scenario 7. All projects have negative NPVs that describe losses of the capital outlays, hence all projects are truly infeasible. In this scenario, IRR of Project 7 is only 1 % which is the lowest rate among the other IRRs of Plant 7 and also BCR is nearly zero. This scenario is regarded as the worst case one compared with other scenarios.

Table 8.11. Financial results of scenario 7

Plants/ Parameters	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7
NPV	$ -52.967.394	$ -63.664.851	$ -65.264.440	$ -54.164.434	$ -57.352.252	$ -37.022.919	$ -16.926.905
IRR	-	-	-	-	-	-	1%
BCR	-1,79	-2,36	-2,44	-1,86	-2,02	-0,95	0,19
Capacity Factor	18,47%	14,31%	13,81%	18,03%	16,79%	24,57%	36,70%
Utilization Rate	100,00%	100,00%	100,00%	100,00%	100,00%	100,00%	100,00%

All cumulative cash flows are negative signed except for Plant 7 over the simulation period and at the end of the 23 years of Project 7, its cumulative cash flow turns into positive. However this is not considered to be a sufficient return to recover the investment when taking into consideration time value of money.

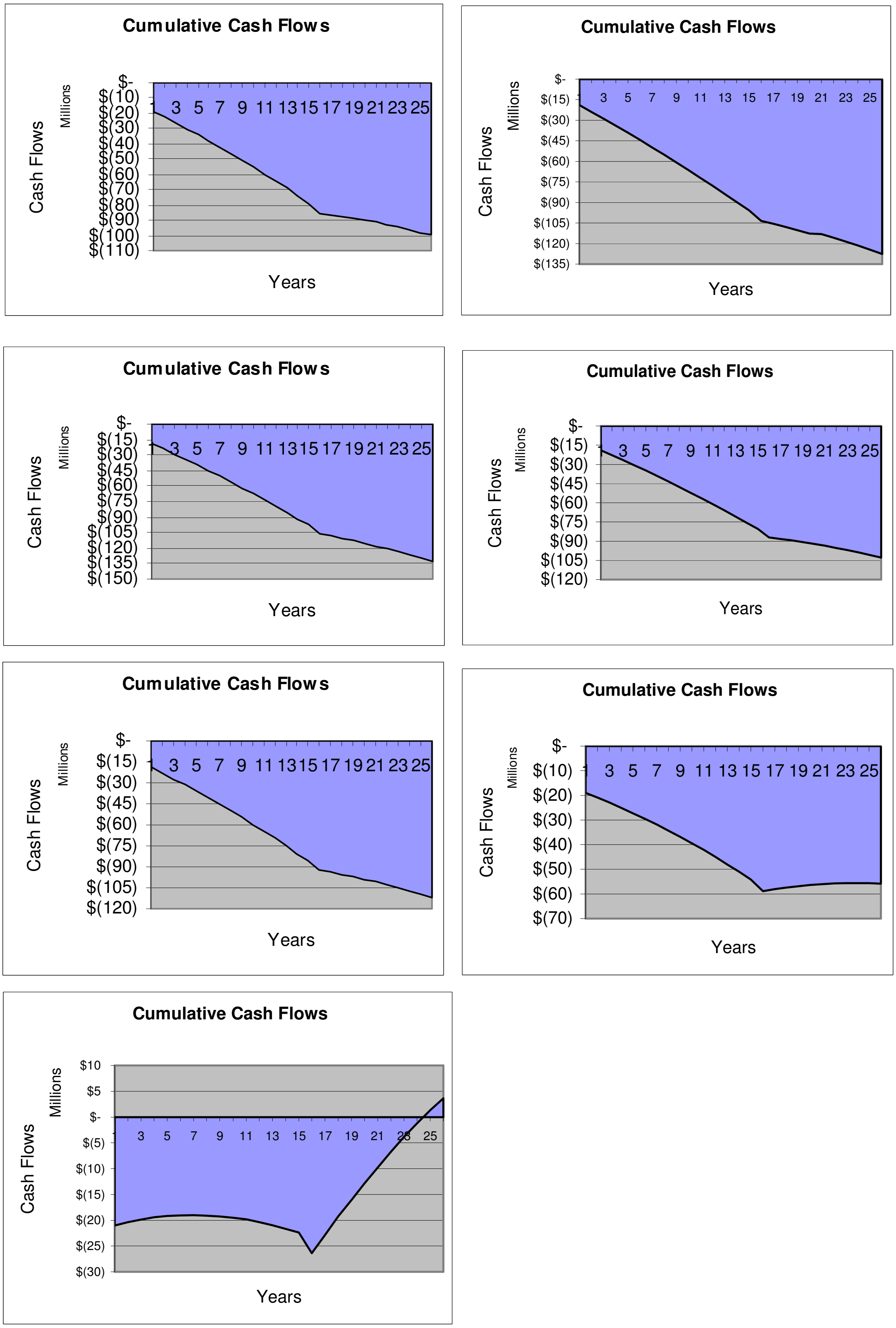


Figure 8.13. Cumulative cash flows of scenario 7

Table 8.12 summarizes the financial results of the Scenario 8. If the electricity generated from wind power plants is guranteed to purchase fixed six euro cent over the lifetime of the plants, different from the scenario based on fixed five euro cent guranteed purchase price, NPV of the Plant 7 becomes positive and this makes the Project 7 feasible and promising. Other economic measures are calculated as 11 % for NPV and 1,11 for BCR which also reflect economic potential of the project.

Table 8.12. Financial results of scenario 8

Plants/ Parameters	Plant 1	Plant 2	Plant 3	Plant 4	Plant 5	Plant 6	Plant 7
NPV	$ -43.272.738	$ -56.109.687	$ -58.029.194	$ -44.709.186	$ - 48.534.567	$ -24.139.368	$ 2.332.080
IRR	-	-	-	-	-	-	11%
BCR	-1,28	-1,96	-2,06	-1,36	-1,56	-0,27	1,11
Capacity Factor	18,47%	14,31%	13,81%	18,03%	16,79%	24,57%	36,70%
Utilization Rate	100,00%	100,00%	100,00%	100,00%	100,00%	100,00%	100,00%

Figure 8.14 shows the cumulative cash flow analysis of theScenario 8. Between Plant 1 to Plant 6, all cumulative cash flows have always negative signed over twenty-five years so this makes these investments unrecovered. On the other hand, cumulative cash flow turns positive between eighth and nineth year of the Project 7 and at the end it reaches nearly $ 60 million.

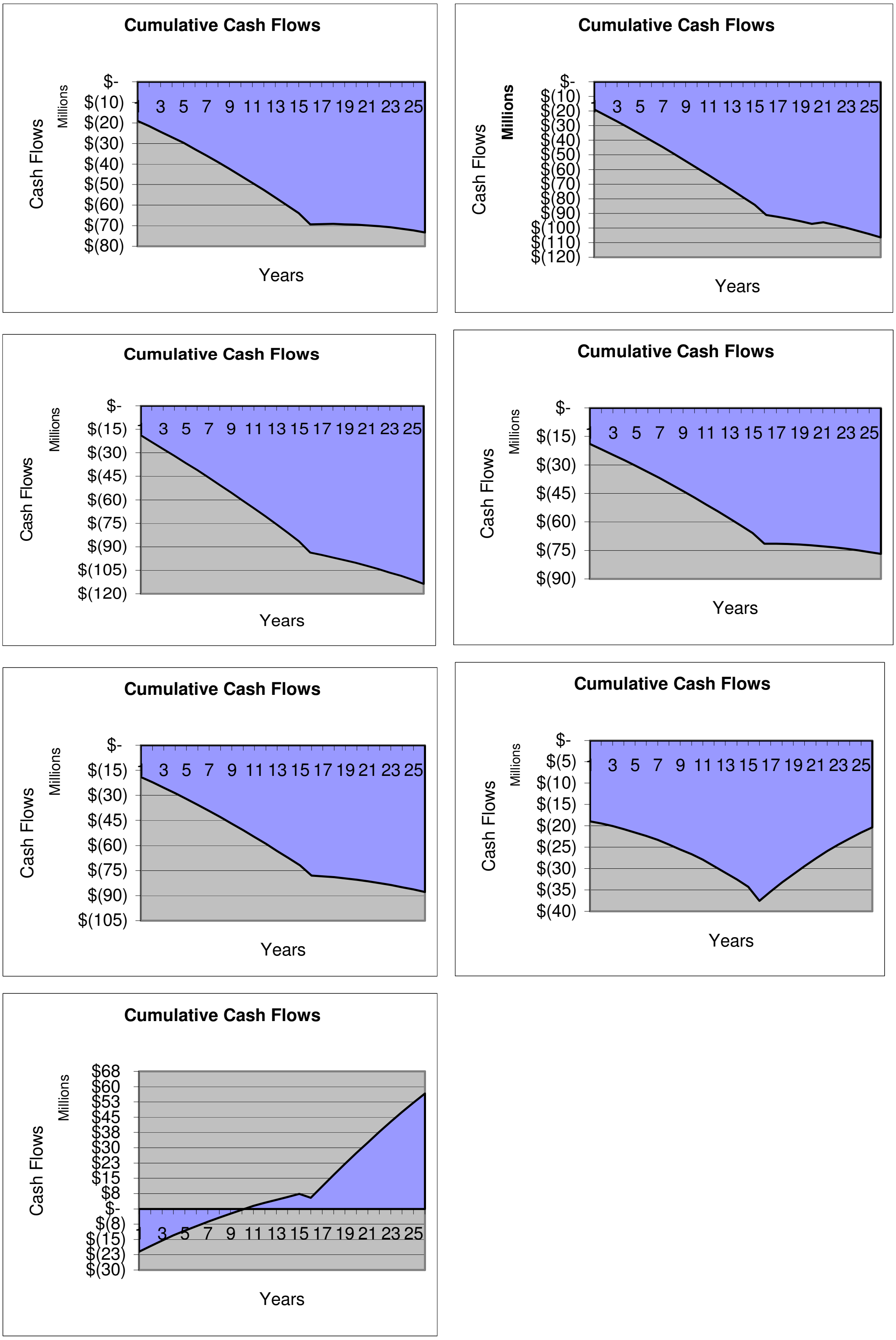


Figure 8.14. Cumulative cash flows of the scenario 8

9. CONCLUSIONS

Wind energy projects are evaluated in this thesis under competitive electricity market conditions (simulating the English market structure via EPSIM) for alternative sites in Turkey. Economic and financial analyses are performed in order to evaluate projects from the view of stakeholders involved. Statistical wind data analysis is performed on hourly wind speed records over a five-year period to evaluate the wind power generation potential of alternative sites. Future projections on wind power generation are obtained through a historical simulation. A time series analysis of Turkish electricity consumption is performed over the same five-year period based on the ARIMA methodology. A Wind Energy Project Evaluation tool (WEPE) has been developed to provide a comprehensive evaluation integrating wind speed data analysis, wind power engineering analysis, financial and economic analyses of wind energy projects, production cost calculation of alternative power generation technologies and simulation of the model. The results of the simulation are explored through a base case reference scenario and eight additional scenarios which are mainly defined in accordance with the draft renewable energy law[1].

The findings and conclusions that can be drawn from the results of WEPE are as follows:

- The results of the simulation show that under competitive electricity market conditions, the wind power projects to be installed at the selected sites appear to be more economically viable than other scenarios with fixed purchase price (assuming that all generation is sold at the guaranteed minimum price). This occurs naturally as a result of high SMPs obtained from unconstrained schedules in the competitive market. That is, due to regional capacity shortages in early years, some wind power producers are able to sell their production at high prices (which allows to recover investment costs). Therefore, the revenue is substantially reduced for some power plants in the fixed price case.

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[1] It should be noted that the guaranteed minimum price defined in the law is assumed to be the purchase price for all generation for a period of either 6 years (after which the wind power plants have to compete in the competitive market) or throughout the whole economic lifetime of the plant.

- Based on cash flow analysis and common to all scenarios, it is found that installing wind turbines in Bandırma, Çanakkale, Güney, Mardin and Pınarbaşı are in no way profitable and economically feasible. This is essentially due to insufficient wind conditions at these locations.[2]
- The effects of the draft renewable energy law under competitive electricity market are observed through scenarios which provide six year purchase price guarantee assumed to be fixed for all electricity generated from wind power plants. In these scenarios, SMPs decrease considerably since wind power plants are not included in the unconstrained schedules. Thus, the financial feasibility of various wind projects in different sites become less attractive as compared to the base case scenario. The revenue of the wind power project in Bozcaada, although still economically viable, is substantially reduced. The plant in Amasra, which is a profitable project under competitive market conditions without price guarantee, becomes economically infeasible.
- The results of extending purchase price gurantee period to cover the whole simulation time horizon are evaluated through four scenarios, and only the scenario setting up purchase gurantee based on SMP is found to give satisfactory results (as compared to fixed price scenarios) close to the base case scenario.
- Financial analysis of the base case scenario shows that two locations, Amasra and Bozcaada, reach 26.6% and 36.7% capacity factors respectively, and are highly attractive for wind power investors. The wind power projects in Amasra and Bozcaada have both positive NPVs (and highest among all alternative projects), their IRRs reach 20% and 44% respectively. Hence, it is found that Amasra and in Bozcada are the most feasible and profitable locations for installing wind turbines under competitive market conditions.
- Scenarios including all years purchase price guarantee at weighted average prices, and scenarios including five Euro cent fixed purchase price result in the most pessimistic conditions. Even the most profitable site, Bozcaada, is affected such that the NPV becomes negative.

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[2] It should be noted that there are significant variations in wind speed measurements from different sources. For example, the EIEI wind measurements find average annual wind speeds as 5.2 and 7.3m/sec for two different locations in Bandırma. The SMO data that has been used in this study, however, has 3.9m/sec 5-year annual average wind speed for Bandırma.

- The results of the scenarios analyzed in this study shows that constituting fixed six Euro/cent tariffs for lifetime of a wind power project are not enough to recover the investment especially for sites having average wind speed under 6 m/s.
- A tariff including all years purchase price gurantee based on weighted average of the plants in the unconstrained schedule is far away from supporting wind power projects which are constructed even on sites having at least 6 m/s average annual wind speeds. Tariffs including six years purchase price guarantee perform better under competitive market conditions due to higher revenues based on SMP after six years. Since the renewable energy law provides seven years purchase price guarantee based on the average wholesale electricity price (some 5 Euro cent/kWh), there needs to be additional and higher revenue in later years in order to make wind energy investments economically attractive. The findings of this study show that a competitive market without any price guarantee can provide better incentives than price guarantees as specified in the evaluated scenarios.
- Considering regional load balances, it is found that the highest value of LMO occurs in Region 1 (northwestern Anatolian region). This happens because (a) available generation capacity doesn't meet total electricity demand in that region, and (b) LMO bidding capacity is higher than that of other regions. Similarly, high LMO payments are observed in regions 2 and 3 (western and central Anatolian regions).
- Over the planning horizon, forced outage occurs only in Region 5 (others including northeastern Anatolia, Thrace, Kepez and ÇEAŞ regions). This happens because(a) available generation capacity doesn't meet total electricity demand in that region, and (b) LMO bidding capacity is not sufficient to fill the demand. It is concluded that additional generation capacity needs to be installed in this region.

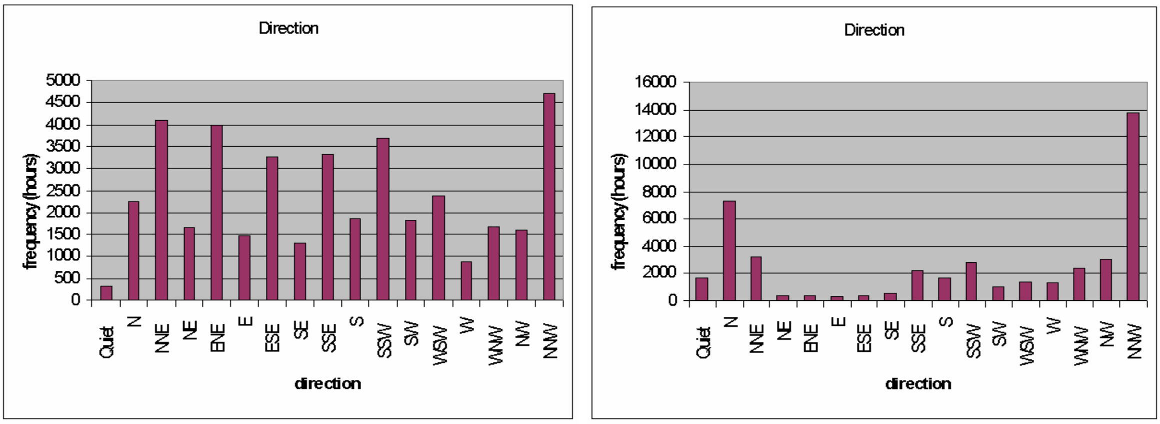
In order to extend this study, further research is needed towards wind speed data verification. As the meteorological stations are not established with the primary aim to evaluate wind power generation potential of the sites, they might not have been constructed on relevant sites. Moreover, older stations might have been outlocated due to urbanization. Also, the curiosity in recording data needs to be verified in this is done manually. The validity of such issues needs to be explored by relevant site visits for data verification.

Future studies can also be undertaken following the EPSIM model structure to simulate bilateral contracts between generators and distribution companies in the case of Turkey.

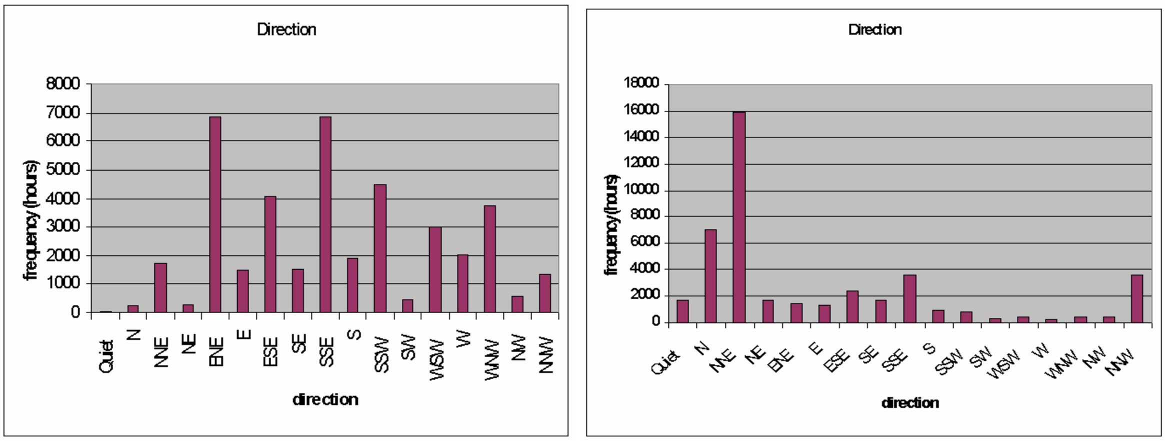
For further extension of WEPE to explore more project alternatives, it is essential that modules of the program be integrated efficiently to reduce time especially for solving the model. Establishing the GAMS-Excel link might be one direction towards handling the large-scale model based on an immense dataset

Research could also be directed towards extending WEPE by an emissions trading module. As wind power generation is CO_2-free, some projects could become financially viable through certifying emission reductions (computed as the difference to reference emissions in the absence of the project) and trading them under the Kyoto flexibility mechanisms, the European emission trading scheme, or trade-to-trade options.

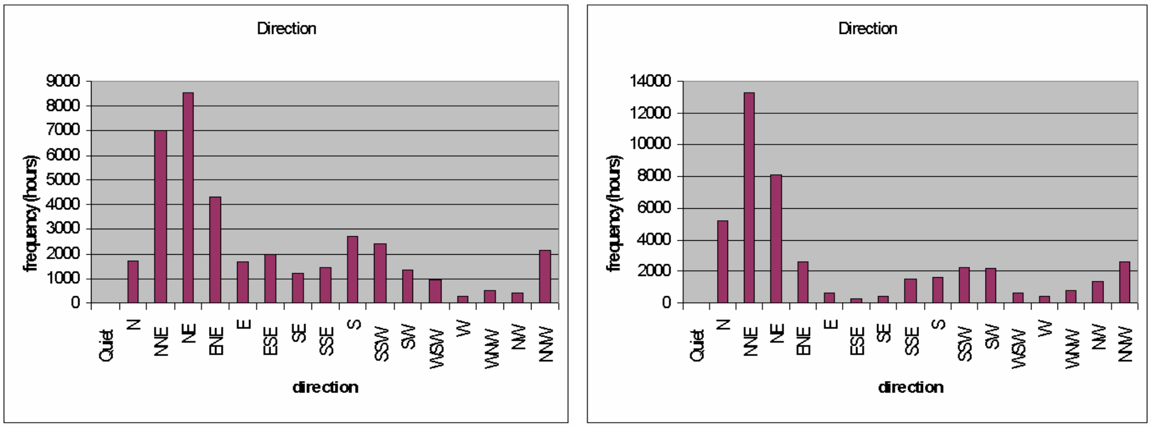
APPENDIX A: WIND DIRECTION FREQUENCY DISTRIBUTIONS



(a) Afşin (b) Akhisar

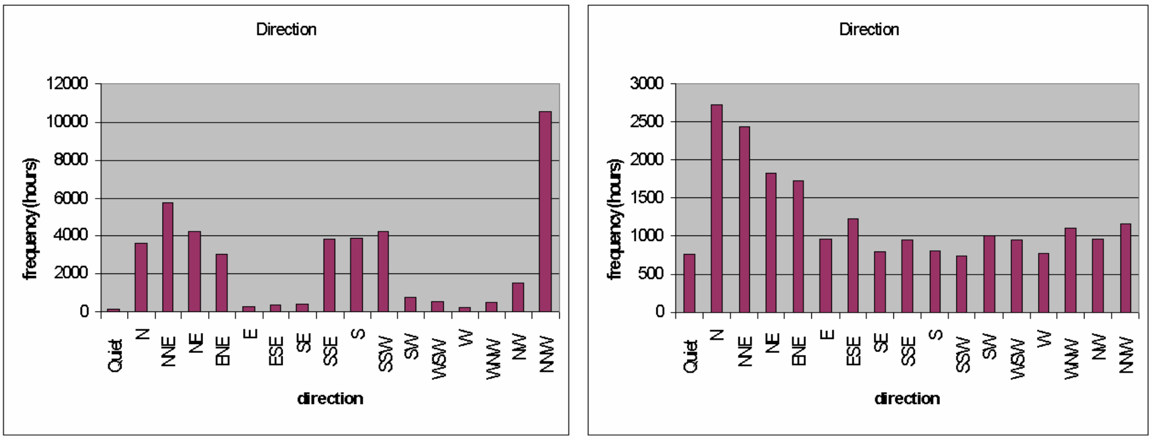


(c) Amasra (d) Bandırma

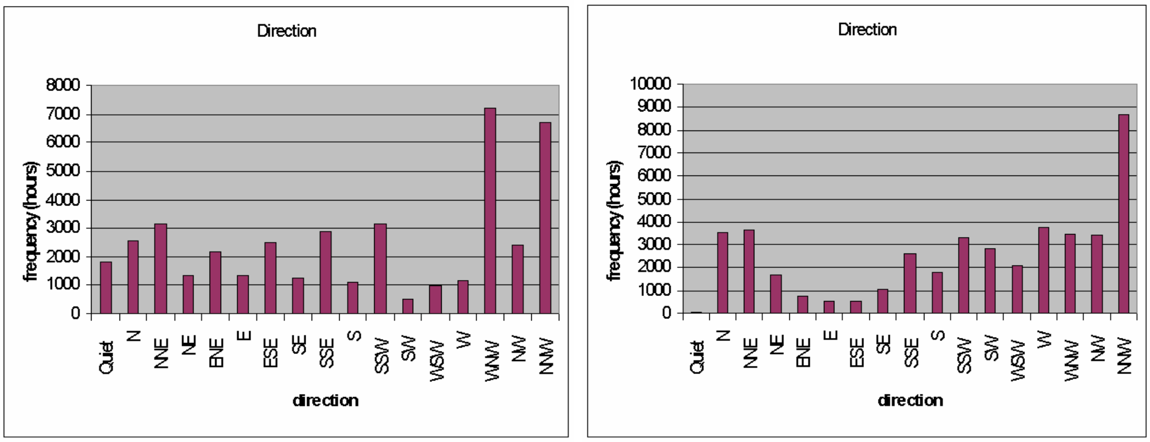


(e) Bozcaada (f) Çanakkale

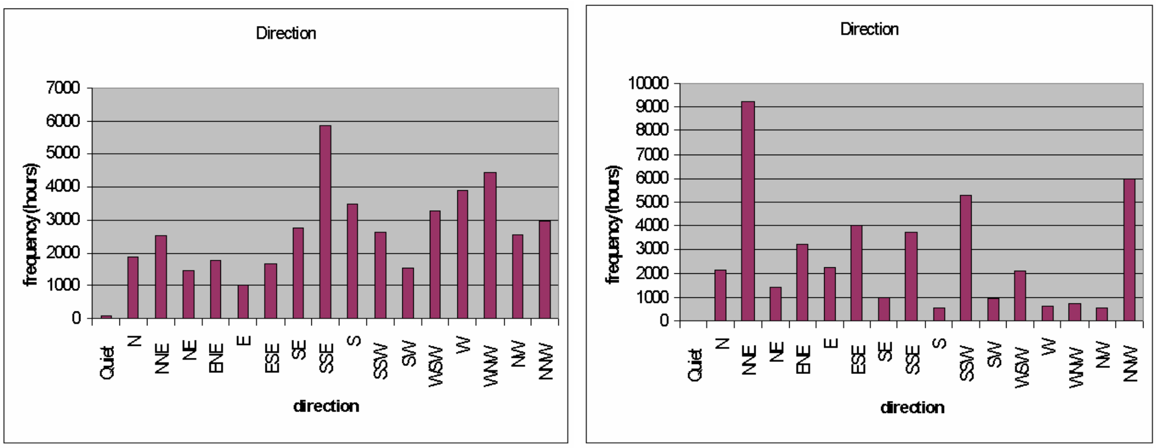
Figure A.1. Wind direction frequency distributions of Afşin, Akhisar, Amasra, Bandırma, Bozcaada and Çanakkale



(a) Çeşme (b) Datça

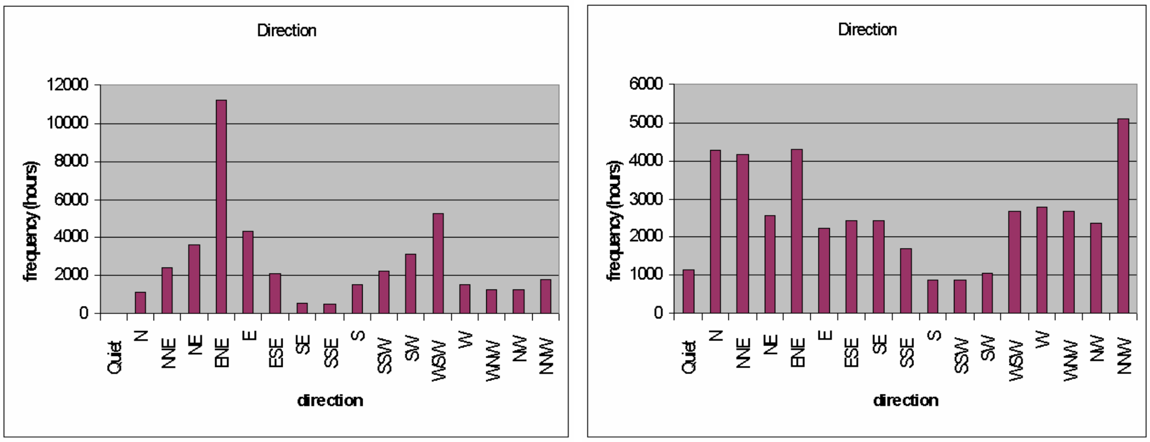


(c) Elbistan (d) Güney

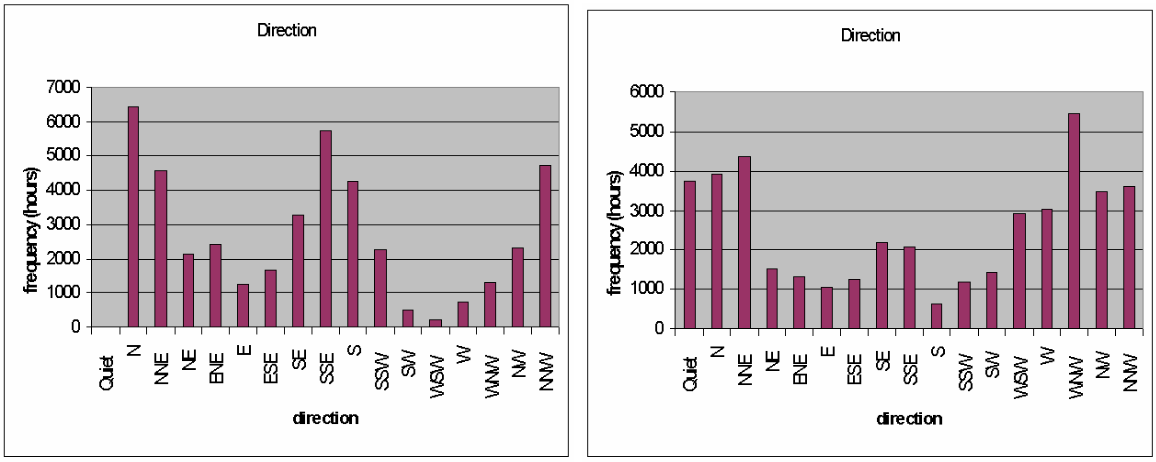


(e) İskenderun (f) Mardin

Figure A.2. Wind direction frequency distributions of Çeşme, Datça, Elbistan, Güney, İskenderun and Mardin



(a) Pınarbaşı (b) Sivas



(c) Şile (d) Elbistan

Figure A.3. Wind direction frequency distributions of Pınarbaşı, Sivas, Şile and Elbistan

APPENDIX B: RESULTS OF LOAD FORECASTING

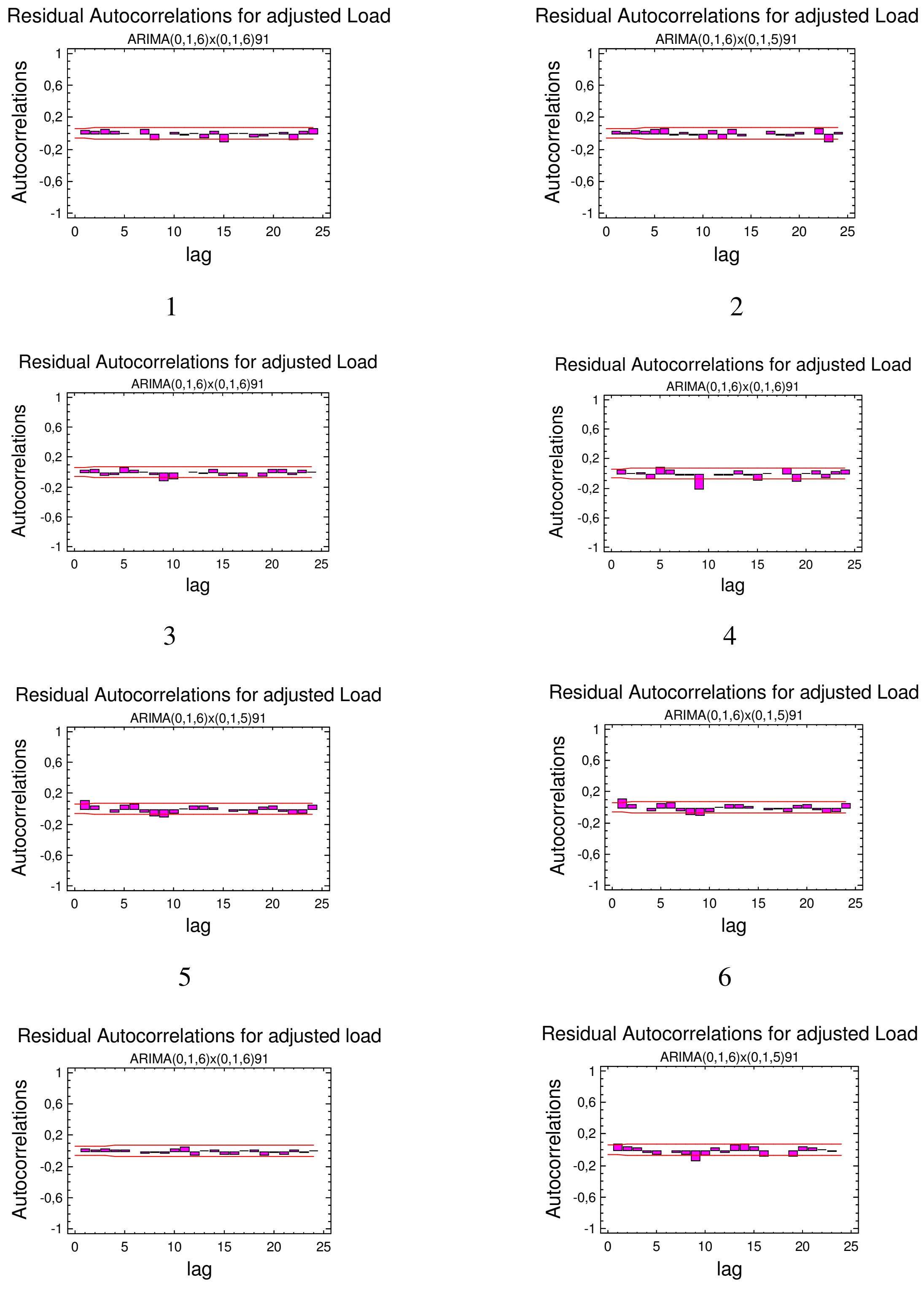


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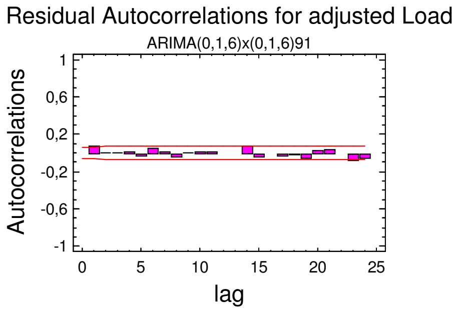
Figure B.1. Autocorrelation functions for region 1


Residual Autocorrelations for adjusted Load
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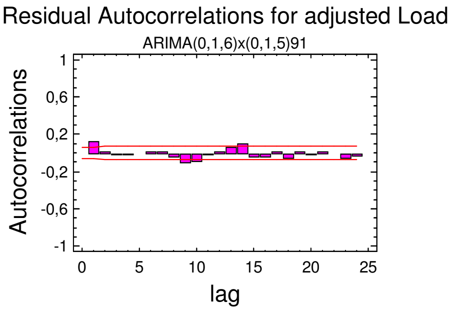
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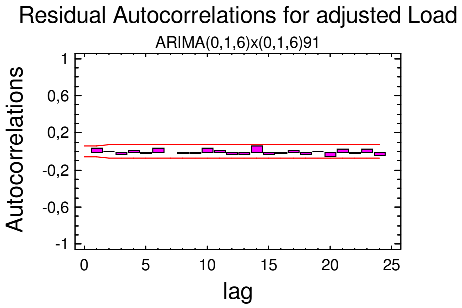
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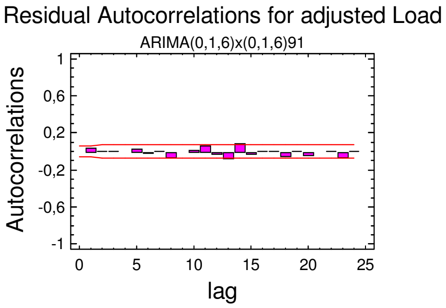
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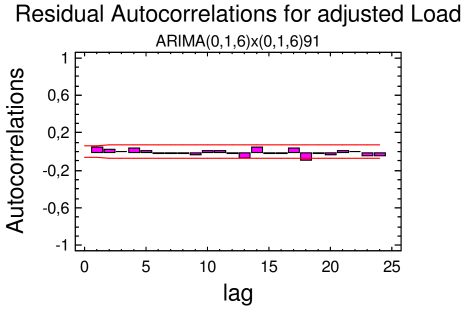
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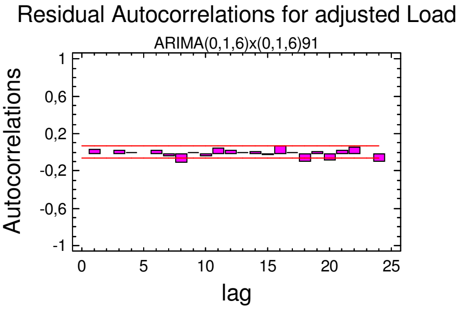
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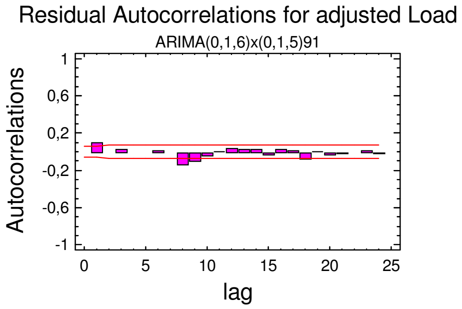
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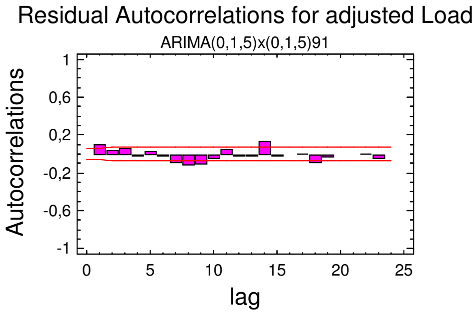
Residual Autocorrelations for adjusted Load
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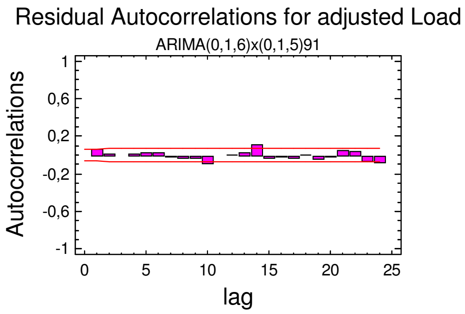
Figure B.1. Autocorrelation functions for region 1 (Continued)



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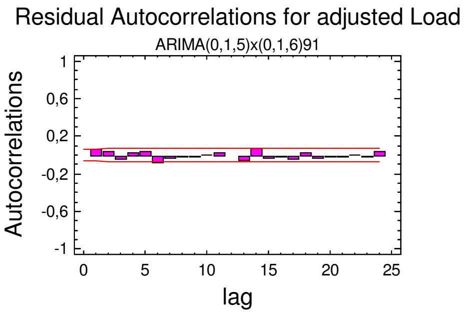

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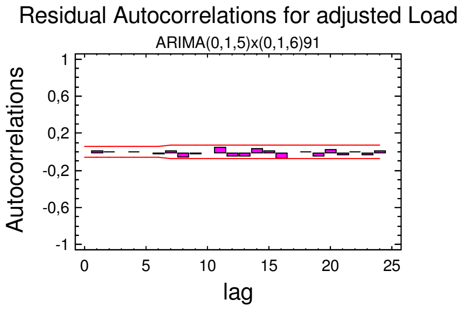

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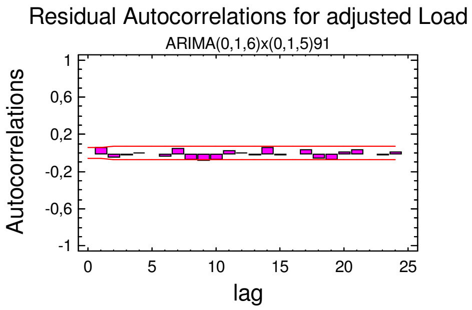

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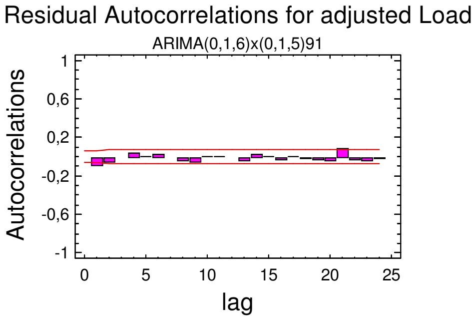

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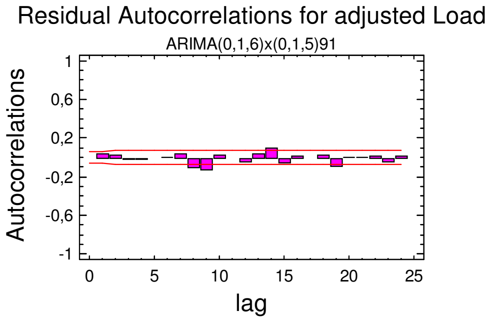

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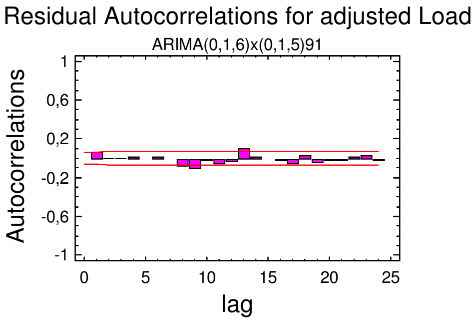

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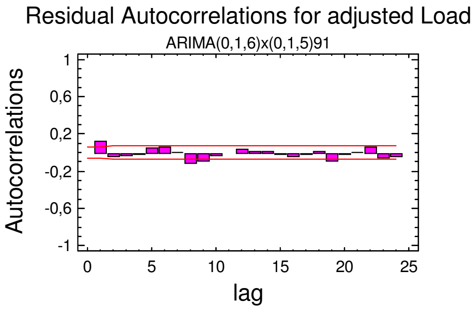

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Figure B.1. Autocorrelation functions for region 1 (Continued)

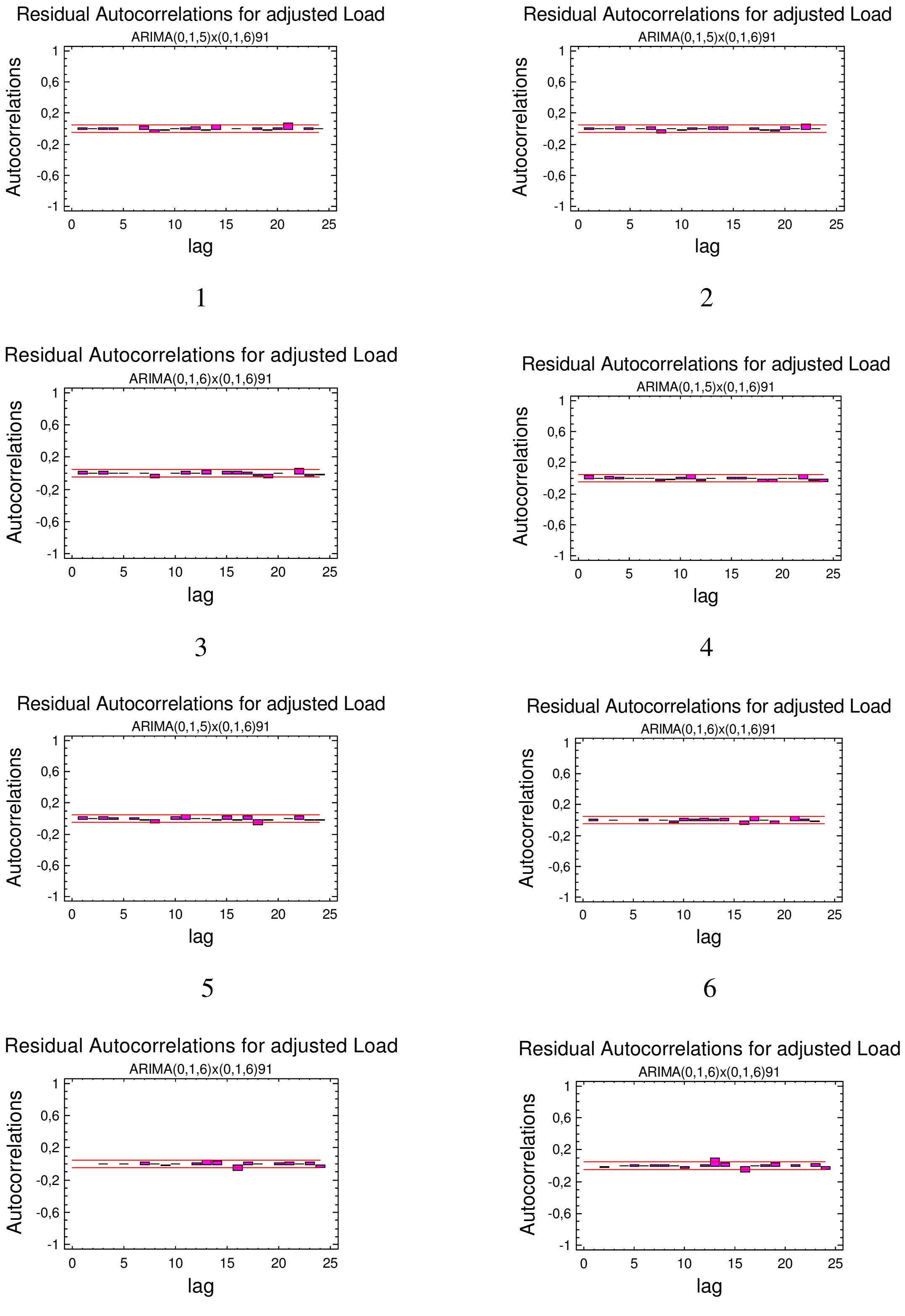

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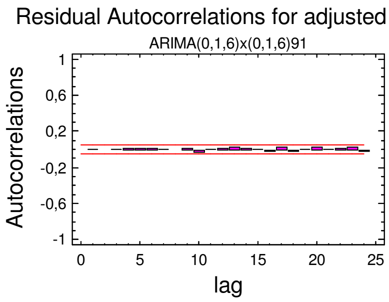
Figure B.2. Autocorrelation functions for region 2



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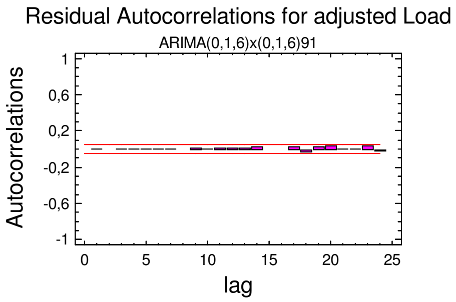

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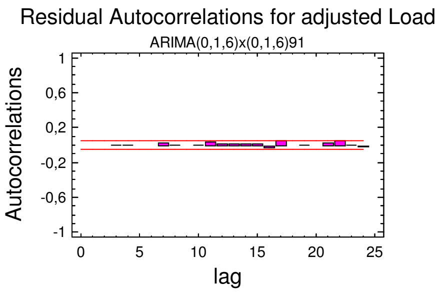

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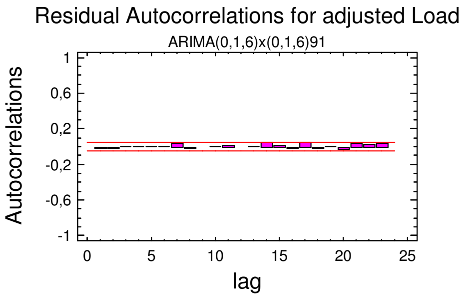

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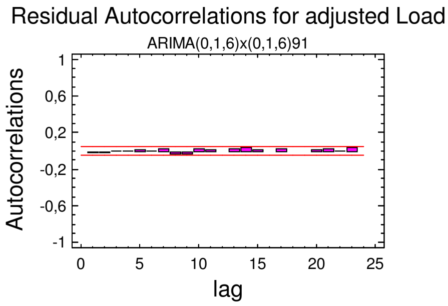

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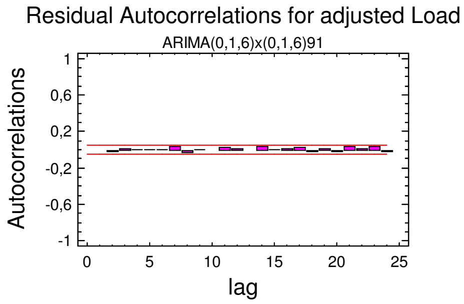

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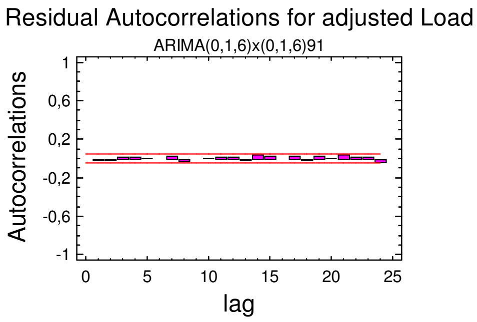

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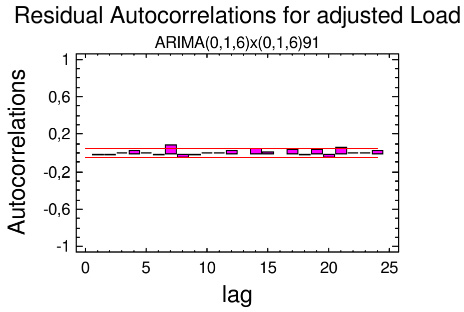

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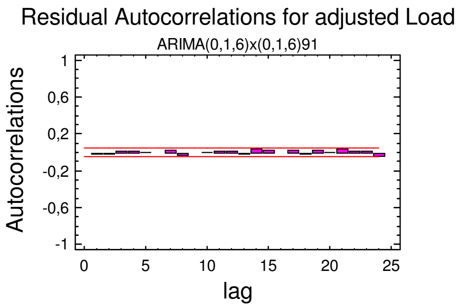
Figure B.2. Autocorrelation functions for region 2 (Continued)



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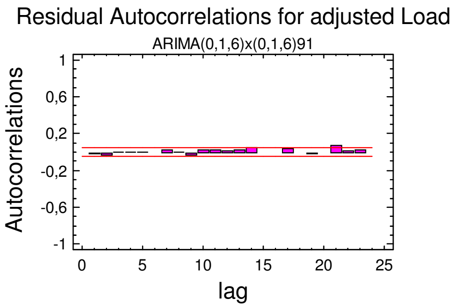

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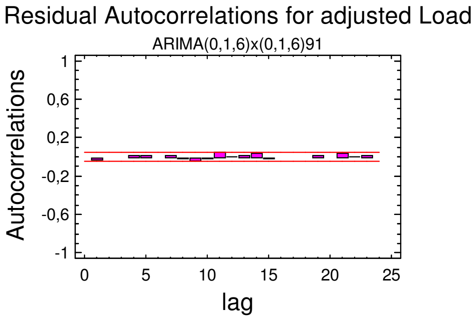

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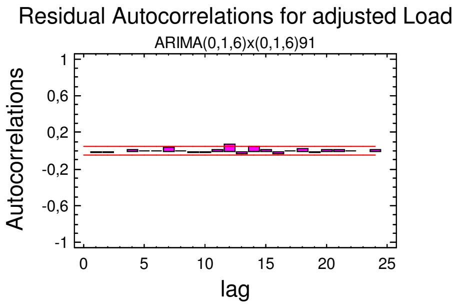

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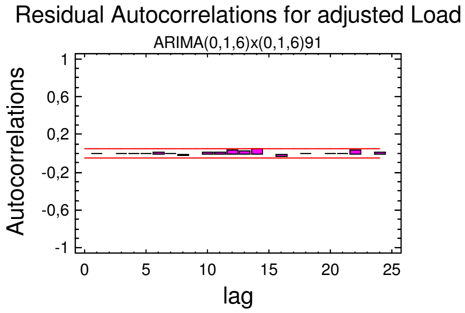

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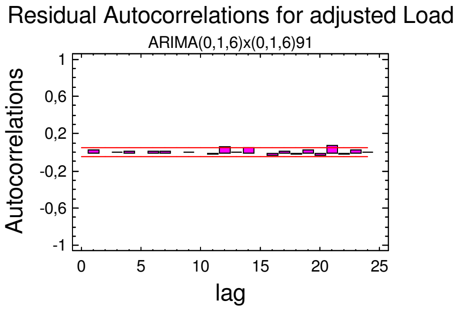

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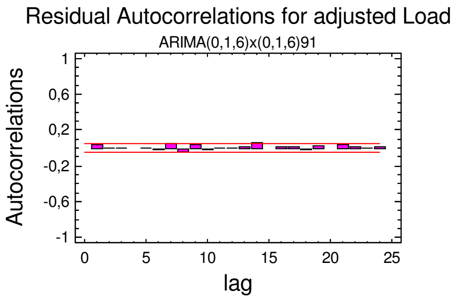

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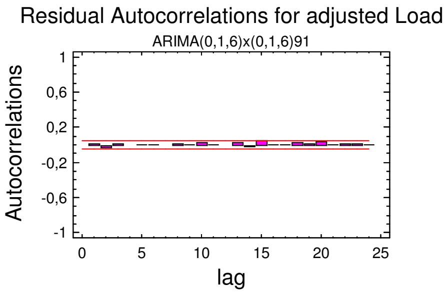

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Figure B.2. Autocorrelation functions for region 2 (Continued)

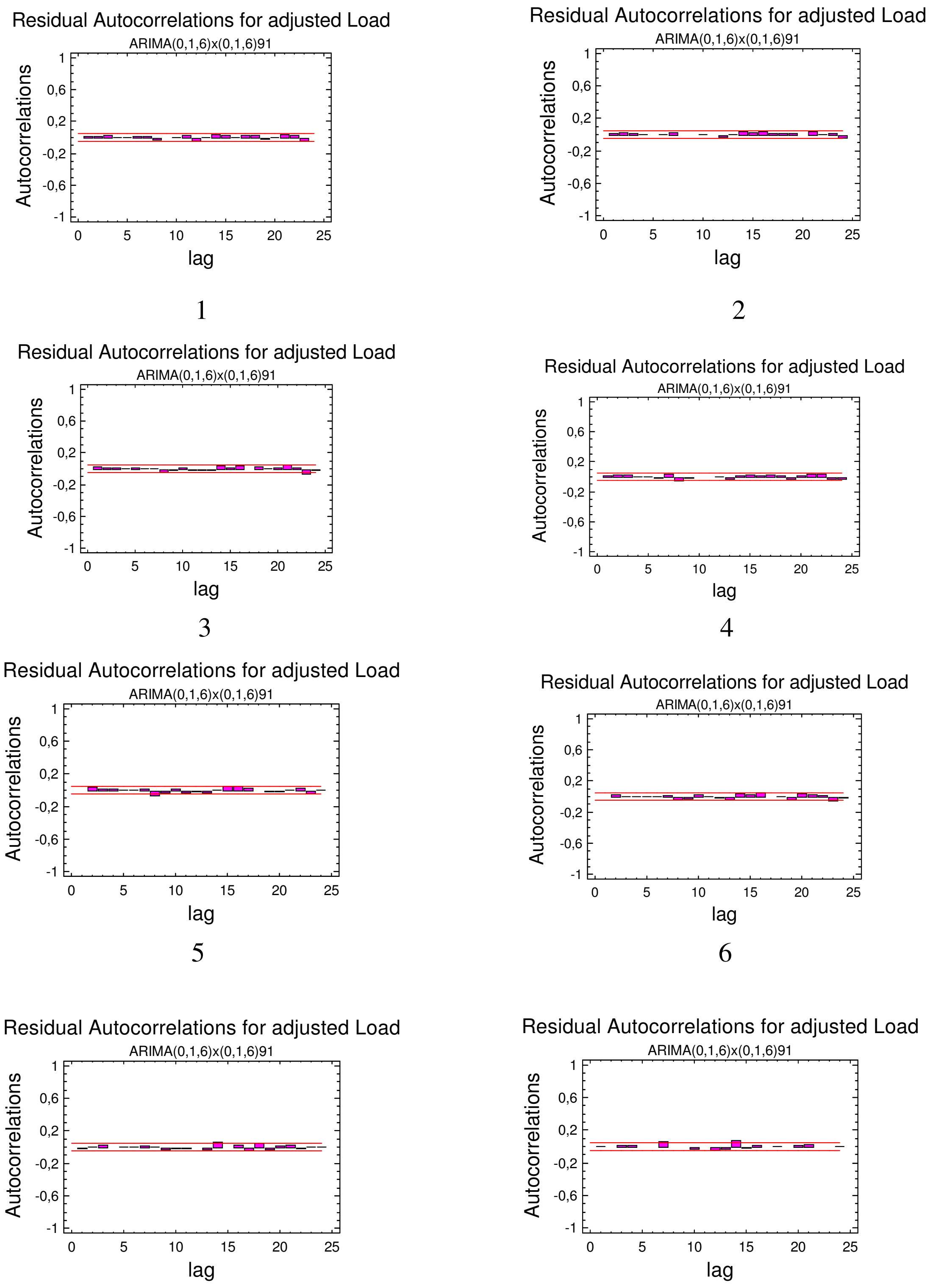

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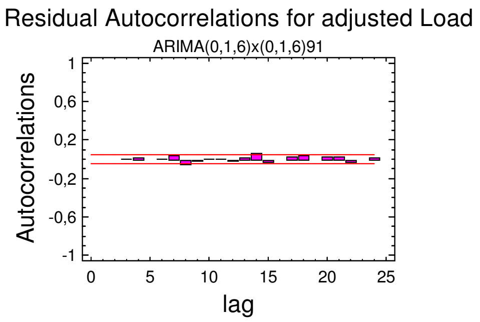
Figure B.3. Autocorrelation functions for region 3



Residual Autocorrelations for adjusted Load

ARIMA(0,1,6)x(0,1,6)91

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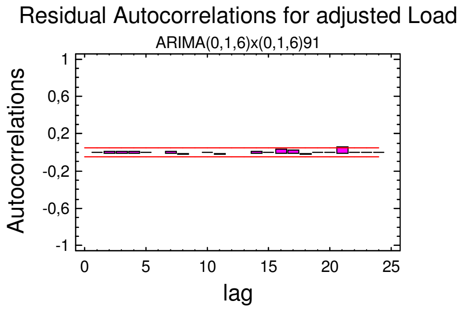

Residual Autocorrelations for adjusted Load

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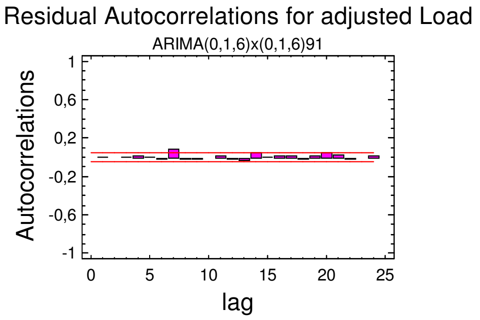

Residual Autocorrelations for adjusted Load

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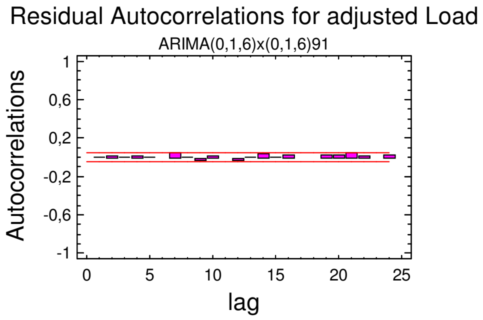

Residual Autocorrelations for adjusted Load

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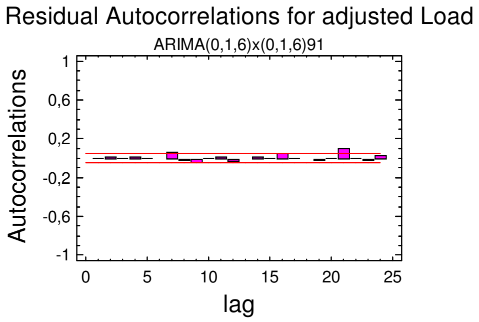

Residual Autocorrelations for adjusted Load

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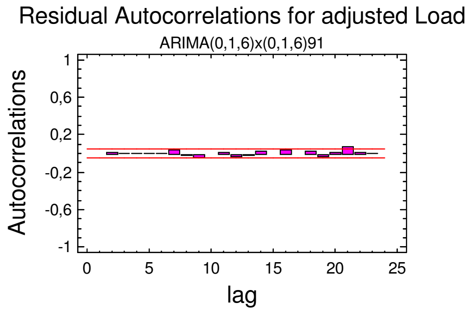

Residual Autocorrelations for adjusted Load

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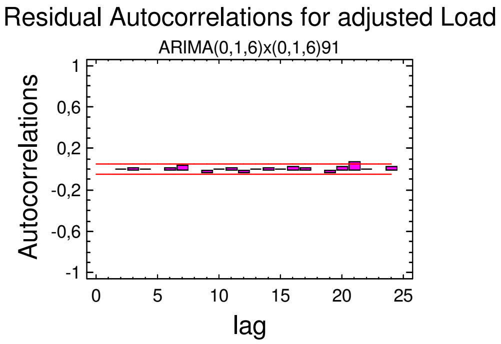

Residual Autocorrelations for adjusted Load

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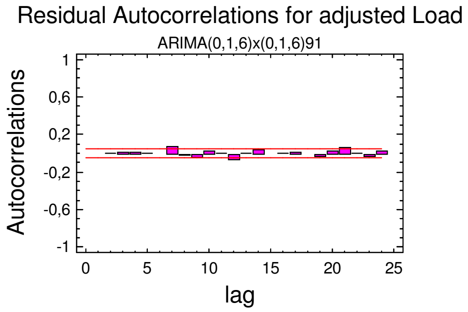

Residual Autocorrelations for adjusted Load

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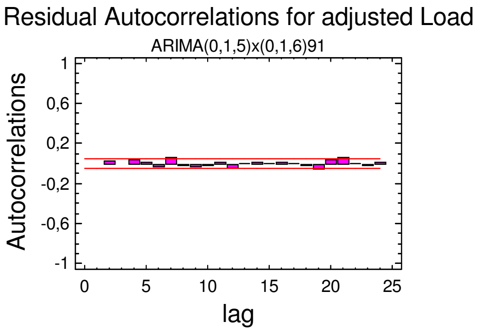
Figure B.3. Autocorrelation functions for region 3 (Continued)



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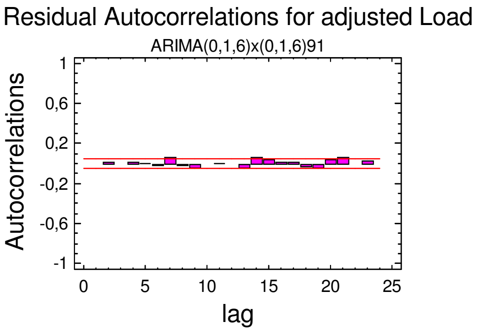

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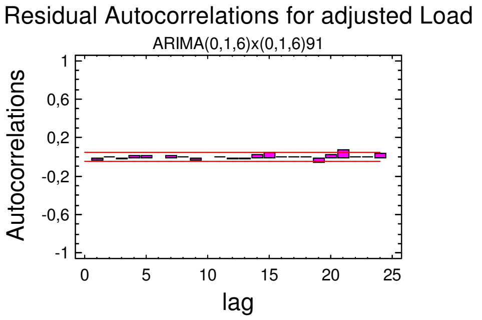

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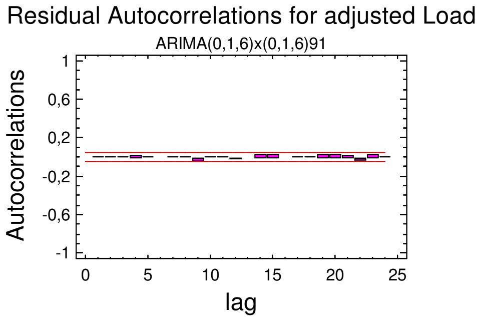

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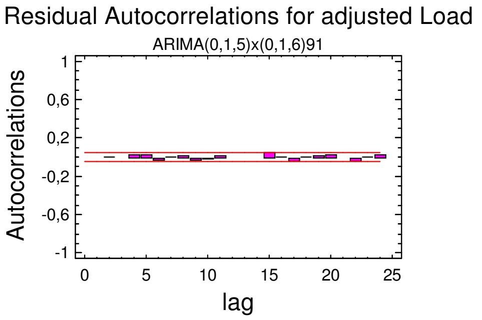

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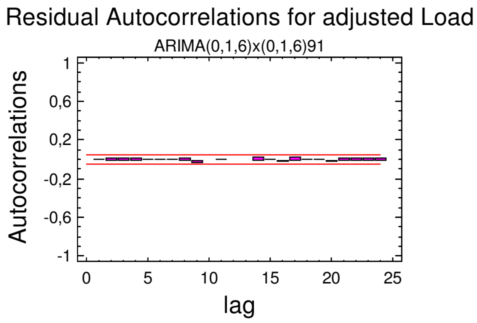

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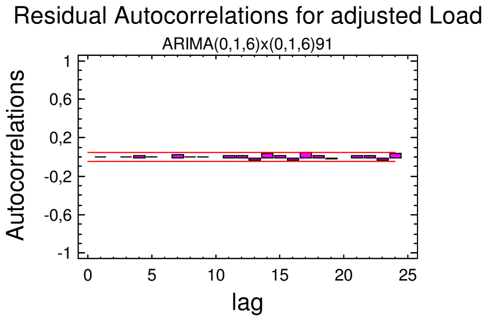

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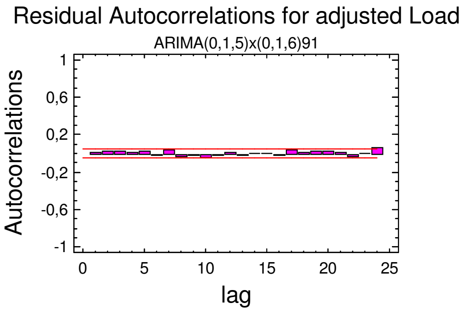

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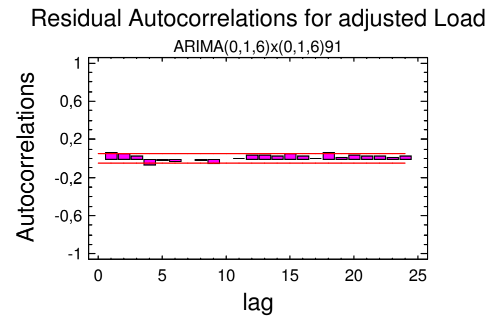
Figure B.3. Autocorrelation functions for region 3 (Continued)



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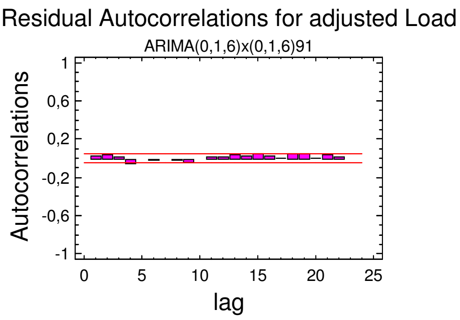

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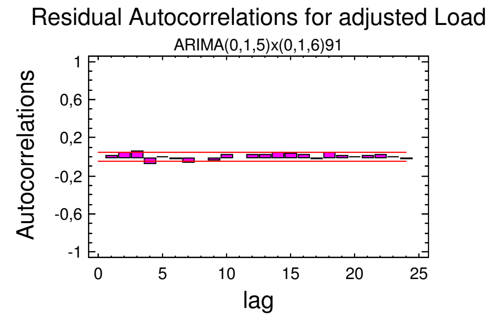

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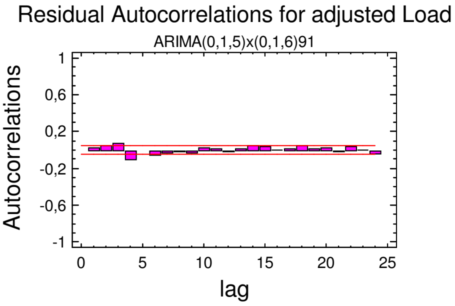

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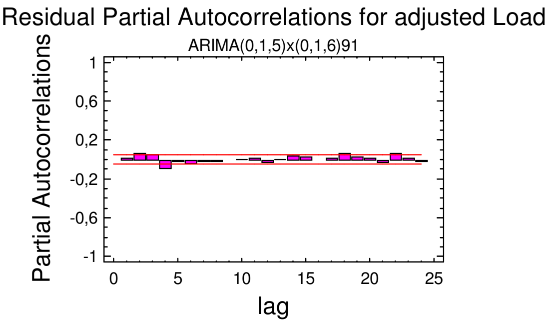

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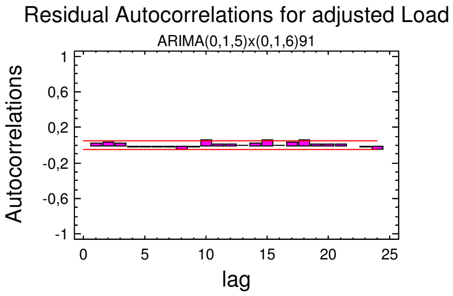

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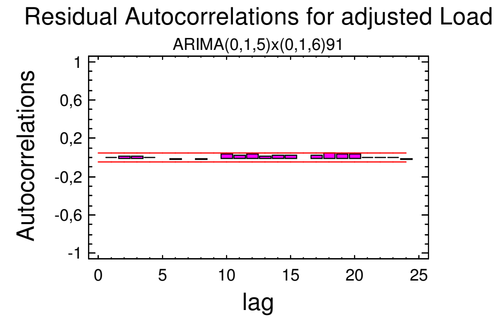

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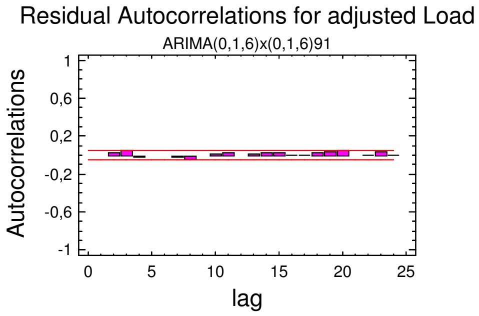

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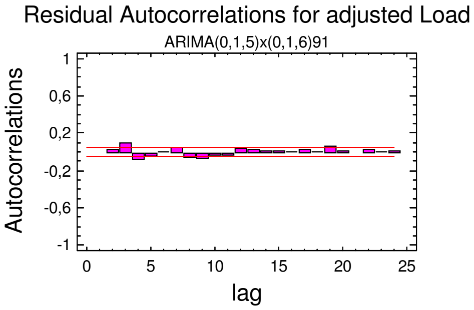
Figure B.4. Autocorrelation functions for region 4



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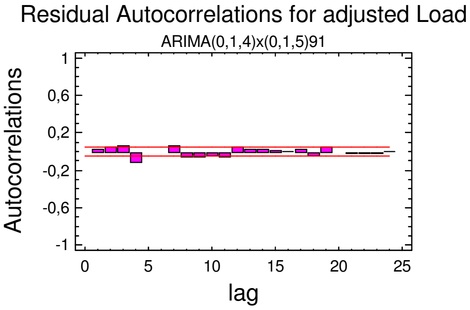

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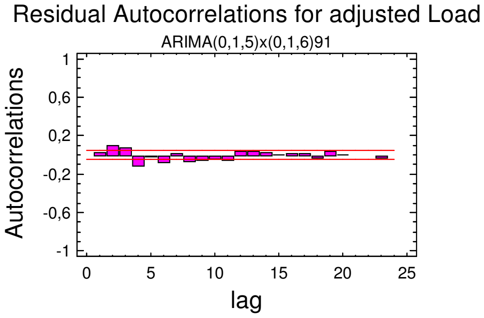

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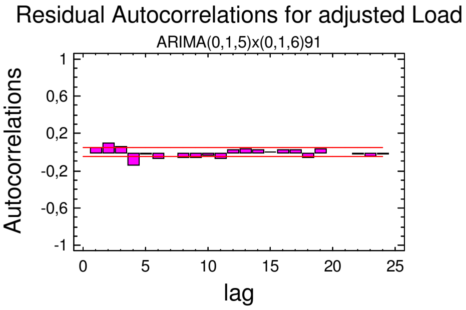

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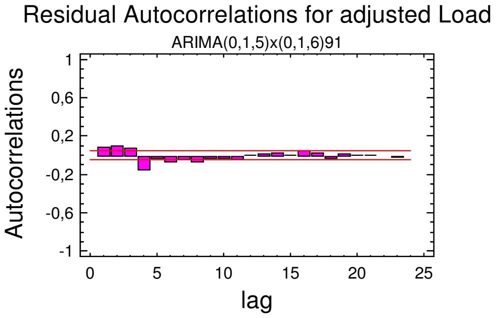

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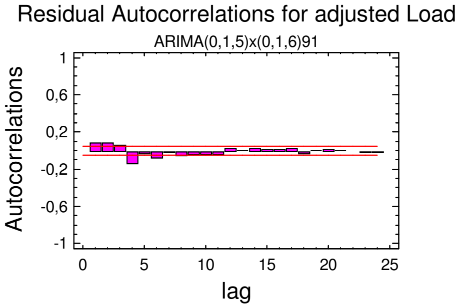

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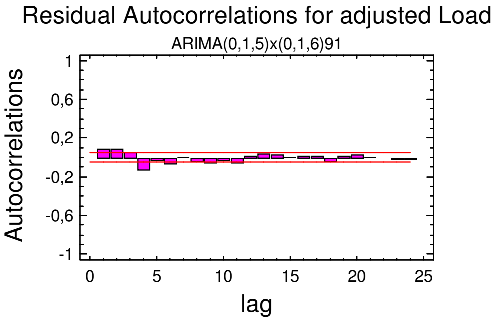

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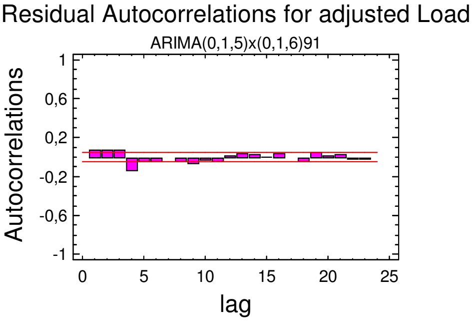

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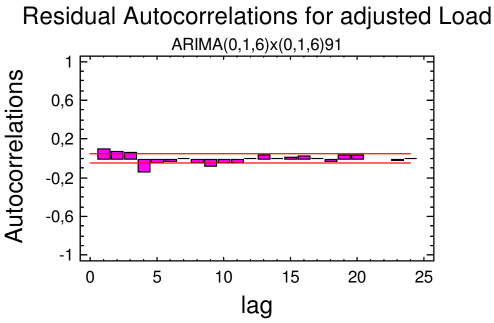
Figure B.4. Autocorrelation functions for region 4 (Continued)



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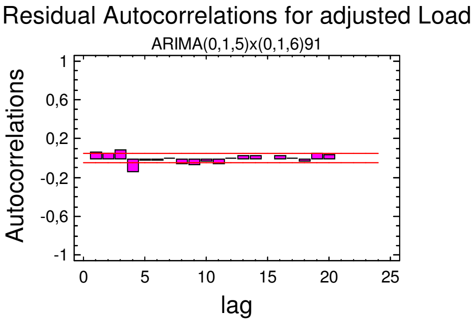

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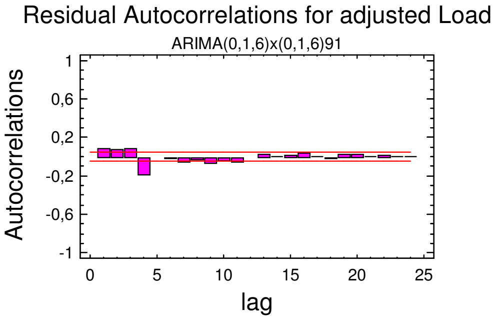

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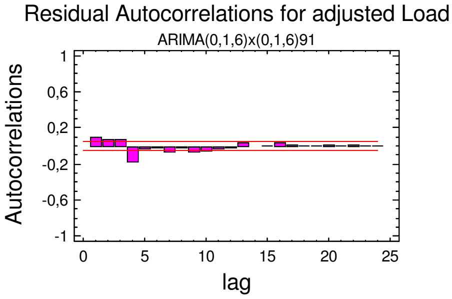

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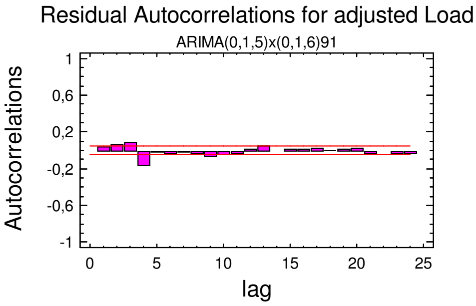

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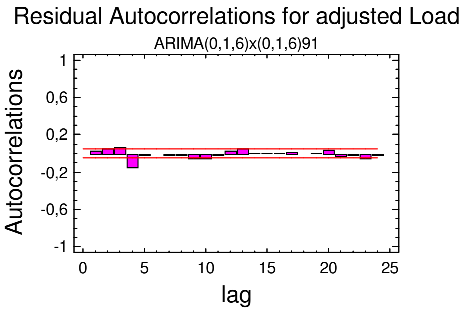

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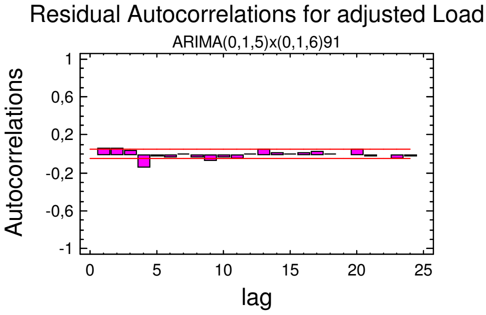

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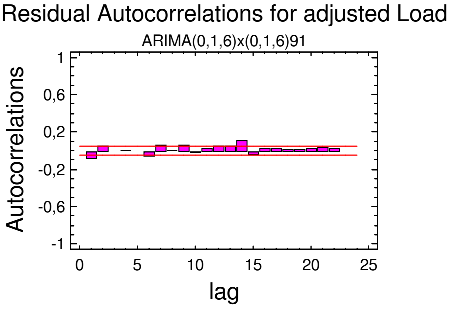

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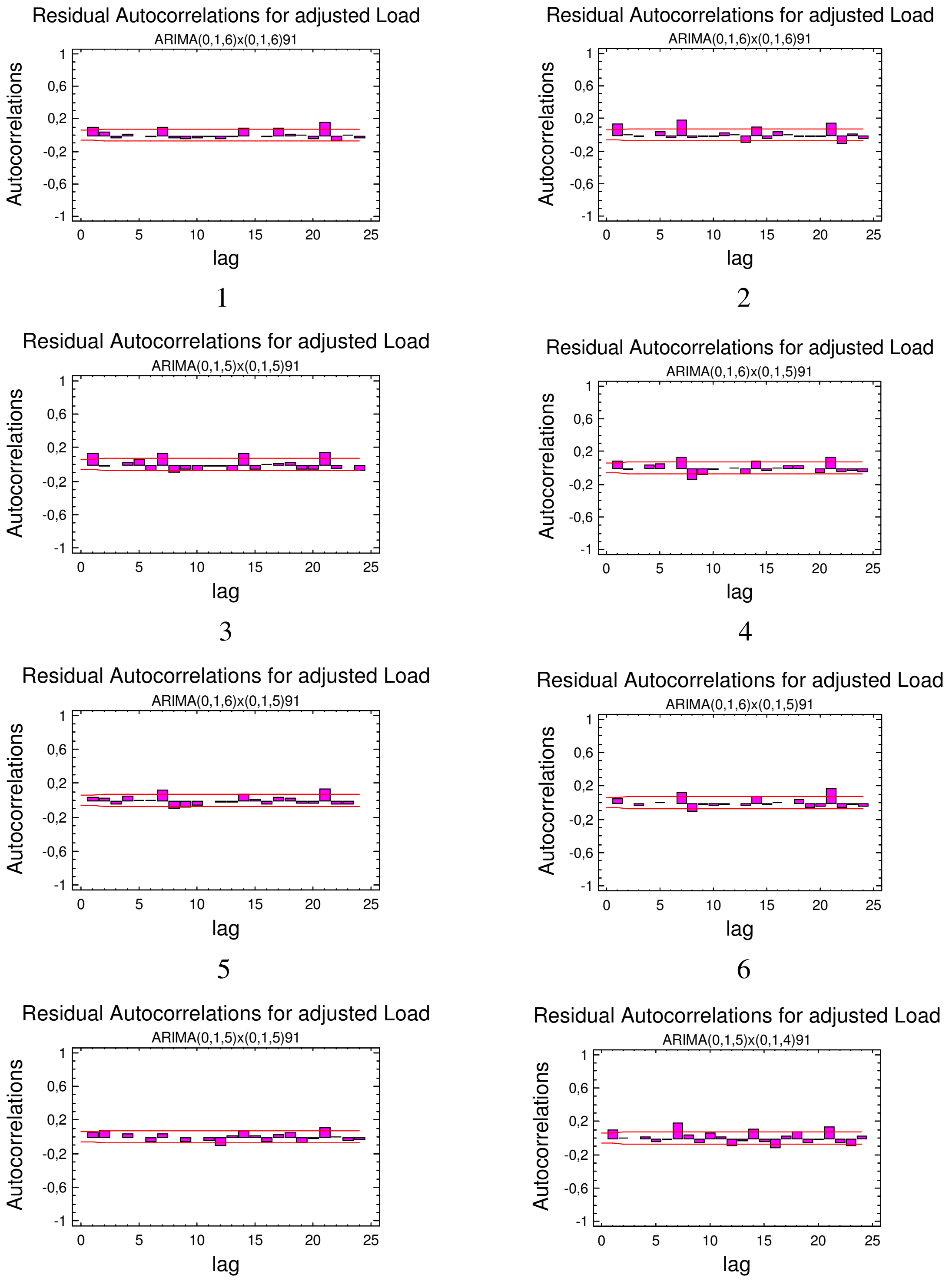
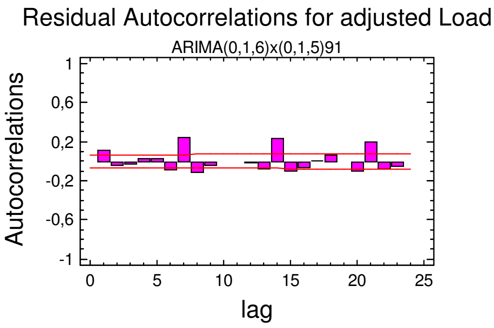
Figure B.4. Autocorrelation functions for region 4 (Continued)



1 2 3 4 5 6 7 8

Figure B.5. Autocorrelation functions for region 5



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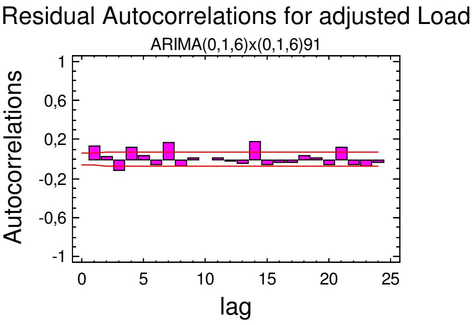

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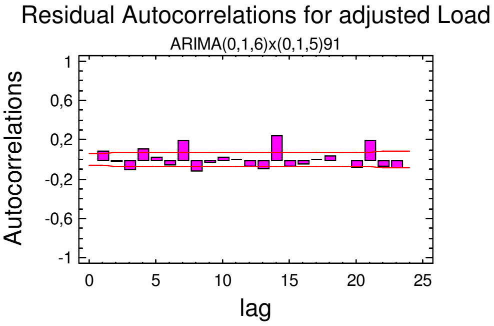

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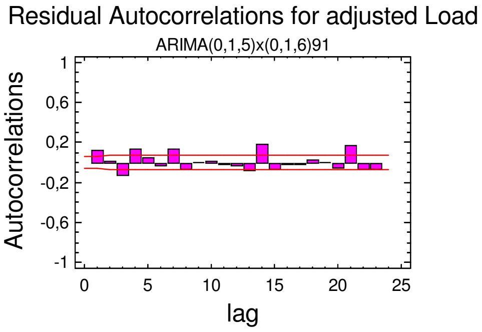

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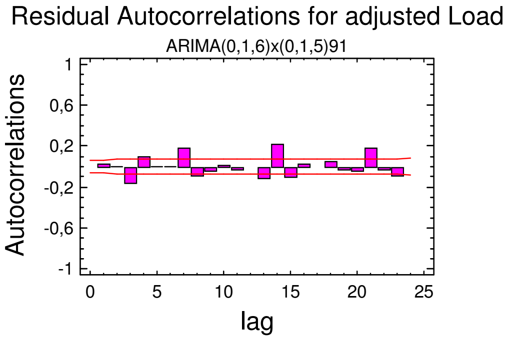

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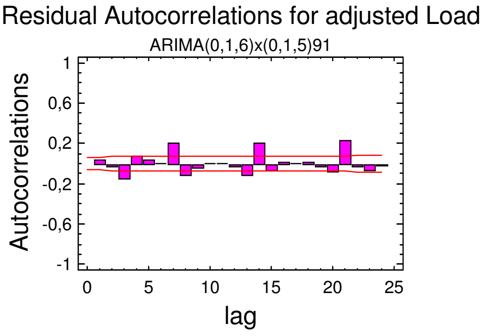

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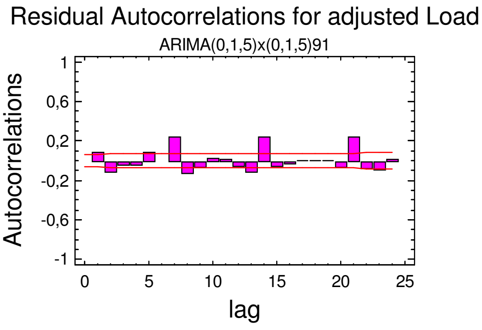

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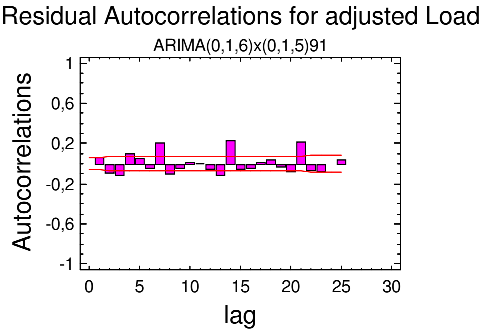

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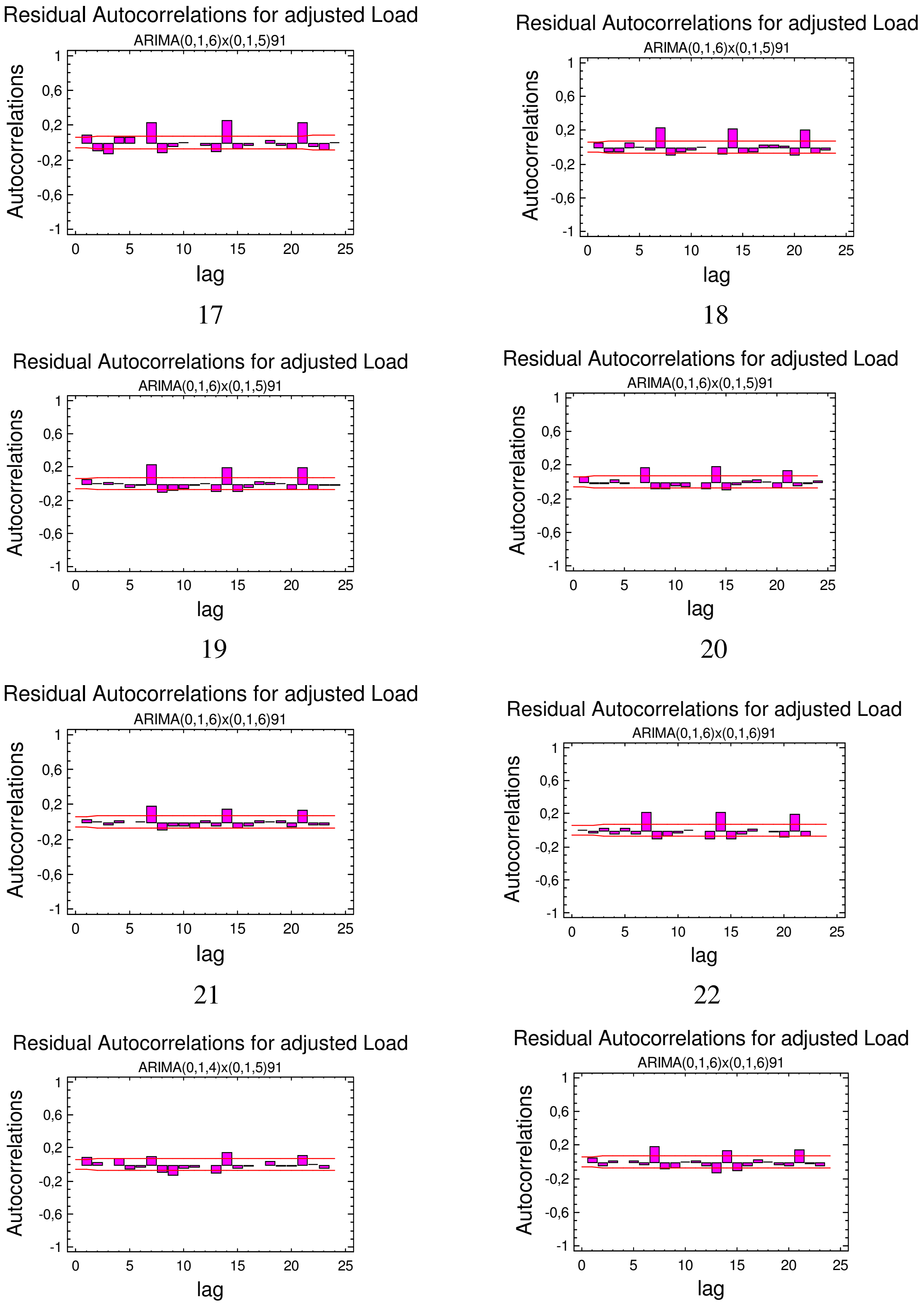
Figure B.5. Autocorrelation functions for region 5 (Continued)



Residual Autocorrelations for adjusted Load
ARIMA(0,1,6)x(0,1,5)91

17

Residual Autocorrelations for adjusted Load
ARIMA(0,1,6)x(0,1,5)91

18

Residual Autocorrelations for adjusted Load
ARIMA(0,1,6)x(0,1,5)91

19

Residual Autocorrelations for adjusted Load
ARIMA(0,1,6)x(0,1,5)91

20

Residual Autocorrelations for adjusted Load
ARIMA(0,1,6)x(0,1,6)91

21

Residual Autocorrelations for adjusted Load
ARIMA(0,1,6)x(0,1,6)91

22

Residual Autocorrelations for adjusted Load
ARIMA(0,1,4)x(0,1,5)91

23

Residual Autocorrelations for adjusted Load
ARIMA(0,1,6)x(0,1,6)91

24

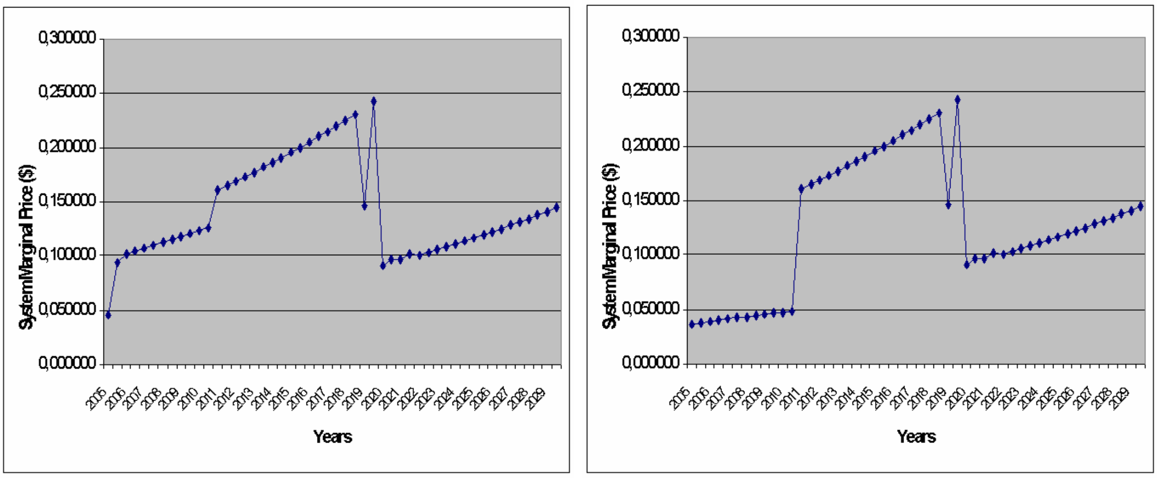
Figure B.5. Autocorrelation functions for region 5 (Continued)

Table B.1. Root mean square errors for all models

Hour/ Region	Region 1	Region 2	Region 3	Region 4	Region 5
1	115,885	48,6885	127,578	126,45	168,289
2	119,808	47,277	123,548	108,295	149,368
3	121,548	46,8897	118,156	101,271	155,106
4	116,349	57,0508	117,793	107,424	155,408
5	113,259	56,3528	120,664	106,932	154,861
6	110,856	51,5931	120,948	122,424	145,877
7	116,108	54,6429	126,781	129,805	155,995
8	144,601	67,07	137,985	124,157	217,475
9	163,336	92,2156	156,835	141,661	285,989
10	173,483	91,9804	182,771	169,722	288,843
11	157,345	87,3414	183,775	165,939	294,264
12	151,369	79,6099	177,324	170,287	274,91
13	148,108	75,8544	158,886	152,357	269,725
14	157,923	78,3586	162,719	162,816	276,146
15	168,327	77,5561	159,879	168,935	287,951
16	164,611	75,9497	160,659	161,885	287,858
17	165,539	76,8167	160,73	165,627	281,461
18	145,387	69,6888	155,291	153,09	267,26
19	134,589	66,06	147,432	135,895	248,912
20	127,667	58,2088	196,45	131,665	222,263
21	158,98	54,6238	132,788	137,506	201,731
22	122,794	56,7013	158,945	129,426	178,109
23	121,195	60,1041	130,955	129,566	181,937
24	155,619	84,3603	235,928	134,898	186,587

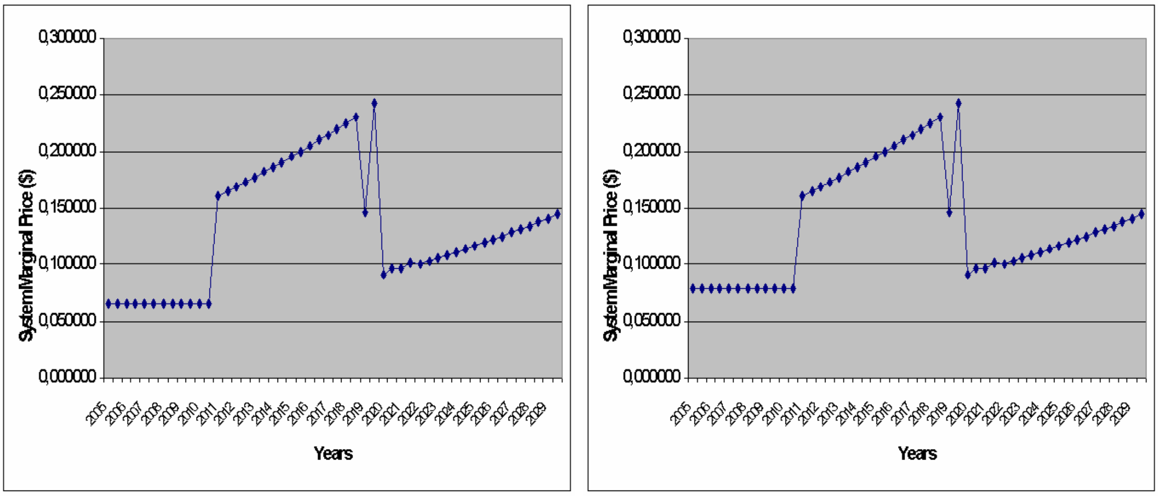
Table B.2. Table B.2. All industry groups used in load management options

APPENDIX C: SMPs OF ADDITIONAL SCENARIOS AND FINANCIAL RESULTS OF THE BASE CASE SCENARIO



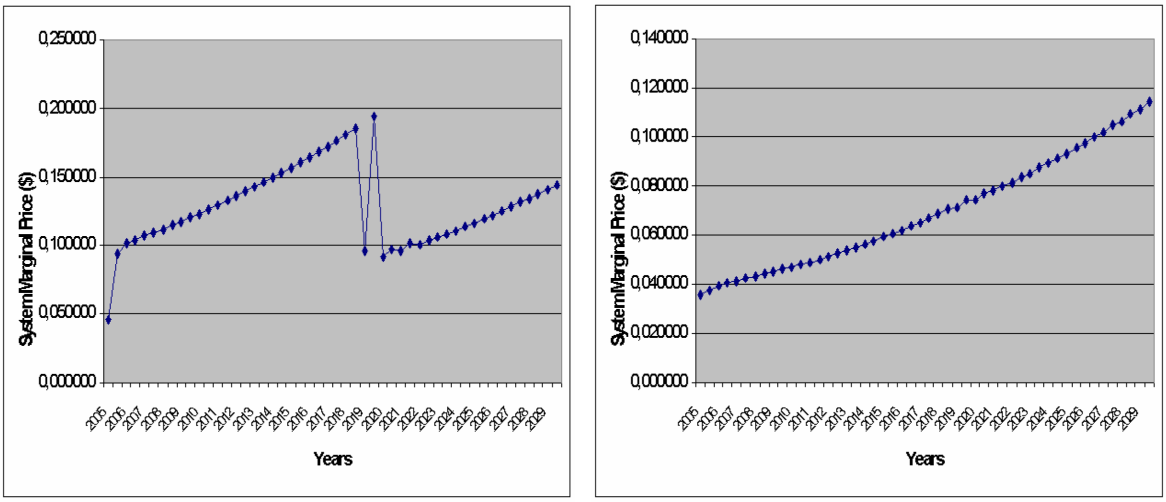
(a) (b)

Figure C.1. SMP of (a) scenario 1 and (b) scenario 2



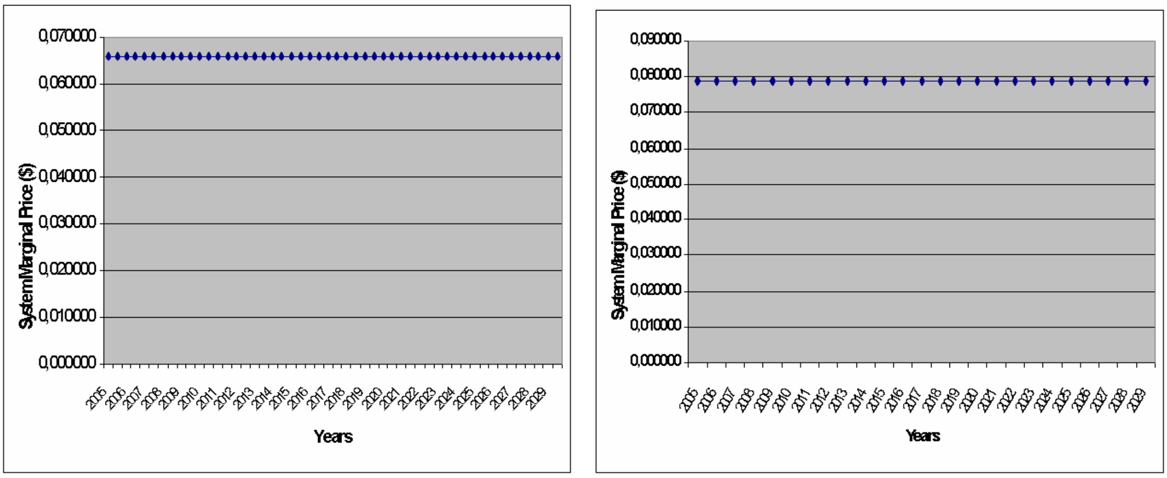
(a) (b)

Figure C.2. SMP of (a) scenario 3 and (b) scenario 4



(a) (b)

Figure C.3. SMP of (a) scenario 5 and (b) scenario 6



(a) (b)

Figure C.4. SMP of (a) scenario 7 and (b) scenario 8

Table C.1. Financial results of the base case scenario for plant 1

Table C.2. Financial results of the base case scenario for plant 2

Table C.3. Financial results of the base case scenario for plant 3

Table C.4. Financial results of the base case scenario for plant 4

Table C.5. Financial results of the base case scenario for plant 5

Table C.6. Financial results of the base case scenario for plant 6

Table C.7. Financial results of the base case scenario for plant 7

APPENDIX D: LIST OF CD CONTENTS

Subject	Folder Name	Number of Files
Wind Speed Data Analysis	Wind_analyses	32
Hourly Load Data	Load Data	60
Historical Simulation Results	His.sim	7
Load Forecasting	Load For	125
Payments of Load Management Options and Forced Outages	LMO-FO	2
State Institute of Statistics Data	SIS	2
Capacity Forecasts	Cap.For	3
Cashflow Analysis of the Base Case Scenario	cashflows	8

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