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Μεταπτυχιακή Εργασία

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υπό

ΠΑΝΑΓΙΩΤΗ ΑΝΔΡΙΑΝΕΣΗ

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Η έγκριση της μεταπτυχιακής εργασίας από το Τμήμα Μηχανολόγων Μηχανικών της Πολυτεχνικής Σχολής του Πανεπιστημίου Θεσσαλίας δεν υποδηλώνει αποδοχή των απόψεων του συγγραφέα (Ν. 5343/32 αρ. 202 παρ. 2).

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Παναγιώτης Ανδριανέσης

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Περίληψη

Στην παρούσα μεταπτυχιακή εργασία ορίζεται, μοντελοποιείται και επιλύεται το πρόβλημα του βραχυπρόθεσμου προγραμματισμού της παραγωγής για το σύστημα ηλεκτρικής ενέργειας της Κύπρου.

Αρχικά, περιγράφεται συνοπτικά το σύστημα ηλεκτρικής ενέργειας της Κύπρου, με ιδιαίτερη έμφαση στον τομέα της παραγωγής.

Στη συνέχεια, διατυπώνεται η μαθηματική μορφοποίηση ενός προβλήματος μεικτού ακέραιου γραμμικού προγραμματισμού που περιγράφει το πρόβλημα ένταξης μονάδων και κατανομής της παραγωγής, και το οποίο αποτυπώνει τα βασικά χαρακτηριστικά του βραχυπρόθεσμου προγραμματισμού της παραγωγής.

Τέλος, επιλύεται το πρόβλημα με τη χρήση εξειδικευμένου λογισμικού βελτιστοποίησης και παρουσιάζονται αριθμητικά αποτελέσματα, τα οποία επιτρέπουν την εξαγωγή χρήσιμων συμπερασμάτων για την πρακτική αξία του μοντέλου.

SHORT-TERM GENERATION SCHEDULING

FOR THE ELECTRICAL POWER SYSTEM OF CYPRUS

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Abstract

In the present master thesis, the short-term generation scheduling problem for the electrical power system of Cyprus is defined, modeled, and solved.

Initially, the electrical power system of Cyprus is described, with particular emphasis on the electricity generation sector.

Furthermore, the mathematical formulation of a mixed integer linear programming problem that describes the unit commitment and economic dispatch problem and captures the main characteristics of the short-term generation scheduling is stated.

Finally, the problem is solved with the use of specialized optimization software, and numerical results are presented, which allow the derivation of useful conclusions on the practical value of the model.

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Chapter 1. Introduction

The scope of this thesis is to describe the short-term generation scheduling problem in Cyprus as a constrained optimization problem, whose objective is to minimize the overall system cost. The problem is modeled as a Mixed Integer Linear Programming (MILP) problem.

This problem is faced daily by the Electricity Authority of Cyprus (EAC) that is called to decide the scheduling of its generation units for the next day. Apart from the high practical interest to the EAC, the problem has also significant research interest, as it refers to an isolated power system with many particularities.

1.1 Motivation

The motivation for the work performed in this thesis has been the communication with the EAC representatives during two energy-related conferences that were held in Cyprus in 2009 and 2010, namely DISTRES and MEDPOWER10 respectively. The outcome of the discussions, which was based on the works presented at the conferences [1] and [2], was the common understanding for the need to develop a tailor-made model that would describe the short-term generation scheduling problem for the electrical power system of Cyprus, as a unit commitment and economic dispatch problem. The problem should simultaneously address the unit commitment and economic dispatch of the generation units, while satisfying the various system and units' constraints.

Currently, the model that is used by the EAC for the short-term generation scheduling is an Excel-based program that performs the economic dispatch, after the user (experienced EAC personnel) has defined the unit commitment; the latter is done manually according to the experience of the user. An iterative procedure is then manually performed to check for alternative solutions and/or satisfy any constraints that were found to be violated. Therefore, it is evident that it is highly unlikely that the currently applied procedure results in an optimal solution.

At this point, we should mention that a tragic event modified to some extent the work that had been performed for this thesis. The explosion of 11/7/2011 in Mari, near the Vasilikos

Power Station, caused extensive damages to all the generation units in that station, which was the heart of the electrical power sector of Cyprus. The loss of approximately half of the installed capacity created a totally new environment in Cyprus. Therefore, the thesis was appropriately adjusted to take into account the current system conditions.

1.2 Literature Review

The problem addressed in this thesis falls into the general category of the "so-called" **unit commitment** and **generation scheduling** problem that is a very important and particularly challenging problem in the electrical power industry.

In general, the problem aims at minimizing the system operational costs of the generation units by providing an optimal schedule of power production for each unit, so that the demand for electricity is met. The generators must operate within certain technical limits; however, the operational constraints, such as the ramp and the minimum up and down time constraints, in addition to the scale of the problem, make large unit commitment problems particularly challenging to solve.

A thorough bibliographical survey of the unit commitment problem is provided by [13]. The paper presents mathematical formulations, and general backgrounds of research and developments in the field of the unit commitment problem based on more than 150 published (until 2003) articles.

Even though the unit commitment model was developed in the monopolistic era, it can be easily extended to produce generation schedules in a competitive market environment [4]. The problem remains particularly important today, even after the deregulation of the power industry [16], as many wholesale electricity markets call on the Independent System Operator (ISO) to determine day-ahead schedules for generation units based on a centralized unit commitment.

The unit commitment problem is generally modeled as a large-scale non-convex problem, and various approaches have been developed to solve it. These approaches have ranged from highly complex and theoretically complicated methods to simple rule-of thumb methods.

Reviews on the methodologies that were employed to solve the unit commitment and generation scheduling problem (until 2003) are listed in [13] and [20].

In the real world, the time required to solve the unit commitment models was a hard practical limitation, which was restricting the size and scope of the problem's formulations. Up until recently, the Lagrangian Relaxation (LR) algorithm was the only practical means of solving an ISO-scale unit commitment problem, and it was the solution technique used by most ISOs in the U.S. However, the availability of modern software has made branch-and bound based techniques for solving MILP an attractive option. As it is reviewed by [12], the first MILP unit commitment formulation was described in [8] with a formulation that used three sets of binary variables to model the on/off status of generation units, and has been extensively used ever since. Recent advances in computing capabilities and optimization algorithms now make the solution of MILP formulations tractable, often with optimality gaps smaller than those of LR algorithms. This development has led most ISOs to adopt this approach. Furthermore, strengthening the basic unit commitment formulation is expected to have a positive effect in solving more advanced models, and a number of recent works have addressed this issue (e.g.[5], [12]).

On the downside, using actual market data from an ISO, [15] demonstrates that both LR and MILP solutions suffer the equity issues that were first identified by [11] for the LR case. Because different commitments that are similar in terms of total system costs can result in different surpluses to individual units, this drawback is inevitable unless the ISO unit commitment problems can be solved to complete optimality within the available timeframe, which is beyond current computational capabilities. From a fairness perspective, this is important in competitive markets as two near-optimal solutions can produce considerably different payments to generator owners.

Last but not least, we should mention that despite the rich literature on the topic of the unit commitment problem (updating the surveys [13], [20] could be a thesis itself), to date, the modeling of the real-sized problem for the electrical power system of Cyprus has not been implemented. To the best of our knowledge, no literature for the unit commitment problem in the Cyprus electrical power system exists; this has been also verified by the EAC and the Cyprus TSO personnel.

1.3 Contribution of the Thesis

The contribution of this thesis can be summarized in **"defining, modeling, and solving the short-term generation scheduling problem in Cyprus."** The model developed in this thesis decides the unit commitment and economic dispatch, co-optimizing the energy, reserve, and commitment costs, while satisfying the system, units', and other constraints; this was not done in Cyprus so far.

Significant effort has been made to define the problem, since this was not formally defined for the electrical power system of Cyprus. One could say that this has been the most difficult part, and can be considered as half of this work. The problem was finally sufficiently defined in cooperation with the EAC, in order to address its needs.

Modeling the problem as an MILP optimization problem is an additional contribution of this thesis, as a sound mathematical formulation has not been implemented so far for the system of Cyprus.

Since the problem addressed in this thesis has high practical interest to the EAC, the solution of the problem in reasonable computational times can be considered as another contribution. In this thesis, the problem is modeled using GAMS [9], and solved with GAMS/CPLEX solver; the input data and the output results were displayed on Excel worksheets.

1.4 Structure of the Thesis

This thesis is structured as follows.

Chapter 2 presents an overview of the electrical power system of Cyprus. A short overview of the history of electricity in Cyprus is also presented along with the history of the EAC. Furthermore, the main aspects of the electrical power system, such as the installed capacity, the transmission system, and the system load, are sketched.

Chapter 3 describes the model of the unit commitment and economic dispatch problem. Firstly, a short description of the main features of the problem is presented. Secondly, a sound mathematical formulation is listed for a basic model that captures the most important features of the problem. Lastly, certain extensions are provided to better address some of the particularities of the problem, and the needs of the EAC.

Chapter 4 shows the numerical results based on the conditions prior to and after the event of 11/7/2011. The basic model is first presented, and then varied to certain directions that seem to be the most interesting among the ones described in Chapter 3.

Chapter 5 summarizes and concludes.

The thesis is supplemented with three Appendices. Appendix A clarifies the procedure for the calculation of the marginal (incremental) cost and of the no-load cost, derived from the heat rate, either directly from the discrete measurements of the heat rate or from the heat rate curve. Appendix B lists the nomenclature of the optimization problem that is presented in Chapter 3. Lastly, the abbreviations that appear in this thesis are shown in Appendix C.

Chapter 2. Description of Cyprus' Electrical Power System

This chapter presents a brief description of the electrical power system of Cyprus. In what follows, a short overview of the history of electricity in Cyprus along with the history of the Electricity Authority of Cyprus (EAC) [7] is sketched. A description of the electricity generation sector and of the current installed capacity is then listed, and the transmission system is reported along with the role of the Cyprus Transmission System Operator (TSO) [17] and of the National Energy Control Center (NECC). Lastly, system load data and profiles are presented.

2.1 The History of Electricity in Cyprus and the Electricity Authority of Cyprus (EAC)

Electricity was first introduced in Cyprus in 1903 with the installation of a power generator to serve the needs of the British colonial government in the capital, Lefkosia. Shortly afterwards, a second generator was installed at the Lefkosia General Hospital. The first company, which operated a power station with generators, was formed in Lemesos, in 1912 (The Limassol Electric Light Company), and was followed by the Nicosia Electricity Company in 1913. Naturally, within the course of a few years, all other towns followed. By 1952, there were 28 companies (sixteen of these were municipal or communal companies) serving 6 major towns and 22 smaller townships and villages.

The need for rapid expansion of electricity supply in the whole country led to the establishment of a centralized system for electricity generation and distribution. On March 20th 1950, work commenced on the construction of a power station in Dhekelia, near Larnaka. With the construction of the first power station, there was a need to set up an organization responsible for the generation, transmission and distribution of electricity in Cyprus. Therefore, on October 30th 1952, the Electricity Authority of Cyprus (EAC) was established under the "Electricity Development Law," whose main objectives were the rational organization of generation, transmission and distribution of electricity throughout the island. In the first two years, the EAC was busy with the expropriation of the small companies in towns.

The first phase of the Dhekelia power station was completed and put into operation on February 2nd 1953. The station reached a total capacity of 84MW, and used imported heavy fuel oil. Further to the construction of the Dhekelia Power Station, the main transmission lines were constructed, linking the station with the main towns.

Following the establishment of the Republic of Cyprus in 1960, the pace of the island's electrification scheme was impressive. The number of consumers, which in 1960 was 80,000, rose to 120,000 by 1966, to 183,000 by 1973, to 313,000 by 1993, to reach 512,000 by 2009. Even more impressive is the fact that the number of towns and villages connected to the electric grid, which was 100 in 1960, reached 527 in 1972, covering all towns and villages of the island.

With the rapid development of all sectors of the Cyprus economy, it soon became apparent that one power station could no longer meet the growing demands for electricity supply. A suitable location was found on the south coast near Moni village, and the EAC proceeded with the construction of a second power station. The first phase of the new station was operational in 1966, and by 1976, when the station was completed, it had an output of 180MW. Until 2010, the Moni Power Station comprised of six steam-turbine units of 30MW each and four gas turbine units of 37.5MW each, with a total output of 330MW.

The impressive growth of the EAC was abruptly halted in July of 1974, following the Turkish invasion of Cyprus and the occupation of 40% of the island's territory. Nevertheless, the Cyprus economy made a rapid recovery, and it soon became evident that there was a need to build a new power station to replace the ageing Dhekelia Station, which was by then becoming uneconomical. Work commenced in February 1980, on a site next to the old station, for the construction of the "Dhekelia ‘B’ Power Station". The first unit of 60MW was completed and commissioned in 1982. Additional units were commissioned in 1983, 1992 and 1993. The Dhekelia “B” Power Station was finally completed in 1993, with a total capacity of 360MW. Following its completion, the Dhekelia “A” Power Station, which had operated for more than 30 years (usual lifetime of such a station), was decommissioned in June 2002 and then dismantled.

In 1997, work began for the construction of a new power station in the Vasilikos area. The Vasilikos Power Station is situated 28 km east of Lemesos, in the vicinity of Governor's Beach and Zygi. The first phase of the Power Station was completed in 2000 and comprised of one gas turbine unit of 37.5MW and two steam-turbine units of 130MW each. A third steam-turbine unit of 130MW was constructed and put in operation in 2007. An additional unit of 220MW came into the grid in 2009; this unit is of combined cycle type, dual firing, using natural gas or diesel oil.

Some indicative figures on the generation sector, the electricity sales, the financial results and the personnel of the EAC are shown in the following Tables [7].

Table 1. Generation Sector of the EAC

Description	2010	2009	Increase (Decrease) %
Total units generated (GWh)	5 204,9	5 133,3	1,4
Installed capacity (MW)	1 438	1 388	7,5
Peak load (MW)	1 148	1 098	4,6
Thermal efficiency of generation (%)	36,08	33,74	6,9
Fuel consumption of generation (tonnes)	1 210 542	1 254 999	(3,5)
Cost of fuel (million €)	439,510	344,915	27,4
Load Factor (%)	51,8	53,4	(3,0)

Table 2. Electricity Sales of the EAC

Description	2010	2009	Increase (Decrease) %
Total Sales (GWh)	4 782,0	4 655,8	2,7
Unbilled consumption (GWh)	7,8	8,4	(7,1)
Average charge per kWh sold (cents)	16,232	13,473	(20,5)
Average Charge per kWh unbilled (cents)	13,72	12,355	11,0
Consumers on Year-End	535 050	520 030	2,9

Table 3. Financial Results of the EAC

Description	2010	2009	Increase (Decrease) %
Total income (million €)	810,159	651,131	24,4
Operating costs (million €)	698,062	595,095	17,3
Profit from operations (million €)	112,097	56,036	100,0
Finance costs-net (million €)	10,243	10,757	(4,8)
Net profit (million €)	73,175	103,584	(29,4)
Capital expenditure (million €)	281,976	269,212	4,7
Return on average net assets employed (%)	6,7	3,6	86,1

Table 4. Personnel of the EAC

Description	2010	2009	Increase (Decrease) %
Permanent Employees in service as at end of the year	2 465	2 466	(0,1)
Sales of electricity per Employee (GWh)	1,94	1,89	2,6
Consumers per Employee	217	211	2,8

2.2 The Electricity Generation Sector

Currently, the electricity generation sector in Cyprus is practically associated with the EAC. In 2011, the EAC owns 26 generation units at its three Power Stations:

- Vasilikos Power Station (VPS)
- Dhekelia Power Station (DPS)
- Moni Power Station (MPS)

The installed capacity of the EAC generation units in the year 2011 is shown in **Table 5** [17].

Table 5. Installed Capacity of the EAC Generation Units

Power Station	**Installed Capacity (MW) per Unit Type**				**Total**
	CCGT (Gasoil)	**ST** (Heavy Fuel Oil)	**GT** (Gasoil)	**ICE** (Heavy Fuel Oil)	
Vasilikos	1 x 220	3 x 130	1 x 37.5	-	**647.5**
Dhekelia	-	6 x 60	-	6 x 16.7	**460.2**
Moni	-	5 x 30	4 x 37.5	-	**300.0**
Total	**220**	**900**	**187.5**	**100.2**	**1407.7**

In addition, there is a self-producer (Vasilikos Cement Works), with installed capacity 11MW (6MW available), a wind park (Oreites) with installed capacity 82MW in the area near Pafos, and another wind park with installed capacity 20MW in the area near the Larnaca airport.

Also, an additional wind park with installed capacity 30MW in the area between Lefkosia and Larnaca is about to enter in operation.

A new CCGT unit of the EAC with installed capacity 220MW, located in the Vasilikos Power Station, was expected to be commissioned in the near future, first in an open cycle mode and then as a combined cycle plant (in 2012).

Unfortunately, the **explosion of 11/7/2011** in Mari, near the Vasilikos Power Station, caused extensive damages to all the generation units in that station (see **Figure 1**), resulting in a **loss of 647.5 MW**, i.e. **46% of the installed capacity of the EAC units**. Up to September 2011, only the GT unit of 37.5MW has been repaired and is currently operational.

Figure 1. Pictures from Vasilikos Power Station (October 13th, 2011).

To deal with this major loss of power, the EAC contracted with the Greek Public Power Corporation (PPC) and with Energy International, and has currently installed 70MW (ICE) in Vasilikos Power Station from PPC, 60MW (ICE) in Dhekelia Power Station and 35MW (ICE) in Moni Power Station from Energy International. In addition, the EAC is purchasing energy from the northern part (with maximum available capacity ranging from 40MW to 120MW, depending on the load and the unit availability in that part).

The installed capacity, which is currently (September 2011) operational, is shown in **Table 6** [17]. The Table does not include the self-producer, the wind parks, and the purchases.

Table 6. Installed Capacity Operational in September 2011

Power Station	Installed Capacity (MW) per Unit Type				Total
	CCGT	ST	GT	ICE	
Vasilikos	-	-	1 x 37.5	1 x 70	**107.5**
Dhekelia	-	6 x 60	-	6 x 16.7 1 x 60	**520.2**
Moni	-	5 x 30	4 x 37.5	1 x 35	**335.0**
Total	**-**	**510**	**187.5**	**265.2**	**962.7**

According to the latest information on the progress of the repair activities, the first CCGT unit in Vasilikos Power Station will start in an open cycle mode in May 2012, and shortly afterwards in a combined cycle mode. It is estimated that the second CCGT unit in Vasilikos Power Station will also have entered the grid by the end of 2012.

2.3 The Transmission System

The electricity generated by the three power stations owned and run by the EAC is carried through the high voltage transmission system (132kV and 66kV) to the transmission substations located near urban, industrial or other areas, through which the main demand for electrical energy is provided. At the transmission substations the high voltage is converted to medium voltage 11kV and through the overhead or underground distribution network the consumer's requirements are satisfied through the 415V, 50Hz distribution substations. The length of the transmission lines in 2005 was 537.1km at 132kV, and 326.26km at 66kV.

Figure 2 [17] shows the geographical location of all power stations and their connection to the transmission system, the location and interconnections of all transmission substations as well as the routes of 66kV, 132kV and 220kV transmission lines and cables. The part of the transmission network north of the Ceasefire Line beyond which the Government of the

Republic of Cyprus cannot exercise effective control is shown as it was installed before July 1974.

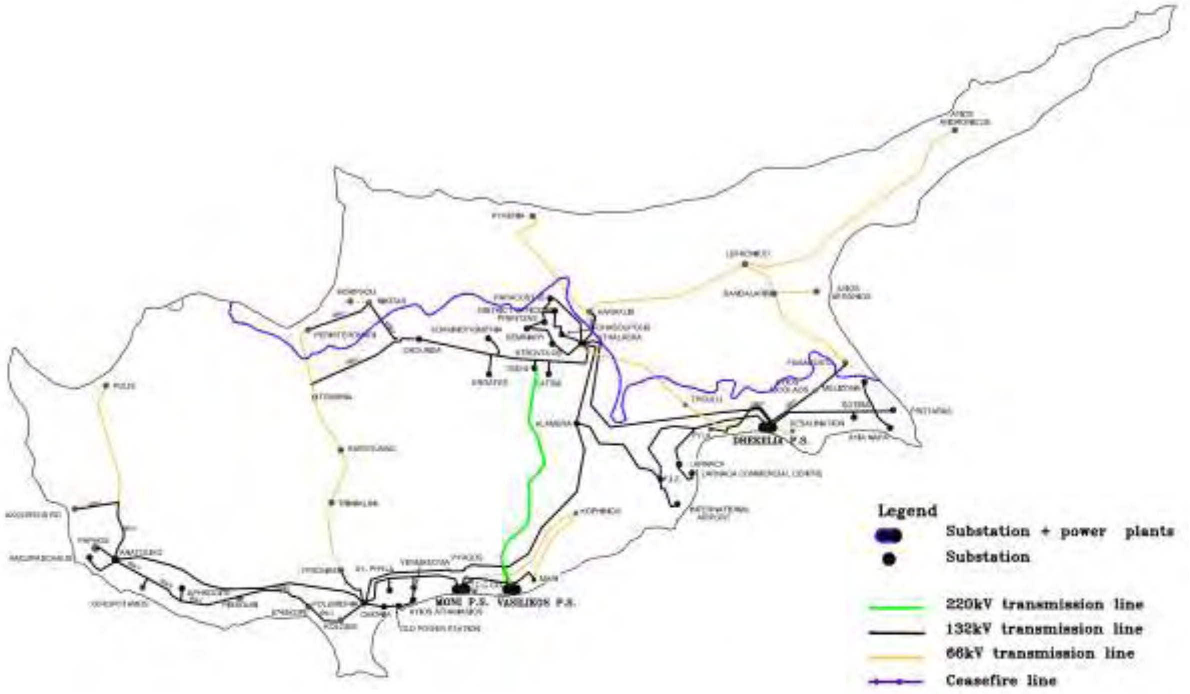

Figure 2. The Cyprus Generation and Transmission System Map

For the purpose of the harmonization with Directives 96/92/EC and 2003/54/EC, and regulating the electricity market in Cyprus, the Transmission System Operator (TSO) was established under the "Law Regulating the Electricity Market", N.122(I)/2003 on July 25th 2003. The TSO became operable after obtaining a license from Cyprus Energy Regulatory Authority (CERA) [6] on September 10th 2004, and its main functions and responsibilities are to secure the operation of the electricity transmission system and to manage the electricity market on an objective non-discriminatory basis in a competitive environment, while at the same time supporting and promoting electricity generation from renewable energy sources. The TSO ensures access to the transmission system of all producers and suppliers of electricity, and coordinates the actions taken for the repair and clearing of faults occurring in the generation or the transmission system, in order for them to operate in an efficient coordinated, secure, reliable, and economical way, ensuring unhindered and uninterrupted supply of electricity to all consumers.

The two principal documents that the TSO manages within the legal framework are the "Transmission and Distribution Rules" [19] that primarily govern the technical aspects of planning and operating the transmission and distribution systems and the "Trading and Settlement Rules" [18] that primarily govern the commercial interactions of all parties using the transmission and distribution systems.

The operation of the generation and the transmission network is monitored on a 24-hour basis by the National Energy Control Centre of Cyprus (NECC), which is situated in Lefkosia, and is equipped with a modern Supervisory Control and Data Acquisition (SCADA) system (see **Figure 3**).

Figure 3. The National Energy Control Centre of Cyprus

Accurate and direct information on the current status of each generation unit and of the transmission system plant is provided through the remote terminal units, an optical fiber network, and a system of screens and projectors. In addition, the NECC is in position to communicate with power station personnel, maintenance crews, interested parties, mass media etc. in a number of alternative ways for coordinating and providing information on system disturbances or other interruptions of supply at all times.

2.4 The System Load

The peak load in Cyprus was 1,148MW in 2010, and 1,098MW in 2009. **Figure 4** [17] shows the load duration curves for the years 2003-2010.

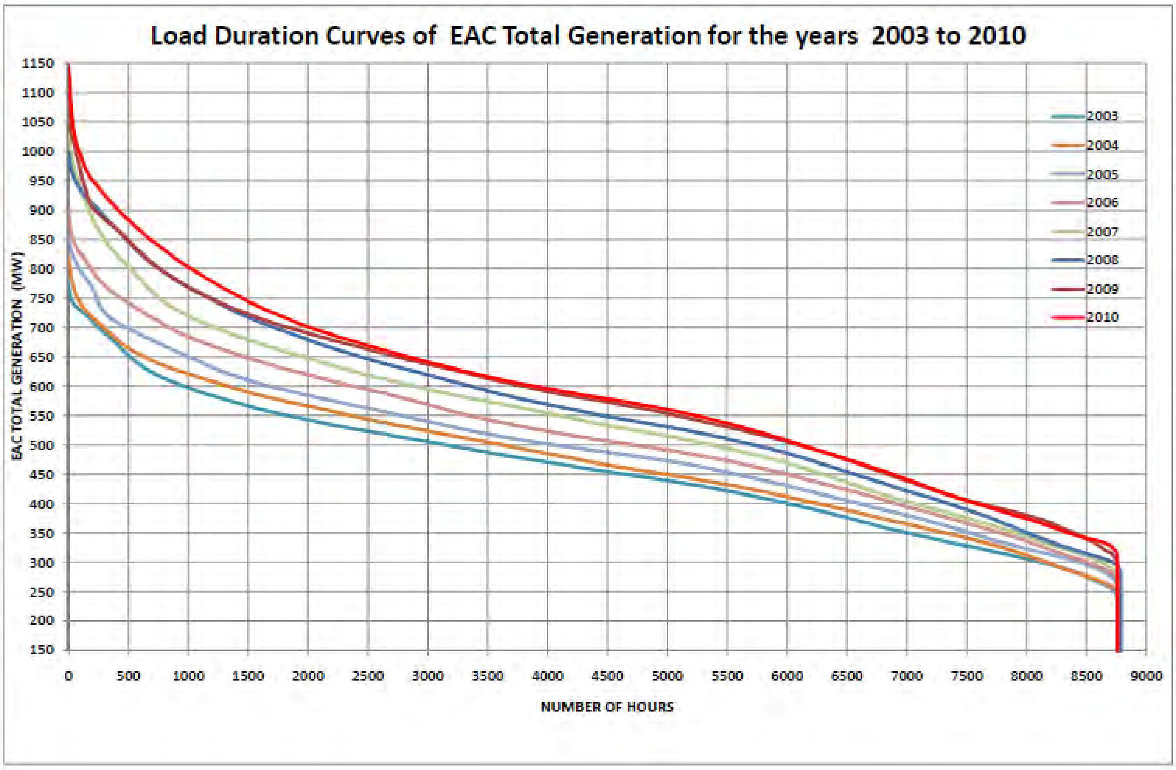

Figure 4. Load Duration Curves for Years 2003-2010

To provide an idea of the load profile in Cyprus, **Figure 5** shows a 7-day profile for the week from Saturday October 8th 2011 to Friday October 14th 2011 (the snapshot is taken from [17]).

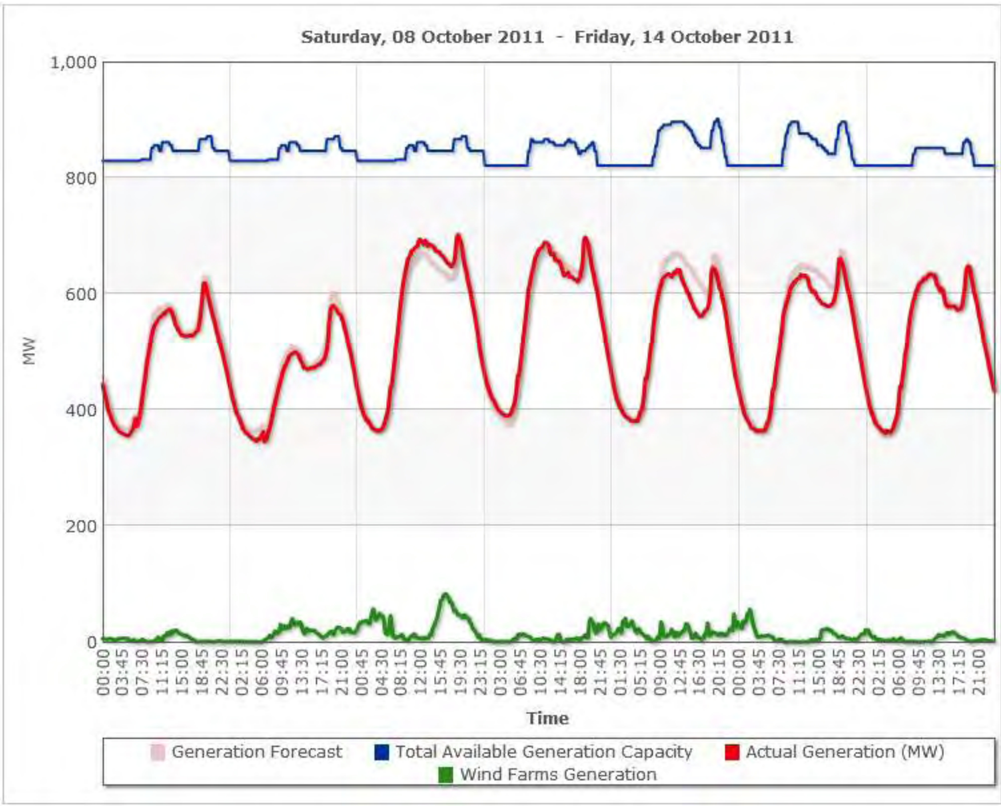

Figure 5. Weekly Profile (October 8th - 14th, 2011)

For historical reasons, we present the event of July 11th 2011 in **Figure 6**.

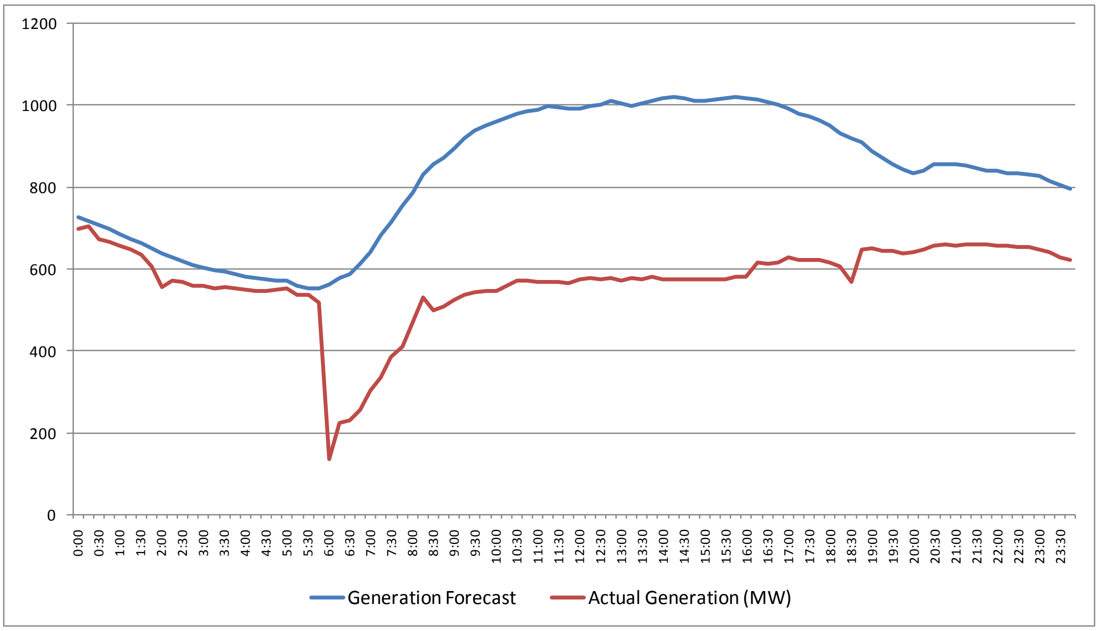

Figure 6. Generation Forecast and Actual Generation on July 11th 2011

The event of the explosion and the loss of the generation from the Vasilikos Power Station is seen as a major drop of the actual generation (red line) with respect to the forecasted generation (blue line).

Chapter 3. Modeling of the Short-Term Generation Scheduling Problem

In this chapter, the modeling of the short-term generation scheduling is performed. The most important features have been extensively discussed with the EAC executives, in order to state the constraints of the problem as accurately as possible. In addition, the modeling has been updated to take into account the recent changes, following the event of 11/7/2011.

The chapter is structured as follows. Firstly, a short description is presented, providing all necessary explanations and definitions. Secondly, the mathematical formulation of a basic model is listed. Lastly, certain extensions of the basic model are discussed and formulated.

3.1 Problem Description

The EAC is called daily to decide the short-term generation scheduling based on the load forecast, the RES forecast, and the availability of the generation units, on a half-hourly basis, for the next day.

***Objective*:**

The objective of the short-term generation scheduling problem is to minimize the total system cost for generating electricity for the next day, while meeting the system and generation units' technical constraints. The system cost includes the cost for providing energy and reserves.

Energy Generation Cost:

The energy generation cost comprises the variable cost and the commitment cost. The variable cost includes the fuel cost, the emissions cost, and other maintenance and operational costs. The commitment cost includes the cost for starting up and shutting down a generation unit, as well as the no-load cost; the latter is not a real cost, but it is needed to be added as an hourly cost that is applicable for all the hours during which the generation unit operates. Had we assumed the traditional quadratic cost function to describe the total hourly cost per unit output, the no-load cost would have been the constant of the quadratic function; hence, the variable cost would have been described by the first and the second order terms (see Appendix A for further details).

In addition to the electricity generation from the conventional EAC generation units, there is also the possibility of purchasing energy from the northern part, at a pre-specified price. Lastly, the wind generation is considered as a mandatory injection.

Reserves Cost:

Let us first define the term "*reserves*": by the term reserves we refer to the frequency-related ancillary services that correspond to the possibility of changing the active power of a generation unit following a frequency disturbance; we shall not deal with voltage control and reactive power in this thesis.

In general, we can distinguish between three types of reserves:

1) <u>Primary Reserve</u>: It is provided automatically by the generation units, according to their droop, within some seconds (ranging from 5 to 20 seconds). Primary reserve is distinguished in primary reserve *up* and *down*: up refers to the increase of active power and down refers to the decrease of active power. Currently, only the primary reserve up is considered in Cyprus.

2) <u>Secondary Reserve</u>: It is provided by the generation units following an instruction of the Transmission System Operator, within a timeframe that ranges between 20 seconds and 5 to 20 minutes. The secondary reserve is activated through tele-control, usually under Automatic Generation Control (AGC) mode; however, AGC does not apply in Cyprus and tele-control is implemented through telephone calls. Secondary reserve is also distinguished in secondary reserve *up* and *down*. Currently, only the secondary reserve up is considered in Cyprus.

3) <u>Tertiary Reserve</u>: Tertiary reserve refers to the increase (or decrease) of active power, in the case of up (or down) reserve, which can take place within a time period of 15min, activated by a relevant instruction of the Transmission System Operator. The objective of the

tertiary reserve is to restore the previous two types (primary and secondary), in case they have been used, following a frequency disturbance. This service is also distinguished in *spinning*, in the case that it is provided by online generation units, and *non-spinning*, in the case that it is provided by fast-start units, e.g. GTs or ICEs. Currently, only the tertiary reserve up is defined in Cyprus; however, it is not still used as a requirement.

The cost for providing reserves constitutes an actual cost for the generation units. Practically, it could be understood as the cost of the wear-and-tear of a generation unit due to the increase and/or decrease of its production. More details on this subject can be found in [14]; however, such details are beyond the scope of this thesis.

***System Energy and Reserve Requirements*:**

The system requirements include the energy balance and the reserve requirements. The energy balance constraint requires that the total generation (from the EAC units plus the purchases plus the RES injections) is equal to the system load. The reserve requirements set a minimum amount of reserve that must be available for each type of reserve. The higher quality types of reserves can substitute the lower quality ones, e.g. primary reserve can substitute secondary and tertiary, while secondary can substitute tertiary.

***Constraints of Generation Units*:**

The main constraints of the generation units include:

Capacity (Power) Constraints:

There is a minimum level of output (technical minimum) under which the unit cannot produce. Also, there is a maximum level of output (technical maximum) above which the unit cannot produce. In addition, there is maximum amount of each reserve type (maximum reserve availability) that the unit can provide.

Minimum Times:

In case a unit starts up, it must remain online for a certain time period (minimum up time). Also, in case a unit shuts down, it must remain offline for a certain time period.

Ramp Limits:

These are the maximum rates at which the unit can increase (ramp up) or decrease (ramp down) its output. In the case of the EAC generation units, and for the case of the half-hour timeframe of the optimization problem, the ramp limits are almost never binding.

Maximum Energy/Emissions Constraints:

There may be an upper limit on the amount of energy (or emissions) that a unit can produce within the optimization horizon.

Personnel Constraints:

Due to limited personnel in a certain power station, there may be constraints with respect to the number of units that can be simultaneously monitored during a startup or a shutdown phase. Also, the time when there is a change of shifts may not be the "best" time to perform a startup or a shutdown of a generation unit.

Lastly, we should mention that the transmission network is not represented in the formulation, and that the transmission constraints are not considered. In general, no significant congestions occur in the Cyprus transmission network, which satisfies an "N-1" security criterion.

3.2 Mathematical Formulation of a Basic Model

The nomenclature of the optimization problem is listed in Appendix B.

***Objective function*:**

The objective is to minimize the total system cost, which consists of the following components:

- Generation Cost
- Reserves Cost
- Commitment Cost

The objective function is shown in (1) below.

$$\text{Minimize } \{\text{Generation Cost} + \text{Reserves Cost} + \text{Commitment Cost}\} \qquad (1)$$

Generation Cost:

The generation cost includes the fuel cost, the maintenance and other operational cost, and the carbon cost of the EAC generation units. It is described in the form of price-quantity pairs which express the marginal cost for energy. In addition, the generation cost includes the cost of potential energy purchased from the northern part, at a pre-specified price. The generation cost is shown in (2) below

$$\text{Generation Cost} = \sum_{u,b,t} C_{u,b}^{\mathrm{G}} \cdot Q_{u,b,t}^{\mathrm{G}} \cdot D + \sum_{t} C^{\mathrm{G,Pur}} \cdot Q_{t}^{\mathrm{G,Pur}} \cdot D \qquad (2)$$

with $D = ½$ for a half-hour period

Reserves Cost:

In practice, there is a cost for providing reserve, mainly due to the wear and tear of generation units, as a result of the increase and decrease of their output (see [14] for further details). However, in this thesis, the reserves cost is assumed to be zero.

Commitment Cost:

The commitment cost includes the startup cost, the shutdown cost and the no-load cost, and is shown in (3).

$$\text{Commitment Cost} = \text{Startup Cost} + \text{Shutdown Cost} + \text{No-Load Cost}$$
$$= \sum_{u,t} X_{u,t}^{\mathrm{SU}} \cdot C_u^{\mathrm{SU}} + \sum_{u,t} X_{u,t}^{\mathrm{SD}} \cdot C_u^{\mathrm{SD}} + \sum_{u,t} X_{u,t}^{\mathrm{St}} \cdot C_u^{\mathrm{NL}} \cdot D \tag{3}$$

***Constraints*:**

The constraints of this basic model include:

- System Constraints
- Generation Units' Technical Constraints

System Constraints:

Energy Balance:

$$\sum_u Q_{u,t}^{\mathrm{G,Total}} + Q_t^{\mathrm{G,Pur}} + RES_t = SysL_t \quad \forall t \tag{4}$$

The energy balance constraint declares that the energy generation (LHS) must meet the system load (RHS) in all time periods. The energy generation includes the energy from conventional generation units (first term in the LHS), the potential purchases from the northern part (second term in the LHS), and the energy from renewable energy sources (third term in the LHS), i.e. the wind park under the current condition. Since it is assumed a half-hour time period, in order to obtain energy in MWh, each term in (4) should be multiplied by D = ½, which can therefore be omitted.

Reserve Requirements:

$$\sum_u Q_{u,t}^{\mathrm{PR^{Up}}} \geq Req_t^{\mathrm{PR^{Up}}} \quad \forall\, t \tag{5}$$

$$\sum_u Q_{u,t}^{\mathrm{PR^{Down}}} \geq Req_t^{\mathrm{PR^{Down}}} \quad \forall\, t \tag{6}$$

$$\sum_u Q_{u,t}^{\mathrm{PR^{Up}}} + \sum_u Q_{u,t}^{\mathrm{SR^{Up}}} \geq Req_t^{\mathrm{PR^{Up}}} + Req_t^{\mathrm{SR^{Up}}} \quad \forall\, t \tag{7}$$

$$\sum_u Q_{u,t}^{\mathrm{PR}^{\mathrm{Down}}} + \sum_u Q_{u,t}^{\mathrm{SR}^{\mathrm{Down}}} \geq Req_t^{\mathrm{PR}^{\mathrm{Down}}} + Req_t^{\mathrm{SR}^{\mathrm{Down}}} \quad \forall\, t \tag{8}$$

Constraints (5)-(8) represent the requirements for the four reserve types (primary up/down, secondary up/down); tertiary reserve is currently not considered in Cyprus. The constraints take into account the substitutability of a lower quality reserve type by a higher quality one, i.e. the possibility of substituting secondary reserve up (down) by primary reserve up (down).

Generation Units' Technical Constraints:

Block Limits:

$$Q_{u,b,t}^{\mathrm{G}} \leq \overline{Q}_{u,b}^{\mathrm{G}} \cdot X_{u,t}^{\mathrm{St}} \quad \forall u,b,t \tag{9}$$

The energy generation cost is defined as cost vs. quantity pairs, which are called blocks. Constraint (9) declares that the quantity scheduled to each generation unit will not exceed the size of the respective block.

Technical Minimum:

$$Q_{u,t}^{\mathrm{G,Total}} - Q_{u,t}^{\mathrm{PR}^{\mathrm{Down}}} - Q_{u,t}^{\mathrm{SR}^{\mathrm{Down}}} \geq X_{u,t}^{\mathrm{St}} \cdot \underline{Q}_u^{\mathrm{G}} \quad \forall u,t \tag{10}$$

Constraint (10) declares the technical minimum constraint of each generation unit. Each unit should operate above a certain level (technical minimum); in addition, if the unit is scheduled to provide some type of down reserve, the scheduled quantity for power should be higher (as high as the amount of the down reserve that is scheduled), so that it has the possibility to decrease the output, in case the down reserve is activated, without violating the technical minimum constraint.

Technical Maximum:

$$Q_{u,t}^{\mathrm{G,Total}} + Q_{u,t}^{\mathrm{PR}^{\mathrm{Up}}} + Q_{u,t}^{\mathrm{SR}^{\mathrm{Up}}} \leq X_{u,t}^{\mathrm{St}} \cdot \overline{Q}_u^{\mathrm{G}} \quad \forall u,t \tag{11}$$

Constraint (11) declares the technical maximum constraint of each generation unit. Each unit should operate below a certain level (technical maximum); in addition, if the unit is scheduled to provide some type of up reserve, the scheduled quantity of power should be lower (as low as the amount of the up reserve that is scheduled), so that the unit has the possibility to increase the output, in case the up reserve is activated, without violating the technical maximum constraint.

Maximum Purchased Power:

$$Q_t^{\mathrm{G,Pur}} \leq \bar{Q}_t^{\mathrm{G,Pur}} \quad \forall t \tag{12}$$

Constraint (12) declares an upper limit on the purchases, indicating the maximum power that can be purchased from the northern part, in each time period.

Reserve Availability:

$$Q_{u,t}^{\mathrm{PR^{Up}}} \leq X_{u,t}^{\mathrm{St}} \cdot \bar{Q}_u^{\mathrm{PR^{Up}}} \quad \forall u \tag{13}$$

$$Q_{u,t}^{\mathrm{PR^{Down}}} \leq X_{u,t}^{\mathrm{St}} \cdot \bar{Q}_u^{\mathrm{PR^{Down}}} \quad \forall u \tag{14}$$

$$Q_{u,t}^{\mathrm{SR^{Up}}} \leq X_{u,t}^{\mathrm{St}} \cdot \bar{Q}_u^{\mathrm{SR^{Up}}} \quad \forall u \tag{15}$$

$$Q_{u,t}^{\mathrm{SR^{Down}}} \leq X_{u,t}^{\mathrm{St}} \cdot \bar{Q}_u^{\mathrm{SR^{Down}}} \quad \forall u \tag{16}$$

Constraints (13)-(16) define the maximum reserve availability for each reserve type. The generation unit should be online, in order to be able to provide primary or secondary reserve. Under the current conditions, there is no requirement for tertiary reserve in Cyprus.

Minimum Up Time:

$$\left(Y_{u,t-1}^{\mathrm{On}} - MT_u^{\mathrm{Up}}\right)\left(X_{u,t-1}^{\mathrm{St}} - X_{u,t}^{\mathrm{St}}\right) \geq 0 \quad \forall u,t \tag{17}$$

The minimum up time constraint requires that the unit should remain online for a minimum number of time periods, following a startup.

Minimum Down Time:

$$\left(Y_{u,t-1}^{\text{Off}} - MT_u^{\text{Down}}\right)\left(X_{u,t}^{\text{St}} - X_{u,t-1}^{\text{St}}\right) \geq 0 \quad \forall\, u,t \tag{18}$$

The minimum down time constraint requires that the unit should remain offline for a minimum number of hours, following a shut-down.

Availability:

$$X_{u,t}^{\text{St}} \leq X_{u,t}^{\text{Av}} \quad \forall\, u,t \tag{19}$$

Constraint (19) sets the status variable equal to zero, in case the unit is not available for a certain time period.

Must-Run Units:

$$X_{u,t}^{\text{St}} \geq X_{u,t}^{\text{Must-Run}} \quad \forall\, u,t \tag{20}$$

For various reasons, a certain generation unit may be declared as must-run for the next day, either for the whole day or for certain time periods of the day.

Definitions of Dependent Variables:

The total energy generation of a generation unit is defined as the sum of the generation of the several blocks that is scheduled for the next day.

$$Q_{u,t}^{\text{G,Total}} = \sum_b Q_{u,b,t}^{\text{G}} \quad \forall u,t \tag{21}$$

The startup (shutdown) signals, which take the value 1 in case a unit startup (shutdown) occurs and 0 otherwise, are linked with the binary variable that declares the status of the generation unit (1: Online; 0: Offline), as follows.

$$X_{u,t}^{\text{SU}} = X_{u,t}^{\text{St}}\left(1 - X_{u,t-1}^{\text{St}}\right) \quad \forall u,t \tag{22}$$

$$X_{u,t}^{\text{SD}} = X_{u,t-1}^{\text{St}}\left(1 - X_{u,t}^{\text{St}}\right) \quad \forall u,t \tag{23}$$

The integer variables that declare the number of hours that the generation unit has been online (offline) are defined as follows.

$$Y_{u,t}^{\mathrm{On}} = \left(Y_{u,t-1}^{\mathrm{On}} + 1\right) X_{u,t}^{\mathrm{St}} \quad \forall u,t \tag{24}$$

$$Y_{u,t}^{\mathrm{Off}} = \left(Y_{u,t-1}^{\mathrm{Off}} + 1\right)\left(1 - X_{u,t}^{\mathrm{St}}\right) \quad \forall u,t \tag{25}$$

Initialization:

$$X_{u,0}^{\mathrm{St}} = X_{u}^{\mathrm{St},0} \quad \forall u \tag{26}$$

$$Y_{u,0}^{\mathrm{On}} = Y_{u}^{\mathrm{On},0} \quad \forall u \tag{27}$$

$$Y_{u,0}^{\mathrm{Off}} = Y_{u}^{\mathrm{Off},0} \quad \forall u \tag{28}$$

Linearization of Nonlinear Constraints:

Note that constraints (17), (18), and (22)-(25) are nonlinear. These constraints can be linearized by equivalent inequalities [3].

The definitions of the startup and shutdown signal variables (22) and (23) can be replaced by inequalities (29)-(30) and (31)-(32) respectively:

$$X_{u,t}^{\mathrm{SU}} \geq X_{u,t}^{\mathrm{St}} - X_{u,t-1}^{\mathrm{St}} \quad \forall u,t \tag{29}$$

$$X_{u,t}^{\mathrm{St}} - X_{u,t-1}^{\mathrm{St}} + 1.1\left(1 - X_{u,t}^{\mathrm{SU}}\right) \geq 0.1 \quad \forall u,t \tag{30}$$

$$X_{u,t}^{\mathrm{SD}} \geq X_{u,t-1}^{\mathrm{St}} - X_{u,t}^{\mathrm{St}} \quad \forall u,t \tag{31}$$

$$X_{u,t-1}^{\mathrm{St}} - X_{u,t}^{\mathrm{St}} + 1.1\left(1 - X_{u,t}^{\mathrm{SD}}\right) \geq 0.1 \quad \forall u,t \tag{32}$$

The counters in constraints (24) and (25) can be replaced by inequalities (33)-(35) and (36)-(38) respectively, where M is a sufficiently large number:

$$Y_{u,t}^{\mathrm{On}} \leq Y_{u,t-1}^{\mathrm{On}} + 1 \quad \forall u,t \tag{33}$$

$$Y_{u,t}^{\mathrm{On}} + \left(M + 1\right)\left(1 - X_{u,t}^{\mathrm{St}}\right) \geq Y_{u,t-1}^{\mathrm{On}} + 1 \quad \forall u,t \tag{34}$$

$$Y_{u,t}^{\mathrm{On}} \leq M \cdot X_{u,t}^{\mathrm{St}} \quad \forall u,t \tag{35}$$

$$Y_{u,t}^{\mathrm{Off}} \leq Y_{u,t-1}^{\mathrm{Off}} + 1 \quad \forall u,t \tag{36}$$

$$Y_{u,t}^{\text{Off}} + \left(M+1\right) X_{u,t}^{\text{St}} \geq Y_{u,t-1}^{\text{Off}} + 1 \quad \forall u,t \tag{37}$$

$$Y_{u,t}^{\text{Off}} \leq M\left(1 - X_{u,t}^{\text{St}}\right) \quad \forall u,t \tag{38}$$

Lastly, the minimum up and down times constraints (17) and (18) can be expressed by the inequalities (39) and (40), where we introduced two auxiliary integer (nonnegative) variables.

$$Y_{u,t-1}^{\text{Aux(1)}} - Y_{u,t}^{\text{On}} + X_{u,t}^{\text{St}} - MT_{u}^{\text{Up}}\left(X_{u,t-1}^{\text{St}} - X_{u,t}^{\text{St}}\right) \geq 0 \quad \forall\, u,t \tag{39}$$

$$Y_{u,h-1}^{\text{Off}} - Y_{u,t}^{\text{Off}} + 1 - X_{u,t}^{\text{St}} - Y_{u,t-1}^{\text{Aux(2)}} - MT_{u}^{\text{Down}}(X_{u,t}^{\text{St}} - X_{u,t-1}^{\text{St}}) \geq 0 \quad \forall\, u,t \tag{40}$$

The auxiliary variables are defined by equalities (41) and (42), which are also nonlinear, and can be replaced by inequalities (43)-(45) and (46)-(48) respectively.

$$Y_{u,t-1}^{\text{Aux(1)}} = Y_{u,t-1}^{\text{On}} \cdot X_{u,t-1}^{\text{St}} \quad \forall\, u,t \tag{41}$$

$$Y_{u,t-1}^{\text{Aux(2)}} = Y_{u,t-1}^{\text{Off}} \cdot X_{u,t-1}^{\text{St}} \quad \forall\, u,t \tag{42}$$

$$Y_{u,t-1}^{\text{Aux(1)}} \leq Y_{u,t-1}^{\text{On}} \quad \forall u,t \tag{43}$$

$$Y_{u,t-1}^{\text{Aux(1)}} + M\left(1 - X_{u,t-1}^{\text{St}}\right) \geq Y_{u,t-1}^{\text{On}} \quad \forall u,t \tag{44}$$

$$Y_{u,t-1}^{\text{Aux(1)}} \leq M \cdot X_{u,t-1}^{\text{St}} \quad \forall u,t \tag{45}$$

$$Y_{u,t-1}^{\text{Aux(2)}} \leq Y_{u,t-1}^{\text{Off}} \quad \forall u,t \tag{46}$$

$$Y_{u,t}^{\text{Aux(2)}} + M\left(1 - X_{u,t-1}^{\text{St}}\right) \geq Y_{u,t-1}^{\text{Off}} \quad \forall u,t \tag{47}$$

$$Y_{u,t-1}^{\text{Aux(2)}} \leq M \cdot X_{u,t-1}^{\text{St}} \quad \forall u,t \tag{48}$$

3.3 Extensions of the Basic Model

The model presented in the previous chapter is a basic model that can be extended in various directions. These directions are summarized as follows:

- Tertiary Reserve
- Ramp Limits
- Energy/Emissions Constraints
- Maximum Number of Startups
- Personnel Constraints
- Penalty Cost (Soft Constraints)

***Tertiary Reserve*:**

As already mentioned, the tertiary reserve is not currently taken into consideration (it is not a requirement) in the electrical power of Cyprus. Nevertheless, it is expected that the volatility introduced in the system by the RES production will eventually lead the Cyprus TSO to consider tertiary reserve requirements for restoring the primary and secondary reserve levels.

The tertiary reserve requirements that are given by constraints (49) and (50) take into account the substitutability of tertiary reserve by secondary or primary reserve.

$$\sum_u Q_{u,t}^{\mathrm{PR}^{\mathrm{Up}}} + \sum_u Q_{u,t}^{\mathrm{SR}^{\mathrm{Up}}} + \sum_u Q_{u,t}^{\mathrm{TR}^{\mathrm{Up}}} \geq Req_t^{\mathrm{PR}^{\mathrm{Up}}} + Req_t^{\mathrm{SR}^{\mathrm{Up}}} + Req_t^{\mathrm{TR}^{\mathrm{Up}}} \quad \forall\ t \tag{49}$$

$$\sum_u Q_{u,t}^{\mathrm{PR}^{\mathrm{Down}}} + \sum_u Q_{u,t}^{\mathrm{SR}^{\mathrm{Down}}} + \sum_u Q_{u,t}^{\mathrm{TR}^{\mathrm{Down}}} \geq Req_t^{\mathrm{PR}^{\mathrm{Down}}} + Req_t^{\mathrm{SR}^{\mathrm{Down}}} + Req_t^{\mathrm{TR}^{\mathrm{Down}}} \quad \forall\ t \tag{50}$$

At this point, we should distinguish between the spinning and the non spinning tertiary reserve up. For the tertiary reserve down, there is no such distinction, as the unit should be online in order to be able to provide down reserve. There could be an option of providing tertiary reserve down by de-committing a flexible unit, but this option will not be modeled, and it will be assumed that the provision of tertiary reserve down does not de-commit generation units. The following constraints are therefore introduced.

$$Q_{u,t}^{\mathrm{TR}^{\mathrm{Up}}} = Q_{u,t}^{\mathrm{TR}^{\mathrm{Up,Spin}}} + Q_{u,t}^{\mathrm{TR}^{\mathrm{NonSpin}}} \quad \forall\ u,t \tag{51}$$

$$Q_{u,t}^{\mathrm{TR}^{\mathrm{Up,Spin}}} \leq X_{u,t}^{\mathrm{St}} \cdot \bar{Q}_u^{\mathrm{TR}^{\mathrm{Up,Spin}}} \quad \forall\ u,t \tag{52}$$

$$X_{u,t}^{\mathrm{NonSpin}} \leq 1 - X_{u,t}^{\mathrm{St}} \quad \forall\ u,t \tag{53}$$

$$Q_{u,t}^{\mathrm{TR}^{\mathrm{NonSpin}}} \geq X_{u,t}^{\mathrm{NonSpin}} \cdot \underline{Q}_{u}^{\mathrm{G}} \quad \forall\, u,t \tag{54}$$

$$Q_{u,t}^{\mathrm{TR}^{\mathrm{NonSpin}}} \leq X_{u,t}^{\mathrm{NonSpin}} \cdot \bar{Q}_{u}^{\mathrm{TR}^{\mathrm{NonSpin}}} \quad \forall\, u,t \tag{55}$$

$$Q_{u,t}^{\mathrm{TR}^{\mathrm{Down}}} \leq X_{u,t}^{\mathrm{St}} \cdot \bar{Q}_{u}^{\mathrm{TR}^{\mathrm{Down}}} \quad \forall\, u,t \tag{56}$$

Constraint (51) declares that the tertiary reserve up consists of both spinning and non spinning reserve. Constraint (52) defines the maximum spinning tertiary reserve up availability, and is linked with the unit status variable, so that the unit should be online in order to be able to provide spinning reserve. Inequality (53) defines a binary variable that declares whether the unit provides tertiary non spinning reserve or not. Constraints (54) and (55) impose a lower and an upper limit on the non spinning reserve provision; note that the lower limit equals to the technical minimum of the generation unit. Constraint (56) defines the maximum tertiary reserve down availability.

By introducing the tertiary reserve, we need to appropriately adjust the technical minimum and maximum constraints. Therefore, constraints (10) and (11) should be replaced by the following constraints (57) and (58) respectively.

$$Q_{u,t}^{\mathrm{G,Total}} + Q_{u,t}^{\mathrm{PR}^{\mathrm{Up}}} + Q_{u,t}^{\mathrm{SR}^{\mathrm{Up}}} + Q_{u,t}^{\mathrm{TR}^{\mathrm{Up,Spin}}} \leq X_{u,t}^{\mathrm{St}} \cdot \bar{Q}_{u}^{\mathrm{G}} \quad \forall u,t \tag{57}$$

$$Q_{u,t}^{\mathrm{G,Total}} - Q_{u,t}^{\mathrm{PR}^{\mathrm{Down}}} - Q_{u,t}^{\mathrm{SR}^{\mathrm{Down}}} - Q_{u,t}^{\mathrm{TR}^{\mathrm{Down}}} \geq X_{u,t}^{\mathrm{St}} \cdot \underline{Q}_{u}^{\mathrm{G}} \quad \forall u,t \tag{58}$$

***Ramp Limits*:**

The ramp up and ramp down rates are considered to be given in MW per minute. The constraints that represent these limits should also take into account the case of a generation unit startup or shutdown. In case we have a unit startup, then it is assumed that the ramp up rate applies above the technical minimum. In this case, at the first period following a startup, the generation unit can be scheduled at a level that is less than or equal to the technical minimum plus the possibility to increase the output within that time period, while respecting the ramp up rate. A similar assumption is made for the ramp down limit in case of a generation unit shutdown. The ramp rate constraints are given by inequalities (59) and (60).

$$Q_{u,t}^{\mathrm{G,Total}} - Q_{u,t-1}^{\mathrm{G,Total}} \leq RR_{u}^{\mathrm{Up}} \cdot 60 \cdot D + X_{u,t}^{\mathrm{SU}} \cdot \underline{Q}_{u}^{\mathrm{G}} \quad \forall u,t \tag{59}$$

$$Q_{u,t-1}^{\mathrm{G,Total}} - Q_{u,t}^{\mathrm{G,Total}} \leq RR_{u}^{\mathrm{Down}} \cdot 60 \cdot D \ + X_{u,t}^{\mathrm{SD}} \cdot \underline{Q}_{u}^{\mathrm{G}} \qquad \forall u,t \tag{60}$$

Due to the ramp limits, an initial condition for the generation output is needed. Therefore, the initialization constraints should also include the following equality.

$$Q_{u,0}^{\mathrm{G}} = Q_{u}^{\mathrm{G,0}} \qquad \forall u \tag{61}$$

***Energy/Emissions Constraints*:**

Maximum Energy Constraint:

Due to fuel or emissions restrictions, constraint (62) sets an upper limit for the daily energy generation output of a certain unit.

$$\sum_{t} Q_{u,t}^{\mathrm{G,Total}} \cdot D \ \leq \ \bar{Q}_{u}^{\mathrm{G,Daily}} \qquad \forall\ u \tag{62}$$

Mandatory Minimum Generation:

For various reasons, a certain generation unit may be declared to generate a mandatory minimum output for certain hours of the next day, as shown by constraint (63). Constraint (63) can also be declared as a strict equality, if there are such cases.

$$Q_{u,t}^{\mathrm{G,Total}} \geq \ Q_{u,t}^{\mathrm{G,Mand}} \qquad \forall\ u,t \tag{63}$$

***Maximum Number of Startups*:**

To avoid frequent startups of a generation unit, a maximum number of startups can be declared as a constraint.

$$\sum_{t} X_{u,t}^{\mathrm{SU}} \ \leq \ \overline{SU}_{u}^{\mathrm{Daily}} \qquad \forall\ u \tag{64}$$

To some extent, frequent startups are discouraged by the startup cost that is included in the objective function. Note also that the maximum number of startups may be considered as a technical constraint due to maintenance reasons.

***Personnel Constraints*:**

The personnel constraints that are taken into consideration impose certain limits on the simultaneous startups and shutdowns of units in certain power stations. These are very specific constraints in ICE1, ICE2 units of the Dhekelia Power Station and the steam units of the Moni Power Station.

Startup/Shutdown Constraints in DPS:

Startups and shutdowns are not allowed at 08:00, 16:00, and 24:00 hour in ICE1 and ICE2 units, due to the change of shifts of the personnel. Therefore, constraints (65)-(70) should be introduced.

$$X_{u,1}^{\mathrm{SU}} = 0 \quad \forall u \text{ in } \mathrm{U}_{\mathrm{ICE}} \tag{65}$$

$$X_{u,17}^{\mathrm{SU}} = 0 \quad \forall u \text{ in } \mathrm{U}_{\mathrm{ICE}} \tag{66}$$

$$X_{u,33}^{\mathrm{SU}} = 0 \quad \forall u \text{ in } \mathrm{U}_{\mathrm{ICE}} \tag{67}$$

$$X_{u,1}^{\mathrm{SD}} = 0 \quad \forall u \text{ in } \mathrm{U}_{\mathrm{ICE}} \tag{68}$$

$$X_{u,17}^{\mathrm{SD}} = 0 \quad \forall u \text{ in } \mathrm{U}_{\mathrm{ICE}} \tag{69}$$

$$X_{u,33}^{\mathrm{SD}} = 0 \quad \forall u \text{ in } \mathrm{U}_{\mathrm{ICE}} \tag{70}$$

Startup/Shutdown Constraints in MPS:

Due to the limited personnel in MPS, it is required that consecutive startups in MPS steam units must be timed 1.5 hours apart.

$$\sum_{u \in \mathrm{U}_{\mathrm{MPSsteam}}} (X_{u,t}^{\mathrm{SU}} + X_{u,t+1}^{\mathrm{SU}} + X_{u,t+2}^{\mathrm{SU}}) \leq 1 \quad \forall t \text{ in } \{1..\mathrm{T}\text{-}2\} \tag{71}$$

Constraint (71) does not "see" the previous day, so the introduction of parameters for the startups that have been taken place in time periods -1 and -2 is needed; however, due to the usually low load values of these periods, this may not be necessary.

For the same reasons, consecutive shutdowns in MPS steam units must be timed 0.5

hours apart.

$$\sum_{u\in \mathrm{U}_{\mathrm{MPSsteam}}} X_{u,t}^{\mathrm{SD}} \leq 1 \quad \forall t \tag{72}$$

***Penalty Cost (Soft Constraints)*:**

The penalty cost in is an additional term imposed in the objective function to deal with infeasibilities. More specifically, selected constraints are relaxed through the introduction of deficit (“slack”) and surplus variables which are multiplied with appropriate penalty coefficients, imposing additional weights in (1). The selection of the values of these penalty coefficients can lead to different priorities for the constraints that are to be relaxed.

Let's assume that the constraints that are to be relaxed are the system constraints, i.e. the energy balance and the reserve requirements.

We add a deficit and a surplus variable in constraint (4), which yields the new constraint

$$\sum_u Q_{u,t}^{\mathrm{G,Total}} + Q_t^{\mathrm{G,Pur}} + RES_t + Q_t^{\mathrm{G,Def}} - Q_t^{\mathrm{G,Sur}} = SysL_t \quad \forall t \tag{73}$$

Similarly, we add deficit variables in constraints (5)-(8) as follows.

$$\sum_u Q_{u,t}^{\mathrm{PR^{Up}}} + Q_t^{\mathrm{PR^{Up},Def}} \geq Req_t^{\mathrm{PR^{Up}}} \quad \forall t \tag{74}$$

$$\sum_u Q_{u,t}^{\mathrm{PR^{Down}}} + Q_t^{\mathrm{PR^{Down},Def}} \geq Req_t^{\mathrm{PR^{Down}}} \quad \forall t \tag{75}$$

$$\sum_u Q_{u,t}^{\mathrm{PR^{Up}}} + \sum_u Q_{u,t}^{\mathrm{SR^{Up}}} + Q_t^{\mathrm{PR^{Down},Def}} + Q_t^{\mathrm{SR^{Up},Def}} \geq Req_t^{\mathrm{PR^{Up}}} + Req_t^{\mathrm{SR^{Up}}} \quad \forall t \tag{76}$$

$$\sum_u Q_{u,t}^{\mathrm{PR^{Down}}} + \sum_u Q_{u,t}^{\mathrm{SR^{Down}}} + Q_t^{\mathrm{SR^{Down},Def}} \geq Req_t^{\mathrm{PR^{Down}}} + Req_t^{\mathrm{SR^{Down}}} \quad \forall t \tag{77}$$

The following cost component (penalty cost) should be added in (1), imposing an additional weight in case any of the deficit or surplus variables take a positive value.

$$\begin{aligned}\text{Penalty Cost} = &\sum_t \left[C^{\mathrm{Pen,G}} \left(Q_t^{\mathrm{G,\,Def}} + Q_t^{\mathrm{G,\,Sur}} \right) \right] \\ &+ \sum_t \left(C^{\mathrm{Pen,\,PR^{Up}}} \cdot Q_t^{\mathrm{PR^{Up},\,Def}} + C^{\mathrm{Pen,\,PR^{Down}}} \cdot Q_t^{\mathrm{PR^{Down},\,Def}} \right) \\ &+ \sum_t \left(C^{\mathrm{Pen,\,SR^{Up}}} \cdot Q_t^{\mathrm{SR^{Up},\,Def}} + C^{\mathrm{Pen,\,SR^{Down}}} \cdot Q_t^{\mathrm{SR^{Down},\,Def}} \right)\end{aligned} \tag{78}$$

Lastly, if we want to combine soft and hard constraints, e.g. for reserve, we can introduce upper bounds for the deficit variables as shown by constraints (79)-(82) below:

$$Q_t^{\mathrm{PR^{Up}},\mathrm{Def}} \leq \bar{Q}_t^{\mathrm{PR^{Up}},\mathrm{Def}} \quad \forall\, t \tag{79}$$

$$Q_t^{\mathrm{PR^{Down}},\mathrm{Def}} \leq \bar{Q}_t^{\mathrm{PR^{Down}},\mathrm{Def}} \quad \forall\, t \tag{80}$$

$$Q_t^{\mathrm{SR^{Up}},\mathrm{Def}} \leq \bar{Q}_t^{\mathrm{SR^{Up}},\mathrm{Def}} \quad \forall\, t \tag{81}$$

$$Q_t^{\mathrm{SR^{Down}},\mathrm{Def}} \leq \bar{Q}_t^{\mathrm{SR^{Down}},\mathrm{Def}} \quad \forall\, t \tag{82}$$

Chapter 4. Numerical Results

In this chapter, we present numerical results of the problem, to illustrate the practical implications of the work performed in this thesis. The results give rise to interesting remarks and reveal the benefits that the EAC can gain by moving towards a MILP formulation of the short-term generation scheduling problem.

Due to the event of 11/7/2011, we will consider both system conditions, i.e. prior to and after the major loss of VPS. We chose to present the basic model along with certain extensions that seem to be the most interesting ones.

In Section 4.1, we consider the basic model, as it is described in Section 3.2, with the currently operating generation units; we will refer to this example as "Example 1." We then introduce the personnel constraints that impose limitations on the startups and shutdowns in certain classes of units, as mentioned in Section 3.3, and we comment on the differences that the introduction of these constraints creates.

In Section 4.2, we consider a numerical example with the condition prior to the event of 11/7/2011, which we refer to as "Example 2." We first solve the basic model supplemented with "soft" constraints for primary and secondary reserve up, and the personnel constraints as well. We present the results with high and low values for the penalty coefficients for primary and secondary reserve deficits, and we calculate the savings from relaxing the reserve requirements. Lastly, we introduce a daily energy limit for a class of generation units that have high NOx emissions.

In all examples, the problem has been modeled with GAMS 23.7.3 [9], and solved with CPLEX 12.3 on an Intel Core i5 @2.67GHz with 6GB RAM. The settings resulted in proven optimal solutions.

4.1 Example 1: Current Condition

Example 1 refers to the current condition of the system, considering the units of **Table 6**. The technical and economic data of the generation units that are used as input data to the problem are shown in the following Tables. Although the data are estimates of the technical and economic data of the EAC generation units, they remain confidential and cannot appear in the public version of this thesis. Therefore, **Table 7** and **Table 8** below are blank in the public version of this thesis (except for the unit type and capacity data that are publicly available).

Table 7. Current Generation Units (Technical Data)

	Power Station	Name	Type	Technical Maximum (MW)	Technical Minimum (MW)	Minimum Uptime (hours)	Minimum Downtime (hours)	Primary Reserve Up/Down (MW)	Secondary Reserve Up/Down (MW)
1	VPS	GT5	GT	37.5					
2	DPS	DPS1	ST	60					
3	DPS	DPS2	ST	60					
4	DPS	DPS3	ST	60					
5	DPS	DPS4	ST	60					
6	DPS	DPS5	ST	60					
7	DPS	DPS6	ST	60					
8	DPS	ICE1 1	ICE	16.7					
9	DPS	ICE1 2	ICE	16.7					
10	DPS	ICE1 3	ICE	16.7					
11	DPS	ICE2 4	ICE	16.7					
12	DPS	ICE2 5	ICE	16.7					
13	DPS	ICE2 6	ICE	16.7					
14	MPS	MPS1	ST	30					
15	MPS	MPS2	ST	30					
16	MPS	MPS3	ST	30					
17	MPS	MPS4	ST	30					
18	MPS	MPS5	ST	30					
19	MPS	GT1	GT	37.5					
20	MPS	GT2	GT	37.5					
21	MPS	GT3	GT	37.5					
22	MPS	GT4	GT	37.5					
23	VPS	VPSICE	ICE	70					
24	DPS	DPSICE	ICE	60					
25	MPS	MPSICE	ICE	35					

Table 8. Current Generation Units (Economic Data)

	Name	Startup Cost	Shutdown Cost	No-load Cost	Block 1 (Q)	Block 2 (Q)	Block 3 (Q)	Block 4 (Q)	Block 5 (Q)	Block 6 (Q)	Block 1 (C)	Block 2 (C)	Block 3 (C)	Block 4 (C)	Block 5 (C)	Block 6 (C)
1	GT5				7	4	5	5	10	7.5						
2	DPS1				32	4	6	6	6	6						
3	DPS2				32	4	6	6	6	6						
4	DPS3				32	4	6	6	6	6						
5	DPS4				32	4	6	6	6	6						
6	DPS5				32	4	6	6	6	6						
7	DPS6				32	4	6	6	6	6						
8	ICE1 1				11	1	2	1	1	0.7						
9	ICE1 2				11	1	2	1	1	0.7						
10	ICE1 3				11	1	2	1	1	0.7						
11	ICE2 4				10	2	2	1	1	0.7						
12	ICE2 5				10	2	2	1	1	0.7						
13	ICE2 6				10	2	2	1	1	0.7						
14	MPS1				20	1	3	1	1	2						
15	MPS2				20	1	3	1	1	2						
16	MPS3				20	1	3	1	1	2						
17	MPS4				20	1	3	1	1	2						
18	MPS5				20	1	3	1	1	2						
19	GT1				6	4	5	5	10	7.5						
20	GT2				6	4	5	5	10	7.5						
21	GT3				6	4	5	5	10	7.5						
22	GT4				6	4	5	5	10	7.5						
23	VPSICE				60	2	2	2	2	2						
24	DPSICE				50	2	2	2	2	2						
25	MPSICE				30	1	1	1	1	1						

All units except for the GTs and the VPSICE, DPSICE, MPSICE are considered to be online at 0:00 (time period: 0). Initial values for the counters of the time periods that the units have been online or offline are set so that they do not affect the commitment. All units are declared to be available and no unit is set as must-run.

Also, the maximum power that can be purchased from the northern part is considered to be 50MW, and the price is set to 180 €/MWh.

Example 1 uses the data of Wednesday, September 28th 2011, with load equal to the actual generation (red line) and wind generation as shown in **Figure 7** below.

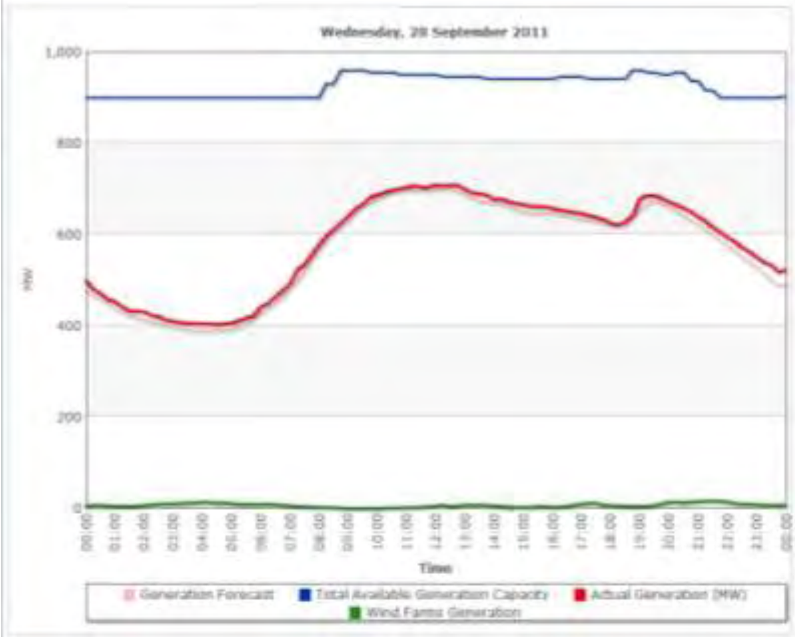

Figure 7. Actual Generation and Wind Generation on Wednesday, 28 September 2011

The reserve requirements are 20MW for primary reserve up and 10MW for secondary reserve up (the down reserve requirements are zero).

Example 1.a: The Basic Model

Example 1.a refers to the basic model. The computational results are summarized in the following Table.

Table 9. Computational Results of Example 1.a (basic model).

Continuous Variables	Discrete Variables	Constraints	Computational Time
13,249	8,525	44,964	~25 sec

Figure 8 shows the numerical results of Example 1.a as they are illustrated in the EAC chart reports. Note that there is an aggregate representation of the generation units: "ICE1" refers to units ICE1 1-3 of DPS, "ICE2" refers to units ICE2 4-6 of DPS, "DPS" refers to units DPS1-6, "MPS" refers to units MPS1-5, "Terna" and "Damco" refer to VPSICE (they appear separately as they belong to different subcontractors of PPC), "EI Moni" and "EI Dhek" refer to MPSICE and DPSICE respectively. "TCC" refers to the energy purchased from the northern part and "GAST" refers to the GTs.

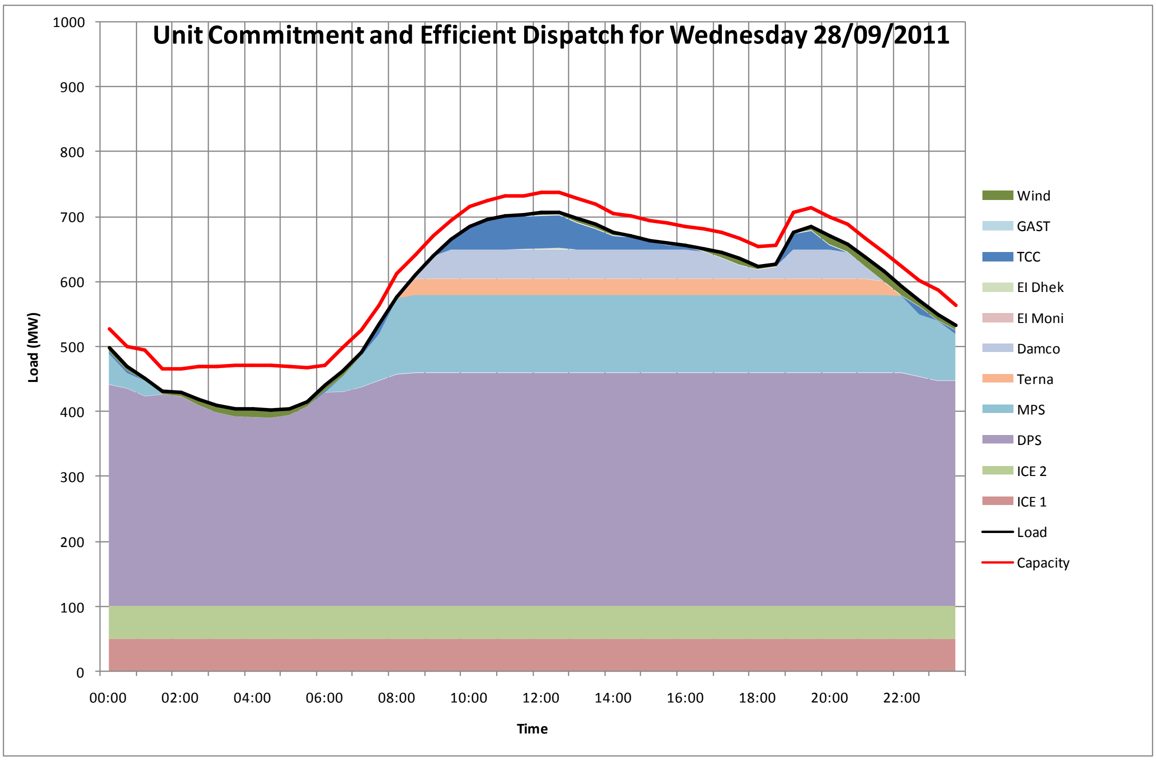

Figure 8. Unit Commitment and Economic Dispatch of Example 1 (basic model)

Due to their relatively low cost, ICE1 and ICE2, and the steam units of DPS are used as base-load units. Then the MPS units are dispatched, and are forced to shut down during the night when the load is low. The peaks are covered by the contracted VPSICE, and DPSICE units (the latter produces a negligible amount), and by purchases from the northern part. GTs and MPSICE do not contribute.

Primary and secondary reserve up is provided by DPS and MPS steam units.

Example 1.b: The Basic Model with Personnel Constraints

We have now added to the basic model the personnel constraints (65) - (72), which limit startups and shutdowns in ICE1, ICE2 and in MPS steam units, and we solved the resulting problem. The constraints are now 45,094, i.e. we have 130 additional constraints.

The introduction of constraints (71) and (72) alters the commitment of the MPS steam units. It is seen in **Table 10** that the shutdown is not performed simultaneously for MPS2, MPS3, and MPS5, since it would violate constraint (72). Also, the time interval between consecutive startups is now 3 time periods (1.5 hour), which is required by constraint (71). In addition, the optimal solution now keeps MPS1 online for the whole day.

Table 10. Commitment of MPS Steam Units in Examples 1.a and 1.b (basic model with and without personnel constraints)

Commitment of MPS steam units in Example 1 (basic model without personnel constraints)

MPS1	1	1													1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MPS2	1															1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MPS3	1	1	1	1													1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MPS4	1																	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
MPS5	1																	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48

Commitment of MPS steam units in Example 1 (basic model with personnel constraints)

MPS1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MPS2	1													1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MPS3	1	1	1	1													1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
MPS4	1	1	1																	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
MPS5	1	1																					1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48

Figure 9 shows the numerical results of Example 1.b, in the form of the EAC chart reports, for the case of the basic model supplemented with the personnel constraints (65) - (72). We observe that a GT unit (GT1) is started up and covers the peak load for the time periods 17 - 31. The energy purchased from the northern part is now significantly reduced (86.2MWh instead of 263.9MWh in the previous case). Primary and secondary reserve up is now provided by DPS, MPS steam units, and by the GT.

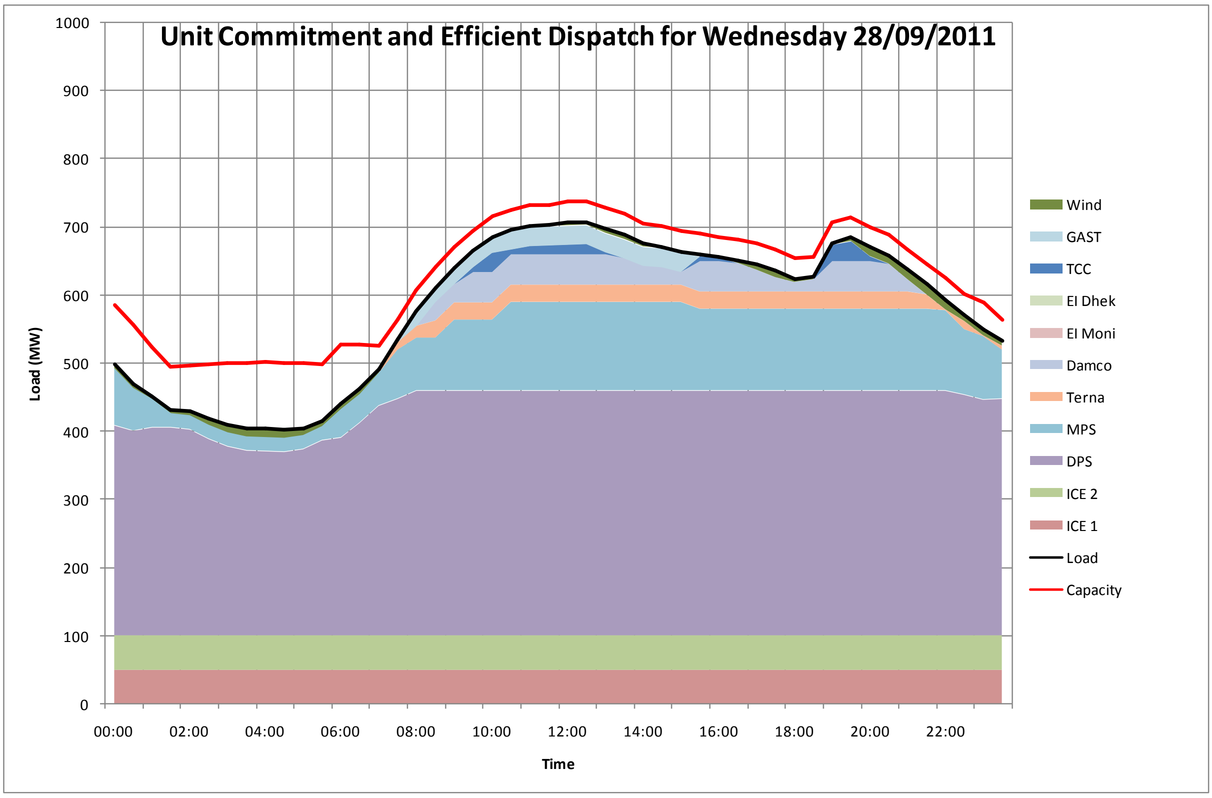

Figure 9. Unit Commitment and Economic Dispatch of Example 1.b (basic model with personnel constraints)

We should also mention the difference in the objective function that the introduction of the personnel constraints produces. This re-scheduling is performed with a cost that is equal to 7,207€. This is indicative of the cost by imposing these personnel constraints and could be useful to the EAC to reconsider such type of constraints.

4.2 Example 2: Condition Prior to the Event of 11/7/2011

The installed capacity of EAC prior to the event of 11/7/2011 was shown in **Table 5**. In this section, we present in the following Tables the technical and economic data of the VPS generation units that were not considered in Example 1.

Once again, the confidential data do not appear in the public version of this thesis.

Table 11. Damaged VPS Generation Units (Technical Data)

	Power Station	Name	Type	Technical Maximum	Technical Minimum	Minimum Uptime (hours)	Minimum Downtime	Primary Reserve Up	Secondary Reserve Up
1	VPS	VPS1	ST	130					
2	VPS	VPS2	ST	130					
3	VPS	VPS3	ST	130					
4	VPS	CCGT4	CCGT	220					

Table 12. Damaged VPS Generation Units (Economic Data)

	Name	Startup Cost	Shutdown Cost	No-load Cost	Block 1 (Q)	Block 2 (Q)	Block 3 (Q)	Block 4 (Q)	Block 5 (Q)	Block 6 (Q)	Block 1 (C)	Block 2 (C)	Block 3 (C)	Block 4 (C)	Block 5 (C)	Block 6 (C)
1	VPS1				60	15	15	15	15	10						
2	VPS2				60	15	15	15	15	10						
3	VPS3				60	15	15	15	15	10						
4	CCGT4				132	18	20	20	15	15						

In this case, we do not consider the contracted ICE units in VPS, MPS, and DPS. There are also no energy purchases from the northern part.

In total, we have 26 conventional generation units. In order to make the problem more realistic, we assume that the units VPS3, DPS6 and MPS5 are not available due to scheduled maintenance.

Example 2 uses the data of Wednesday, July 6th 2011, with load equal to the actual generation (red line), as shown in **Figure 10**. Note that the RES generation is not available, and we considered it zero.

The reserve requirements were set to 55MW for primary reserve up, 5MW for secondary reserve up, 10MW for primary reserve down, and 5MW for secondary reserve down.

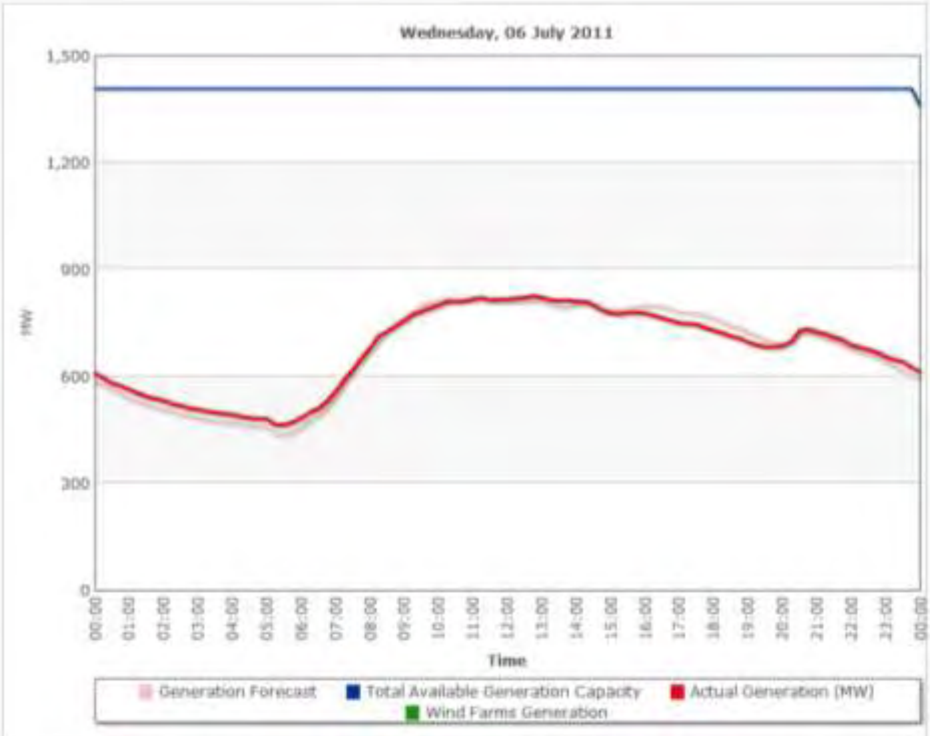

Figure 10. Actual Generation on Wednesday, 6 July 2011

Example 2.a: The Basic Model with Soft Reserve Constraints, and Personnel Constraints

We solve the basic model, with the personnel constraints (65) - (72), which limit startups and shutdowns in ICE1, ICE2 and in MPS steam units, and with soft constraints for primary up and secondary up reserve. We have applied an upper bound of 15MW for the deficit in primary reserve up and 5MW for the deficit in secondary reserve up. Initially, the penalty coefficients were set to high values (25,000€ for a deficit of 1MW of primary reserve up for one time period, and 20,000€ for a deficit of 1MW of secondary reserve up for one time period); we refer to this case as "***Case 1***."

The computational results of the basic model in Example 2.a with the soft primary and secondary reserve up constraints and the personnel constraints are summarized in the following Table.

Table 13. Computational Results of Example 2.a

Continuous Variables	Discrete Variables	Constraints	Computational Time
13,825	8,866	46,929	~36sec

The results are shown in **Figure 11** in the form of the EAC chart reports. We observe that ICE1 and ICE2, VPS steam units (VPS1 and VPS2), and DPS serve the base load. The MPS are used from midnight until the early afternoon. Also, the CCGT shuts down at midnight and starts up in the morning to remain online until the end of the day.

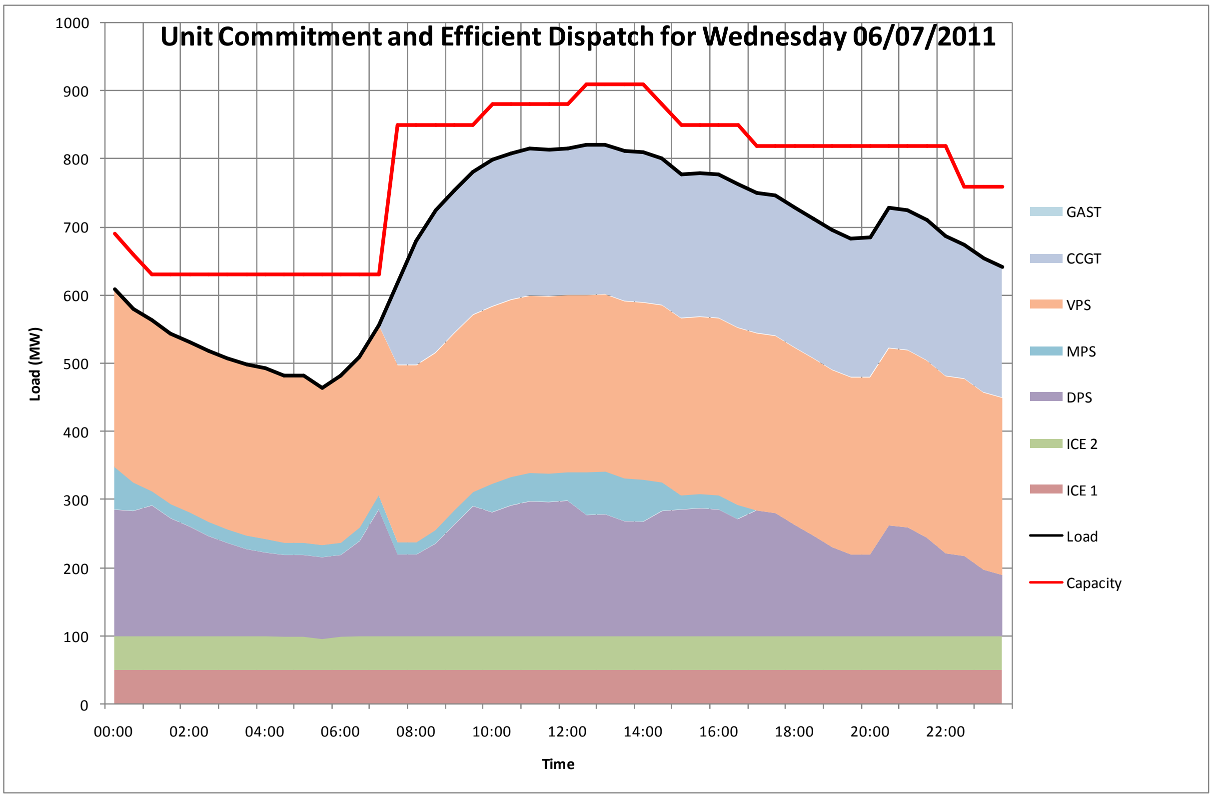

Figure 11. Unit Commitment and Economic dispatch of Example 2.a (basic model with soft primary and secondary up reserve constraints and personnel constraints, under Case 1)

We then experimented with the penalty coefficients, in an attempt to make the reserve constraints "softer." We calculated the savings in the total cost for several values of penalty coefficients as well as the deficits in primary and secondary reserve up. We present the results in the following Table.

Table 14. Savings from Relaxing the Primary and Secondary Reserve Up Constraints

Case	Penalty Coefficient for Deficit in:		Deficit in Certain Time Period		System Cost	Savings
	Primary Reserve Up	Secondary Reserve Up	Primary Reserve Up	Secondary Reserve Up		
1	25,000	20,000			1,703,754	
2	1,000	500	-	**26**:0.8; **27**:1.8	1,701,354	2,400
3	250	500	**26**:0.8; **27**:1.8; **34**:2.8	-	1,700,756	2,998
4	50	100	**4-14**:5; **15**:15; **21**:8.8; **26**: 0.8; **27**:1.8; **34**:2.8; **48**:1.8	**15**:1.8	1,693,369	10,385
5	40	20	**4-14**:5; **15**:11.8; **21**:3.8; **22**:13.8; **30**:5.8	**15**:5; **21**:5; **22**:5; **26**:0.8; **27**:1.8; **30**:5; **34**:2.8; **48**:1.8	1,692,370	11,384
6	10	5	**2** :5; **3**:10; **4-5**:15; **6-14**:5; **15**:15; **21**: 10; **22**:14.8; **23**:5; **24**:4.8; **25-27**:5; **28**:2.8; **29**:15; **30**:10; **31-33**:15; **34**: 5.8; **38**:12.8; **47**:14.8; **48**:1.8	**15**:1.8; **22**:4; **29**:4.8; **30**:0.8; **31**:1.8; **32**:3.8; **33**:1.8	1,690,339	13,415

We show the results for the last case (Case 6) in **Figure 12**.

We observe that the MPS units operate in three intervals, and that the capacity line is lower than or equal to the capacity line under Case 1. As shown in **Table 14**, the savings from relaxing the reserve constraints are 13,415€.

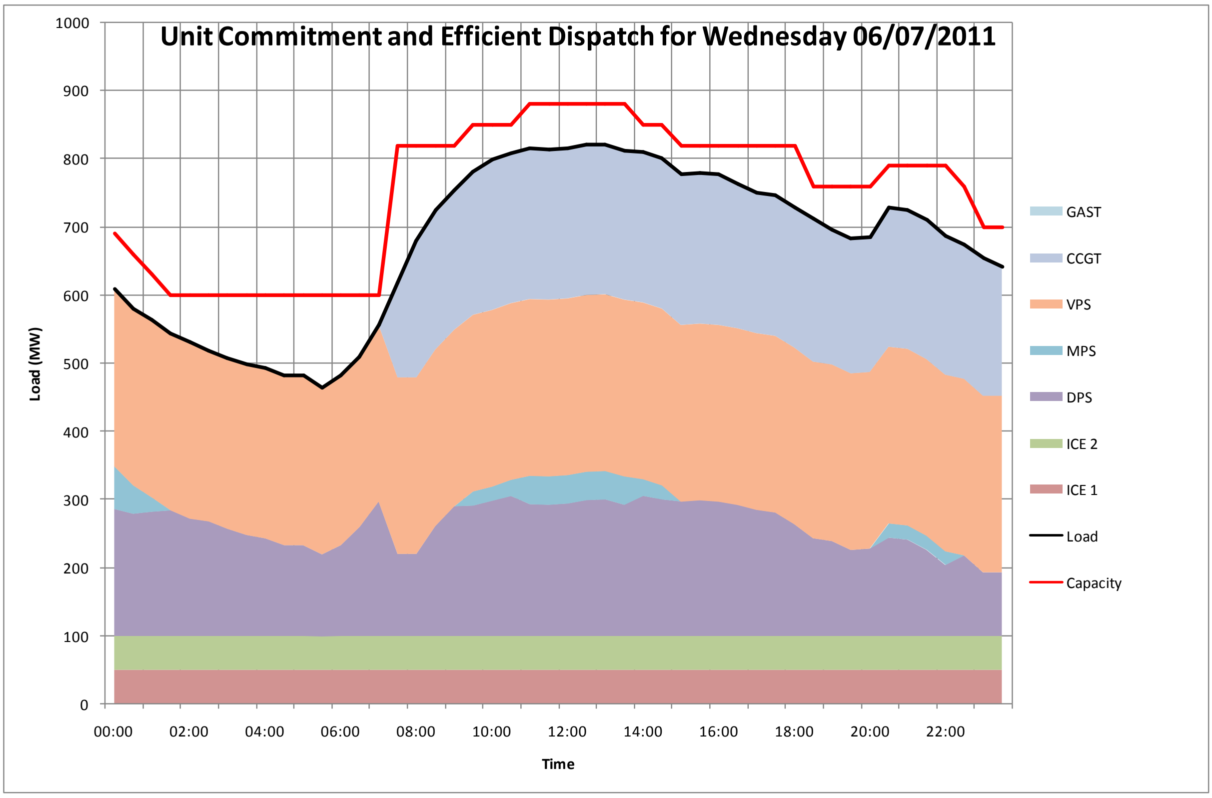

Figure 12. Unit Commitment and Economic Dispatch of Example 2.a (basic model with soft primary and secondary up reserve constraints and personnel constraints, under Case 6)

At this point, we should mention that one should be very careful when relaxing reserve constraints, in order not to risk the system security. Nevertheless, with careful manipulations, the system cost can be reduced, without practically risking system security, as is done for example in Cases 2 and 3 of **Table 14**.

Example 2.b: Adding a Daily Energy Constraint for ICE1 Units to Example 2.a

The 3 units ICE1 1, ICE1 2 and ICE1 3, which are aggregated as ICE1, have a yearly energy limit of 200,00MWh due to high NOx emissions.

These 3 units in both Cases 1 and 6 that were previously shown generate at full capacity. Therefore, they produce a daily amount of 1,204.2MWh. We impose a daily limit of 800MWh (one additional constraint) and we present the results in **Figure 13**.

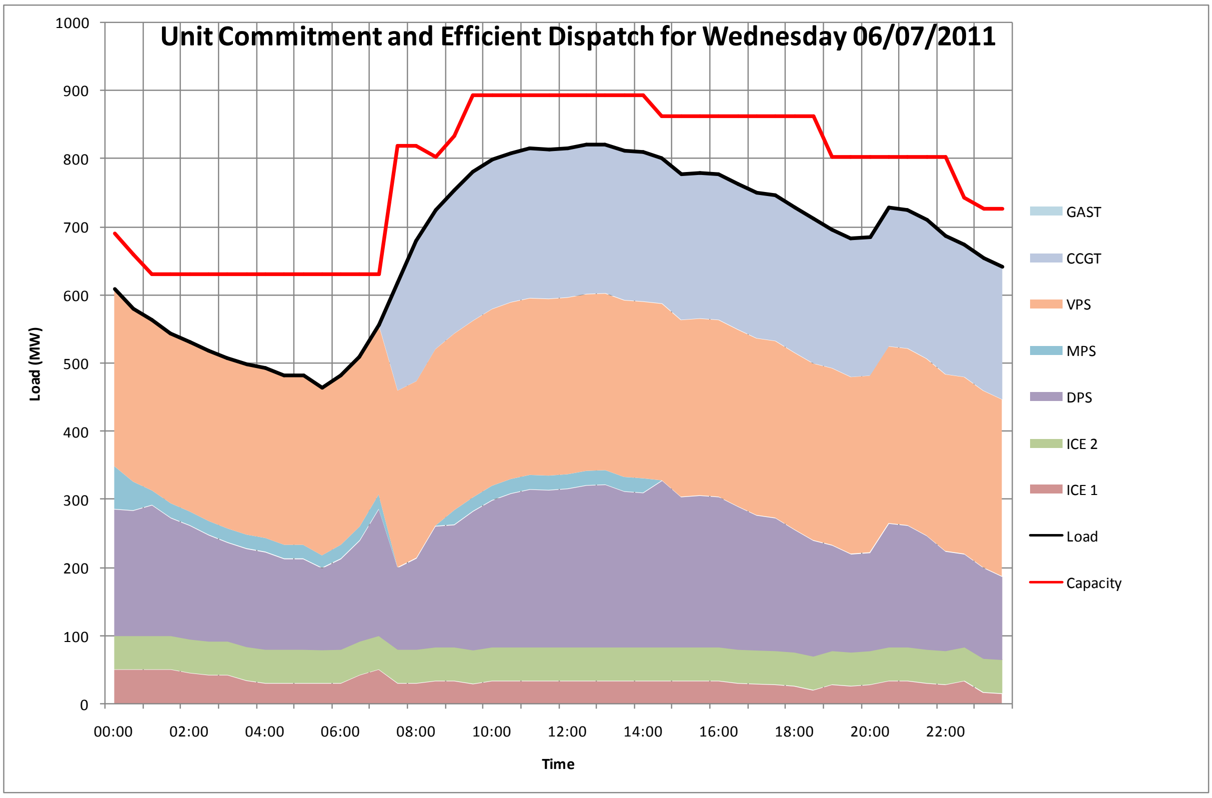

Figure 13. Unit Commitment and Economic Dispatch of Example 2.b (basic model with soft primary and secondary up reserve constraints, personnel constraints, and a daily energy limit for ICE1 units, under Case 1)

The daily energy of ICE1 units is now exactly 800MWh. The system cost for lowering the energy of these units is 11,430€. Had we solved the problem with the penalty coefficients of Case 6, we would have ended up with 13,511€ savings from relaxing the primary and secondary reserve up constraints.

Chapter 5. Summary and Conclusions

In this thesis, we defined, modeled, and solved the short-term generation scheduling problem for the electrical power system of Cyprus as an MILP unit commitment and economic dispatch problem. This has not been implemented so far.

The model developed was tailor-made to address the needs and particularities that the EAC faces daily, when called to decide the commitment of its generation units for each half-hour period of the next day, their energy generation output in order to satisfy the system load, and the provision of reserves in order to meet the system reserve requirements. This decision is taken in the most economical way (the overall operational cost is minimized), while respecting all the technical constraints of the generation units as well as other additional constraints and requirements specifically set by the EAC.

Due to the tragic event of the explosion in Mari in July 2011, the present thesis was appropriately modified to take into account the current conditions in the electrical power system of Cyprus. The loss of approximately half the installed capacity created a totally new environment, with temporary ICE units and energy purchased from the northern part being the most important differences. A short description of the electrical power system of Cyprus was presented in Chapter 2.

In our main Chapter 3, the mathematical formulation of the short-term generation scheduling problem was listed. A basic model was first stated that described the very basic features of the problem, and was then supplemented with additional constraints that extended the model to include other important aspects of the problem. We do not claim that the formulation is complete; however, the compromises made within the context of this thesis are far beyond the currently applied by the EAC procedure for solving the short-term generation scheduling problem.

The main contribution of this thesis is found in the application itself. Although the research area is not new, and the literature devoted on the unit commitment and generation scheduling problem is very rich, the application of existing methodologies on real-sized systems is a task worth pursuing, as there is always space for applied research in case studies, due to the particularities of each system and the various needs and demands that arise in each case. The contribution is strengthened by the fact that not all the details of the problem were formally defined in official documents, which made the work performed for this thesis even more interesting.

The numerical results presented in Chapter 4 are basically for illustration purposes. The idea was to show that the formulation manages well with the specific problem, in reasonable computational times, and that the results can reveal some interesting findings. The numerical examples addressed both system conditions, prior to and after the event of 11/7/2011, and various extensions of the basic formulation. It was seen that the model can be used not only for solving the unit commitment and economic dispatch problem of the next day, but also for assisting the EAC reconsider various constraints and demands, as the quantification (monetization) of the various requirements is now much easier.

Last but not least, we should point out the potential savings from implementing the proposed methodology on solving the daily unit commitment problem and economic dispatch problem. To get an order of magnitude, 0.5% savings would translate to 7,500€ daily savings in terms of operational cost (assuming a daily operational cost of 1.5 million €) or to 2.2 million € savings in terms of yearly fuel cost (considering the yearly data of 439.51 million € of fuel cost for the year 2010). It is believed that 0.5% savings is not an unrealistic target.

Appendix A. Calculation of Marginal and No-Load Costs

In this Appendix, we describe two procedures for the calculation of the marginal and no-load costs of a generation unit. For the needs of the optimization problem, the marginal cost will be approximated as a piecewise step function with six price-quantity pairs; this is called Incremental Cost (IC), and it is shown in **Figure 14** below. The no-load cost is an hourly cost, which is applicable as long as the generation unit is online.

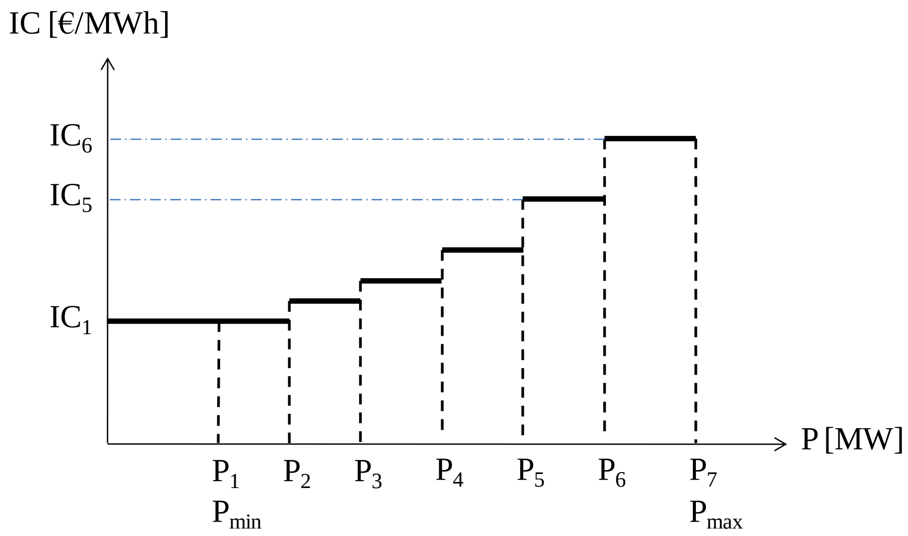

Figure 14. Incremental Cost. Piecewise Approximation of the Marginal Cost.

In both procedures, the basis of the calculations is the heat rate of the generation unit. Starting from the heat rate data, we finally obtain a function of the hourly total cost, which we use to derive the marginal cost.

In the first procedure, we use the direct measurements of the heat rate for specific output levels, and hence we obtain a piecewise linear function of the hourly cost.

In the second procedure, from the direct measurements of the heat rate for specific output levels, we approximate the heat rate with a curve, and hence we derive the commonly used quadratic function that approximates the total hourly cost. We then approximate the quadratic cost function with a piecewise linear function.

Both procedures introduce errors of measurements and approximations. The first procedure introduces the error of the heat rate measurements and the piecewise linear approximation. The second procedure smoothes out the error of the discrete heat rate measurements by approximating with a curve, but the specific type of the curve used so that a quadratic cost function is finally obtained introduces approximation errors; in addition, the piecewise approximation of the quadratic cost function introduces an additional error. Nevertheless, all the aforementioned errors are not considered to be significant for the purposes of this thesis.

A.1 Calculation of the Marginal and No-Load Costs Directly from the Discrete Measurements of the Heat Rate.

In this section, the marginal cost and the no-load cost are derived directly from the discrete measurements of the heat rate curve.

The input parameters are:

- The Heat Rate measurements in [GJ/MWh]: The Heat Rate HR(P) is measured in [GJ/MWh] in 7 points of the unit output P [MW]. The first measurement is taken at the unit's technical minimum ($P_1 = P_{min}$) and the last measurement is taken at the unit's technical maximum ($P_7 = P_{max}$).
- The Fuel Type: There are two fuel types: Heavy Fuel Oil (HFO) and Gasoil (Gas)
- The Fuel Price (FP) in [€/ton]
- The Fuel Net Calorific Value (FNCV) in [GJ/ton]
- The Carbon Price (CP) in [€/ton CO_2]
- The Carbon Conversion Efficiency (CCE): The CCE has a value around 99.5%.
- The Fuel Carbon Content (FCC): The FCC has a value of 88% for HFO and 86% for Gasoil.

▪ The Maintenance and Other Costs (MOC): The Maintenance Cost for each generation unit is the maintenance cost associated with the operation of the unit between the technical minimum and technical maximum. It can be proportional to the generation (MWh) or the hours of operation or both. Other costs include the costs of lubricants (significant for ICE operation) and catalytic converter operation cost (applicable to ICE2 type engines), electrical consumption from common station supplies, as well as any other significant variable cost. They can be proportional to the generation (MWh) or the hours of operation or both.

***Procedure*:**

Step 1. Our starting point is the Heat Rate curve of the generation unit in [GJ/MWh] vs. the output of the generation unit [MW] for specific output. We assume that we have measurements for 7 points as shown in **Figure 15**.

Step 2. From the Heat Rate curve, we calculate the Variable Fuel Cost (**Figure 16**) and the Variable Emission Cost.

Step 3. From the Variable Fuel Cost (VFC), the Variable Emission Cost (VEC), and the Maintenance and Other Costs, we calculate the Hourly Cost (HC) (**Figure 17**) and the No-Load Cost (NLC) (**Figure 18**).

Step 4. From the Hourly Cost, we calculate the Incremental Cost (**Figure 14**), which is an approximation of the marginal cost.

Finally, the total generation cost is expressed by the No-Load Cost and the 6 block offers (price-quantity pairs) that represent the Incremental (Marginal) Cost.

The Heat Rate in [GJ/MWh] can be measured in specific points of the unit output [MW]. For the needs of this analysis, we assume that we have measurements in 7 points $\{(P_1, HR_1), (P_2, HR_2), \ldots, (P_7, HR_7)\}$.

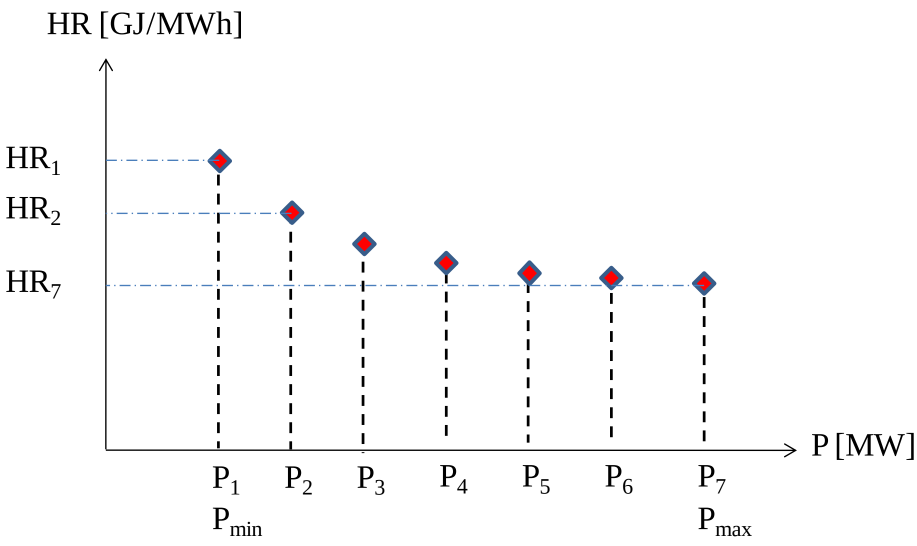

Figure 15. Heat Rate Measurements

From the Heat Rate measurements, we can derive the Variable Fuel Cost curve for a specific output. This curve will be of the same form with the heat rate curve, multiplied with a coefficient that equals the Fuel Price (FP) over the Fuel Net Calorific Value (FNCV), i.e.

$$\mathrm{VFC}_i\ [€/\mathrm{MWh}] = \frac{\mathrm{FP}\ [€/\mathrm{ton}]}{\mathrm{FNCV}\ [GJ/\mathrm{ton}]}\ \mathrm{HR}_i\,[\mathrm{GJ/MWh}]\ ,\ \text{ for } i = 1, 2,.., 7. \tag{83}$$

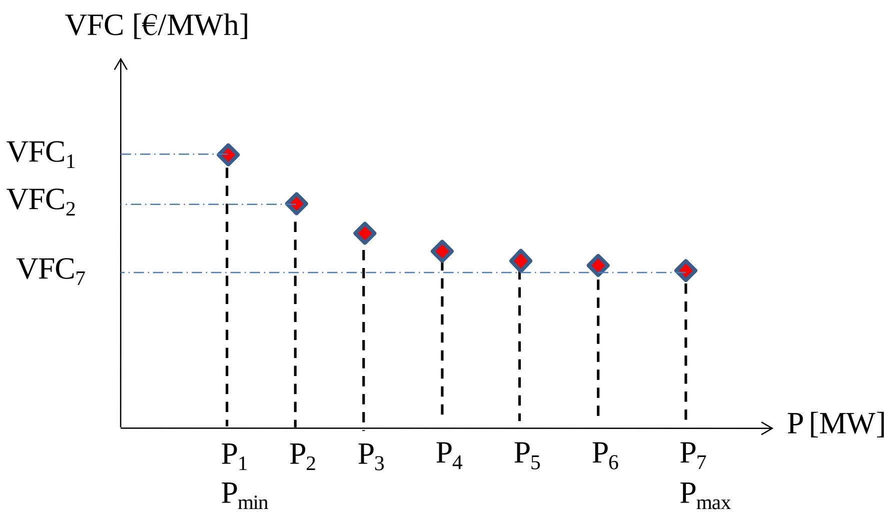

Figure 16. Variable Fuel Cost

We calculate the Variable Emission Cost, at the specific output, according to:

$$\mathrm{VEC}_i\ [€/\mathrm{MWh}] = \frac{\mathrm{HR}_i\,[\mathrm{GJ/MWh}]}{\mathrm{FNCV}\ [\mathrm{GJ/ton}]} \cdot \mathrm{FCC} \cdot \mathrm{CCE} \cdot \frac{44}{12}\,[\mathrm{tonCO_2/ton}] \cdot \mathrm{CP}\ [€/\mathrm{tonCO_2}], \tag{84}$$

for i = 1, 2,.., 7.

The total Hourly Maintenance and Other Costs (HMOC) in [€/h] are given by

$$\mathrm{HMOC}\ [€\,/\,\mathrm{h}] = \mathrm{b}_2\ [€\,/\,\mathrm{MWh}] \cdot \mathrm{P}\ \ [\mathrm{MW}] + \mathrm{b}_3\ [€\,/\,\mathrm{h}] \tag{85}$$

The hourly cost comprises of three components: the fuel cost, the emissions cost and the maintenance and other costs, i.e.:

$$\mathrm{HC}_i\ [€/\mathrm{h}] = (\mathrm{VFC}_i + \mathrm{VEC}_i + \mathrm{b}_2)\ [€/\mathrm{MWh}] \cdot \mathrm{P}\ [\mathrm{MW}] + \mathrm{b}_3\ [€/\mathrm{h}]\text{, for } i = 1, 2,.., 7. \tag{86}$$

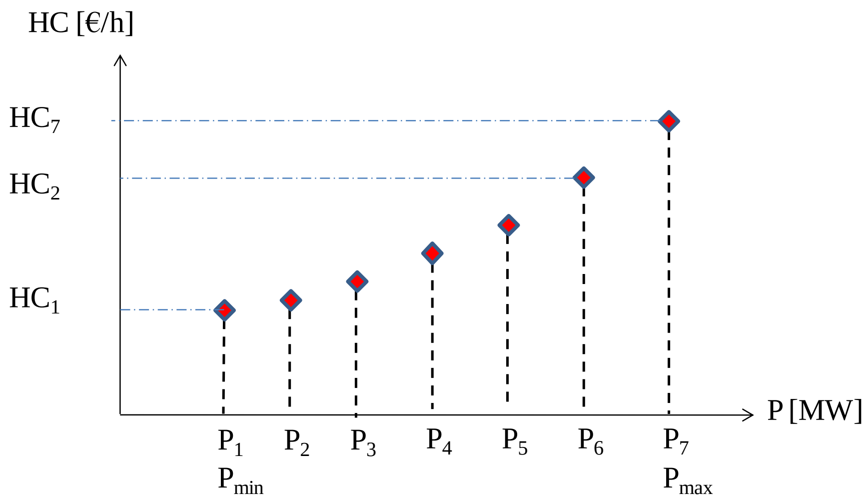

Figure 17. Hourly Cost

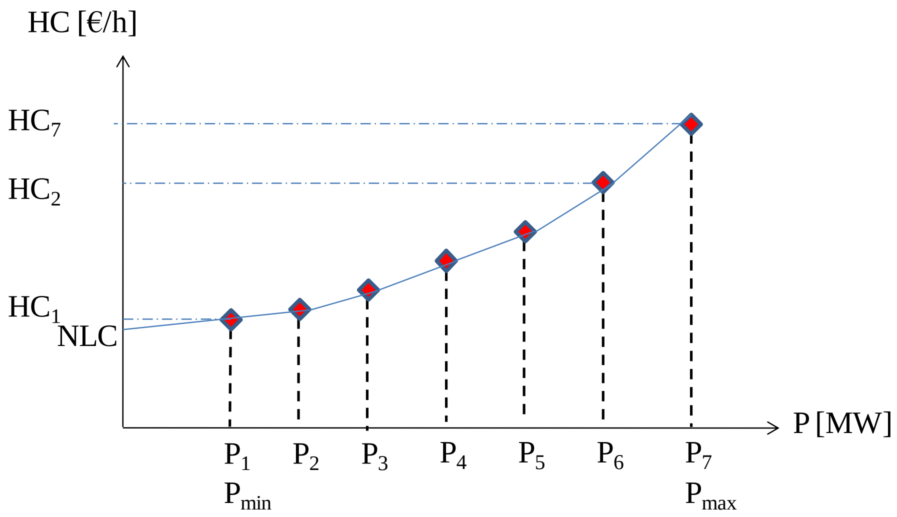

Figure 18. Hourly Cost and No-Load Cost

The Incremental Cost is given by

$$\mathrm{IC}_i\ [€/\mathrm{MWh}] = \frac{\mathrm{HC}_{i+1} - \mathrm{HC}_i}{\mathrm{P}_{i+1} - \mathrm{P}_i}, \text{ for } i = 1, 2,.., 6. \tag{87}$$

Therefore, the cost function will be a stepwise price vs. quantity function, as shown in **Figure 14**.

The hourly cost is now represented by

$$\mathrm{HC(P)}\ [€/\mathrm{h}] = \int_0^P \mathrm{IC}(p)dp + \mathrm{NLC}\ [€/\mathrm{h}] \tag{88}$$

Therefore, the no-load cost represents the constant of the integration, i.e.

$$\mathrm{NLC}\ [€/\mathrm{h}] = \mathrm{HC(P)}\ [€/\mathrm{h}] - \int_0^P \mathrm{IC}(p)dp \tag{89}$$

For clarification, we present the procedure in the following Table.

Table 15. Incremental Cost Calculation

Output **[MW]**	$\mathbf{P_1}$	$\mathbf{P_2}$	$\mathbf{P_3}$	$\mathbf{P_4}$	$\mathbf{P_5}$	$\mathbf{P_6}$	$\mathbf{P_7}$
Heat Rate(P) **[GJ/MWh]**	$\mathbf{HR_1}$	$\mathbf{HR_2}$	$\mathbf{HR_3}$	$\mathbf{HR_4}$	$\mathbf{HR_5}$	$\mathbf{HR_6}$	$\mathbf{HR_7}$
Variable Fuel Cost (P) [see (83)] **[€/MWh]**	VFC_1	VFC_2	VFC_3	VFC_4	VFC_5	VFC_6	VFC_7
Variable Emissions Cost (P) [see (84)] **[€/MWh]**	VEC_1	VEC_2	VEC_3	VEC_4	VEC_5	VEC_6	VEC_7
Maintenance and Other Cost (P) proportional to generation **[€/MWh]**	$\mathbf{b_2}$	$\mathbf{b_2}$	$\mathbf{b_2}$	$\mathbf{b_2}$	$\mathbf{b_2}$	$\mathbf{b_2}$	$\mathbf{b_2}$
Maintenance and Other Cost (P) proportional to hours **[€/h]**	$\mathbf{b_3}$	$\mathbf{b_3}$	$\mathbf{b_3}$	$\mathbf{b_3}$	$\mathbf{b_3}$	$\mathbf{b_3}$	$\mathbf{b_3}$
Hourly Cost (P) [see (86)] **[€/h]**	HC_1	HC_2	HC_3	HC_4	HC_5	HC_6	HC_7
Incremental Cost (P) [see (87)] **[€/MWh]**		IC_1	IC_2	IC_3	IC_4	IC_5	IC_6

A.2 Calculation of the Marginal and No-Load Costs from the Heat Rate Curve

In this section, we present the derivation of the hourly cost from the heat rate curve.

***Procedure*:**

Step 1. Our starting point is the Heat Rate curve (**Figure 19**) of the generation unit in [GJ/MWh] vs. the output of the generation unit [MW] for specific output.

Step 2. From the Heat Rate curve, we calculate the Variable Fuel Cost (**Figure 20**) and the Variable Emission Cost.

Step 3. From the Variable Fuel Cost, the Variable Emission Cost, and the Maintenance and Other Costs, we calculate the Hourly Cost (**Figure 21**).

Step 4. We approximate the quadratic function of the hourly cost with a piece-wise linear function of 6 segments (**Figure 22**).

Step 5. From the Hourly Cost, we calculate the Incremental Cost (**Figure 14**), and the no-load cost.

Once again, the heat rate curve is derived by discrete measurements, and then approximated with the following Heat Rate curve HR(P)

$$\text{HR(P) [GJ/MWh]} = A_1 \cdot P + A_2 + A_3 / P \qquad (90)$$

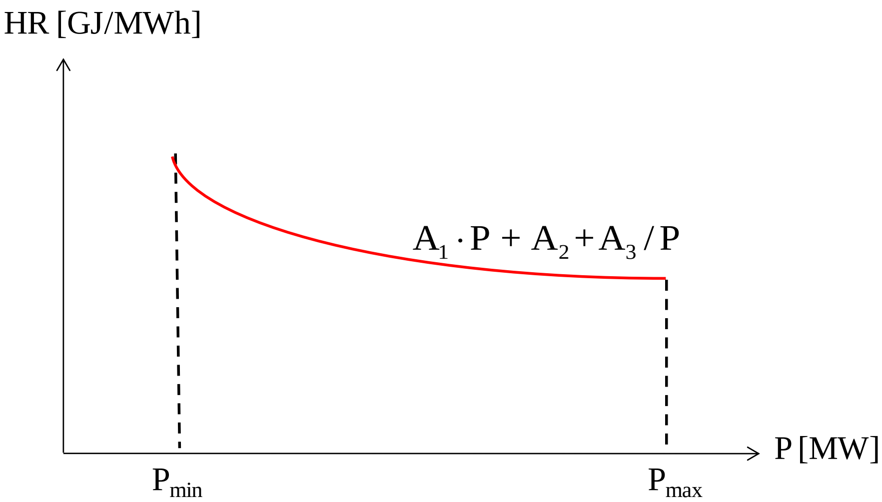

Figure 19. Heat Rate Curve

The Variable Fuel Cost VFC(P) is now given by

$$\text{VFC(P) [€/MWh]} = \frac{\text{FP [€/ton]}}{\text{FNCV [GJ/ton]}} \text{HR(P) [GJ/MWh]} = A_1' \cdot P + A_2' + A_3' / P \qquad (91)$$

with $A_i' = \dfrac{\text{FP [€/ton]}}{\text{FNCV [GJ/ton]}} A_i$ for i = 1, 2, 3. (92)

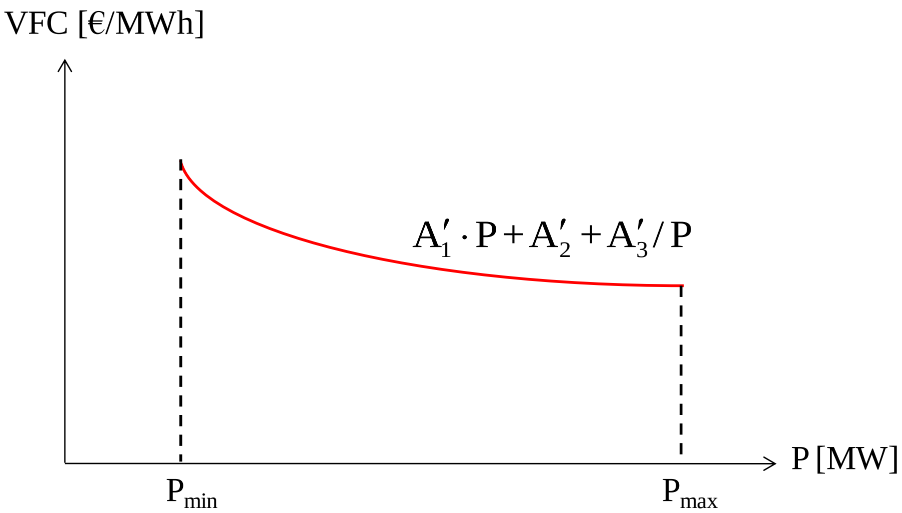

Figure 20. Variable Fuel Cost Curve

The Variable Emissions Cost VEC(P) is given by

$$\text{VEC(P) [€/MWh]} = \frac{\text{HR(P) [GJ/MWh]}}{\text{FNCV [GJ/ton]}} \cdot \text{FCC} \times \text{CCE} \times \frac{44}{12} [\text{tonCO}_2/\text{ton}] \times \text{CP}[\text{€/tonCO}_2] = \\ = A_1'' \times P + A_2'' + A_3''/P \tag{93}$$

$$\text{with } A_i'' = \frac{\text{FCC} \times \text{CCE} \times \frac{44}{12} [\text{tonCO}_2/\text{ton}] \times \text{CO}_2\text{P}[\text{€/tonCO}_2]}{\text{FNCV[GJ/ton]}} \cdot A_i \text{ for } i = 1, 2, 3. \tag{94}$$

The Variable Maintenance and Other Costs VMOC(P) is given by

$$\text{VMOC(P) [€/MWh]} = b_2 + b_3 / P \tag{95}$$

The Variable Cost VC(P) is given by

$$\begin{aligned}
VC(P)[€/MWh] &= VFC(P) + VEC(P) + VMOC(P) = \\
&= A_1' \cdot P + A_2' + A_3'/P + A_1'' \cdot P + A_2'' + A_3''/P + b_2 + b_3/P = \\
&= (A_1' + A_1'')\, P + (A_2' + A_2'' + b_2) + (A_3' + A_3'' + b_3)/P = \\
&= a_1 \cdot P + a_2 + a_3/P
\end{aligned} \tag{96}$$

$$\text{with } a_i = A_i' + A_i'' + b_i, \text{ for } i = 1,2,3, \text{ with } b_1 = 0 \tag{97}$$

Therefore the Hourly Cost HC(P) is given by

$$\begin{aligned}
HC(P)\ [€/h] &= HVC(P)\ [€/MWh] \times P\ [MW] \\
&= a_1 \cdot P^2 + a_2 \cdot P + a_3
\end{aligned} \tag{98}$$

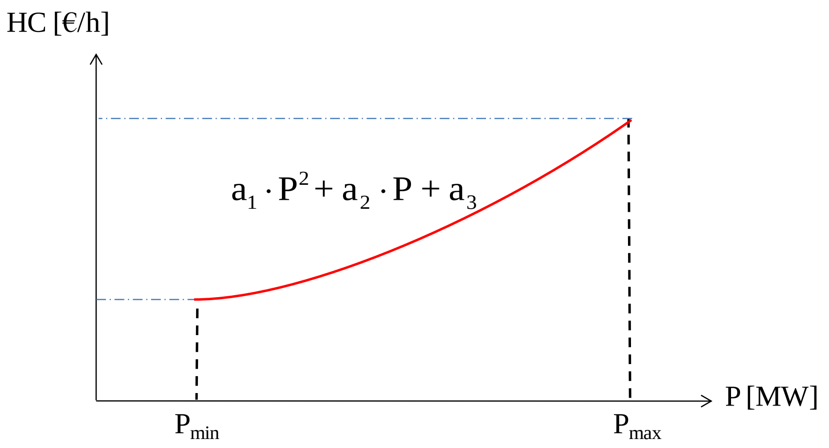

Figure 21. Hourly Cost Curve (quadratic cost function)

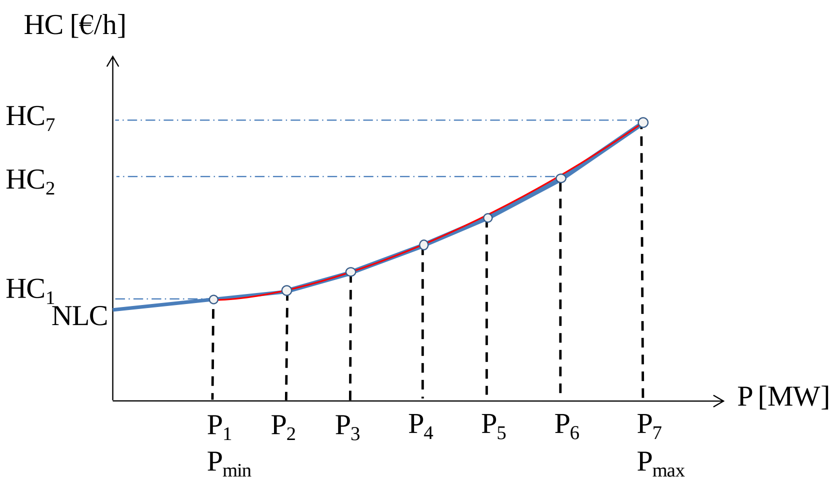

Figure 22. Hourly Cost. Piecewise Linear Approximation of the Quadratic Curve.

The incremental cost is now given by (87).

Note also that the marginal cost derived directly by (98) is given by

$$MC(P) = \frac{\partial HC(P)}{\partial P} = 2a_1P + a_2 \tag{99}$$

The incremental cost in (87) is a piecewise approximation of the linear marginal cost in (99).

The no-load cost is given by (89) and shown in **Figure 22**.

Lastly, we can note that, in case we did not consider a piecewise approximation for the marginal cost in the objective function, the no-load cost would be the constant of the quadratic function in (98), and the marginal cost would be given by (99). Therefore, the no-load cost would be the constant of integration of (99).

Appendix B. Nomenclature

***Acronyms*:**

C	Cost
Q	Quantity
X	Binary variable, $X \in \{0,1\}$
Y	Integer variable, $Y \in \{0,1,2,\ldots\}$ (non-negative)
SysL	System Load
Req	Requirements for Ancillary Services (AS)
MT	Minimum Time (in hours)
G	Generation or energy (superscript)
PR	Primary Reserve (superscript)
SR	Secondary Reserve (superscript)
TR	Tertiary Reserve (superscript)
St	Status of a generation unit: Online or Offline (superscript)
SU	Startup of a generation unit (superscript)
SD	Shutdown of a generation unit (superscript)
NL	No-load (refers to cost) of a generation unit (superscript)
Pur	Purchased (refers to energy purchased from the northern part) (superscript)
Aux	Auxiliary (refers to auxiliary integer variables) (superscript)

***Indices- Sets - Subsets*:**

u Generation unit, $u \in U$, with *U*: set of generation units or $u \in U_s$ (with U_s: subset of generation units, e.g. *s* = VPS, DPS, MPS, MPSsteam, ICE, etc.)

b Block of offer, $b = 1,\ldots,B$, with $B = 6$: total number of allowable blocks

t Half-Hour (Dispatch Period), $t = 1,\ldots, T$, with $T = 48$: total number of Dispatch Periods

***Input Parameters*:**

Costs: $C_{u,b,t}^{\mathrm{G}}$ C_u^{SU} , C_u^{SD} , C_u^{NL} , $C^{\mathrm{G,Pur}}$

System load: $SysL_t$

RES injections: RES_t

Reserve requirements: $Req_t^{\mathrm{PR^{Up}}}$, $Req_t^{\mathrm{PR^{Down}}}$, $Req_t^{\mathrm{SR^{Up}}}$, $Req_t^{\mathrm{SR^{Down}}}$, $Req_t^{\mathrm{TR^{Up}}}$, $Req_t^{\mathrm{TR^{Down}}}$

Block limits: $\bar{Q}_{u,b}^{\mathrm{G}}$

Minimum and maximum generation: $\underline{Q}_u^{\mathrm{G}}$, $\bar{Q}_u^{\mathrm{G}}$

Maximum reserve limits: $\bar{Q}_u^{\mathrm{PR^{Up}}}$, $\bar{Q}_u^{\mathrm{PR^{Down}}}$, $\bar{Q}_u^{\mathrm{SR^{Up}}}$, $\bar{Q}_u^{\mathrm{SR^{Down}}}$, $\bar{Q}_u^{\mathrm{TR^{Up,Spin}}}$, $\bar{Q}_u^{\mathrm{TR^{NonSpin}}}$ $\bar{Q}_u^{\mathrm{TR^{Down}}}$

Minimum up/down times: MT_u^{Up} , MT_u^{Down}

Ramp limits: RR_u^{Up} , RR_u^{Down}

Unit availability: $X_{u,t}^{\mathrm{Av}}$

Unit must-run status: $X_{u,t}^{\mathrm{Must\text{-}Run}}$

Maximum daily energy limit: $\bar{Q}_u^{\mathrm{G,Daily}}$

Maximum power purchased from the northern part: $\bar{Q}_t^{\mathrm{G,Pur}}$

Mandatory generation: $Q_{u,t}^{\mathrm{G,Mand}}$

Maximum number of daily startups: $\overline{SU}_u^{\mathrm{Daily}}$

Penalty Coefficients: $C^{\mathrm{Pen,G}}$, $C^{\mathrm{Pen,\,PR^{Up}}}$, $C^{\mathrm{Pen,\,PR^{Down}}}$, $C^{\mathrm{Pen,\,SR^{Up}}}$, $C^{\mathrm{Pen,\,SR^{Down}}}$

Upper bounds for deficit variables: $\bar{Q}_t^{\mathrm{Def,\,PR^{Up}}}$, $\bar{Q}_t^{\mathrm{Def,\,PR^{Down}}}$, $\bar{Q}_t^{\mathrm{Def,\,SR^{Up}}}$, $\bar{Q}_t^{\mathrm{Def,\,SR^{Down}}}$

Initial values (at hour 0): $X_u^{\mathrm{St,0}}$, $Y_u^{\mathrm{On,0}}$, $Y_u^{\mathrm{Off,0}}$, $Q_u^{\mathrm{G,0}}$

Time period coefficient (fraction of hour): D

***Decision Variables*:**

Priced power quantities: $Q_{u,b,t}^{\mathrm{G}}$, $Q_t^{\mathrm{G,Pur}}$ (nonnegative)

Total power quantities: $Q_{u,t}^{\mathrm{G,Total}}$ (nonnegative, dependent variable)

Reserve quantities: $Q_{u,t}^{\mathrm{PR}^{\mathrm{Up}}}$, $Q_{u,t}^{\mathrm{PR}^{\mathrm{Down}}}$, $Q_{u,t}^{\mathrm{SR}^{\mathrm{Up}}}$, $Q_{u,t}^{\mathrm{SR}^{\mathrm{Down}}}$, $Q_{u,t}^{\mathrm{TR}^{\mathrm{Up,Spin}}}$, $Q_{u,t}^{\mathrm{TR}^{\mathrm{NonSpin}}}$, $Q_{u,t}^{\mathrm{TR}^{\mathrm{Down}}}$ (nonnegative)

Total tertiary reserve up quantity: $Q_{u,t}^{\mathrm{TR}^{\mathrm{Up}}}$ (nonnegative, dependent variable)

Binary variables: $X_{u,t}^{\mathrm{St}}$, $X_{u,t}^{\mathrm{SU}}$, $X_{u,t}^{\mathrm{SD}}$, $X_{u,t}^{\mathrm{NonSpin}}$

Integer variables: $Y_{u,t}^{\mathrm{On}}$, $Y_{u,t}^{\mathrm{Off}}$

Deficit and surplus (nonnegative) variables: $Q_t^{\mathrm{G,\ Def}}$, $Q_t^{\mathrm{G,\ Sur}}$ $Q_t^{\mathrm{PR}^{\mathrm{Up}},\mathrm{Def}}$, $Q_t^{\mathrm{PR}^{\mathrm{Down}},\mathrm{Def}}$, $Q_t^{\mathrm{SR}^{\mathrm{Up}},\mathrm{Def}}$, $Q_t^{\mathrm{SR}^{\mathrm{Down}},\mathrm{Def}}$

Auxiliary integer variables: $Y_{u,t}^{\mathrm{Aux(1)}}$, $Y_{u,t}^{\mathrm{Aux(2)}}$

Appendix C. Abbreviations

AGC	Automatic Generation Control
CCGT	Combined Cycle Gas Turbine
CERA	Cyprus Energy Regulatory Authority
DPS	Dhekelia Power Station
EAC	Electricity Authority of Cyprus
GT	Gas Turbine (open cycle)
HFO	Heavy Fuel Oil
ICE	Internal Combustion Engine
ISO	Independent System Operator
LR	Lagrangian Relaxation
MILP	Mixed Integer Linear Programming
MPS	Moni Power Station
NECC	National Energy Control Center
PPC	Public Power Corporation
RES	Renewable Energy Sources
SCADA	Supervisory Control and Data Acquisition
ST	Steam Turbine
TSO	Transmission System Operator
VPS	Vasilikos Power Station

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