

COST AND EMISSION OPTIMIZATION IN SHORT TERM POWER GENERATION  
SCHEDULING

by

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*To my family,*

*For their everlasting support and unique love*

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## **ABSTRACT**

### **COST AND EMISSION OPTIMIZATION IN SHORT TERM POWER GENERATION SCHEDULING**

Worldwide a considerable increase in energy use is being experienced day by day. Likewise, ever increasing electrical energy demand leads to an increasing need in installed capacity, clean energy resources and low cost generation technologies. In this respect, efficient electrical energy generation plays a crucial role in worldwide energy policies globally. This study aims to construct an optimization model of Short Term Generation Scheduling (STGS) problem to generate a short term dynamic power generation profile for a given set of power plants (PPT) for any specified scheduling period, such as a daily or weekly time horizon. The constructed STGS model aiming the minimization of the total electricity generating cost is determined as a single main model including the combination of two subproblems called the Unit Commitment and the Economic Dispatch problems. Having originated from this point of view, both selection of the individual PPTs when to be in operation and for how long, and optimal allocation of the power demand among the committed and operating units are determined in one main model, in a clear and applicable way. The STGS model, which is formulated as a mixed integer non-linear programming model, is solved under a variety of scenarios. Accordingly, this study is expected to provide a platform to better analyze the effects of various key factors such as customer load demand, system maximum emission limit, total cost per production, and minimum up and down time limitations on the STGS. Moreover, in the study, comparative analyses of the scenario results are discussed and presented in detail.

## ÖZET

### **KISA DÖNEM ENERJİ ÜRETİMİNDE MALİYET VE EMİSYON OPTİMİZASYONU**

Dünya genelindeki enerji kullanımında günden güne bir artış gözlemlenmektedir. Aynı şekilde giderek artan elektrik enerjisi talebi, kurulu güç, temiz enerji kaynağı ve düşük maliyetli teknolojilerde daha fazla artış ihtiyacı doğurmaktadır. Bu bakımdan verimli elektrik enerjisi üretimi dünya çapındaki enerji politikalarında hayati bir rol oynamaktadır. Bu çalışma, günlük ya da haftalık zaman dilimi gibi herhangi belirlenmiş bir planlama periyodu süresince, belirlenmiş bir güç santrali grubu için; kısa dönem, dinamik bir enerji üretimi profili oluşturmada Kısa Dönem Enerji Üretimi Planlaması (KDÜP) problemine ait bir optimizasyon modeli inşa etmeyi amaçlamaktadır. Toplam elektrik üretim maliyeti minimizasyonunu hedefleyen yapılandırılmış modeli, Birim Taahhüt ve Ekonomik Dağıtım adlı iki alt problemin kombinasyonu olarak tek bir ana model dahilinde belirlenmiştir. Bu düşünce ile, hem bireysel üretim santrallerinin ne zaman ve ne kadar süre üretimde olacağına seçimi hem de enerji talebinin taahhütlenmiş ve üretimde olan birimler arasındaki optimal dağıtımını tek bir modelde, daha açık ve uygulanabilir bir yolla belirlenmiş olmaktadır. Doğrusal olmayan bir karışık tamsayı programlama modeli ile formülize edilen KDÜP modeli, çok sayıda farklı senaryo altında çözümlenmiştir. Dolayısıyla bu çalışmanın; müşteri yük talebi, maksimum sistem emisyonu sınırı, üretim başına toplam maliyet ve minimum açık ve kapalı durma süresi sınırları gibi çeşitli temel faktörlerin, KDÜP üzerindeki etkilerini daha iyi incelemeye yönelik bir platform oluşması beklenmektedir. Ayrıca, çalışmada, senaryo sonuçlarının karşılaştırmalı analizleri tartışılmış ve deyalı bir şekilde sunulmuştur.

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## LIST OF ACRONYMS / ABBREVIATIONS

CCS	CO <sub>2</sub> Capture and Storage
CED	Constrained Economic Dispatch
CF	Capacity Factor
CHP	Combined Heat and Power
ECD	Economic Dispatch
EMRA	Energy Market Regulatory Authority
FOM	Fixed Operation and Maintenance cost
IEA	International Energy Agency
LCC	Levelized Capital Cost
MENR	Ministry of Energy
MINLP	Mixed Integer Non Linear Programming
OECD	Organisation for Economic Co-operation and Development
OPF	Optimal Power Flow
PBUC	Priced Based Unit Commitment
PPT	Power Plant
SCUC	Security Constrained Unit Commitment
STGS	Short-term power Generation Scheduling
TSLC	Estimated Total System Levelized Costs per MWh
UC	Unit Commitment
VOM	Variable Operation and Maintenance cost
WEC	World Economic Council
CO <sub>2</sub>	Carbon dioxide
Mtoe	Million tonne of oil equivalent
GW	Gigawatt (10 <sup>3</sup> MW)

MW	Megawatt
kWh	Kilowatt-hour
MWh	Megawatt-hour ( $10^3$ kWh)
TWh	Terawatt-hour ( $10^9$ kWh)

## 1. INTRODUCTION

Energy is defined as the capacity of a physical system to perform work; it exists in several forms such as mechanical, chemical, light, nuclear, electrical etc. and is based on potential and kinetic energy [1]. It is needed in various areas in our lives such as health, education, transportation, public services, industry etc; in short it is essential for survival.

Today, whole world needs ever increasing amounts of energy for economic, social and cultural development, as well as a better quality of life. On the other hand, in order to minimize the impacts of that immense energy generation and consumption on resource depletion and environment; sustainable ways of energy production, transmission and consumption should be sought and integrated into national and/or regional energy policies.

A sustainable process has the characteristic of being carried out over and over with minimal or no environmental effects or impossibly high costs [2]. Accordingly, sustainability requires efficient use of energy and integration of safe and clean technologies. Also, sustainability can be met by energy savings, which decrease energy consumption by responsible use of energy, while increased energy efficiency reduces energy losses of energy conversion processes [3]. Besides, sustainable energy generation and consumption processes corresponds to reduced pollutant emissions, reduced greenhouse gas emissions and also reduced rates of resource depletion supported by increased usage of renewable resources (solar, wind, small-scale hydro, geothermal etc.).

This study's focus is on the short term efficient generation of electrical energy with the aim of making a contribution to this sustainability issue.

## 1.1. General Information

### 1.1.1. An overview of Electrical Energy

Electricity generation is the process of generating electrical energy from other forms of energy. Related with that, electricity we use today is generated by means of power plants (PPT) that are fed with various types of primary energy resources. Primary energy is a form of energy found in nature which has not been in any kind of transformation or conversion processes. Primary energy sources may be classified under two main categories as; renewable and non-renewable energy resources, whereas electricity converted from these sources is a type of secondary energy source.

- Non-renewable resources, as the name implies, are those resources that cannot be replenished in a short period of time. Non-renewable resources can be categorized under two main types: fossil fuels such as coal, oil and natural gas and nuclear power. The name “fossil fuel” refers to the fact that such fuels have been formed from the organic remains of prehistoric plants and animals.
  - (i) Coal, which is the most common and easy accessible fossil fuel within the primary resources in the world, is often divided into two main categories hard and brown coal. According to the 2009 data, coal has 27.2 % share of total primary energy supply and 10.0 % of world total energy consumption [6]. On the other hand, in order to meet the world’s increasing energy demand globally, coal is expected to have 24.9 % share of total primary energy demand in 2030 [7]. Besides, global coal consumption in the share of world total electricity generation is expected to increase from 40.6 % in 2009 to 43.9 % in 2030 [6].
  - (ii) Natural gas, combusted to generate electricity, refers to a fossil fuel type in gaseous form which is formed when layers of buried plants and animals are exposed to intense heat and pressure. [8]. As stated in 2009 reports, natural gas has 20.9 % share of world total primary energy supply and 15.2 % share of world total energy consumption. Moreover, natural gas has 21.4 % share of world electricity generation [6]. Additionally, natural gas is expected to meet 28.4 % share of world primary energy demand in 2030 [7].

- (iii) Oil, which is a fossil fuel in liquid form, is the end product of the decomposition of organic materials that are exposed to heat and pressure [8]. According to 2009 publications, oil has 32.8 % share of world total primary energy supply and 41.3 % share in world total energy consumption. Furthermore, oil has 5.1 % share in world electricity generation [6]. On the other hand, being the dominant fuel in primary energy resources, oil is expected to sustain its strategical position for a long time and its share in meeting world primary energy demand is expected to reach 28.4 % in 2030 [7].
- (iv) As reported in 2009, nuclear power, generated through controlled fission of Uranium metal, has 5.8 % share in world total primary energy supply and 13.4 % in world gross electricity production [6]. On the other hand, being reliable and not emitting CO<sub>2</sub> or other pollutants, nuclear power is expected to have 7.4 % share of world primary energy demand in 2030 [7].
- Renewable resources are those resources that can be naturally replenished in a short period of time. They include wind, solar, geothermal energy, biomass and hydropower (water). Today, only 3.3 % of global energy demand is provided by renewable energy sources; however this share is expected to reach 22 % in 2030, being encouraged by the high and ever increasing costs of oil and natural gas [9].
    - (i) Hydropower refers to the energy captured from the kinetic energy of flowing water via various types of dams. While having the least operating cost compared to other large scaled energy production alternatives, hydroelectricity also has the longest operating life.

As stated in 2009 reports, hydropower has 5.8 % share of world total primary energy supply and 16.2 % of world gross electricity production [6]. Worldwide, hydraulic sources generate more electricity than solar, wind, biomass and all other renewable sources combined [4]. However, hydropower share of world gross electricity production is expected to reach 2.8 % in 2030 [7].
    - (ii) Wind energy refers to the (mainly electrical) energy captured from the mechanical power obtained from the kinetic energy in the wind by wind turbines [10]. Wind velocity stability and continuity play key roles in this conversion process.

(iii) Solar energy is the energy of light and radiation that comes from the sun and is primarily used to generate electricity and/or heat. As stated in 2009 reports, solar and wind energy has 1.5 % share in world gross electricity production.

(iv) Geothermal energy refers to the energy continuously generated beneath the Earth's surface from the extreme heat contained in liquid rock (magma) within the Earth's core [8]. Also, geothermal energy generates the heat and steam that are used in the electricity generation by geothermal PPTs [9].

According to 2009 reports, geothermal energy has 0.3 % share in world gross electricity production [7]. Moreover, geothermal, solar and wind energy has 0.8 % share in world total primary energy supply and 3.3 % of world total energy consumption [6].

(v) Biomass energy, which is derived from living organisms like agricultural wastes, is both burned to generate electricity and/or heat and converted to gas for fuel use [7]. Today, in most countries, use of biomass is expanding due to its low cost and low emission convertibility into secondary usable energy forms. Low emission status is based on the fact that biomass releases to the environment only the carbon that it has already captured in its growth period.

According to 2009 publishes, biofuels and waste have 10.2 % share in world total primary energy supply and 12.9 % in world total energy consumption [6]. Besides, their share in the global gross electricity production is 1.4 %. However, the biomass and waste share supplying to cover global primary energy demand is expected to reach 12.2 % in 2030 [7].

All over the world, a considerable increase in energy use is being experienced day by day, (except for the 1.1 % decrease in 2009 caused by the financial and economic crisis). After this slight decrease, energy consumption rose by 5.5 % in 2010 (see Figure 1.1) [11]. On the other hand, although the 2008-2009 global economic downturn slowed down the rate of growth in electricity use, worldwide electricity demand increased by 5.4 % in 2010. There is still a population of 1.5 billion people (especially in Africa) having no access to electricity. Accordingly, the electricity demand is projected to increase by 2.2 % per year between 2008 and 2035, with more than 80 % of the growth occurring in non-OECD

countries. So, meeting this rapidly increasing demand has become one of the world's major energy challenges [5].

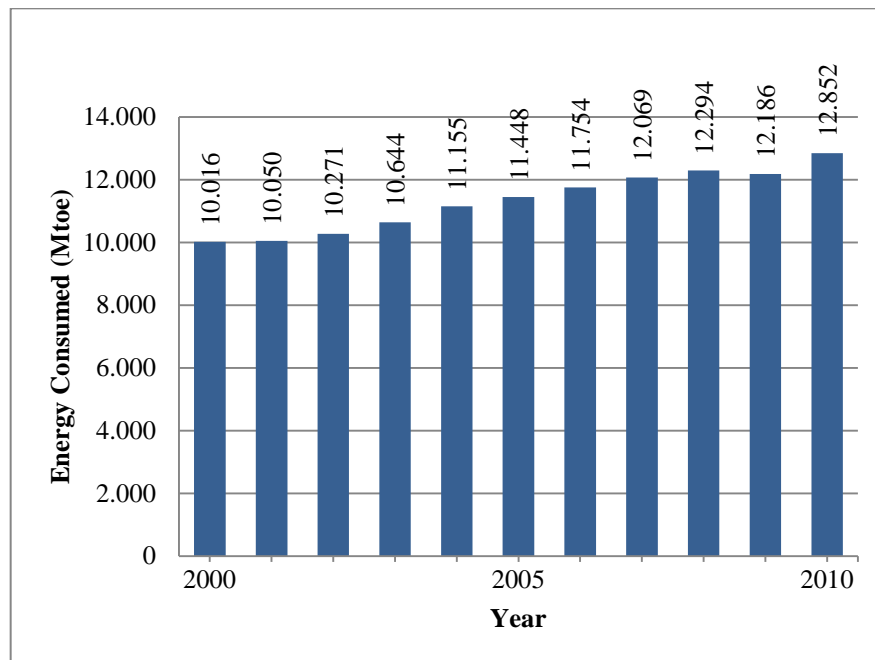


Figure 1.1. World energy consumption.

### 1.1.2. Electrical Energy Generation in Turkey

Population increase, industrialization, urbanization, and general socio-economic development have led to ever increasing electrical energy demands all over the world. In this regard, Turkey became the first within the OECD countries, regarding the rate of increase in hers electricity and natural gas demands. All through 1990s, the annual rate of electricity demand increase was nearly 8.5%, however it decreased to 6.7 % average because of the global crisis, in 2000s [12]. According to the demand forecast studies published by Ministry of Energy and Natural Resources (ETKB), the demand is expected to raise at an average annual rate of 7.5 %, between 2011 and 2020. The list of annual demand and generation amounts in 2011 is displayed in Table 1.1.

Table 1.1. Power generation and consumption values of Turkey in 2011.

Organizations	Thermal		Geothermal		Hydro		Wind		Total	
	Production (MWh)	Contribution (%)	Production (MWh)	Contribution (%)	Production (MWh)	Contribution (%)	Production (MWh)	Contribution (%)	Production (MWh)	Contribution (%)
<b>EÜAŞ</b>	17,655,118	16.78	0	0	17,403,592	16.54	9	0	35,058,710	33.32
<b>Affiliated Partnerships of Eüaş</b>	8,281,011	7.87	0	0	0	0	0	0	8,281,011	7.87
<b>Transfer of Operation Rights (TOR)</b>	2,100,414	2	0	0	86,091	0.08	0	0	2,186,505	2.08
<b>Auto Producers</b>	4,935,170	4.69	0	0	796,346	0.76	901	0	5,732,417	5.45
<b>Generation Companies</b>	17,498,660	16.63	326,972	0.31	6,528,880	6.21	1,756,369	1.67	26,110,882	24.82
<b>Build Own Operate (Bo)</b>	21,427,926	20.37	0	0	0	0	0	0	21,427,926	20.37
<b>Build Operate Transfer (BOT)</b>	4,662,241	4.43	0	0	1,730,637	1.64	21,988	0.02	6,414,866	6.1
<b>Turkeys' Production</b>	76,560,540	72.77	326,972	0.31	26,545,546	25.23	1,779,259	1.69	105,212,317	100
<b>Import</b>									1,882,706	
<b>Export</b>									1,266,353	
<b>Turkeys' Consumption</b>									105,828,670	

Today, electrical energy sector forms 2.5 % share of the Turkish economy (2010-2011) and the public companies that are responsible for electricity generation, transmission and trading are Electricity Generation Company (EÜAŞ), Electricity Transmission Company (TEİAŞ), Electricity Distribution Company (TEDAŞ) and Turkish Electricity Trading and Contracting Company (TETAŞ). There are also other private enterprises in the energy sector involved (and aspiring to expand their involvement) in electricity generation, transmission and distribution.

Regarding the shares of the production companies in total electricity generation, EÜAŞ is at the top with 45.23 % (95.532 GWh); it is followed by Build Own Operate (BOO) PPTs with 21.41 %, Generation Companies + Transfer of Operation Rights (TOR) PPTs with 21.04 %, Build Operate Transfer (BOT) PPTs with 6.43 % and Auto-producers with 5.89 %. EÜAŞ also has 45.2 % of the total generation capacity of Turkey [13]. TOR refers to transferring the operating rights of a public company to private sector, while the ownership is still kept under the former's legal entity. BOT refers to the contract between the state and private sector, in which the operation and building of a facility is provided by a private company which then gains the right to the financial revenues of that facility for a specified period. At the end of that period, the facility is transferred back to public ownership without any further financial liabilities incurred by the state. Unlike BOT contracts, a BOO contract is made for an indefinite period and the facilities are not transferred back to the state at the end of the contract period. Auto-producers, as the name implies are private companies that supply their own power demand, while they are allowed to sell up to 50 % of their supply to the general market [14].

In 2010, the total electrical energy production of Turkey reached to 210.2 GWh. Shares of the primary sources regarding the installed capacity and the electricity generation in Turkey are as follows: natural gas 32.53 % and 46.47 %, hydraulic 31.97 % and 24.52 %, lignite 16.43 % and 17.02 %, imported coal, hard coal, asphaltite 7.57 % and 9.05 %, multi fuel fired 5.36 %, liquid fuels (referring to oil productions such as: fuel-oil, diesel and naphtha) 3.08 % and 1.03 %, wind 2.67 % and 1.38 %, biofuels and wastes 0.20 % and 0.22 % and geothermal 0.19 % and 0.32 % [12,13]. It is clearly seen that natural gas and hydraulic resources are on the top of the list in electricity generation.

## 1.2. Power Generation Scheduling

There are many important issues related to electrical energy generation such as; energy price forecasting for sound energy supply and demand management, electricity demand forecasting at periodic (hourly) level since electricity cannot be stored and various resource, capacity transmission and/or emission based electricity generation scheduling problems.

In electricity generation processes, since the electricity can never be stored, it must be generated at least in the amounts sufficient to cover the demand at any time. Moreover, as the demand level changes continuously, generation level should be kept in line with these changes all the time. In order to meet the electrical demand load at any given time in electricity generation, different combinations of the power generation units can be used regarding the types of technology and fuel they use. On the other hand, some basic specifications like operating cost, system emission level, minimum and maximum generation capacities of PPTs have significant effects on the status of the generating units (i.e. the status of individual PPTs is being opened or closed at any given time). Besides, it is not easy to start up or shut down a generating unit to keep up with the sudden demand changes. Therefore, varying the generation status of a generating unit creates two main scheduling procedures, namely, a long term continuous operation with less unit cost or a short term continuous operation with high unit cost. By taking all these factors into account, the efforts to build up a dynamic electrical power generation profile are examined as “the short term power generation scheduling” problem (STGS) in this study.

Large scale power generation scheduling problems are often difficult to solve because of their combinatorial characteristics. But, in order to reach optimal or near optimal economic operations of electric power systems, these power generation schedules must be prepared and applied, carrying multiple objectives such as cost optimization, profit maximization and/or emission minimization. Power generation scheduling, sometimes named as economic scheduling or production scheduling, basically comprises unit selection and load allocation. Unit selection is based on the determination of the units that

are going to operate in any time in the system; and load allocation refers to the allocation of the generated power among the operating units.

Traditionally, the schedule of the generating units is determined in two stages: the Unit Commitment (UC) stage and the Economic Dispatch (ECD) stage. UC is considered as an important sub-problem of production scheduling in which the generating units that are going to be up (on) or down (off) during the planning horizon are determined. At the same time, the system demand and reserve requirements are also met at optimal (minimum) cost subject to various constraints such as equipment, environmental and system/operation [15]. However, together with the consideration of the transmission capacity, reserve requirements and generation limits, optimal allocation of the system load among the committed generating units is determined in the ECD stage [16]. Basically this stage includes the process of actual load allocation among the PPTs. In this study, these two stages are considered as a unique phase which refers to the fundamental representation of the described STGS problem.

### **1.3. Objectives of the Study**

In order to take the power generation process under control, first of all the main objectives should be determined and the process should be modeled in a careful manner. In view of that, this study aims to model and examine the STGS problem with the aim of guiding the short term power generation schedules of the PPTs producing electricity.

The main objective of this study is both building up an optimization model that refers to a dynamic electrical power generation profile for the STGS problem and also aiming at minimizing the total cost of electricity generation from a set of existing (available) PPTs, while making sure that various greenhouse gas and pollutant emissions are kept under control, minimum and maximum power generation capabilities of PPTs are abided, periodic demands are satisfied, start-up and shut-down durations are taken into consideration as well.

Those aims and requirements mentioned above have led to the development of a mixed-integer non-linear programming (MINLP) model, which includes various linear and non-linear constraints, while having a linear objective function. This optimization model is solved (via various commercially available solvers) to generate near optimal and optimal solutions for various scenarios in the STGS problem and various applications.

So, before describing the model, a detail research regarding the framework, application needs, pros and cons of the STGS problem is presented. Then, after the development and integration of the model, scenario analysis is taken into account in the study.

The next chapter features, a review and discussion of the literature on power generation scheduling and the short term resource scheduling studies.

In chapter 3, first, compilation and analysis of the data, which has been used in this study, are presented. After that, the framework of the constructed mathematical model of the short term power generation scheduling problem is presented in detail.

Various scenario analyses and related case implementations are presented in Chapter 4. The primary aim of this scenario analysis has been to better understand the impacts on costs, emission and generation schedule characteristics of various single and multiple factor changes in problem (setting) parameters. In this part, the key factors that the scenarios are based on, several remarkable combinations of the scenarios and also result comparison are analyzed and presented.

Chapter 5 includes the conclusions and further studies regarding the presented study. Finally, tables and figures formed in the study are listed in the Appendices.

## 2. LITERATURE SURVEY

In this chapter, other studies on the problems of electrical power production/generation scheduling and short-term resource scheduling in the literature are briefly presented. Since there are many studies on this subject, only the most important and ground breaking ones are taken into account in this section.

In real life several objective types might be considered in the operation of electric power systems such as; cost minimization, emission minimization and security or reliability maximization problems. Scheduling problems that have the minimization of total production cost as an objective basically focus on fuel, maintenance and start-up costs in their objective functions. Scheduling problems aiming at emission minimization focus on the minimization of emissions like particular matter and gaseous pollutants stemming from the PPTs. However, such concerns might be represented as a constraint, as well as being included in the objective function. Whether the emission is used as an objective also, the UC becomes a multiple and objective-oriented problem. On the other hand, of security or reliability concerns are most frequently represented as constraints [15].

After various examination of different market structures and relevant market models, Yamin [17] reviews two main UC formulations used among various markets in power generation scheduling, namely Security Constrained Unit Commitment (SCUC) and Priced Based Unit Commitment (PBUC). In the SCUC problem, scheduling of the generating units and minimization of operating cost subjected to related constraints are satisfied. Conversely, profit maximization is the objective of the PBUC problems, in which load satisfaction is a requirement for market price forecasting. Also in this study, an extensive review on the thermal unit commitment problem (in both regulated and deregulated power markets) is presented, under major headings as deterministic and meta-heuristic techniques. Besides, some existing solution methods used for the hydrothermal coordination problem (in which UC and short term hydro scheduling are considered as the subproblems) are summarized. Most of them are said to be based on decomposition methods involving the UC and hydro scheduling subproblems. Here, again, it is aimed to

minimize production cost subjected to meeting load and additional generation requirements, while obtaining the over-all problem solution by coordinating between the solution of the thermal UC and hydro scheduling subproblems.

In their study, again Sen and Kothari [15] briefly discusses various mathematical programming and optimization techniques that are available in literature, in order to model and solve the general economic thermal UC problem, which they formulate as a time-dependent combinational optimization problem. They argue that extensive enumeration approach which generates and evaluates all possible combinations of the generating units is fit for very small scaled systems. In addition to its simplicity, ease of understanding and application, creation of a priority list based on extensive enumeration, is likely to provide a near optimal feasible schedule, which is quite sufficient in most situations. Besides, they claim that Dynamic Programming (DP) method has the ability to maintain solution feasibility and it builds and evaluates the complete decision tree for the optimization. According to the authors, contrary to DP, Lagrangian Relaxation (LR) method neither needs a priority list nor has a slower solution time, LR is faster. Sen and Kothari claim that, unless a modification of multipliers is ensured in each iteration of LR, unnecessary commitment of generating units resulting higher production costs might occur. Accordingly, they summarize a new approach namely Augmented LR technique, in which quadratic penalty terms of the load demand are added to the relaxed objective function. On the other hand, they argue that, Branch and Bound (B&B) method differs from majority of other methods or algorithms in some ways such as assuming no-priority ordering, directly taking stochastic demand, unit outages and time-dependent start-up costs in the account. Furthermore, they say that, solution of the UC problem in an Expert system setting by adjusting the program's parameters through interaction with the system operator provides good results. Alternatively they claim that, Simulated Annealing (SA) method, which is much faster than DP, can be applied to large-scale UC problems and a near-optimal and feasible solution is provided by SA. On the other hand, Sen and Kothari argue that Genetic Algorithm (GA) method is a global optimization technique which has the advantage of providing the flexibility in modeling both time-dependent and coupling constraints. Despite being a poor local-search technique, GA is a good global-search technique. They

claim that, as it exploits network structures, Network programming method is sufficient, simple and fast.

In an earlier study, Garver [18] defines the power generation scheduling problem as economic scheduling, and formulates it as an integer program with the purpose of identifying both the selection of units that are going to operate at any given time and power demand allocation among these units. Discontinuous power output characteristics referring to a minimum or zero amount of power generated are included in the model. At the same time, the objective contains costs of start-up, power production at and above the minimum output (incremental cost) for each time period. In this study, in order to reach only integer values, dual Euclidean method (by matrix operations in a finite number of steps) is recommended in the solution of the scheduling problem.

Bai and Shahidehpour [19] are also concerned about the UC problem and they propose an optimizing algorithm based on the Augmented LR, neighborhood tabu search (TS) and Benders decomposition. While using a neighborhood TS method in the main problem, a two-level iterative method is applied to the sub-problem which refers to Constrained Economic Dispatch (CED) or ECD problem. Starting from the initial UC, a number of candidate units for adjustment are selected by neighborhood search and the sub-optimal solutions are excluded by Benders cuts. Besides, at the sub-problem level, a conventional ECD is solved and by iterative computations between the main problem (for the states of the UC) and the sub-problem, better solutions for the UC and satisfaction of operational constraints are provided with more efficient solutions.

Lu and Shahidehpour [20] evaluate the optimal short term generation scheduling of combined cycle (CC) plants, by the decomposition of the large and complex SCUC problem into a master (unit generation) and sub-problem (includes network constraints). LR is applied to the master problem, which divided into a set of sub-problems for the individual generating units. These sub-problems are solved by DP to get the optimal commitment in all periods. On the other hand, various case studies that refer to the advantages of the CC units are presented in this paper. A CC plant is described to contain several combustion turbines (CT) and steam turbines (ST), while, based on the various

combinations it has, a CC unit can operate at multiple configurations consistent with its operation limits. Their study results show that, CC plants are preferable to other types of thermal generating units for their advantages such as high efficiency, emission friendliness (average CO<sub>2</sub> production per kWh) and fast response (low installation time); however, solving the ECD and the UC of CC units is more difficult than the traditional thermal units since they have multiple operating configurations.

Abdul-Rahman and Shahidehpour [16] present an approach based on the Augmented LR method to solve an extended STGS problem that features ramp rate limits (the rate of change in instantaneous output from a PPT), fuel constraints and emission requirements that are not considered in their previous study. Again, in this research, the problem is studied in two stages, namely the UC and the CED (or the ECD) successively. Optimal Power Flow (OPF) constraints that refer to relevant active power constraints such as transmission, system-area emission and fuel constraints are incorporated in the UC stage. It is claimed that, inclusion of the OPF constraints improves the feasibility of the ECD stage, at the same time a large and appropriate solution space for the ECD is also satisfied. Then, the minimization of the power system operating cost and optimal unit commitment states of the individual units are provided by an adopted dynamic programming model. In the ECD, optimal allocation of the system demand among the generating units that are committed in the UC stage is determined, at the same time a Linear Programming (LP) approach is used for fuel cost minimization.

Uyar, Türkyay and Keleş [21] deploy a new technique named Differential Evolution (DE) (as a nature-inspired heuristic within the Evolutionary Algorithm (EA) approaches) to solve the short-term power generation scheduling (SEPGS) problem. In their approach optimal start-up and shut-down schedules are determined under operational constraints for any given time period, for a group of PPTs. In the research, they deploy an EA for the generation of the on/off schedule, whereas the lambda-iteration technique (an iterative local search technique which is computationally costly) is used for the solution of the ECD problem. They claim that, their proposed approach for applying a DE to the SEPGS achieves a good solution quality, competing with existing methods, without needing the lambda-iteration technique. Besides, a modified version of the DE, called the Binary

Differential Evolution (BDE) has been proposed in their previous studies, corresponding to the binary decision part of the SEPGS. According to the performed experiments on several data sets, comparison of the ES and the BDE algorithms show that the DE performs well on both small and large size problems, while it is able to produce better quality solutions, at the same time not sticking at the local optima not like other ones.

After a successful application of their proposed Augmented Hopfield Neural Network (AHN) to the STGS problem, Walsh and O'Malley [22] present an extended version of the AHN including transmission, ramp-rate and fuel constraints. Since proposed scheduling algorithm contains all constraints and related discrete, continuous and temporal components simultaneously, as expected, it can be applied to the scheduling problem successfully. Application of this method together with the binding constraints (transmission, fuel and ramp-rate) brings feasible solutions to power generation scheduling.

In a generation company, the generation scheduling might be divided into three stages as: long term scheduling (LTS), short term scheduling (STS) and real-time economic dispatch. Marwali and Shahidehpour [23] briefly overviewed these stages and defined the LTS as the representation of fuel allocation and budgeting, emission and production costing including a time horizon of one to two years and where weeks can be considered as intervals. In the LTS problem, maintenance scheduling is used to determine a specific time window for generation maintenance scheduling. Besides, STS refers to the minimization of the operation cost within hourly, daily or weekly horizon, whereas unit commitment requirements, transmission security, hourly demand and fuel limits should be met in this stage. Real-time economic dispatch proposes the optimal dispatch of the committed units in order to meet system requirements in the real-time operations. Relevant to these stage concepts, Marwali and Shahidehpour review the importance of coordination between LTS and STS, and present an approach based on this coordination. They claim that, the maintenance periods or schedules of a generation company for any specified time horizon are determined in the LTS stage, whereas the UC solution for that horizon is provided in the STS stage. Furthermore, the proposed LTS is submitted to the STS module.

Consequently, coordination between the stages to get a feasible solution for generation maintenance scheduling is offered.

Lu and Shahidehpour [24] investigate in their study flexible operation conditions such as CC and fuel-switching (between oil and gas for instance) blending units in the SCUC. Since high gas prices increase their generation cost compared with other types of units, CC units are committed only during peak load periods. If there is a price increase of natural gas in the market, operation of gas-fired CC units and their dispatch are affected. Also, although they have high efficiencies, CC units lose their competitive advantage,. Accordingly, the need for fuel diversity for decreasing the dependence of electric power systems on natural gas is expected to meet the power demand while keeping the environmental constraints within their limits. The study results show the operational flexibility of generating units which have flexible operating conditions including CC and fuel-switching units and potential effects of higher natural gas prices. Also, Lu and Shahidehpour discuss that; as a cleaner fuel option, gas might satisfy the environmental concerns, but if gas-fired units are in the majority of generation resources and generating power potential of coal-fired units are limited, customers might have to pay for higher costs of supplying the load demands.

### **3. THE OPTIMIZATION MODEL AND COMPUTATIONAL ANALYSIS**

As stated before, the aim of this study is to construct an optimization model of the STGS problem to generate a short term dynamic power generation profile for a given set of PPTs of various technical characteristics. By considering both the UC and the ECD problems simultaneously, the STGS problem is modeled aiming at the minimization of the total electricity generating cost, while meeting various related constraints for any specified scheduling period such as a daily or weekly time horizon.

In this chapter, compilation and analysis of the required data for the constructed STGS model are presented. Additionally, the model construction and computational analysis are taken into account.

#### **3.1. Data Compilation and Analysis**

Data necessary for the developed STGS problem is compiled through the technical reports and websites of various generation companies (primarily Turkish companies such as EÜAŞ), the Turkish Regulatory Authority (EPDK), the Ministry of Energy (MENR) and some related nongovernmental organizations (such as WEC-Turkey).

As in other traditional STGS problems, primarily technical information about the PPTs are taken into account rather than the primary resources used in the generation processes. In this regard, power generation capacities, emission characteristics, fuel costs, efficiencies, start-up and shut-down durations of different types of PPTs are examined and compiled. The set of generating facility considered is by no means a comprehensive set related to any real power market. Rather, a hypothetical representative set of PPTs are considered. On the other hand, although it is aimed to reflect the technical characteristics of the Turkish generating facilities, in some cases generic data from international companies or from other markets are used because of the lack of reliable data associated with the Turkish facilities.

### 3.1.1. Power/Energy Demand

As a developing country, Turkey has experienced an increase in her energy supply capacity (see Table 3.1). Right along with this as of 2010, the supply capacity reached to 33,392 MW by an 11.8 % increase, while the energy demand reached to 209 TWh with a 7.9 % increase in just one year [25].

Table 3.1. Energy and Peak Load Demand Development

Year	Energy Supply (MW)	Rate of Increase (%)	Energy Demand (GWh)	Rate of Increase (%)
2000	19,390	2.4	128,276	8.3
2001	19,612	1.1	126,871	-1.1
2002	21,006	7.1	132,553	4.5
2003	21,729	3.4	141,151	6.5
2004	23,485	8.1	150,018	6.3
2005	25,174	7.2	160,794	7.2
2006	27,594	9.6	174,637	8.6
2007	29,249	6.0	190,000	8.8
2008	30,517	4.3	198,085	4.2
2009	29,870	-2.1	194,079	-2
2010	33,392	11.8	209,390	7.9
<b>Average</b>		5.4		5.4

In Turkey, although annual peak load, which is the highest rate of electricity usage at any time in a year, is generally seen in winter, recently some electricity consumption peaks are also seen in summer periods. Although the peak load continuously increases every year, periodic load variability is unsteady related to irregular changes in the minimum load [9]. Relationship between the peak load demand and minimum load (the lowest instant consumption value) is an important factor in electricity consumption in terms of productivity. In any country, the productivity of PPTs is examined by the ratio between the minimum load and the peak load demand. For example, when this ratio (minimum load/peak load) gets higher, the cost of generating electrical energy gets higher either as well, because the generation capacities of the PPTs, which have a significant share in this cost, must increase in proportion to peak load. If electricity were to be used steadily all day long, electricity generation could be done in a much more effective way with using lesser installed capacities.

In this study, the demand profile that the electricity supplied by the selected set of PPTs' addresses is also hypothetical. However, both the periodic total supply/periodic total demand ratios assumed and the variability in the demand profile are selected based on the actual realizations in the Turkish electricity market. This is done by setting the peak periodic demand (of the planning horizon) deployed in the model such that the peak capacity usage ratio (peak periodic demand/aggregate periodic generation capacity) deployed in the model equal to its counterpart in a typical "planning horizon duration" (in a typical summer day in 2011) in the Turkish electricity market [26]. The demand variability (among different periods of the planning horizon) is reflected in the model by setting the individual periodic demands in the model to certain % of the peak demand, where the percentages are obtained from the real situation (i.e. periodic demands in a typical time interval of planning horizon duration in the Turkish electricity sector expressed as percentages of the peak periodic demand in that interval). Accordingly, by considering all these, the demand profile of the planning horizon is determined as displayed in Table 3.2.

Table 3.2. The power demand profile.

<b>Time (Hour)</b>	<b>Demand (MWh)</b>
1	6182
2	5793
3	5539
4	5361
5	5252
6	5053
7	5067
8	5536
9	6638
10	7370
11	7565
12	7793
13	7499
14	7694
15	7803
16	7704
17	7603
18	7265
19	6901
20	6819
21	7007
22	7184
23	7095
24	6837

On the other hand, in order to better observe the effects of minimum up and down time limits clearly, a 48 hour demand profile is prepared and used in the study. As mentioned before, while setting the peak periodic demand deployed in the model and determining the variability of the demand profile, periodic demands in a typical time interval of the planning horizon duration presented by EPDK are used because of the lack of reliable data associated with the Turkish generating facilities [26]. Besides, the peak periodic demand (of this planning horizon) deployed in the model is set such that the peak capacity usage ratio deployed in the model equal to its actual counterpart in a typical time period of the same length (which is taken as 0.72).

### 3.1.2. Power Generation Capacity

According to the official publications by EPDK, total installed capacity in Turkey has reached to 67,869 MW with 984 licenses of production companies and auto producers, while installed capacity in operation has reached to 49,562 MW with 569 individual PPTs, by the end of 2010. In addition, capacity under public control (EÜAŞ, Subsidiaries of EÜAŞ, İHD, BO, BOT arrangements) comprises about two thirds of the total installed capacity, whereas percentages of installed capacity by thermal, hydro and wind resources are observed as 65 %, 32 % and 3 % respectively. On the other hand, as displayed in Figure 3.1 hydroelectric, coal and natural gas PPTs have the main shares of the licensed capacities [25].

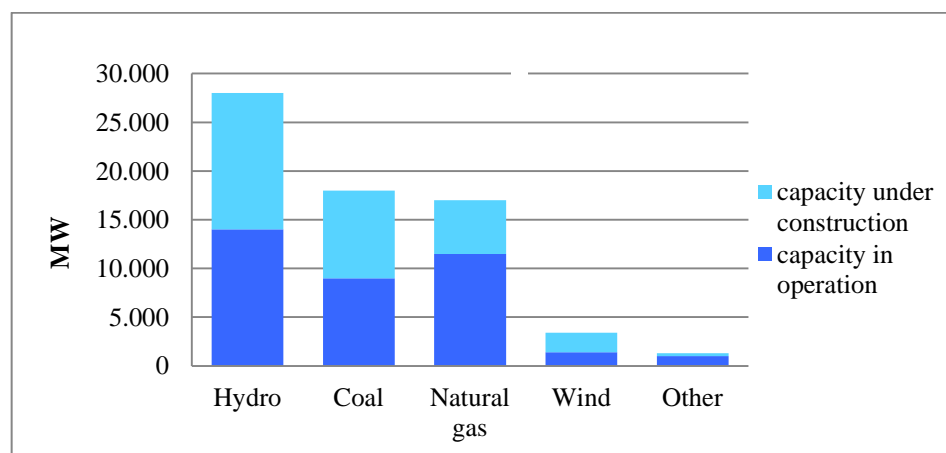


Figure 3.1. Licensed generation capacities in (MW) in terms of fuel types.

In line with the real situation (where coal, natural gas, hydro and wind based generation facilities constitute more than 99 % of the supply side), in this study only coal, natural gas, hydro and wind based power generation facilities are considered in the generation scheduling optimization model. The primary resource shares in terms of electricity generation and installed capacity of Turkey can be seen from Figure 3.2.

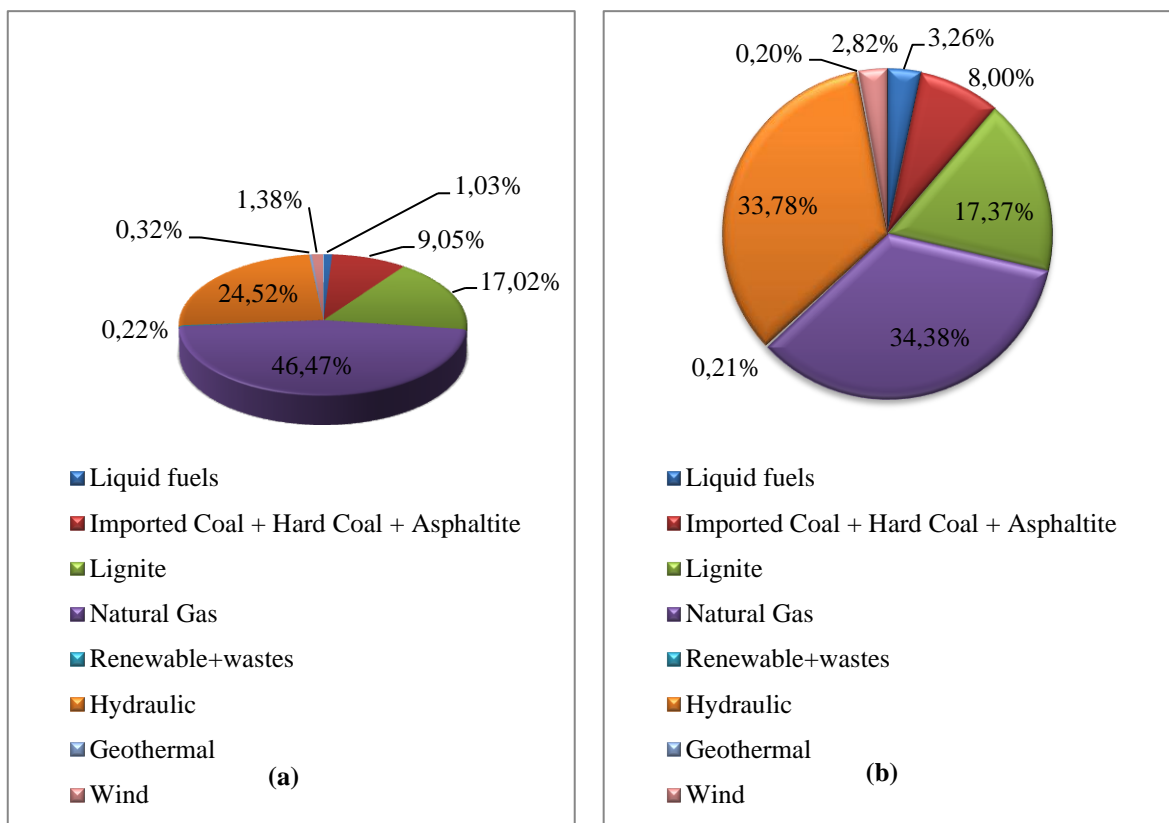


Figure 3.2. (a) Shares of primary sources in Turkey's electricity generation.

(b) Shares of primary resources regarding Turkey's installed capacity.

Minimum and maximum power generation capacities of individual PPTs are associated with the number of generating units they have. The minimum power generation capacity corresponds to the capacity of a single generating unit, while the maximum generation capacity of an individual PPT equals to total capacity of all the generating units it has.

Another important classification regarding installed capacities of PPTs is with respect to plant size. Coal based PPTs are classified as large, medium and small for installed capacities larger than 1000 MW, between 500-1000 MW and less than 500 MW respectively, while natural gas based PPTs are classified as large, medium and small for installed capacities larger than 1000 MW, between 400-1000 MW and less than 400 MW respectively. Moreover, hydropower plants are classified as large, medium and small for installed capacities larger than 1000 MW, between 25-1000 MW and less than 25 MW respectively, whereas wind turbines are classified as large, medium and small for installed capacities larger than 100 MW, between 25-1000 MW and less than 25 MW respectively. In this study a total of 15 PPTs are considered whose resource usage profile (in percentage) and installed capacity profile (in percentage) are in line with the real situation described above. So, selected PPTs are grouped according to their fuel types (primary resources they use) as previously mentioned; five coal plants, four natural gas plants, four hydrothermal plants and two wind turbines and these are categorized in line with their maximum and minimum production capacities, which can be seen in Table 3.4.

Table 3.3. Resource types and production capacities of the generators considered in the model.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Minimum Production Capacity (MWh)</b>	<b>Maximum Production Capacity (MWh)</b>
Coal	1	126	210
	2	252	630
	3	194	600
	4	442	1376
	5	206	1440
Natural Gas	6	60.1	120.2
	7	93	486
	8	200	1350
	9	720	1432
Hydro	10	11.85	23.7
	11	42	81
	12	601.26	2405
	13	180.64	540
Wind	14	0	24.3
	15	0	142.5

### 3.1.3. Start-up and Shut-down Time Requirements

Another set of critical characteristics of a PPT is the time it requires to engage in routine (generation) operation from passive (down) status (which is named as “start-up time”) and the time it requires to enter passive (down) state from 100 % operational (up) state (which is named as “shut-down time”). These parameters are generally quite long for coal-fired plants, while almost negligible for hydraulic and wind plants. Furthermore, most generating units, such as combined cycle plants, have a daily start-stop operating system, which refers to the generating units that start-up two times a day for instance.

On the other hand, data regarding start-up and shut-down times is not easy to compile since most companies consider it as sensitive and private information. However, data on minimum up and down times (of generators) is more readily available and can be deployed as a proxy for the unavailable start-up and shut-down time (the longer the start-up time is, the longer the minimum up time and the longer the shut-down time is, the longer the minimum down time). Installed capacity size and resource type are the main factors influencing these up/down durations. Such a listing of minimum up and down times for all generation types considered in this study is compiled from the related literature and other studies and is displayed in Table 3.4.

Table 3.4. Minimum up and down times by means of fuel resources (hour).

Power Resource Type	PPT	Maximum up time (h)	Minimum down time (h)
Coal	1	1.68	1.68
	2	2.84	1.89
	3	2.7	1.8
	4	7.64	5.09
	5	8.12	5.41
Natural Gas	6	2.71	1.81
	7	2.12	2.12
	8	3.34	3.34
	9	5.32	5.32
Hydro	10	0.21	0.26
	11	0.35	0.42
	12	0.91	0.67
	13	0.69	0.51
Wind	14	0	0
	15	0	0

Minimum up and minimum down times are almost negligible for hydropower plants and negligible for wind plants. Conversely, these parameters are quite long for coal-fired and natural gas-fired PPTs regarding their huge installed capacities and generation process structures.

#### 3.1.4. Emission Coefficient

As discussed in Section 1.1, the most important negative impact of the electricity sector on the environment and global warming is the carbon dioxide emission generated by the PPTs during their power generation processes. On the other hand, different types of PPTs have different emission levels (per unit of electricity produced) depending on their resource usage, technology and capacity. So, generation scheduling while giving consideration to CO<sub>2</sub> emission becomes quite important. On the other hand, data regarding emission per unit of electricity generated is not readily available for specific generators. In this study such data is obtained from ABARE (Australian Bureau of Agricultural and Resource Economics) and ACIL-Tasman (an economic and industrial consulting company providing analysis and advices to clients in Australia and internationally) sources regarding resource and technology type and generation capacity [28]. The emission parameters such obtained are displayed in Table 3.5.

Table 3.5. Emission coefficients/intensities (tons of CO<sub>2</sub>/MWh).

<b>Fuel Type</b>	<b>Pattern</b>	<b>ABARE + DCC</b>	<b>ACIL - Tasman</b>	<b>Study Interval</b>
Coal	1.43	1.20	1.32	1.20-1.43
Natural Gas	0.46	0.49	0.67	0.46-0.67
Wind	0.00			
Hydro	0.00			

As can be seen from Table 3.5, there is considerable variation in emission amounts (probably depending on technology, size and specific resource used). Since that information is not available, in this study specific values from the defined ranges are assigned to the generators considered in the model.

### 3.1.5. Cost Structure

Another important parameter of a PPT is the unit production cost. This parameter should be carefully set in terms of its content such as total fuel cost, total operating and maintenance cost and/or annualized investment cost.

The model developed in this study, features total operation cost per unit production (\$/MWh) as an objective to be minimized. This cost contains both fixed costs and variable operation and maintenance costs (VOM costs include the fuel cost), and levelized capital costs. However, actual cost parameters are generally another type of confidential data. Owing to this, there is not any existing data presented or shared. Alternatively, after some research, a list of estimated levelized costs of the generation resources associated with the plant and technology types has been compiled and by considering these cost values a new cost structure is determined [29]. Estimated total system levelized costs per MWh (TSLC - net cost to install an energy system divided by expected life-time energy output) are displayed in Table 3.6 which include levelized capital cost (LCC), fixed operation and maintenance (FOM) cost, variable operation and maintenance (VOM) cost (contains fuel cost-FC) and the transmission investments. In this study, TSLC values are referenced for the determination of total cost (C) which is considered as the total operation cost per unit production and TSLC values are taken into account by grouping, according to the plant types.

In order to evaluate the total cost of each generator  $i$ ,  $C_i$ , firstly, capacity factors (CF) of the selected PPTs are obtained according to the types of PPTs and related technologies. CFs, which are defined according to Equation 3.1, feature the ratio of net annual production divided by the maximum possible production. Generic CFs for some power generation facilities as obtained from the literature [29] are also given in Table 3.6.

Table 3.6. Estimated Levelized Cost of New Generation Resources.

Plant Type	Capacity Factor (%)	U.S. Average Levelized Costs (2008 \$/MWh) for Plants Entering Service in 2016				
		Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System Levelized Cost
Conventional Coal	85	69.2	3.8	23.9	3.6	100.4
Advanced Coal	85	81.2	5.3	20.4	3.6	110.5
Natural Gas-fired	85	92.6	6.3	26.4	3.9	129.3
Conventional Combined	87	22.9	1.7	54.9	3.6	83.1
Advanced Combined	87	22.4	1.6	51.7	3.6	79.3
Advanced CC with CCS	87	43.8	2.7	63.0	3.8	113.3
Conventional	30	41.1	4.7	82.9	10.8	139.5
Advanced Combustion	30	38.5	4.1	70.0	10.8	123.5
Advanced Nuclear	90	94.9	11.7	9.4	3.0	119.0
Wind	34.4	130.5	10.4	0.0	8.4	149.3
Wind-Offshore	39.3	159.9	23.8	0.0	7.4	191.1
Solar PV	21.7	376.8	6.4	0.0	13.0	396.1
Solar Thermal	31.2	224.4	21.8	0.0	10.4	256.6
Geothermal	90	88	22.9	0.0	4.8	115.7
Biomass	83	73.3	9.1	24.9	3.8	111.0
Hydro	51.4	103.7	3.5	7.1	5.7	119.9

On the other hand, assumed CFs of the plants considered in the study are selected from the ranges displayed in Table 3.7. Since the actual capacity factor information is incomplete, by taking these intervals as reference, an approximation method is used in order to get reasonable CFs for the study set (named as  $CF_i$ ). These ranges correspond to actual data obtained from Turkish generation facilities as reported in [30].

Table 3.7. Capacity factors of PPTs in Turkey in terms of their types.

Types of PPT	CF %
Coal	60-85
Natural gas combined cycle	60-80
Natural gas turbine	20-30
Hydro plant with dam	30-50
Hydro plant with run of river	50-80
Wind	15-35

After the determination of  $CF_i$ 's for the study set, the  $C_i$ s are evaluated based on Equation 3.2. The  $TSLC_k$  (\$/MWh) and the  $CF_k$  values chosen for the specific plant type  $k$  from the list displayed in Table 3.6 are also deployed in Equation 3.2. In this equation the numerator corresponds to a levelized capital cost value per MWh if the facility were in operation continuously, while the denominator adjusts this value according to the assumed capacity factor.

$$CF = \frac{P_{net}}{P_{IC} * 24 * 365} \quad (3.1)$$

$$C_i = (TSLC_k * CF_k) / CF_i' \quad (3.2)$$

Related parameters used in the equations listed above:

$P_{net}$  : annual net electricity generation amount;

$P_{IC}$  : amount of electricity generated in permanent power capacity (installed capacity);

$LT$  : life time;

$CF_i'$  : assumed capacity factor (of the selected PPT  $i$  in this study);

As mentioned, parameters  $C_i$ , deployed in the STGS optimization model in the following sections, includes fixed and variable operation and maintenance costs, (VOM cost contains fuel cost) and levelized capital cost regarding the TSLCs presented in the Annual Energy Outlook 2010, which presents long-term projections of energy supply, demand, and prices [29].

Final status of the assumed capacity factors and estimated total costs for the entire system are displayed in Table 3.8.

Table 3.8. Determined capacity factors and system costs.

Plant & Technology Type - $k$	PPT - $i$	Total System Levelized Cost (TSLC <sub>k</sub> - \$/MWh)	Capacity Factor (CF <sub>k</sub> - %)	Assumed Capacity Factor (CF' <sub>i</sub> - %)	Total Cost (C <sub>i</sub> - \$/MWh)
Conventional Coal	1	100.40	85	81	105.36
	2	100.40	85	53	161.02
	3	100.40	85	60	142.23
	4	100.40	85	44	193.95
	5	100.40	85	72	118.53
Natural Gas-Fired: Conventional Combined Cycle	6	83.10	87	72	100.41
	7	83.10	87	65	111.23
	8	83.10	87	78	92.69
	9	83.10	87	85	85.06
Hydro	10	119.90	51.4	70	88.04
	11	119.90	51.4	45	136.95
	12	119.90	51.4	50	123.26
	13	119.90	51.4	35	176.08
Wind	14	149.30	34.4	30	171.20
	15	149.30	34.4	25	205.44

### 3.2. The Short Term Power Generation Scheduling Problem

During a scheduling period, selection of the individual PPTs when to be in operation and for how long are decided in the UC subproblem solution. The system demand and other significant constraints are met by those committed generated units. Accordingly, optimal allocation of the power demand among the committed and operating units is performed in the ECD subproblem solution, where power balance and unit operation limits are also satisfied. Combining these two parts into one main model brings a clear, step by step, and more applicable model structure to the STGS problem in real-life.

#### 3.2.1. The Mixed Integer Nonlinear Programming Model

Being one of the most flexible modeling approaches, a Mixed Integer Nonlinear Programming (MINLP) formulation is widely preferred in various applications in many industrial and service sectors. Problems in portfolio selection, process flows, batch

processing and optimal design of gas or water transmission networks are included in these sectors [31]. Generally, both discrete decisions and non-linear relationships are involved in optimization problems like the STGS and having considerable effects on feasibility and optimality of the solutions. On the other hand, combination of the optimization difficulty over large discrete variable sets with challenging usage of non-linear functions (constraints) make most MINLP problems NP complete and computationally burdensome to solve for large problems.

Although MINLP problems may be difficult to solve regarding their combinatorial nature and non-convex or convex nonlinear programs structure, MINLP is a widely used approach in solving STGS problems, which is also preferred in this study. Accordingly, the STGS problem is not only a MINLP problem, but also it is a problem which merges both UC and ECD problems and related to that it has a complex structure with respect to the non-linearity and combinatorial form.

The needs in various areas have forced research and developments in solver technology of the MINLP, particularly in algorithms to overcome large-scale, highly combinatorial and nonlinear problems [31]. However, practical implementation of the MINLP concept is still problematic regarding computation power and time needs. In addition, specification of the appropriate algorithmic tolerances, memory limitations and determination of the default options of the selected suitable solver can be taxing and should be carefully considered in the solver selection. In this study, GAMS is used as a reliable and large scale package, whereas BARON is chosen as the solver that uses convex relaxations in a B&B algorithmic framework.

### **3.2.2. Model Structure**

As mentioned, the STGS problem involves the scheduling of the individual generation units in a power system in which total operating cost of the system is to be minimized and related customary constraints are satisfied. The main aim of the STGS model is to minimize the total operation cost of the entire system among the determined power plants that are committed to be in operation, while this model satisfies the customer

load demands at the same time. Even though transmission line requirements, fuel cost limits (the cost needed for the resource of the generating units), ramp rates and spinning reserves (the extra/unused generating capacity provided by devices that are synchronized to the network) make power generation scheduling process much more complex in terms of various constraints and parameters, they are sometimes preferred to be used in unit generation schedules, and in the STGS problems, as well. If the optimization is performed regarding the power load balance, system emission limits, minimum up and down times and generation limits, the resulting total cost of the associated PPTs have the potential to be significantly improved as a result of the short term scheduling optimization.

In this study, in order to represent the above discussed issues associated with the STGS problem, the following MINLP optimization model is developed. The main sets and parameters of the STGS model are described in detail and are listed as follows.

- $N = \{1, 2, \dots, n\}$  is the set of PPTs;
- $T = \{1, \dots, 48\}$  is the set of scheduling time periods;
- $S = \{(i, t) : i \in N, t \in T\}$  is the set of (PPT, period) pairs in the scheduling;
- $C_i$  is the total operation cost of PPT  $i$  per unit production;
- $D_t$  is the total load (energy) demand of the system at time  $t$ ;
- $P_i^{min}$  and  $P_i^{max}$  are the minimum and the maximum production capacities of PPT  $i$  respectively (electrical power generation limits);
- $E_i$  is the greenhouse gas (CO<sub>2</sub>) emission level for one unit energy that is generated from PPT  $i$ ;
- $T_i^{up}$  and  $T_i^{down}$  are up and down time limits of PPT  $i$  successively;
- $EMN$  is the total system greenhouse gas (CO<sub>2</sub>) emission limitation in the scheduling horizon.

The decision variables of the STGS model are as follows:

- $UC(i, t)$  is the commitment state of PPT  $i$  at time  $t$ ; which is set to one if and only if PPT  $i$  is up (ready for generating electricity) at hour  $t$  and zero otherwise (i.e. down-not generating electricity). As such they are all binary variables.
- $P(i, t)$  is the power (energy) output of PPT  $i$  within the scheduling period  $t$ ; as such they are all continuous variables.
- $X_{up}(i, t)$  and  $X_{down}(i, t)$  are the times that PPT  $i$  has been up and down respectively at hour  $t$ ; as such they are all integer variables.

The full optimization model is as follows:

- (i) The objective function is formulated as follows representing the minimization of the total cost of the entire system in the scheduling horizon.

$$\text{Minimize } z = \sum_{i=1}^N \sum_{t=1}^T P(i, t) * C_i \quad (3.4)$$

Subjected to prevailing constraints;

- (ii) Power balance of the entire system is provided by:

$$\sum_{i=1}^N UC(i, t) * P(i, t) \geq D_t \quad \forall t \quad (3.5)$$

- (iii) Power generation limits are described as:

$$P_{i, \min} * UC(i, t) \leq P(i, t) \leq P_{i, \max} * UC(i, t) \quad \forall i, t \quad (3.6)$$

- (iv) Total system greenhouse gas (CO<sub>2</sub>) emission is limited by:

$$\sum_{t=1}^T \sum_{i=1}^N P(i,t) * E_i \leq EMN \quad (3.7)$$

(v) Minimum up and minimum down times are controlled by:

$$(X_i^{up}(i,t-1) - T_i^{up}) * (UC(i,t-1) - UC(i,t)) \geq 0 \quad \forall i \in N, t \in T; t=2,\dots,48 \quad (3.8)$$

$$(X_i^{down}(i,t-1) - T_i^{down}) * (UC(i,t) - UC(i,t-1)) \geq 0 \quad \forall i \in N, t \in T; t=2,\dots,48 \quad (3.9)$$

(vi) Where,

$$X_i^{up}(i,t) = UC(i,t) * (X_i^{up}(i,t-1) + 1) \quad \forall i \in N, t \in T; t=2,\dots,48 \quad (3.10)$$

$$X_i^{down}(i,t) = (1 - UC(i,t)) * (X_i^{down}(i,t-1) + 1) \quad \forall i \in N, t \in T; t=2,\dots,48 \quad (3.11)$$

(vi) Starting conditions of the previous constraints are defined as:

$$X_i^{up}(i,1) = UC(i,1) \quad \forall i \in N \quad (3.12)$$

$$X_i^{down}(i,1) = 1 - UC(i,1) \quad \forall i \in N \quad (3.13)$$

$$UC(i,t) \boxtimes = \begin{cases} 1, & \text{if PPT } i \text{ is opened (up) at time } t \\ 0, & \text{otherwise} \end{cases} \quad \forall i \in N, t \in T \quad (3.14)$$

$$P(i,t) \geq 0 \quad \forall i \in N, t \in T \quad (3.15)$$

$$X_{up}(i,t) \geq 0, X_{down}(i,t) \geq 0 \quad \forall i \in N, t \in T \quad (3.16)$$

By the objective function defined in Equation 3.4, minimization of the total system cost is provided. Total power generated in the system is determined and balanced hourly against the hourly demand set as developed and discussed on page 31 in the constraint set (3.5). The unit commitment states associated with the system power generation and demand satisfaction are taken into consideration in constraint set (3.6). Besides, constraint (3.6) assures that the amount of generated electrical power should be within the specified generation limits.

The total system emission is restricted with respect to the specified system emission limit and this can be seen from the Equation 3.7.

Constraint sets (3.8) and (3.9) administer minimum up and down time requirements. Accordingly, if the time, which PPT  $i$  has been up at time  $t-1$  ( $X_{up}(i, t-1)$ ) is less than the defined minimum up time of PPT  $i$  ( $T_i^{up}$ ), the unit commitment state of hour  $t$  should be at least as large as the state of hour  $t-1$ . But when at time  $t-1$ ,  $T_i^{up}$  is less than  $X_{up}(i, t-1)$ , then PPT  $i$  in following hour  $t$ , can be up or down. On the other hand, if the time, which PPT  $i$  has been down at hour  $t-1$  ( $X_{down}(i, t-1)$ ), is less than the defined minimum down time of PPT  $i$  ( $T_i^{down}$ ), then the unit commitment state of hour  $t$  should equal to zero ( $UC(i, t)=0$ ). However, when at time  $t-1$ ,  $T_i^{down}$  is less than  $X_{down}(i, t-1)$ , then PPT  $i$  in following hour  $t$  can be up or down.

Since the constraint sets (3.8), (3.9), (3.10) and (3.11) do not cover period  $t=1$ , constraint sets 3.12 and 3.13 become necessary to define the relationship between  $X_{up}(i, t)$ ,  $X_{down}(i, t)$  and  $UC(i, t)$  variables in the first period.

Non-negativity constraint sets of the model are presented in (3.15) and (3.16). On the other hand, in this model, there is the necessity that unit commitment variables are defined as integers. So, constraint (3.14) is situated as integrality constraint in the STGS model, which shows the commitment status of the PPTs.

### 3.2.3. Assumptions of the model

A number of assumptions are used in order to simplify and rationalize the modeling of the STGS problem and make it more efficient. Assumptions related with the adapted model in this study are listed as following:

- The STGS model is presented for a two-day (48 hours) time horizon in order to better observe the effects of minimum up and down time requirements by which more reasonable power generation schedules can be defined.
- Ramp up or ramp down rates (the time it takes to reach full operational status and to full stoppage) are not considered; minimum up and down times are deployed as proxies for these parameters.
- As flows in transmission lines are not included in this model, the transmission flow capacities are not considered.
- System spinning reserve, the unused (extra) generating capacity provided by devices that are synchronized to the network, are able to increase the power output of the PPTs [32]. Systems operating reserve is defined as the generating capacity available within a short time interval, in order to meet the sudden demand increase in case a PPT goes down or there is another demand growth in terms of the existing supply. Although they are included in some scheduling problems, neither the spinning reserve nor the systems operating reserve are considered in this model [33].
- Instead of considering area emission limits, the system emission limits are taken into account due to the existence of only a single area where only CO<sub>2</sub> is stemmed out.
- Despite the aim of the total cost minimization, start-up costs are not considered in the objective function.
- Due to the lack of data availability, some approximations (based on the reference data and observations) are made as explained in Sections 3.1.5, 3.1.3 and 3.1.4.
- The described model is run with various solvers of GAMS, among them, BARON with stopping condition adjusted to 2 % gap value (instead of the standard 10 %) showed the best performance.

Consequently, these assumptions associated with the STGS model listed above simplify the formulation of the STGS problem and give a clear adaptation of the corresponding MINLP model.

## 4. SCENARIO ANALYSIS AND RESULTS

In this study, a wide variety of scenarios are formed by changing the values of one or more key parameters. Then the model is solved under each scenario setting and the outputs of the scenarios are compared. The comparative analysis of the scenario results are discussed in this chapter.

### 4.1. Base Scenario

The main parameter values of the STGS model are displayed as a collective list in Table 4.1. The model is run several times with this data set, just varying the maximum emission limit parameter in order to track the impacts of emission relaxation and/or tightening on other system performance indicators and feasibility in the reference case.

Table 4.1. The data set of the base scenario.

Power Resource Type	PPT	Total Cost (\$/MWh)	Emission Coefficient (tons/MWh)	Minimum Production Capacity (MWh)	Maximum Production Capacity (MWh)	Minimum Up Time (hr)	Minimum Down Time (hr)
Coal	1	105.36	1.26	126	210	1.68	1.68
	2	161.02	1.20	252	630	2.84	1.89
	3	142.23	1.30	194	600	2.70	1.80
	4	193.95	1.40	442	1376	7.64	5.09
	5	118.53	1.22	206	1440	8.12	5.41
Natural Gas	6	100.41	0.51	60.1	120.2	2.71	1.81
	7	111.23	0.56	93	486	2.12	2.12
	8	92.69	0.46	200	1350	3.34	3.34
	9	85.06	0.65	720	1432	5.32	5.32
Hydro	10	88.04	0	11.85	23.7	0.21	0.26
	11	136.95	0	42	81	0.35	0.42
	12	123.26	0	601.26	2405	0.91	0.67
	13	176.08	0	180.64	540	0.69	0.51
Wind	14	171.20	0	0	24.3	0	0
	15	205.44	0	0	142.5	0	0
<b>Hourly Demand Load (MW)</b>							
1	2	3	4	5	6	7	8
6182	5793	5539	5361	5252	5053	5067	5536
9	10	11	12	13	14	15	16
6638	7370	7565	7793	7499	7694	7803	7704
17	18	19	20	21	22	23	24
7603	7265	6901	6819	7007	7184	7095	6837

Some other key parameters of the optimization model developed are displayed in Table 4.2.

Table 4.2. Emission coefficients and cost parameters of the PPT groups used in this study.

<b>Power Resource Type</b>	<b>Emission Coefficient (tons/MWh)</b>	<b>Total Cost (\$/MWh)</b>
Coal	1.28	144.22
Natural Gas	0.51	101.44
Hydro	0.00	131.08
Wind	0.00	188.32

#### 4.1.1. The Reference Case

Regarding the investigation of various emission limits, the lowest feasible maximum emission limit is determined as 110,000 tons of CO<sub>2</sub>. The optimal solution in terms of the unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs during the planning horizon under this setting of the emission limit is displayed in Table 4.3 and Table 4.4. In these tables, value “1” corresponds to the “up” state of the related PPT at that time period, whereas the blanks (value zero) stand for the “down” times. Alternatively, the optimal solution of the reference case for the base scenario including the main and detailed results is obtained as displayed respectively in Table 4.5 and Table 4.6.

As can be seen in Table 4.3 and Table 4.4, there is not a significant change in the “on/off” behavior of individual generating units during the scheduling horizon. One observation is that, less costly/more efficient coal based individual generation units have long and stable “up” time windows compared to the other more costly plants. Additionally, wind turbines which have shorter up/down time durations display more frequent state changes (from “up” to “down” or vice-versa).

Table 4.3. The optimal schedule of the reference case for the base scenario in terms of unit commitment and power generation.

UC (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1									1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
2																									
3																									
4																									
5										1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
7	1	1	1						1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
8	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
9	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
13	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
14	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
15	1					1			1	1	1	1	1	1	1	1	1		1	1	1				
P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1									126,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	126,00	126,00	196,30	210,00	210,00	168,80
2																									
3																									
4																									
5										555,30	750,30	978,30	684,30	879,30	988,30	889,30	788,30	592,80	206,00	206,00	206,00	511,80	422,80	206,00	
6	120,20	120,20	120,20	120,20	108,00	60,10	60,10	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	93,00	93,00	93,00						486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1155,80	901,80	816,80	720,00	720,00	720,00	991,80	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13	540,00	540,00	540,00	540,00	540,00	388,90	402,90	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15	112,80								49,80	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50		106,80	24,80	142,50				

Table 4.3. The optimal schedule of the reference case for the base scenario in terms of unit commitment and power generation (continued).

UC (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	1								1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2																								
3																								
4																								
5										1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
7	1								1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
9	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
13	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
14	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
15									1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	126,00								126,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	126,00	126,00	196,30	210,00	210,00	126,00
2																								
3																								
4																								
5										555,30	750,30	978,30	684,30	879,30	988,30	889,30	788,30	450,30	206,00	206,00	206,00	369,30	280,30	206,00
6	120,20	120,20	120,20	120,20	108,00	60,10	60,10	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	93,00								437,49	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	474,38	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1418,80	1248,80	994,80	816,80	720,00	720,00	720,00	991,80	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13	540,00	540,00	540,00	540,00	540,00	388,90	402,90	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15									98,31	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	118,42	24,80	142,50	142,50	142,50	42,80





First of all, it is noted that supply over demand ratio in each scenario equals to one as expected. Furthermore, total utilization rate corresponding to the ratio of total power generated and total maximum power generation capacity (321,120 MWh/521,314 MWh) is observed as 62 %. The total cost at the end of the entire scheduling horizon is 36,465,369 \$/MWh as displayed in Table 4.5.

Table 4.5. The main system results of the reference case.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.62
<b>Total Power Generation (MWh)</b>	321,120
<b>Total Cost (\$/MWh)</b>	36,465,369
<b>Total Emission (tons)</b>	110,000

As can be seen from Table 4.6, with the feature of not discharging any CO<sub>2</sub> emissions, hydropower plants have the highest percentage (100 %) in average up hours and in utilization rates among all groups under this setting. Hydropower plants are followed by natural gas-fired PPTs (having 94 % percentage in average up hours and 90 % percentage in utilization rates) since they have the minimum total cost value on average. Wind turbines are up on average 81 % of the time and have 59 % in utilization rates, even though their share in total production is only 1 %. Wind turbines do not have any minimum up or down time limitations which facilitate their high up time and utilization rates even though their costs are relatively high. On the other hand, because of their high emission coefficients (1.28 tons/MWh on average) and high costs (144 \$/MWh on average), coal-fired PPT group is observed to be the last with respect to up time percentage and utilization rates, as can be seen in Table 4.6.

Besides the discussed reference case, the model is solved under the following more relaxed settings of the maximum emission limit, in order to better observe the effects of the maximum emission limit on the system performance. The optimal solutions of all these cases in terms of unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs within the planning horizon are displayed in Table A.1 – Table A.3.

Table 4.6. The detailed system results of the reference case.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	0.69	0.26	0.07	0.61	0.11
	2	0.00			0.00	
	3	0.00			0.00	
	4	0.00			0.00	
	5	0.63			0.25	
Natural Gas	6	1.00	0.94	0.46	0.95	0.90
	7	0.75			0.68	
	8	1.00			1.00	
	9	1.00			0.89	
Hydro	10	1.00	1.00	0.45	1.00	1.00
	11	1.00			1.00	
	12	1.00			1.00	
	13	1.00			0.98	
Wind	14	1.00	0.81	0.01	1.00	0.59
	15	0.63			0.52	

In these cases the total power generation still equals to the system power demand. Also, as the system power demand does not change, the total power generation and total utilization rates of the entire system remain unchanged.

#### 4.1.2. Case 1 (EMS: 150,000)

In this case of the base scenario, the maximum emission limit is adjusted to 150,000 tons of CO<sub>2</sub>, while other data parameters are kept the same as in the reference case. The optimal solution of this case is displayed in Table 4.7 and Table 4.8. As can be seen from Table 4.7, there is a significant decrease in costs as the system takes advantage of the relaxed emission requirements and utilizes higher emission/lower cost generation opportunities.

Table 4.7. The main system results of case 1 for the base scenario.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.62
<b>Total Power Generation (MWh)</b>	321,120
<b>Total Cost (\$/MWh)</b>	34,316,597
<b>Total Emission (tons)</b>	150,000

As can be seen from the results in Table 4.8, the total cost of the entire system decreases associated with the considerable decrease in the utilization rate of the wind turbines compared to the reference case. Since they have the highest total costs on average, the utilization rate of the wind turbines is reduced to 1 % (from the original 59 %). On the other hand, associated with the relaxation in the amount of total emission, utilization rate of coal-fired plants (which feature, on average, the high emission coefficients) rises. Additionally, because of having the second highest emission coefficients on average, a significant increase in the utilization rate of natural gas-fired PPTs is also observed.

Table 4.8. The detailed system results of case 1 for the base scenario.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0.75	0.40	0.15	0.72	0.24
	2	0.00			0.00	
	3	0.40			0.14	
	4	0.00			0.00	
	5	0.85			0.54	
Natural Gas	6	1.00	1.00	0.51	1.00	1.00
	7	1.00			1.00	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	1.00	0.63	0.34	1.00	0.75
	11	0.50			0.39	
	12	1.00			0.93	
	13	0.00			0.00	
Wind	14	0.67	0.63	0.00	0.00	0.01
	15	0.58			0.01	

When individual coal based generation facilities are investigated, it can be observed that, as emission restriction is relaxed, the more efficient (or less costly) units have their utilizations increased, while the less efficient (more costly) units start getting deployed when the efficient ones reach their full capacity. Similar observation can also be made for other types of generation facilities.

On the other hand, as can be seen in Table A.1, there is a significant change in up/down time series/frequencies of individual generating units compared to the reference case. For example, coal-fired PPTs are deployed to be up in the peak demand hours and accordingly their up/down time frequency increases. Besides, natural gas-fired PPTs are

generally up at times in which they were down in the reference case. Conversely, hydropower plants and wind turbines are now in the “down” state at these hours. Also, a considerable state change frequency (from up to down or vice versa) of individual wind turbines and hydropower generating units is seen related to their up/down time series.

#### 4.1.3. Case 2 (EMS: 190,000)

In this case, the maximum emission limit is further relaxed to 190,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table 4.9 and Table 4.10.

According to the results in Table 4.9, the amount of total emission rises to 189,030 tons of CO<sub>2</sub> in this case. In other words, when the maximum emission limit is increased, more generation units having higher emission coefficients are deployed to be up in the production process. Accordingly, since these PPTs have less costs per production compared to others having less emission coefficients, the total system cost further decreases.

Table 4.9. The main system results of case 2.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.62
<b>Total Power Generation (MWh)</b>	321,120
<b>Total Cost (\$/MWh)</b>	34,130,564
<b>Total Emission (tons)</b>	189,030

As can be seen from the results in Table 4.10, in parallel to the developments in the previous subsections, utilization rates of the coal-fired and natural gas-fired PPTs are further increased, whereas, the rates of hydropower plants and wind turbines are decreased (due to their lower emission coefficients and higher total costs).

When individual generation facilities are investigated, it is observed that the trends identified in the previous sub-section continue.

Table 4.10. The detailed system results of case 2.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	1.00	0.48	0.25	1.00	0.39
	2	0.00			0.00	
	3	0.40			0.14	
	4	0.00			0.00	
	5	1.00			0.96	
Natural Gas	6	1.00	1.00	0.51	1.00	1.00
	7	1.00			1.00	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	1.00	0.55	0.24	1.00	0.53
	11	0.27			0.21	
	12	0.94			0.66	
	13	0.00			0.00	
Wind	14	0.73	0.75	0.00	0.05	0.03
	15	0.77			0.02	

In other words, as emission restrictions are relaxed, shares of efficient/less costly coal and natural gas generation facilities expand, while shares of higher costly hydro and wind facilities shrink.

#### 4.1.4. Case 3 (EMS: 220,000)

In this case, the maximum emission limit is relaxed to 220,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table 4.11 and Table 4.12. As can be seen from Table 4.11, this additional relaxation does not bring much benefit since total emission remain at 190,000 level, while total costs are not better than those of the previous case (i.e. under 190,000 ton emission restrictions). The primary reason of this development is the saturation of the market. In other words, the system is able to take full advantage of the less costly (but higher emission) generation alternatives under the 190,000 ton limit; therefore relaxing this limit to 220,000 ton does not bring additional benefit.

Table 4.11. The main system results of case 3.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.62
<b>Total Power Generation (MWh)</b>	321,120
<b>Total Cost (\$/MWh)</b>	34,184,554
<b>Total Emission (tons)</b>	190,580

In summary, according to the optimal solutions of the base scenario; the total system costs from the reference case, to case 3 has a declining structure; whereas the amount of total emission has an increasing trend. Regarding individual generation facilities, the relative efficiency/cost of generation facilities within a generation group plays an important role in their utilization rate.

Table 4.12. The detailed system results of case 3.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1.00	0.58	0.25	1.00	0.40
	2	0.10			0.00	
	3	0.79			0.24	
	4	0.00			0.00	
	5	1.00			0.93	
Natural Gas	6	1.00	1.00	0.51	1.00	1.00
	7	1.00			1.00	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	0.85	0.55	0.24	1.00	0.53
	11	0.40			0.18	
	12	0.94			0.65	
	13	0.00			0.00	
Wind	14	0.71	0.66	0.00	0.02	0.01
	15	0.60			0.00	

In order to better observe the effects of increasing customer load demand, the changes in the total cost per production and the modifications in the minimum up and down time duration limits; the model is run under different types of scenarios. So, comparative analyses of the scenario results are presented and discussed in the following sections.

## 4.2. Demand Scenarios

In order to better observe the effects of power demand change, three basic demand scenarios are formed through various types of demand modifications. Firstly, in order to see the impacts of demand increase, demand values of the base scenario are increased by 20 % and 30 % in Demand Scenario 1 and Demand Scenario 2, respectively. Then, in order to see the impacts of demand fluctuations, the demand variation between the time periods in the base scenario is increased (e.g. power demands between 5000-5900 MW are decreased by 20 %, and demands between 7000-7803 MW are increased by 20 %, while the overall demand is kept at the level of the reference scenario) in Demand Scenario 3. The adjusted demand data are displayed in Table 4.13. Although the hourly power demand values are given in this table, a two day planning horizon is taken into account. On the other hand, cases formed related to these demand scenarios also feature the change effect of the total system emissions. So, both the demand scenarios and related cases are discussed in detail, in the following sub-sections.

Table 4.13. The revised hourly power demand values deployed in the demand scenarios.

Hours	Power Demand (MWh)			
	Base Scenario	Demand Scenario 1	Demand Scenario 2	Demand Scenario 3
1	6.182	7.418	8.036	4.837
2	5.793	6.951	7.530	3.476
3	5.539	6.647	7.201	3.323
4	5.361	6.433	6.969	3.216
5	5.252	6.302	6.827	3.151
6	5.053	6.064	6.569	3.032
7	5.067	6.080	6.586	3.040
8	5.536	6.644	7.197	3.322
9	6.638	7.965	8.629	5.543
10	7.370	8.844	9.581	8.844
11	7.565	9.078	9.835	9.078
12	7.793	9.351	10.130	9.351
13	7.499	8.999	9.749	8.999
14	7.694	9.232	10.002	9.232
15	7.803	9.363	10.143	9.363
16	7.704	9.245	10.015	9.245
17	7.603	9.124	9.884	9.124
18	7.265	8.718	9.445	8.718
19	6.901	8.282	8.972	7.592
20	6.819	8.183	8.865	7.501
21	7.007	8.409	9.109	7.708
22	7.184	8.621	9.339	7.902
23	7.095	8.514	9.223	7.804
24	6.837	8.204	8.888	7.179

#### 4.2.1. Demand Scenario 1

Regarding the investigation of various emission limits, the lowest feasible maximum emission limit is determined as 190,000 tons of CO<sub>2</sub> in demand scenario 1. The optimal solution of this scenario is displayed in Table 4.14 and Table 4.15.

According to the results in Table 4.14, since the total power generation equals to the system power demand, the ratio of supply and demand is still equal to one as was the case in the base scenario. But, associated with the increased power demand, the amount of total power generation in demand scenario 1 rises and the total utilization rate of the entire system increases from 62 % to 74 %.

Table 4.14. The main results of demand scenario 1.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.74
<b>Total Power Generation (MWh)</b>	385,342
<b>Total Cost (\$/MWh)</b>	43,787,591
<b>Total Emission (tons)</b>	190,000

When the system power demand is increased, in parallel to the overall system utilization rate, the utilization rates of the PPT groups also increase. As can be seen from Table 4.15, since they have the minimum total costs on average (101 \$/MWh), the natural gas PPT group carries on power generation at full capacity. Accordingly, natural gas-fired PPTs have the highest percentage (100 %) in average up hours and in total production (42 %) among all groups. Natural gas-fired PPTs are followed by hydropower plants (having 95 % each in average up hours and in utilization rates of the groups) since they have the second lowest total cost value in average. Wind turbines are up on average 65 % of the time and have 38 % utilization rate, even though their share in total production is only 1 %. Wind turbines do not have any minimum up or down time limitations which facilitate their high up time and utilization rates even though their costs are relatively high.

When individual generation facilities are investigated, it can be observed that, as the system power demand is increased, the more efficient (or less costly) units have their

utilizations increased, while the less efficient (more costly) units start getting deployed when the efficient ones reach their full capacity.

Table 4.15. The detailed results of demand scenario 1.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	0.96	0.58	0.21	0.92	0.40
	2	0.29			0.17	
	3	0.31			0.49	
	4	0.31			0.00	
	5	1.00			0.75	
Natural Gas	6	1.00	1.00	0.42	1.00	1.00
	7	1.00			0.97	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	1.00	0.95	0.36	1.00	0.95
	11	1.00			1.00	
	12	1.00			1.00	
	13	0.81			0.74	
Wind	14	0.73	0.65	0.01	0.63	0.38
	15	0.56			0.34	

Compared to the second case of the base scenario, there is a significant increase in the total cost of the entire system, associated with the considerable increase in the utilization rates of all PPT groups. On the other hand, when the optimal schedule of the individual generation facilities are investigated, it is observed that, as the system utilizes the more efficient (or less costly) units, there is a significant change in on off behavior of individual generating units during the scheduling horizon.

As can be seen in Table A.4, along with the power demand increase, individual low cost coal based generating units are deployed to be up in the peak demand hours and accordingly their up/down time frequency increases compared to the reference case. Moreover, hydropower plants are deployed to be up at times in which they are down in the reference case. However, high cost hydropower plants are no longer deployed in the second day of the schedule. Although, most of the wind turbines are down in the reference case, they are deployed to be up at several hours (especially during the peak demand

hours). So, a considerable on/off state change is observed in the operation of individual wind turbines.

The detailed solutions of all demand scenarios in terms of  $UC(i,t)$ ,  $P(i,t)$  and  $X_{up}(i,t)$ ,  $X_{down}(i,t)$  of the PPTs are given in Appendix A.

#### 4.2.2. Demand Scenario 2

Regarding the investigation of various emission limits, the lowest feasible maximum emission limit is determined as 220,000 tons of CO<sub>2</sub> in demand scenario 2. The optimal solution obtained for this scenario is displayed in Table 4.16 and Table 4.17.

According to the results in Table 4.16, since the total power generation equals to the system power demand, the ratio of supply and demand is still equal to one as was the case in demand scenario 1. But, associated with the increased power demand, the amount of total power generation in demand scenario 2 rises and the total utilization rate of the entire system increases from 62 % to 80 %.

Table 4.16. The main results of demand scenario 2.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.80
<b>Total Power Generation (MWh)</b>	417,448
<b>Total Cost (\$/MWh)</b>	49,210,963
<b>Total Emission (tons)</b>	220,000

When the system power demand is increased, in parallel to the overall system utilization rate, the utilization rates of the PPT groups also increase. As can be seen from Table 4.17, since they have the minimum total costs on average (101 \$/MWh), the natural gas PPT group carries on power generation at full capacity. Accordingly, natural gas-fired PPTs have the highest percentage (100 %) in average up hours and in total production (39 %) among all groups. Natural gas-fired PPTs are followed by hydropower plants (having

99 % in average up hours and in utilization rates of the groups) since they have the second lowest total cost value in average. Wind turbines are up on average 97 % of the time and have 73 % utilization rate (however, their share in total production is still around 1 %).

Table 4.17. The detailed results of demand scenario 2.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0.94	0.72	0.25	0.92	0.51
	2	0.65			0.46	
	3	0.67			0.60	
	4	0.33			0.12	
	5	1.00			0.80	
Natural Gas	6	1.00	1.00	0.39	1.00	1.00
	7	1.00			1.00	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	1.00	0.99	0.35	1.00	0.99
	11	1.00			1.00	
	12	1.00			1.00	
	13	0.98			0.96	
Wind	14	1.00	0.97	0.01	1.00	0.73
	15	0.94			0.69	

When individual generation facilities are investigated, it can be observed that, as the system power demand is increased, the more efficient (or less costly) units have their utilizations increased, while the less efficient (more costly) units start getting deployed when the efficient ones reach their full capacity.

Compared to the third case of the base scenario, there is a significant increase in the total cost of the entire system, associated with the increase in the utilization rates of all PPT groups. On the other hand, when the optimal schedule of the individual generation facilities are investigated, it is observed that, the on/off behavior of the individual units is quite similar to their behavior in Demand Scenario 1. However, in this scenario the high cost hydropower plants are also deployed to be up at several additional hours (primarily the peak demand hours).

### 4.2.3. Demand Scenario 3

As mentioned, demand scenario 3 focuses on power demand fluctuations while keeping the total power demand unchanged. For this scenario, the lowest feasible maximum emission limit is determined as 150,000 tons of CO<sub>2</sub>. Unlike the reference case, 110,000 tons of CO<sub>2</sub> is no longer feasible in this scenario, because of the heavier reliance on high emission (coal) generators during the higher demand periods in the scheduling horizon. The optimal solution of this scenario is displayed in Table 4.18 and Table 4.19.

According to the results in Table 4.18, since the total power generation equals to the system power demand, the ratio of supply and demand is still equal to one as was the case in demand scenario 2. Additionally, as the system power demand does not change, the amount of total power generation and the total utilization rate of the entire system remain the same as in the base scenario (62 %).

Table 4.18. The main results of demand scenario 3.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.62
<b>Total Power Generation (MWh)</b>	321,160
<b>Total Cost (\$/MWh)</b>	36,350,457
<b>Total Emission (tons)</b>	150,000

Although the system power demand remains unchanged, associated with the higher demand fluctuations in the identified time periods, various changes are observed in the utilization rates of the PPT groups. As can be seen in Table 4.19, with the feature of not discharging any CO<sub>2</sub> emission, hydropower plants have the highest percentage (82 %) in average up hours and second highest percentage in utilization rates (81 %) among all groups under this scenario. Wind turbines are up on average 77 % of the time and have 41 % utilization rate (their share in total production is still around 1 %).

On the other hand, demand fluctuations have distinct effects on individual generating units. Compared to first case of the base scenario, for example, coal-fired PPTs

which were down, are now deployed to be up in the peak demand hours in this scenario, (since demand values between hours 10.00 a.m. and 6.00 p.m. are increased by 20 %). However, the high cost natural gas and hydropower plants are deployed to be down at hours in which demand loads are minimum (demands between hours 2.00 a.m. and 8.00 a.m. are decreased by 40 %). Besides, the low cost wind turbines also stop generation in that time interval.

Table 4.19. The detailed results of demand scenario 3.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	0.58	0.37	0.18	0.63	0.29
	2	0.25			0.17	
	3	0.44			0.36	
	4	0.00			0.00	
	5	0.58			0.54	
Natural Gas	6	0.63	0.77	0.44	0.67	0.86
	7	0.63			0.64	
	8	1.00			1.00	
	9	0.83			0.83	
Hydro	10	0.98	0.82	0.37	0.98	0.81
	11	0.67			0.67	
	12	1.00			0.85	
	13	0.63			0.63	
Wind	14	0.81	0.77	0.01	0.63	0.41
	15	0.73			0.38	

So, when the optimal schedule of individual generation facilities are investigated, it is observed that, the higher demand fluctuations within the relative time durations play an important role in their up/down time series/frequencies. Accordingly, demand fluctuations have distinct effects on natural gas based individual generating units which have long up and down time limits. When natural gas based PPTs are faced with power demand variation, they cannot keep up with this fluctuation and then shut down.

Compared to the first case of the base scenario, all PPT groups except the natural gas plants have higher utilization rates. Even though they have the minimum total cost on average (101 \$/MWh), the utilization rate of the natural gas-fired PPTs is reduced to 86 %

(from 100 %) associated with the long minimum up/down durations of the natural gas-fired plants compared to hydropower plants and wind turbines.

### 4.3. The Cost Scenario

In order to better observe the effects of changes in total cost per unit production, a cost scenario focusing on cost modification is formed. So, in order to see the impacts of total cost per MWh increase, total costs of coal-fired and natural gas-fired plants are increased by 25 % and 75 % respectively. The adjusted cost data can be seen in Table 4.20.

Table 4.20. The revised values of total cost per unit production deployed in the cost scenario.

Power Resource Type	PPT	Total Cost (\$/MWh)	
		Base Scenario	Cost Scenario
Coal	1	131.70	105.36
	2	201.27	161.02
	3	177.79	142.23
	4	242.44	193.95
	5	148.16	118.53
Natural Gas	6	175.72	100.41
	7	194.65	111.23
	8	162.20	92.69
	9	148.85	85.06
Hydro	10	88.04	88.04
	11	136.95	136.95
	12	123.26	123.26
	13	176.08	176.08
Wind	14	171.20	171.20
	15	205.44	205.44

Regarding the investigation of various emission limits, in cost scenario the lowest feasible maximum emission limit is determined as 110,000 tons of CO<sub>2</sub>. The optimal solution of this scenario is displayed in Table 4.21 and Table 4.22.

It is noted that supply over demand ratio in this scenario equals to one as was the case in the previous scenarios. Also, as the system power demand does not change, the total power generation and total utilization rate of the entire system remain unchanged as

displayed in Table 4.21. (These are quite expected results, since demand, supply and other technical parameters of the overall system are left unchanged.)

Table 4.21. The main results of the cost scenario.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.62
<b>Total Power Generation (MWh)</b>	321,120
<b>Total Cost (\$/MWh)</b>	47,209,480
<b>Total Emission (tons)</b>	110,000

Compared to the reference case of the base scenario, there is a significant increase in the total cost of the entire system, associated with the increases in total cost per unit production of coal-fired and natural gas-fired PPTs (25 % and 75 % respectively). Since the total costs per unit production of natural gas-fired plants are increased, utilization rate of this group is reduced to 89 % (from the original 100 %) compared to the reference case. Although their total costs per unit production increased by 25 %, utilization rate of coal-fired plants unexpectedly increases by 1 %. However, hydropower plant group still carries on power generation at full capacity. But, utilization rate of wind turbines, being up on average 94 % of the time and having only 2 % share in total production, considerably increases to 75 % (from 59 %). Since generation capacities of the wind turbines are small, their effect of changes in the total production is insignificant (1 %).

On the other hand, when the optimal schedule of the individual generation facilities are investigated (see Table A.10), it is observed that, there is a slight change in up/down time series/frequencies of the individual units compared to the reference case. Regarding coal based generation facilities; it can be observed that, the ones having the minimum total costs on average start up in some of the lower demand hours while they shut down in some of the off-peak demand hours. On the other hand, since their total cost per unit production is increased significantly, some natural gas based generation facilities, are shut down not only in low demand periods, but also in some off-peak demand periods. Moreover, (originally) high cost wind turbines are now shut down only in some of the off-peak demand hours (e.g. t=11, 12, 35 and 36) while they are deployed to be up in most other

periods (e.g.  $t=17, 22-25$ ). Additionally, all these PPT groups display more frequent state changes (from “up” to “down” or vice-versa).

Table 4.22. The detailed results of the cost scenario.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	0.71	0.27	0.08	0.68	0.12
	2	0.00			0.00	
	3	0.00			0.00	
	4	0.00			0.00	
	5	0.65			0.26	
Natural Gas	6	0.73	0.87	0.45	0.70	0.89
	7	0.75			0.60	
	8	1.00			0.99	
	9	1.00			0.90	
Hydro	10	1.00	1.00	0.46	1.00	1.00
	11	1.00			1.00	
	12	1.00			1.00	
	13	1.00			1.00	
Wind	14	1.00	0.94	0.02	1.00	0.75
	15	0.88			0.70	

Compared to the reference case, utilization rates of coal-fired PPTs and wind turbine plants increase in association with the increases in total cost per unit production examined in this scenario. As a result, utilization rates of the coal-fired plants, who experience a smaller cost increase than natural gas plants, and the wind turbine groups increase to 12 % (from the original 11 %) and 75 % (from the original 59 %). Besides, total production shares of both coal-fired, PPTs and the wind turbines increase to 8 % and 2 % (from their original 7 % and 1 %) respectively, whereas the share and utilization rate of natural gas-fired PPTs decrease to 45 % (from the original 46 %) and 89 % (from 90 %) respectively.

The detailed solutions of the cost scenario in terms of  $P(i,t)$  and  $X_{up}(i,t)$ ,  $X_{down}(i,t)$  of the PPTs are given in Table A.10 and Table A.11.

#### 4.4. Scenarios Featuring Changes in Up and Down Times

In order to better observe the effects of changes in minimum up and down times, two basic scenarios featuring various modifications of minimum up and down time limitations are generated. So, in order to see the impacts of reductions in minimum up and down times, these time values are decreased by 50 % (compared to the reference scenario) in Time Scenario 1 and are set to zero in Time Scenario 2. The adjusted minimum up/down times are given in Table 4.23.

Table 4.23. The revised minimum up and down time values deployed in the time scenarios.

Power Resource Type	PPT	Base Scenario		Time Scenario 1		Time Scenario 2	
		Minimum Up Times (hour)	Minimum Down Times (hour)	Minimum Up Times (hour)	Minimum Down Times (hour)	Minimum Up Times (hour)	Minimum Down Times (hour)
Coal	1	1.68	1.68	0.84	0.84	0	0
	2	2.84	1.89	1.42	0.95	0	0
	3	2.70	1.80	1.35	0.90	0	0
	4	7.64	5.09	3.82	2.55	0	0
	5	8.12	5.41	4.06	2.71	0	0
Natural Gas	6	2.71	1.81	1.36	0.91	0	0
	7	2.12	2.12	1.06	1.06	0	0
	8	3.34	3.34	1.67	1.67	0	0
	9	5.32	5.32	2.66	2.66	0	0
Hydro	10	0.21	0.26	0.11	0.13	0	0
	11	0.35	0.42	0.18	0.21	0	0
	12	0.91	0.67	0.46	0.34	0	0
	13	0.69	0.51	0.35	0.26	0	0
Wind	14	0	0	0	0.00	0	0
	15	0	0	0	0.00	0	0

It is noted that supply over demand ratio in these scenarios equals to one as expected. Furthermore, as the system power demand does not change, the total power generation and total utilization rates of the entire system remain unchanged as displayed in Table 4.24 and Table 4.26.

#### 4.4.1. Time Scenario 1

Regarding the investigation of various emission limits in time scenario 1, the lowest feasible maximum emission limit is determined as 110,000 tons of CO<sub>2</sub>. The optimal solution of this scenario is displayed in Table 4.24 and Table 4.25

Table 4.24. The main results of time scenario 1.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.62
<b>Total Power Generation (MWh)</b>	321,120
<b>Total Cost (\$/MWh)</b>	36,450,893
<b>Total Emission (tons)</b>	110,000

As can be seen from Table 4.24, the total cost of the entire system decreases slightly associated with the effects of relaxation in minimum up/down time limitations compared to the reference case. Since they have the second lowest minimum up and down time values on average, utilization rate of hydropower plant group is also slightly reduced to 99 % (from the original full capacity), as can be seen in Table 4.25. Hydropower plants have the highest percentage (98 %) in average up hours, whereas natural gas plants have the highest percentage (46 %) in total production among all groups. On the other hand, since their minimum up and down times are decreased by 50 %, utilization rates of natural gas-fired plants slightly increases to 91 % (from 90 %), however the utilization rate of coal plants remain the same (at 11 %) even though they feature the major reductions in up/down times. This can be explained by the relative insignificance of up/down time limits in the reference scenario.

When the optimal schedule of the individual generation facilities are investigated (see Table A.12), it is observed that, there is a slight change in up/down time series/frequencies of individual generating units compared to the reference case. Regarding coal based generation facilities, it is observed that, although their high minimum up/down time limits are decreased by 50 %; their utilizations and productions remain unchanged. On the other hand, it is observed that, natural gas based generation facilities are now deployed in a more flexible fashion, increasing their production in peak hours, while shutting down

at other times. However, the high cost wind turbines are deployed to be up in the high demand hours.

Table 4.25. The detailed results of time scenario 1.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	0.52	0.23	0.07	0.49	0.11
	2	0.00			0.00	
	3	0.00			0.00	
	4	0.00			0.00	
	5	0.63			0.26	
Natural Gas	6	1.00	0.93	0.46	0.97	0.91
	7	0.73			0.67	
	8	1.00			1.00	
	9	1.00			0.91	
Hydro	10	1.00	0.98	0.45	1.00	0.99
	11	1.00			1.00	
	12	1.00			1.00	
	13	0.92			0.92	
Wind	14	1.00	0.95	0.02	1.00	0.73
	15	0.90			0.69	

#### 4.4.2. Time Scenario 2

The lowest feasible maximum emission limit is also determined as 110,000 tons of CO<sub>2</sub> in time scenario 2. The optimal solution of this scenario is displayed in Table 4.26 and Table 4.27

Table 4.26. The main results of time scenario 2.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.62
<b>Total Power Generation (MWh)</b>	321,120
<b>Total Cost (\$/MWh)</b>	36,459,956
<b>Total Emission (tons)</b>	110,000

As can be seen from Table 4.26, the total cost of the entire system further decreases (even though very slightly) associated with the decrease in up/down times of generation facilities (implying more efficient deployment of these facilities). Since minimum up/down

time durations of all PPTs are set to zero, PPTs having the longest up/down times in the reference are expected to be deployed more frequently. But, the utilization rate of coal plants remain the same (11 %) although they feature the major reductions in up/down times, while utilization rate of natural gas-fired plants slightly increases to 91 % (from the original 90 %) as expected.

As can be seen in Table A.14, there is a slight change in up/down time series/frequencies of individual generating units during the scheduling horizon compared to the reference case and time scenario 1. This is associated with the relative insignificance of up/down time limits in the reference case. For example, average up hours of wind turbines increases to 89 % (from 81 %) where even the highest cost units are deployed in the peak hours (such as hours 18 and 22-25). The high cost natural gas and hydropower generating units are closed in low demand hours (refers to a 1 % decrease) and accordingly their up/down state change frequency increases.

Table 4.27. The detailed results of time scenario 2.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	0.54	0.23	0.07	0.49	0.11
	2	0.00			0.00	
	3	0.00			0.00	
	4	0.00			0.00	
	5	0.63			0.27	
Natural Gas	6	1.00	0.93	0.46	0.95	0.91
	7	0.71			0.67	
	8	1.00			1.00	
	9	1.00			0.90	
Hydro	10	1.00	0.99	0.45	1.00	0.99
	11	1.00			1.00	
	12	1.00			1.00	
	13	0.98			0.96	
Wind	14	1.00	0.89	0.02	1.00	0.63
	15	0.77			0.57	

The detailed solutions of the time scenarios in terms of  $UC(i,t)$ ,  $P(i,t)$  and  $X_{up}(i,t)$ ,  $X_{down}(i,t)$  of the PPTs are given in Appendix A.

Some additional scenarios featuring multiple parameter changes (such as fuel cost and up/down time limit changes in tandem). These scenarios enable the investigation of the combined effects of the involved changes on the total system performance. So, related case scenarios are discussed, in the following sections.

#### 4.5. Mixed Scenarios

In addition to the single parameter change scenarios, three “mixed” scenarios involving multiple parameter changes are generated in order to observe possible combined effects of parameters. These scenarios involve coupled changes in cost, demand and up/down time parameters. (Demand is increased by 20 % in all these mixed scenarios. Besides this demand increase, total costs of coal-fired and natural gas-fired plants are increased by 25 % and 75 % respectively; in mixed scenarios 1 and 2. Moreover minimum up and down times are set to zero in mixed scenarios 2 and 3.) On the other hand, the lowest feasible maximum emission limit is determined as 190,000 tons of CO<sub>2</sub> in all these three scenarios associated with the power demand increase compared to the base scenario.

Basically, since the total power generation equals to the system power demand, the ratio of supply and demand is still equal to one in the following three scenarios as was the case in the previous scenarios. But, as the amount of total power generation in this mixed scenario rises associated with the increased power demand, the total utilization rate of the entire system increases from 62 % to 74 %. Besides, the amount of total power generation increases from 321,160 MW to 385,342 MW.

The optimal solutions of all these scenarios in terms of unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs within the planning horizon are displayed in Appendix A.

#### 4.5.1. Mixed Scenario 1

Mixed Scenario 1 features changes in cost (25 % increase in coal plants and 75 % in natural gas plants) and demand (20 % increase in hourly power demands) compared to the reference scenario. Compared to the associated base scenario (i.e. base scenario under the 190,000 emission limit), when the system power demand is increased, in parallel to the overall system utilization rate, the utilization rates of the PPT groups also increase. Additionally, there is a significant increase in the total cost of the entire system, associated with the considerable increase in the utilization rates of all PPT groups and total cost per unit production increases of coal-fired and natural gas-fired PPTs (25 % and 75 % respectively). The optimal solution of this scenario is displayed in Table 4.28 and Table 4.29.

Table 4.28. The main results of mixed scenario 1.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.74
<b>Total Power Generation (MWh)</b>	385,342
<b>Total Cost (\$/MWh)</b>	57,219,837
<b>Total Emission (tons)</b>	190,000

Compared to the base scenario, utilization rates of coal, hydropower plants and wind turbines increase by 3 %, 44 % and 69 % respectively, associated with the demand increases rather than the cost increases. However, the utilization rate of natural gas plants group reduces to 93 % (from 100 %), associated with the impact of the cost increase.

As can be seen in Table A.16, there is a significant change in up/down time series/frequencies of individual generating units compared to the associated base scenario. For example, some of the coal-fired PPTs are deployed to be up in the peak demand hours (their up time frequency increases associated with the system power demand increase). Moreover, the highest cost natural gas plant is shut down in low demand hours (t=1-8 and 25-28), while others are shut down in some of these hours (t=1-8 and 25-32). Although, most of the wind turbines are down in the base scenario, they are deployed to be up at almost the whole scheduling period, while the most costly ones are down in the low

demand hours. So, a considerable on/off state change of individual wind turbines is seen related to their up/down time series.

Table 4.29. The detailed results of mixed scenario 1.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	1.00	0.58	0.22	1.00	0.42
	2	0.29			0.17	
	3	0.58			0.44	
	4	0.00			0.00	
	5	1.00			0.83	
Natural Gas	6	0.75	0.85	0.39	0.71	0.93
	7	0.67			0.60	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	0.88	0.95	0.37	0.88	0.97
	11	1.00			1.00	
	12	1.00			1.00	
	13	0.92			0.86	
Wind	14	1.00	0.93	0.01	1.00	0.72
	15	0.85			0.67	

Compared to demand scenario 1, utilization rate of the natural gas PPT group decrease by 7 % (as expected) associated with their total cost per unit production increase. However, utilization rate of the coal-fired plant group increases slightly by 2 %. Additionally, utilization rates of hydropower plants and wind turbines increase by 2 % and 34 % respectively associated with the cost increases (of their competitors). This result shows that wind turbines which had the highest costs per unit generation and featured no emissions, is the group most favorably impacted by this “demand plus cost increase” scenario.

As can be seen in Table A.16, there is a significant change in up/down time series/frequencies of individual generating units compared to demand scenario 1. For example, the high cost natural gas plants being are shut down in the low demand hours related to the total cost per unit production increases, as expected, whereas average up hours and utilization rates of individual coal based generating units remain unchanged. Moreover, the lowest cost hydropower plant is also shut down in some of the low demand hours (t=25-30), while the highest cost one is deployed to be up in some of these hours

(t=1-8 and 25-28, 30 and 32). (This is because under the fuel cost increases, even the highest cost hydropower plant, which has a considerable minimum production limit, becomes attractive). Accordingly, the highest cost natural gas plant is deployed to be up only in some of the low demand hours (t=1-2, 5-9, 25-28, 32, 33) and in average demand periods (t=19-24). Additionally, low cost wind turbines are observed to be up most of the time; while higher cost wind turbines are up in high demand periods and are shut down in low demand periods.

#### 4.5.2. Mixed Scenario 2

Mixed Scenario 2 features changes in cost (25 % increase in coal plants and 75 % in natural gas plants), in demand (20 % increase in hourly power demands) and in minimum up/down time limits (all set to zero) compared to the reference scenario. Compared to the associated base scenario (i.e. base scenario under the 190,000 emission limit), when the system power demand is increased, in parallel to the overall system utilization rate, the utilization rates of the PPT groups also increase. Additionally, there is also a significant increase in the total cost of the entire system, associated with the considerable increase in the utilization rates of these groups and total cost per unit production increases. The optimal solution of this scenario is displayed in Table 4.30 and Table 4.31.

Table 4.30. The main results of mixed scenario 2.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.74
<b>Total Power Generation (MWh)</b>	385,342
<b>Total Cost (\$/MWh)</b>	57,258,276
<b>Total Emission (tons)</b>	190,000

Compared to the associated base scenario, utilization rates of coal, hydropower plants and wind turbines increases by 3 %, 45 % and 68 % respectively, associated with the demand increases and up/down time reductions and the cost increases. However, in parallel to the previous mixed scenario, the utilization rate of natural gas plants group reduces to 92 % (from 100 %), associated with the impact of the cost increase.

On the other hand, when the optimal schedule of the individual generation facilities are investigated (see Table A.17), it is observed that, there is a considerable change in up/down time series/frequencies of individual generating units compared to the base scenario. Regarding individual coal based generation facilities, it can be observed that, the ones having average total costs are deployed to be up most of the time including the peak demand hours associated with the reduction in up/down time limits and also the demand increase. On the other hand, since their total cost per unit production is increased significantly, the high cost natural gas generation facilities are shut down even in the peak demand hours (this may also be due to the ease of up/down state change in the scenario investigated).

Table 4.31. The detailed results of mixed scenario 2.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1.00	0.60	0.22	1.00	0.42
	2	0.48			0.25	
	3	0.52			0.38	
	4	0.00			0.00	
	5	1.00			0.83	
Natural Gas	6	0.67	0.83	0.39	0.67	0.92
	7	0.67			0.56	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	1.00	0.97	0.37	1.00	0.98
	11	1.00			1.00	
	12	1.00			1.00	
	13	0.88			0.88	
Wind	14	1.00	0.94	0.01	1.00	0.71
	15	0.88			0.66	

Compared to demand scenario 1, total utilization rates of coal, hydropower plants and wind turbine groups increase by 2 %, 3 % and 33 % respectively, while the utilization rate of natural gas-fired PPT group decreases by 8 %. This result shows that wind turbines which had the highest costs per unit generation and featured no emissions, is the group most favorably impacted by this “demand plus cost increase and up/down time decrease” scenario. Also total cost of the entire system increases significantly associated with the cost increases. On the other hand, when individual generation facilities are investigated, it can

be observed that, as up/down times are set to zero the average up hours of coal plants increase. Additionally, as the total cost of coal and natural gas plants are increased, average up hours of hydropower plants and wind turbines increases. Although their high up/down times are set to zero, average up hours of natural gas plants decrease associated with the cost increases.

When the optimal schedule of the individual generation facilities are investigated (see Table A.17), it is observed that, there is a slight change in up/down time series/frequencies of individual generating units compared to demand scenario 1. Regarding individual coal generation facilities, it is observed that, as their minimum up/down time requirements are set to zero; the least costly ones are deployed to be up in more frequently (including the least demand hours) despite their total cost per unit production increase. On the other hand, natural gas generation facilities are shut in the lowest demand hours associated with their cost increase. Regarding wind turbines, the high cost turbines are kept in operation most of the time (with the exception of low demand periods) while low cost turbines are deployed at all times due to demand and cost changes.

Compared to the first mixed scenario, there is no significant change in the utilization rates of the groups. Utilization rates of the coal-fired plants remain unchanged, while the utilization rate of hydropower plants increases by 1 %. Moreover, utilization rates of the natural gas-fired plants and wind turbines decrease by 1 % each. However, it is observed that, average up hours of coal and hydropower plants and wind turbines increase by 2 %, 2 % and 1 % respectively, whereas the share of natural gas-fired PPTs decreases by 2 %. On the other hand, when individual coal based generation facilities are investigated, it can be observed that, as the total cost of natural gas-fired PPTs are increased and their up/down time limits are decreased, they are readily shut down in the least demand hours. The high cost natural gas based generating units are generally down in the least demand hours in which they were up in the first mixed scenario.

### 4.5.3. Mixed Scenario 3

Mixed Scenario 3 features changes in demand (20 % increase in hourly power demands) and up/down times (all set to zero) compared to the reference scenario. Compared against the associated base scenario (i.e. base scenario under the 190,000 emission limit), when the power demand is increased, in parallel to the overall utilization rate, utilization rates of the hydropower plants and wind turbines are increased. Additionally, there is also a significant increase in the total cost of the entire system, associated with the considerable increase in the utilization rates of the wind turbines and also the cost increases related to power demand increase. The optimal solution of this scenario is displayed in Table 4.32 and Table 4.33.

Table 4.32. The main results of mixed scenario 3.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.74
<b>Total Power Generation (MWh)</b>	385,342
<b>Total Cost (\$/MWh)</b>	43,818,212
<b>Total Emission (tons)</b>	190,000

Compared to the associated base scenario, utilization rates of the coal-fired and natural gas-fired PPTs do not change, while utilization rates of the hydropower plants and the wind turbines increase by 42 % and 32 % respectively associated with the demand increases. Since the generation capacities of wind turbines are small (having only 1 % share in total production) their effect of changes in the total production is still insignificant (1 %) even though they are up on average 86 % of the time.

When the optimal schedule of individual generation facilities are investigated (see Table A.18), it is observed that, there is a significant change in up/down time series/frequencies of individual generating units compared to the associated base scenario. Regarding individual coal based generation facilities, it is observed that, as their high minimum up/down time requirements are set to zero; all coal plants except the highest cost one are getting deployed in most of the demand periods. On the other hand, it is observed that, wind turbines are getting deployed at all times due to demand increases.

Table 4.33. The detailed results of mixed scenario 3.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	0.88	0.57	0.21	0.87	0.40
	2	0.46			0.24	
	3	0.60			0.46	
	4	0.00			0.00	
	5	0.90			0.74	
Natural Gas	6	1.00	1.00	0.42	1.00	1.00
	7	1.00			0.99	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	1.00	0.96	0.36	1.00	0.95
	11	1.00			1.00	
	12	1.00			1.00	
	13	0.83			0.73	
Wind	14	0.96	0.86	0.01	0.91	0.35
	15	0.77			0.26	

Compared to demand scenario 1, it is observed that, total utilization rate of the wind turbines decrease by 3 %, while the rates of other PPT group remain unchanged. This result shows that up/down time limitations have very marginal impact even under a heavy demand environment. Eliminating such limitations did not change anything other than reducing (by 3 points) the utilization of wind turbines which did not have such limitation in the first place; however, since the overall contribution of wind turbines is very lower (1%), this change is indeed marginal.

As can be seen in Table A.18, there is a slight change in up/down time series/frequencies of individual generating units compared to demand scenario 1. For example, all coal based generating units except the most costly one start getting deployed, related to the system power demand increase and up/down time relaxation. Moreover, hydropower plants (the low cost ones) are deployed to be up at times in which they were down in the base scenario. Regarding wind turbines, low cost wind turbines are deployed to be up at several hours, while higher cost ones are less utilized.

## 4.6. Extension of Demand Scenario 1

Besides the discussed Demand Scenario 1, the model is solved under the following more relaxed settings of the maximum emission limit, in order to better observe the effects of the maximum emission limit on the system performance. The optimal solutions of all these cases in terms of unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs within the planning horizon are displayed in Appendix A.

### 4.6.1. Case 1

In this case, the maximum emission limit is adjusted to 220,000 tons of CO<sub>2</sub>, while other data parameters are kept the same as in demand scenario 1. The optimal solution of this case is displayed in Table B.1 and Table B.2. As can be seen from Table B.1, there is a significant decrease in costs as the system takes advantage of the relaxed emission requirements and utilizes higher emission/lower cost generation opportunities.

Compared to demand scenario 1, the total cost of the entire system decreases associated with the decrease in the utilization rate of the more expensive alternatives. The utilization rate of the wind turbines is reduced to 5 % (from 38 %). On the other hand, associated with the relaxation in the amount of total emission, utilization rate of coal-fired plants (which feature, on average, the high emission coefficients) rises. Natural gas PPTs which have the minimum total cost on average (101 \$/MWh), carry on power generation at full capacity. Additionally, the utilization rate of the hydropower plants is reduced to 5 % (from 38 %).

When individual coal based generation facilities are investigated, it can be observed that, as emission restriction is relaxed, the more efficient (or less costly) units have their utilizations increased, while the less efficient (more costly) units start getting deployed when the efficient ones reach their nearly full capacity. Similar observation can also be made for other types of generation facilities.

#### 4.6.2. Case 2

In this case, the maximum emission limit is further relaxed to 225,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.3 and Table B.4.

When the maximum emission limit is increased, generation units having higher emission coefficients are more frequently deployed in the production process. Additionally, since these PPTs are less costly compared to the ones having less emission coefficients, the total system cost further decreases.

As can be seen from the results in Table B.4, in parallel to the developments in the previous subsection, utilization rates of the coal-fired PPTs are further increased, whereas, the rates of hydropower plants and wind turbines are decreased (due to their lower emission coefficients and higher total costs). The natural gas PPTs carry on power generation at full capacity.

Regarding individual generation facilities, it is observed that the trends identified in the previous sub-section continue. In other words, as emission restrictions are relaxed, shares of efficient/less costly coal generation facilities expand, while shares of higher costly hydro and wind facilities shrink.

#### 4.6.3. Case 3

In this case, the maximum emission limit is relaxed to 250,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.5 and Table B.6. As can be seen from Table B.5, this additional relaxation does not bring much benefit since total emission remains at 241,860 level, while total costs are not better than those of the previous case (i.e. under the 225,000 ton emission restrictions). The primary reason of this development is the saturation of the market. In other words, the system is able to take full advantage of the less costly (but higher emission) generation alternatives under the 241,860 ton limit; therefore relaxing this limit to 250,000 ton does not bring additional benefit.

Regarding individual generation facilities, the trends observed in the previous two subsections continue. In summary, compared to the optimal solutions of demand scenario 1; the total system costs in these three cases have a declining structure; whereas the amount of total emission has an increasing trend. Regarding individual generation facilities, the relative efficiency/cost of generation facilities within a generation group plays an important role in their utilization rate.

#### 4.7. Extension of Demand Scenario 2

Pursuing demand scenario 2, the model is solved under the following more relaxed settings of the maximum emission limit, in order to better observe the effects of the maximum emission limit on the system performance. The optimal solutions of all these cases in terms of unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs within the planning horizon are displayed in Appendix A.

##### 4.7.1. Case 1

In this case, the maximum emission limit is adjusted to 225,000 tons of CO<sub>2</sub>, while other data parameters are kept the same as in demand scenario 2. The optimal solution of this case scenario is displayed in Table B.7 and Table B.8. As can be seen from Table B.7, there is a significant decrease in costs as the system takes advantage of the relaxed emission requirements and utilizes higher emission/lower cost generation opportunities.

The total cost of the entire system decreases associated with the considerable decrease in the utilization rate of the wind turbines and hydro plants compared to demand scenario 2 (as indicated before, these two groups carry high generation costs but cause no emission, which is no longer an advantage under the relaxed setting of the emission limit). The utilization rate of the wind turbines is reduced to 57 % (from 73 %) and that of the hydro plants to 97 % (from 99 %). On the other hand, associated with the relaxation in the amount of total emission, utilization rate of coal-fired plants rises. Since they have the

minimum total cost on average (101 \$/MWh), natural gas-fired PPT group carry on power generation at full capacity.

When individual hydropower generation facilities are investigated, it can be observed that, as emission restriction is relaxed, the more efficient (or less costly) units have their utilizations increased, while the less efficient (more costly) units start getting deployed when the efficient ones reach their full capacity. Similar observation can also be made for other types of generation facilities.

#### **4.7.2. Case 2**

In this case, the maximum emission limit is relaxed to 220,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.9 and Table B.10.

As can be seen from the results in Table B.10, in parallel to the developments in the previous subsections, utilization rates of the coal-fired PPTs are further increased, whereas, the utilizations of hydropower plants and wind turbines are decreased (due to their lower emission coefficients and higher costs). The natural gas PPTs carry on power generation at full capacity

### **4.8. Extension of Demand Scenario 3**

Pursuing demand scenario 3, the model is solved under the following more relaxed settings of the maximum emission limit and increased the power demand, in order to see the impacts of both demand increase and maximum emission limit change on the system performance. The optimal solutions of all these cases in terms of unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs within the planning horizon are displayed in Appendix A.

Associated with the 10 % increased power demand, the amount of total power generation rises and the total utilization rate of the entire system increases from 62 % to 68 % in the following two case.

#### **4.8.1. Case 1**

Due to the 10 % increase in the hourly power demands, the lowest feasible maximum emission limit is determined as 190,000 tons of CO<sub>2</sub> in this case scenario. The optimal solution of this case is displayed in Table B.11 and Table B.12.

When the system power demand is increased, in parallel to the overall system utilization rate, the utilization rates of the PPT groups (except the utilization of hydropower plants) also increase. As shown in Table B.12, the utilization rate of hydropower plants decreases by 3 % (due to the relaxation in emission limits), whereas the utilization rates of coal and natural gas PPTs and wind turbines increase by 12 %, 7 % and 9 % respectively. Additionally, there is an increase in the total cost of the entire system, associated with the increase in the system power demand and the utilization rates of all PPT groups (except the utilization of natural gas plants).

Natural gas plants have the highest percentage (93 %) in utilization rate have high percentage (47 %) in total production among all groups. They are followed by hydropower plants (having 78 % in utilization and 35 % in total production). Additionally, wind turbines are up on average 90 % of the time and have 50 % in utilization rates.

Regarding coal based generation facilities, it can be observed that, as the power demand is increased the highest cost one (which was off during the scheduling horizon) starts getting deployed in the peak demand hours, in addition to the utilization increase of other coal plants. On the other hand, the high cost wind turbine is shut down even in high demand periods.

#### 4.8.2. Case 2

In this case, the maximum emission limit is relaxed to 220,000 tons of CO<sub>2</sub> while the power demand is increased by 10 % (as in case 1). The optimal solution of this case is displayed in Table B.13 and Table B.14. According to the results in Table B.13, the amount of total emission rises to 219,370 tons of CO<sub>2</sub> in this case. In other words, when the maximum emission limit is increased, generation units having higher emission coefficients are more frequently deployed in the production process. Additionally, since these PPTs are less costly compared to the ones having lower emission coefficients, the total system cost further decreases compared to the previous case. However, compared to demand scenario 3, there is a considerable increase in the total system cost associated with the power demand increase.

Compared to the previous case, associated with the relaxation in the amount of total emission, utilization rate of coal-fired plants (which feature, on average, the high emission coefficients) rises. The utilization rates of coal and natural gas plants increase by 11 % and 2 % respectively, while the utilization rates of hydropower plants and wind turbines decrease by 15 % and 43 % respectively.

Regarding individual coal based generation facilities, it can be observed that, as emission restriction is relaxed, the more efficient (or less costly) units have their utilizations increased, while the less efficient (more costly) units start getting deployed when the efficient ones reach their full capacity. For example, the lowest cost (most efficient) coal plant (1) is deployed to be up during the scheduling horizon and carries on power generation at full capacity most of the time. On the other hand, the more costly one (4) start getting deployed in some of the peak demand hours (t=10-18 and 34-42), while the most costly one is deployed to be up at times hours in which it was off in the previous case (t=1-9 and 25-33). Similar observation can also be made for other types of generation facilities.

#### 4.9. Extension of The Cost Scenario

Besides the discussed cost scenario, the model is also solved under the following more relaxed settings of the maximum emission limit, in order to better observe the effects of the maximum emission limit on the system performance. The optimal solutions of all these cases in terms of unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs within the planning horizon are displayed in Appendix A.

##### 4.9.1. Case 1

In this case, the maximum emission limit is adjusted to 150,000 tons of CO<sub>2</sub>, while other data parameters are kept the same as in the cost scenario. The optimal solution of this case is displayed in Table B.15 and Table B.16. As can be seen from Table B.16, there is a significant decrease in costs as the system takes advantage of the relaxed emission requirements and utilizes higher emission/lower cost generation opportunities.

Compared to the cost scenario, the total cost of the entire system decreases associated with the decrease in the utilization rates of the more expensive alternatives. The utilization rate of the wind turbines is reduced to 12 % (from 75 %). Besides, the utilization rates of natural gas and hydropower plants are reduced to 79 % and 88 % (from 89 % and 100 %) respectively. On the other hand, associated with the relaxation in the amount of total emission, utilization rate of coal-fired plants rises (from 12 % to 31 %).

When individual coal based generation facilities are investigated, it can be observed that, as emission restriction is relaxed, the more efficient (or less costly) units have their utilizations increased, while the less efficient (more costly) units start getting deployed when the efficient ones reach their nearly full capacity. For example, the less costly coal plants (1 and 5) start getting deployed during the scheduling horizon and carries on power generation at full capacity. Also, another low cost coal plant (3) starts (at hour 9) and carries on power generation at full capacity.

#### 4.9.2. Case 2

In this case, the maximum emission limit is further relaxed to 190,000 tons of CO<sub>2</sub>. The optimal solution of this case scenario is displayed in Table B.17 and Table B.17. As can be seen from Table B.17, this additional relaxation does not bring much benefit since total emission remains at 167,210 level, while total cost is slightly better than that of the previous case (i.e. under the 150,000 ton emission restriction). It is reduced to 45,502,207 \$/MWh (from 45,812,048 \$/MWh).

Nevertheless, there is considerable change in utilization rates. As can be seen from the results in Table B.18, in parallel to the developments in the previous subsection, utilization rate of the coal-fired PPTs is further increased, whereas, the rates of hydropower, natural gas-fired PPTs and wind turbines are decreased (due to their lower emission coefficients and higher total costs). Utilization rate of the coal plants increases to 42 % (from 31 %), whereas the utilization rates of natural gas, hydropower plants and wind turbines decreases by 3 %, 45 % and 68 % respectively.

The primary reason of this development is the partial saturation of the market. In other words, the system is able to take full advantage of the less costly (but higher emission) generation alternatives with a total emission of 167,210 tons; therefore relaxing this limit to 190,000 ton does not bring much additional benefit.

When the maximum emission limit is increased, generation units having higher emission coefficients are more frequently deployed in the production process.

#### 4.9.3. Case 3

In this case, the maximum emission limit is relaxed to 220,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.19 and Table B.20. As can be seen from Table B.19, this additional relaxation brings even less additional benefits. The reason of this development is the saturation of the market. In other words, the system is able to

take full advantage of the less costly (but higher emission) generation alternatives under the 163,060 ton limit; therefore relaxing this limit to 220,000 ton does not bring benefit.

In summary, the total system costs in these three cases have a declining structure; whereas the amount of total emission has an increasing trend. Regarding individual generation facilities, the relative efficiency/cost of generation facilities within a generation group plays an important role in their utilization rate.

#### 4.10. Extension of Time Scenario 1

Pursuing time scenario 1, the model is solved under the following more relaxed settings of the maximum emission limit, in order to better observe the effects of the maximum emission limit on the system performance. The optimal solutions of all these cases in terms of unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs within the planning horizon are displayed in Appendix A.

##### 4.10.1. Case 1

In this case, the maximum emission limit is adjusted to 150,000 tons of CO<sub>2</sub>, while other data parameters are kept the same as in time scenario 1. The optimal solution of this case is displayed in Table B.21 and Table B.22. According to the results in Table B.21, there is a significant decrease in costs as the system takes advantage of the relaxed emission requirements and utilizes higher emission/lower cost generation opportunities.

As can be seen from Table B.21, the total cost of the entire system decreases (from 36,450,893 \$/MWh to 34,304,630 \$/MWh) associated with the decrease in the utilization rate of the hydropower plants and wind turbines compared to time scenario 1. As indicated before, these two groups carry high generation costs but cause no emission which is no longer an advantage under the relaxed setting of the emission limit. Since, utilization rates of the coal and natural gas plants are increased associated with the effects of relaxation in

their minimum up and down time limitations, utilization rates of the wind turbines and hydropower plants are easily decreased.

The utilization rate of the wind turbines is reduced to 1 % (from 73 %). Besides, the utilization rate of hydropower plants is reduced to 7 % (from 99 %). On the other hand, associated with the relaxation in the amount of total emission, utilization rate of coal plants rises from 11 % to 24 %. Additionally, since they have the second highest emission coefficients on average, utilization rate of natural gas-fired plants is also increased from 91 % to full capacity.

#### **4.10.2. Case 2**

In this case, the maximum emission limit is further relaxed to 190,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.23 and Table B.24.

According to the results in Table B.23, the amount of total emission rises to 189,980 tons of CO<sub>2</sub> in this case. In other words, when the maximum emission limit is increased, generation units having higher emission coefficients are more frequently deployed in the production process. Additionally, since these PPTs are less costly compared to the ones having less emission coefficients, the total system cost decreases (from 34,304,630 \$/MWh to 34,105,627 \$/MWh). This is also associated with the effects of relaxation in minimum up/down time limitations of coal and natural gas plants. Since their up and down time limits are relaxed in addition to the system emission limit, they start getting deployed while other most costly wind turbines start getting shut down.

The utilization rate of the wind turbines and hydropower plants is decreased by 22 % and 1 %. On the other hand, since total emission is relaxed, utilization rate of coal plants (which feature, on average, the high emission coefficients) is increased by 16 %. Since they have the second highest emission coefficients on average, natural gas PPTs group goes on power generation at full capacity.

As can be seen from the results in Table B.24, in parallel to the developments in the previous subsections, utilization rates of the coal-fired PPTs are further increased, whereas, the utilizations of hydropower plants and wind turbines are decreased (due to their lower emission coefficients and higher costs). Since they have the minimum total costs on average (101 \$/MWh), the natural gas PPTs group carry on power generation at full capacity.

### 4.10.3. Case 3

In this case, the maximum emission limit is relaxed to 220,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.25 and Table B.26. As can be seen from Table B.25, this additional relaxation does not bring much benefit since total emission remain at 187,960 level, while total cost is not better than that of the previous case (i.e. under 190,000 ton emission restrictions). The primary reason of this development is the saturation of the market. In other words, the system is able to take full advantage of the less costly (but higher emission) generation alternatives under the 187,960 ton limit; therefore relaxing this limit to 220,000 ton does not bring additional benefit.

## 4.11. Extension of Time Scenario 2

Pursuing time scenario 2, the model is solved under the following more relaxed settings of the maximum emission limit, in order to better observe the effects of the maximum emission limit on the system performance. The optimal solutions of all these cases in terms of unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs within the planning horizon are displayed in Appendix A.

### 4.11.1. Case 1

In this case, the maximum emission limit is adjusted to 150,000 tons of CO<sub>2</sub>, while other data parameters are kept the same as in the reference case. The optimal solution of

this case is displayed in Table B.27 and Table B.28. As can be seen from Table B.27, there is a significant decrease in costs as the system takes advantage of the relaxed emission requirements and utilizes higher emission/lower cost generation opportunities.

As can be seen from Table B.28, the total cost of the entire system decreases (from 36,459,956 \$/MW to 34,252,308 \$/MW) associated with the decrease in the utilization rate of the more expensive alternatives (such as wind turbines) compared to time scenario 2. Since, the utilization rates of coal and natural gas plants are increased associated with the effects of relaxation in the minimum up/down time limitations, utilization rates of the wind turbines and hydropower plants are easily decreased.

The utilization rate of the wind turbines is reduced to 2 % (from the original 63 %). On the other hand, associated with the relaxation in the amount of total emission, utilization rate of coal-fired plants rises from 11 % to 24 %.. Additionally, since they have the second highest emission coefficients on average, utilization rate of natural gas-fired plants is also increased from 91 % to full capacity.

#### **4.11.2. Case 2**

In this case, the maximum emission limit is further relaxed to 190,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.29 and Table B.30.

According to the results in Table B.29, the amount of total emission rises to 188,750 tons of CO<sub>2</sub> in this case. In other words, when the maximum emission limit is increased, generation units having higher emission coefficients are more frequently deployed in the production process. Additionally, since these PPTs are less costly compared to the ones having less emission coefficients, the total system cost decreases (from 34,252,308 MWh to 34,130,161 MWh). This is also associated with the effects of relaxation in minimum up/down time limitations of coal and natural gas plants. Since their up and down time limits are relaxed in addition to the system emission limit, they start getting deployed, while other most costly wind turbines start getting shut down.

The utilization rate of the wind turbines and hydropower plants is decreased by 21 % and 1 %. On the other hand, since total emission is relaxed, utilization rate of coal plants (which feature, on average, the high emission coefficients) is increased by 15 %. Since they have the second highest emission coefficients on average, natural gas PPTs group goes on power generation at full capacity.

As can be seen from the results in Table B.30, in parallel to the developments in the previous subsections, utilization rates of the coal-fired are further increased, whereas, the utilizations of hydropower plants and wind turbines are decreased (due to their lower emission coefficients and higher costs). Since they have the minimum total costs on average (101 \$/MWh), the natural gas PPTs group carry on power generation at full capacity.

#### **4.11.3. Case 3**

In this case, the maximum emission limit is relaxed to 220,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.31 and Table B.32. As can be seen from Table B.31, this additional relaxation does not bring much benefit since total emission remain at 190,000 level, while the total cost is better than that of the previous case (i.e. under the 190,000 ton emission restrictions). The primary reason of this development is the saturation of the market. In other words, the system is able to take full advantage of the less costly (but higher emission) generation alternatives under the 190,000 ton limit; therefore relaxing this limit to 220,000 ton does not bring additional benefit.

In summary, according to the optimal solutions of the time scenarios; the total system costs from case 1, to case 3 has a declining structure; whereas the amount of total emission has an increasing trend. Regarding individual generation facilities, the relative efficiency/cost of generation facilities within a generation group plays an important role in their utilization rate.

#### **4.12. Mixed Scenarios Featuring Changes in Demand Scenario 3 and Time Scenarios**

In order to better observe the effects of both power demand fluctuation and minimum up and down time changes at the same time, several scenarios featuring emission relaxations are formed based on demand scenario 3 and the time scenarios. These scenarios are discussed in the following sections. Besides, the optimal solutions of all these cases in terms of unit commitment states ( $UC(i,t)$ ), power generation capacities ( $P(i,t)$ ) and up and down time durations ( $X_{up}(i,t)$  and  $X_{down}(i,t)$ ) of the PPTs within the planning horizon are displayed in Appendix A.

##### **4.12.1. Case Scenario 1 Related to Time Scenario 1 and Demand Scenario 3**

As the lowest feasible maximum emission limit is determined as 150,000 tons of CO<sub>2</sub> in demand scenario 3, it still remains unchanged. The optimal solution of this case is displayed in Table B.33 and Table B.34. As can be seen from Table B.33, there is a little increase in the total cost of the entire system, associated with the slight increase in the utilization rate of the hydropower plants.

Compared to demand scenario 3, the total production shares and utilization rates of the PPT groups remain unchanged, whereas little changes are observed in the average up hour shares. For example average up hour shares of all PPT groups are increased while the share of hydropower plants remains unchanged.

##### **4.12.2. Case Scenario 2 Related to Time Scenario 1 and Demand Scenario 3**

In this case, the maximum emission limit is further relaxed to 190,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.35 and Table B.36. As can be seen from Table B.35, there is a significant decrease in costs (from 36,357,646 \$/MWh to 35,446,907 \$/MWh) as the system takes advantage of the relaxed emission requirements and utilizes higher emission/lower cost generation opportunities compared to the previous

case. There is a considerable decrease in the utilization rate of the wind turbines and hydropower plants compared to the previous case. As indicated before, (these two groups carry high generation costs but cause no emission which is no longer an advantage under the relaxed setting of the emission limit). The utilization rate of the wind turbines is reduced to 2 % (from 41 %) and that of the hydro plants to 56 % (from 81 %). On the other hand, associated with the relaxation in the amount of total emission, utilization rate of coal-fired plants rises. Additionally, a significant increase in the utilization rate of natural gas-fired plants is also observed.

#### **4.12.3. Case Scenario 3 Related to Time Scenario 1 and Demand Scenario 3**

In this case, the maximum emission limit is relaxed to 220,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.37 and Table B.38.

As can be seen from Table B.37, this additional relaxation does not bring much benefit since total emission remains at 198,140 level, while the total cost of the entire system is not better than that of the previous case (i.e. under the 190,000 ton emission restrictions). The primary reason of this development is the saturation of the market. In other words, the system is able to take full advantage of the less costly (but higher emission) generation alternatives under the 198,140 ton limit; therefore relaxing this limit to 220,000 ton does not bring additional benefit.

When individual coal based generation facilities are investigated, from case 1 to case 3, the lowest cost generating unit (1) starts getting deployed considerably and in case 3 it is in operation during all scheduling horizon. Similar observation can also be made for the natural gas plants.

#### **4.12.4. Case Scenario 1 Related to Time Scenario 2 and Demand Scenario 3**

As the lowest feasible maximum emission limit is determined as 150,000 tons of CO<sub>2</sub> in demand scenario 3, it still remains unchanged. The optimal solution of this case is

displayed in Table B.39 and Table B.40. According to the results in Table B.40, there is a small increase in the total cost of the entire system, associated with the slight increase in the utilization rate of more expensive alternatives (such as hydropower plants). Since, the utilization rates of coal plants are slightly increased (associated with the effects of relaxation in the minimum up/down time limitations) utilization rates of the wind turbines are decreased to 34 % (from the original 41 %).

Compared to demand scenario 3, little changes are observed in the average up hour shares. For example average up hour shares of all PPT groups are increased while the share of hydropower plants remains unchanged.

#### **4.12.5. Case Scenario 2 Related to Time Scenario 2 and Demand Scenario 3**

In this case, the maximum emission limit is further relaxed to 190,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.41 and Table B.42.

As can be seen from Table B.41, the amount of total emission nearly meets its specified value; it reaches to 188,420 tons of CO<sub>2</sub>. In other words, when the maximum emission limit is increased, more generation units having higher emission coefficients are deployed to be up in the production process. Additionally, since these PPTs have less costs per production compared to others having less emission coefficients, the total system cost further decreases.

As can be seen from Table B.42, the utilization rate of the wind turbines is reduced to 14 % (from the original 34 %). On the other hand, associated with the relaxation in the amount of total emission, utilization rate of coal-fired plants (which feature, on average, the high emission coefficients) rises. Additionally, a significant increase in the utilization rate of natural gas-fired plants is also observed.

Regarding individual generation facilities, it is observed that the trends identified in the previous sub-section continue. In other words, as emission restrictions are relaxed,

shares of efficient/less costly coal and natural gas generation facilities expand, while shares of higher costly hydro and wind facilities shrink.

#### **4.12.6. Case Scenario 3 Related to Time Scenario 2 and Demand Scenario 3**

In this case, the maximum emission limit is relaxed to 220,000 tons of CO<sub>2</sub>. The optimal solution of this case is displayed in Table B.43 and Table B.44.

As can be seen from Table B.43, this additional relaxation does not bring much benefit since total emission remain at 188,880 level, while the total cost is better than that of the previous case (i.e. under the 190,000 ton emission restrictions). The primary reason of this development is the saturation of the market. In other words, the system is able to take full advantage of the less costly (but higher emission) generation alternatives under the 188,880 ton limit; therefore relaxing this limit to 220,000 ton does not bring additional benefit.

#### **4.12.7. Mixed Scenario Related to Time Scenario 2 and Demand Scenario 3**

Pursuing the above scenarios, a mixed scenario focusing on both demand scenario 3 and time scenario 2 is generated and presented in this section. Additionally, the demand data is adjusted including both higher demand fluctuations (as in demand scenario 3) and 10 % demand increase while minimum up and down times are set to zero as in time scenario 2. Besides, the maximum emission limit is adjusted to 190,000 tons of CO<sub>2</sub>. The optimal solution is displayed in Table B.45 and Table B.46.

As can be seen from Table B.46, the total cost of the entire system increases associated with the increase in the utilization rate of the wind turbines compared to the first case of demand scenario 3. The utilization rates of the PPT groups remain unchanged, whereas only the wind turbines' utilization rises to 53 % (from 50 %) regarding the relaxation in the minimum up/down time limitations (all set to zero). On the other hand, slight changes are observed regarding the average up hour shares of the PPT groups.

## 5. CONCLUSION AND REMARKS

Power generation scheduling is a critical issue for generation companies and in the competitive energy sector; it is very important to manage scheduling activities in the most cost effective way. Under the light of this fact, the Short Term Power Generation Scheduling Problem (STGS) is investigated in this thesis with the aim of guiding the short term efficient power generation schedules of the PPTs generating electricity. The constructed STGS model in this study provides a sound platform both determine and test the effectiveness of various key parameters within various scenarios related with the electrical power generation processes.

Generally, the STGS problem is formed as a two stage optimization model including the UC and the ECD subproblems which correspond to the problems of selecting which power generating units to be in operation and for how long, and optimally allocating the load demand among the operating units. In this study, both the UC and the ECD problems are considered simultaneously as a single main model. As a result, the STGS problem is modeled aiming the minimization of total electricity generating cost while meeting prevailing system constraints over the specified scheduling period as a daily or weekly time horizon. Moreover, a clear, step by step, and more applicable model structure to the STGS problem in real-life is also obtained. Since the optimization is performed regarding the power load balance, system emission limits, minimum up and down times and generation limits, the total cost at the end of the scheduling horizon is significantly improved as a result of the short term scheduling optimization.

Since the STGS model is formulated as a MINLP problem and merges the two subproblems, it has a non-trivial structure featuring various non-linear relationships and combinatorial characteristics. On the other hand, as primarily technical information about the PPTs are taken into account, power generation capacities, emission characteristics, fuel costs, efficiencies, start-up and shut-down durations of different types of PPTs are examined and compiled. The set of generating facility considered is a hypothetical representative data set of PPTs is used in the model. Even though it is aimed to reflect the

technical characteristics of the Turkish generating facilities, in some cases, the data set contains generic data from international companies, because of the lack of reliable data associated with the Turkish facilities.

After the generation of the data set and model construction, a wide range of scenarios have been generated by adjusting one or more key parameter values. The STGS model is solved under each scenario setting and the results of the scenarios are examined and discussed. The key parameters of the scenarios can be listed as, total system greenhouse gas (CO<sub>2</sub>) emission limit, system power demand, total cost per unit production, and minimum up and down time durations. According to the comparative analysis of the scenario results related to the two day time horizon STGS; the main findings can be summarized as follows:

- As the system load/power demand increases, the total utilization rate of the entire system increases regarding the increase in the amount of the total power generation. Moreover, the ratio of total supply/total demand always equals to one.
- When the total system emission limit is increased, the optimal total system cost significantly decreases.
- When fuel cost per unit production of coal plants and natural gas plants are increased, the utilization rates of the natural gas plants are decreased as expected. However, utilization rates of the coal plants are considerably increased associated with having their fuel cost less increased compared to natural gas plants. On the other hand, the utilization rates of other most costly generating unit groups (e.g. wind turbines) increase associated with the feature of not discharging any CO<sub>2</sub> emission.
- It is observed that, the effects of relaxations in minimum up/down time limitations are insignificant regarding the slight changes in the utilization rates of natural gas plants and unchanged utilizations of coal plants.
- When the power demand fluctuations are taken into account while keeping the total power demand unchanged, utilization rates of the high emission (coal) generators during the higher demand periods are increased. Also, demand fluctuations have distinct effects on natural gas based individual generating units which have long up and down time limits. When natural gas based PPTs are faced with power demand

variation, they cannot keep up with this fluctuation and then shut down. Additionally, the utilization rates of high cost natural gas plants are decreased at hours in which demand loads are minimum.

On the other hand, since the STGS problem is formulated as a MINLP model, increasing the model size is actually challenging and makes the problem computationally burdensome to solve. By increasing the amount of PPTs or extending the scheduling horizon brings more complexity to the STGS problem regarding the challenging usage of non-linear constraints. Furthermore, average compilation time of the STGS model is recorded as 30 minutes corresponding size of the problem. But when the problem size is tried to be increased much compilation time is needed in order to run the model.

In future studies, the STGS model can be expanded in terms of some parameters which are neglected in this study, such as transmission lines, ramp rates and spinning reserves. Accordingly, constraints regarding these parameters could be considered for power systems, including transmission networks, at the cost of increasing model complexity and computational difficulties.

As for some additional items to study, selection of multiple objectives such as cost minimization, profit maximization and/or emission minimization could be considered in the STGS model. Accordingly, carrying multiple objectives would bring a more comprehensive model structure. Also, load forecasting would be required for market price forecasting, since the profit maximization is to be in consideration. Thus, an extensive analysis regarding the effects of different threshold values (according to resource types and attributes) would certainly be worthwhile in future models.

It is expected that this model will provide an efficient power generation schedule of a determined PPT set for any specified scheduling period such as a daily or weekly time horizon. However, through a further study, much large scheduling periods can also be examined. On the other hand, the constructed STGS model will be used by the operators or project managers to get a realistic power generation schedule of a given PPT set before the scheduling and operational processes.

In the light of these findings, it is believed that further effort of research on the STGS problems will provide additional insights to electric power systems. Also, it is hoped that this study will bring about various point of view and activate further research in this regard in future.



Table A. 2. The optimal schedule of case 2 for the base scenario in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2																									
3											194,00	245,10	194,00	194,00	255,10	194,00									
4																									
5	1440,00	1440,00	1315,84	1137,84	1028,84	829,84	843,84	1312,84	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11											42,00	81,00		42,00	81,00	43,10	81,00								
12	1120,10	731,10	601,26	601,26	601,26	601,26	601,26	601,26	1576,10	2308,10	2267,10	2405,00	2243,10	2396,10	2405,00	2405,00	2405,00	2203,10	1839,10	1757,10	1945,10	2122,10	2033,10	1775,10	
13																									
14																									
15																	55,10								
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2																									
3								194,00	194,00	194,00	194,00	245,10	194,00	194,00	255,10	194,00					194,00	194,00	194,00	194,00	
4																									
5	1440,00	1440,00	1315,84	1137,84	1440,00	1431,10	1440,00	1118,84	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11					81,00						42,00	81,00		42,00	81,00	43,10	81,00								
12	1120,10	731,10	601,26	601,26				601,26	1382,10	2114,10	2267,10	2405,00	2243,10	2396,10	2405,00	2405,00	2405,00	2203,10	1839,10	1757,10	1751,10	1928,10	1839,10	1581,10	
13																									
14					24,30		5,10											24,30							
15					84,80													30,80							

Table A. 3. The optimal schedule of case 3 for the base scenario in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2																									
3											194,00	245,10	194,00	194,00	255,10	194,00	194,00	194,00	194,00	194,00	194,00	194,00	194,00	194,00	
4																									
5	1440,00	1440,00	1315,84	1137,84	1028,84	1431,10	843,84	1312,84	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11											42,00	81,00		42,00	81,00	43,10	42,00								
12	1120,10	731,10	601,26	601,26	601,26		601,26	601,26	1576,10	2308,10	2267,10	2405,00	2243,10	2396,10	2405,00	2405,00	2305,10	2009,10	1645,10	1563,10	1751,10	1928,10	1839,10	1581,10	
13																									
14																									
15																									
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2																									
3	194,00	194,00	194,00	194,00	194,00	194,00	194,00	194,00	194,00	194,00	194,00	245,10	194,00	194,00	255,10	194,00					194,00	194,00	194,00	194,00	
4																									
5	1440,00	1375,84	1121,84	943,84	834,84	635,84	649,84	1118,84	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11											42,00	81,00		42,00	81,00	43,10	81,00								
12	926,10	601,26	601,26	601,26	601,26	601,26	601,26	601,26	1382,10	2114,10	2267,10	2405,00	2243,10	2396,10	2405,00	2405,00	2405,00	2203,10	1839,10	1563,10	1751,10	1928,10	1839,10	1581,10	
13																									
14																		24,30							
15																		30,80							

Table A. 4. The optimal schedule of demand scenario 1 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	210,00	210,00	210,00	148,46	126,00			210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2											252,00	496,30	252,00	377,30	508,30	414,60	293,60							
3										589,30	571,30	600,00	571,28	600,00	600,00	600,00	600,00	487,60	194,00	194,00	321,10	533,10	401,80	194,00
4																								
5	1285,80	278,80	206,00	206,00	206,00	206,00	206,00	206,00	1292,80	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1341,10	1440,00	1440,00	1440,00	1337,80
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	486,00	486,00	486,00	377,46	446,10	281,46	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13		540,00	308,80	180,64	180,64		180,64	305,80	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30					24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30							24,30
15										142,50	142,50	142,50	63,52	142,50	142,50	142,50	142,50	142,50	0,10					
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	210,00	210,00	210,00	148,46	198,10	126,00	126,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2													252,00	496,30	286,80	377,30	508,30	390,30	269,30					
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	463,30	194,00	194,00	321,10	533,10	426,10
4																								
5	1285,80	818,80	514,80	206,00	206,00	206,00	206,00	511,80	1292,80	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1415,80	1316,80	1440,00	1440,00	1440,00	1337,80
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	486,00	486,00	486,00	486,00	320,10	336,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13				180,64					540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30					24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										131,80	113,80	142,50		142,50	142,50	142,50	142,50	142,50						

Table A. 5. The optimal schedule of demand scenario 1 in terms of up and down time durations.

(Values in paranthesis correspond to down time durations: Xoff(i,t), while others stand for up time durations: Xon(i,t))

XoN(i,t) & Xoff(i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	1	2	3	4	5	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
2	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	1	2	3	4	5	6	7	(1)	(2)	(3)	(4)	(5)	(6)	(7)
3	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
4	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
6	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
7	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
8	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
9	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
10	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
11	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
12	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
13	(1)	1	2	3	4	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
14	1	2	3	4	5	(1)	(2)	1	2	3	4	5	6	7	8	(1)	(2)	(3)	(4)	(5)	(6)	(7)	1	2
15	(1)	(2)	1	2	(1)	1	1	(1)	1	2	3	4	5	6	7	8	9	10	11	(1)	(2)	(3)	(4)	(5)
XoN(i,t) & Xoff(i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
2	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	1	2	3	4	5	6	7	(1)	(2)	(3)	(4)	(5)	(6)	(7)
3	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
4	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
5	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
6	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
7	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
8	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
9	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
10	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
11	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
12	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
13	(1)	(2)	(3)	1	(1)	(2)	(3)	(4)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
14	3	4	5	6	7	8	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	(1)	(2)	(3)	1
15	(1)	(2)	(3)	(4)	(5)	1	2	3	4	5	6	7	(1)	1	2	3	4	5	(1)	(2)	(3)	(4)	(5)	(6)



Table A. 7. The optimal schedule of demand scenario 2 in terms of up and down time durations.

<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>4</b>	<b>5</b>	<b>6</b>	<b>7</b>	<b>8</b>	<b>9</b>	<b>10</b>	<b>11</b>	<b>12</b>	<b>13</b>	<b>14</b>	<b>15</b>	<b>16</b>	<b>17</b>	<b>18</b>	<b>19</b>	<b>20</b>	<b>21</b>	<b>22</b>	<b>23</b>	<b>24</b>
<b>1</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	(1)	(2)	(3)	(4)	(5)	(6)	(7)
<b>5</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>6</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>7</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>8</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>9</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>10</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>11</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>12</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>13</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>14</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>15</b>	1	(1)	1	2	3	(1)	1	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>25</b>	<b>26</b>	<b>27</b>	<b>28</b>	<b>29</b>	<b>30</b>	<b>31</b>	<b>32</b>	<b>33</b>	<b>34</b>	<b>35</b>	<b>36</b>	<b>37</b>	<b>38</b>	<b>39</b>	<b>40</b>	<b>41</b>	<b>42</b>	<b>43</b>	<b>44</b>	<b>45</b>	<b>46</b>	<b>47</b>	<b>48</b>
<b>1</b>	25	26	27	28	(1)	(2)	(3)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	(1)	(2)	(3)	(4)	(5)	(6)	(7)
<b>5</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>6</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>7</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>8</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>9</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>10</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>11</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>12</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>13</b>	25	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
<b>14</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>15</b>	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40

Table A. 8. The optimal schedule of demand scenario 3 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1										210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2											252,00	496,30	252,00	377,30	508,30	390,30	269,30								
3										589,30	571,30	600,00	492,30	600,00	600,00	600,00	600,00	463,30							
4																									
5										1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	919,80	828,80	1.035,80	1.229,80	1.131,80	506,80
6									120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7									131,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00
9	1.058,30	1.432,00	1.348,04	1.241,04	1.199,74	1.057,04	1.065,04	783,03	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00
10	23,70	23,70	23,70	23,70		23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11									81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2.405,00	670,30	601,26	601,26	601,26	601,26	601,26	1.165,27	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00
13										540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50						
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1										210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2											252,00	496,30	252,00	377,30	508,30	390,30	269,30								
3										589,30	571,30	600,00	492,30	600,00	600,00	600,00	600,00	463,30							
4																									
5										1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	919,80	828,80	1.035,80	1.229,80	1.131,80	506,80
6									120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7									131,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00
9	1.432,00	720,00							1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11									81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2.031,30	1.382,30	1.949,30	1.842,30	1.777,30	1.658,30	1.666,30	1.948,30	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00
13										540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50							

Table A. 9. The optimal schedule of demand scenario 3 in terms of up and down time durations.

<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>4</b>	<b>5</b>	<b>6</b>	<b>7</b>	<b>8</b>	<b>9</b>	<b>10</b>	<b>11</b>	<b>12</b>	<b>13</b>	<b>14</b>	<b>15</b>	<b>16</b>	<b>17</b>	<b>18</b>	<b>19</b>	<b>20</b>	<b>21</b>	<b>22</b>	<b>23</b>	<b>24</b>
<b>1</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	1	2	3	4	5	6	7	(1)	(2)	(3)	(4)	(5)	(6)	(7)
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	(1)	(2)	(3)	(4)	(5)	(6)
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>5</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>6</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>7</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>8</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>9</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>10</b>	1	2	3	4	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
<b>11</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>12</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>13</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>14</b>	1	(1)	(2)	(3)	1	(1)	1	2	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>15</b>	1	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	3	4	5	6	7	8	9	(1)	1	2	3	4	5
<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>25</b>	<b>26</b>	<b>27</b>	<b>28</b>	<b>29</b>	<b>30</b>	<b>31</b>	<b>32</b>	<b>33</b>	<b>34</b>	<b>35</b>	<b>36</b>	<b>37</b>	<b>38</b>	<b>39</b>	<b>40</b>	<b>41</b>	<b>42</b>	<b>43</b>	<b>44</b>	<b>45</b>	<b>46</b>	<b>47</b>	<b>48</b>
<b>1</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	1	2	3	4	5	(1)	(2)	(3)	(4)	(5)	(6)	(7)
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	(1)	(2)	1	2	3	(1)
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>5</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>6</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>7</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>8</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>9</b>	25	26	(1)	(2)	(3)	(4)	(5)	(6)	1	2	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>10</b>	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43
<b>11</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>12</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>13</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>14</b>	16	17	(1)	(2)	(3)	1	2	3	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>15</b>	(1)	1	2	3	(1)	1	2	3	(1)	1	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13



Table A. 11. The optimal schedule of the cost scenario in terms of up and down time durations.

<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>4</b>	<b>5</b>	<b>6</b>	<b>7</b>	<b>8</b>	<b>9</b>	<b>10</b>	<b>11</b>	<b>12</b>	<b>13</b>	<b>14</b>	<b>15</b>	<b>16</b>	<b>17</b>	<b>18</b>	<b>19</b>	<b>20</b>	<b>21</b>	<b>22</b>	<b>23</b>	<b>24</b>
<b>1</b>	1	2	(1)	(2)	(3)	(4)	1	2	3	4	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>5</b>	(1)	(2)	(3)	(4)	(5)	(6)	1	2	3	(1)	(2)	(3)	1	2	3	4	5	6	7	8	9	10	11	12
<b>6</b>	1	2	3	(1)	(2)	(3)	1	2	3	4	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>7</b>	(1)	(2)	(3)	(4)	(5)	(6)	1	2	3	4	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>8</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>9</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>10</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>11</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>12</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>13</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>14</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>15</b>	1	2	3	4	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>25</b>	<b>26</b>	<b>27</b>	<b>28</b>	<b>29</b>	<b>30</b>	<b>31</b>	<b>32</b>	<b>33</b>	<b>34</b>	<b>35</b>	<b>36</b>	<b>37</b>	<b>38</b>	<b>39</b>	<b>40</b>	<b>41</b>	<b>42</b>	<b>43</b>	<b>44</b>	<b>45</b>	<b>46</b>	<b>47</b>	<b>48</b>
<b>1</b>	13	14	(1)	(2)	(3)	(4)	1	2	(1)	(2)	(3)	(4)	1	2	3	4	5	6	7	8	9	10	11	12
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>5</b>	(1)	(2)	(3)	(4)	(5)	(6)	1	2	3	4	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>6</b>	(1)	(2)	(3)	(4)	(5)	(6)	1	2	3	4	(1)	(2)	1	2	3	4	5	6	7	8	9	10	11	12
<b>7</b>	13	14	(1)	(2)	(3)	(4)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
<b>8</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>9</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>10</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>11</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>12</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>13</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>14</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>15</b>	19	(1)	(2)	(3)	1	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18



Table A. 13. The optimal schedule of time scenario 1 in terms of up and down time durations.

<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>4</b>	<b>5</b>	<b>6</b>	<b>7</b>	<b>8</b>	<b>9</b>	<b>10</b>	<b>11</b>	<b>12</b>	<b>13</b>	<b>14</b>	<b>15</b>	<b>16</b>	<b>17</b>	<b>18</b>	<b>19</b>	<b>20</b>	<b>21</b>	<b>22</b>	<b>23</b>	<b>24</b>
<b>1</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	3	4	5	6	7	8	9	10	11	(1)	(2)	1	2	(1)
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>5</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>6</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>7</b>	1	2	(1)	(2)	(3)	(4)	(5)	(6)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>8</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>9</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>10</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>11</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>12</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>13</b>	1	2	3	4	5	6	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	(1)
<b>14</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>15</b>	1	2	3	(1)	1	(1)	1	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>25</b>	<b>26</b>	<b>27</b>	<b>28</b>	<b>29</b>	<b>30</b>	<b>31</b>	<b>32</b>	<b>33</b>	<b>34</b>	<b>35</b>	<b>36</b>	<b>37</b>	<b>38</b>	<b>39</b>	<b>40</b>	<b>41</b>	<b>42</b>	<b>43</b>	<b>44</b>	<b>45</b>	<b>46</b>	<b>47</b>	<b>48</b>
<b>1</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	2	(1)	1	2	3	4	5	6	7	(1)	(2)	1	2	3	(1)
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>5</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>6</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>7</b>	17	(1)	(2)	(3)	(4)	(5)	(6)	(7)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>8</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>9</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>10</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>11</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>12</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>13</b>	1	2	3	(1)	1	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
<b>14</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>15</b>	(1)	1	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21

Table A. 14. The optimal schedule of time scenario 2 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1									126,00		210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	150,80	196,30	210,00		126,00	
2																									
3																									
4																									
5										765,30	750,30	978,30	684,30	879,30	988,30	889,30	788,30	450,30	228,80	206,00	206,00	511,80	490,30	206,00	
6	120,20	120,20	120,20	120,20	108,00	60,10	60,10	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	205,80								393,30	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	386,30
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1248,80	994,80	816,80	720,00	720,00	720,00	991,80	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13	540,00	540,00	540,00	540,00	540,00	388,90	402,90	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15									142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50			142,50		142,50	142,50
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1							126,00	126,00		210,00	210,00	210,00	210,00	210,00	210,00	210,00			126,00		210,00	210,00			
2																									
3																									
4																									
5										765,30	750,30	978,30	684,30	879,30	988,30	889,30	788,30	660,30	438,80	206,00	402,30	369,30	280,30	232,30	
6	120,20	120,20	120,20	120,20	108,00	60,10	60,10	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	93,00								478,99	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1248,80	994,80	816,80	720,00	720,00	720,00	1405,80	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13	540,00	540,00	540,00	540,00	540,00	388,90	402,90		540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15	112,80								56,81	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50			24,80	142,50	142,50	142,50	142,50

Table A. 15. The optimal schedule of time scenario 2 in terms of up and down time durations.

<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>4</b>	<b>5</b>	<b>6</b>	<b>7</b>	<b>8</b>	<b>9</b>	<b>10</b>	<b>11</b>	<b>12</b>	<b>13</b>	<b>14</b>	<b>15</b>	<b>16</b>	<b>17</b>	<b>18</b>	<b>19</b>	<b>20</b>	<b>21</b>	<b>22</b>	<b>23</b>	<b>24</b>
<b>1</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	1	(1)	1	2	3	4	5	6	7	8	9	10	11	12	(1)	1
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>5</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>6</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>7</b>	1	(1)	(2)	(3)	(4)	(5)	(6)	(7)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>8</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>9</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>10</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>11</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>12</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>13</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>14</b>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
<b>15</b>	(1)	1	(1)	(2)	(3)	1	(1)	1	2	3	4	5	6	7	8	9	10	11	(1)	(2)	1	(1)	1	2
<b>XoN(i,t) &amp; Xoff(i,t)</b>	<b>25</b>	<b>26</b>	<b>27</b>	<b>28</b>	<b>29</b>	<b>30</b>	<b>31</b>	<b>32</b>	<b>33</b>	<b>34</b>	<b>35</b>	<b>36</b>	<b>37</b>	<b>38</b>	<b>39</b>	<b>40</b>	<b>41</b>	<b>42</b>	<b>43</b>	<b>44</b>	<b>45</b>	<b>46</b>	<b>47</b>	<b>48</b>
<b>1</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	1	2	(1)	1	2	3	4	5	6	7	(1)	(2)	1	(1)	1	2	(1)
<b>2</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>3</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>4</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
<b>5</b>	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
<b>6</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>7</b>	17	(1)	(2)	(3)	(4)	(5)	(6)	(7)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>8</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>9</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>10</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>11</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>12</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>13</b>	25	26	27	28	29	30	31	(1)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<b>14</b>	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
<b>15</b>	3	4	5	6	7	(1)	1	(1)	1	2	3	4	5	6	7	8	9	10	(1)	1	2	3	4	5



Table A. 17. The optimal schedule of the second mixed scenario in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	210,00	210,00	210,00	210,00	210,00	210,00	179,22	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2												252,00	496,30	252,00	377,30	508,30	390,30	269,30	463,30					
3																								
4																								
5	1352,00	885,00	581,00	367,00	236,00	538,00	206,00	1118,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6												120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7												196,30	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1188,78	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13	540,00	540,00	540,00	540,00	540,00		540,00		540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15												142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2													252,00	496,30	252,00	377,30	508,30	390,30	269,30	252,00	252,00	252,00	252,00	252,00
3													337,30	571,30	600,00	492,30	600,00	600,00	600,00	211,30	194,00		194,00	194,00
4																								
5	1352,00	885,00	581,00	907,00	776,00	538,00	554,00	578,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6												120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7												196,30	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	93,00	162,30	194,30	406,30
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13	540,00	540,00	540,00					540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15													142,50	142,50	142,50	142,50	142,50	142,50	142,50	116,80	142,50	142,50	142,50	142,50

Table A. 18. The optimal schedule of the third mixed scenario in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	210,00	210,00			210,00		182,10		210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2											252,00	496,30	252,00	377,30	508,30	390,30	269,30								
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	194,00	194,00	296,80	508,80	401,80	194,00	
4																									
5	1105,16	638,16	724,80	510,80				721,80	1309,88	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1415,80	1316,80	1440,00	1440,00	1440,00	1337,80	
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	486,00	486,00	486,00	486,00	471,46	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	
13	180,64	180,64			180,64	180,64			522,92	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	
14	24,30	24,30	24,30	24,30	13,46			24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	
15										131,80	113,80	142,50	34,80	142,50	142,50	142,50	142,50	5,80							
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1	210,00	210,00	210,00	210,00			182,10	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2										252,00	365,80	496,30	252,00	377,30	508,30	390,30	269,30	252,00	252,00	252,00	252,00	252,00	252,00	252,00	
3										479,80	600,00	600,00	600,00	600,00	600,00	600,00	600,00	353,80	194,00	194,00	194,00	256,80	194,00		
4																									
5	745,80	818,80	514,80		379,80	206,00		331,16	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1163,80	1064,80	1290,80	1440,00	1395,80	1279,80	
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	486,00	486,00	486,00	486,00	265,46	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	
13	540,00			300,80		180,64		180,64	392,80	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	
14	24,30	24,30	24,30	24,30	24,30			24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	
15												142,50	34,80	142,50	142,50	142,50	142,50								







Table A. 22. The optimal schedule of case 1 related to demand scenario 2 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2										284,30	538,30	630,00	452,30	630,00	630,00	630,00	587,30	590,30	252,00	252,00	254,30	484,30	368,30	252,00
3									516,80	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	500,80	600,00	600,00	600,00	523,80
4										442,00	442,00	645,30	442,00	517,30	658,30	530,30	442,00							
5	1363,80	857,80	696,08	656,16	694,80	256,16	206,00	524,80	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13	540,00	540,00	372,72	180,64		180,64	247,80	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	7,80		142,50	142,50	142,50	
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2										284,30	538,30	630,00	452,30	630,00	630,00	630,00	587,30	590,30	252,00	252,00	254,30	484,30	368,30	252,00
3									516,80	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	500,80	600,00	600,00	600,00	523,80
4										442,00	442,00	645,30	442,00	517,30	658,30	530,30	442,00							
5	1363,80	857,80	528,80	296,80	694,80	436,80	453,80	1064,80	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13	540,00	540,00	540,00	540,00					540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	7,80		142,50	142,50	142,50	

Table A. 23. The optimal schedule of case 2 related to demand scenario 2 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2									481,10	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	559,46
3	488,10	194,00	194,00						600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00
4										442,00	492,80	787,80	442,00	659,80	800,80	672,80	541,80								
5	1440,00	1309,10	980,10	1118,39	1440,00	1440,00	1440,00	1170,10	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00								81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2228,71	1760,12	1507,10	1524,10	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13										336,80	540,00	540,00	504,80	540,00	540,00	540,00	540,00	540,00	194,10			306,80	536,80	420,80	180,64
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30					24,30	24,30	24,30	
15																		127,10		87,10					
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2									481,10	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	536,46	630,00	630,00	630,00	
3	488,10								600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	
4										442,00	492,80	787,80	442,00	659,80	800,80	672,80	551,80								
5	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11	81,00	63,10							81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	
12	2405,00	2405,00	2139,10	1907,10	1760,12	1507,10	1524,10	2135,10	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	
13										336,80	540,00	540,00	504,80	540,00	540,00	540,00	540,00	540,00	180,64	180,60	330,50	540,00	444,50		
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	13,46		24,30	24,30	24,30	
15																		102,80				20,50		109,50	

Table A. 24. The optimal schedule of case 1 related to demand scenario 3 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1									174,80	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2										431,30	630,00	630,00	601,30	630,00	630,00	630,00	630,00	293,30							
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	194	194	224,3	580,8	329,3		
4										442,00	501,30	801,30	442,00	671,30	815,30	684,30	551,30	442,00							
5										1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.384,80	1.440,00	1.440,00	1.440,00	1.224,80
6	110,30	60,10	60,10							120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,2	120,2	120,2	120,2	120,2	120,2	
7										486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350	1350	1350	1350	1350	1350	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00
9	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	884,00	1.369,04	720,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2.405,00	957,20	790,20	732,30	660,30	1.077,30	601,26	1.560,30	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00
13										540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	44,80			142,50		142,50	
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1										174,80	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2										431,30	630,00	630,00	601,30	630,00	630,00	630,00	630,00	630,00	293,30						
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	194	194	366,8	438,3	329,3	194	
4										442,00	501,30	801,30	442,00	671,30	815,30	684,30	551,30	442,00							
5										1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.384,80	1.440,00	1.440,00	1.440,00	1.030,80
6										120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,2	120,2	120,2	120,2	120,2	120,2	
7										486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00
9	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.360,04	1.369,04	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2334,66	1017,3	850,3	732,3	660,3	601,26	601,26	848,30	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00
13	180,64									540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	44,80				142,50		142,50	

Table A. 25. The optimal schedule of case 2 related to demand scenario 3 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	210,00	126,00	126,00	126,00	126,00	126,00	126,00	126,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2									252,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	252,00	252,00	331,10	545,10	436,10	
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	551,10	451,10	600,00	600,00	600,00	349,10
4										442,00	643,80	943,80	555,80	813,80	957,80	826,80	693,80	442,00						
5	1097,84	206,00	206,00	206,00	206,00	206,00	206,00	206,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6	120,20	60,10	60,10	60,10	60,10	60,10	60,10	60,10	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	93,00	93,00	93,00				93,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1280,94	1113,94	995,94	1016,94	885,94	894,94	1111,94	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	601,26	601,26	601,26	601,26	601,26	601,26	601,26	601,26	783,10	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13										483,80	540,00	540,00	540,00	540,00	540,00	540,00	540,00	345,80						
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30						
15																								
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	210,00	210,00	210,00	210,00	210,00	126,00	126,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2									252,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00			331,10	545,10	436,10	372,80
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	
4										442,00	643,80	943,80	555,80	813,80	957,80	826,80	693,80	787,80						
5	1097,84	206,00	206,00	206,00	206,00	206,00	206,00	206,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6	120,20	120,20	120,20	120,20	120,20	104,30	113,30	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	481,10	314,10	196,10	124,10	93,00	93,00	312,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	601,26								783,10	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13										483,80	540,00	540,00	540,00	540,00	540,00	540,00	540,00		203,10					
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30						
15																					103,10			





Table A. 28. The optimal schedule of case 3 related to the cost scenario in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2																								
3												194,00	194,00	194,00	194,00	194,00								
4																								
5	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6													120,20	120,20	120,20	120,20	120,20	118,36	60,10					
7																								
8	590,30	201,30	200,00	200,00					1046,30	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1068,56	1227,30	1234,66	1350,00	1322,66	1245,30
9	1432,00	1432,00	1179,30	1001,30	1092,30	893,30	907,30	1376,30	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13										404,00	2405,00	512,80	218,80	413,80	522,80	423,80	516,80	180,64	180,64		180,64	218,00	180,64	
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30				24,30		
15																								
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2																								
3													194,00	194,00	194,00	194,00								
4																								
5	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6											120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20						
7																								
8	590,30	201,30	200,00					200,00	946,66	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1209,66	1308,30	1350,00	1350,00	1350,00	1326,30
9	1432,00	1432,00	1179,30	1201,30	1092,30	893,30	988,30	1257,30	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11	81,00	81,00	81,00	81,00	81,00	81,00				81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00					81,00		
12	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13									180,64	283,80	478,80	512,80	218,80	413,80	522,80	423,80	516,80	259,80	180,64			218,00	234,30	
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30			24,30	24,30		
15																					122,00			

Table A. 29. The optimal schedule of case 1 related to time scenario 1 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	159,10								210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2																									
3												245,10	194,00	194,00	255,10	194,00	194,00	194,00							
4																									
5	206,00	206,00	206,00	206,00	206,00				611,10	1343,10	1440,00	1440,00	1278,10	1392,10	1440,00	1440,00	1301,10	1044,10	874,10	792,10	980,10	1076,10	1068,10	729,10	
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11											81,00	81,00		81,00	81,00	43,10	81,00					81,00		81,00	
12	2405,00	2175,10	1921,10	1743,10	1634,10	1641,10	1655,10	2124,10	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	
13																									
14											17,10														
15																									
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1	129,10								210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2																									
3	194,00	194,00			194,00	194,00						194,00	326,10		194,00	255,10	194,00								
4																									
5									530,10	1343,10	1263,10	1440,00	1415,93	1431,10	1440,00	1440,00	1440,00	1238,10	874,10	792,10	980,10	1157,10	1049,80	791,80	
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11	42,00								81,00		81,00		56,17	42,00	81,00	43,10	81,00						42,00	42,00	
12	2405,00	2187,10	2127,10	1949,10	1646,10	1447,10	1655,10	2124,10	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	
13																									
14																		24,30							
15																		30,80							





Table A. 32. The optimal schedule of case 1 related to time scenario 2 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	159,1		126		150,73		210		210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210
2																								
3												245,1		194	255,1	194	194							
4																								
5	206								611,1	1343,1	1440	1440	1440	1431,1	1440	1440	1340,1	1238,1	874,1	792,1	980,1	1157,1	1068,1	810,1
6	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2
7	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486
8	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350
9	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432
10	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7
11											81	81		42	81	43,1	42							
12	2405	2381,1	2001,1	1949,1	1689,37	1641,1	1445,1	2124,1	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405
13																								
14											17,10		24,3											
15													7,30											
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	210		210	210				210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210
2																								
3												245,1		194	255,1	194								
4																								
5	206								611,1	1343,1	1440	1440	1440	1431,1	1440	1440	1440	1238,1	874,1	792,1	980,1	1157,1	1068,1	810,1
6	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2	120,2
7	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486	486
8	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350	1350
9	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432	1432
10	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7	23,7
11											81	81		42	81	43,1	81							
12	2354,1	2381,1	1917,1	1739,1	1840,1	1641,1	1655,1	1914,1	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405	2405
13																								
14											17,10							24,3						
15													32,1					30,8						

Table A. 33. The optimal schedule of case 2 related to time scenario 2 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2																								
3	194,00	194,00		194,00	194,00	194,00	194,00	194,00	194,00	194,00	194,00	245,10		194,00	255,10	194,00	194,00							
4																								
5	1440,00	1375,84	1315,84	943,84	834,84	1237,10	1251,10	1118,84	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11												42,00	81,00		42,00	81,00	43,10	42,00		42,00				
12	926,10	601,26	601,26	601,26	601,26			601,26	1382,10	2114,10	2267,10	2405,00	2405,00	2396,10	2405,00	2405,00	2305,10	2203,10	1839,10	1715,10	1945,10	2122,10	2033,10	1775,10
13																								
14														24,30										
15																								
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48
1	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00
2																								
3													245,10	194,00	194,00	255,10	194,00		194,00					
4																								
5	1440,00	1440,00	1315,84	1137,84	1028,84	1431,10	843,84	1312,84	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11												81,00	81,00		42,00	81,00	43,10	81,00						
12	1120,10	731,10	601,26	601,26	601,26		601,26	601,26	1576,10	2308,10	2405,00	2405,00	2243,10	2396,10	2405,00	2405,00	2405,00	2009,10	1839,10	1757,10	1945,10	2122,10	2033,10	1775,10
13																								
14												17,10						24,30						
15																		30,80						



Table A. 35. The optimal schedule of case scenario related to time scenario 1 and demand scenario 3 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1										210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2											252,00	496,30	252,00	377,30	508,30	390,30	269,30								
3										589,30	571,30	600,00	492,30	600,00	600,00	600,00	600,00	463,30							
4																									
5										1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	919,80	828,80	1035,80	1229,80	1131,80	506,80	
6								60,10	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7									131,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1058,30	720,00	720,00	720,00	720,00	720,00	720,00	720,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11									81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2405,00	1382,30	1229,30	1122,30	1057,30	938,30	946,30	1168,20	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13										540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50							
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1										210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2										252,00	252,00	496,30	252,00	377,30	508,30	390,30	269,30								
3										337,30	571,30	600,00	492,30	600,00	600,00	600,00	600,00	463,30							
4																									
5										1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	919,80	828,80	1035,80	1229,80	1131,80	506,80	
6									120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7									131,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1272,42	200,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1058,30	720,00	720,00	720,00	720,00	720,00	720,00	720,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11									81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	
12	2405,00	1382,30	1229,30	1122,30	1057,30	938,30	1023,88	2378,30	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	
13										540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50							

Table A. 36. The optimal schedule of case 2 related to time scenario 1 and demand scenario 3 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	210,00	210,00							210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2										515,46	630,00	630,00	409,10	630,00	592,46	474,46	534,10	252,00							
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	476,10			241,10	354,10	256,10		
4												548,80	442,00	442,00	442,00	442,00	442,00	442,00	442,00						
5	413,84	206,00	206,00	206,00	206,00				1.319,84	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.123,10	1.440,00	1.440,00	1.440,00	1.440,00	1.152,10	
6	120,20	120,20	120,20	111,30	60,10	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7	486,00	134,10	191,10	93,00	93,00	106,10	114,10	396,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1.350,00	1.350,00	1.350,00	1.350,00	1.336,20	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00
9	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00		42,00		81,00	81,00		
12	801,26								601,26	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.397,10	2.405,00	2.405,00	2.405,00	
13										180,64	275,80				180,64	180,64									
14											24,30	24,30		12,10											
15																									
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1	210,00	210,00	210,00	197,10	132,10				210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2						252,00	252,00	252,00	252,00	515,46	488,10	580,46	409,10	630,00	592,46	630,00	630,00	389,46							
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	194,00		194,00	354,10	256,10		
4											442,00	442,00	442,00	442,00	442,00										
5	206,00								206,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.371,10	1.440,00	1.440,00	1.440,00	1.440,00	1.110,10	
6				120,20	120,20				120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	460,30	307,30	93,00	93,00			264,30	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.324,30	1.332,30	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	
9	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00			47,10	81,00	81,00	42,00	
12	1.129,30								1.463,10	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	
13										180,64		180,64			180,64	442,80	321,80	180,64							
14														12,10		24,30	24,30			24,30					
15																				9,80					



Table A. 38 The optimal schedule of case 1 related to time scenario 2 and demand scenario 3 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1										210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2												252,00	496,30	252,00	377,30	508,30	390,30	269,30							
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	194,00						
4																									
5										1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	744,15	828,80	1035,80	1440,00	1440,00	506,80
6										120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7										131,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00			1241,04			1065,04		1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11									81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2031,30	2102,30	1949,30	601,26	1777,30	1658,30	601,26	1948,30	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13										540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	521,65	540,00	540,00	329,80	231,80	540,00
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										131,80	113,80	142,50	34,80	142,50	142,50	142,50	142,50	5,80							
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1										210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2												252,00	496,30	252,00	377,30	508,30	390,30	269,30							
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	194,00						
4																									
5	206,00									1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	725,80	828,80	1035,80	1229,80	1131,80	506,80
6										120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7										131,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00
9	1432,00		1348,04		1176,04		1065,04		1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11									81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	1825,30	2102,30	601,26	1842,30	601,26	1658,30	601,26	1948,30	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00
13										540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										131,80	113,80	142,50	34,80	142,50	142,50	142,50	142,50	5,80							

Table A. 39. The optimal schedule of case 2 related to time scenario 2 and demand scenario 3 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	210,00	210,00	210,00	210,00	210,00			210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2										630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00	570,10							
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	194,00	194,00		354,10	256,10		
4												573,10			560,80										
5	1215,10								1319,84	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	
6	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	340,10	187,10					186,10	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	42,00		81,00	81,00	81,00		
12										601,26	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2294,10	2245,10	2405,00	2405,00	2405,00	1936,46	
13												275,80	196,80	429,80		442,80	321,80							180,64	
14				24,30		24,30	24,30			24,30	24,30		24,30	24,30	24,30	24,30	24,30				24,30				
15				55,80	15,10	81,80	89,80			41,80											135,80				
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1	210,00	210,00	126,00	126,00	126,00			126,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2										630,00	630,00	630,00	630,00	630,00	630,00	630,00	630,00		252,00						
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00				354,10	256,10		
4															560,80										
5	1034,46								1139,20	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	1440,00	
6	120,20	120,20	117,66	60,10	60,10	60,10	60,10	116,66	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7	486,00	159,46	93,00	93,00	93,00			93,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1350,00	1350,00	1350,00	1300,56	1235,56	1335,56	1343,56	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	1350,00	
9	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	1432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00			81,00	81,00	81,00		
12										601,26	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2405,00	2278,10	2405,00	2405,00	2405,00	2405,00	2117,10	
13	180,64	180,64	180,64	180,64	180,64	180,64	180,64	180,64	180,64		275,80	540,00	196,80	429,80		442,80	321,80	540,00							
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30			24,30	24,30				
15										41,80		8,80						30,10		9,80	135,80				



Table A. 41. The optimal schedule for the mixed scenario related to time scenario 2 and demand scenario 3 in terms of unit commitment and power generation.

P (i,t)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1									199,10	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2										431,30	630,00	630,00	630,00	630,00	630,00	630,00	630,00	293,30							
3										600,00	600,00	600,00			600,00		600,00	600,00	238,80		391,10	462,60	353,60	194,00	
4										442,00	501,30	801,30	1.013,30	1.271,30	815,30	1.284,30	551,30	442,00							
5										1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.055,10	
6	110,30									120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20
7										486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00
8	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00
9	1.432,00	1.432,00	1.432,00	1.359,81	1.432,00	1.327,58	1.369,04	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00
12	2.405,00	1.017,30	850,30	804,49	660,30	633,72	601,26	848,30	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00
13										540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50		138,80		142,50	142,50	
P (i,t)	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	
1									199,10	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	210,00	
2										431,30	630,00	630,00	601,30	630,00	630,00	630,00	630,00								
3										600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	600,00	194,00		224,30	438,30	329,30		
4										442,00	501,30	801,30	442,00	671,30	815,30	684,30	551,30	735,30							
5										1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.440,00	1.224,80	
6	110,30									120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	120,20	
7										486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	486,00	
8	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00		1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	1.350,00	
9	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.360,04	1.369,04	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	1.432,00	
10	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	23,70	
11										81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	81,00	
12	2.405,00	1.017,30	850,30	732,30	660,30	601,26	601,26	2.198,30	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	2.405,00	
13										540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	540,00	
14										24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	24,30	
15										142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	142,50	44,80	138,80	142,50	142,50	142,50		

## APPENDIX B: RESULTS OF THE SCENARIOS

Table B.1. The main results of case 1 related to demand scenario 1.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,74
<b>Total Power Generation (MWh)</b>	385.342
<b>Total Cost (\$/MWh)</b>	43.229.589
<b>Total Emission (tons)</b>	220.000

Table B.2. The detailed results of case 1 related to demand scenario 1.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	1.00	0.66	0.27	1.00	0.51
	2	0.63			0.47	
	3	0.69			0.62	
	4	0.00			0.00	
	5	1.00			0.90	
Natural Gas	6	1.00	1.00	0.42	1.00	1.00
	7	1.00			1.00	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	1.00	0.83	0.30	1.00	0.80
	11	0.79			0.67	
	12	0.92			0.93	
	13	0.60			0.24	
Wind	14	0.81	0.61	0.00	0.31	0.05
	15	0.42			0.01	

Table B.3. The main results of case 2 related to demand scenario 1.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,74
<b>Total Power Generation (MWh)</b>	385.342
<b>Total Cost (\$/MWh)</b>	43.222.509
<b>Total Emission (tons)</b>	225.000

Table B.4. The detailed results of case 2 related to demand scenario 1.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	1,00	0,66	0,28	1,00	0,53
	2	0,65			0,50	
	3	0,67			0,60	
	4	0,00			0,00	
	5	1,00			0,96	
Natural Gas	6	1,00	1,00	0,42	1,00	1,00
	7	1,00			1,00	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	1,00	0,75	0,29	1,00	0,77
	11	0,65			0,65	
	12	1,00			0,90	
	13	0,35			0,24	
Wind	14	0,63	0,66	0,00	0,23	0,04
	15	0,69			0,01	

Table B.5. The main results of case 3 related to demand scenario 1.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,74
<b>Total Power Generation (MWh)</b>	385.342
<b>Total Cost (\$/MWh)</b>	43.407.842
<b>Total Emission (tons)</b>	241.860

Table B.6. The detailed results of case 3 related to demand scenario 1.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1.00	0.69	0.29	1.00	0.56
	2	0.54			0.40	
	3	0.67			0.61	
	4	0.23			0.07	
	5	1.00			1.00	
Natural Gas	6	1.00	1.00	0.42	1.00	1.00
	7	1.00			1.00	
	8	1.00			1.00	
	9	1.00			1.00	
Hydro	10	1.00	0.76	0.28	1.00	0.74
	11	0.67			0.66	
	12	1.00			0.86	
	13	0.38			0.21	
Wind	14	0.67	0.70	0.00	0.23	0.04
	15	0.73			0.01	

Table B.7. The main results of case 1 related to demand scenario 2.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,80
<b>Total Power Generation (MWh)</b>	417.448
<b>Total Cost (\$/MWh)</b>	48.953.978
<b>Total Emission (tons)</b>	225.000

Table B.8. The detailed results of case 1 related to demand scenario 2.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1,00	0,73	0,26	1,00	0,53
	2	0,63			0,45	
	3	0,67			0,65	
	4	0,33			0,12	
	5	1,00			0,83	
Natural Gas	6	1,00	1,00	0,39	1,00	1,00
	7	1,00			1,00	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	1,00	0,97	0,34	1,00	0,97
	11	1,00			1,00	
	12	1,00			1,00	
	13	0,90			0,85	
Wind	14	1,00	0,92	0,01	1,00	0,57
	15	0,83			0,50	

Table B.9. The main results of case 2 related to demand scenario 2.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,80
<b>Total Power Generation (MWh)</b>	417.448
<b>Total Cost (\$/MWh)</b>	48.586.027
<b>Total Emission (tons)</b>	250.000

Table B.10. The detailed results of case 2 related to demand scenario 2.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1,00	0,76	0,31	1,00	0,63
	2	0,69			0,65	
	3	0,75			0,71	
	4	0,35			0,15	
	5	1,00			0,98	
Natural Gas	6	1,00	1,00	0,39	1,00	1,00
	7	1,00			1,00	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	0,92	0,81	0,30	0,92	0,86
	11	0,73			0,72	
	12	1,00			0,95	
	13	0,58			0,48	
Wind	14	0,83	0,77	0,00	0,51	0,13
	15	0,71			0,07	

Table B.11. The main results of case 1 related to demand scenario 3.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,68
<b>Total Power Generation (MWh)</b>	353.276
<b>Total Cost (\$/MWh)</b>	40.965.033
<b>Total Emission (tons)</b>	190.000

Table B.12. The detailed results of case 1 related to demand scenario 3.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,67	0,53	0,26	0,66	0,41
	2	0,38			0,34	
	3	0,60			0,49	
	4	0,38			0,16	
	5	0,63			0,61	
Natural Gas	6	0,73	0,85	0,47	0,71	0,93
	7	0,67			0,67	
	8	1,00			1,00	
	9	1,00			0,98	
Hydro	10	1,00	0,83	0,35	1,00	0,78
	11	0,67			0,67	
	12	1,00			0,81	
	13	0,65			0,63	
Wind	14	1,00	0,90	0,01	0,67	0,50
	15	0,79			0,47	

Table B.13. The main results of case 2 related to demand scenario 3.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.68
<b>Total Power Generation (MWh)</b>	353,276
<b>Total Cost (\$/MWh)</b>	40,572,416
<b>Total Emission (tons)</b>	219,370

Table B.14. The detailed results of case 2 related to demand scenario 3.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	1,00	0,72	0,33	0,93	0,52
	2	0,60			0,51	
	3	0,60			0,59	
	4	0,38			0,20	
	5	1,00			0,74	
Natural Gas	6	1,00	0,98	0,48	0,92	0,95
	7	0,94			0,79	
	8	1,00			0,97	
	9	1,00			1,00	
Hydro	10	0,98	0,71	0,29	0,98	0,63
	11	0,63			0,63	
	12	0,85			0,69	
	13	0,38			0,35	
Wind	14	0,73	0,70	0,00	0,38	0,07
	15	0,67			0,02	

Table B.15. The main results of case 1 related to cost scenario.

<b>Supply/Demand</b>	1.00
<b>Total Utilization Rate</b>	0.62
<b>Total Power Generation (MWh)</b>	321.120
<b>Total Cost (\$/MWh)</b>	45.812.048
<b>Total Emission (tons)</b>	150.000

Table B.16. The detailed results of case 1 related to cost scenario.

Power Resource Type	PPT	Open (up) hours %	Average up hours % of PPT groups	Total production % of PPT groups	Utilization Rate	Utilization rates of PPT groups
Coal	1	1,00	0,57	0,20	1,00	0,31
	2	0,00			0,00	
	3	0,83			0,27	
	4	0,00			0,00	
	5	1,00			0,65	
Natural Gas	6	0,38	0,59	0,40	0,21	0,79
	7	0,00			0,00	
	8	1,00			0,90	
	9	1,00			1,00	
Hydro	10	1,00	0,88	0,40	1,00	0,88
	11	1,00			1,00	
	12	1,00			1,00	
	13	0,52			0,32	
Wind	14	0,79	0,74	0,00	0,79	0,12
	15	0,69			0,00	

Table B.17. The main results of case 2 related to cost scenario.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.120
<b>Total Cost (\$/MWh)</b>	45.502.727
<b>Total Emission (tons)</b>	167.210

Table B.18. The detailed results of case 2 related to cost scenario.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,98	0,51	0,27	1,00	0,42
	2	0,00			0,00	
	3	0,58			0,21	
	4	0,00			0,00	
	5	1,00			1,00	
Natural Gas	6	0,50	0,58	0,34	0,43	0,67
	7	0,00			0,00	
	8	0,83			0,66	
	9	1,00			0,93	
Hydro	10	1,00	0,84	0,39	1,00	0,86
	11	1,00			1,00	
	12	1,00			1,00	
	13	0,38			0,24	
Wind	14	0,73	0,73	0,00	0,36	0,07
	15	0,73			0,02	

Table B.19. The main results of case 3 related to cost scenario.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.120
<b>Total Cost (\$/MWh)</b>	45.477.939
<b>Total Emission (tons)</b>	163.060

Table B.20. The detailed results of case 3 related to cost scenario.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1,00	0,45	0,25	1,00	0,40
	2	0,00			0,00	
	3	0,23			0,07	
	4	0,00			0,00	
	5	1,00			1,00	
Natural Gas	6	0,35	0,55	0,34	0,34	0,67
	7	0,00			0,00	
	8	0,83			0,68	
	9	1,00			0,94	
Hydro	10	1,00	0,84	0,41	1,00	0,89
	11	0,81			0,81	
	12	1,00			1,00	
	13	0,54			0,42	
Wind	14	0,71	0,73	0,00	0,44	0,08
	15	0,75			0,02	

Table B.21. The main results of case 1 related to time scenario 1.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.120
<b>Total Cost (\$/MWh)</b>	34.304.630
<b>Total Emission (tons)</b>	150.000

Table B.22. The detailed results of case 1 related to time scenario 1.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,71	0,36	0,15	0,70	0,24
	2	0,00			0,00	
	3	0,33			0,12	
	4	0,00			0,00	
	5	0,77			0,55	
Natural Gas	6	1,00	1,00	0,51	1,00	1,00
	7	1,00			1,00	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	0,96	0,58	0,34	0,96	0,75
	11	0,38			0,31	
	12	1,00			0,93	
	13	0,00			0,00	
Wind	14	0,77	0,69	0,00	0,04	0,01
	15	0,60			0,00	

Table B. 23. The main results of case 2 related to time scenario 1.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.120
<b>Total Cost (\$/MWh)</b>	34.105.627
<b>Total Emission (tons)</b>	189.980

Table B. 24. The detailed results of case 2 related to time scenario 1.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1,00	0,48	0,25	1,00	0,40
	2	0,00			0,00	
	3	0,21			0,13	
	4	0,17			0,00	
	5	1,00			0,97	
Natural Gas	6	1,00	1,00	0,51	1,00	1,00
	7	1,00			1,00	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	0,96	0,53	0,24	0,96	0,53
	11	0,25			0,17	
	12	0,92			0,66	
	13	0,00			0,00	
Wind	14	0,81	0,75	0,00	0,01	0,00
	15	0,69			0,00	

Table B.25. The main results of case 3 related to time scenario 1.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.120
<b>Total Cost (\$/MWh)</b>	34.116.447
<b>Total Emission (tons)</b>	187.960

Table B.26. The detailed results of case 3 related to time scenario 1.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1,00	0,47	0,25	1,00	0,39
	2	0,00			0,00	
	3	0,33			0,12	
	4	0,00			0,00	
	5	1,00			0,95	
Natural Gas	6	0,98	0,99	0,51	0,98	1,00
	7	1,00			1,00	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	1,00	0,53	0,25	1,00	0,54
	11	0,29			3,12	
	12	0,83			0,57	
	13	0,00			0,00	
Wind	14	0,88	0,82	0,00	0,02	0,02
	15	0,77			0,02	

Table B.27. The main results of case 1 related to time scenario 2.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.120
<b>Total Cost (\$/MWh)</b>	34.252.308
<b>Total Emission (tons)</b>	150.000

Table B.28. The detailed results of case 1 related to time scenario 2.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,83	0,37	0,15	0,81	0,24
	2	0,00			0,00	
	3	0,19			0,07	
	4	0,00			0,00	
	5	0,81			0,55	
Natural Gas	6	1,00	1,00	0,51	1,00	1,00
	7	1,00			1,00	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	1,00	0,55	0,34	1,00	0,75
	11	0,25			0,20	
	12	0,94			0,94	
	13	0,00			0,00	
Wind	14	0,50	0,44	0,00	0,07	0,02
	15	0,38			0,01	

Table B.29. The main results of case 2 related to time scenario 2.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.120
<b>Total Cost (\$/MWh)</b>	34.130.161
<b>Total Emission (tons)</b>	188.750

Table B.30. The detailed results of case 2 related to time scenario 2.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1,00	0,49	0,25	1,00	0,39
	2	0,00			0,00	
	3	0,44			0,15	
	4	0,00			0,00	
	5	1,00			0,95	
Natural Gas	6	1,00	1,00	0,51	1,00	1,00
	7	1,00			1,00	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	1,00	0,55	0,24	1,00	0,54
	11	0,27			0,20	
	12	0,94			0,66	
	13	0,00			0,00	
Wind	14	0,67	0,65	0,00	0,06	0,01
	15	0,63			0,00	

Table B. 31. The main results of case 3 related to time scenario 2.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.120
<b>Total Cost (\$/MWh)</b>	34.128.782
<b>Total Emission (tons)</b>	190.000

Table B. 32. The detailed results of case 3 related to time scenario 2.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	1,00	0,49	0,25	1,00	0,40
	2	0,00			0,00	
	3	0,46			0,16	
	4	0,00			0,00	
	5	0,98			0,96	
Natural Gas	6	1,00	1,00	0,51	1,00	1,00
	7	1,00			1,00	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	1,00	0,55	0,24	1,00	0,53
	11	0,27			0,19	
	12	0,94			0,65	
	13	0,00			0,00	
Wind	14	0,71	0,68	0,00	0,05	0,01
	15	0,65			0,01	

Table B. 33. The main results of case scenario 1 related to time scenario 1&demand scenario 3.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.160
<b>Total Cost (\$/MWh)</b>	36.357.646
<b>Total Emission (tons)</b>	150.000

Table B. 34. The detailed results of case scenario 1 related to time scenario 1&demand scenario 3.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,63	0,39	0,18	0,63	0,29
	2	0,31			0,18	
	3	0,38			0,35	
	4	0,00			0,00	
	5	0,63			0,54	
Natural Gas	6	0,69	0,84	0,44	0,68	0,86
	7	0,67			0,64	
	8	1,00			0,98	
	9	1,00			0,84	
Hydro	10	1,00	0,82	0,37	1,00	0,81
	11	0,67			0,67	
	12	1,00			0,86	
	13	0,63			0,63	
Wind	14	0,81	0,75	0,01	0,63	0,41
	15	0,69			0,38	

Table B. 35. The main results of case 2.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.160
<b>Total Cost (\$/MWh)</b>	35.446.907
<b>Total Emission (tons)</b>	190.000

Table B. 36. The detailed results of case 2.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,81	0,57	0,26	0,80	0,40
	2	0,46			0,35	
	3	0,52			0,43	
	4	0,27			0,09	
	5	0,79			0,65	
Natural Gas	6	0,88	0,96	0,49	0,86	0,97
	7	0,96			0,81	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	1,00	0,61	0,25	1,00	0,56
	11	0,52			0,49	
	12	0,71			0,66	
	13	0,21			0,09	
Wind	14	0,65	0,69	0,00	0,12	0,02
	15	0,73			0,00	

Table B. 37. The main results of case 3.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.160
<b>Total Cost (\$/MWh)</b>	35.723.893
<b>Total Emission (tons)</b>	198.140

Table B. 38. The detailed results of case 3.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,94	0,62	0,22	0,88	0,42
	2	0,42			0,32	
	3	0,48			0,42	
	4	0,48			0,16	
	5	0,79			0,69	
Natural Gas	6	0,98	0,96	0,39	0,93	0,92
	7	0,85			0,75	
	8	1,00			0,99	
	9	1,00			1,00	
Hydro	10	1,00	0,58	0,37	1,00	0,98
	11	0,46			0,44	
	12	0,67			0,62	
	13	0,19			0,09	
Wind	14	0,83	0,85	0,01	0,12	0,71
	15	0,88			0,00	

Table B. 39. The main results of case scenario 1 related to time scenario 2 and demand scenario 3.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.160
<b>Total Cost (\$/MWh)</b>	36.389.519
<b>Total Emission (tons)</b>	150.000

Table B. 40. The detailed results of case scenario 1 related to time scenario 2 and demand scenario 3 case 1.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,63	0,40	0,19	0,63	0,29
	2	0,29			0,17	
	3	0,42			0,39	
	4	0,00			0,00	
	5	0,65			0,54	
Natural Gas	6	0,67	0,79	0,43	0,67	0,85
	7	0,67			0,64	
	8	1,00			1,00	
	9	0,81			0,79	
Hydro	10	1,00	0,82	0,37	1,00	0,82
	11	0,67			0,67	
	12	1,00			0,87	
	13	0,63			0,60	
Wind	14	0,85	0,83	0,01	0,63	0,34
	15	0,81			0,29	

Table B. 41. The main results of case 2.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.160
<b>Total Cost (\$/MWh)</b>	35.419.345
<b>Total Emission (tons)</b>	188.420

Table B. 42. The detailed results of case 2.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,92	0,51	0,25	0,88	0,40
	2	0,38			0,36	
	3	0,50			0,43	
	4	0,06			0,03	
	5	0,71			0,69	
Natural Gas	6	1,00	0,97	0,49	0,96	0,96
	7	0,88			0,76	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	1,00	0,66	0,25	1,00	0,56
	11	0,52			0,51	
	12	0,67			0,63	
	13	0,46			0,24	
Wind	14	0,77	0,80	0,00	0,44	0,14
	15	0,83			0,09	

Table B. 43. The main results of case 3.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,62
<b>Total Power Generation (MWh)</b>	321.160
<b>Total Cost (\$/MWh)</b>	35.385.482
<b>Total Emission (tons)</b>	188.880

Table B. 44. The detailed results of case 3.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,92	0,51	0,25	0,91	0,40
	2	0,35			0,33	
	3	0,50			0,42	
	4	0,08			0,03	
	5	0,71			0,70	
Natural Gas	6	1,00	0,97	0,49	1,00	0,97
	7	0,90			0,78	
	8	1,00			1,00	
	9	1,00			1,00	
Hydro	10	1,00	0,66	0,25	1,00	0,55
	11	0,52			0,49	
	12	0,67			0,62	
	13	0,44			0,23	
Wind	14	0,77	0,80	0,00	0,42	0,13
	15	0,83			0,09	

Table B. 45. The main results of mixed scenario related to time scenario 2 and demand scenario 3.

<b>Supply/Demand</b>	1,00
<b>Total Utilization Rate</b>	0,68
<b>Total Power Generation (MWh)</b>	353.276
<b>Total Cost (\$/MWh)</b>	41.071.926
<b>Total Emission (tons)</b>	190.000

Table B. 46. The detailed results of mixed scenario related to time scenario 2 and demand scenario 3.

<b>Power Resource Type</b>	<b>PPT</b>	<b>Open (up) hours %</b>	<b>Average up hours % of PPT groups</b>	<b>Total production % of PPT groups</b>	<b>Utilization Rate</b>	<b>Utilization rates of PPT groups</b>
Coal	1	0,67	0,50	0,26	0,66	0,41
	2	0,35			0,33	
	3	0,50			0,41	
	4	0,38			0,19	
	5	0,63			0,62	
Natural Gas	6	0,71	0,84	0,47	0,70	0,93
	7	0,67			0,67	
	8	0,98			0,98	
	9	1,00			0,99	
Hydro	10	1,00	0,82	0,35	1,00	0,78
	11	0,67			0,67	
	12	1,00			0,81	
	13	0,63			0,63	
Wind	14	0,75	0,72	0,01	0,54	0,53
	15	0,69			0,53	

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