The Liberalization of the Greek Electricity Supply Market

by

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ABSTRACT

The motivation for this work is an interest in investigating the particular situations and circumstances that have emerged as the Greek electricity industry moves from its previous form of market organization as a vertically integrated state-owned monopoly to a new liberalized form of market incorporating competition. It should be noted that this market reform is introduced to Greece by the European Union and therefore this reform is externally motivated. Whilst progress has been made to the direction of the market reform, full liberalization has not been achieved.

The analysis involves an initial discussion of the Greek electricity market, a literature review in order to identify gaps in the existing literature and then modelling the Greek electricity market. This modelling uses the kinked demand curve with price caps to show how the absence of time-varying tariffs can create opportunities for profitability for new entrants in a market when these new entrants are not obliged to serve the whole demand and at all times. We examine these markets using varying price caps and show how the level of the price cap, together with the size of the market, determines profitability. We examine specific cases where entry can occur in electricity markets that are facing transitionary periods or where asymmetric conditions might apply for various market participants. We use game theory to illustrate the specific cases that reflect conditions in the Greek case and we examine the foundations of the operation of the Greek political system to identify the effects on the Greek economy. We examine various patterns of system load using empirical data. We also examine data of wholesale electricity prices to identify the effect that the introduction of competition in the wholesale market has for the wholesale electricity prices as well as the dependency of wholesale electricity prices on international fuel prices. Through the examination of these data we observe the impact that political decisions might have on the electricity industry.

The contribution to knowledge lies in illustrating how the specific conditions that exist within a political and economical setting like the Greek one can present obstacles to the introduction of changes and reforms. Considering liberalization of

the electricity industry as a technical issue can be misleading. Pre-existing market distortions and cross-subsidizations that remain within the economic system as a result of industrial and social policies driven by cultural and political considerations are shown to have a significant impact to the market reform. Efforts targeted at making changes to increase economic efficiency and welfare are likely to meet significant obstacles.

The important implication for policymakers has to do with the commitment to market reform, once this is decided. This commitment needs to go beyond the letter of the necessary reform conditions. It should extend into a true willingness by the political forces to give up control of the market so that competition can emerge. In terms of how liberalization should be delivered, we find that the use of asymmetric regulation can result in problematic and unsustainable market conditions and should therefore be used with caution. Also, transparency and information availability across the market are key issues and policy-makers should be made aware that this is to be taken care of.

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Glossary

PPC: Public Power Company

HTSO: Hellenic Transmission System Operator

IPTO: Independent Power Transmission Operator

OOEM: Operator Of Electricity Market

HEDNO: Hellenic Electricity Distribution Network Operator

SMP: System Marginal Price

DMP (or ex-post SMP): Deviations Marginal Price

Maximum profits of the unconstrained case: The profits that a monopolist would make if there is no regulatory intervention and he can set price and quantity.

Maximum profits of the constrained case: The maximum profits that a firm can make given the presence of a price cap.

PC_i is the price cap for market *i*.

P_0 is the price cap as it appears on our diagrams when we only use one price cap.

P_i^* is the profit maximizing price of the unconstrained monopolist as it appears on our algebraic analysis, appears as P_1 in the diagrams.

P_1 is the profit maximizing price of the unconstrained monopolist as it appears on our diagrams, appears as P_i^* in the algebraic analysis.

P_2 is the price that we get at the point where MVC curve intersects the demand curve D.

P_3 is the price that we get at the point where MVC curve intersects the vertical price axis. That means that it is the Marginal Variable Cost at zero market quantity.

P_A is the price where super normal profits are zero. This price is set by the intersection of the demand curve and the AVC curve (we only account for variable cost in our analysis).

Q_i^* is the profit maximising quantity of the unconstrained case.

Q_i^{PC} is the profit maximising quantity of the constrained case.

Q_0 is the quantity that the market demands when the market price is set at P_0 (which is the price cap on the diagrams where we have only one price cap).

π_i are the profits in market *i*

$\pi_{1,2}$ are the profits from participating in markets 1 and 2.

π_i^* are the maximum profits of the unconstrained case when participating in market *i*

$\pi_{1,2}^*$ are the maximum profits of the unconstrained case when participating in markets 1 and 2.

Chapter 1

Description of the Greek Electricity Market

1.1 Introduction to the Study

1.1.1 Research objectives and research questions

In recent times, many western countries have opted to deregulate and liberalize their electricity markets with mixed results. There has been criticism levied on such endeavors given the inherent complexities of this type of market. The successful reforms that took place in many countries are countered by less successful results to be found elsewhere. The issue addressed in this thesis is the liberalization of the Greek electricity market. We discuss particularly the specific characteristics of an institutional and political character which affect the Greek liberalization process. We examine the attempts to introduce competition within the Greek electricity market, the asymmetries that are present and how these affect the outcome of the reform effort. Specifically we are focusing on the retail electricity supply, because this is an area of the literature which is relatively lightly researched.

Research questions:

The research questions that we deal with in this thesis are:

- What progress has been made in the Greek electricity market in terms of its movement from a vertical integrated monopoly towards a liberalized form of market organization?
- What are the circumstances that are inherited from the previous market setting that significantly affect the reform process? Why is it that these circumstances are halting the introduction of competition?
- How can the policymakers control the market power of the incumbent and facilitate entry in the electricity supply market? What are the cases where this is done in a manner that is inefficient?
- What is the role of political forces in the determination of market reform outcomes?

- What are the factors that affect demand in the Greek electricity industry and wholesale electricity prices? What implications are there for tariff setting?
- What factors aid or hinder new entry into electricity supply markets with price caps?
- Can we identify the impact of liberalization in wholesale electricity prices?

1.1.2 Overview of the research

This study undertook an extensive desk analysis of the Greek electricity market to uncover the underlying structure and day to day operation of the sector and the role of regulation and of the market participants. The study adopts both qualitative and quantitative approaches in terms of the analysis of the content of targeted websites of the market regulator, the previous and the current grid operator, the market operator and the incumbent. It also provides theoretical modelling approaches to the research problem. For data analysis, for simulations and for theoretical modelling, the software used was Microsoft Excel and Microsoft Powerpoint. The thesis text was written in Microsoft Word.

1.1.3 Novelty of this research

The research presents the situations that have emerged in the reform of the Greek electricity market as competition is introduced. Within the discussion of the general issues that are introduced through liberalization, the specific characteristics of the Greek case (the size of the market, the structure of the retail tariffs and the regulatory setting) are identified and discussed, as well as the impact that these have on the liberalization process. This is done using theoretical modeling that also can apply to other circumstances with similar characteristics. Important to this is the position of the government and the framework it uses for decision making. Secondary data are analyzed for the determination of the way that certain factors are affecting the System Load and the wholesale electricity prices in the Greek electricity market.

1.1.4 Organization of the thesis

This thesis examines the Greek Electricity Market. It examines the reform effort made to affect a transition from a vertically integrated regulated monopoly to a situation where competition takes place both in the retail and the wholesale electricity markets. In that reform effort, the transmission and distribution sectors remain regulated monopolies.

In Chapter 1, the energy policy of the government is discussed from a security of supply and capacity planning perspective. The structure of the market, the role of the regulator and the regulatory rules under which the electricity market operates is discussed. We also examine the wholesale market for electricity, how competition has been introduced and how adequately large generating capacity can assist in the development of competition in the long run. We look at the role of tariff setting in making the electricity supply market attractive or non-attractive to potential new suppliers.

We investigate how the market outcome can be affected by the available capacity, the fuels used in the generation and the bidding strategies of the market participants. Market design and implementation planning is crucial in the success of the introduction of competition. We bear in mind in our discussions that the electricity market should be further exposed to competition and that this should happen in a way that would lead to reduced wholesale electricity prices. We also present some standard models of market reform that are found in the literature and use them as benchmarks against which to measure the performance of the Greek reform.

The overall aim of Chapter 1 is to provide the context of the Greek electricity industry as this has evolved since the introduction of the liberalization reforms. This helps to understand how the models presented in Chapters 3 and 4 fit the details of the Greek electricity industry. Also, the information presented in Chapter 1 is useful in contextualizing the discussion around the data presented in Chapter 5.

Chapter 2 is a literature review of previous research done in the Greek electricity market as well as of the large body of literature on electricity reforms and on a variety of issues concerning the operation of electricity markets. We also report work referring to reforms in the electricity markets of other countries. The usefulness and contribution of Chapter 2 to the overall thesis lies in identifying gaps in the literature on electricity supply markets as well as in the literature on the operation and organization of the Greek electricity market after the introduction of the market reforms. The organization of the literature review identifies these gaps which are addressed through this thesis.

Chapter 3 examines the situation that is created in the electricity supply industry. We create a theoretical model that describes the situation in the supply of electricity and use it to evaluate decisions concerning the market. The model is presented diagrammatically in the chapter and algebraically in Appendix C. Simulations are being used as well as some comparative statics. We focus on the use of price cap regulation as a regulatory instrument and on the implications of price cap setting at different levels. This analysis is used to demonstrate how inappropriate price cap setting and the incorporation in price cap decision making of non-market elements, such as social considerations, can lead to varying levels of profitability across the different customer categories in an electricity supply market. This has implications when such a market is subject to competition, since competition is expected to apply pressure for the removal of any cross-subsidizations that might exist in the market tariffs. This relates to the case of Greece. We show how such circumstances can act to delay the progress of electricity market reforms by having some market segments served under tariffs that are unprofitable and unattractive for investors.

Chapter 4 examines the conditions under which the entry of new suppliers can occur and the policies employed by the regulator. We present and examine cases where we show diagrammatically the effect of the decisions of the regulator in the market. The asymmetry of the sets of rules that apply for the incumbent supplier compared to the new entrants is a key point in the discussion. We demonstrate how a new entrant can take advantage of such a situation and how poor or flawed market design and implementation planning can slow down or even stop the progress towards competition. We also use game-theoretic modeling approaches to address the issue of new entry and of the potential strategic interactions between market players. All these theoretical approaches are relevant to the Greek case as they reflect the situations that have emerged during the entry of new suppliers in the Greek electricity market. Chapter 4 focuses on the issues of entry and of the coexistence of multiple electricity suppliers in the same market. Chapter 4 shows how entry can occur under asymmetric conditions, picking up cases that follow the details of the Greek electricity industry. Entry can be unsustainable if it happens under asymmetric conditions and following the removal of protectionism of the new entrants these might not be able to maintain their market position, leading to an exit from the market.

Chapter 5 presents secondary data referring to System Load, System Marginal Price and Deviations Marginal Price[1]. This is followed by analysis of the factors that determine these data. Temperature data are used as well as data on fuel prices and fuel indexes. The argument is made that System Load is dependent on temperatures and also that it is varying following specific intra-day and annual patterns. We argue that intra-day wholesale pool prices are dependent on the System Load, and that wholesale pool prices are dependent upon domestic and international fuel prices across larger periods of time. Also, we present the effect that a strike organized by the Union of PPC had on the market operation, highlighting the reliance of the electricity industry on the previous incumbent as well as the strength of the Union. In Chapter 5 we show empirically how the issues that were discussed in Chapter 4 regarding the setting of market tariffs and the incorporation of political considerations apply to the Greek electricity industry. Also, we identify the dependence of wholesale electricity prices on fossil fuel prices as well as other effects on the wholesale markets after the introduction of competition in electricity generation.

Chapter 6 summarizes the findings of all the chapters, which are listed separately. The unique characteristics of the Greek case are identified, and the lessons learned

[1] Throughout the thesis we will be referring to Deviations Marginal Price, which is also mentioned in the sources as ex-post System Marginal Price.

are presented. Specific weight is given to the implications for policy. We also present some suggestions for further research as well as the limitations of the study.

1.2 The need for reform

The liberalization of the Greek electricity market came as a requirement of the European Union that established this liberalization with Directive 96/92/EC ([Thomas, 2006a], [Andrianesis, 2011]). It was introduced in Greece with Law 2773/1999 [Journal of the Greek Government, 1999]. Unfortunately, for a series of reasons that are not so uncommon in South East Europe, competition was not introduced effectively and there are still unsolved problems both in the wholesale and the retail electricity supply markets (especially on the supply). These persisting problems have halted the development of the market and proposal to address them are being discussed.

1.3 Structure of Greek Electricity Market

The electricity industry is divided in four parts, each of which is a separate set of activities in a liberalized electricity market. These four activities are Generation, Transmission, Distribution and Supply. Nevertheless, there are many differences in the way the sectors are linked and these are discussed below.

Generation is *"The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in kilowatthours."* [US Energy Information Administration, 2012b]. This refers to the first stage of the electricity market and it is the transformation of energy from one non-electrical form to an electrical form. In order for this to happen there are a number of technologies that can be employed. These include energy from oil, gas, coal, nuclear, hydro, solar, wind, waves, geothermic steam, tidal energy and other sources. Not all energy sources are available in the same quantities nor are they easily exploitable. Also, the waste that derives from electricity generation is an important issue. CO_2 and other greenhouse gas emissions have become an increasing global concern and nuclear waste needs special care in its treatment and disposition and this is very costly [Hewlett, 2005].

Transmission is *"An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems."*. [US Energy Information Administration, 2012b]. This is the second stage of operations for electricity utilities and it involves transferring electricity between power plants and electricity substations. Due to the fact that the amounts of electricity transferred during this stage are large, it takes place under high voltage in order to reduce losses.

Distribution is *"The delivery of energy to retail customers."* [US Energy Information Administration, 2012b]. This is the third stage in the electricity utilities operation and it is the transferring of electricity between electricity substations and the consumers. It usually takes place under medium or low voltage. However according the US Energy Information Administration definition given for the activities of the distribution provider, we find that he *"Provides and operates the wires between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the Distribution function at any voltage."* [US Energy Information Administration, 2012b]. So, although distribution takes place usually in medium or low voltage, that is not necessarily always the case.

Transmission and Distribution are natural monopolies and therefore no competition is introduced to these sectors. A natural monopoly occurs when *"...a single firm can satisfy the entire market demand for the range of goods or services at lower total cost than any other combination of firms."* [Newbery, 1999, pages 27-28]. Different solutions have been applied for the operation of these natural monopolies, depending on the specific characteristics of the electricity system in question.

The last and final stage of the electricity operations is electricity supply. Retail sales of electricity are the *"Sales made directly to the customer that consumes the energy product"* [US Energy Information Administration, 2012b]. This involves a supplier that sells electricity to the end users. Supplier obligations include contracting, meter maintenance and reading, billing, customer service as well as assuring that the supplier is able to supply the end users with the electricity they need.

1.4 The Electricity Regulator- Regulatory Authority for Energy (RAE)

According to law 4001/2011 [Journal of the Greek Government, 2011b] the Energy Market Operation is monitored by the State through the Minister of the Environment, Energy and Climate Change as well as of through the Regulatory Authority for Energy (RAE). This law sets the responsibilities and the operation of RAE. According to the provision of law 4001/2011, the long-run energy planning for the country aims at addressing:

1. Reaching an integrated European internal energy market with competition and improvements.

2. The issue of security of energy supply and of climate change measures as well as competitiveness concerns.

3. Environmental considerations.

4. Balanced regional development with the purpose of integrating isolated microgrids to the interconnected system leading the creation of a national and European market.

5. Productivity improvements and competition.

6. Energy poverty.

The responsibilities of RAE and its role of operations is defined in law 4001/2011 [Journal of the Greek Government, 2011b, pp. 3797-3812].

The responsibilities of RAE cover a large area and in this way there are informational advantages that favour the organisation's operation. Examples are those that arise from the fact that RAE monitors the security of supply for the country and at the same time decides on the energy activities licencing. Nevertheless, the vast scope of RAE's responsibilities is likely to create complications. Trying to accomplish many goals through one organisation might cause the organisation to lose its focus, since these goals are set in different areas. Worse still, contradictions arise from the fact that RAE can be directed at times to satisfy conflicting objectives. These contradictions become apparent in the work reported in subsequent chapters.

Focusing on these possible controversial situations, we can claim that when an organisation is responsible for performing judicial duties and at the same time participates in the legislative procedure, controversies might arise. The importance of the distinction between the legislative and the judicial function has been discussed [Cowles, 1892] and is considered crucial. RAE is in the best possible position to provide unbiased advice on the legislative process of energy markets and in the same time to understand the issues in the market operation so as to be able to perform dispute settlement duties and impose fines for energy legislation violations. However, this is an issue that one has to proceed with care about.

1.5 Energy Policy in Greece

1.5.1 Security of supply and adequacy of generating capacity

Security of supply in a time of deregulated markets is a very important issue since we cannot know whether the free market will be able to handle this issue without regulatory intervention [Batlle and Rodilla, 2010]. The consequences of security of supply failures can be very severe for the electricity market operation [Ochoa and van Ackere, 2009]. Security of supply is regarded as an important issue in Greece and the regulator has specific responsibilities for monitoring this. The North

American Electric Reliability Council [NERC, 2012] provides the following definitions for the reliability of an interconnected system:

“Adequacy — The ability of the bulk power system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security — The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from credible contingencies.”

However, for our discussion, both the requirements of the definitions provided for Adequacy and Security are going to be included in the term Security of Supply.

Approaching the security of supply from a point of view of established reliability, we look at the definition of “reliability of an electric system” which can be found in the glossary of the US Energy Information Administration [2012b] and defines it as *“A measure of the ability of the system to continue operation while some lines or generators are out of service. Reliability deals with the performance of the system under stress.”*.

In the case of Greece, security of supply has been a serious problem in the past years. This had to do with security of fuel supply (oil and natural gas), as well as with ensuring adequate generating and transmitting capacity. When capacity was insufficient, such as in summer 2005, increases in electricity demand led to electricity shortages during peak periods [PPC, 2005a]. The Greek electricity system has found itself in situations where it had to rely on using all its generating capacity and all of its interconnection capacity for electricity imports in order to be able to respond to system load requirements whenever demand peaked. That event typically occurred during the warm summer months. In the last few years, the fiscal problems of Greece and the financial crisis that has emerged in the country ([Douzinas, 2010], [Lapavitsas, 2010], [Sakellaropoulos, 2010], [Arghyrou and

Tsoukalas, 2011], [Featherstone, 2011], [Bickerton, 2011], [Zahariadis, 2012], [Arghyrou and Kontonikas, 2012]), and the resulting recession and slowing down of the economy resulted in decreased demand for electricity. Additionally, new electricity generating units have been built close to the positions where electricity demand occurs, addressing the previous issues [HTSO, 2009, page 5]. In the same time the decrease of system load requirements has eased the situation.

No guarantees can be expressed that electricity demand can be satisfied during peak demand periods, especially during the summer months. In the past it was not uncommon to have disruptions in the electricity supply in the interconnected system, a situation referred to as Loss Of Load. Specifically, the US Energy Information Agency refers to this as Loss of service and defines it as: *" Any loss in service for greater than 15 minutes by an electric utility of firm loads totaling more than 200 MW, or 50 percent of the total load being supplied immediately prior to the incident, whichever is less. However, utilities with a peak load in the prior year of more than 3000 MW are only to report losses of service to firm loads totaling more than 300 MW for greater than 15 minutes. (The DOE shall be notified with service restoration and in any event, within three hours after the beginning of the interruption.)."* [US Energy Information Administration, 2012b]. This definition applies to US standards and specific ranges of time and electricity not delivered are used. However the characterization of a Loss of Load event is described well in that definition.

The issue of security of supply is very important and RAE has been given the task of market monitoring and reporting to the Minister of Environment, Energy and Climate Change, to the Greek Parliament and to the European Commission on that issue on a biannual basis [Journal of the Greek Government, 2011, page 3802]. Abbott [2001] notes that the security of supply is so important, that it could be said to possess *"public good characteristics"*.

1.5.2 Security of fuel supply

Another energy policy concern is ensuring the adequate supply of the countries for fuel. Fuel supply security is vital to the operation of the electricity system. Recently oil and natural gas have been the most important imported fuels and special care needs to be undertaken in order for their supply to be assured. Political crises and conflicts in oil producing counties as well as political tensions and business games (speculation) involving the price of these fuels seems to affect not only fuel prices (which are very important for the electricity industry and the economy overall), but also fuel availability. For Greece, the decision to built high generating capacity from lignite in 1950 when electricity was initially introduced in Greece and PPC was first established [PPC, 2012a] as a nationally owned vertically integrated monopolistic firm, has not only helped the development of the country, but has also made the country less dependent on fuel imports. This has diminished the political pressures that can be put on the country because of that and also reduced the annual amounts that had to be paid for fuel imports.

The heavy dependence of the country on oil and gas imports is a major issue, since the non-interconnected islands have oil-fired units and for the new power stations built currently in the interconnected system there seems to be a preference for natural gas. The same preference has also been noted by Green and Newbery [1997] for England and Wales in the past. We can get to that conclusion by examining RAE records for electricity generation licences [RAE, 2010b] which show that amongst the nine generators that are listed in the OOEM records [OOEM, 2012b], seven have elected to build natural gas-fired units, especially Combined Cycle. PPC also owns natural gas fired units. Also note that Protergia, Korinthos Power and Aloumínion are affiliated with Mytilineos Holdings S.A., bringing the amount of independent players in natural gas-fired electricity generation down to three. Natural gas-fired thermal plants therefore seem to be the choice preferred by new generators in the liberalised electricity generation market of Greece, as well as RES power plants [RAE, 2010b]. Table 1.1 provides a list of the natural gas-fired units owned by independent generators as well as their capacity and the date where they started operating. There are also other generators listed in OOEM's and RAE's records, however these seem to be inactive.

The supply of the country with natural gas is therefore an issue of critical importance for the interconnected system. Events such as the disruption in the 1st of January 2009 of the gas supply of Greece from Russia due to the inability of Ukraine to reach an agreement on the price it would pay to Gazprom [European Parliament, 2009] demonstrate the vulnerability of energy market to political agendas and highlight the need for measures to be taken (such as keeping inventories) to manage risks that might result in energy and electricity market destabilisation.

Nuclear stations are not used in the Greek electricity system and the use of renewable energy is not very widespread, except for hydroelectric power plants. Despite that, nuclear energy could be seriously considered as a solution for the future and despite the difficulties involved and the low speed of evolutions in the sector, renewable energy sources become more and more important in the electricity generation mix.

Natural Gas Fired Independent Generators	**Licensed Generation Capacity in MW**	**Start of operation**
Elpedison	390,00	May 2005
Elpedison	421,60	April 2010
Heron I	187,46	Summer 2004
Heron II	435,00	January 2010
Protergia	444,48	November 2010
Korinthos Power	436,60	30 March 2012
Alouminion	334,00	May 2008

Table 1.1 Table of Independent Natural Gas-Fired Generators (made with information sourced from RAE, OOEM, DEPA and Motor Oil Hellas as well as from a research paper from Iliadi [2009]), ([RAE, 2010b], [OOEM, 2012b], [DEPA, 2012], [Motor Oil Hellas, 2012])

1.6 The Electricity Market

1.6.1 Generation

1.6.1.1 Wholesale Market

In Greece, there are 1.271 licensed generators [RAE, 2010b]. However, the record of generators that are participating in the electricity market only lists 9 electricity generators [OOEM, 2012b]. The difference is due to the fact that some of the licenced generators are not actively operating and also a large amount of them are small-scale generators that do not participate in the wholesale electricity pool.

All electricity generators sell their electricity though auctions that were held by Hellenic Transmission System Operator (HTSO) daily in a day-ahead market. By provisions of law 4001/2011 issued on 22/08/2011 [Journal of the Greek Government, 2011], the role of HTSO has been taken by the Independent Power Transmission Operator (IPTO) and the Operator Of Electricity Market (OOEM) in 2011. The generators submit offers of prices and quantities of electricity that they can sell to the pool for each hour of the following day whereas suppliers/load representatives are providing information on the amounts of electricity that they project that they will absorb in the following day. Each generator should submit offers for the sum of his generating capacity [OOEM, 2012e, pages 23-24]. In addition to that, the ancillary services of the market are set through the pool. Ancillary services are defined as *"the services required to transfer energy through the system from the injection points to the consumption points and ensure the quality of energy supply through the system"* ([Andrianesis et al., 2011], [OOEM, 2012e, page 74]).

OOEM solves the algorithm that decides which units are going to be employed to generate electricity in each dispatch period in the following day and announces the Dispatch Scheme. There are 24 dispatch periods, one for each hour of the day. The System Marginal Price (SMP) is set equal to the bid of the marginal generator that is included in the dispatch scheme. So, we end up having 24 SMPs per day, one for each hour of the day. All transactions take place through the pool and at the end of each day OOEM makes clearance and determines what amounts should be paid from and to each market participant [OOEM, 2012e, pages 57-59].

These amounts do not only refer to the scheduled operation but also to the actual operation of the market and have to do with the scheduled transactions and with the deviations from the schedule as well. The SMP is an ex-ante determined price that is set by the results of the auctioning mechanism in the day-ahead market for electricity. That price is determined by the highest bid amongst the generators that are included in the dispatch scheme and are expected to be selling electricity in each dispatch period. Also, restrictions of the transmission system are taken into consideration as well as technical characteristics of the power stations that are employed. We also have the mandatory use of hydroelectric plants in order for the level of the available waters to be kept in safe levels or for fields to be watered (in that case the hydroelectric plants are inserted into the pool with price zero [OOEM, 2012e, page 70]).

However, that dispatch scheme does not always fit exactly the actual market operation and deviations are present in many occasions, either because the actual system load is different to the one that was initially projected or because some generators were unable to operate as planned. As a result, there is a second price for electricity that is determined ex post, meaning after the operation of the market and after the determination of the actual quantities of electricity that have been absorbed. That price is called the ex-post System Marginal Price and we will refer to it as Deviations Marginal Price (DMP). DMP is the price that is paid for any amounts of electricity that were actually sold but were not included in the daily dispatch scheme. It also is the price that generators have to pay in case they deliver less electricity to the system as compared to the amount that they were expected to according to the daily dispatch schedule. Additionally, all electricity generators are paying through the Deviations Clearance for a number of other charges [Journal of the Greek Government, 2005a, pp. 9458-9469]. It is important to note that the DMP is not calculated by OOEM, but by IPTO [IPTO, 2012a].

So, all participating generators are paid the same SMP in each dispatch period, irrespective of what their bid was. They are also being paid the DMP for electricity sold that was not included in the day-ahead schedule, or they pay the DMP for the electricity they were expected to deliver but which they did not deliver. An exception applies for the case where the amount paid to an electricity generating unit, after combining SMP and DMP with their respective quantities, is smaller than the Variable Cost of the unit increased by a certain percentage. In case where that happens, a mechanism called Mechanism for Covering Variable Cost is activated and the amount paid to the generator is equal to the Variable Cost of the unit increased by a percentage that has been set to be equal to 10% [RAE, 2010a].

1.6.1.2 Capacity market

There is a capacity market in Greece between load representatives, which are the retail suppliers of electricity, and generators for Capacity Availability Contracts (CAC) that are sold according to the Capacity Availability Tickets (CAT) that the generators have. This market has been established as the Mechanism for Ensuring Adequate Capacity by the Decision of Minister of Development that approved the Code of System Management and Electricity Transactions [Journal of the Greek Government, 2005a, pp. 9470-9501]. The load representatives need to have the necessary CACs available in order to be able to buy electricity from the wholesale market. Where they have an inadequate number of CACs, they have to pay a Non Compliance Penalty for the uncovered part of their contracts [Andrianesis et al., 2011]. For the amounts of electricity that correspond to capacity that a load representative absorbs through the pool without having the appropriate CACs, the load representative is obliged to pay through the Transitionary Mechanism of Capacity Assurance. The capacity price in Greece through that mechanism is currently at 45,000 euros/MW-year ([Andrianesis et al., 2011], [IPTO, 2012b]).

Through this mechanism, generators retrieve fixed costs and of course this cost is typically passed on by the load representatives to be covered though the retail tariffs. The role of capacity markets is not only to cushion generators against making losses on their operation, but also to attract generators to build extra generation capacity.

The combination of the capacity market (as this is expressed through the Transitionary Mechanism of Capacity Assurance) and of the Mechanism for Covering Variable Cost aims to ensuring generators that they will be able to recover their costs, thereby decreasing the uncertainty and the risk that otherwise could have driven investors away from the decision to built electricity generating plants.

1.6.1.3 Non-interconnected islands

The non-interconnected islands are not actually part of the interconnected system since they have to operate using their own resources with their own independent generation capacitywhile being unable to serve other island systems or the mainland interconnected system. Nevertheless they are of concern to the country's energy policy planning since they have to be provided with oil needed for their power stations. It is also important to mention that the consumers on the non-interconnected islands enjoy the same tariffs as the consumers that are connected to the interconnected system, despite the fact that the electricity that is sold to them has a distinct cost for each microgrid that can be calculated. The use of the same tariffs for the non-interconnected island's consumers and for the mainland consumers has been recognised as being a Public Service Obligation (PSO), and PPC is compensated through a scheme for this service ([PPC Press Release,2012], [Greek Government press announcement, 2012]).

For those PPC's services that have been recognized as PSOs, methodologies have been established [Journal of the Greek Government, 2007, 2009] to calculate the amount of compensation that PPC should receive. Apart from the non-interconnected islands tariff, this covers the supply of electricity to other vulnerable consumers (customers in non-interconnected islands are also considered to be vulnerable). These vulnerable consumers are families with four or more children and the population groups that are eligible to be supplied under the Social Residential Tariff.

The non-interconnected islands use electricity generation based almost solely on imported oil and, to some extent, renewable energy. The non-interconnected islands are a different story in the Greek electricity industry as their geographical positioning leads them to operate under the previous monopolistic regime, being served only by the previous incumbent (Public Power Company-PPC).

1.6.1.4 Fuel used in the Greek electricity industry

Lignite accounts for approximately 60% of total generation in Greece [PPC, 2012a]. Oil and natural gas are also very important fuels, given the use of natural gas in the interconnected system and the use of oil in both the interconnected system and the non-interconnected islands. In the interconnected electricity system, oil is gradually being replaced by natural gas. Natural gas has a share which has been increasing since 1997, mainly because it seems to be the lowest cost method for the generation of electricity. Renewable sources (mainly hydroelectric generation and wind farms) account for the largest part of the rest of electricity generating capacity in Greece [RAE, 2010b].

The fuel mix used by Greece during the periods October 2008-September 2009 and during the year 2010 can be seen in Diagrams 1.1 and 1.2. During the period October 2008-September 2009 the capacity transmitted through the interconnected system was 52,063 GWh and during the year 2010 it was 52,366 GWh, with 46,660 GWh of them correspond to domestic electricity production ([HTSO, 2010b, page 5], [HTSO, 2011b, page 6]).

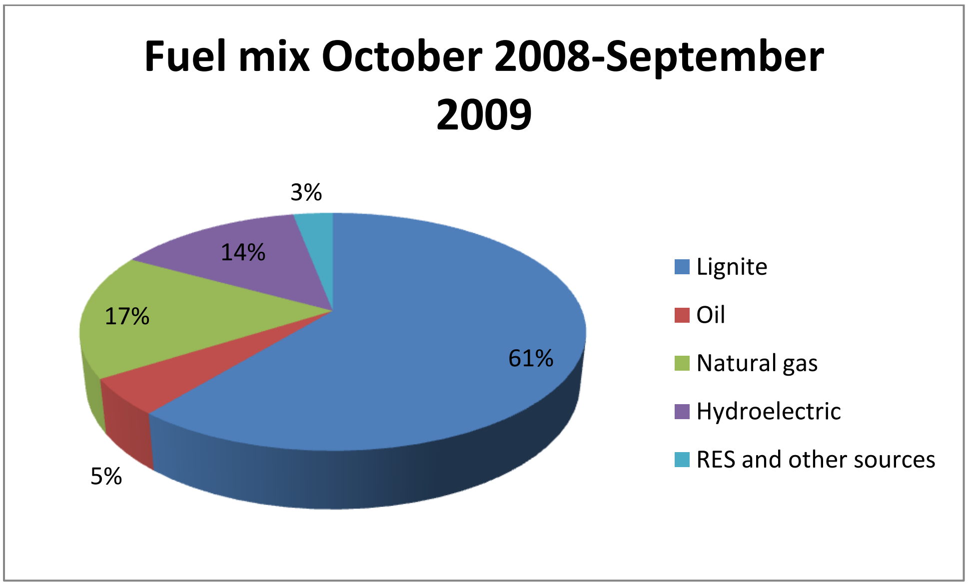


Diagram 1.1 Fuel mix for electricity generation during the period October 2008-September 2009 [HTSO, 2010b, page 5].

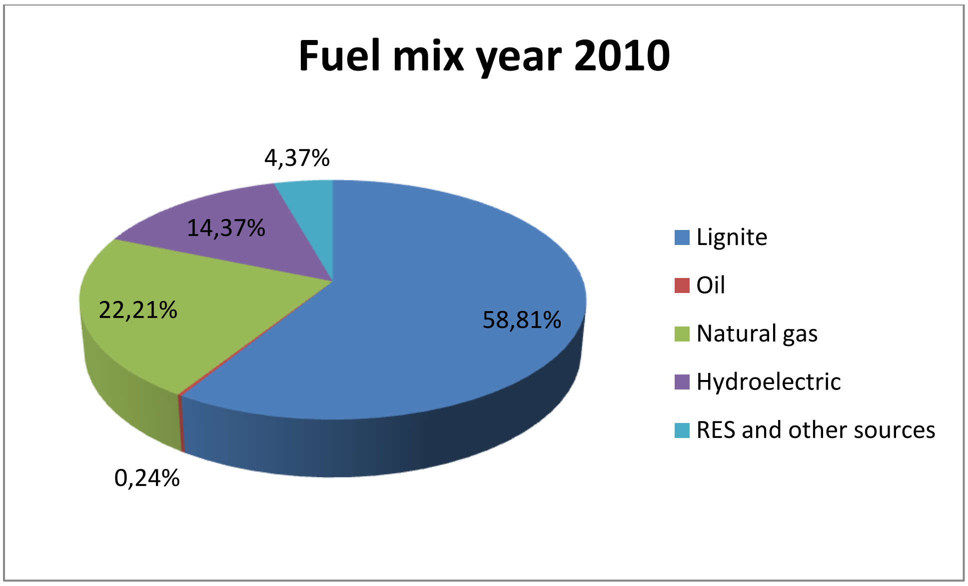
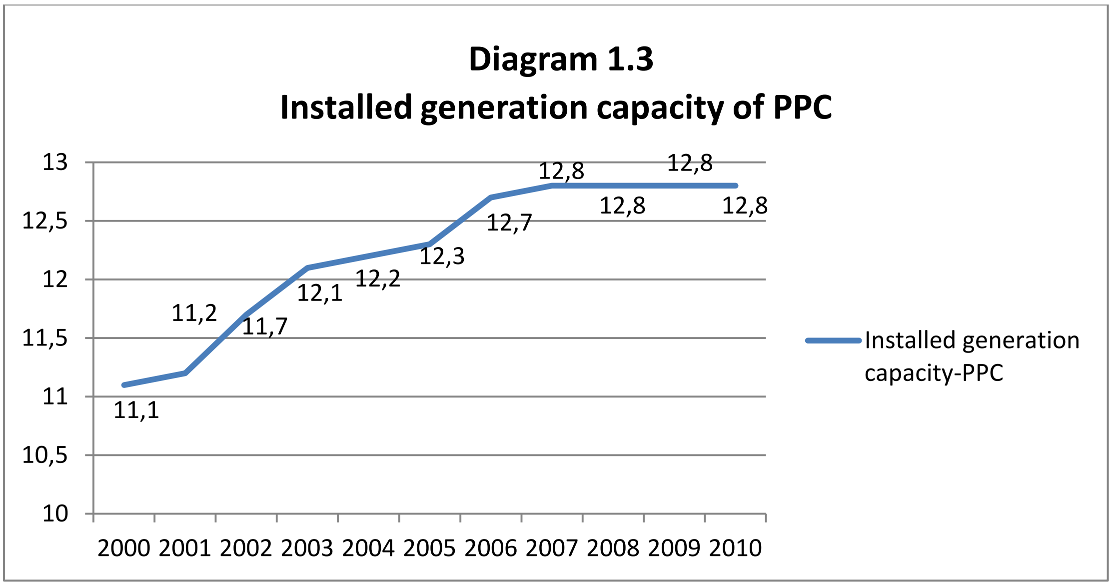


Diagram 1.2 Fuel mix for domestic electricity generation in year 2010 [HTSO, 2011b, page 6].

PPC reports on its website that its current generating capacity is 12.782 MW in 103 power plants, which accounts for 78% of the installed capacity in Greece [PPC, 2012a].

On Diagram 1.3, we can see the evolution of the installed generation capacity of PPC. PPC generating capacity is due both to commissioning of new units and at the same time decommissioning of old units. In the PPC Business Plan for 2009-2014 [PPC, 2008a], the investment plan of PPC for new generation capacity included the new units that were being scheduled to be built as well as the list of old ineffective units that were destined for decommissioning.



Source: PPC [2012f]

Competition takes place in the wholesale market as there is installed capacity by generators other than PPC, but the dominant position of PPC means that it is able to influence the SMP most of the time. That is due to its ability to generate electricity by using its lignite-fired plants and its hydro-electric units. We should note here that the hydro-electrics do not always actively participate in the SMP or DMP determination. This only happens when their use is deemed mandatory for reasons external to the electricity market and on these occasions these units are inserted in the pool with zero price [OOEM, 2012d, page 70]. However having them employed might result in some other, more expensive, units not being included and therefore on keeping the wholesale prices lower. This constitutes a situation where high market power is in the hands of one of the participants and there is a large asymmetry that is inherited from the previous situation where PPC was the single generator. Making a successful transition from the previous situation to the new one requires reducing this market power.

1.6.2 Transmission and Distribution

1.6.2.1 The Transmission system

In Greece, the interconnected transmission and distribution system is owned by Public Power Company and was operated by the Hellenic Transmission System Operator (HTSO) which lately [Journal of the Greek Government, 2011] gave the operation of the system to Independent Power Transmission Operator (IPTO) which constitutes a reformed version of the previous operator. HTSO also operated the wholesale electricity market where generators sell and suppliers buy electricity and this responsibility was given to Operator Of Electricity Market (OOEM) [Journal of the Greek Government, 2011].

A map of the Greek electricity Transmission system is to be found in Appendix A [HTSO, 2010a].

The transmission system in Greece is set up by 400 kV lines, 150 kV lines and 66kV lines. The overall length of these lines at 31/12/2009 was 16,049.1 klm (4,377.9 klm of 400 kV lines, 11,671.2 klm of 150 kV lines) [HTSO, 2011b, pages 4-5]. In Table 1.2 we can see the lengths of transmission line routings for the Greek transmission system in 31/12/2009. There is a difference between transmission line routings and the length of the transmission lines. The difference is due to the fact that some of the routings carry multiple lines. Therefore the numbers in Table 1.2 are generally less than the figures given earlier in the paragraph.

As reported by HTSO [2010, p. 5], an important characteristic of the Greek system is that there is large generating capacity in the North part of Greece whilst the largest part of electricity consumption occurs in the area of Attica which is the geographical district around the city of Athens. Adding to this the fact that the interconnections with other countries for importing electricity are also in the north side of the country, makes the transmission of electricity a very difficult task. Three 400 kV double circuit lines are employed to connect the area of Western Macedonia with Athens and according to HTSO, the imbalance issues are being addressed with the introduction of new units in the south part of the electricity system.

	400 kV	D.C. 400 kV	150 kV	66 kV	Total
Overhead lines	2,535	107	8,043	39	10,724
Submarine lines	0	160	140	15	315
Underground lines	4.5	0	48.5	-	53
Total	**2,539.5**	**267**	**8,231.5**	**54**	**11,092**

Table 1.2 Lengths of Transmission Line Routings for the Greek Transmission System in klm (at 31/12/2009), [HTSO, 2011b, p. 6].

1.6.2.2 Interconnections with other countries

The Greek transmission system is interconnected with the transmission systems of Albania, Former Yugoslav Republic Of Macedonia (FYROM), Bulgaria, Turkey and Italy. The Bulgarian interconnection is a 400 kV line. Interconnections with Albania are set through a 400 kV line and a 150 kV line. FYROM interconnections are also set through two lines, both 400kV. Turkey is interconnected through a 400 kV line and the interconnection with Italy is a double circuit 400kV line with 500 MW transmission capacity [HTSO, 2011b, page 9].

These interconnections are used primarily for importing electricity to Greece, as we can see from the 2010 activity in Diagram 1.4. Turkey, FYROM and Bulgaria are used almost exclusively for imports, Albania is balanced in its imports and exports and the Italian interconnection is mainly used for electricity exports.

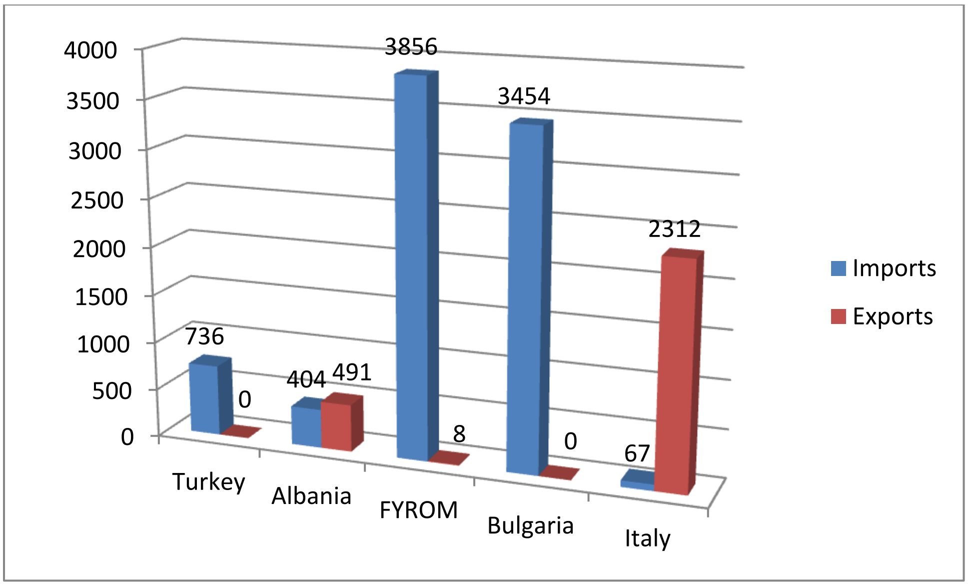


Diagram 1.4 Electricity imports-exports balance from the Greek Interconnections for 2010, [HTSO, 2011b, page 9].

1.6.2.3 The Greek Distribution system

The Greek distribution system is currently owned by PPC and was operated by it until recently. An independent distribution operator has been formed and is operating the distribution system from 1st May 2012. This operator will not only operate the mainland distribution system, but also the distribution systems of the non-interconnected islands. This distribution operator is owned 100% by PPC since it constitutes the Distribution Branch of PPC that has been legally and operationally unbundled in order to be reformed into an independent firm, according to the provisions of law 4001/2011 and in compliance with the Directive 2009/72/EC ([PPC, 2012d], [Hellenic Electricity Distribution Network Operator, 2012b], [Journal of the Greek Government, 2011, pp. 3854-3862]).

The length of the distribution network lines in 2011 in Greece is 228,900 klm, which break down to 107,500 klm of medium voltage lines and 121,400 klm of low voltage lines. There are 7,503,265 customers connected, 10,147 in medium voltage and 7,493,118 in low voltage and the electricity consumption of the customers is 45,721 GWh, which break down to 11,592 GWh in medium voltage and 34,129

GWh in low voltage. The annual investment expenditure in the network is 300 million euros, the annual operating expenses of the network are 440 million euros and the revenue from use of the network are approximately 800 million euros [Hellenic Electricity Distribution Network Operator, 2012a].

1.6.3 Retail Supply Market

1.6.3.1 Retail Supply Market description

Retail electricity markets are the final stage of the electricity business. In Greece, there are 33 companies [RAE, 2012c] which are licensed to supply electricity. In the OOEM records there are 25 registered suppliers and 30 registered traders [OOEM, 2012c, 2012d], as well as one self-supplying firm [OOEM, 2012a]. Most of these suppliers and traders are fringe firms that do not have significant market shares in the retail electricity supply market.

The electricity supply market for customers that are being supplied in High Voltage does not face regulated tariffs and tariffs are being set on an individual basis [RAE, 2007, 2012b]. High Voltage customers have faced the same PPC tariffs since 01/07/2008 and these are Tariff A and Tariff A/E (reserve) [PPC, 2008e, 2012m, 2012n]. Also, from 01/01/2012, the Medium Voltage tariffs in Greece are not subject to regulatory control [Journal of the Greek Government, 2011a, page 43864]. Retail electricity tariffs that are used by PPC for the Low Voltage are approved and announced by the decision of the Minister of Environment, Energy and Climate Change [Journal of the Greek Government, 2012]. Given that requirement, tariff changes are rendered not only slow and difficult, but also a political matter in many occasions.

In the Greek electricity market, PPC is the largest electricity supplier. In the retail electricity markets, after their liberalization, entry has only occurred in specific tariff categories and with new entrants serving only a small part of the market. Also, it is worth noting that some of the new entrants exited the market after a short period of time. These markets that we will be referring to as retail markets are the Low Voltage and Medium Voltage markets and not the High Voltage ones.

The Greek electricity market has an electricity supply firm that bears an obligation to supply electricity to residential customers and small businesses. In case no other supplier is interested in taking this role, the supplier with the largest market share is set by RAE to bear this obligation [Journal of the Greek Government, 2011b, page 3817].

1.6.3.2 The 2008 PPC tariffs

The tariffs that were imposed in the electricity market from 01/07/2008 included very low charges for certain customer categories, thus serving social policy targets set by the government. In the PPC Business Plan for 2009-2014, published in 2008, PPC mentions that in Greece both the industrial and the residential tariffs are *"Regulated tariffs, without discrete charges, that do not reflect costs"* [PPC, 2008a].

What is very interesting to note from a policy perspective, and from a political economy point of view, is that at the end of 2008 the wholesale electricity price was very high but the tariffs that PPC were using were not adjusted to reflect that fact. The increased wholesale electricity prices were the result of the international fossil fuel prices being particularly high. That resulted in PPC notably making financial losses during that fiscal year [PPC, 2009a]. During that time, the electricity supply industry was not attractive for new entry and the regulated monopolist was not able to control the level of its tariffs, since these were regulated. The unwillingness of the Minister of Development (at the time responsible for the energy market) to adjust tariff levels despite the financial losses of PPC demonstrates the political view on the issue and the concerns of the government in office about the social implications of doing so. These social implications seem to be of large concern to the government. However they seem to also be of large concern to each political party that makes any decision and thereafter is allocated the "political cost" (or expenditure of political capital) for its actions. This problem for Greece is also mentioned by Pollitt [2009, page 18]. Running the electricity industry is an issue of large political significance and making strategic decisions in it seems to be an issue that worries the government especially when it is called upon to take action that is thought to be politically risky.

1.6.3.3 Fuel clause in retail tariffs

With a Decision from the Minister of Development on November 2007 fuel clauses were to be included from 01/01/2009 to the bills of PPC [PPC, 2008b]. In that way, it would become possible for PPC to smooth the effect of fuel price fluctuations on its profits by connecting the fuel prices that the firm faces with the retail prices that consumers pay. Nevertheless, on 30/12/2008, the Minister of Development (then responsible for the energy sector) asked from RAE to postpone the application of these fuel clauses and postpone the date for them to be put into operation, until 31/12/2009. However, from 01/08/2010, the Minister of Environment, Physical Planning and Public Works (the new title for the position previously known as Minister of Development, later renamed to Minister of Environment, Energy and Climate Change) suspended the application of the fuel clause for the benefit of social policy of the government. It should be noted however that as a result of evolution in the international fuel markets, the cost of fuel was generally reduced at the time and the fuel clause was not acting to protect the electricity industry.

The decisions on part of the government to proceed with postponing the application of the fuel clause for the benefit of the consumers demonstrates in some extent the application of a social policy perspective on decision making. However in the same time it raises the concern of how much that decision was guided purely by the concern of the government about social welfare or by the concern for keeping voters satisfied, thereby attracting or maintaining their positive stance towards re-voting for the same political party to stay in office.

1.6.3.4 Entry in the Retail Supply market in 2009

In the early days after the full liberalization of the Greek electricity supply market which occurred in 1/7/2007 [Journal of the Greek Government, 2005b, Article 16, page 5671] when all consumer were allowed to choose electricity supplier, there seemed to be no interest from any investor wishing to enter the supply side of the market. Up until 2009, the tariffs set for the market were set at levels that did not provide attractive profit opportunities. This was also due to the fact that at that period, the wholesale cost of electricity in the electricity pool was very high due to the increased international fossil fuel prices. As a result, PPC was the sole supplier in the market and was going through a tough financial situation. After international fossil fuel prices started decreasing and subsequently the wholesale electricity prices in the Greek pool decreased as well, some segments of the Greek electricity supply industry became attractive as they presented opportunities for profit making for potential entrants. Even though entry occurred at the beginning of 2009, this happened in a very small scale as these new entrants were addressing only selected parts of the market.

In November 2009, an important change occurred with PPC announcing the retail supply tariffs that were to apply for the monopolistic activities in Medium and Low Voltage [PPC, 2009b]. In that way, the customers would be in position to know what they are paying for in each part of their electricity service.

1.6.3.5 PPC tariffs for 2011 and 2012

The response of PPC to the event of the new entry was to design and propose new tariffs that were adopted and put into use by the market mechanisms. These new tariff categories and retail prices for these that would be competing with the tariffs set by the new entrants so as to avoid customers switching suppliers. A change in the tariffs was approved at the start of 2011 when competition was already in place in the retail electricity supply. Also, the wholesale pool prices were notably lower than in 2008. The presence of competition made PPC redesign its tariffs and have them set in a way that more accurately reflect the costs of the service provided.

According to PPC, *"The changes in the structure of the PPC tariffs are aiming to the rationalization and mitigation of the current distortions and subsidizations amongst customer categories"* [PPC, 2010b]. Some of these changes would mean increased bills for customers and others decreased. The important thing to note is the lack of response by the government to the appeals of PPC for previous tariff adjustments even in light of the fact that the tariffs were not accurately reflecting electricity cost.

So, from 1st January 2011, PPC has issued new tariffs for their customers, adjusting their previous tariffs to the ones of the competition. At the time, PPC was facing competition in the retail electricity market by two other suppliers, Energa Power Trading and Hellas Power (previously known as Aegean Power). That move by PPC can be viewed as an effort on behalf of the firm to stop the customer switching that was occurring as a result of the attractive prices that the other two electricity retailers were offering. Also it can be viewed as the result of introduction of competition. Notably, the new tariffs matched exactly the tariffs of Energa Power Trading. An important change that occurred was that the new retail tariffs were offering separate charges for monopolistic activities and for competitive activities [PPC, 2011c].

From the 1st of January 2012, PPC has applied new tariffs for customers connected at Low Voltage [PPC, 2012l], increasing its previous 2011 tariff levels. Also, from 1st of February 2012, the Medium Voltage electricity market had its imposed tariffs removed [Journal of the Greek Government, 2011a] and prices in it are set freely by the suppliers. PPC has announced its new tariffs, which were increased as compared to the 2011 tariffs [PPC, 2012g, 2012h, 2012i].

1.6.3.6 New suppliers exit the market

At 24/01/2012, two supplier firms, Energa Power Trading and Hellas Power, failed to meet their financial obligations in the Greek electricity market and lost their licenses to participate in the wholesale electricity market of Greece. Their client bases returned to PPC which is again a retail supply monopolist. PPC, being the

Supplier of Last Resort, has started supplying the customers of these firms since 25/1/2012 according to the provisions of law 4001/2011, section 57. That role was undertaken by PPC for a time period of 3 months ([RAE, 2012a], [HTSO, 2012]). The same happened at 29/05/2012 for supplier Elliniki Enallaktiki Energiaki and at 30/05/2012 for supplier Revmaena [OOEM, 2012f, 2012g].

The fact that during the retail electricity market operation in its current form, there have been firms that have been unable to meet their financial obligations is a cause of concern. It possibly suggests the need for closer market monitoring and for stricter rules governing the financial transactions between the electricity firms, the market operator and the network operators.

Currently, a number of suppliers are active in the supply market, supplying selected parts of the electricity industry. These usually are the Industrial and Commercial Tariffs in Low Voltage and Medium Voltage as well as Residential Tariffs. In most instances, the customers are being served with tariffs that constitute discounts on the PPC tariffs. The tariffs of the new entrants are usually targeting consumers with a large consumption of electricity. That could be due to the fact that electricity firms would like to manage not only the cost paid for electricity in the pool, but also their capacity payments. Note that these new suppliers are able to structure their tariffs as they wish and therefore they are also in a position to include clauses for tariff adjustments that help them manage risk [Elpedison Trading, 2012a, 2012b].

From a policy standpoint, the exit of the new entrants from the supply industry appears to be a retrograde step, since we are returning to a situation where PPC is almost a monopolist in the supply market. The introduction of competition was not successful and this can be attributed to a number of reasons. This will be discussed more fully in Chapter 4.

There are few things that a policy-maker can do about the people's income in a setting like the one in Greece during the financial crisis and the austerity measures that he wouldn't have done anyway. But there may be things that can be done for the introduction of competition in the supply market, such as the full removal of regulated tariffs from all markets. However that could lead to increased retail electricity prices which would not be desirable, leading subsequently to further issues, such as inflation, electricity poverty and restricted access to electricity due to its price.

The very existence of two Social Residential Tariff Categories in both the 2011 and 2012 retail tariffs [PPC, 2011c, 2012k] along with a tariff category for families with 4 or more children indicates the importance of the protection of social group that can be defined as vulnerable. Supplying electricity under these tariff categories constitutes a Public Service Obligation (PSO) [PPC, 2012b]. PSOs are defined by the European Commission as: *"obligations which the undertaking ..., if it were considering its own commercial interests, would not assume or would not assume to the same extent or under the same conditions."* [European Commission, 2004]. In Law 4001/2011, Article 52, the Vulnerable customers are defined and in Article 55, the need for the protection of these customers through PSOs is stated [Journal of the Greek Government, 2011b].

PSOs constitute instruments of income redistribution since in order for these to be supplied, a charge is applied to the electricity tariffs. Therefore, through that mechanism, the rest of the consumers are openly subsidizing the consumers that are in vulnerable positions. Although one could say that this constitutes a market distortion, it should also be said that this might be an efficient distortion as it evens out the income inequalities, at least to an extent that it would allow those on the lowest incomes to cover their basic needs. Such a distortion would not be problematic, in contrast it would be desirable as it would assist in helping the State in achieving its social targets.

1.7 Electricity pool operation

1.7.1 UK and Greek electricity pool design

Examining pool design, we can say that the UK was used as a benchmark. The standard model of electricity market reforms that has incorporated the UK experience appears to have served as a model for Greece.

The Greek electricity market has adopted the pool design, except for the option of using bilateral contracts between generators and suppliers. The Greek wholesale electricity pool is mandatory for all electricity transactions. The expected outcome from such a market setting is for the pool participants to be acting in a competitive manner. However this is not inevitably the case, as deviations from that behaviour can occur. When a generator controls a large portion of the capacity that participates in the pool, then the price can be manipulated upwards [Newbery, 1998b]. Alternatively, wholesale pool price could also be manipulated downwards. In the Greek electricity pool, in order for market power to be addressed, a price cap limits the bids that can be submitted. The maximum limit is set at 150 euro/MWh. The minimum allowable bid equals the Minimum Variable Cost for each thermal unit and the Variable Cost for each hydroelectric unit. Exceptions apply in the case where the hydroelectric units are employed mandatorily, in which case the offer they submit is zero [OOEM, 2012, page 70].

1.7.2 Electricity imports through interconnections

Electricity imports are possible through the interconnections. This imported electricity is introduced to the Greek electricity market through the wholesale pool at the pool price (although the imported electricity is introduced with zero bids) [OOEM, 2012e, page 70]. The electricity imports can address the issue of system load coverage. However, if relied upon for long-term needs in electricity, they also create a dependency which could leave the national electrical system unable to cover its own needs. Therefore these imports should not be regarded as substitutes for generation capacity building [Ochoa and van Ackere, 2009]. Further, this dependency might well have serious political implications which should be discussed first. The Balkans is a geographical area that has been politically unstable for a long part of its history, with many conflicts in their very recent past. One should not only take into consideration the political implications of electricity-exporting country putting pressure on Greece by refusing to sell electricity at any time. One should also consider the possibility of countries being unable to sell electricity through the interconnections or to provide natural gas, simply because these countries might be at war or their power stations and/or transmission grid might be maliciously damaged (through bombings or sabotage actions for example).

1.7.3 Bidding strategies in the pool

The bidding strategies of the generating firms that participate in the electricity pool are a very interesting topic [Li et al., 2011]. In the case of Greece however, things are more complicated than the standard case of an electricity pool with competing generators. The previous incumbent firm is simultaneously a generator owning a large amount of generating capacity and the supplier that supplies the largest part of the market. We would therefore expect that the incumbent would want to manipulate the wholesale electricity price downwards. In that way, profits in the supply side of the market would increase, but these would be profits that would be made for the most part by the incumbent. At the same time, the low wholesale electricity prices paid to the generators would result in low profits for all generators. However there is no risk for any of the generators from making losses by selling electricity below its cost (including the PPC units). This is because of the existence of capacity payments to the generators and of the Mechanism for Covering Variable Cost. So by keeping the wholesale electricity prices at low levels, PPC is able to collect larger parts of its revenues from the activity of electricity supply. At the same time, the existence of the capacity payments and of the Mechanism for Covering Variable Cost are favouring new entry in the generation part of the electricity market.

1.8 Demand for electricity and the economic climate in Greece in 2012

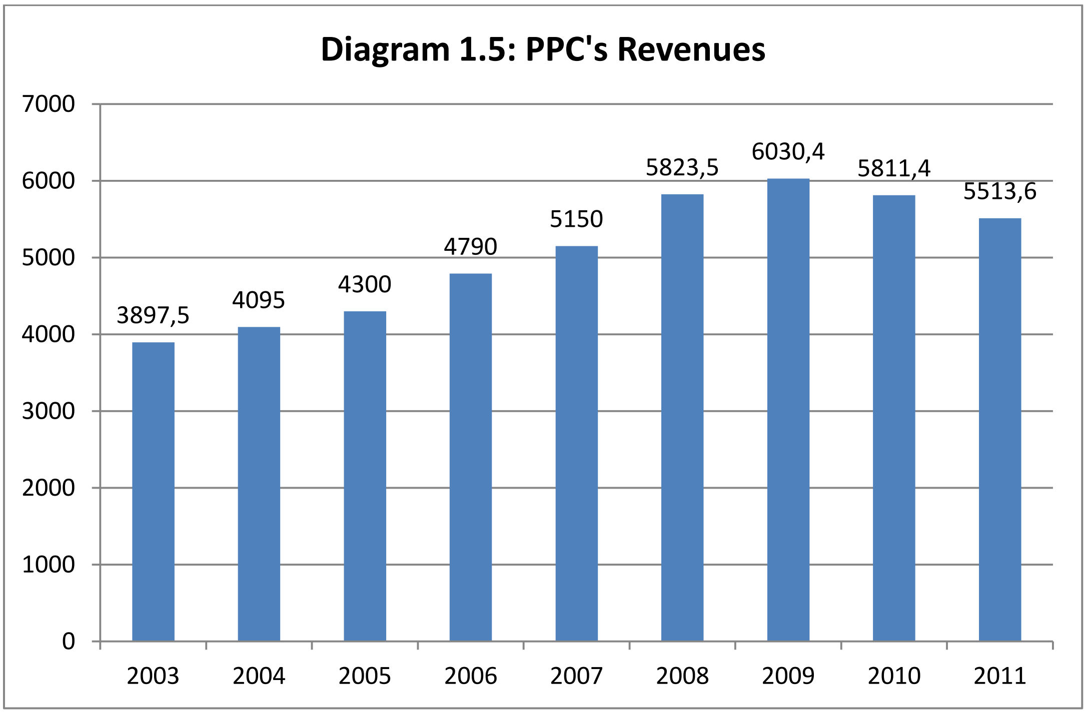
Security of supply issues have not emerged recently due to the fall in the demand for electricity as a result of the decrease in aggregate economic activity in Greece, coupled with additions to generating capacity from independent generators. Greece faced a very difficult financial situation that became apparent from the end of 2009 and remains unresolved until this point. This is a very large financial crisis with political and social implications ([Douzinas, 2010], [Lapavitsas, 2010], [Sakellaropoulos, 2010], [Arghyrou and Tsoukalas, 2011], [Featherstone, 2011], [Bickerton, 2011], [Zahariadis, 2012], [Arghyrou and Kontonikas, 2012]). It has had major impact on the Greek economy and the Greek electricity market. There have been reductions in the pensions and salaries of public servants, as well as the decreases in salaries in the private sector. These, along with sharp increases in taxation, have negatively affected the income of the people as well as the level of aggregate demand in the economy. This has resulted in a slowing down of the economy and in the closure of a number of businesses which has translated into a fall in the demand for electricity.

The intervention from the International Monetary Fund, the European Central Bank and the European Union in order to get the situation under control by providing bail-out funds in terms of loans, and by setting a framework for necessary structural changes for the Greek economy, has had an impact on the electricity market. Of specific importance are the taxation practices of the Greek government. Direct taxes that have been imposed, such as the tax on natural gas, have had a direct impact on wholesale electricity prices, as is evident in the wholesale market prices that have been experienced in some dispatch periods after September 2011, when that tax was introduced.

1.9 Financial results of PPC

This section summarizes some of the most important points from PPC press announcements concerning their financial results in each year. The data given by the press announcements are not consistently available for each year. However, they provide an account of the evolution of the Greek electricity market for the period 2004-2011.

Diagrams 1.5, 1.6, 1.7, 1.8 and 1.9 summarize these financial results in histograms showing the evolution of PPC figures across the years.



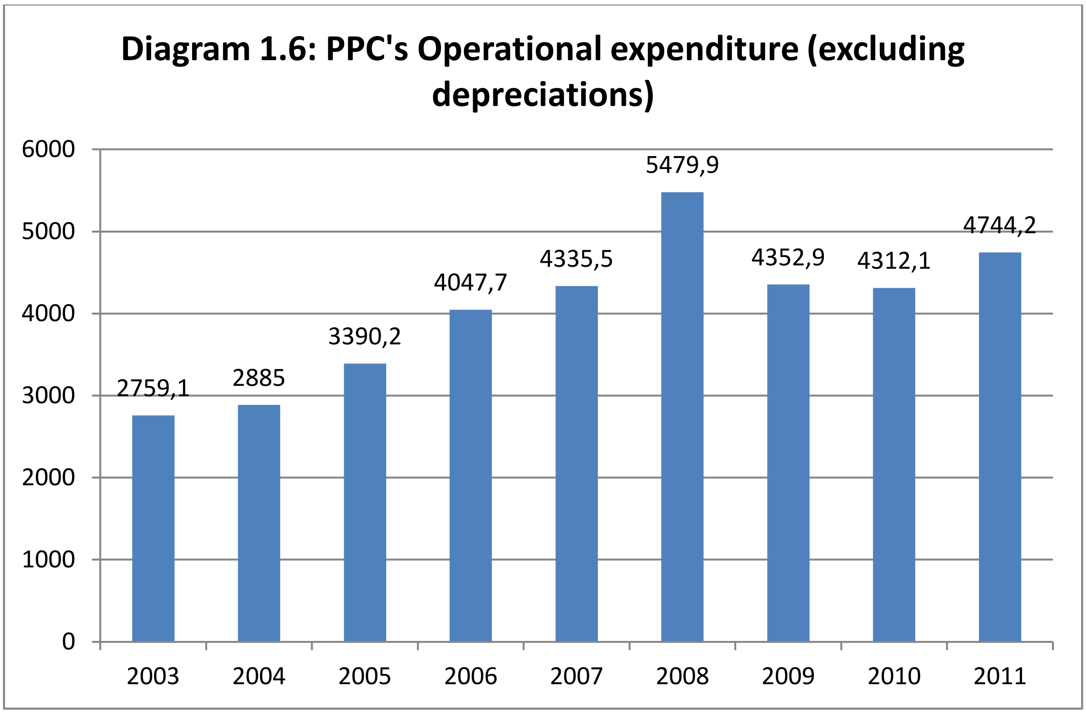


Diagram 1.6: PPC's Operational expenditure (excluding depreciations)
6000
5000
4000
3000
2000
1000
0
2759,1
2885
3390,2
4047,7
4335,5
5479,9
4352,9
4312,1
4744,2
2003
2004
2005
2006
2007
2008
2009
2010
2011

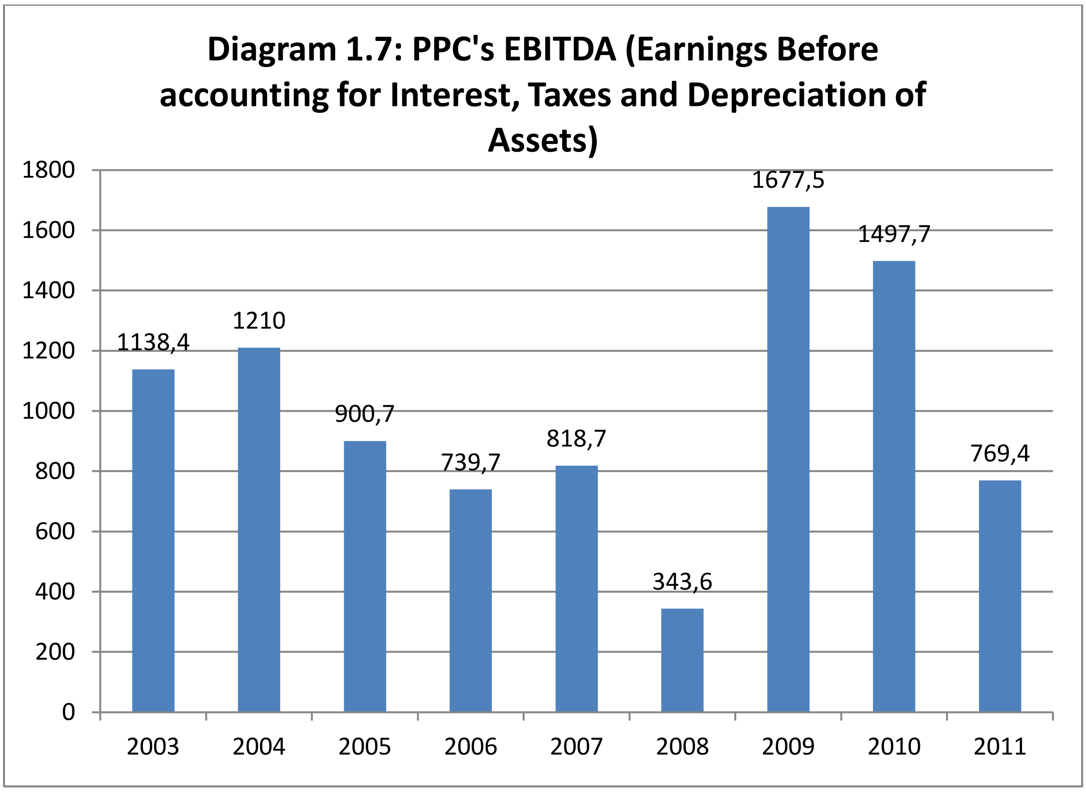
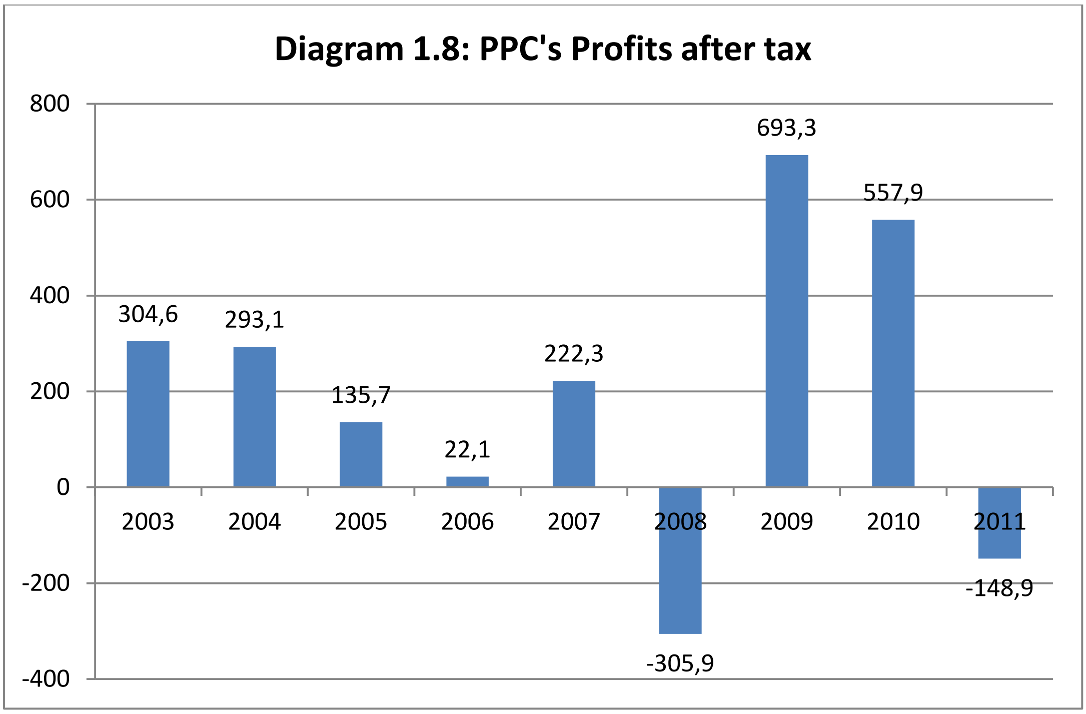
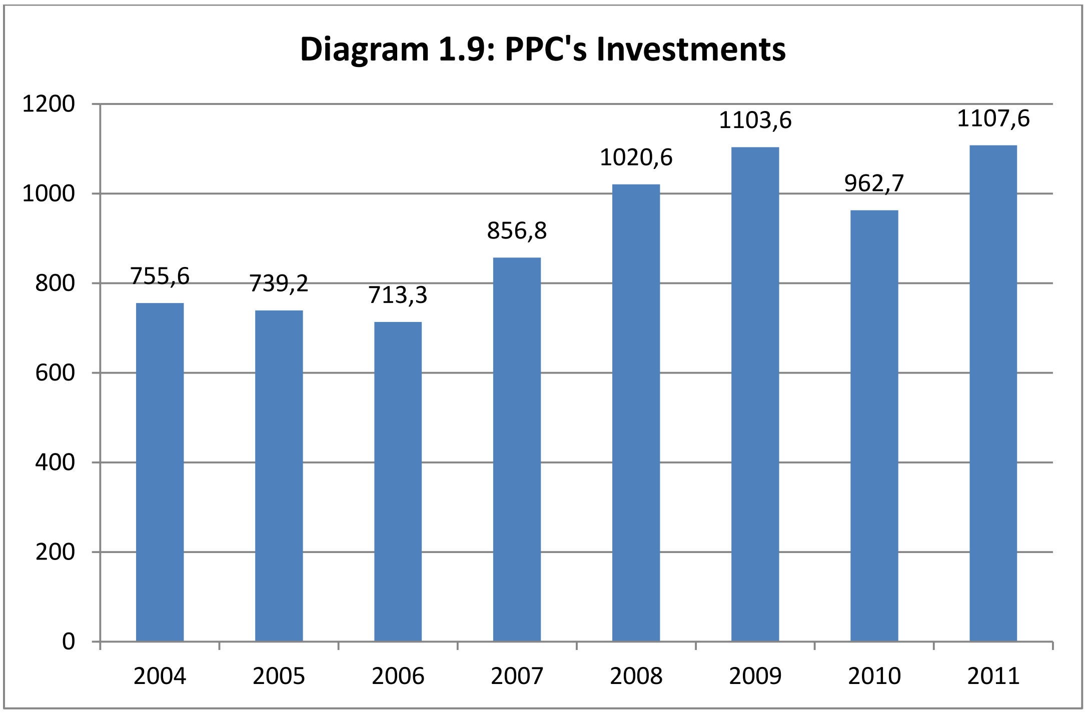


Diagram 1.7: PPC's EBITDA (Earnings Before accounting for Interest, Taxes and Depreciation of Assets)
1800
1600
1400
1200
1000
800
600
400
200
0
1138,4
1210
900,7
739,7
818,7
343,6
1677,5
1497,7
769,4
2003
2004
2005
2006
2007
2008
2009
2010
2011





For 2004, the after tax profits of PPC were 293.1 million euros, as opposed to 475.3 million euros in 2003. The cost of fuel in 2004 was 733.8 million euros and the cost for imported electricity 182.2 million euros, whereas in 2003 it was 751.8 million euros for fuel and 157.3 million euros for imported electricity [PPC, 2005b].

For 2005, the after tax profits of PPC were 135.7 million euros. PPC made investments of 739.2 million euros in 2005 as opposed to 755.6 million euros in 2004. The price of oil increased by 59% and the price of natural gas by 64%, so the overall expenditure on fuel and imported electricity was 307.9 million euros, depressing the firm’s profits. Oil expenditure was increased by 165.4 million euros, natural gas expenditure was increased by 85.8 million euros and imported electricity expenditure by 56.7 million euros. The fuel expenditure was 985.1 million euros in total and the electricity imports expenditure 240 million euros. Also, 2005 was the first year where PPC had to buy emission rights totaling 12.6 million euros [PPC, 2006].

For 2006, the after tax profits of PPC were 22.1 million euros. PPC made investments of 713.3 million euros in 2006. Income from electricity sales increased by 12%. This was the result of a 5.8% increase in the volume of sales, of adjustments in the electricity tariffs of 3.2% in September 2005 and of 4.8% in August 2006, as well as a change in the sales mix. However operating expenses increased by 19.4%, with expenditures for fuel increasing by 263.6 million euros and expenditures for electricity imports increasing by 283.8 million euros. PPC did not need to buy any CO_2 emission permits in 2006 [PPC, 2007].

For 2007, the after-tax profits of PPC were 222.3 million euros. PPC made investments of 856.8 million euros in 2007. PPC notes that during the summer of 2007 there were extremely warm days for long periods during which time the country’s electricity generation, transmission and distribution system was tested to its limits. Due to decreased levels of available water, hydroelectric generation has been limited and replaced by electricity imports (22.8% increase in expenditure) and natural gas fired units (31.9% more generation from natural gas). Electricity generated from lignite increased by 6.6%. Sales increased by 2.8% and tariffs also increased on four occasions between August 2006 and December 2007. PPC did not need to buy any CO_2 emission permits for 2007 [PPC, 2008c].

For 2008, PPC announced an after-tax loss of 305.9 million euros, stating that without the EU-ETS emission licenses that the firm paid and if the fuel prices had remained at the 2007 level, it would have made a profit of 393.1 million euros. PPC made investments of 1,020.6 million euros in 2008. For 2008 the projected amount that has to be paid for EU-ETS licences is 108.1 million euros. More specifically, expenses on fuel, imported electricity and CO_2 emission rights increased from the 2007 levels by 921 million euros. As compared to 2007, lignite fired generation was reduced by 3.9% and hydroelectric generation was reduced by 5.4% [PPC, 2009a].

For 2009, the after tax profits of PPC were 690.7 million euros. PPC stated that this improvement had a lot to do with decreased international fuel prices and imported electricity prices, with generation of 60.4% of electricity using domestic fueled units (lignite, hydroelectric, RES) as opposed to 52.2% in 2008, and to the decrease in electricity demand. This seemingly paradoxical result is a problem related to fixed retail tariffs and is discussed in more detail in Chapter 3. PPC made investments of 1,103.6 million euros in 2009. Compared to 2008, natural gas-fired generation was reduced by 28.3%, oil-fired generation was reduced by 22.3% and expenditure on imported electricity was reduced by 45.7%. As far as renewable energy is concerned, in 2009 PPC produced 247 GWh and the rest of the generators 3,331 GWh. In addition to covering outstanding CO_2 emission rights from 2008, another 68.3 million euros were spent on emission permits for 2009 [PPC, 2010].

For 2010, the after tax profits of PPC were 557.9 million euros, with PPC covering the 77.3% of electricity needs of the country, either through generation or through electricity imports. The percentage of the country’s electricity demand covered by PPC in 2009 was 85.6%. Overall electricity demand in 2010 was 61,817 GWh, practically unchanged from the 61,842 GWh in 2009. Non-PPC thermal electricity generation was 1,614 GWh in 2009 and grew to 2,709 GWh in 2010. Non PPC owned installed capacity grew by 850MW split between two independent generators. Electricity imports from other firms were increased from 3,987 GWh in 2009 to 6,049 GWh in 2010 and PPC electricity imports were reduced from 2,774 GWh in 2009 to 2,255 GWh in 2010. The share of lignite in the energy mix was reduced to 48% in 2010, as opposed to 51.6% in 2009. As far as renewable energy is concerned, in 2010 PPC produced 274 GWh and the rest of the generators 3,685 GWh. Expenditure on liquid fuels, natural gas and imported electricity increased by 199.5 million euros [PPC, 2011a].

For 2011, the after-tax losses of PPC were 148.9 million euros, with electricity demand remaining at similar levels to 2010 (61,817 GWh in 2010 and 61,834 GWh in 2011) and with PPC covering the 70.1% of electricity needs of the country, either through generation or imports. As far as renewable energy is concerned, in 2010 PPC produced 248 GWh. Compared to 2010, PPC paid an additional 553.2 million euros for liquid fuels, natural gas and electricity imports. This increase is attributed to the rise of the international prices of oil and natural gas, to the rise in the Special Tax on Consumption for oil and to the introduction of the Special Consumption Tax on natural gas from September 2011. The market share of PPC in the electricity supply market was 95.8% for 2010 and 92.3% for 2011 [PPC, 2012c].

An important note here is that the increased electricity prices in the pool have been a fact for a 24-month period extending roughly during the timespan 03/2007-02/2009 and it remains for us to examine later if there is any connection between these increased periods of inflated prices and the international fuel prices.

Also, in Diagram 1.8 we observe how PPC's profitability varies across the years. This is due to the exposure of PPC to varying market conditions that are coupled with regulated tariffs which are slow to adjust to market conditions. In both years where losses are made (2008 and 2011), these losses have been attributed to combinations of retail tariffs and market conditions.

1.10 Pool price manipulation and market power

PPC is the main electricity generator and market supplier and it has no interest in having artificially higher wholesale electricity prices in the current regime, since that would actually result in losses. This is so because PPC would buy electricity from the pool at higher prices but would still sell it to end-users under the existing tariffs. However higher wholesale electricity prices benefits electricity importers and other electricity generators that are selling electricity through the pool.

Under these conditions, it could be profitable in some cases for an electricity generation company to sell its own electricity to the pool and then buy back this electricity from PPC at the price set in the regulated tariffs to use in any other activities that this company might engage in. This happened during the summer of 2008 when an electricity generator was selling electricity to the pool, receiving the wholesale electricity prices for these transactions and at the same time buying electricity from the pool at regulated high voltage tariffs which were much lower than the wholesale pool price [PPC, 2008d].

When PPC finds itself in such a position, it is obliged to sell to any end-user at the tariffs set. And that happens regardless of the price paid by PPC to get this electricity from the electricity pool, given that there is no connection between the pool prices and the tariffs. So, in cases where the pool prices are high and tariffs are low, generators can take advantage of the obligation of PPC and make profit.

1.11 Regulatory Suggestions

In order for the existing market design to be effective, more generation capacity is needed and preferably not owned by the incumbent so that competition can be established in the pool [Newbery, 1998b]. That is essential in order for the pool to operate under competition, so that benefits will emerge for consumers. Adequate capacity is necessary for the elimination of the market power of generators. Capacity solutions employed should be such that entry will result in decreases in the effective pool price as a result of the generators competing in the pool.

For the Greek electricity market, the lack of a fuel clause in the retail tariffs results in a situation where increases in wholesale electricity prices cannot be passed on to the consumers. This means that the suppliers are exposed to risk and they will have to absorb the shocks of the pool price variations. A solution could be the introduction of a mechanism that connects the retail tariffs either to an index of fuel prices or to the wholesale electricity prices.

1.12 The Greek Electricity industry and the Memorandum

1.12.1 Competition in the electricity pool and the Memorandum

A possible concern is the extent to which the size of the Greek market allows for competition to take place. Capacity planning is an important part of energy policy. But if it is based solely on the replacement of retiring power plants or on the absolutely necessary expansions of system capacity, the introduction of competition is expected to be quite a long process. Given that, and given the installed capacity owned by PPC, we can see that there is little room for competition to be introduced in the generation sector. That is so because the introduction of any new generators will be adding new capacity to the system, and they will only decide to build this generating capacity if they think that they will be able to sell their electricity.

That is the reasoning behind the argument that in order for the wholesale market to move towards competition, some of the installed capacity owned by PPC should be sold to other generators. Particularly, that argument refers to low-cost lignite-fired power plants that are used to cover base-load which are included to a very large extent into the Daily Dispatch Schedule (due to their low bids) and to hydroelectric plants. This view is incorporated in the austerity measures introduced by the International Monetary Fund, the European Union and the European Central Bank. In the Memorandum of 2012, there are specific provisions that refer to the sale of lignite-fired electricity power plants as well as to hydroelectric plants [Memorandum of Understanding on Specific Economic Policy Conditionality, 2012, page 35]:

"The Government finalises the remedies to ensure the access of third-parties to *lignite-fired electricity generation.* ***[Q1-2012]***

The Government starts implementing the measures ensuring the access by third parties to lignite-fired electricity generation. ***[Q2-2012]***

The implementation of the measures to ensure access by competitors of PPC to lignite-fired electricity generation is completed. Third parties can effectively use lignite-fired generation in the Greek market. ***[November 2013]***

In the context of the privatization of PPC, the Government takes the necessary steps to be able to sell hydro capacity and other generation assets to investors. That sale is separate from the divestiture of lignite capacity provided for in the Commission's decision on the Greek lignite case. Nevertheless, investors may be given the possibility to buy hydro capacity / other generation assets jointly with the lignite capacity provided for in that decision. The sale of hydro capacity will i) not delay the sale of lignite assets beyond the time frame provided for in the relevant Commission Decision and ii) not prevent the sale of lignite assets without a minimum price."

One solution would be to allow new generators to make use of available lignite deposits in new power plants that they can build. That solution has been rejected as Greece would not want to increase its greenhouse gas emissions. So, the market would remain with the existing lignite-fired units and a reasonable part of that capacity has to be sold or rented. However, we should be cautious with that approach, as a number of issues arise.

For PPC, selling these power plants would mean that they lose part of its future profits, since these low-cost units are very often dispatched. When these units are dispatched near their bid price, SMP is very low. When these are dispatched at market clearing prices as determined by the pool which are higher than their bids, extra profits are made for the generating unit. However, in the current setting, the buyer of that electricity is going to be PPC, as the sole supplier. So these profits are made for the power plant if considered as a separate financial entity, but not really for PPC since in that transaction it is the seller and the buyer. For PPC profitability comes down to the point where profits are determined by comparing the actual costs with the retail tariffs used.

Should the lignite-fired units be owned by another entity, the power plant will keep receiving the clearing prices that it did in the past. PPC though, will face increased cost of electricity since the market clearing price will be the price to be paid to the generators. Given that the generator will no longer be PPC, but another electricity company, that means that the profits of PPC will be depressed.

Given the nature of these risks and also the fact that:

- the Greek government do not want PPC to sell its units. This would affect the capital structure of the firm, by having it give away some of its most profitable and valuable assets, which would negatively affect the value of the firm. After all, it is not just the value of the power plants that is of interest, it is also the right to extract and use lignite for electricity generation with no cost (save for the cost of extraction)

- the labour union of PPC, which is very powerful in its ability to strike and has demonstrated in the past that it possesses increased ability to affect political parties with its opinions, opposes to selling or renting these power plants

- the sale of the lignite fired units would drastically change the form of the electricity industry in Greece by altering ownership status for the generating capacity. These electricity generating plants are a very profitable part of PPC's operation and their sale would severely weaken its position with unpredictable results.

- it would be hard to agree on the price that should be paid for these units by the potential buyers. When negotiating the price, these buyers would know that PPC would have to sell these units to conform with the EU requirements for market reform. Therefore the potential buyers are likely to make low offers for these assets.

1.12.2 Retail tariffs and the Memorandum

Another important issue to consider is the regulated tariffs which leave no space for electricity suppliers to make profits in situations where fuel prices increase. Incorporating a fuel clause could be a solution, as this would be providing a connection between the prices paid by the suppliers in the pool and the prices paid by the final consumers.

However in the Memorandum of 2012, there are specific provisions that refer to the regulated tariffs [Memorandum of Understanding on Specific Economic Policy Conditionality, 2012, page 36]:

"Further measures are adopted to ensure that the energy component of regulated tariffs for households and small enterprises reflects, at the latest by June 2013, wholesale market prices, except for vulnerable consumers. ***[Q2-2012]***

The Government removes regulated tariffs for all but vulnerable consumers ***[Q2-2013]****"*

In the view of the Memorandum, the introduction of competition comes through restructured tariffs that reflects the wholesale market prices, without ordering that a specific type of tariff is used for this purpose. However and even more importantly the Memorandum asks for the full removal of all regulated tariffs (vulnerable consumers excluded) and therefore allowing free-market forces to determine retail prices. In that way, it would be possible that new suppliers would consider entry in the supply market.

A possible problem would be putting the Memorandum in practice would be the political cost. Politicians seem to be very much concerned with their popularity and with their ability to be re-elected. Removing the regulated tariffs from the market could have very strong negative consequences in getting the retail prices increasing for a short period or permanently. The decision of doing so is likely to be unpopular to the people. Policymakers might be very concerned about the reaction of the voting body to price increases.

So even though competition can be a much better solution for increased efficiency as compared to regulation and it is expected that the efficiency gains from competition will be favoring the customers instead of the firms [Newbery, 1999, page 171], the problem is the implementation of the liberalization in taking bold decisions.

1.12.3 Renewable Energy Sources and the Memorandum

In terms of evolutions with regards to Renewable Energy Sources, the Greek Memorandum asks for *"the transportation and the implementation of the renewable energy Directive (2009/28/EC)"* [Memorandum of Understanding on Specific Economic Policy Conditionality, 2012, page 36]. In order for evolutions in the market to occur, the Memorandum specifically asks for a plan to be set in order for the support schemes for renewable energy electricity generation to be reformed and to become more compatible with market developments, asking for specific measures for the development of the potential on wind and solar energy.

1.13 Utility function of the government

The utility function of the government is a crucial issue. We must bear in mind that the government in office is at the same time the leadership of the political party that has won the last elections in any given time. Winning an elections battle is what brings and maintains a political party in power. Therefore the interests of the party might be ranked as of higher importance than the ones of the good governance. The Greek political system is one where there is high level of concentration of voters around political parties and there is also a high degree of loyalty. However, this loyalty is maintained through exchange-type transactions from all political parties. In such an environment, engaging in this type of client-based political activity in order to built political capital can be of critical importance to the survival of the political parties. Within such a political culture, a whole different range of agendas than what is written in their manifestoes might emerge for the political parties to serve.

The interests of any given political party are not necessarily aligning with the role that the government is called to play or the agenda imposed by the European Union. Under these circumstances there could be some controversial decisions needing to be taken. That means that whenever a situation emerges where a decision has to be taken that reflects on the interests of the party, it is upon the actual political party's utility function that the decisions are expected to be formed. Pollitt [2009, page 18] argues that such a situation applies in Greece.

1.14 The standard model for electricity reform

Although it seems that there is a “textbook model” for electricity restructuring and competition [Littlechild, 2006b], it seems that a lot of the cases where problems have emerged, were cases where deviations from that model took place, either because of allowing too much freedom on the market, or because of overregulation.

According to the “standard model” for electricity reform proposed by Littlechild [2006b], there are 10 components for restructuring and competition. We present these 10 components one-by-one and at the same time incorporate into the discussion what the Greek approach has been to moving towards competition. Therefore what we get is each of the elements of the textbook case analyzed for Greece.

1. *“Privatization to enhance performance and reduce the ability of the state to use these enterprises to pursue costly political agendas.”* [Littlechild, 2006b, p. xviii]

This is one of the most interesting parts of the discussion of the 10 standard components of electricity market reforms. The reason for such a requirement to be put into place is because a market operating under competition should be a market that operates under market laws and conforms to market forces. However that cannot be possible if the firms operating in this market, being state controlled, also serve political agendas of the government. All the decisions of the firms in the market should have a market rationale and market participants should act to protect their own interest instead of acting as an agent of the government.

In the Greek case, privatization seemed to be a decision taken because of the requirement to conform to the agendas imposed by the European Union. Performance enhancement seems to have been one of the reasons behind that, with the aim that the benefits from the increased performance would be transferred to the consumers through setting of the retail prices at competitive levels.

The use of the electricity sector to implement social policy by the Greek government would not be as easy as before the liberalization of the market. The incumbent electricity firm (Public Power Company-PPC), once in a competitive market that operates with market rules, could find it much harder to adopt any policy stance which deviates from the commercial market-based one. It is important to note that after the privatization of PPC, the state remained the majority owner of the company and keeps control over it.

The political agendas that were being pursued through the vertically integrated monopoly can however also be pursued through the regulatory process in a liberalized market. Although the regulatory authority is deemed to be independent, many of the regulator's actions and decision need to be approved by the Ministry monitoring the electricity sector. A problem that is present in this situation is that the State (we are not using the term Government, as it seems that this trend holds even when governments change) seems to be rather unenthusiastic with some of the elements of the liberalization of the market. Joskow [2006b] notes that if the policymakers are not committed to the reform efforts of electricity markets, then in any problematic situations that might emerge, they probably will not seek the best possible solutions and instead they accept sub-optimal solutions that are easy and fast to apply. Joskow [2006b] also argues that in order for the reforms to be in position to affect the status quo, the commitment to these reforms should be strong to begin with.

Also, the opening of the market and the opportunities given to investors to participate in its competitive segments can be considered to be part of the EU plan for general opening of the markets and for allowing electricity firms and investors from other countries-members of the EU to be able to pursue economic activity inside the economic area of Greece (as well as the rest of the country-members of EU).

Another reason could be related to the effort of the European Union to create a unified European electricity market that will extend beyond the borders of the countries and that will cover the European space. These concerns are explicitly expressed in the provisions of law 4001/2011 [Journal of the Greek Government, 2011b, pp. 3797-3798]. Greece is geographically isolated from the rest of the European countries, since it is located in the South East of Europe. Greece's sole direct electricity interconnection with Europe is a submarine transmission cable that connects the Greek system with the Italian one. Greece's other electricity interconnections are with Balkan countries and therefore there is no direct connection with the electricity systems of most of the EU countries.

2. *"Vertical separation of competitive and regulated monopoly sectors to facilitate competition and regulation."* [Littlechild, 2006b, p. xviii]

Vertical separation is vital since if that is not into place, the four sectors of the electricity market merge one with another and competition is distorted. In the electricity industry, competition can only exist in the generation and supply of electricity. Transmission and distribution are natural monopolies. Natural monopolies are defined by Newbery [1999, page 28] using the catalog that Farrer provided for their characteristics. These characteristics are: *"Economies of scale; Capital-intensity; Nonstorability with fluctuating demand; Producing necessities or essential for the community; Involving direct connections to customers".*

The natural monopoly parts of the electricity market should only be served by one regulated entity and the profits allowed for that one entity should only refer to its own activities, applying rate-of-return regulation. In order for this regulation to be applied and for access charges to the electricity network to be determined, the electricity activities should be unbundled from one another. After this unbundling occurs, the regulator will be able to monitor the costs across the market and set retail tariffs and network access charges.

In Greece, the four sectors of the electricity industry have been separated. Regulation has been put into place for Transmission and Distribution (natural monopolies), and the network access costs are set by a regulatory process. The allowed return on investment for the electricity network is set at 8% [RAE, 2009, 2010c]. The electricity bills that consumers pay in Greece include separate charges for the monopolistic activities and for the competitive ones ([PPC, 2011c, 2012g, 2012h, 2012j, 2012k], [Elpedison Trading, 2012a, 2012b]). The introduction of competition is still on its early stages for the sector of electricity supply. Competition in generations has progressed much more, but still there remain a lot to be done in both competitive parts of the market (generation and supply) in order for the liberalization process to progress.

3. *"Horizontal restructuring to create an adequate number of competing generators and suppliers."* [Littlechild, 2006b, p. xviii]

Having an increased number of competing firms within an industry is connected to the very idea behind the introduction of competition. The more the participants, the stronger the competing forces are going to be, given that these participants will be in position to compete in the market. The issues of the conditions of entry, contestability of the market and potential for competition have been discussed in the literature ([Baumol, 1982], [Pindyck and Rubinfeld, 1996], [Tirole, 1998]).

The horizontal restructuring of the Greek electricity industry has taken place to a small extent. However more need to be done. The introduction of competition in the generation sector has progressed much more than it has in the electricity supply sector. In electricity supply there is still one dominant supplier in the market (the previous incumbent, PPC) and some other suppliers that are partially supplying selected parts of the market.

Newbery [2006a] presents two ways to introduce effective competition in electricity generation. The one is to divide capacity between a number of competing generators ensuring that there is no generator that can influence the price. The other way is to make generators sell a part of their electricity under contracts and in the same time introduce a credible threat of entry in the market. That threat of entry will refer to the case where prices (in the contracts and in the wholesale pool) rise beyond the competitive level. The first solution has the advantage that after being employed it can work on its own, based on the forces of competition. That does not apply to the second solution that relies upon the existence of threat of entry in order to generate effective competition. The second of these two proposed solutions is not adopted in the Greek electricity market as generators are not allowed to sell electricity to suppliers using bilateral contracts. The largest problem with employing such a solution has to do with the relative size of PPC in both generation and supply markets, which could result in PPC making such contracts between its own power plants and the electricity supply part of the firm, bypassing the electricity pool and excluding other generators and suppliers. The introduction of competition is planned to occur by the participation of an adequate number of competing generators. This has happened to an extent. However asymmetries exist in the fact that new entrants do not have access to lignite-fired generation and large hydro-electric generation.

Joskow [2006b] writes that customer's switching of electricity supplier is more common and occurs more rapidly for industrial customers. Households, on the other hand, tend to switch electricity much less and at a much slower rate. In the same text, Joskow [2006b] refers to households and small commercial customers stating that in order for the electricity suppliers to decide to supply these customers, there should be a considerable difference between retail tariffs and wholesale electricity prices. That is necessary because the suppliers need not only to cover their own costs, but also to be in position to offer retail electricity prices that will attract customers. Evidence from other countries suggests that the new entrants should be offering discounts in the range of 5-10% as compared to the incumbent's total bills in order for adequate customer switching between electricity suppliers to take place. This paper also notes that for these specific customer categories, the cost of supply activities that are not related to the cost of electricity can be significantly high, thus making the decision to supply these customers harder as specific market conditions need to be met.

Considering the discounts on the total bill that a new entrant need to offer, and taking into consideration the level at which residential tariffs are set in Greece and the wholesale level of electricity prices, we can see why there is currently very limited intention by electricity companies and investors to enter these segments of the Greek electricity supply sector.

4. *"Designation of an independent system operator to maintain network stability and facilitate competition."* [Littlechild, 2006b, p. xviii]

In a regulated liberalized market there should be some instruments ensuring and facilitating the proper operation of the market. There is no single firm carrying out the whole electricity market operation as occurs under a vertically integrated monopoly. Regulatory instruments therefore need to be set in place to ensure that the market does not fail in these parts in which none of the participants have a particular interest to organize. One of these instruments in an electricity market is a network operator that deals with day-to-day technical issues of the network operation, such as network stability and quality of service as well as network maintenance. This network operator also facilitates competition by ensuring access to the network for all generators and all suppliers. Newbery [1998b] has discussed the role of the system operator in such a system. Pollitt [2005] addresses the use of benchmarking as a technique for setting price-targets that incentivize cost reductions in the transmission and distribution of electricity in the UK, suggesting that there are difficulties in the application of this technique. These problems are associated with data availability as well as with the approach to benchmarking that OFGEM (the UK regulator) had adopted. Jamasb and Pollitt [2007] have discussed the role of the distribution network operator in employing incentive regulation, presenting insights and experiences learned in the UK electricity distribution sector. Pollitt [2012] presents experiences from the use of independent system operators in electricity markets and describes the ideal market operator organization, whilst also noting that the role of the independent system operators evolves.

In the Greek electricity industry, this step has been taken, initially with Hellenic Transmission System Operator (HTSO) being put into place, having the responsibility of operating the transmission system. The distribution activity has remained in the control of PPC until recently. HTSO also would hold the auctions for the electricity pool and would determine the System Marginal Price (SMP), the Deviations Marginal Price (DMP) as well as the Day Ahead Schedule of the electricity market. HTSO would also fully operate the market and determine all necessary transactions for market clearance. That situation has changed after the introduction of law 4001/2011 [Journal of the Greek Government, 2011b], that has split the HTSO into two firms, the Independent Power Transmission Operator (IPTO) and the Operator Of Electricity Market (OOEM). Also the operation of the distribution network is set to be carried out by the Hellenic Electricity Distribution Network Operator (HEDNO) which has been formed by the department of PPC that was previously carrying out this activity.

5. *"Creation of voluntary energy and ancillary services markets and trading arrangements, including contract markets and real-time balancing of the system."* [Littlechild, 2006b, p. xviii]

In addition to the network and market operators, other mechanisms should also be introduced. These mechanisms substitute the operation of a market that is run by one firm (which coordinates all its operations) and therefore help the new form of the market which includes multiple firms be at least as effective as the previous market model.

In the Greek electricity market, ancillary services markets have been set up and are being provided by the wholesale pool. Time balancing of the system is set up for the electricity market. There is no bilateral contracts market between generators and suppliers in Greece.

Bilateral contracts seem to be a necessity in electricity markets, but these are not yet incorporated as an option in Greece although it could be an option for the future, should market conditions change. The decision not to include the option of bilateral contracts could be related to the effort from the regulator to introduce competition in the market. If that option was available, the incumbent generator could largely contract itself as a supplier and in that way, prevent entry in both generation and supply to other investors. We should bear in mind that in 2010 PPC had a market share of 95.8% of the electricity supply market and this market share has dropped to 92.3% for 2011. [PPC, 2012c].

6. *"Application of regulatory rules to promote access to the transmission network and incentivize efficient location and interconnection of new generation facilities."* [Littlechild, 2006b, p. xviii]

Access to the transmission network for all generators is necessary for new generators in order for them to enter the market. This settlement is absolutely necessary in order to invite new generators to the market. The location of these generators cannot be random. They should be located taking into consideration their generating capacity, the capacity of the transmission system in their position, the geographic distribution of the needs for electricity and the transmission losses that are going to result from the distance between the point of electricity generation and the point of electricity consumption.

The charges that the regulator can apply for access to the network are an issue that has been discussed in the literature. Dewenter and Haucap [2007] present the different approaches to access pricing for natural monopoly networks, including the electricity ones. Gans and Williams [1999] examine regulatory concepts referring to access pricing and infrastructure investments. Gans [2001] discusses optimal access pricing that encourages investment. Gautier [2007] discusses the use of two-part tariffs and of single tariffs, noting that the use of both might result in distortions in the entry decisions and in the supply decisions. He also notes that if the network owner has information on the other potential user's costs, he will attempt to set tariffs that transfer all super-normal profits to him. That signifies the importance of having a market regulator that ensures that the market is operated under fair and equal terms.

In Greece, access to the transmission network is provided to all licensed electricity generators. All the electricity related activities in Greece are *"monitored by the State through the Minister of Environment, Energy and Climate Change and* *through RAE in the context of their responsibilities and of the long-run energy planning of the country"* [Journal of the Greek Government, 2011b, Article 3.1, p. 3797]. In Greece, new electricity generating units are being added to the available capacity, notably in the southern part of the interconnected system, with the purpose of mitigating the problem of imbalance that Greece had because of the geographical distance between the positions of electricity generation and of electricity demand [HTSO, 2010b].

7. *"Unbundling of retail tariffs and rules to enable access to the distribution networks in order to promote competition at the retail level."* [Littlechild, 2006b, p. xviii]

Retail tariffs in a competitive market should have any cross-subsidization removed from within them and should only reflect the costs of the electricity that customers are receiving and the profits for the suppliers of that electricity. For competition to be made possible, the monopolistic and competitive electricity activities should be charged separately in the electricity bills. In this way, competition is possible amongst suppliers for all customers since all the suppliers are facing the same challenges and there are no cross-subsidizations between competitive and monopolistic activities. Of course in order for this to be absolutely true, access to the distribution network should be unrestricted as well.

Rules are set for the Hellenic Electricity Distribution Network Operator to provide to all generators, suppliers and customers access on equal terms to the distribution network [Journal of the Greek Government, 2011b, Article 127, p. 3858].

8. *"Specification of arrangements for supplying customers until retail competition is in place."* [Littlechild, 2006b, p. xviii]

Joskow [2006b] explains that there can be situations where competition will not truly emerge for some customer categories such as residential and small commercial customers. For that scenario, he suggests that some electricity suppliers or distributors should be bearing an obligation to supply these markets where competition has not been fully developed. This solution can be applied whenever a transition period is necessary.

These arrangements correspond to the form of the retail electricity market in Greece in 2012 as it is for residential and small commercial customers. With effective competition not yet being in place for these customer categories, there are legal provisions for a supplier to be given the obligation to supply these customers [Journal of the Greek Government, 2011b, Article 58, p. 3817]. The existing competition in the Greek electricity supply market is only serving a part of the market, leaving the remaining tariff categories to be supplied by the incumbent.

9. *"Creation of independent regulatory agencies with adequate information, staff and powers, and duties to implement incentive regulation and promote competition."* [Littlechild, 2006b, p. xviii]

The role of a regulatory agency in a transition from one situation to another, as well as in the operation of the market afterwards is vital. Many writers (Newbery [1998b], Vickers [1998], Baldwin and Cave [1999]) have referred to the role of the regulator in such a situation and the challenges that should be addressed. Averch and Johnson [1962] introduce the rate-of-return regulation, as an instrument that provides a fair return to firms that are regulated. Demsetz [1968] discusses the need for utilities to be regulated. Callen et al. [1976] refer to rate-of-return regulation as an instrument to control a regulator. Schmalensee [1979] discusses the issues of regulating the natural monopolies, applying controls with the purpose of achieving increased economic efficiency. Laffont and Tirole [1986] refer to regulation that is put into practice with the regulator being informed about cost details, and with cost reductions being implemented. Sibley [1989] presents a regulatory setting in a regulated monopoly where the regulated firm knows the market demand that it faces and its cost structure whereas the regulator does not have information on either of the two. However the regulator is monitoring profits, prices and market quantities as they occur and eventually manages to generate efficient market behaviour as far as pricing, operation and investments by the regulated firm are concerned. Kirkpatrick et al. [2005] presents a survey of the techniques that are used by regulators of privatized utilities to control prices and profits, finding that the most common incentive regulation scheme involves the use of price caps. Currier and Jackson [2008] suggest that price-cap regulation is superior to rate-of-return regulation, as rate-of-return regulation provides no incentives for cost reductions or efficiency improvements. Abbott and Cohen [2011] discuss the role of regulatory agencies in Australia and New Zealand focusing on safety standards. They also discuss the issue of the independence of a regulatory authority. Nezlobin et al. [2012] present a model where rate-of-return regulation is applied for firms that engage in investment in new capacity. They find that depreciation schemes that are applied on the assets of the regulated firms are crucial to the efficiency of the overall regulatory application.

In Greece, the Regulatory Authority for Energy (RAE) is set in place and monitors the market. Its role, responsibilities, legal status and organizational structure are defined in law 4001/2011 [Journal of the Greek Government, 2011b]. In the provisions of this law, it is made clear that promoting competition is one of the main issues that the energy planning of the country is concerned with [Journal of the Greek Government, 2011b, Article 3, pp. 3797-3798]. Incentive regulation is used in the regulation of the Greek electricity market where price cap regulation is combined with rate-of-return regulation. The use of incentive regulation in electricity industry has been discussed by Joskow [2006a] and Jamasb and Pollitt [2007].

10. *"Provision of transition mechanisms that anticipate and respond to problems and support the transition rather than hinder it."* [Littlechild, 2006b, p. xviii]

For such a complicated task as the transition from one market condition to another, problems and complications are expected to emerge, no matter how well designed the initial setting is going to be. Corrective adjustments are always a necessity and are going to be needed to be carried out as the market evolves across time.

In the Greek electricity market, these mechanisms are incorporated in the duties of RAE. Problems are dealt with as they emerge, so RAE monitors the transition and intervenes to facilitate the resolution of any emerging issues.

In Table 1.3 we can see the 10 components of liberalization that we presented and the Greek situation, summarized.

	Reform model propositions, as presented by Littlechild [2006b]	Situation in the electricity market in Greece
1	Liberalization aiming at performance enhancement and stopping serving political agendas	Electricity market is moving to that direction.
2	Separation of competitive and monopolistic sectors	Yes.
3	Increasing the number of market participants	Licenced market participants are numerous, however the number of active generators that play a significant role is low and the active supply market players are even less.
4	Setting a system operator	The market operator has been HTSO and with the Law 4001/2011, the market operator has been set to be the OOEM.
5	Service market arrangements in the wholesale market	Yes.
6	Access to the grid and location of new generation capacity	Yes.
7	Tariffs unbundling competitive and monopolistic charges	Yes.
8	Arrangement of transitionary mechanisms in retail markets	With Law 4001/2011, arrangements are in place for Suplier of Last Resort and for Supplier of Overall Service. Also, regulated tariffs are still used in Low Voltage.
9	Creation of independent regulator, with the purpose of promoting competition and applying incentive regulation	RAE is the electricity market regulator.
10	Transition mechanisms for potential problems	Problems are addressed by RAE and the Ministry of Environment, Energy and Climate Change.

Table 1.3: Reform model by Littlechild [2006b] and the Greek market.

The same 10 key components as the ones above are also presented and discussed by Joskow [2006b], in exactly the same order as these were presented here. Whilst there are some deviations from the discussion here, the general framework seems to remain the same. Sioshansi [2008a] notes that market reforms present peculiarities that the strict scientific approach might not be able to deal with. He also warns of the existence of unintended market outcomes as a result of the introduction of market reforms and of the need for further reforms and of a process of adjustments and of customizations in order for the reformed market to be able to operate properly.

1.15 Another approach for competitive electricity markets

A description of the situation of competitive electricity markets in Continental Europe is done by Haas et al. [2006]. The writers conclude that in order for effective competition to be introduced in *"a single integrated European electricity market",* five conditions should be met: *"(i) a complete separation of ownership of the transmission grid and the generation and supply in all countries and submarkets; (ii) sufficient transmission capacity for creating a larger market; (iii) adequate margins in generation capacity; (iv) a sufficiently large number of generators to share this capacity; (v) a secure and competitive supply with primary fuels (notably natural gas)."* [Haas et al., 2006, p. 265]. The authors conclude that since these conditions seems unlikely to be met, the evolution of such a market does not appear to be likely.

In the discussion of this paper, a number of European countries are included, but not Greece. Its geographical position is such that it would be very difficult for the inclusion of Greece in such a market, due to distance-related restrictions. However, putting the Geek case under examination to see to what extent it meets the criteria used by the authors might give us some insight to the mechanisms of its electricity market.

Condition (i)

In Greece, this target is not met. The transmission and distribution system is fully owned by separate firms, established with Law 4001/2011 [Journal of the Greek Government, 2011b] that are 100% owned by PPC. In the same time a large part of the generating capacity is owned by PPC and the largest part of the market supply is carried out by PPC.

Condition (ii)

Transmission system capacity is in position to adequately serve the electricity market in Greece. Adding new generating plants might mean that more transmission capacity would be necessary. The technical characteristics of the transmission system and its performance is documented in reports that have been published by HTSO [HTSO, 2010b, 2011b].

Condition (iii)

A generating capacity level that could barely cover the peak market demand was the situation in Greek electricity generation in the past. Under such conditions, no room would have been left for the development of healthy competition amongst generators, since all of them would be needed. If the situation had remained unchanged, we would have very high incentives to collude as well as very high market power. In recent years new capacity has been introduced by independent generators ([HTSO, 2010b], [DEPA, 2012]). However that does not mean that the ability of these new generators to compete in the market is similar to that of PPC.

Condition (iv)

The larger generator in Greece is PPC, and that can be a problem for the market operation. High concentration in the market translates to high market power and to incentives for predatory behaviour of the incumbent in order to deter entry and increase profitability.

Condition (v)

Security of fuel supply is a major issue for electricity generation firms. In Greece, this is also a major issue for the regulator (RAE) and the Minister of Environment, Energy and Climate Change [Journal of the Greek Government, 2011b, Article 3, pp. 3797-3798]. As recent experience has shown, fuel prices can be heavily influenced by international tensions as well as warfare in fuel-exporting countries. Also, political agendas might reach as far as interfering with fuel supply, thereby resulting in fuel supply interruptions, as happened at the start of 2009 when the supply of natural gas from Russian Federation to Ukraine was interrupted [European Parliament, 2009].

As we can see, conditions (i), (ii) and (iv) are not met in the Greek case and that can be part of the reason why developments in the electricity market reform are being held back. A summary of the above can be seen in Table 1.4.

	Conditions for introduction of competition as presented by Haas et al. [2006]	**Situation in the electricity market in Greece**
1	Separation in terms of ownership of the network and of the firms that engage in competitive activities.	The ownership of the transmission network belongs to a separate firm, however these are owned by the previous incumbent.
2	Adequate transmission capacity to serve larger markets.	Transmission capacity is adequate for the current market status, however expansions would be needed if this was to change.
3	Adequate generation capacity.	Yes.
4	Adequate number of generators sharing the capacity	A small number of generators own generation capacity, however PPC owns a very large part of the capacity and has exclusive access to large hydro-electricity and lignite-fired generation.
5	Security of fuel supply	Yes.

Table 1.4: Conditions for introduction of competition by Haas et al. [2006] and the Greek market.

Apart from these conclusions, Haas et al. [2006] also come up with some more remarks referring to the developments of these markets. A very important observation is that, although previous experience from the UK and Norway cases was available, the Continental European countries that they refer to didn't make use of this experience and instead followed their own policies. *"Instead of divesting generation capacity and increasing the number of competitors […], most countries pursued mergers (DE, NL), retained oligopolies (NL, ES, AT, CH), private monopoly (BE), or supported the concept of national champions (PO, FR). Only*

Italy has chosen a quite different strategy of divestment of the former national champion ENEL" [Haas et al., 2006, p. 308]. As we can see from the remarks made by the authors, it is not uncommon within the European Union to get governments that are handling the issue of electricity market reform with approaches that favor national firms and previous incumbents more than they favor open competition.

In addition, Haas et al. [2006] mentions that in general there seem to be low levels of competition in wholesale and retail electricity markets of the Continental European countries that they discuss. They attribute this to the small number of market players, to the difficulty of entry and to the existence of incentives for collusion in these markets. Looking at the Greek electricity market to examine to what extent that is true, we realize that in Greece we have: low number of market participants and high market power for the incumbent (PPC). PPC has incentive to collude not with other firms, but with itself, acting as a monopolist. If bilateral contracts were allowed, that would mean that we would have PPC-supply contracting PPC-generation and therefore creating barriers to entry for other possible players in both generation and supply.

Haas et al. [2006] specifically refers to the issue of market power for large incumbent generators. They also mention that since EC cannot command large structural or regulatory reforms, market power is hard to be dealt with. The writers also mention that Transmission System Operators might cause problems to the market operation when these operators are also electricity generating entities or when they share interests with the previous incumbent. Both of these problems are present in the Greek case, since the Greek independent transmission operator is 100% owned by PPC. According to the writers, the European Court of Justice has the power to impose changes and to force countries to the direction of promoting reforms. The inefficiencies that have been identified as the reasons that stand in the way of moving towards a CE electricity market are also present in the Greek electricity market and might be blocking progress in the Greek market as well. Truth of the matter is that Greece is not currently trying to integrate in a CE electricity market, however examining its electricity market under this framework and asking these questions reveals the problems that are present within it.

In another paper, Haas and Auer [2006] discuss the wholesale electricity markets after their deregulation and argue across the whole paper in order for effective competition to be achieved, the following condition should be true [Haas and Auer, 2006, p. 857]:

"1. Separation of the grid from generation and supply

2. Wholesale price deregulation

3. Sufficient transmission capacity for a competitive market and non-discriminating grid access

4. Excess generation capacity developed by a large number of competing generators

5. An equilibrium relationship between short-term spot markets and the long-term financial instruments that marketers use to manage spot-market price volatility

6. An essentially hands-off government policy that encompasses reduced oversight and privatization"

The authors state that the absence of any of these above conditions may lead to oligopolistic or monopolistic outcomes. In the case of the Greek electricity market, it seems that the market has not matured to the point that the fourth condition is met. In Table 1.5 we can see the aforementioned six conditions and the situation in Greece with regards to them.

	Conditions for introduction of competition in wholesale electricity markets as presented by Haas and Auer [2006]	Situation in the electricity market in Greece
1	Separation in terms of ownership of the network and of the firms that engage in competitive activities	The ownership of the transmission network belongs to a separate firm, however these are owned by the previous incumbent.
2	Wholesale price deregulation.	Yes.
3	Adequate transmission capacity and non-discriminating access to the grid	Yes.
4	Excess generation capacity and adequate number of generators sharing the capacity	Generation capacity is at levels that allows for competition to take place. The is a number of generators, however PPC still owns a very large part of the installed capacity.
5	Balancing the use of spot market with financial instruments to manage them.	Firms are not restricted in the financial instruments that they employ.
6	Policies that allow and encourage competition without interventions.	Interventions occur, since the market is still in a transitionary period. However, the approach adopted maintains that competition is the target.

Table 1.5: Conditions for introduction of competition by Haas and Auer [2006] and the Greek market.

Financial instruments such as the ones referred to in condition 5 are the power derivatives. The prices for power derivatives are estimated by Pirrong and Jermakyan [2008] using a model that sets the wholesale electricity prices to be determined by demand and fuel prices.

The use of power derivatives is also discussed by Willems and Morbee [2010], who show that welfare and investments increase as a result of the existence of hedging opportunities.

Hedging electricity prices is also referred to by Cartea and Villaplana [2008] who calculate forward contracts and forward premiums using data on electricity demand and on installed capacity.

In Section 2.2.1 of Chapter 2, we present more on the liberalization and the reforms of electricity markets and we also use a reform model by Joskow and Noll [1999] and benchmark the performance of the Greek reforms against that.

The main lesson learned through Sections 1.14 and 1.15 is that although there are some standard models for electricity market reforms that derive from past experiences, in fact electricity market reform is a difficult and extended process. The standard reform recipes constitute starting points and rough guidelines. However the institutional background of each country, the geographical position, the ability to secure fuel, the ability to engage in electricity exchanges, the generation capacity adequacy, the transmission capacity adequacy, the legal framework, the political framework, the culture of the country and the social structure play significant roles. The market formations and structures should adapt to the pre-existing setting for each country and that calls for customized solutions being adopted in many cases. Also, this process is continuing and it is the role of the market to be in position to keep improving with the aim of increasing efficiency and welfare.

1.16 Conclusions

In Chapter 1, we point out that the reform of the Greek electricity market is a work-in-progress. Only in the very recent years have adequate levels of capacity been in the hands of independent generators so that effective competition has been possible. As a result, the percentage of the total electricity generated by the previous monopolist has decreased. In the main part, the new capacity comprises natural-gas fired generation plus some electricity generated from new renewable energy sources. The lignite-fired units and large hydroelectric power plants remain in the hands of the previous monopolist. The market is organized as a mandatory pool and at the same time there is a capacity market, which is being reorganized. Additionally there is a mechanism for ensuring that the variable cost of electricity generators is covered.

In the electricity retail supply market very little progress has been made, although there has been entry in selective segments of the market since 2009. A number of those new entrants eventually exited the market and the firms that compete in the supply market are only targeting specific customer categories. The competition has however led to restructured retail tariffs.

The natural monopoly parts of the electricity industry have been reorganized, with transmission being transferred to an independent transmission operator, establishing a new market operator for the wholesale electricity market and a new distribution operator. Both the transmission and distribution networks are owned 100% by PPC. The market is regulated by an independent regulator (RAE).

Some reform models are presented and the performance of the Greek electricity industry is benchmarked against them. Shortcomings of the Greek electricity market reform are identified with the use of these reform models.

In Chapter 1 we have tried to describe the developments that have occurred in the Greek electricity market. In subsequent chapters, these issues are tackled in a more analytical and empirical fashion.

Chapter 2

Literature Review

2.1 Research on the Greek electricity and energy market

In this literature review we demonstrate that there is a large amount of published work that refers to the operation and organization of electricity markets, as well as to their organization. This large knowledge base can be useful to any policymaker who decides to proceed with market reforms. However, this available literature does not generally cover the electricity supply markets where only a limited amount of work has been done. This gap in the literature is addressed by the work in this thesis. Additionally, most of the research done on the Greek electricity sector refers to its earlier form of market organization or to issues other than the current operation as a wholesale market (issues such as electricity generation and environmental performance). Also, this previous work does not address the issue of retail tariffs in the post-reform era. The work done in this thesis also addresses this gap with an updated account of the Greek electricity market, its evolution and the factors that have led to its current state.

2.1.1 Research on the Greek electricity market for the pre-2000 period

There is a number of research papers that refers to the Greek electricity market in the pre-2000 period. These study a variety of general issues concerning the operation of the electricity industry, electricity demand, carbon emissions and the Renewable Energy Sources Electricity (RES-E). A review of that work is presented below. However, this does not directly reflect on the work presented in this thesis, given the fact that the electricity industry was operating at that time under a completely different framework. We present these in order to provide an understanding of the topics that were covered in the previous published academic work with regards to the Greek electricity industry.

Efthymoglou [1987] makes an econometric and dynamic programming analysis with the purpose of setting rules for the use of available hydro-electric plants. The Greek power system is used to test this model and the results are compared with the ways that PPC was using hydro-electric plants at the time. The results suggest that PPC is not following the optimal practice, storing more water than the optimal in the early months of each year. The paper also provides us with water values and short-run marginal costs.

Efthymoglou and Vlachou [1989] study the productivity of the vertically integrated system of the state owned PPC during the years 1970-85. In this early paper, the productivity of electricity generation from lignite is discussed, as well as the productivity of the processes that refer to generation, transmission and distribution of electricity. Total factor productivity is found to be growing only due to improvements in the distribution process.

Donatos and Mergos [1989] examine the effect that two energy crises had in the demand for energy in Greece. They find that the structure of energy demand was not changed by the 1973/74 and 1978/79 crises. They attribute this to *“the stage of development of the country and the structure of the economy [...], the low efficiency of the energy sector and the lack of alternative energy sources [...]”* [Donatos and Mergos, 1989, p.152]. They also cite as reasons the low degree of industrialization of Greece at the time and to the low energy consumption.

Donatos and Mergos [1991] examine the residential consumption of electricity in Greece for the time period 1961-1986. The writers also estimate the elasticities of residential demand for electricity. They conclude that demand is price inelastic and income elastic, that the number of consumers has driven the expansion of electricity consumption in Greece and that electricity demand per person does not vary across regions, meaning that the demand pattern is uniform. The latter is of interest to us as this suggests that population alone can be an allocation key for the residential demand in Greece. Also, learning that residential demand is price inelastic and income elastic means that tariff changes should not have major impact on demand whereas reductions in income will be reflected in the residential system load.

Vlachou et al. [1996] present the issue of CO_2 emissions from electricity generation. Two modeling approaches are used, an econometric one and an economic-engineering one. The writers find that reductions in CO_2 emissions call for reduction in the use of lignite-fired electricity generation. They also suggest that setting the prices for carbon emissions around 100 (USD/ton of carbon) would lead to reductions in CO_2 emissions that will be larger than 50%.

Prior to the introduction of natural gas in Greece, a paper by Caloghirou et al. [1996] has used input-output analysis to examine and assess the macroeconomic impacts of introducing natural gas to the Greek energy system. 5 macroeconomic indicators are used and these are: Gross Domestic Product (GDP), sectoral production, value added, employment, wages. The writers conclude that the introduction of natural gas in Greece will constitute an important development. It will not only affect the structure of the economy but it will also provide a boost to the economy.

Dalianis et al. [1997] calculate the social cost that was incurred in Greece during 1990 because of the electricity generation from fossil fuels. That social cost is incurred because of environmental externalities, human health concerns, externalities imposed on agricultural production, and impact of the energy systems in the economy. By calculating the social damage caused by the fossil fuel usage, the writers determine an amount by which the electricity prices should increase in order to account for the full extent of the externalities that electricity causes. In that way, it will be possible to compare these prices to the cost of electricity generation from renewable energy sources.

In a paper by Mourelatos et al. [1998], the methodological framework for the introduction and integration of Renewable Energy Sources (RES) together with existing conventional power generating solutions is presented and specifically discussed for the independent energy system of Crete. The four stages of the procedure are presented and explained and for the case of Crete, three plans of action are being proposed that differ in the degree of penetration of the RES technologies.

Giovanis and Skiadas [1999] developed a stochastic model that they used with electricity consumption data from Greece (25 years of data) and United States (28 years of data) to create 6 years of forecasting for each country.

The Greek wind energy market is presented on a paper by Kaldellis [2004], using the period 1985-2000 and modeling that period to explain the evolution of that sector. Also, the writer uses his results to suggest the prospects of evolution for that specific market for electricity generation.

The state of the Greek energy system (including the electricity system) for the period 1985-2000 is presented in a paper by Agoris et al. [2004]. The electricity generation per fuel type is also presented and models are used to determine the appropriate policies in order for Greece to be able to comply with the Kyoto commitments. These models are extending into the future and the conclusions mention that these commitments are achievable in terms of the investments required. Another important observation is that the most carbon-intensive sector in Greece is the electricity industry.

The residential demand for electricity in Greece during the period 1986-1999 is examined in a paper by Hondroyiannis [2004], taking into account weather conditions and population sizes. Monthly data are used for the period 1986-1999. The writer concludes that there is a long run residential demand function that is sensitive to real income, price level and weather conditions and short run deviations are also presented. The results propose a stable aggregate residential demand for electricity, thus allowing for forecasting of electricity demand. Also, the writer suggests that pricing policy can be used as an instrument for electricity conservation but only in the long run.

Rapanos and Polemis [2006] model energy demand in Greek households. They use data from the period 1965-1999. They find that residential energy demand is price inelastic and income elastic. They also find a result similar to Donatos and Mergos [1989], by stating that the two energy crises during the period 1973/79 did not significantly affect energy demand. Rapanos and Polemis [2006] also point out that income elasticity of residential electricity demand in Greece is higher than it is in other OECD countries. A potential explanation provided has to do with the concealed economic activity in Greece, which was estimated to be above 20% of GDP.

2.1.2 Research on greenhouse gas emissions in Greece

The three research papers presented in this section are focused on the greenhouse gases emissions in Greece. Although that is not the main issue of discussion here, these three papers have important by-products that are of interest for this thesis, since these relate with issues that are discussed later in the thesis. The first one [Kaldellis et al., 2005a] captures the inability of the Greek authorities to meet the performance standards set for emissions. The second one [Papathanasopoulou, 2010] provides us with the understanding that air conditioning devices play an important role in the determination of electricity demand during the summer months. The third one [Kaldellis et al., 2011] presents recent technical information on the Greek electricity generation system. The decisions that are taken at the political level in Greece seem to be affected by a complicated networking framework that generates inefficiencies and externalities. That paper is relevant to the operation of the electricity market given the participation of Greece in the Kyoto Protocol and in the European Union-Emissions Trading Scheme (EU-ETS).

Kaldellis et al. [2005a] examine the nitrogen oxides emissions of the Greek electricity sector for the period 1995-2002. The nitrogen oxides emissions are increasing during that period, despite the introduction of natural gas and that is mainly due to the increase of the electricity production during the last 10 years of the period under examination. That is strongly associated with the electricity production at the time being based 90% on carbon containing fuels. The stance of the Greek state at the time was focused on using lignite, heavy-oil and natural gas and that was only leading to higher and higher emissions levels. According to the writers, in 2001 and 2002 the country marginally violated the emissions ceilings of two EU Directives. That is of concern since we understand that an evolution of the

Greek power generating capacity that would incorporate more and more emission intensive electricity generation would not result in acceptable emissions levels.

Papathanasopoulou [2010] researches household expenditure in Greece for the period 1990-2006 and relates it to fossil fuel demand and to CO_2 emissions. Fossil fuels are directly attributed to be consumed by households for operating vehicles, for heating and through electricity consumption, whereas many more paths result in indirect fossil fuel consumption. The writer also specifically refers to air conditioning devices as being one important element that determines residential electricity consumption during the summer months when Greece experiences high temperatures. The potential for reducing CO_2 emissions from Greek households is recognized and the paper suggests that this could happen through shifting the households consumption of fossil fuels. In order for this to occur, the writer notes that the government should engage in central planning focused on specifically achieving that goal.

Kaldellis et al. [2011] discuss the issue of the greenhouse gas (GHG) emissions of the power plants in Greece and their ability to conform to the obligations posed by the National Allocation Plans of the European Union Emission Trading Scheme (EU-ETS). The electricity generation fuel mix of Greece is presented as well as the GHG emissions for the country during the period 1990-2007. Also, the writers present a table with the characteristics of the 29 PPC power stations that are included in the NAP and their use for the time period 2005-2007. The paper concludes that unless action is taken, the NAP allowances will be violated for the period 2008-2012 by the vast majority of power stations. The use of additional RES capacity would be necessary in order for NAP dictates to be satisfied. That is a very important concern as the need for GHG emissions permits that are bought through the EU-ETS scheme is increasing the cost of electricity as it is generated by the existing power system.

2.1.3 Research on generation balance in Greece

A number of research papers refer to the electricity generation sector in Greece in the post-2000 era. A large part of this research refers to RES-E applications, especially wind power and hydroelectricity which seem to be very interesting options for the Greek electricity industry. Of major interest to us are the papers by Hooper and Medvedev [2009] where information is made available not only on Greece but also on its neighbouring countries and by Kaldellis et al. [2009], where the importance of lignite for the Greek electricity and economy is highlighted.

Kaldellis et al. [2005b] examine the small hydroelectric applications in Greece, finding that the internal rate of return for these applications can exceed 18%. The viability of small hydroelectric power stations is found to be dependent on three factors: *"installation capacity factor, annual escalation rate of local market electricity price and reduced first installation cost"* [Kaldellis et al., 2005b, p. 1985].

Doukas et al. [2006] discuss the introduction of sustainable applications for electricity generation in Greece. The potential energy sources for electricity generation are presented and evaluated using the multi-criteria decision-making (MCDM) methodology. The writers find that lignite, wind and biomass constitute very appealing solutions.

Kaldellis [2007] reports the situation in Greece with regards to small hydro power stations and their prospects. The significant hydro-electric potential of Greece is mentioned. However the writer also discusses the fact that existing problems do not allow for this potential to be exploited, such as the administrative bureaucracy, the lack of a rational management plan for water resources and the over-sizing of the projects that are proposed (thereby making it difficult to be characterized as "small hydro power stations"). According to the writer, these types of generating plant can make remarkable contributions to the electricity balance, replacing generation by lignite and oil.

Papadopoulos et al. [2008] focus on the electricity generation from wind sources in the Greek electricity market. They present the regulatory framework as well as the market status with regards to the participants and the market shares of these generators. The writers identify five problematic areas in the market operation which have hindered the evolution of the market and that need to be addressed. These areas are related to bureaucracy in the licencing procedure and in the market monitoring; inappropriate setup of the investment schemes; stance of regional communities towards investments; ability of the grid to connect these generators to it.

Kaldellis [2008] examines the hydroelectricity sector in Greece. He presents the installed hydroelectricity power stations and analyses data for the usage of the hydroelectric plants in Greece for 1995-2005. He finds that these are mainly used for peak load demand coverage. The writer also discusses the hydropower potential of the country and it can be used to increase the RES-E generation. The writer notes the absence of planning for water resource usage which he considers to be an essential element of hydroelectric power plant management and in extension, an element of the electricity market operation. He also notes that the increased usage of hydropower can result in profitability for the plants and reduction in the dependency on fuel imports for Greece.

Kavouridis [2008] discusses the lignite industry around the world and in Greece specifically. The writer notes the right of PPC to exploit 60.5% of the exploitable lignite resources [Kavouridis, 2008, p. 1262] as well as the important role that this fuel plays for the electricity generation sector in Greece. He also notes the significant electricity cost advantages that Greece receives as a result of the use of lignite, as well as the challenges that Greece faces as a result of the participation in the Kyoto protocol.

Kaldellis et al. [2009] present the potential for Greece as a country that utilizes lignite and analyses the situation for that part of Greek electricity generation that is lignite-fired. The lignite fired plants are described and data on electricity generation are presented for the period 1960-2005. The benefits and the problems with utilizing lignite are presented and the emissions issue is discussed. The Greek electricity generation fuel mix for the period 1990-2005 is also presented and a model is made in order to allow for estimations to be made about the lignite-fired electricity generation and the results of the model are used to address energy policy concerns. This paper is very interesting as it highlights the crucial role that lignite has played as the main electricity generation fuel historically in the Greek electricity system and also touched upon the very important issue of fuel security as part of a long term planning for Greece.

Hooper and Medvedev [2009] present the situation concerning electricity generation in 10 countries in South East Europe (SEE) (including Greece and many of these countries neighbouring with Greece). They report that the SEE region has low gasification and only a few nuclear power plants, whereas some countries rely heavily on hydroelectricity. The writers recognize an opportunity for regional trade in electricity and note that this type of electricity exchange (imports and exports) could displace a part of investment in generation that otherwise would be necessary to avoid power shortages. The paper states that the Nordic market can serve as an example and benchmark for how some vertically integrated electricity markets can co-integrate to a regional market, noting though that the Nordpool has taken years to reach its present state that happened with all parties seeing their strategic interests being served by it.

In a paper by Georgakellos [2010], the cost of CO_2 gases in Greece is calculated and the impact of incorporating this cost to electricity generation is estimated. The externalities caused by greenhouse gases are found to be of significant magnitude, thus suggesting that incorporating them to the current electricity generation cost would result in substantial increases in electricity generating costs. This finding can alert policymakers to issues regarding the full impact of emissions from electricity generation, in order for them to act in forming environmental and energy policy frameworks that account for them.

In two papers by Kalampalikas and Pilavachi [2010a, 2010b], the Greek Interconnected Grid has been modeled and scenarios have been made for it for the period 2009-2030 with regard to the different fuel options that there are available, taking into consideration the RES EU targets that have to be met. Three scenarios are examined in the first paper and another three scenarios in the second one. These scenarios examine energy sources, CO_2 capture policies, and Renewable Energy Sources (RES) in a sensitivity analysis carried out. The use of natural gas is found to be the best choice of fuel and the RES is shown to be very expensive.

Kambezidis et al. [2011] use a simulation model to present four scenarios for potential policy mixes of Greece and these scenarios aim at increasing the electricity produced by renewable energy sources. The outcomes of the model are evaluated with a multi-criteria evaluation method and the results show that there is a maximum limit of 25% electricity production from renewable energy sources in the mainland (without the hydro-electrics). The writers conclude that the 40% RES share in electricity generation by 2020 is a very difficult target to achieve, given that the non-interconnected islands only produce 9% of total electricity.

Andritsos et al. [2011] discuss the geothermal potential of Greece, noting that no geothermal electricity is produced in Greece and that it is currently found in direct uses (heat pumps, swimming and balneology, greenhouse heating and soil warming). Also, the writers note that a very large part of the geothermic potential for power generation in Greece is located in the non-interconnected islands of the South Aegean volcanic arc.

Patlitzianas and Kolybiris [2012] refer to the problem of water and electricity supply in small islands and remote areas in Greece. They investigate the potential for use of JESSICA (Joint European Support for Sustainable Investment in City Areas) for funding RES-E applications and water supply projects. The case of the Greek island Ios is examined and it is found that quality of life enhancements are possible.

Kaldellis et al. [2012] discuss the need for the introduction of electricity generating capacity from RES in order for Greece to be in position to meet the 2020 targets *"[…] which dictate that 20% of the national gross energy consumption and 40% of the national gross electricity consumption should be covered by RES"* [Kaldellis et al., 2012, p. 37]. The writers investigate, using a questionnaire based survey, what the attitude of the public is towards RES applications. The specific survey took place in an area where large lignite-fired generation is installed. The results indicated that the public is positively positioned towards the installation of RES-E generating capacity. The writers also note that these responses might be biased by the existence of the lignite fired unit in the area of the survey.

2.1.4 Research on electricity demand in Greece

Electricity demand in Greece in the post-2000 era is discussed in the four research papers presented in this section. The key issue is that electricity demand in Greece is strongly affected by the weather conditions. This result is in alignment with the findings produced in Chapter 5 of this thesis.

Mirasgedis et al. [2006] develop two models for demand forecasting in the Greek electricity sector. These models utilize economic variables as well as climatic conditions. Specific weight is given on the effect of climatic conditions. The most important weather parameters that are found to be affecting electricity consumption in Greece are the temperature of the day that the electricity demand is projected, the temperature of the two previous days and the relative humidity. This is a very important tool to use for planning fuel procurements, scheduling unit maintenance and for electricity imports.

Dagoumas et al. [2008] examine the different electricity consumption strategies in the post-Kyoto era of the Greek interconnected electricity grid for the time period 2005-2025. These strategies are considered with their economic and environmental consequences in mind and it is shown that policies that address the issue of managing seasonal peak levels of electricity demand or strategies that affect the total electricity consumption are those that result in increased financial rewards and in lower emissions levels. This is very important to consider since it suggests that system load peaks are very expensive and emissions intensive, and that makes us aware of the need, from a policy-maker point of view, to put these policies into practice.

A paper by Hekkenberg et al. [2009] examines the relationship between temperature and electricity demand for the Netherlands. The authors have chosen Greece, Spain and Italy as comparisons using not only annual temperature averages but also incorporating a historical perspective of examining the evolution of temperatures along with the daily electricity demand during the period 1970-2007. The evolution of that demand is investigated not only on a year by year basis but also on a monthly basis. The results suggest that although the Netherlands has traditionally its demand peak in the winter months, it is now getting an additional peak in the summer. The Greek electricity demand is used as a benchmark in this study.

Residential demand for electricity in Greece and its main determinants, as well as its long-run and short-run elasticity, has been examined for the period 1964-2006 in a paper by Dergiades and Tsoulfidis [2011]. It employs two different econometric techniques in doing so in order to estimate the results. An equilibrium relationship among the variables involved is suggested and the writers believe that these findings may help to generate energy policies that will be more effective in the area of electricity. More specifically, the writers suggest that the residential consumers do not respond strongly to price changes for electricity and that this can be used to increase tax revenue, without losing any substantial electricity consumption. Also that inelasticity can be used to inform the policy makers for capacity planning purposes and forecasting. The suggested dependence of electricity demand on weather conditions suggests that energy saving can be made through changes to building codes or the introduction of energy efficient appliances.

2.1.5 Research on electricity system efficiency and electricity market regulation in Greece

We present research work referring to the post-2000 era of the Greek electricity industry and a number of issues are included. Of particular importance in this section are the papers that refer to the role of the regulatory authorities [Larsen et al., 2006], to the market organization [Iliadou, 2009], to the wholesale market operation [Andrianesis, 2011] and to the regulatory framework for RES feed-in tariffs for photovoltaic systems [Danchev et al., 2010]. The research presented in this section is particularly important for this thesis. These papers provide the framework of academic work that refers to the regulatory performance and electricity market operation in Greece after the introduction of the market reform.

In a paper by Larsen et al. [2006] the objectives of the regulatory authorities of 16 European electricity markets are presented along with their powers and their independence from their respective governments. The outcomes of the policies that are implemented are also discussed. Greece is amongst these countries that are studied and the Greek electricity regulator is the one that has the highest number of objectives with 7 (tied with the electricity regulatory authority of France). These objectives are stated to be competition, market transparency, consumer protection, economic efficiency in the supply industry, environmentally friendly electricity supply, security of supply and socially responsible price policies. The independence of the regulators from the governments and from the stakeholders in the markets is also discussed, given that the regulators are usually appointed by the government and that in some occasions (including Greece) governments participate in decision making.

The System Marginal Price (SMP) of the Greek electricity system is examined in a paper by Theodorou and Karyampas [2008], where the return and the volatility of that price is modeled and examined. The determination of prices is explained through the market mechanism and the regulation before proceeding with econometric techniques. The results indicate market inefficiencies and arbitrage opportunities. Also, the writers find that the regulatory framework has a significant impact and any change in it impacts the accuracy of the models used.

In another paper, Tourkolias et al. [2009] examine the impact of the different employment opportunities that are created in Greece by different electricity generation power stations. Comparisons are made between lignite-fired and natural gas fired stations and a more rounded approach is adopted in also examining the environmental externalities associated with the lignite-fired power units. The lignite fired electricity generation in found to have much higher employment benefits than the natural gas fired ones and the environmental externalities do not make up for that difference between the two of them.

Iliadou [2009] presents the electricity sector reform that took place in Greece and the electricity sector organization as it was at the time. The writer notes that the required restructuring in PPC tariffs and the possibility of PPC losing market share are significant political economy issues of the reform.

Danchev et al. [2010] present a paper that investigates the return on investment in photovoltaic systems in Greece. The writers present the de-escalating feed-in tariffs that were introduced in Greece in 2009 for electricity generated from photovoltaic systems. They incorporate these feed-in tariffs in a methodology that calculates the internal rate of return (IRR) for these investments and they reach the conclusion that early entry in the market is very important for the potential investors. That has strong implications about the evolution of the market in the future as entry is considered by the authors to be impossible after 2015 and that could not only result in a closed market but also in a market locked into sub-optimal technological solutions given the fast development of relevant technology. A solution proposed by the author is policy related and asks for the policy makers to link the tariff feed-in de-escalations to be reflecting realistic expectations on the technology learning curve.

The operation of wholesale electricity market in Greece is presented in a paper by Andrianesis et al. [2011], and specific emphasis is given to ancillary services. The electricity market is presented, explaining the operation of the wholesale electricity market and the capacity assurance market. Also, the different types of ancillary services are introduced and explained. A model is presented and these different types of ancillary services are incorporated in it. The Greek market model is discussed with regards to the elements that are incorporated in it already and the need for further progress is recognized.

Fiorio and Florio [2011] conduct an analysis of the reports of three Eurobarometer surveys for years 2000, 2002 and 2004 in order to examine how happy the

European consumers are with the electricity prices after all the electricity market reforms that have occurred across the EU. Greece is included in the reported countries. The findings of the writers are indicating that satisfaction is higher when there is both a liberalized electricity market and public ownership in the same time.

An analysis of the energy and exergy (the energy's usefulness or quality or potential to cause change) use in Greece is done in a paper by Koroneos et al. [2011] where data for the period 1990-2004 are used. Energy and exergy analyses and efficiencies are obtained and compared to those of the transport industry. That study is aiming at determining the efficiency of the economy as a whole.

2.2 Literature on Electricity Markets

2.2.1 Reforms and liberalization of the electricity markets

Given the aim of this thesis to examine the conditions and the outcomes of the electricity market reform in Greece, we review the literature around electricity market reform in general. This is useful in presenting previous knowledge and experience regarding market reforms. Three market reform models have been presented in Sections 1.14 and 1.15 of Chapter 1 and the performance of Greece has been benchmarked against them. In this section we present policy recommendations sourced from a range of research work and we also present in Table 2.1 the performance of the Greek reform benchmarked against the model of Joskow and Noll [1999].

In a book by Hunt and Shuttleworth [1996] the issues around the organization of a liberalized electricity market with active competition are presented. Joskow [1998] presents the reforms that are being implemented in market structure and in the regulatory practice as the liberalization of the electricity industry is put forward. The writer presents a standard model for electricity sector reform, consisting of 6 elements. Productivity improvements and cost savings are mentioned as being the desired outcomes of the market reforms, and that is done making the distinction between the performances of developed and developing countries. The writer discusses how electricity market reforms affects: electricity prices and cost, network reliability, general economic activity, income distribution, electricity generation technologies, R&D, and the environment.

Another nice introduction to the theoretical examination of electricity markets is done by Roberts et al. [1991, Chapter 1]. In Chapter 4 of the same book, we find a quote of Cecil Parkinson, Secretary of State for Energy who, introducing the White Paper “Privatizing Electricity” in the House of Commons in February 1988 presented his six principles relevant to his proposals for privatization [Roberts et al., 1991, p. 57]:

“In framing my proposals for privatization, I have adopted six principles:

- *Decisions about the supply of electricity should be driven by the needs of customers.*
- *Competition is the best guarantee of the customers’ interests.*
- *Regulation should be designed to promote competition, oversee prices and protect the customers’ interests in areas where natural monopoly will remain.*
- *Security and safety of supply must be maintained.*
- *Customers should be given new rights, not just safeguards.*
- *All who work in the industry should be offered a direct stake in their future, new career opportunities and the freedom to manage their commercial affairs without interference from Government”.*

On a reference, later in the same book, on the issues of security of supply that comes from the text “Privatising Electricity” from the Department of Energy we read [Roberts et al., 1991, p.64]:

“There are three principal conditions for a secure supply of electricity:

- *Proper control of the generating and transmission systems, to ensure that power can be delivered to where it is needed.*
- *Sufficient generating capacity to meet demand.*
- *Protection against interruptions in fuel supply.”*

Helm and Jenkinson [1998] note that the UK utility's reforms constitute an important benchmark for other countries that are considering liberalization. They also note that there is a general tendency for separating monopolistic from competitive activities. However there does not seem to exist a standard recipe with regards to the decision of allowing bilateral contracts between production and supply. They also point out that when reforming a utilities market that previously incorporated cross-subsidizations, the consumers that were being benefited will find themselves in a more difficult position. As a result, social considerations should be incorporated in the policies that will be employed after the introduction of competition.

Green [1991] describes the provisions of the electricity market reform in England and Wales and clearly states that this was done to the direction of achieving optimal pricing. However the weaknesses are also acknowledged as these were perceived at the time and these were the lack of competition in generation and the lack of incentives for the generators to build new capacity.

In a paper by Green [1999], the design of the electricity spot market in England and Wales is discussed. Contrary to the belief of the government that the wholesale electricity pool was biased in its prices and specifically created increased prices, the writer believes that the pool was well set and that the problems were the result of market power. However, the new market design can also be efficient as well. An important issue highlighted here is that the positioning of buyers and sellers of electricity towards risk and their ability to trade will determine whether prices will increase or will be at the competitive level.

Thomas [2006b] mentions that British reforms are considered successful and as a model for other reforms around the world whenever electricity markets are liberalized. However he argues that this reputation is not justified and that problems are emerging in the British model. The criterion used is the efficiency of wholesale and retail markets. Wholesale markets are difficult to access for new entrants since these are dominated by bilateral contracts and often self-dealing. Retail markets on the other side are called upon to regularly switch supplier in order to put pressure on the supply side of the market, which does not happen and therefore the benefits of competition are not present.

Durakoglu [2011] examines the regulatory framework of the liberalized electricity market of Turkey, adopting a point of view that relates regulatory practice with politics. The writer notes that regulation can be limited in the outcomes that it can achieve because of restrictions imposed by political entities and by institutional dynamics. The political setting is considered by the writer to be crucial in providing the basis for the operation of a regulatory authority. The institutional framework and the restrictions that it poses are taken into consideration when analyzing the outcomes of the market reforms in Turkey and the paper finds that the market regulation has been unable to perform at high standards.

Arocena et al. [1999] make the argument that the electricity market reform in Spain has been a lost opportunity, mainly because there was a high level of vertical integration between generation and distribution and because the supply of electricity was not fully liberalized. What is also very important is that the Spanish case highlights the problems that can exist in countries with liberalizing markets when the state is regularly intervening and regulatory schemes are hard to interpret and understand.

In a paper by Joskow and Noll [1999] we have a presentation of the Bell Doctrine which refers to antitrust policy and which can be applied to network industries that combine monopolistic segments with competitive ones. The writers discuss the reforms in the telecommunications industry in many countries (mentioning Greece amongst others) and then go on to discuss the industries of electricity, natural gas and railroad freight transportation. The paper presents five elements that constitute *"the standard public policy prescription for reforming electricity sectors around the world"* [Joskow and Noll, 1999, pp. 1299-1302]. These are:

"1. Privatize state owned enterprises to create hard budget constraints and more powerful efficiency incentives and to help to depoliticize the sector.

2. Promote competition in generation by opening entry to new suppliers and deregulating prices and the terms and conditions of contracts between generators and distribution systems, marketers, or direct retail service customers.

3. Implement transmission network access rules and associated access prices that support efficient competition in generation and minimize any losses associated with the decentralization of control of generation and transmission facilities.

4. Adopt new approaches to transmission pricing which recognize the physical and economic attributes of AC transmission networks.

5. Reform regulation of the distribution function to facilitate competition in generation and perhaps retail sales."

Another very important issue highlighted by the writers is the relationships between the generators in the industry and the transmission network operators and owners. The issues around the transmission part of the industry are of paramount importance to the application of the Bell Doctrine to electricity. Also, with regards to the separation of electricity distribution from electricity supply, the paper makes a distinction between when this is applied to electricity and when it is applied to telecommunications.

In Table 2.1 we can see the 5 elements of market reform that we presented and the Greek situation as far as these reform directions are concerned.

	Reform model propositions, as presented by Joskow and Noll [1999]	Situation in the electricity market in Greece
1	Privatizations, use of incentives for efficiency and removal of politics.	Electricity market is moving to that direction.
2	Promotion of competition in generation though market opening and allowing bilateral contracts between generators and other firms.	Competition is introduced in generation. However, bilateral contracts between generators and suppliers are not allowed and the market operates through a mandatory wholesale electricity pool.
3	Provide access to the transmission network and establish transmission network access charges that promote competition.	Yes.
4	New approaches to transmission pricing	The transmission part of the market is unbundled from the other electricity activities and access charges are set specifically for these services.
5	Reform of electricity distribution sector	Electricity distribution sector has been reformed with Law 4001/2011 that established an independent distributor.

Table 2.1: Reform model by Joskow and Noll [1999] and the Greek market.

Sioshansi [2008b] refers to the process of liberalization of electricity markets and points out that a lot of effort has to be put in it for a long period of time in order to be successful. Also, the writer notes that the choice of the initial market design and how it is put into practice plays a very significant role.

Sioshansi [2006] also refers to the possible market designs for liberalized electricity markets and to the implementation issues that emerge whenever such a reform is put forward. The shortcomings of the regulated monopoly model are also presented *("over-investment in rate-base; risks borne by ratepayers; no customer choice; price disparities; price subsidies; sub-optimal regulation; skewed reward and penalty; political meddling; nuclear energy")* [Sioshansi, 2006, pp. 64-65], to explain why a reform can be beneficial. The paper also presents what leads countries to decide to go on with reforms *("inefficiencies; ideology and politics; public debt; regulatory complexity; inadequate investment in infrastructure;*

decentralized decision making") [Sioshansi, 2006, p. 67] and also describes the attributes that a functioning competitive electricity market has *("self sustaining; efficient; resilient; customer choice; absence of abusive market power; transmission management; regulatory, administrative and monitoring costs")* [Sioshansi, 2006, p. 70]. The problems of these markets are also presented *("capacity markets; market power and monitoring; resource adequacy and investment in infrastructure; demand participation; renewable energy; distributed generation; design, implementation and operation of RTOs/ISOs")* [Sioshansi, 2006, p. 73], noting that these issues remain hard to deal with.

Pollitt [2009] presents the European Union (EU) electricity reform model and lessons learned in the area of regulatory practice for national electricity markets in the EU. The key role of independent regulation is presented and the success of that specific model is discussed and the South East Europe (SEE) peculiarities are also addressed. The writer notes that it is difficult to evaluate the impact of electricity reforms and that the EU electricity reform model might not be the best option for SEE countries. The need for more extensive institutional reforms is stated as well as the difficulty anticipated in creating a supra-national electricity market in that specific geographical area, given that in order for this to work, specific conditions are required. Finally, the writer concludes that these reforms test the commitment that the political leaders have on going forward with market based reforms. Greece is included in the list of the countries that the writer refers to as SEE countries and it seems that the specific issues raised are directly reflected in the Greek situation as it has evolved.

In a paper by Green [2006] the liberalization of the electricity industries in Western Europe is discussed. From 2007 and onwards, by decision of the EU, all customers should be able to choose electricity supplier and that has resulted in mergers of electricity companies across countries. That concentration in European level is discussed and the writer examines the competitive elements of the resulting industry structure and the gains that this liberalization delivers. The writer concludes that for final consumers to get benefits from competition they would have to shop around the electricity industry, since genuine competition was not possible by the market setting across Europe at the time. It is the work of the competition authorities to control the market in order for it to deliver gains to consumers. That description seems to be very useful for the case of Greece, where market developments have led to the market having only one electricity supplier and as a result the tariff setting task is of paramount importance in order to have these tariffs set at levels that are similar to competitive ones.

Branston [2000] examines whether the electricity privatization in the UK (markets of England and Wales as well as Scotland) actually was beneficial in managing to decrease the electricity prices. The paper compares electricity prices with those that would have been had the market reform not occurred. In order to do so, a scenario is developed about how a publicly owned firm would have acted on this market and the results are compared. The writer concludes that the electricity prices in the liberalized market are higher than they would have been without the reforms. Additionally the writer notes that the privatization has led to the decline of the British coal mining industry and its spillover effect on the economy and that the new market participants are sometimes foreign owned firms that are taking their profits overseas and are paying dividends from their profits to consumers on other economies.

Thomas [2006a] notes that in the reforms that have taken place in the EU, it has been the case that some countries were meeting the EU Directives by adopting the standard model for electricity liberalization and that resulted in many occasions in not having any real competition and not taking away the market power of the incumbent firms. That was the result of the reform efforts not taking into consideration the specific characteristics of each case such as resource availability, specific national requirements, existing structure of the industry and national cultural and economic traditions. The writer mentions that countries which are outside the Nordic region and which have small electrical systems, are dominated by one or two firms. As such cases, the writer presents Austria, Belgium, Greece, Ireland, Netherlands and Portugal. The writer also goes on to explain under what circumstances, the countries of the Nordic region were able to be successful in creating a liberalized electricity market and identifies seven factors that have contributed to this success.

Gratwick and Eberhard [2008] present the power sector reforms as are being put into practice through a standard model that however has not been fully successful in most developing countries that present different characteristics than the western economies. The writers also describe new hybrid electricity markets that are emerging and that are widespread in most developing countries. In these markets public and private sectors coexist and planning, procurement and contracting challenges are of critical importance for investments in new power generation capacity to be addressed. That specific paper is of interest as it seems that Greece is facing difficulties in going forward with the reform model as it is and the hybrid power market could seem as an interesting alternative if the standard model would finally fail to materialize to an effectively operating liberalized market.

Dastan [2011] refers to the privatization of electricity markets and the use of regulatory models as they are without individually customizing and adjusting them to the specific case that we have in hand. In many occasions institutional reforms deeper than the regulatory framework are required, since the institutional setting affects the credibility of the commitment that the regulator is presented with, the quality of the design of the regulatory framework and the ways that the policies are transferred. The writer discusses the experience in Turkey's energy market. However these issues are not specifically limited to Turkey alone and many countries could possibly relate to them, especially if the existing institutional setting does not help the introduction of an independent regulator.

Meeus [2011] discusses the electricity market integration in the European Union (EU). The writer compares the two types of wholesale electricity market frameworks (merchant model and cost-of service regulated model) that are adopted across Europe. This study finds that the cost-of-service regulated model, which is adopted by the Greek electricity market, can assist in the development of the EU market integration, despite not leading to efficiency improvements. As proposals for the regulators, the paper mentions the need for reducing market power that exists in wholesale electricity markets and suggests some ways in which for this might happen, as well as the use of quality-of-service regulatory frameworks for cross-border electricity trading.

Makkonen et al. [2012] present the results of a study that investigates the opinions of European electricity market specialists on the potential for creating unified internal European electricity markets, as these are set by the European Union to be created. The main concern with achieving this market unification is the availability of the necessary transmission capacity required to provide the potential for competition to develop without excluding market players through the inability of the grid to serve them. Trading arrangements, on the other hand, despite playing a significant role, were not considered to constitute a threat to the creation of a unified European electricity market.

Pollitt [2008] compares the ownership unbundled transmission models with other models. Recognizing the positive contributions from the ownership unbundling, the writer questions whether these are counter-balanced by the cost of the process of doing so. The paper also lists and discusses the issues that are present in implementing ownership unbundling, noting also that it is a necessary part of the market reform.

Al-Sunaidy and Green [2006] discuss the electricity deregulation in OECD countries. Having started since the 1990s, most OECD countries have introduced some degree of liberalization. The writers focus on the competitive parts of the electricity industry, which are the retail supply and the electricity generation while also pointing out the need for effective regulation of the parts of the electricity industry that cannot be liberalized and remain monopolistic. Greece is included in the countries that the paper refers to.

In a paper by Shuttleworth [2005], the use of the benchmarking technique together with regulatory frameworks is discussed. He identifies the subjective judgment as being the main problem behind efficient use of benchmarking in regulation, noting that the risks involved in using it are: *"choice of technique; choice of variables and model; interpretation of the residual; burden of proof; duration of glide path"*

[Shuttleworth, 2005, p. 316]. The writer proposes other ways to conduct improvements which he considers to be superior, such as the measurement of total factor productivity.

Haney and Pollitt [2009] survey the use of incentive regulation by the regulators of electricity and gas industries from 40 countries with reference to the performance of networks. The survey examines the extent to which benchmarking techniques are used by regulators in order to be able to identify and adopt best practice. A number of countries are found to be using benchmarking and to have adopted a series of good practices, such as the use of economics and engineering expertise and the use of international and panel data. Greece is included in the countries of the survey, but benchmarking techniques were not adopted at the time.

Haney and Pollitt [2011] use their 2009 paper to construct an index that refers to best practices in electricity network regulation. In their model they set *"Size of the industry; Economic institutional environment; and Political institutional environment"* [Haney and Pollitt, 2011, p. 7742] to be the factors that affect the choice of regulatory methods. Through their analysis, they suggest that industry size and political institutions play a significant role in electricity regulation. They also find it hard to distinguish the effects of economic and political institutions, noting also that the specific characteristics of every country act in a constraining manner as far as the choice and implementation of best practices in electricity regulation are concerned. The writers also note that these characteristics can be viewed from a regional point of view.

In a paper by Dubois [2009], the issue of adaptability of the liberalized electricity markets is examined. The necessary adaptations are presented and formally introduced through frameworks. These frameworks rely on the different modules of the electricity markets reforms in order to explain how the adaptation takes place.

It would be very interesting to consider the liberalization frameworks presented here and those that are presented later in this chapter ([Roberts et al., 1991, p. 57], [Joskow and Noll, 1999], [Littlechild, 2006b], [Joskow, 2006], [Haas et al., 2006], [Haas and Auer, 2006]) coupled with the arguments that refer to the difficulty of making these market reforms in general [Sioshansi, 2006] and more specifically in small markets [Thomas, 2006a] or and in markets of South East European countries ([Pollitt, 2009], [Hooper and Medvedev, 2009]). The liberalization prescriptions that are offered by the literature incorporate the notion that the countries are implementing them because there is a purpose that they want to serve. This can be somewhat problematic in cases where the reforms are mandated from external bodies, such as is the case in the EU. Also, the culture of each country plays a very important role. Of very large importance is also the institutional organization of the economy and the political structure. The adaptability proposed by Dubois [2009] is a crucial element for progress to be made in market reforms, as also suggested by Sioshansi [2008b]. All these issues strongly relate to the case of the Greek electricity industry, as Greece is a SEE country that is going through such a market reform.

2.2.2 Electricity generation in the liberalized markets

In this section, we present some theoretical approaches that refer to the operation of the generation sector of electricity markets. These theoretical and empirical issues around the determination of investments and efficiency in the generation and transmission sectors are of interest for the Greek electricity industry. The lessons learned from the examination of the experience in other countries can be used by policymakers to support decision making.

Newbery [1995] notices the high coal shares in electricity generation of Denmark, UK, Germany and Spain and examines the effect on electricity prices from removing coal subsidies. The writer concludes that the effect of these subsidies is heavily dependent on the form of subsidies and their method of finance. That paper can also be related to the Greek electricity market given the extent to which Greece is using its own coal which is lignite. The fact that PPC is given by the Greek state the right for lignite extraction and use [Iliadou, 2009] without any payment is a form of subsidization and therefore removing this arrangement and asking a reasonable price for lignite could have a considerable impact on electricity prices.

Borenstein et al. [2000] discuss the issue of competition between electricity generators in a deregulated electricity industry taking into consideration the transmission capacity of the grid. The writers argue that the transmission capacity in an electricity market may be unrelated to market equilibrium quantities and to the degree of competition in the market. However, when that transmission capacity is limited, the behavior of the firms that participate in the market is affected as these firms might be in position to manipulate the market. As a result it can be that even small investments in transmission capacity can result in increased competition. That could be relevant to the Greek case, since transmission capacity is important in Greece. That is so because the largest part of electricity generation takes place in the North part of the interconnected system and that transmission capacity is necessary to deliver that electricity to the South part of the system where it is consumed. This situation is gradually being addressed with locating new power plants in the South part of the Greek electricity system [HTSO, 2010b].

Castro-Rodriguez et al. [2009] look at the issue of investment in generation in liberalized markets. They use the market of Spain as an example and they find that private investment decisions lead to generating capacities that are below the social optimum. They also show how the capacity payments and the price-adder, which are regulatory tools set in place in order to encourage the creation of new generating capacity from private investors, as these are set to operate in the Spanish electricity market are not effective and/or very costly.

Batlle and Rodilla [2010] examine the issue of whether the market is in position to satisfactory solve the problem of the security of supply in term of power generation. Since that issue was addressed by the electricity firm before the reforms took place, the question is whether on the regulatory mechanisms specifically for this issue that these reforms should include. Different regulatory approaches to the issue are presented as well as the lessons learned from the application of these approaches in different settings. The writers finally propose the principles and the criteria around which such a system should be set. That is very interesting from a regulator standpoint and especially for the case of Greece where that task is in the agenda of the regulator and the market reform is still a work in progress.

In a paper by Erdogdu [2011], we have a testing of the assumption that the electricity industry reforms take place in order for efficiency improvements to be achieved. The writer uses panel data from 92 countries (including Greece) and the period 1982-2008 to conclude that performance of the electricity industry is positively affected by liberalization but on a limited basis. Additionally, the paper finds that the reform process results in increases in the percentage of the electricity generated that is lost in the network. The final conclusion is that the deregulation process in an electricity market has only a limited ability to improve performance.

Arango and Larsen [2011] discuss the "cycle hypothesis" in electricity generation. That issue refers to situations where an electricity system is found to have over- and unde-capacity after the introduction of deregulation in it. That is of very large importance because it affects the issues of security of supply, of profitability of electricity firms and of consumer prices. Evidence is found in the English and in the Chilean markets, as well as in the Nordpool market. The writers suggest mechanisms that can be introduced to solve that problem, such as mothballing, capacity payments and reliability markets. That specific problem seems to have been addressed in the Greek case from the very initial market design, given that a capacity market has been set already.

Rubin and Babcock [2011] present a model for deregulated electricity markets that incorporate forward premiums and price-cost markups in the spot market. These characteristics are considered by the writers to be the ones that are leading to efficient allocation of generation capacity and not the risk preferences of the market participants.

Safarzynska and van den Bergh [2011] model the UK electricity generation market and discuss the transition to low carbon electricity, with new technologies gradually entering the electricity mix. The model is presented in two versions, assuming different decision making approach of the investors each time. One model explains well the actual market outcomes. According to this version of the model, Renewable Energy Sources (RES) and nuclear power generation cannot be introduced into the market. In the second version, the largest part of electricity generation comes through nuclear power. This indicates that the model parameters are crucial to the results that are generated by the model. It also shows that market outcomes as dependent on investor behaviour.

2.2.3 Wholesale electricity market operation

The theoretical models that describe the operation of wholesale electricity markets apply to the Greek electricity industry because the Greek government has adopted a mandatory electricity pool. Market reform requires the development of competition between generators through the bids that they submit in the electricity pool and the potential for strategic bidding by generators is a matter of concern. As a result, the research papers in this area which are presented below are useful as they provide insight on the details of the operation of wholesale electricity markets that share similarities with the Greek market.

Green and Newbery [1992] show that in the absence of contracts and any threat of entry, the market power of the main generators in the UK Pool, as it was in 1990, would enable them to raise Pool prices substantially above their efficient level. In the Greek electricity market, we have a market without bilateral contracts and with the main generator being also the supplier firm that supplies the largest part of the market. In such a situation, the incumbent generator and supplier would want to reduce the wholesale electricity price in order to increase his profits as a supplier.

Newbery [1998b] has argued that for competition in the wholesale electricity market to exist, there should be at least four generators that are competing in equal terms and with equally sized capacity. He also notes that in contestable wholesale markets, the reform is not likely to result in differentiated prices. This paper also states that system design could make the largest generators withhold generating capacity with the purpose of increasing the Loss of Load Probability and in that way manipulate wholesale electricity prices upwards. That type of behaviour can lead to decreased levels of security of operation of the electricity system. Also an observation made about the UK electricity market might also apply to the Greek electricity market. This is that the fact that the generators have full knowledge of the technical constraints of the system, of the actual electricity demand, and of the way that the scheduling algorithm is solved, gives to the generators the ability to determine pool prices that were largely unrelated to electricity cost. This outcome can be partly attributed to market power.

Green [1998] makes a presentation of the idea behind the creation of the electricity pool in the UK and explains its operation. He discusses the components that determine the final price paid in the pool namely the System Marginal Price (SMP), the Capacity Payments and the Uplift. He also introduces the issues of market power and gaming behavior by generators in order to spike electricity prices and increase their revenues through the pool. It is interesting to note that capacity payments as described in this paper are organized in a different way to those currently in the Greek electricity market. Also, we should note that the payment that is referred to as Uplift constitutes an equivalent of the combined payments made to Deviations Marginal Price and the Payments for the Mechanism for Covering Variable Cost in the Greek electricity market.

Newbery [1998a] has also engaged in another very interesting discussion of a theoretical model of a wholesale market model with an electricity pool and bilateral contracts between suppliers and generators. Remarks are made about entry conditions and how bilateral contracts might facilitate entry if potential entrants sign such contracts, locking-in their post-entry price without risk. Also, the writer predicts that in order to prevent that, incumbents with spare capacity will sell bilateral contracts at entry deterring prices and will make profits by colluding and offering these prices. The writer concludes that the threat of entry leads to increased contract coverage by the incumbents, meaning they can bid more competitively in the pool, leading the pool price downwards.

Vickers [1998] has discussed how marginal cost pricing might not be optimal pricing in some situations, especially when significant externalities or other distortions are present. If there are economies of scale or scope, then marginal cost pricing will not lead to coverage of all costs. Vickers suggests Ramsey pricing as an answer to this problem.

A framework for the analysis of bilateral transactions in an electricity market with competition and open transmission access has been developed by Galiana and Ilic [1998].

Song et al. [2000] examine the bidding decision making problem as well. They do this through a modeling approach and they present the optimal decisions for bidders in an electricity pool.

Li et al. [2011] examine the position of the generators in the new framework of competitive electricity markets. These firms, having to participate in the wholesale electricity pool and trying to be dispatched at the highest possible price, have the incentive to develop optimal bidding strategies to maximize their profits and in the same time minimize the risks of not being dispatched. The introduction of renewable energy makes the outcome of the market even more complex and the writers of the paper present the many different modeling approaches are being adopted in order to determine bidding strategies. That research is relevant as it is to be expected that generators is Greece will also try to employ similar bidding strategies.

2.2.4 Retail electricity supply

The retail electricity supply seems to have been researched to only a very small extent. The switching behaviour of customers is an issue of critical importance since it affects the potential competitiveness of the retail electricity markets. This also depends on the levels of retail and wholesale electricity prices. In this thesis, we are looking at issues related to the organization and operation of the electricity market in Greece, as well as to the application of incentive regulation in it. These concepts can be also applied to other electricity markets or to other industries with similar characteristics. We present two research papers studying issues in retail electricity markets.

Defeuilley [2009] discusses the introduction of competition in electricity supply markets. He notes that there is only limited success in the level of penetration of competition to the supply markets. Two reasons are identified for this outcome. The first one is related to consumer's behaviour and their decisions to switch electricity supplier or not. The other one has to do with the uniformity of electricity and the resulting inability of new entrants in the supply market to compete in any other way than price.

Littlechild [2009] presents a paper where he comments on the paper by Defeuilley [2009] arguing against a number of Defeuilley's points. The expectations concerning the impact of market reform are listed, coupled with a description of the evolution of the UK electricity market as it was being liberalized. Littlechild also discusses the customer switching numbers that were provided and also provides some notes on the economic theory that was behind the UK market reforms. The argument made is that retail competition, where it has been developed, has delivered more than was anticipated. Nonetheless it is always going to be the case that not all customers are going to benefited in the same way, or at all, which is something of which policymakers should be aware of.

Consumer's behaviour in electricity retail markets is also discussed by Wieringa and Verhoef [2007] who examine electricity supplier switching behaviour in the Dutch market. Their findings suggest that customers value a combination of elements when considering switching electricity supplier, with service quality being a very important one. At the same time, the writers note that there is a large segment of customers that fail to react to retail market opportunities.

Swadley and Yucel [2011] examine the effect that the restructuring of the retail electricity market had in the US. The writers note that after the price caps were removed from the market, higher prices were established by the electricity suppliers, passing the cost of electricity to the consumers. They find that in most of the markets that they examined, policymakers did not introduce appropriate incentives to residential consumers for switching electricity supplier. Retail electricity prices seem to be decreasing as the participation in the market increases, as price controls are being imposed by the policymakers, as the market increases in size, and as the capacity for hydroelectricity increases. These retail prices are increasing when natural gas and coal become more expensive. Also, the existence of competition acts to reduce the markup that suppliers use on the wholesale electricity price when setting their retail prices.

Kleit et al. [2012] discuss the liberalization of the tariffs in the retail electricity market in Pennsylvania. They discuss the factors that affect the decision over switching electricity supplier and the timing of that decision. The factors that they find to be leading to increased switching of electricity supplier and faster switching are: increased usage of electricity; use of electricity for heating; residing in areas that are more urban and have a higher educational standard. The factors that lead to lower switching are found to be: inconsistent volume of usage of electricity; customers already using a specific electricity supply program that potentially fits their needs; customers residing in the area for a small period of time (being new in the area). With reference to the benefits of retail electricity competition for poorer and older people, the paper mentions that from the areas that were researched, poorer customers have higher switching rates than the others and areas where older people reside have switching rates similar to the other areas.

2.2.5 Research on Renewable Energy Sources (RES)

Renewable Energy Sources (RES) are of specific interest to the Greek electricity industry because of the requirements that Greece needs to meet for 2020. The policies that the Greek government can put into practice, and the schemes discussed in the above papers for supporting these policies can be crucial for successfully meeting the RES targets. In this section some research papers are presented where the promotion of Electricity from Renewable Energy Sources (RES-E) in liberalized electricity markets is considered.

In a paper by Fouquet [1998] we have a description of some possible scenarios about how it could be that electricity from Renewable Energy Sources (RES) could be promoted after the UK electricity market liberalization. The writer argues that a combination of prices and beliefs can form the customer's willingness to pay an increased cost for electricity that is environmentally friendly. The suggestion of the paper is that the UK government can take action to promote investment in renewable technology, to impose taxes that bring the prices of standard electricity at the same levels as renewable electricity and to encourage the creation of schemes that promote electricity generation from RES.

Lipp [2007] discusses the RES-E policies that are in place in Denmark, in Germany and in the UK. The writer introduces the two main policy frameworks that are used, namely the Feed-In Tariff (FIT) and the Renewable Portfolio Standard (RPS). After presenting the main factors that affect policy-setting decisions for RES-E (*"policy objectives; energy security; protecting the environment; fostering innovation; promoting local and regional development; meeting the least-cost criterion; determinants of policy",* [Lipp, 2007, pp. 5483-5486]), there follow case-study investigations on how the policies were put into practice by the three countries under discussion (FIT by Denmark and Germany, RPS by the UK) and what were the results that were delivered. The main determinants of success are found to be the commitment of the policymaker to the scheme that is employed as well as the policy design. The writer concludes that FITs are more successful that RPSs, noting that in the cases of Denmark and Germany, performance with regards to meeting RE targets is world-leading, and at the same time other objectives are also met, such as industrial development and job creation.

Klessmann et al. [2008] examine the different regulatory approaches that Germany, Spain and UK have adopted for managing the financial risk involved in generators introducing RES. The writers recognize that generators are not exposed to the same level of risk in all markets and that the risk levels call for measures to manage them. It is also noted that risk can act in a way that pushes the generators to seek efficiency improvements and thereby create positive externalities.

In a paper by Sandsmark and Tennbakk [2010], the writers propose a procedure for market monitoring that is tailored to the characteristics of an electricity market with large hydropower. A market value is given to water and suspicious price formations can be screened through a set of indicators that are designed to highlight signs of short term market power abuse. This approach is applied in the Nordic Electricity

Market for the year 2002/2003 to explain the Nord Pool prices spiking during that time period. This approach is interesting given the large hydropower potential of Greece and the fact that this hydropower is exclusively in the hands of the incumbent. Market power abuse of that specific resource and using it to decrease the system load that is required to be dispatched through the wholesale market pool might be a serious concern, both for the market participants and for the policy makers.

Green and Vasilakos [2010] model the UK wholesale electricity market in 2020 and they use it to estimate the effects on it from the wind generation capacity that it incorporates. They project the degree of price volatility that will result from the wind speed variations in 2020, when there is a target for 20% of electricity to be generated by RES and wind generation will therefore be playing a significant role in the wholesale electricity market. They find that the wholesale electricity prices are expected to be strongly affected by wind generation. An important thing to note is that when the writers reduced the number of firms in their model from six to two, generator revenues increased by more than 100%.

2.2.6 Electricity Pricing

Electricity pricing and the structure of retail tariffs are issues of critical importance. This thesis examines retail electricity prices and market conditions and uses them to draw regulatory suggestions for the electricity retail supply markets, as we will see in Chapters 3 and 4. The potential for development of competition in the Greek electricity supply sector seems to be determined by the retail prices that are used in it. Research on electricity pricing and tariff setting is presented below.

Knittel and Roberts [2005] conduct an empirical analysis of restructured electricity prices and model the price formation process using elements from the asset-pricing literature as well as from models that fit the specific characteristics of the electricity prices. They conclude that there are several characteristics in them that are unique such as prices of different frequencies. They also find an “inverse leverage effect” that suggests that positive price shocks generate larger price volatility than negative ones. The writers find that in order for these prices to be modeled, features of electricity prices should be modeled which are not usually included in models that are used to price other assets.

Joskow and Tirole [2006] discuss load profiling for electricity consumers, and the implication that this might have for tariff setting with zonal charges if appropriate meters that allow for it are used. Also the possibility of cutting off electricity consumers during specific times in the day is discussed.

Reiss and White [2008] examine the use of pricing and public appeals in the management of electricity consumption. They use the example of the Californian electricity market during the crisis that it faced in 2000-2001, when these measures were used. They suggest that in the aftermath of supply shocks both high prices and publicly asking for reduced electricity consumption are effective measures for demand management.

Nakajima and Hamori [2010] examine the electricity price elasticity for residential customers in order to compare the effect that the deregulation of the retail electricity market has on them. They use data from USA electricity market and find that consumers present demand patterns that have similar price elasticities in pre- and post-deregulation periods.

Jamasb and Pollitt [2011] investigate the relationship between electricity market reforms and innovation. In order to do so they examine the effect that the reforms of the UK electricity sector had on the patenting activity and they find that initially there was a positive relationship between the reforms and the electricity related patents in non-nuclear and renewable technologies and that trend has moved to a decline of that innovation. Understanding the importance of innovation and suspecting that patenting by electricity supply companies is declining, the writers propose that in order for the pace of innovation to be maintained, a framework that co-aligns with the operation of the liberalized market should be put in place.

Akkemik [2011] examines the potential impact for the general economic activity as well as for the households that will result from a restructuring of electricity tariffs in order for these to reflect cost. This is done using the Social Accounting Matrix

(SAM) price modeling perspective. Given that the Greek electricity market is also trying to restructure tariffs to make them reflect costs, such an approach could be applied to Greece as well.

Lin and Liu [2011] discuss the policy decision of the imposition of differential pricing for electricity used in industry in China. They present the concepts of price discrimination and of Ramsey pricing and then they present the theoretical approach to differential pricing. The specific effect that this policy has on specific industrial sectors in China is presented and discussed. They writers find that this policy results in improved efficiency and decreased cost as the industries act proactively, knowing of the electricity pricing structure that they face.

Balaguer [2011] examines the pricing behaviours of electricity exporters in order to identify the degree to which electricity markets are integrated. Using pricing behaviour of electricity exporters from Norway he finds that Denmark and Sweden have a high degree of integration and competition in their electricity markets. The same does not hold true for Swiss exporters that differentiate their electricity prices depending on the market conditions of each of the countries that they are dealing with (Italy, France and Germany). Given the market power that electricity exporters possess as a result of market segmentation, the writer concludes by noting that electricity market's integration is very important and the need for it to be prioritized because of its economic implications.

Friedman [2011] examines the potential impact on greenhouse gas emissions that can be achieved by using retail electricity pricing schemes. The usefulness of time-of-use (TOU) pricing is discussed and the writer suggests the use of TOU pricing combined with electricity prices that are related to the marginal cost of electricity. Time-invariant rates lead to cross-subsidizations of peak-load period consumptions from non-peak load period consumptions, since these two periods are expected to be facing different electricity generation cost. The use of time-varying retail electricity rates is expected to help managing the greenhouse gas emissions by shifting electricity consumption from peak-load to non-peak load periods. In order for these prices to generate GHG emissions reduction, the paper argues for the use of rates that reflect the marginal cost of electricity for each of the periods.

Lee and Chiu [2011] construct a model that examines the electricity markets of 24 OECD countries during the years 1978-2004, including Greece. They find that electricity demand, electricity prices, temperature and real income are linked in a non-linear way. In Chapter 5 of this thesis, we approach the issue of interrelationship of system load, wholesale electricity prices and temperatures (as well as other factors) in a descriptive way, rather than adopting the econometric approach of Lee and Chiu.

Chao [2011] examines the problem of retail pricing and of investments in RES-E in liberalized electricity markets, acknowledging the fact that pricing should account for the problem of market risk and for the needed support of investment decisions. The writer presents a model with intermittent resources, to account for using RES-E for electricity generation, and two retail pricing alternatives: ex ante pricing, where electricity prices do not vary during the day, and dynamic pricing, where the prices vary according to the time of the day that consumption occurs. It is found that using either of the two pricing options, market entry is consistent with optimal investment in a competitive setting. It is also found that if the ex ante price approach is adopted, the optimal level for retail prices covers marginal operating cost and marginal outage cost. The results of simulating market operation using this model, suggest that combining dynamic pricing (that shifts consumption from peak-load hours to non-peak load ones) and wind power leads to reduction in the average cost of electricity.

2.2.7 Market Power

Market power is a very important concern in electricity markets and it can heavily impact market outcomes. The fact that the Greek electricity market is going through a transition period and the previous monopolist is still in a very powerful position makes market power a very significant issue for the Greek case. Market power was also an important element in the reasons that have led to the Californian electricity market crisis which is presented in more detail in Chapter 4.

Another concern is that of market power. An interesting and deep discussion of oligopolistic competition in general is done by Kuenne [1998, pp. 50-79]. A simple duopoly model is presented and discussed. This approach in very useful as it can be used to analyze the behaviour of the participants in electricity supply markets. A similar approach to this is adopted in later chapters in this work.

Green [1999] refers to market power as a major problem in the electricity spot market of England and Wales and attributes to it the fact that the electricity pool was essentially abandoned and replaced by a market that is covered by bilateral contracts. The pool, according to the writer, was in position to send the right price signals to the generators, exactly as an efficient bilateral contract market could. The rise in prices however is due to the risk aversion of the buyers and the bidding abilities of the sellers.

Joskow [2006b] recognizes that market power can be an important issue in the operation of electricity markets. He explains the reasons why that problem occurs and then goes on to say that market power issues have been present in the UK and that similar concerns in the USA were reinforced by the California electricity market crisis of 2000, which demonstrated how market power can be abused in an electricity market. The paper argues that there isn't any design for electricity market operation that can produce satisfactory results without there being an adequate number of electricity generators in the market. Alternatively, satisfactory market operation requires the reduction and mitigation of the market power of incumbent firms. Referring to how the US market deals with this problem, Joskow explains that price caps are used in the wholesale markets and these have been implemented in combination with bidding restrictions for generators that are placed in specific geographic areas, depending on the load requirements that they are serving. The writer goes on to explain how these measures have been successful in constraining prices.

Weigt and von Hirschhausen [2008] construct a model of the German wholesale electricity market and use it to calculate the 2006 expected electricity prices. When these expected prices are found to be less than the ones actually observed, the writers suggest that this might be the result of existence of market power.

Pepall et al. [2008, pp. 44-57] refer to market structure and market power and how these can be measured, suggesting the Lerner Index as an effective measure.

2.3 Electricity Markets of Other Countries

The section below presents references to a wide collection of research work that has been done for various countries that have attempted to proceed with market reforms. Some of these reforms have been attempted prior to the beginning of the Greek electricity reform, whilst others were done at the same time. A variety of lessons can be drawn from other cases and past experience can be very useful to support future efforts. The work done in this thesis adds to this literature by concentrating on the Greek case and taking into account its peculiarities. The extent to which all this empirical knowledge will be actually put into use by the policymakers is left to the policymakers themselves to decide.

By examining the UK experience in specific, we can identify the elements of the liberalization that were not successful and plan ahead avoiding such mistakes. As far as Greece is concerned, the areas where the country should focus at are: the existence of market power; the application of appropriate regulation that avoids unintended outcomes and creates the necessary market conditions; and the realization that in order for competition to exist, adequate capacity is necessary but on the condition that this is divided amongst a high number of market players that are competing on equal terms.

Also, by looking at the countries of the Nordpool we observe that we have a cooperative market of a number of smaller countries. Although this market is not uniform in its retail part and not all consumers are facing the same opportunities, the wholesale part of the market is much more successful in the introduction of competition. An important lesson in this setting is that the common cultural characteristics that these countries were sharing and the adoption of similar points of view from their policymakers and governments has aided the achievement of the market form as it is.

In a book edited by Sioshansi and Pfaffenberger [2006] there is a large collection of work that refers to experiences from the reform efforts in electricity market of various countries in Europe, North and South America, Japan, Australia and New Zealand. Table 2.2 gives a collection of references to research that has been done on the liberalization efforts of various countries around the world.

Country	References of relevant work that has been done
United Kingdom	Helm and Powell [1992], Exelby and Lucas [1993], Green [1996], Green and Newbery [1997], Newbery and Pollitt [1997], Green and McDaniel [1998], Littlechild [1998], Helm [2003], Gorini de Oliveira and Tolmasquim [2004], Jamasb et al. [2008], Yu et al. [2009], Denny et al. [2010], Steggals et al. [2011], Carstairs and Pope [2011], Toke [2011]
Nordpool countries (Finland, Norway, Sweden and Denmark)	Midtunn [1996], Midttun and Summerton [1998], Eikeland [1998], Pineau and Hamalainen [2000], Olsen et al. [2006], Littlechild [2006a], Amundsen and Bergman [2007], Munksgaard and Morthorst [2008], Johnsen and Olsen [2011], Lehto [2011], Tahvanainen et al. [2012]
Russia	Kennedy [2003]
Netherlands	Reijnders [2002]
Switzerland	Ochoa and Ackere [2009]
Germany	Liebau and Strobele [2011]
Spain	Moutinho et al. [2011]
Portugal	Ferreira et al. [2007]
Argentina	Haselip and Potter [2010]
India	Kundu and Mishra [2011], Shukla and Thampy [2011]
Philippines	Toba [2007]
China	Du et al. [2009], Ngan [2010]
Thailand	Wisuttisak [2012]
Bangladesh, India, Pakistan, Nepal, Sri Lanka	Bhattacharyya [2007]
Pakistan	Jamil and Ahmad [2011]

Table 2.2: References of research work done for the electricity markets of various countries.

2.4 Conclusions

Chapter 2 provides a review of the literature and the research that has been done in the Greek electricity market. Part of this research refers to the pre-liberalization period of the Greek electricity market and there is also research on greenhouse gas emissions, the demand for electricity, the fuel mix potential, and the renewable energy sources potential of Greece. A gap in the literature is identified with regards to the area of electricity supply in Greece and to the retail electricity markets in general. The existence of this gap presents us with an opportunity that is covered by the research presented in this thesis.

The implications that the operation and regulation of the retail electricity supply sector have for the successful introduction of competition is not heavily researched either. The identification of this gap in the literature is another contribution of this chapter, as it justifies the usefulness of the work presented in subsequent chapters. The electricity industry has some very marked peculiarities that have been recognized in previous work. These peculiarities give the industry special characteristics that are rarely found in other sectors.

Standard market reform models and prescriptions, as shaped by previous experience, are presented as the lessons learned from the past that can be useful for policymaking. A large body of work has focused on the UK electricity market, due to that market being the pioneer in market liberalization.

An important finding from Chapter 2 lies in the similarities that Greece has with other South East European countries. We also find similarities and differences between the liberalization efforts of other countries and those of Greece.

Literature on the deregulation of electricity markets has been reviewed including a collection of research papers which focus on the reform efforts in various countries. These have been presented in the form of a table, providing a collection of the references to previous academic work.

Chapter 3

The theoretical model: Diagrammatic Analysis, Algebraic Presentation, Comparative Statics and Simulation in a Price-Cap Regulated Monopolistic Market

3.1 Introduction

3.1.1 Introduction to the model

In Chapter 3 we introduce and discuss a theoretical model that aims to tackle some of the issues that are present in the Greek electricity supply market and seriously affect its operation. In Chapter 1 we outlined the situation in the Greek electricity market in generation, transmission, distribution and supply. The references that were made in Chapter 1 to the generation, transmission and distribution sectors adopted a descriptive approach. In the present chapter we focus on the electricity supply sector and model its operation.

The model that we present outlines the situations that emerge in electricity supply markets under monopolistic supply. These markets face price caps and we show how the level of the price cap affects the profitability and the attractiveness of each market for new entrants. In Chapter 4 we extend this analysis to situations where these markets are served by two suppliers: the incumbent that bears an obligation to serve all the markets (by all markets we mean all tariff categories) and meet the demand in each of them; and a new supplier that bears no such obligation and can choose in which market to enter and what quantity of electricity to supply. The transition from monopoly to competition is expected to affect the previous incumbent in a negative way, since market shares decrease in all competitive markets and prices move from their monopolistic levels to competitive ones.

In Chapter 3 we use a theoretical model that is represented diagrammatically in the text and algebraically in Appendix C in order to show how price caps that are introduced adopting non-market rationales cannot be sustained after the emergence of competition since these lead to losses for the incumbent. Where equations are reported in the text, the numbering is that of the Appendix C. We also run simulations based on the algebraic formulations of the model and show how the diagrammatic and the algebraic presentations of the model are aligned and how these can be utilized in a modeling manner.

The approach adopted here is that of a simple model that can help us reach conclusions that can be applied in other similar cases. Talbot [2004, page 7] states that *"in attempting theoretical explanation or model construction it was possible to have simplicity, generalisability and accuracy, but not all three at once"*. In the model that we are discussing, we aim for simplicity and generalization, ranking accuracy third in our priorities.

3.1.2 Relevance to the Greek case

In the Greek electricity supply market, regulated tariffs are used to support the monopolistic activities of the market. These are recovered from a distinct section of the electricity bill. They are determined by the cost of operation of the transmission and distribution networks. This part of the bill does not relate to our discussion since it constitutes a regulated tariff that applies to all suppliers and is directly recovered from the electricity bills. What is of interest to us is the tariff structure that is imposed by the Greek government to PPC with regards to the competitive activities section of the electricity bill, as well as the other retail tariffs that independent electricity suppliers choose to use in the Greek electricity supply market. The two parts of the bill (monopolistic and competitive) were bundled in previous tariffs structures [PPC, 2008e, 2008f, 2008g] and the separation of these two parts [PPC, 2011c, 2012g, 2012h, 2012j, 2012k] constitutes an evolution that took place as competition was being introduced, and in order to facilitate its development. The Medium Voltage tariffs have been liberalized ([Journal of the Greek Government, 2012, p. 97], [RAE, 2011b, p. 1]), and the Low Voltage tariffs are expected to be liberalized in the future as well. Nonetheless, the tariff setting for

PPC in the previous years is something that we can examine and reflect on how different tariff levels can affect the entry decisions of the potential suppliers. We consider that these entry decisions are influenced by the attractiveness that markets which is determined by their profitability.

In the analysis included in Chapter 3, we examine and discuss certain situations. Whilst not fully describing the Greek market and not necessarily incorporating all of its details and peculiarities, this analysis highlights key aspects of the actual and potential operation of this market. If we want to relate this approach to the situation in the Greek liberalized electricity market, the incumbent supplier with the obligation would be the Public Power Company (PPC), which is the previous monopolist electricity firm in the Greek electricity market, and the other supplier (the one that does not bear an obligation to meet the market demand) would be any other possible new entrant.

3.1.3 The usefulness of the model

The main issue that is identified in Chapter 3 is the use of price caps that are set at inappropriate levels. These price cap levels might result in some markets being served under unprofitable terms whilst others are served under very profitable terms. This pattern of price caps can be in place when there is a vertically integrated monopolistic firm that serves the whole market and cross-subsidizes customer categories with the purpose of serving social agendas and income redistribution policies. However, when such a market is liberalized and therefore faces the potential introduction of new suppliers, the pressure of competition on prices eventually eliminates these profitability asymmetries across markets and cross-subsidization is no longer possible as we show later in the thesis.

The focus in this chapter is the impact of price caps or tariffs in the encouragement of competition. We also analyze how these markets are affected by the introduction of an obligation to meet the market demand. The understanding of these concepts and of the mechanisms that determine if the operation of the market is allowing competition in general but new entry in particular to be developed. This can lead to a better comprehension of the essential elements of market operation. The approach is innovative in examining the Greek electricity market from an analytical point of view.

3.2 The market conditions

3.2.1 Basic assumptions

The setting that we are considering is constituted by:

- multiple electricity supply markets
- a single supplier that serves all these markets as a monopolist (the incumbent) and potential other entrants for any of these supply markets
- all suppliers have profit maximizing behavior
- the price of the inputs of the supply industry (electricity bought in the wholesale market) is increasing as the total electricity demand for each hourly period (which is the output for all players combined) increases
- price caps set by a regulator which monitors and controls the monopolistic power of the incumbent. These price caps might be set either with the notion of stopping the incumbent from making super normal profits at the monopolistic level or with the notion of serving a "social" agenda. These price caps are referring to the retail tariffs that firms can charge to final consumers.

The use of price cap regulation as an alternative to rate-of-return regulation is discussed by Liston [1993]. These two regulatory approaches have been compared in a model presented by Pint [1992]. Braeutigam and Panzar [1993] discuss the change from rate-of-return regulation to price cap regulation for the US telecommunication market. Ros [2003] also investigates the use of price cap regulation in telecommunications industries. Discussing the use of price caps as a regulatory instrument, Pollitt [2005] notes that the incorrect setting of the price cap is problematic. Using a low price cap restricts profits and might lead to losses and bankruptcy whilst using a high price cap leads to unacceptably large profits from a political point of view. Currier and Jackson [2008] note the cost reduction incentives that are provided by prices caps but also the risk for financial losses that can be made when input prices are increasing. Recognizing that there could be political pressure for reductions in price cap levels, Currier and Jackson [2008] argue that regulators that use price cap regulation should be committed to their price caps regardless of whether these lead to high profits or losses for the regulated firms. They also mention that as a result of political considerations, markets could have prices imposed in them which result in distorted total surplus distributions.

We will be examining the impact on profits in these markets as the price caps are introduced and set at varying levels. We will also be doing the same as we are introducing the obligation (for the incumbent) to serve the whole market and we will compare the outcome with the outcome when that obligation is not in place.

The case of Greece seems to be fitting the above description, given the presence of price caps for each market, with an obligation for the incumbent to meet the market demand and the suspicion that cross-subsidization of larger markets by smaller ones takes place [PPC, 2008a, p. 7]. To be more accurate, in the Greek case we do not have price caps but imposed tariffs, however these tariffs act as caps for the new entrants since pricing above them while entering a new market does not make sense.

3.2.2 Supplier unbundling

3.2.2.1 The need for unbundling

For this discussion the supplier is considered to be completely separated from any other electricity activity and all the profits or losses made are only on the supply side of the market. So we assume that full unbundling of the different sections of the vertically integrated incumbent has occurred not only in legal terms and accounting terms, but to the extent that the four sectors of the electricity industry, generation, transmission, distribution, and supply, operate separately in terms of decision making and profit making. No tariff setting implications stemming from any business connections that the suppliers might possibly have with other participants in the electricity market are considered. We also do not take into consideration the possibility that these firms that are electricity suppliers are also electricity generators participating in the pool. Such an assumption would complicate the modeling effort and would go beyond the purposes of the work presented in this section. The implications of the potential use of market power of the incumbent and of his effort to manipulate the wholesale electricity price upwards or downwards are discussed separately in Chapter 4.

We also assume that a competitive market operates in electricity generation. The complexities of the actual operation of the wholesale electricity market and their effect on the supply market, if considered, would add extra complexities to the discussion.

3.2.2.2 Unbundling of accounts and activities in the Greek case

The main idea behind the decision to unbundle the accounts and the activities of previously vertically integrated monopolies in electricity is the promotion of competition in those parts of the electricity industry where it can exist. In order for this to happen, potential new entrants should be secured against the asymmetric threat of the previous incumbent firm having connections with the rest of the electricity industry sections. Although that is not possible to be achieved fully due to the ownership status of the firms owned by the previous Greek incumbent, the separation of the operation of transmission and distribution networks from the generation and supply activities of the incumbent firm is an important part of the introduction of competition in the supply market.

For PPC, the unbundling of accounts and of activities meant for PPC that it had to be separated into distinct parts. These parts were formed into new separate firms and these operate the monopolistic activities of the electricity industry on an independent basis [Journal of the Greek Government, 2011b]. The competitive activities are undertaken by PPC as well as by other firms that participate in the sectors of electricity generation and supply.

The purpose behind the separation of the electricity market into the different sectors, monopolistic and competitive ones, was to create the conditions so that any possible entrant would be able enter the market and compete against PPC, without PPC enjoying the advantage of cross-subsidizing between monopolistic (the natural monopolies of transmission and distribution) and competitive (generation and supply) sections of the electricity industry. The electricity industry sectors have been separated initially in accounting terms and then in legal terms. Two separate firms, the Independent Power Transmission Operator (IPTO) and the Hellenic Electricity Distribution Network Operator (HEDNO) have been established with Law 4001/2011 [Journal of the Greek Government, 2011b] and the cost of each electricity market sector is recovered separately by separate charges of the final consumers. Bills issued to consumers list charges for monopolistic activities and charges for competitive activities separately ([PPC, 2011c, 2012g, 2012h, 2012j, 2012k], [Elpedison Trading, 2012a, 2012b]).

3.2.3 Tariff setting challenges

3.2.3.1 Tariff setting in the Greek electricity supply market

Initially in our model the incumbent is viewed as a monopolist and we examine how the levels of the price caps can affect its tariff setting. These tariffs are set by the regulator and in our approach the regulator and the incumbent are treated as distinct entities with essentially different objectives. In the Greek case, PPC does not operate under a price cap with free price setting underneath it; instead it has its tariffs approved by the Ministry of the Environment, Energy and Climate Change. To make matters simpler in our discussion, we consider that the regulator alone sets the tariffs. For any given price cap that the regulator imposes, we can find out using diagrammatic analysis what is the price that PPC, or any other incumbent, is asking for and the quantity of electricity that the supplier has to supply and the quantity that the supplier wishes to supply (these two are not always the same).

An issue that calls to be dealt with is the viewpoint that will be adopted for decision making purposes by the government and the Ministry of the Environment, Energy and Climate Change. The situation is complicated by the fact that the government is at the same time the major owner of PPC and also the entity that controls a series of very important decisions about the regulation of the whole electricity industry. In the way that Talbot [2004, pages 4-5] defines governmental agencies, PPC could be considered to be a governmental agency, and despite the fact that PPC is a private firm, the fact that the State has the largest share of the ownership means that PPC remains closely linked with the government through ownership status. Additionally, some Greek political parties maintain links with the labor union of PPC workers, which can possibly affect the decisions of the firm. So the government might find itself in situations where it has to make decisions that are controversial in terms of hurting the company that the Greek State owns, PPC. Such decisions could be those that concern the determination and the approval of retail tariffs.

Another concern is that given the role that the government plays in the economy, it might also use PPC in order to apply welfare and income distribution policies. That can be done by imposing specifically structured tariffs that serve special social goals (such as low-priced electricity for vulnerable social groups), and that can be achieved through having the government in that special position where it can not only accept the tariffs, but also be the major shareowner of the company that puts these tariffs into practice and serves the market. A decision of this type was the introduction of a PPC tariff category called “Social Household Tariff” which offers even lower retail electricity prices to households that are in vulnerable position.

3.2.3.2 Tariff setting in our model

What we will examine is:

- How the retail price caps (or retail tariffs) can affect the profitability of the retail suppliers. We will examine how the price cap setting can move a supplier from profit to loss, with that loss being reinforced by the obligation to meet the market.
- How the profits or losses that are made are also dependent on the wholesale price of electricity. The use of different marginal cost (MC) curves helps us highlight how that affects profitability under identical price caps.
- That profits and losses are also dependent on the demand. We use different demand curves and marginal revenue (MR) curves under identical MC curves and price caps to investigate that.

Another issue that is worth mentioning is the allocation of the overhead costs. With the incumbent serving all of the market tariffs, there are more customers amongst which the incumbent can spread its overhead costs, whereas the new entrants that choose only a few tariffs to serve, have fewer customers to which they can spread these overheads. These costs only refer to the electricity supply activities and have nothing to do with the overhead costs of operating the Grid, since the changes for that are separate. However for simplicity we will not take overhead costs into consideration and for the most cases, when referring to marginal cost, we will only be referring to cost that relates to the prices paid for wholesale electricity alone.

3.3 The model

In this model that we will be looking at, diagrammatic analysis is applied. This type of approach for analysis has also been used by Kuenne [1998, pp. 50-79], Tirole [1988], Varian [1992, 2006], Viscusi et al. [2005], Pindyck and Rubinfeld [1996], Shepherd [1979] in the presentation of their arguments.

As far as our algebraic presentation in concerned, a similar approach has also been adopted by Brunekreeft [2002], applied for access charges to the transmission and distribution network.

Also, in a working paper, Newbery [2008a] has adopted the approach of Supply Function Equilibria for an electricity wholesale pool.

With reference to our price cap setting discussion, a behavioral approach to how decisions are taken by regulated firms with regard to them requesting a retail tariff adjustment from the regulator of their market is presented by Joskow [1973].

Of particular interest also is another working paper by Newbery [2008b] that examines the relationship between electricity pricing and the ability of electrical utilities to fund their investments.

In some of our diagrams we are considering one market, indicated by the existence of a sole demand curve and in other diagrams we are considering two markets that we compare and we face two demand curves. Whenever we are facing two demand curves, we consider that the output in each market does not affect the marginal cost in the other one. The reason why we are doing so is because we are considering that these two markets do not exist in the same time period. The larger market is the peak-hours market and the smaller market is the non-peak hours market. We also do not take into consideration fixed costs and we assume that all costs are variable. The notion of peak-load markets and peak-load pricing in electricity has also been discussed by Viscusi et al. [2005, pp. 447-453].

This approach is used because we want to build a case that reflects the specific aspects of the Greek electricity market, the price setting within it and how this determines the potential for development of competition in the market. The conditions for potential entry and exit in the market and the resulting degree of market contestability is also a very interesting issue which has been discussed in the literature [Baumol, 1982]. In our discussion we focus on the issue of competition, recognizing the entry and exit in the market is not costless as entry costs and fixed capital costs play a role, thereby not allowing the market to be characterized as perfectly contestable.

In the Greek electricity market, High Voltage tariffs include zonal charges that separate the hours of the day in three zones [PPC, 2008e]. The same would apply in the past for Medium Voltage tariffs [PPC, 2008g]. Also the Medium Voltage and Low Voltage tariffs of PPC for 2011 and 2012 include different daily and nightly charges in certain tariff categories as well as farming tariffs with obligation for those that receive them to interrupt their electricity consumption whenever asked [PPC, 2011c, 2012g, 2012h, 2012j, 2012k]. The use of different charges for electricity that is supplied to the same customers depending on the hour of the day is approached by using the concept of markets that have different demand levels and that do not coexist in the same time.

In order to examine the impact of the Greek electricity market tariffs, we use price caps in our analysis. We investigate how different market conditions and varying price cap levels can affect the market outcomes and the ability of markets to make profits or not.

The concept used in the diagrams and the models of the markets that are presented is the kinked demand curve [Tirole, 1988, pp. 240, 243, 244]. However, in our case we do not adopt the notion of collusion to describe the market conditions, considering that the players in the market will be competing on price. In the specific model discussed in this chapter, only one supplier is considered.

The approach that we adopt in the way that we graph the kinked demand curve is the one described by Shepherd [1979, pp. 284-286].

The obligation to meet the market demand is a concept that we use and refers to the obligation of the monopolist to satisfy all of the market demand. That obligation is present for only one of the electricity suppliers, the incumbent firm. This concept is introduced in our analysis to account for the fact that such a market setting is in place in the Greek electricity market for residential and small business customers [Journal of the Greek Government, 2011b, Article 58, p. 3817].

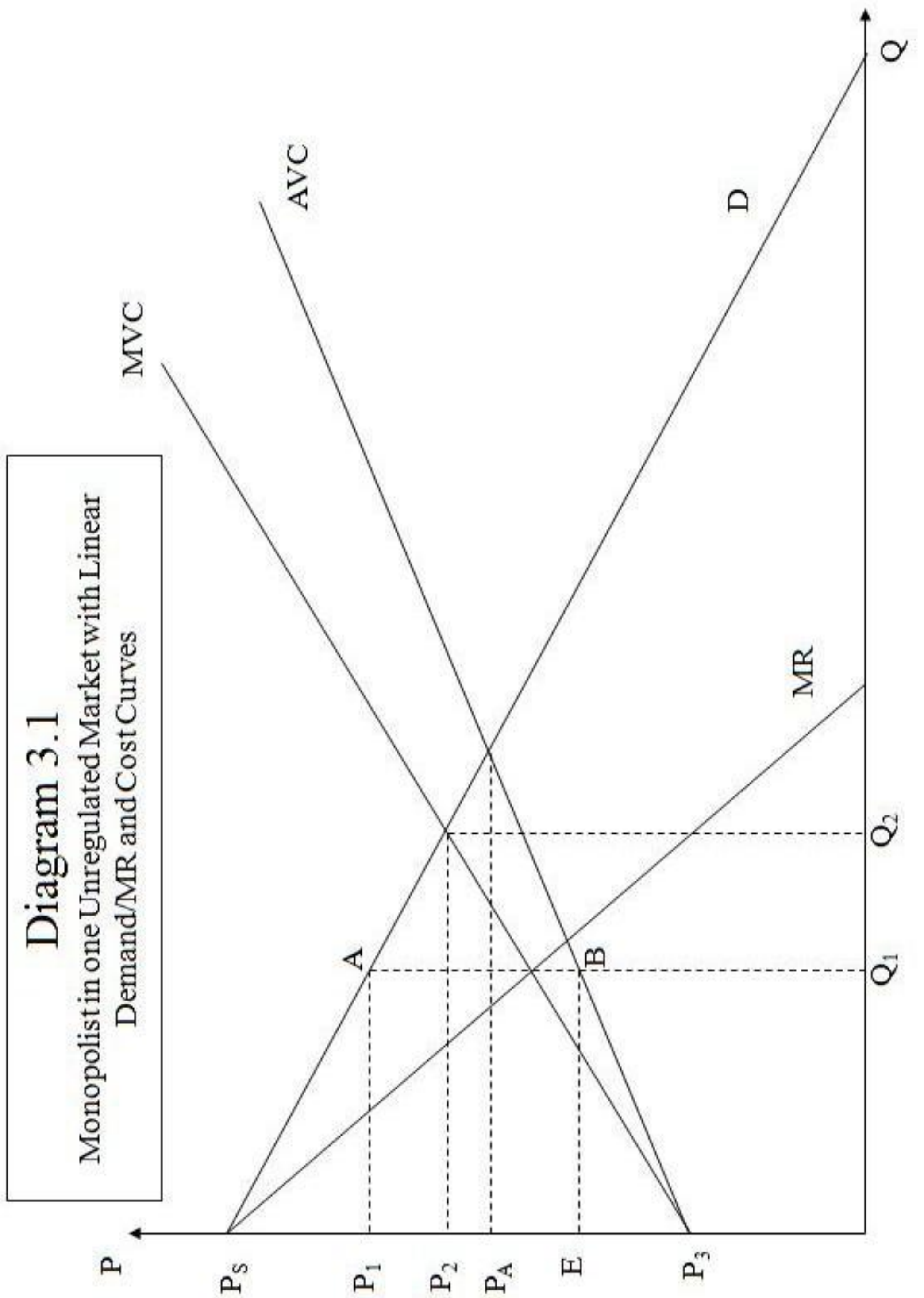


Diagram 3.1
Monopolist in one Unregulated Market with Linear
Demand/MR and Cost Curves
P
Q
MVC
AVC
D
MR
A
B
Q1
Q2
PS
P1
P2
PA
E
P3

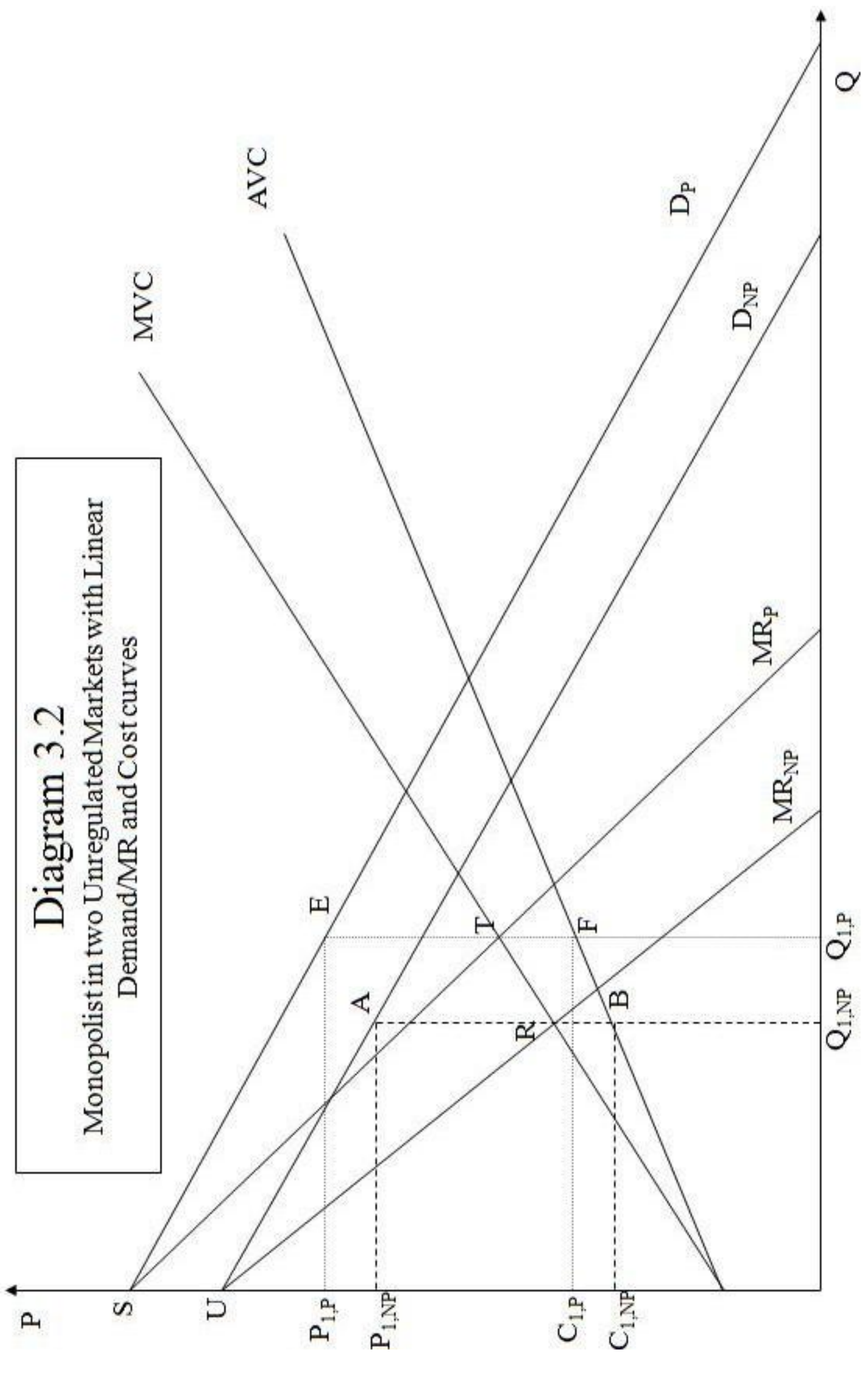


Diagram 3.2
Monopolist in two Unregulated Markets with Linear Demand/MR and Cost curves

3.3.1 Discussing the diagrams

In Diagram 3.1, the monopolist is free to select its price and supply the market. The monopolist is expected to supply its profit maximizing quantity Q_1 for price P_1. These maximum profits are equal to rectangle $ABEP_1$.

In Diagram 3.2, the monopolist is facing two different demand curves. The monopolist facing demand curves D_P and D_{NP} selects prices $P_{1,P}$ and $P_{1,NP}$ respectively and supplies the market with quantities $Q_{1,P}$ and $Q_{1,NP}$ respectively. In each separate market, the monopolist maximizes its profits. These maximum profits are equal to rectangle $ABC_{1,NP}P_{1,NP}$ when facing D_{NP} and rectangle $EFC_{1,P}P_{1,P}$ when facing D_P. It should be stressed that profits made in the peak-hour market, which is the larger market, are larger than those made in the non-peak hour market, which is smaller. These profits are larger by the amount equal to the area in the quadrilateral STRU. This is so because for output from 0 to $Q_{1,NP}$, this area includes the difference $MR_P - MR_{NP}$ and for output from $Q_{1,NP}$ to $Q_{1,P}$, it includes the difference $MR_P - MVC$.

In Diagrams 3.3a, 3.3b and 3.3c we introduce the price cap without an obligation for the supplier to meet the market demand. We use the notation PC for the price cap and in the diagrams where we have only one price cap, the price level of the price cap is set as P_0. We show how the price cap might not affect profits at all (Diagram 3.3a) and how it might affect profits (Diagrams 3.3b and 3.3c). In Diagrams 3.3a, 3.3b and 3.3c, P_1 is the price that corresponds to the profit maximization of the unconstrained monopoly and P_2 is the price that corresponds to the competitive outcome of the unconstrained market (P=MVC). In 3.3a we have $PC \rangle P_1$, in 3.3b we have $P_1 \rangle PC \rangle P_2$ and in 3.3c we have $P_2 \rangle PC$. Profits are not affected when $PC_i \rangle P_1$ and are affected when $PC_i \langle P_1$ and when $P_2 \rangle PC$, since then the supplier cannot sell at the unconstrained profit maximizing price. Apart from the price and the profits, the imposition of the price cap also affects the output of the supplier, as we can see in Diagrams 3.3b where output is Q_0 instead of Q_1 and

Diagram 3.3c where output is Q_i^{PC} instead of Q_1. In both Diagrams 3.3b and 3.3c we can see that the imposition of the price cap alone, without any other restriction applying, has led to the expansion of the suppliers output, since $Q_0 \rangle Q_1$ in Diagram 3.3b and $Q_i^{PC} \rangle Q_1$ in Diagram 3.3c.

In the case that is given by Diagram 3.3b, we have $P_1 \rangle P_0 \rangle P_2$ and $Q_0 \rangle Q_1$. However, when $P_2 \rangle P_0$, as it the case in Diagram 3.3c, then the output can be read off the MVC curve and that can either be greater or less than Q_1.

Diagram 3.3a

Introducing the Price Cap. Price Cap set too high, does not affect the profitability of the monopolist. Profits are equal to rectangle $ABEP_1$.

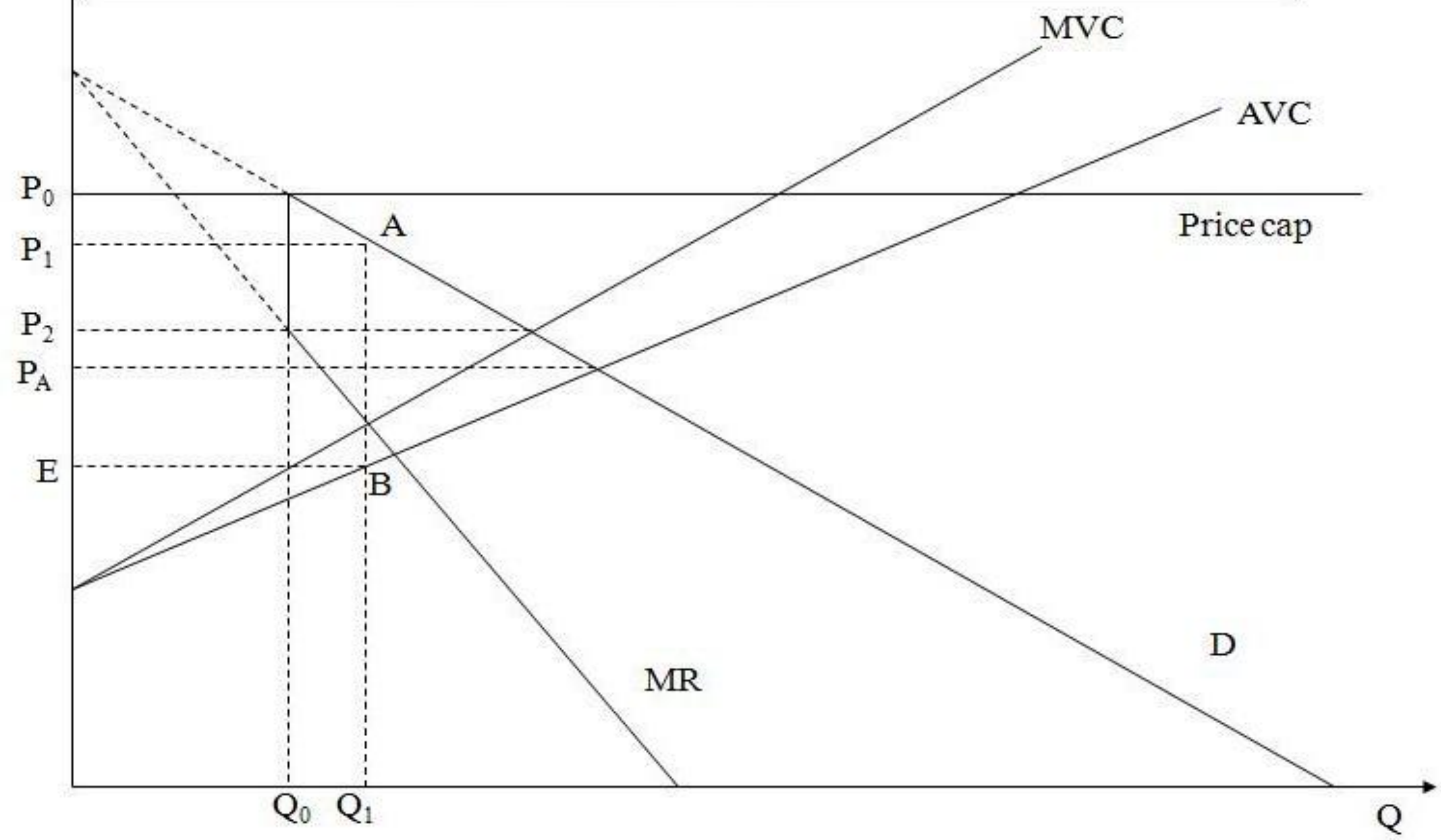


Diagram 3.3b

Introducing the Price Cap. Price Cap affects the market price, the market quantity and the profitability of the monopolist, and profits are made. These are equal to rectangle $ABEP_0$.

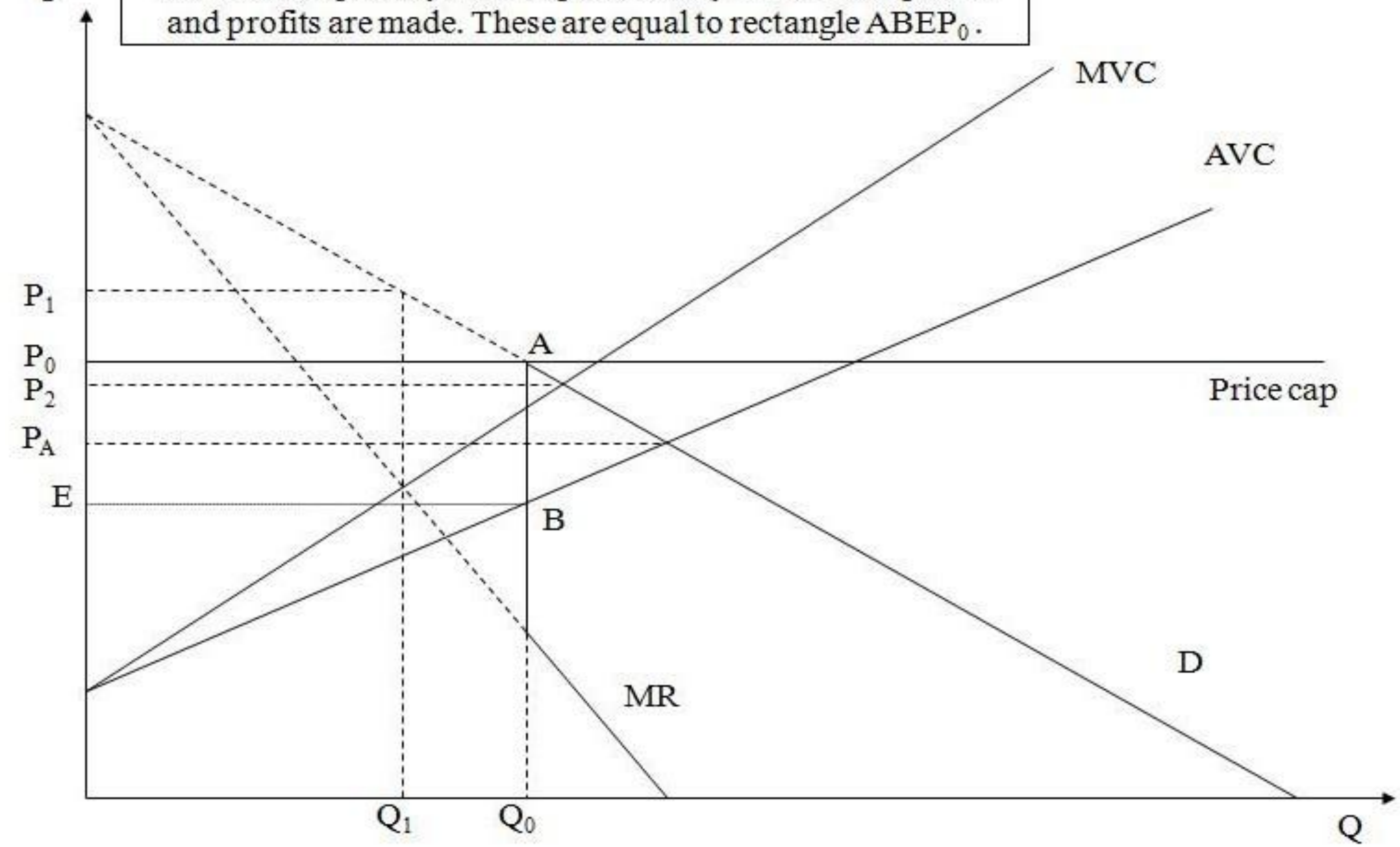
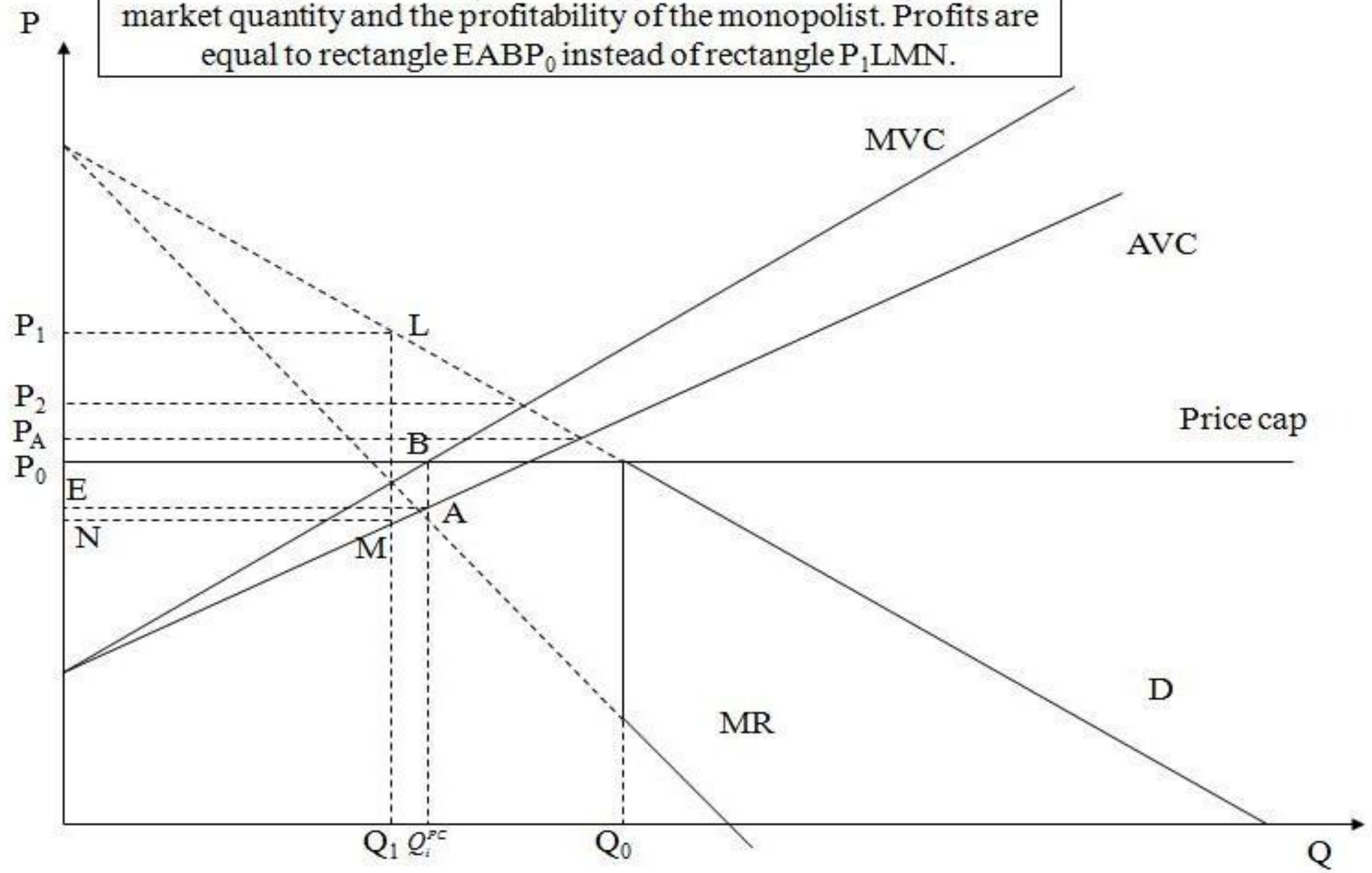


Diagram 3.3c

Introducing the Price Cap. Price Cap affects the market price, the market quantity and the profitability of the monopolist. Profits are equal to rectangle $EABP_0$ instead of rectangle P_1LMN.



A notable difference between Diagrams 3.3b and 3.3c is that in Diagram 3.3c there is a case of a non-market rationing as price is set to a level which implies that the corresponding demand will not be met by the supplier. That means that in Diagram 3.3c and without further regulation, the supplier would not supply the output Q_0 demanded by the market for price equal to the price cap P_0 and would only supply the output Q_i^{PC} that would lead to profit maximization (under these circumstances).

In Diagram 3.4, we have a case where a monopolist is serving the two different markets, each having its own demand curve. For simplicity we have assumed that the price cap is the same both for the market of the peak hour periods and for the market of the non-peak hour periods. For the low-demand curve (non-peak load period), the supplier makes profits equal to rectangle $ABEP_0$. For the high-demand curve (peak load period), supplier makes profits equal to rectangle $FGHP_0$. Profits made in the peak-hour market are again larger than those made in the non-peak hour market. These profits are larger by the quantity equal to the shape AFKL. This shape shows the difference between the MR_P curve, which is the horizontal line at price level P_0 from point A until point F and then the vertical line until point K, and the MVC curve as quantity increases from $Q_{0,NP}$ to $Q_{0,P}$. It should also be noted that for Diagram 3.4, we have $P_{1,NP}, P_{1,P} \rangle P_0 \rangle P_{2,NP}, P_{2,P}$, although it is not shown. That means that the profit maximizing prices of the unconstrained case for both markets ($P_{1,NP}, P_{1,P}$), are higher than the price cap P_0 that we use in Diagram 3.4. Also it means that the prices $P_{2,NP}, P_{2,P}$ that correspond to the points where MVC=MR, for both markets, lower than the price cap that we use. So, we get that for both markets the price cap falls in an area where the monopolist wants to meet the market demand in order to maximize profits under the price cap, which is the case that we saw in Diagram 3.3b.

In Diagram 3.4, it is important to note that what leads the supplier to choose to supply quantities $Q_{0,NP}$ and $Q_{0,P}$ is the discontinuity on the MR curves in each case. In the case of the MR_{NP}, if the supplier decides to supply any quantity smaller than $Q_{0,NP}$, then the supplier loses MR equal to P_0, which is above the MVC curve for that output level. If the supplier supplies quantities larger than $Q_{0,NP}$, the supplier receives marginal revenue that is lower than its marginal variable cost, since MR_{NP} is below the MVC curve for these quantities. That discontinuity is what makes the supplier decide to supply the quantities that correspond to the point where demand curves kink.

Diagram 3.4

Monopolist in two Price Cap Regulated Markets, with the same price cap and with Linear Demand/MR and Cost curves. Both markets make profits, however that would not necessarily always be the case.

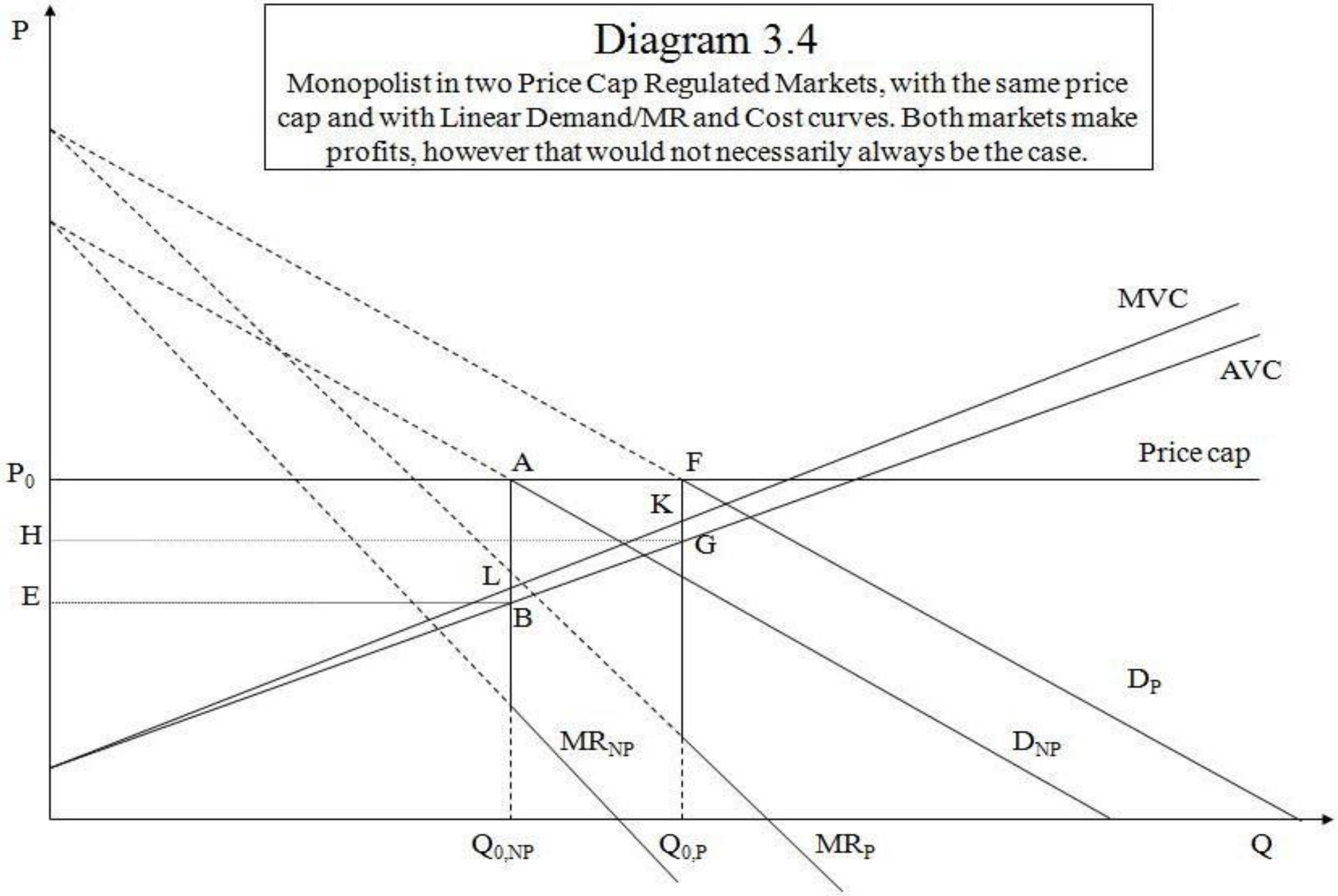


Diagram 3.5a

Introducing the obligation to meet the market demand. The supplier should supply quantity Q_{0}, as that is the quantity demanded for price P_0. Supplier makes losses instead of profits.

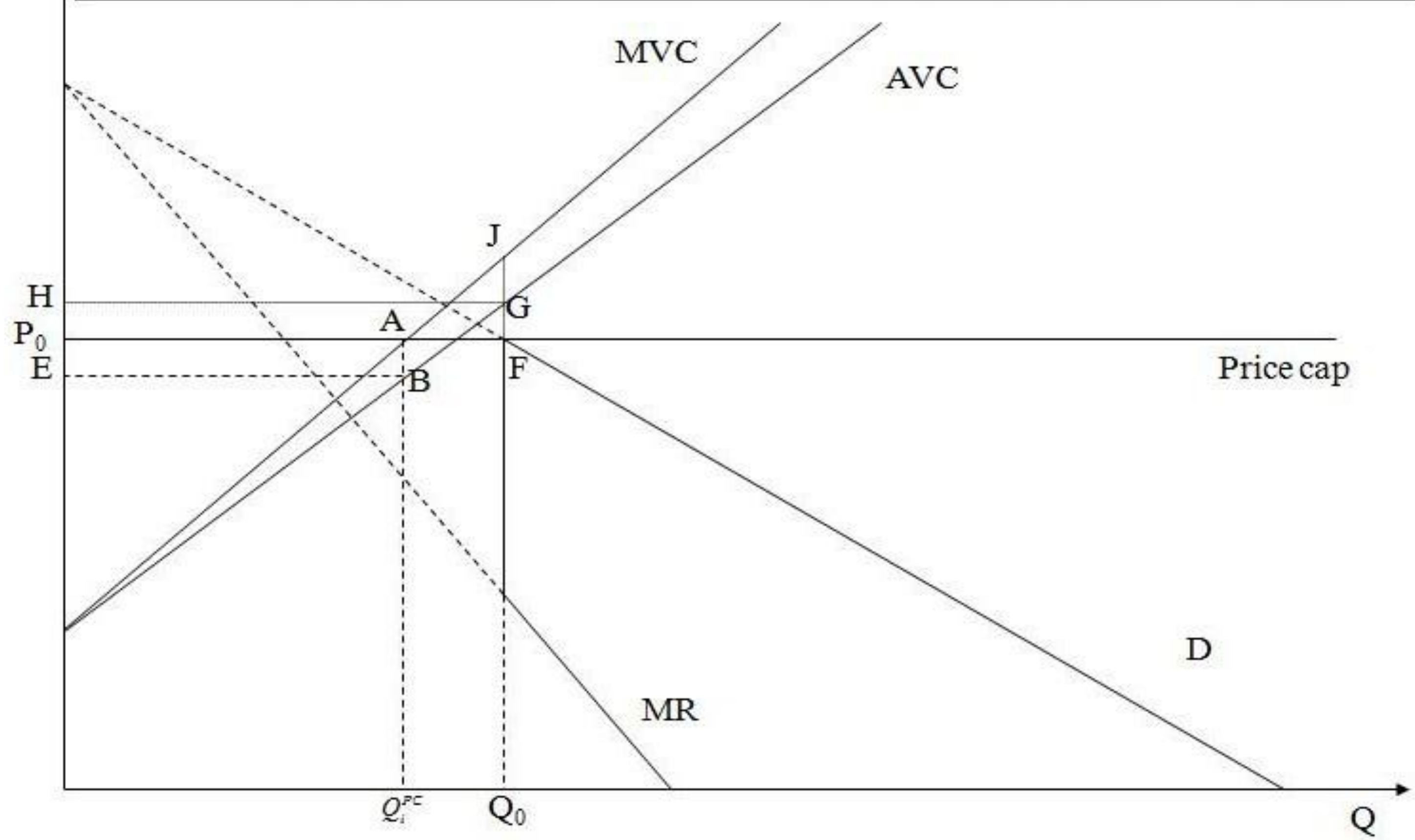
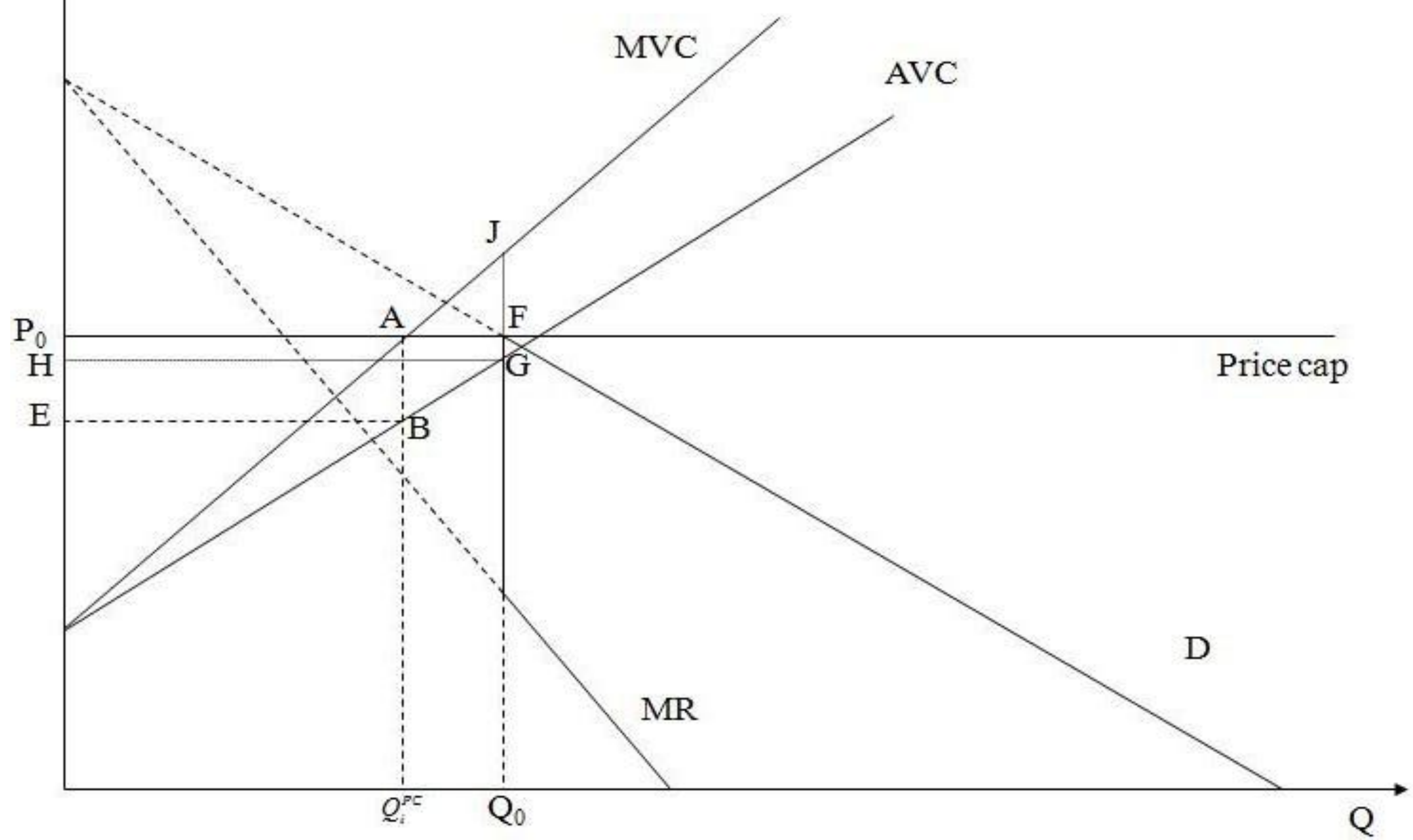


Diagram 3.5b

Introducing the obligation to meet the market demand. The supplier should supply quantity $Q_{0,}$ as that is the quantity demanded for price P_0. Supplier makes profits.



Next, we introduce the obligation to meet the market. Diagrams 3.3a and 3.3b would remain unaffected in the presence of such an obligation. Diagram 3.3c turns into Diagram 3.5a and instead of profits equal to rectangle $ABEP_0$, the monopolist makes losses equal to rectangle $FGHP_0$. The reduction in profit that results from the imposition of this obligation is equal to the triangle AJF that is formed by the MVC and MR curves and it represents the negative profits (MVC-MR) which incurs as the quantity supplied increases from Q_i^{PC} to Q_0.

While profits are always reduced by the introduction of the obligation when price cap is lower than the competitive price, this does not mean that profits always become negative. The imposition of the obligation reduces profits by an amount equal to AJF in Diagram 3.5a, and if initial profits are greater than that amount, then profits under the obligation will be positive. That can be seen on Diagram 3.5b which is similar to 3.5a but with different AVC curve. In this case, initial profits $ABEP_0$ are reduced by AJF, but that is not enough to turn them into losses, so we have diminished profits $FGHP_0$.

Although Diagrams 3.5a and 3.5b only differed in their AVC curves, we can see that when combining this specific price cap, which is lower than the competitive market price, and a obligation to meet the market, we had losses in Diagram 3.5a and profits in Diagram 3.5b. The important difference is the relationship between the price cap P_0 and price P_A, which is the price where AVC and Demand curves intersect (shown in diagram 3.3c). Price P_A can be seen on Diagram 3.6a and for price cap $PC_i = P_0 = P_A$, and with an obligation for the supplier to meet the market demand, we get zero profits. With an obligation to meet the market demand imposed on the supplier, when $PC_i = P_0 \rangle P_A$ we have profits and when $PC_i = P_0 \langle P_A$ we have losses.

In Diagrams 3.6a, 3.6b, 3.6c and 3.6d we can see how different price caps relate to profits π_i. We consider fixed costs to be sunk cost and therefore not used in the construction of the diagrams, although these are an important consideration for new entrants if they need to built capacity. Despite fixed costs needing to be covered as well, these diagrams will be more useful for decision making purposes (regarding the setting of the price cap) if they help consider the relationship solely between variable measures.

In this case, we discussed the introduction of price caps and the imposition of an obligation to serve the market demand in markets of different sizes that do not coexist in the same time and the cost of each is disconnected from what happens in the other. The issues discussed in this simplified case become more complex when we consider a situation with a number of markets that have different price caps and different Demand/Marginal Revenue curves and operate in the same time, therefore the quantity supplied in each of the markets results in increased cost in the rest of the markets, regardless of the quantity supplied in them.

Diagram 3.6a

Relationship between profits and price cap. This is the case where we have a price cap and there is no obligation to meet the market demand.

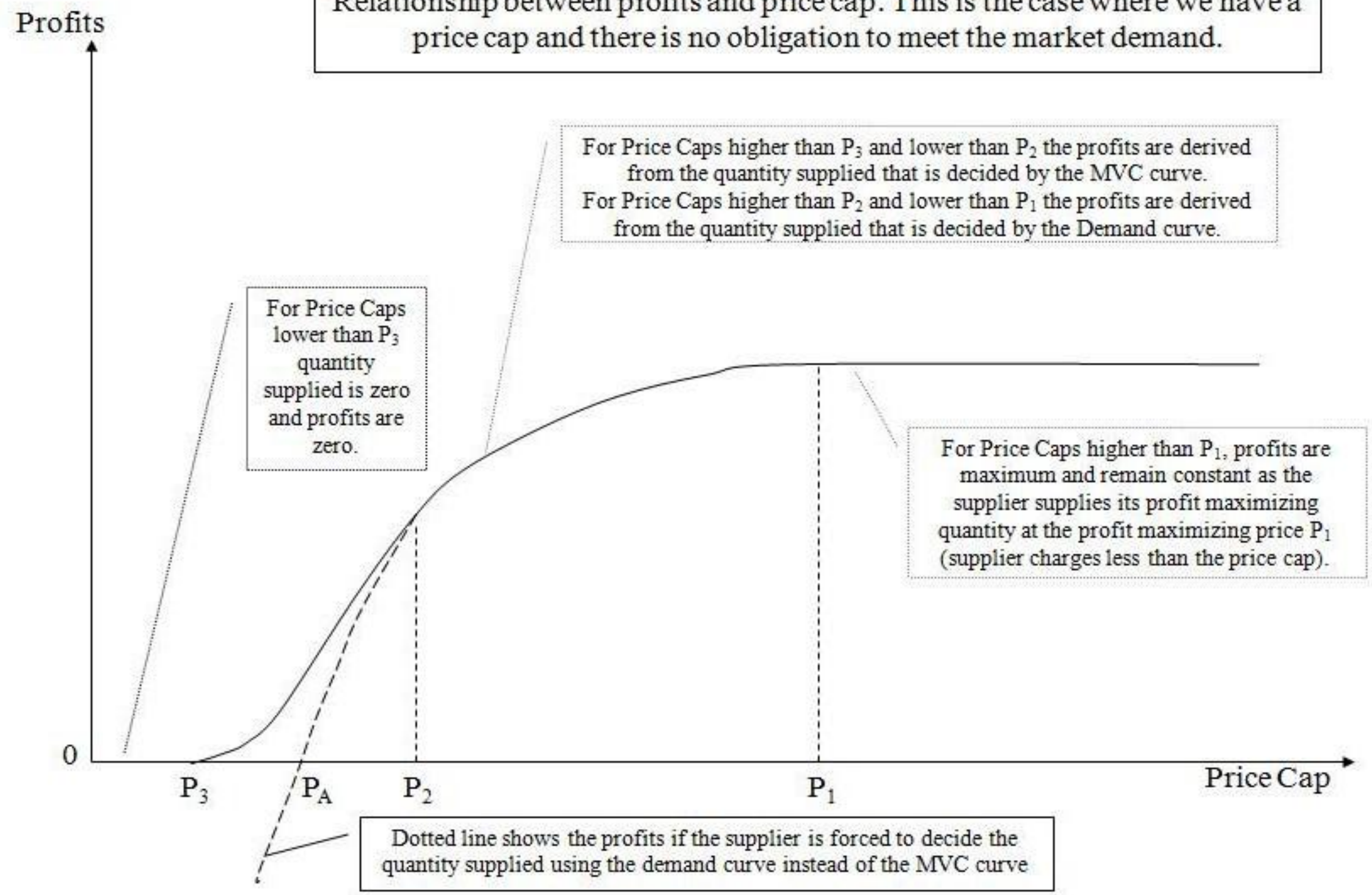


Diagram 3.6b

Relationship between profits and price cap. This is the case where we have a price cap and there is an obligation to meet the market demand.

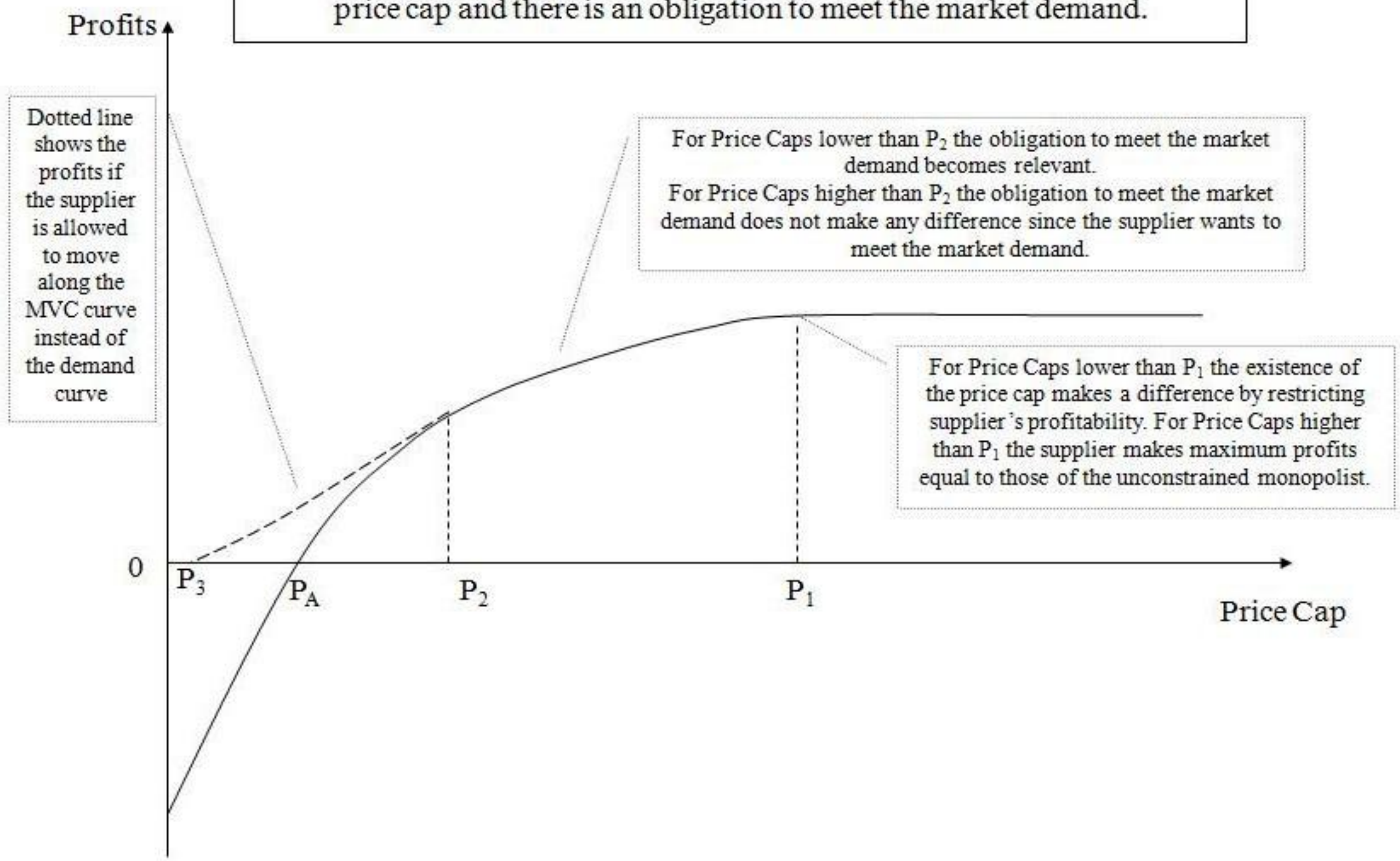


Diagram 3.6c

Relationship between profits and level of tariffs. This is the case where we have an imposed tariff and there is no obligation to meet the market demand.

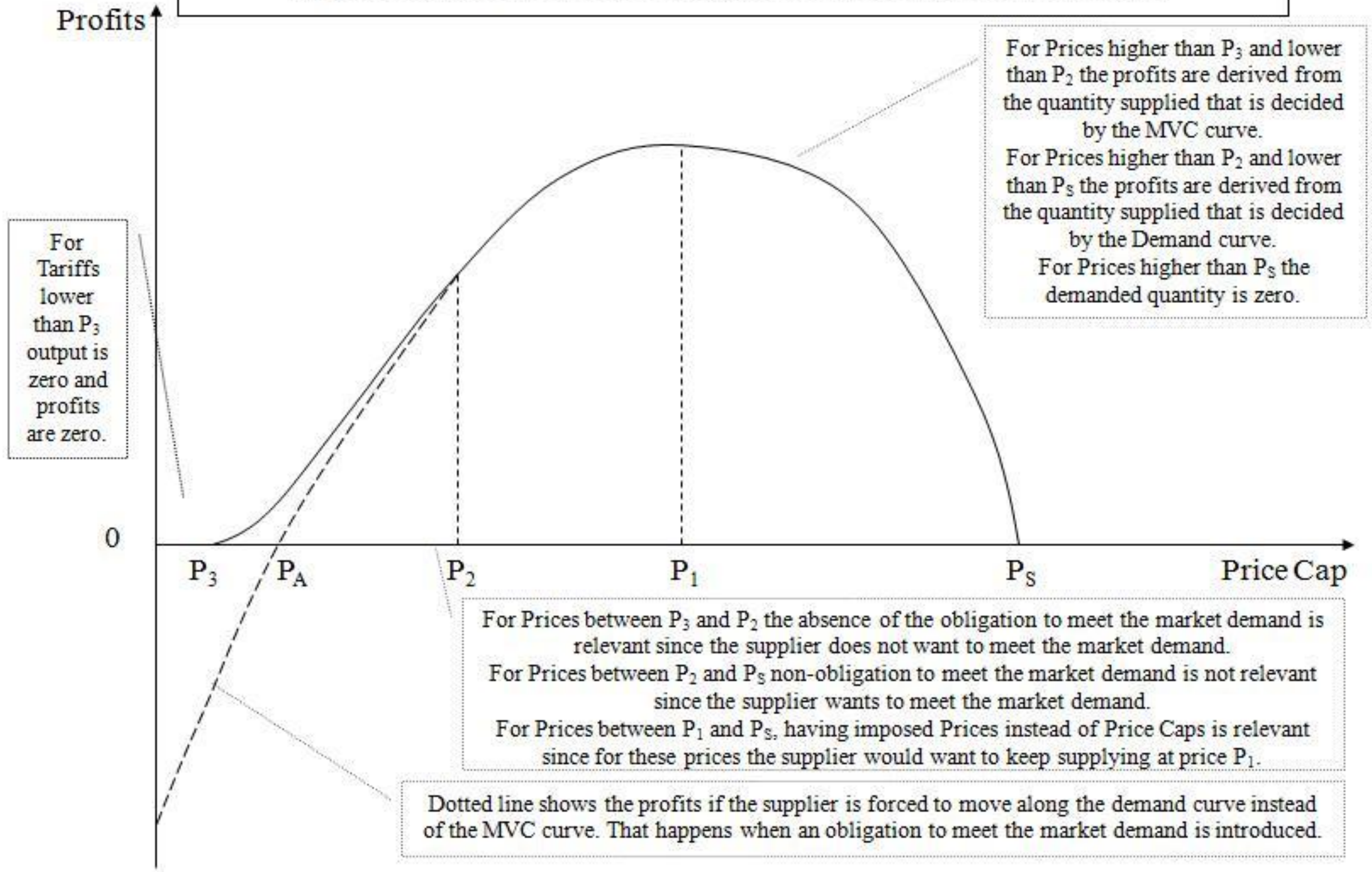
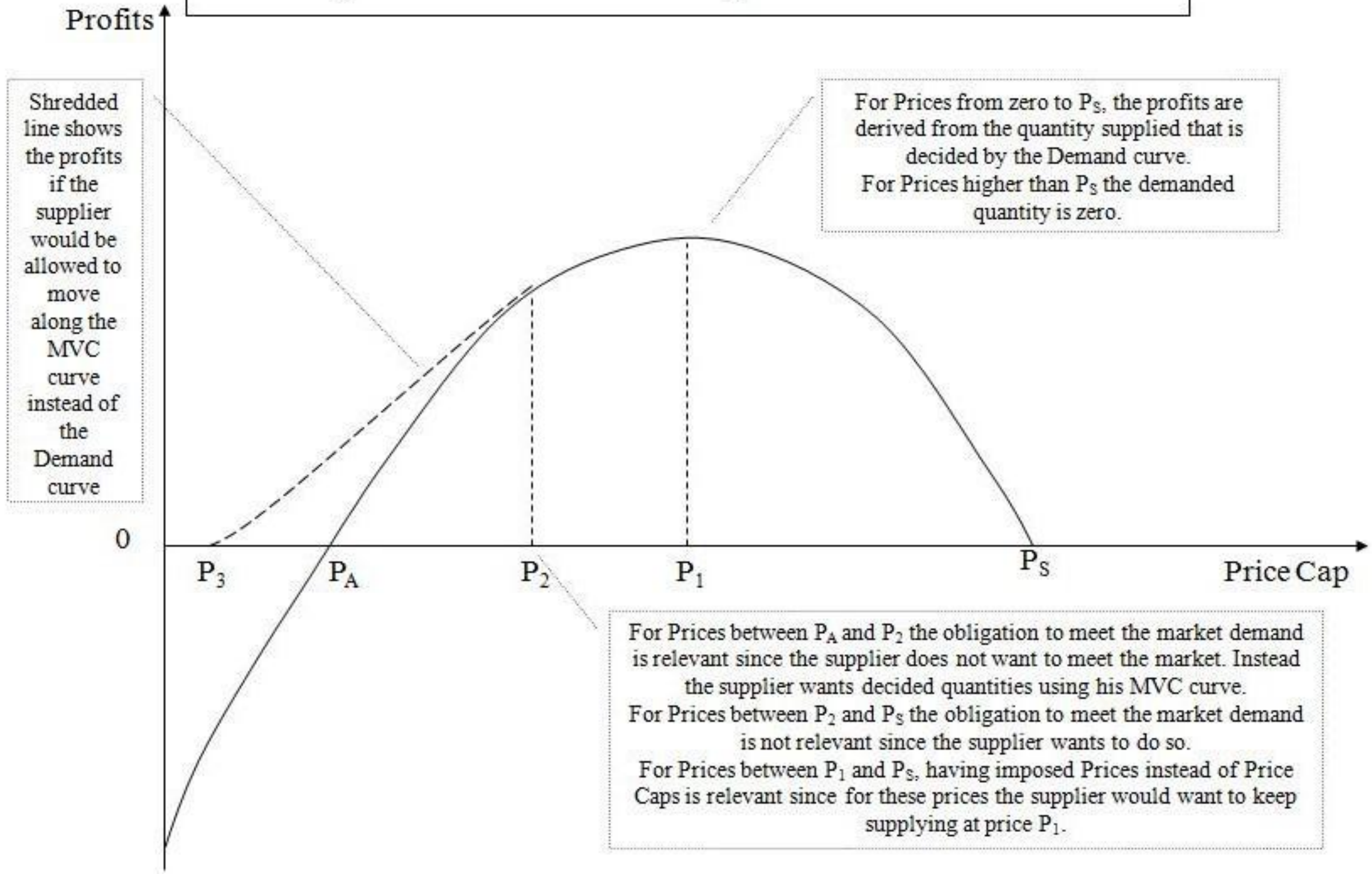


Diagram 3.6d

Relationship between profits and level of tariffs. This is the case where we have an imposed tariff and there is an obligation to meet the market demand.



3.3.2 New entrants considering entry in the market

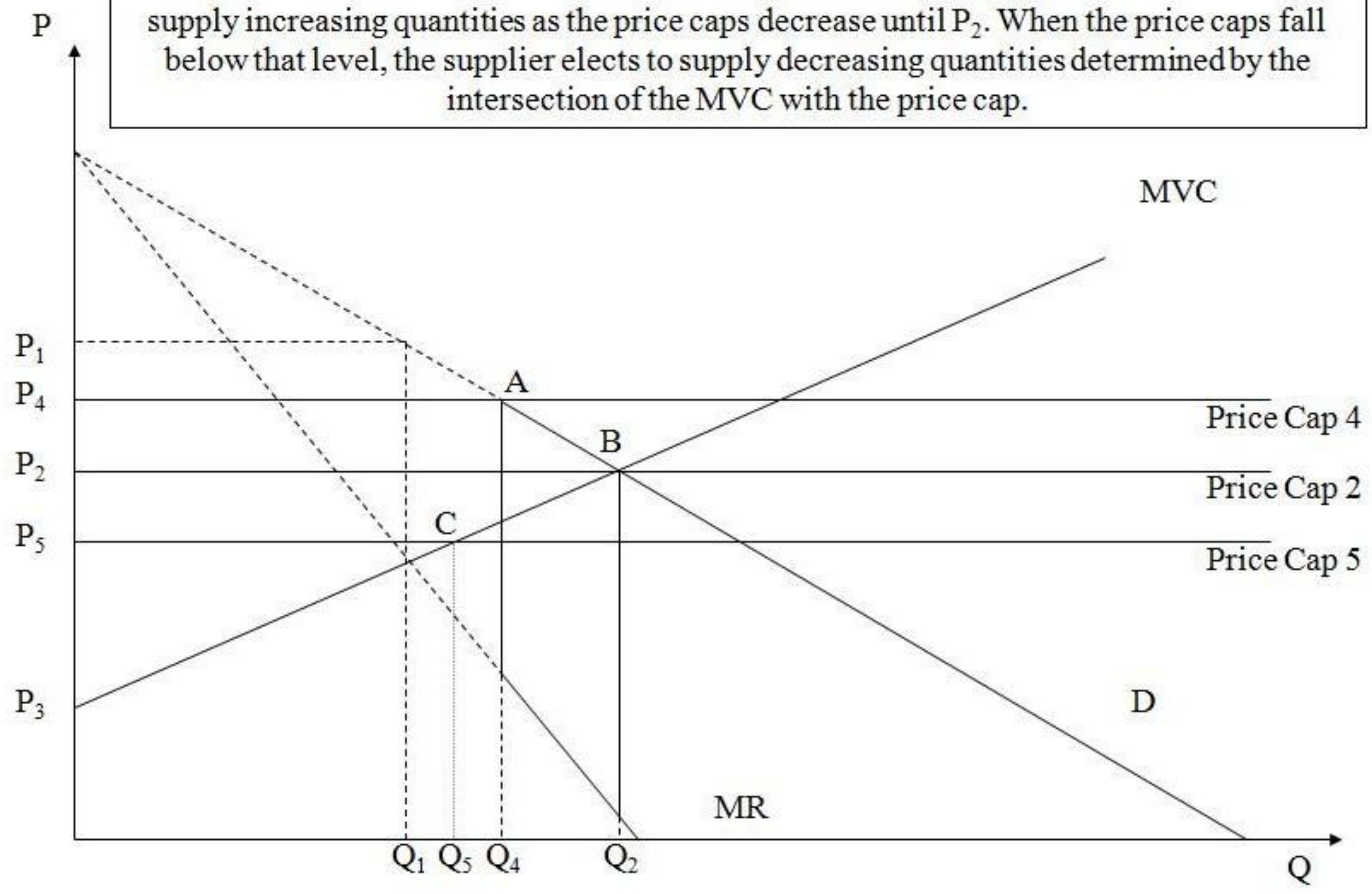
The discussion up to now was with reference to the incumbent. However, if we examine the position of potential new entrants, fixed capital costs should be added to the discussion, since before entering the market these are not sunk and are considered in decision making. If the capacity already exists and is sufficient to supply the quantity that the supplier wants to supply, then there is no additional capital expenditures required and all we should consider is the amount $TR - TVC$ in order to decide on entry. Fixed cost allocation and planning for cost recovery is an important issue when we have to calculate and build the optimal supply capacity in order to be able to enter markets. Also, in the notion that was discussed by Tirole [1988, page 255], available capacity is a matter of strategic importance.

When a new entrant enters the supply market, this new supplier has the option of entering as many markets/tariff categories as he wants. The new complexity in that case is that this new entrant is expected to only choose the markets/tariff categories that will be profitable after the fixed cost allocation.

We will examine the profitability of the markets where potential entry might occur without considering any implications stemming from competition, as we will only be considering the market to be supplied from only one supplier.

Diagram 3.7

Three Price Caps. Without obligation to meet the market, the supplier will choose to supply increasing quantities as the price caps decrease until P_2. When the price caps fall below that level, the supplier elects to supply decreasing quantities determined by the intersection of the MVC with the price cap.



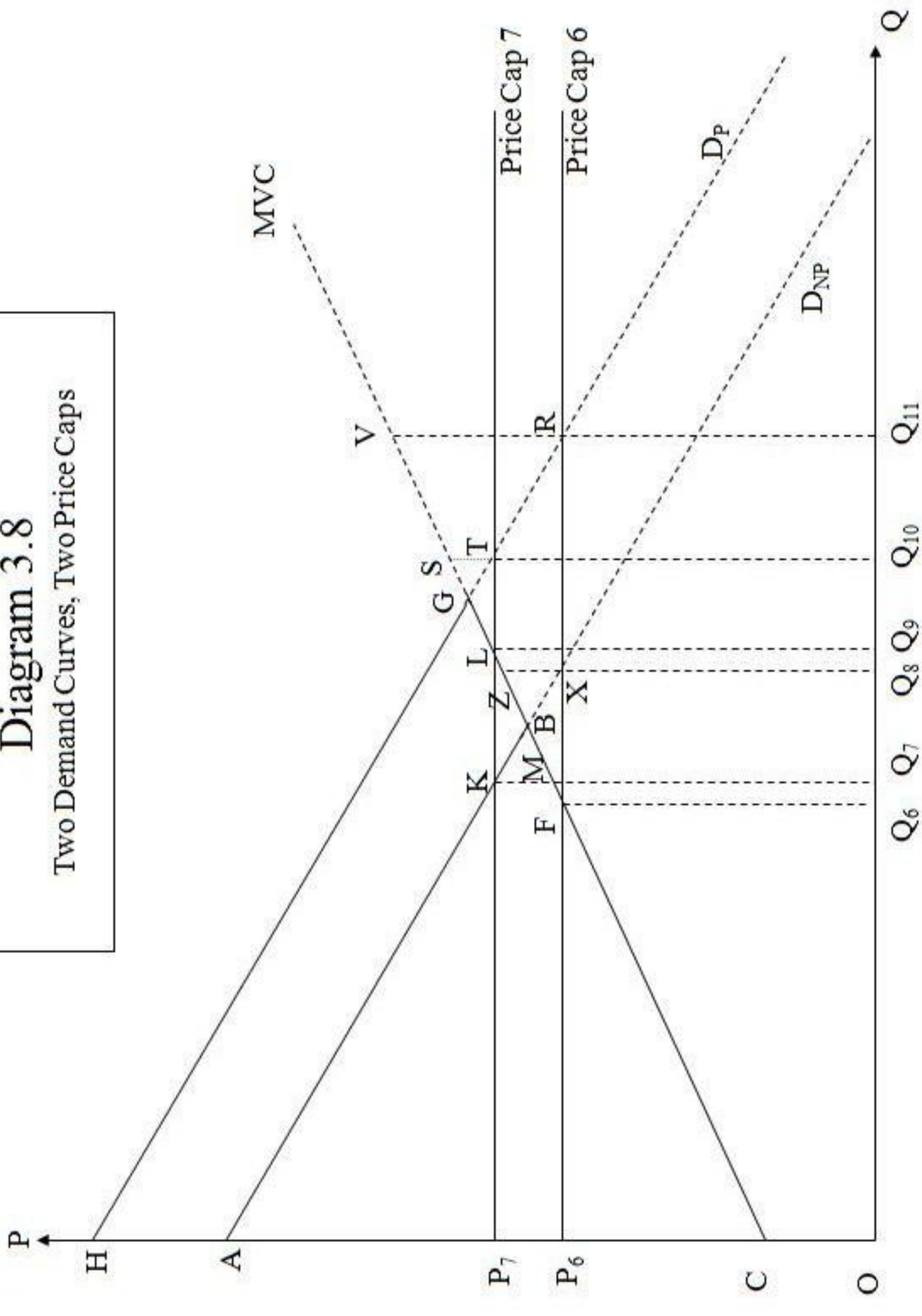


Diagram 3.8
Two Demand Curves, Two Price Caps

3.4 The relationship between profits and regulatory constraints

There are three cases relating to the relationship between profits and regulatory constraints in the markets. In order to make this discussion simpler, we will consider the case of the linear demand function $P_i = b_0^i - b_1^i Q_i$ (5). We assume b_1^i is the same for all demand curves, varying only b_0^i. The three cases are:

1. where there are no constraints imposed in the market.
2. where there is a price cap imposed but no obligation to meet the market demand.
3. where there is a price cap imposed and an obligation to meet the market demand as well.

For case 1, we can see from Diagram 3.2, that with no constraints imposed, it will always be the case that profits will be larger in a market with a larger market demand. The supplier has no constraints and can fully use the larger potential of the larger market demand.

For case 2, we can see from Diagram 3.4, that in the presence of a price cap, profits in a market with a larger market demand will always be larger than or equal to the profits in a market with smaller market demand. That would be the case since the supplier would try to use the full potential of the larger market demand to the extent that this would be possible, given the presence of the price cap.

For case 3, which can be seen in Diagram 3.8, in the presence of a price cap and of an obligation to meet the market demand, when the price cap is set at low levels, then the smaller market demand can have higher profitability than the larger market demand. That is related to the fact that a low market price cap would result in a high market quantity demanded. And the obligation to meet the market would force the supplier supply the quantity that the market demands, no matter what that would mean to his profitability. With a larger market demand, the output that the supplier would be forced to supply would be higher. For any given price cap that is set at a level that is below the price level where D=MVC, the supplier will make less profits in the larger market than he will make in the smaller market. The higher the price cap levels, the less amount of restriction is imposed on the supplier with regard to his effort to maximize his profits.

3.5 Four Cases for the level of the Price cap

From inspection of Diagram 3.7, we can see that there are four cases of interest in analysing the Price Cap. The first two cases can also be seen in Diagram 3.3a.

1. $PC_i \geq P_1$

In this case, the price cap has no effect since the supplier is allowed to supply its profit maximizing quantity Q_1 at its profit maximizing price P_1.

2. $P_1 \rangle PC_i \geq P_2$

In this case, price is set by the supplier equal to the price cap $P_i = PC_i$ and the quantity is determined by the demand curve. This quantity is $Q_i = b_0^i - b_1^i PC_i$. The supplier will choose to meet the whole market demand at each price cap within this range. Price cap $PC_i = P_2$ is the lowest price cap for which the supplier wants to fully meet the market demand and maximise profits in the same time (this refers to profit maximisation under constraints). So, by setting the price cap at that level, the regulator puts the supplier in a situation where no obligation to meet the market demand is needed. Also in that situation the supplier wants to supply output that is larger than he would want to in any other case.

3. $P_2 \rangle PC_i \rangle P_3$

In this case, if there is no obligation to meet the market, the supplier sets the price equal to the price cap $P_i = PC_i$ and the quantity is determined by the intersection of the horizontal MR curve (MR is horizontal at the level of the price cap until the point where it meets the market demand curve and kinks at that point) and the MVC curve. So, for the given range of prices for the price cap, the quantity that the supplier wants to supply is determined by the point of intersection of the price cap and the MVC curve.

This is the case where the obligation to meet the market becomes relevant. For the price caps that we are discussing, the supplier wants to supply the output that corresponds to $MVC = MR = PC_i$ and that output decreases as the price cap is lowered. At the same time, as the prices gets lower, the output demanded by the market increases and the supplier is not willing to fully meet the market demand unless an obligation forces him to do so. If that obligation is introduced into the market, it would have an impact as the supplier would be supplying more than he would want to. So, without the obligation, it is the MVC curve that determines the output that the supplier will supply, and with the obligation it is the damand curve.

4. $P_3 \geq PC_i$

In this case, the supplier does not want to supply any quantity to the market. The price cap is set lower than the MVC curve for all quantities. An obligation to meet the market demand would also be relevant in this case, as it would force the supplier to remain in the market and meet the market demand at unfavourable terms. In the same time, the market will be supplied in prices that do not reflect market rationing.

3.6 Diagrammatical presentation of Profit maximising quantities at different Price Caps and the Obligation to meet the market demand

It is interesting to note what are the profit maximising quantities for the supplier as the regulator sets the price cap to different levels. As we have presented in Section 3.5, from inspection of Diagram 3.7, we can see that any price cap above price P_1 will not affect the price and the quantity that the supplier will want to supply. When the price cap is set above P_1 the supplier meets the market and profit maximizes at the same time by supplying Q_1 for P_1 so any price cap higher than that will leave the supplier unaffected.

Also in Diagram 3.7, we can see that as long as the price cap is being lowered below P_1, the decrease in the price cap results in an increase in the quantity that the supplier wants to supply to the market, as this quantity grows from Q_1 to Q_2. This increase occurs until the point where $PC_i = P_2$ (price corresponding to the point where MVC curve and Demand curve intersect) and the quantity that the supplier wants to supply is Q_2. The supplier wants to supply more as he takes advantage of the opportunities that are present in the market. By saying that, we refer to the difference between the price level and the MVC curve for that range of prices and quantities.

In Diagram 3.7 when the price cap gets lower than P_2 the supplier wants to supply less. That is due to the fact that the supplier chooses its outcome using $MVC=MR=PC_i$ as a criterion. As the price cap lowers, MR lowers and its interception with MVC moves to the left. The supplier is only willing to supply the quantities for which MR is larger than MVC.

In Diagram 3.7 again, when the price cap is set at P_4 the supplier's profit maximising output is Q_4. When price cap lowers to P_2, the profit maximising quantity (in the presence of the price cap) increases from Q_4 to Q_2. After that point, as price cap keeps lowering below P_2, the quantity that the supplier chooses to supply decreases following the MR and MVC curves intersection that moves to the left. So, when price cap is set at P_5 the supplier chooses to supply Q_5.

In Diagram 3.8, we can see the willingness of the supplier to supply different quantities under different price caps. For demand curve D_{NP}, the quantity that the supplier will want to supply will be determined by the point where the price cap intersects the line ABCO. For demand curve D_P, the quantity that the supplier will want to supply will be determined by the point where the price cap intersects the line HGCO.

In Diagram 3.8, when the price cap is set at P_6, facing either demand curve D_{NP} or D_P the supplier wants to supply quantity Q_6. If there was an obligation for the supplier to meet the market demand, the quantities that the supplier would be obliged to supply would be Q_8 for D_{NP} and Q_{11} for D_P. We can see that for a price cap that intercepts the line BC, under both demand curves, the supplier does not want to meet the market. If the supplier is forced to do so, that would mean that output should extend and as a result the supplier will make less than the maximum profits of the constrained case. We can see that for demand D_{NP} the supplier will be forced to supply an additional output $Q_8 - Q_6$ and for demand D_P, an additional output $Q_{11} - Q_6$. From the diagram we can see that $Q_8 - Q_6 \langle Q_{11} - Q_6$. So we conclude that for demand D_{NP}, output is extended by a smaller quantity than it is under D_P. Also, in that case, profits will be larger for demand D_{NP} than for demand D_P. That is because profits when facing demand D_{NP} are equal to triangle CFP_6 minus triangle FZX whereas profits when facing demand D_P are equal to triangle CFP_6 minus triangle FVR and we have $FVR \rangle FZX$ because FZX is smaller than and fully part of FVR.

So we can see that in the case of Diagram 3.8, with the price cap set at P_6, the smaller market (the one facing demand D_{NP}) is more profitable than the larger market (the one facing demand D_P). That contradicts what we have found in the comparative statics earlier and demonstrates how the regulatory imposition of a price cap and of an obligation to meet the market demand is changing the profitability of markets and might make smaller markets more attractive than others.

In Diagram 3.8 again, when the price cap is set at P_7, when facing demand curve D_{NP} the supplier wants to supply quantity Q_7, meeting the market demand. When facing demand curve D_P the supplier wants to supply quantity Q_9 not meeting the market demand. If there was an obligation for the supplier to meet the market demand D_P, the quantity that the supplier should supply would be Q_{10}. We can see that for a price cap that intercepts the line GB, the supplier will want to meet the market only when facing demand D_{NP}. When facing demand D_P, the supplier does not want to meet the market and if he is forced to do so, he will supply an output greater than the profit-maximizing output of the constrained case and as a result he will make less than the maximum profits of the constrained case.

Another interesting point in the above case is that under price cap P_7, when demand shifts from D_{NP} to D_P the supplier wants to switch from Q_7 that he was supplying to Q_9 but no further than that. That happens because as the quantity supplied increases up to Q_9 we have the case that $MR \rangle MVC$ as we can see from the diagram. For quantities higher than Q_9 the supplier has a lower marginal revenue than marginal cost since MVC is above the price cap (MR is equal to the price cap for the quantity from Q_7 to Q_9). So, triangle KLM represents the benefit that the supplier gets from the fact that there is a larger market demand in D_P. Triangle LST represents the loss that the supplier incurs when he is forced to meet the market under demand D_P and price cap P_7. An interesting point here is that when comparing triangles LST and KLM, we get to conclude that if $LST \rangle KLM$, then the obligation to meet the market demand ends up making the market less profitable when facing demand D_P than it is when facing demand D_{NP}. What can be seen on the diagram is that the higher the position of the demand curve D_P, the bigger the size of triangle LST will be, whereas triangle KLM will remain the same. So, for the case where we have parallel demand curves (meaning we would have $b_1^1 = b_1^2$), as far as D_P intercepts P_7 at any point to the right of point L, then the higher the b_0^2, the lesser the profitability when facing demand D_P is going to be.

Although without the obligation to meet the market demand, the market under demand D_P is always more than or equally profitable as the market under demand D_{NP}, the introduction of the obligation to meet the market demand will only allow the market under demand D_P to be more profitable if the price cap is set above the point that corresponds to having KLM=LST.

3.7 Diagrams 3.6a-3.6d

In Diagram 3.6a, where we have a market without an obligation for its supplier to meet the market demand, the supplier no matter how low the price cap is set, cannot incur losses, since the supplier chooses its own output. As a result the supplier cannot be forced to supply any quantity for which it will be that $MR\langle MVC$. $P_1 = P_i^*$ is the profit maximizing price of the unconstrained case and if we have $PC_i \geq P_1$, then the supplier chooses price P_1 and makes the maximum profits of the unconstrained case. For $P_1 \rangle PC_i \geq P_2$, the supplier chooses to set his price equal to PC_i and makes the maximum profits of the constrained case (given the presence of the price cap). These profits (as well as the output) are determined by the demand curve as shown on Diagram 3.7. For $P_2 \rangle PC_i \rangle P_3$, the supplier chooses to set his price equal to PC_i and makes maximum profits given the presence of the price cap. These maximum profits (as well as the output) are determined by the MVC curve as shown in Diagrams 3.7 and 3.8. For $PC_i \leq P_3$, the supplier chooses not to supply any quantity.

In Diagram 3.6b, we have a market with a price cap and also the obligation for the supplier to meet the market demand. That means that the supplier can have situations where losses are made. Diagrams 3.6a and 3.6b are identical for price caps that satisfy the condition $PC_i \geq P_2$, as it is only for prices under P_2 that the supplier does not want to meet the market demand. For $PC_i \langle P_2$, the profits are determined by the relationship between the AVC curve and the demand curve (which has to be fully met due to the obligation). That is so because the quantities supplied in the market are determined by the market demand and not by the willingness of the supplier, as was the case in Diagram 3.6a (where quantities supplied for these price caps were determined from the MVC curve). As we can see in Diagram 3.1, the price P_A is the price where AVC equals demand. As a result, if the price cap is set at $PC_i = P_A$ and there is an obligation to meet the market demand, that means that the quantity supplied will be the quantity that makes profits drop to zero. For $PC_i \langle P_A$, we have losses as the supplier's prices are lower its the corresponding AVCs and we can see on Diagram 3.6b that profitability becomes negative.

In Diagram 3.6c, we have the case where the price cap is not just a cap, but an imposed tariff that has to be met. For price caps $P_2 \geq PC_i \geq P_3$, profits are derived from the quantities supplied that are decided by the MVC curve, as the supplier chooses to supply the quantity that is given by the intersection of MVC and the price cap (which is also the MR curve). Diagrams 3.6b and 3.6c are identical for price caps that satisfy the condition $P_1 \geq PC_i \geq P_2$, as within this range the supplier wants to meet the demand supplying at a price equal to the price cap. For price caps $P_S \rangle PC_i \rangle P_1$, because of the fact that the supplier is obliged to set his price equal to PC_i, profits begin to shrink as the retail price increases until we get to the point where $PC_i = P_S$ when the supplier supplies zero output and therefore makes zero profits. That is also the case for any mandatory price cap that satisfies the condition $PC_i \rangle P_S$. We can see when examining imposed tariffs in the range $P_S \rangle PC_i \rangle P_1$ how it is that an imposed tariff can put a supplier in a difficult position when the supplier would like to decrease the price but has no control over it.

In Diagram 3.6d, we have again the case where the price cap is a mandatory tariff. Diagrams 3.6c and 3.6d are identical for price caps that satisfy the condition $P_S \geq PC_i \geq P_2$. In diagram 3.6d, for $PC_i \langle P_2$, the obligation to meet the market demand becomes relevant exactly as it happened in Diagram 3.6b.

An important observation is that Diagrams 3.6b and 3.6d, which incorporate obligations to meet the market demand, are the only ones where the supplier might get losses and that is in both cases, when the price cap is set at $PC_i \langle P_A$. P_A is the price that when applied as a price cap coupled with an obligation to meet the market demand, there are no profits at all. For example, in Diagram 3.8, if we are under price cap P_6 and there is an obligation to meet the market demand and we also have FCP_6=FVR, then $P_A = P_6$.

3.8 A discussion of the determination of supply capacity

3.8.1 Capacity allocation in markets that do not coexist in the same time (Peak Load and Non-Peak Load markets)

This discussion is carried out under the assumption that the higher the demand that a supplier faces, the larger the supply capacity that this supplier should built. Should we want to allocate fixed costs in these markets, we could allocate the whole amount of fixed costs of the supplier to the market that faces the larger demand, and which calls for higher quantities to be supplied. In that case the whole cost of building supply capacity will be allocated to the market that uses the full amount of that capacity.

Although a percentage of the supplier's capacity would be used solely in order for the supplier to be able to supply the peak-load demand, which is only to be found in the larger market, it is also true that a large part of the capacity is associated with the non-peak load market as it is used in order to serve that market as well. That capacity is equal to[2]:

$$Capacity = \max(Q_1, Q_2) \qquad \text{(C63)}$$

Since the two markets do not co-exist in the same time, we assume that the supply capacity needed would be equal to the largest of the two capacities. The allocation of the fixed cost relevant to this capacity being built should be distributed across these two markets in order for it to be recovered through its usage. There are many approaches to this:

- Allocate all capacity cost to peak load market, based on the idea that this capacity would be necessary for this market to be supplied anyway. However, doing so would lead to false understanding of the market's profit-making potential and could make the other markets appear more profitable than they actually are.

[2] We use the following convention: the equation number C63 represents equation 63 in Appendix C.

- Allocate to the non-peak load market all of the cost of the capacity that it needs and then allocate the remaining cost to the peak load market. That reflects the idea that the capacity necessary for the non-peak load market needs to be built and then if the supplier decides to enter the peak load market, additional capacity is built specifically for it.
- Allocate the cost between the two markets evenly or by some arbitrarily chosen allocation percentage.
- Allocate it according to its usage rate using allocation keys such as: total amount of electricity supplied, total amount of customers, hours of market operation per day, revenue from the market, profits made in the market.

The key point here is that as capacity is being built, fixed cost is incurred and it has to be recovered, affecting profitability. In order for the profits to be accurately determined, we need to choose the appropriate method of fixed cost allocation that will assist the supplier in decision making. Discussing fixed cost and capacity building is only useful to the supplier when determining optimal capacity. When the capacity is already built, fixed costs are sunk and therefore should not be considered when making decisions.

If the firm decides to operate in more than one market, then the decision on the capacity should be made by considering the maximization of joint profit of both markets. Under the same rationale, if the supplier decides to operate in only one market, then the fixed costs for capacity should be covered by the income from that market only.

3.8.2 *n* markets

For the supplier that supplies *n* markets, the total profits (from both markets combined) will be:

$$\pi_n = \sum_{i=1}^{n} TR_i - \sum_{i=1}^{n} TVC_i - TFC \qquad \text{(C64)}$$

By TFC we refer to the total fixed cost of a specific period of market operation.

In order for the supplier to be able to calculate the additional profits generated by the participation in the peak-hour market, the supplier should calculate profits for both markets separately and jointly, taking into consideration the amount of fixed costs involved each time. Being in position to calculate the profit potential will allow a rational decision on entry.

To implement this idea, we introduce F_i which is the fixed cost of market *i*. We have $F_n = \sum_{i=1}^{n} F_i$ (C65)

where F_n are the total fixed costs as presented in the above case and $\sum_{i=1}^{n} F_i$ is the sum of the fixed costs for a supplier for participating in all of the *n* markets when these markets co-exist at the same time.

3.8.3 One market

The profits when only participating in market *i* are given by (C13)

$$\pi_i = b_0^i Q_i - b_1^i (Q_i)^2 - [(V_i Q_i + a_0 Q_i + a_1 (Q_i)^2]$$

We adjust it by incorporating fixed cost and it becomes:

$$\pi_i = (b_0^i Q_i - b_1^i (Q_i)^2) - [(F_i + V_i Q_i + a_0 Q_i + a_1 (Q_i)^2)] \qquad \text{(C66)}$$

3.8.4 From one market to two markets

For a supplier in an unrestricted market, the choice to enter only one of the two markets would be to enter the large one, since more revenue would be generated there. If this supplier has the capacity to serve that large market, and given that the two markets do not co-exist in the same time, then he can examine whether he can also supply the small market. We consider that the supplier will supply its profit maximising quantity Q_P^* in the large market (notation P is used for peak load). If the profit maximising quantity Q_{NP}^* in the small market (notation NP is used for non-peak load) satisfies the condition $Q_{NP}^* \langle Q_P^*$, then the supplier can also enter the small market without any need for additional capacity to be added.

If $Q_{NP}^* \rangle Q_P^*$, then there is a need for increase in capacity in order to reach the level where the supplier makes maximum profits is the small market. As we have seen already (equations (C16) and (C43)), the profit maximising quantity in each market is related to the retail price in each market.

If capacity is very expensive to build and the supplier is capacity constrained, what he can do when entering the small market is to set the quantities in both markets as $Q_{NP}^* = Q_P^*$. In that way the supplier will not have any unused capacity in any one of the two markets.

Another way to see the above issue is to determine the optimal capacity that the supplier should have by comparing the net marginal revenue that the supplier has by increasing capacity, with the marginal cost that the supplier incurs due to that increased capacity.

3.9 Simulation of our model

In this part, we will be presenting a simulation of the previous market. Using the Microsoft Excel as the software for our simulation, we created some stylized versions of the cases that we discussed earlier. In our simulation, the different curves that we are using we set to be determined by the following forms. In our simulations, we consider the existence of three markets facing different demand curves, with one supplier supplying them under varying regulatory constraints.

3.9.1 Equations

Demand curve:

$$P_i = b_0^i - b_1^i Q_i \qquad \text{(C5)}$$

Total Revenue:

$$TR = P_i Q_i = b_0^i Q_i - b_1^i (Q_i)^2 \qquad \text{(C11)}$$

MR curve:

$$MR = \frac{\partial TR}{\partial Q_i} = b_0^i - 2b_1^i Q_i$$

Average wholesale price of electricity:

$$P_{Ei}^W = a_0 + a_1 Q_i \qquad \text{(C4)}$$

Average variable cost:

$$AVC = a_0 + V_i + a_1 Q_i \qquad \text{(C58)}$$

Total Variable Cost:

$$TVC = V_i Q_i + a_0 Q_i + a_1 (Q_i)^2 \qquad \text{(C20)}$$

Marginal Variable Cost:

$$MVC = \frac{\partial TVC}{\partial Q_i} = a_0 + V_i + 2a_1 Q_i \qquad \text{(C21)}$$

Profits when determined by the demand curve are calculated by (C13):

$$\pi_i = b_0^i Q_i - b_1^i (Q_i)^2 - [(V_i Q_i + a_0 Q_i + a_1 (Q_i)^2] \qquad \text{(C13)}$$

When supplier is setting its output following the MVC curve (and setting $MVC = P_i$ when doing so), output is determined by (21) and is given by:

$$Q_i = \frac{P_i - a_0 - V_i}{2a_1} \qquad \text{(C67)}$$

Profits when determined by the MVC curve are calculated as:

$$\pi_{MVC} = (P_i - AVC)Q_i = (P_i - a_0 - V_i - a_1 Q_i)Q_i \qquad \text{(C68)}$$

Substituting (67) in (68), we get:

$$\pi_{MVC} = (P_i - a_0 - V_i - a_1 \frac{P_i - a_0 - V_i}{2a_1}) \frac{P_i - a_0 - V_i}{2a_1}$$

$$\pi_{MVC} = \frac{(P_i - a_0 - V_i)^2}{4a_1} \qquad \text{(C69)}$$

3.9.2 Diagrams from the simulation

We are taking three cases for demand in our simulations. The three cases for demand curve that appear on Diagrams 3.9, 3.10, 3.11, 3.12a, 3.12b, 3.12c and 3.12d are as follows:

- Demand 1 is demand where we have (b_0^1, b_1^1).
- Demand 2 is demand where we have (b_0^2, b_1^2).
- Demand 3 is demand where we have (b_0^2, b_1^1).

We have used $b_0^1 = 85$, $b_0^2 = 130$, $b_1^1 = 2$ and $b_1^2 = 3$. Therefore, we have $b_0^1 \langle b_0^2$ and $b_1^1 \langle b_1^2$. So the market that faces Demand 1 is smaller than the market that faces Demand 2, because $b_0^1 \langle b_0^2$. The market that faces Demand 2 is smaller than the market that faces Demand 3 because $b_1^1 \langle b_1^2$.

The specific values for b_0^i and b_1^i used in these simulations has no particular significance as these numbers have been selected arbitrarily for illustrative purposes. Qualitatively similar results would have been obtained if, taking a sensitivity analysis point of view, we altered these values whilst maintaining the relationships: $b_0^1 \langle b_0^2$ and $b_1^1 \langle b_1^2$.

The diagrams that we get are:

Diagram 3.9: Shows Demand Curve 1 and Marginal Revenue Curve 1 as well as Average Variable Cost and Marginal Variable Cost curves.

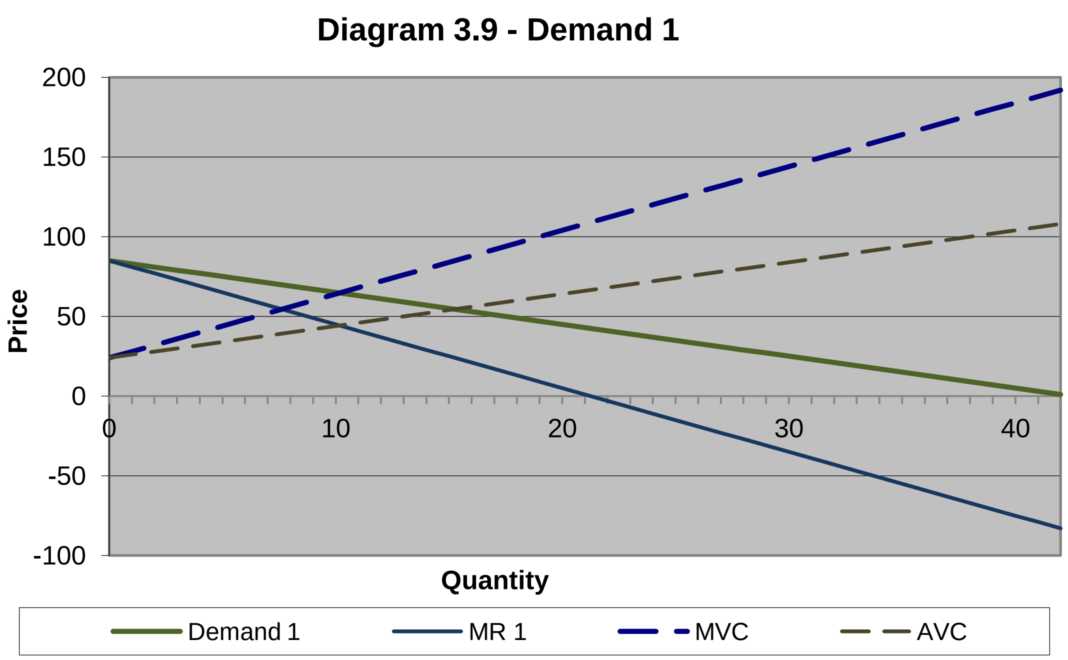


Diagram 3.10: Shows Demand Curve 1, Marginal Revenue Curve 1, Demand Curve 2, Marginal Revenue Curve 2, as well as Average Variable Cost and Marginal Variable Cost curves. As we can see, Demand 2 is larger that Demand 1.

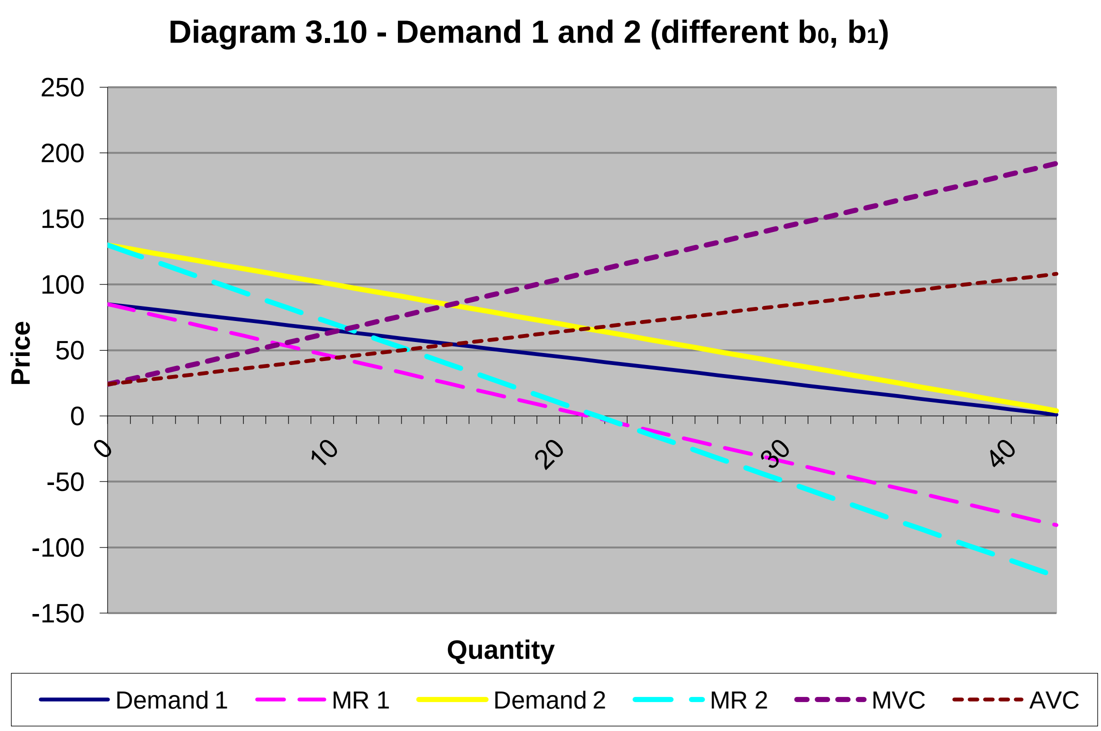
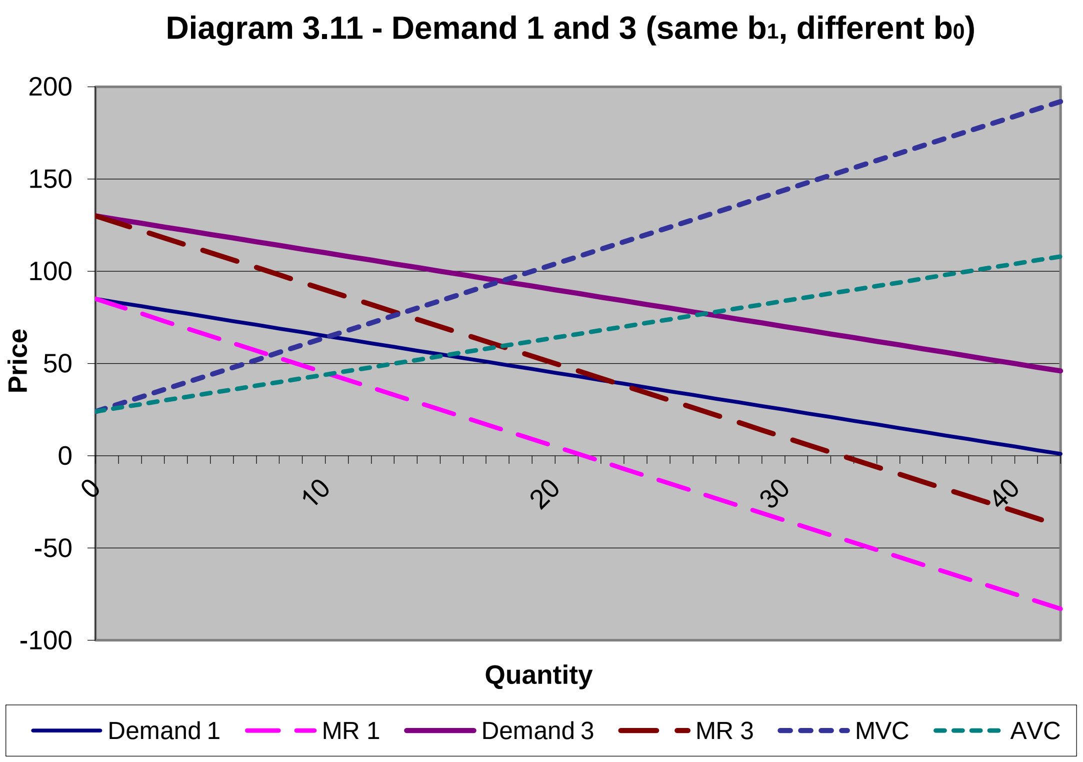


Diagram 3.11: Shows Demand Curve 1, Marginal Revenue Curve 1, Demand Curve 3, Marginal Revenue Curve 3,as well as Average Variable Cost and Marginal Variable Cost curves. As we can see, Demand 3 is larger that Demand 1.



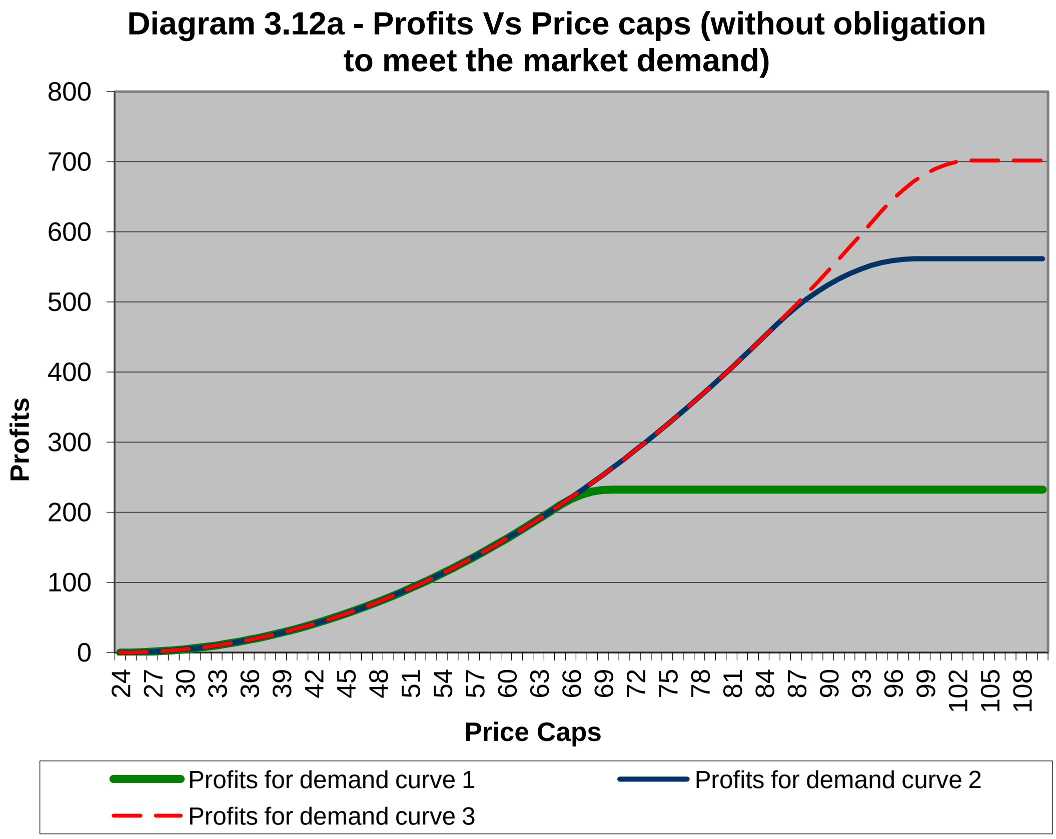
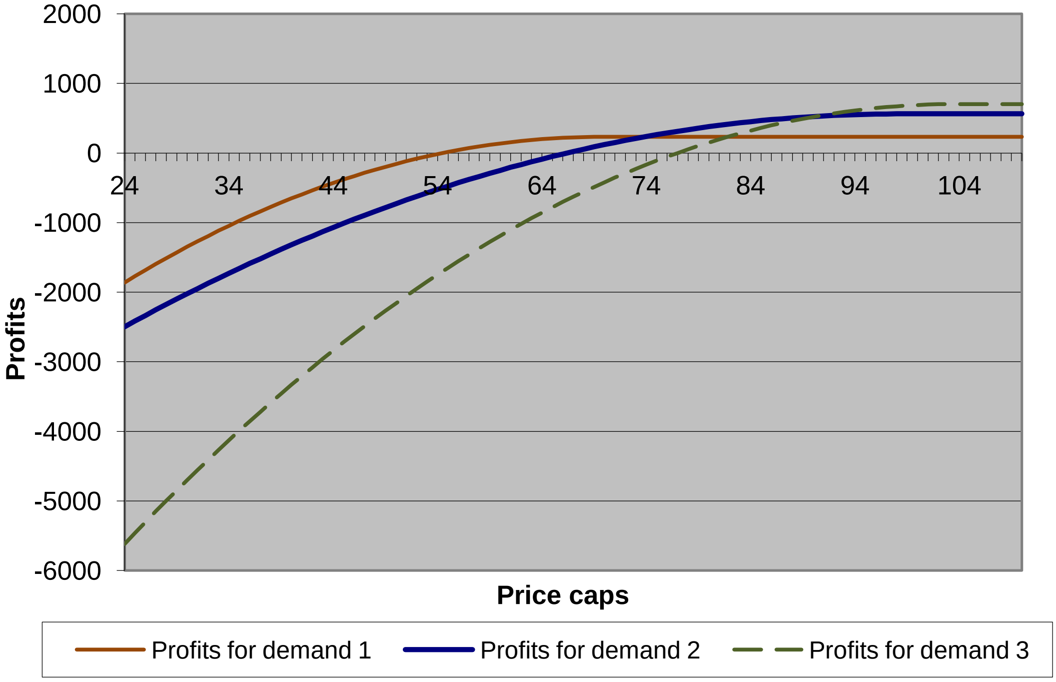


Diagram 3.12a: Shows the profitability of a supplier in a market in relation to the price caps that can be imposed in that market (the price caps are on the horizontal axis). There is no obligation to meet the market demand. This diagram is similar to Diagram 3.6a from the diagrammatic analysis. We observe that for low price caps, all three demand curves present exactly the same profitability. As the price caps increase, the smaller markets reach their maximum profits and cannot make use of the increasing price caps. Profits of Demand curve 1 reach their maximum for price cap=70, whereas the profits of Demand curves 2 and 3 keep increasing. Profits of Demand curve 2 reach their maximum for price cap=98 and for Demand curve 3 for price cap=103. The maximum profits that we refer to are the maximum profits of the unconstrained case, and that is the reason why further cap increases do not affect the supplier's profitability.

Diagram 3.12b: Shows the profitability of a supplier in a market in relation to the price caps that can be imposed in that market (the price caps are on the horizontal axis). There is an obligation to meet the market demand. This diagram is similar to Diagram 3.6b from the diagrammatic analysis. In this diagram it is important to note that for low price caps, the smaller markets are more profitable than the larger ones. We observe that for low price caps, the larger markets incur much larger losses than the smaller markets. However, as the price caps increase, the profitability of the smaller markets increases at lower rates than the profitability of larger markets. The result is that the determination of which market size is the most profitable varies with the level of the price cap that is used in the market. For example, for price caps 55-66, Demand 1 makes profits whereas Demands 2 and 3 make losses. For price cap=78, Demand 2 makes the larger profits than Demand 1 and Demand 1 makes larger profits than Demand 3. For price cap=100, Demand 3 makes the larger profits than Demand 2 and Demand 2 makes larger profits than Demand 1.

Diagram 3.12b - Profits Vs Price caps (with obligation to meet the market demand)



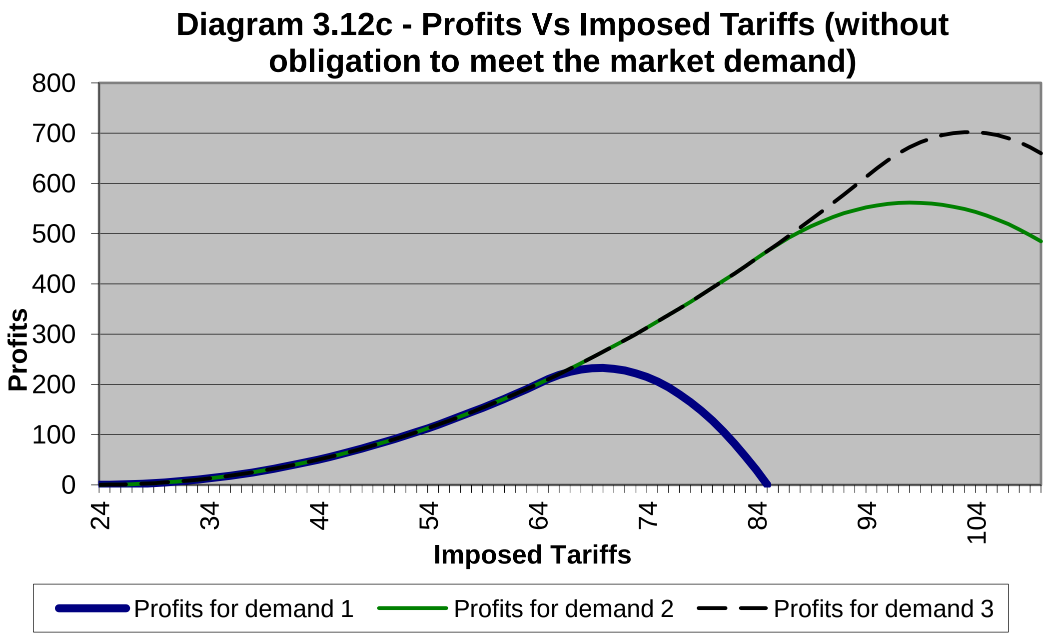


Diagram 3.12c: Shows the profitability of a supplier in a market in relation to the tariffs that can be imposed in that market (the tariffs are on the horizontal axis). There is no obligation to meet the market demand. This diagram is similar to Diagram 3.6c from the diagrammatic analysis. Similarly as the case was with Diagram 3.12a, for low levels of imposed tariffs, we get identical profitability for all three demand curves. However, as the price caps are getting higher, the smaller demand curves reach their maximum profits for lower tariffs than the larger demand curves. The important difference from what we had in Diagram 3.12a is that in Diagram 3.12c, the suppliers cannot keep their prices at the profit maximizing level. Instead, as the imposed tariffs are getting higher, the supplier has to apply these into the market, thus leading to decreases in quantity demanded and shrinking of profits. For tariff=85, the profits under the Demand curve 1 are zero, whereas for price cap=85 in Diagram 3.12a, the profits under Demand curve 1 were 232.5 which is their maximum level of the unconstrained case. This shows that when we have imposed tariffs, the exact level where tariffs are set is very important since it determines the exact level of market quantity and market profitability, and that includes the risk of decreased profits that result when using high tariffs.

Diagram 3.12d: Shows the profitability of a supplier in a market in relation to the tariffs that can be imposed in that market (the tariffs are on the horizontal axis). There is an obligation to meet the market demand. This diagram is similar to Diagram 3.6d from the diagrammatic analysis. This diagram also presents similarities with Diagram 3.12b. For low levels of imposed tariffs, the profitability is identical to the one that we get when using price caps. However, after reaching the tariff level where we get the maximum profits that can be achieved for each demand curve and as we are experiencing increasing retail tariffs, the supplier is not allowed to maintain the profit maximizing tariff, as was the case when using price caps. As higher tariffs are used, the market demand decreases and eventually the profits reach zero. This shows that when we have imposed tariffs, the exact level where tariffs are set is very important since it determines the exact level of market quantity and market profitability, and that includes the risk of decreased profits that result when using high tariffs.

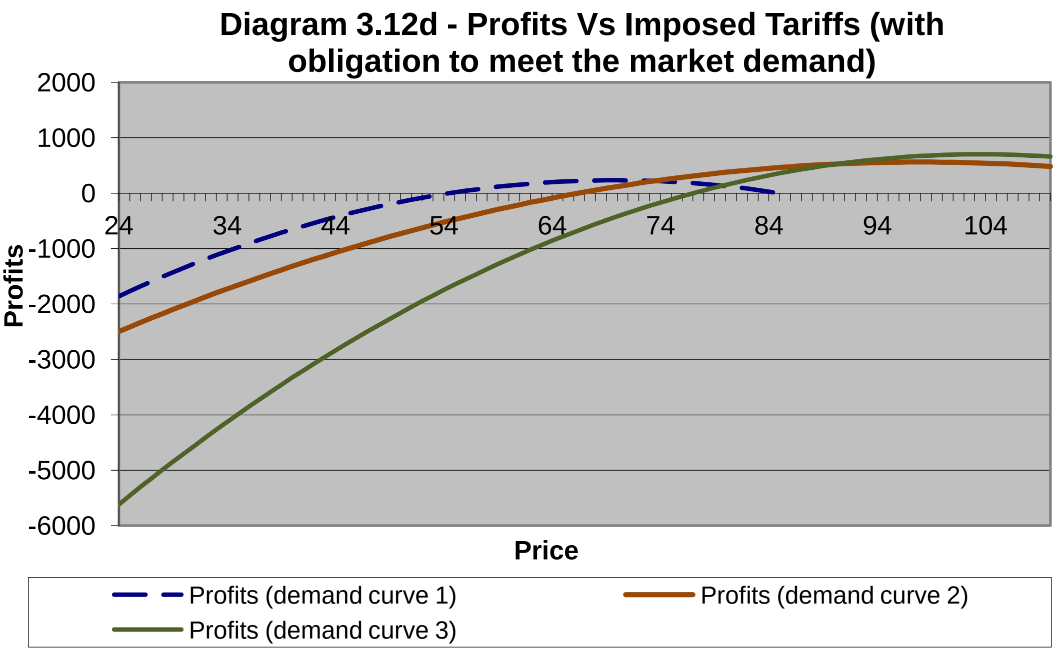
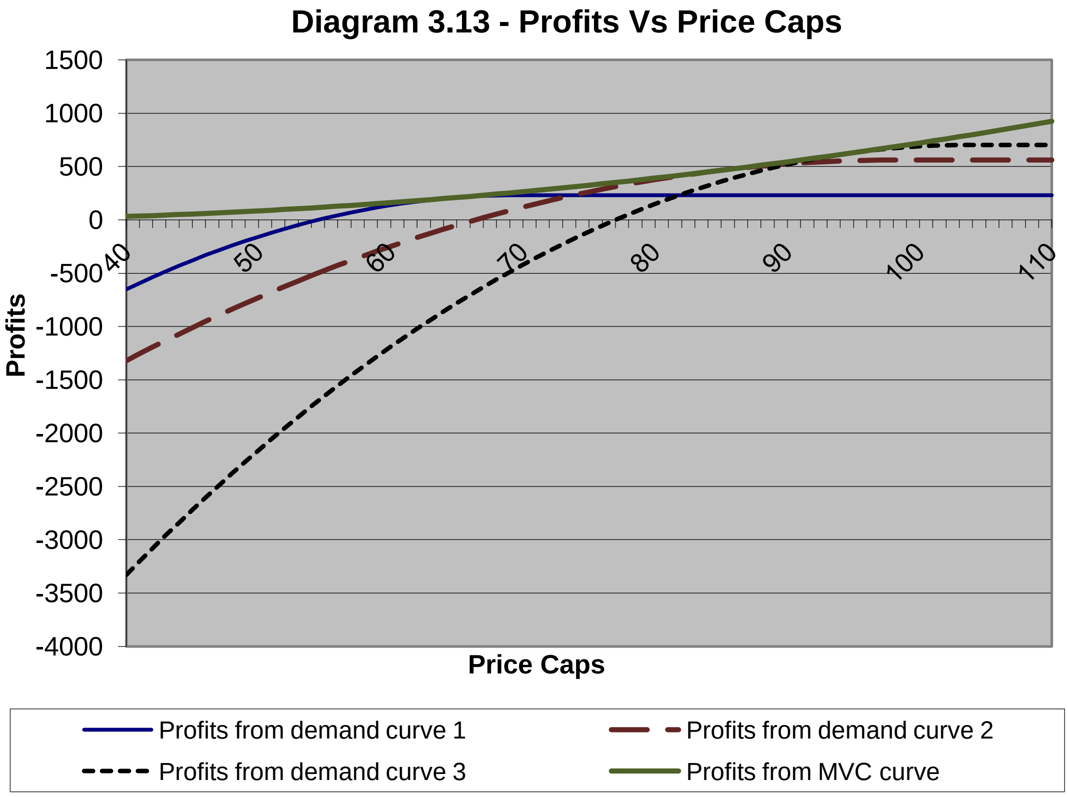


Diagram 3.13: Shows the profitability curves for quantities determined by Demand curves 1, 2 and 3 separately, as well as the profitability when the quantity is determined by the MVC curve. That is done in relation to the price caps that can be imposed in that market (price caps are on the horizontal axis). These curves

constitute the elements from which Diagrams 3.12a and 3.12b have been constructed. We should note that the profit curves that refer to each of the three demand curves that we examine touch the profits curve from the MVC curve at one point each.



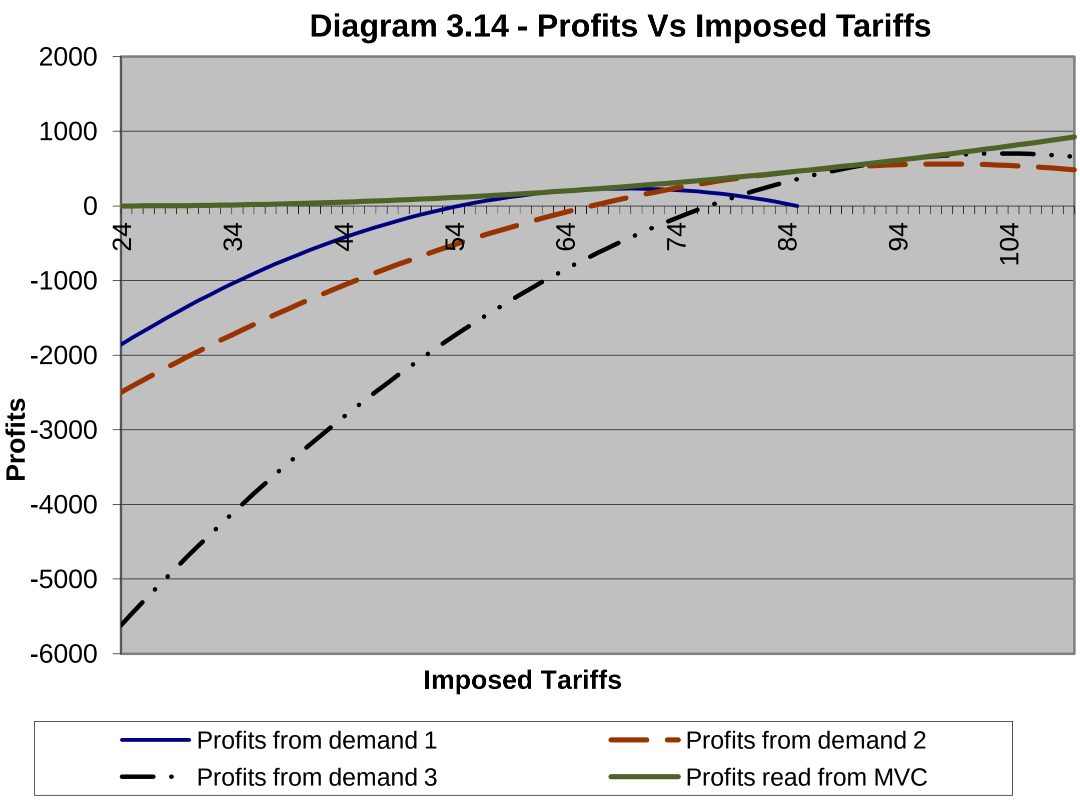


Diagram 3.14: Shows the profitability curves for quantities determined by Demand curves 1, 2 and 3 separately, as well as the profitability when the quantity is determined by the MVC curve. That is done in relation to the tariffs that can be imposed in that market (tariffs are on the horizontal axis). These curves constitute the elements from which Diagrams 3.12c and 3.12d have been constructed. We should note that the profit curves that refer to each of the three demand curves that we examine touch the profits curve from the MVC curve at one point each.

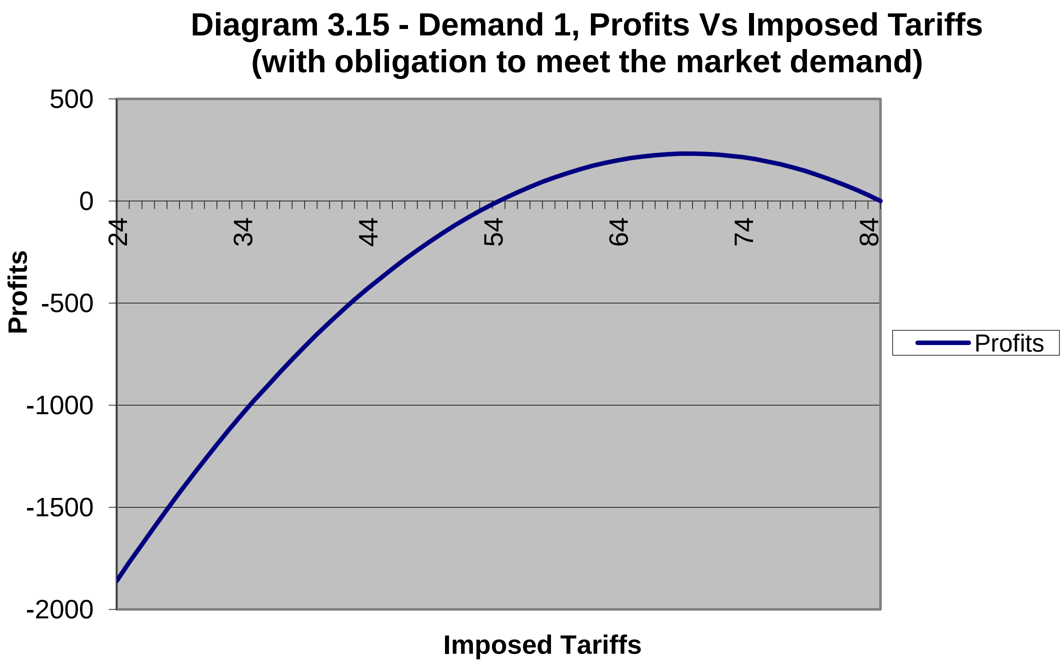
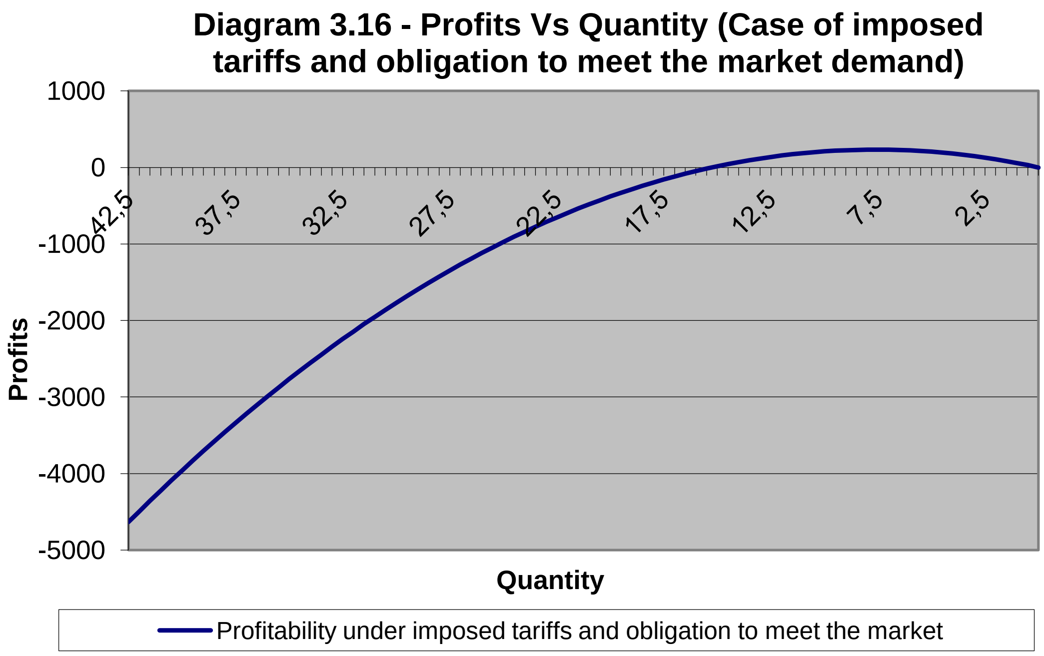


Diagram 3.15: Shows the profitability curve for quantities determined by demand curve 1 in the presence of imposed tariffs and of an obligation to meet the market demand. That is done in relation to the tariffs that can be imposed in that market (tariffs are on the horizontal axis). This curve is also found in Diagram 3.14.

Diagram 3.16: Shows the profitability curve for quantities determined by demand curve 1 in the presence of imposed tariffs and of an obligation to meet the market demand. That is done in relation to the quantities that supplier is obliged to supply to the market (quantities are on the horizontal axis).



3.9.3 Examining the simulation results

In Diagram 3.12a, we can see that as the market demand gets larger by going from Demand curve 1 to Demand curve 2 and then to Demand curve 3, the profit making potential increases. The effect of the use of price cap as an instrument for market regulation is shown. For price caps that are set at low levels, the profitability of the markets is identical regardless of the demand level. However as the price cap increases, the larger markets present much larger profit making potential, whereas the smaller ones cannot use the larger cap to increase profits since these markets reach their optimum price level for lower price caps.

Examining Diagram 3.12b and the differences between the profits for Demand curves 1, 2 and 3, we get to conclude that when b_0 increases, then the profit curve shifts downwards for lower price caps and in the same time presents higher profit potential for higher price caps. Also, by comparing Diagram 3.12a and 3.12b, we observe that after the introduction of the obligation to meet the market demand, the profitability either decreases or stays identical as it was without the obligation (depending on the price cap).

In Diagram 3.12b, we can see that the smaller market (the one that faces Demand 1) is more profitable than the other two markets (the ones facing Demand curves 2 and 3) when the price caps on the market are set at levels $PC_i \leq 73$. The smaller the market is, the lower the price caps that it needs in order to be able to make profits and in order to make its maximum profits. In Diagram 3.12b, Demand 1 starts making profits for $PC_1 = 55$, whereas Demand 2 starts making profits for $PC_2 = 67$. Demand 3 makes losses for $PC_3 \leq 76$, breaks even for $PC_3 = 77$, and makes profits for price caps $PC_3 \geq 78$. For price caps up until the level where profit curve for Demand 1 and the other two profit curves intersect (this happens for $PC_i = 74$ for Demand 2 and for $PC_i = 82$ for Demand 3), the market facing Demand 1 is more profitable. From that level and for price caps above that, each of the larger markets (which are the ones facing Demand 2 and Demand 3 since these have larger b_0) is more profitable than the market facing Demand 1.

Also, we observe what we have seen in Diagram 3.12a: the larger the markets are, the larger the maximum profits that can be made in these. The same holds true for the relationship between profit curves for Demands 2 and 3, where Demand 2 is a smaller market than Demand 3 (b_0 is identical, however Demand 2 has a higher b_1 than Demand 3). The market that faces Demand 2, when compared with the market that faces Demand 3, will be offering higher profitability for lower price caps and lower maximum profits, when the price caps are set high enough to allow for them. For price cap $PC_i \leq 90$ the profits of the market that faces Demand curve 2 are larger than those of the market that faces Demand curve 3. However, for price caps $PC_i \geq 103$ where the profits under Demand curve 3 are maximized, we can see that these maximum profits are larger than the maximum profits under Demand curve 2.

For low levels of price caps and with the existence of the obligation to meet the market demand, the bigger a market is, the less profitable it is going to be. In

Diagram 3.12b, the market facing Demand 1 is profitable for price caps $PC_1 \geq 55$ which is the price cap where the profits curve for Demand 1 intersects the horizontal axis. At that price cap level, the other two larger markets facing Demand curves 2 and 3 are making losses. The market with Demand 2 becomes profitable for $PC_2 \geq 67$ which is the price cap where the profits curve for Demand 2 intersects the horizontal axis. At that level, the market that faces Demand 3 is still making losses. The market with Demand 3 needs the highest price cap of the three of them to become profitable and that happens for $PC_3 \geq 78$ (for $PC_3 = 77$ profits are zero). Therefore, we have ranges of price caps where:

- Market for Demand 1 makes profits and the other two markets make losses (that is for $PC_i \leq 66$).
- Markets for Demand 1 and 2 make profits and the market for Demand 3 makes losses (that is for $67 \leq PC_i \leq 76$).
- Markets for Demand 1, 2 and 3 make profits (that is for $PC_i \geq 78$).

In Diagram 3.12b, depending on the price cap and given the existence of an obligation to meet the market demand:

- Smaller markets can be more profitable than larger ones and that happens when price caps set at low levels, not allowing larger markets to be profitable whereas smaller are already profitable.
- For high price caps, larger markets become more profitable than the smaller ones and are the ones that are the most attractive for new entry.

So depending on the levels of price caps and in the absence of an obligation to meet the market demand, the smaller markets can be more attractive to new entry than the larger ones.

In Diagrams 3.12c and 3.12d we have imposed tariffs instead of price caps. That difference becomes relevant whenever the supplier wants to supply at a price less than the imposed tariff. That happens for tariffs set above the profit maximizing price of the unconstrained case, which is the price of an unrestricted monopolist. When the tariffs increase above that level, the profits start decreasing as we can see in Diagrams 3.12c and 3.12d until they reach a point where they become zero.

In Diagrams 3.12c and 3.12d, the markets facing Demand curves 1, 2 and 3 reach their maximum profits for Tariffs 70, 98 and 103 respectively. As the tariffs in each case increase higher than the optimum level, the profits are decreasing. The tariff levels for which that happens are exactly the same as the price cap levels in Diagram 3.12a and 3.12b, however in Diagrams 3.12a and 3.12b for any price caps that are higher than the optimum, the supplier elects to maintain the optimum price level and therefore the profits remain at the maximum level (which is the profit maximum of the unconstrained case).

So in the case where we have tariffs instead of price caps, the tariff setting includes the risk that if set too high, quantity supplied will be restricted and profits will be lost.

In Diagram 3.13, we observe that the price cap at which the profit curves are tangent to the profit curve given by the MVC curve moves higher when b_0 is higher. That means that in a market with higher b_0 we would need a higher price cap for the supplier to want to meet the market, since until the point where the two curves are tangent, the supplier prefers to supply quantities corresponding to its MVC curve, and thereby make higher profits without meeting the market demand.

Also in Diagram 3.13, by examining the differences between the profits for Demand curves 2 and 3 (that have identical b_0), we notice that when we have a lower b_1 (Demand 3 has lower b_1 than Demand 2), then the price cap for which the profit curve that is read off the demand curve is tangent to the profit curve that is read off the MVC curve is higher. Therefore in a market with lower b_1 we would need a higher price cap in order for the supplier to want to meet the market.

In Diagram 3.14, the demand curve driven profitability is identical to the one in Diagram 3.13 until the price cap level reaches the profit maximizing price of the unconstrained case for each demand curve. After that level, as the tariffs increase, we can see that the profitability is decreasing until it reaches zero.

In Diagram 3.15, we use only one curve to show what is the relationship between profitability and imposed tariffs in the case where we have an obligation to meet the market demand. We show how the tariffs act as a regulatory instrument to determine the supplier’s profitability. The profitability under the same framework is presented in Diagram 3.16, but this time in relation to the quantities supplied (note the inverse order of the quantities in the horizontal axis).

3.10 Conclusions

In this chapter, we presented a theoretical model for the electricity supply market. This modeling approach employs diagrammatic and algebraic methods. The diagrammatic representation is presented in the main body of the text and the algebraic model is found in Appendix C. We consider markets that apply over particular time periods in order to accommodate the notion of zonal charges within tariff structures. In the absence of regulation, larger markets appear more attractive because of their larger profit making potential. However, the introduction of regulatory constraints, such as the imposition of tariffs/price caps and/or an obligation to fully satisfy market demand, might mean that smaller markets have a better profit making potential. We show diagrammatically the price ranges over which this happens and we relate the price ranges to profitability. In terms of zonal charges, that would mean that in a market with regulatory constraints, dispatch periods with lower levels of demand might present greater profitability than dispatch periods with higher demand.

We use simulation to verify the findings of our diagrammatic analysis. In these simulations, we considered three cases. In each, a single supplier operates under a different regulatory constraint. We conclude that a combination of the imposed tariffs/price caps and of the obligation to meet the market demand could leave the previous monopolist that operates strictly under these conditions in a financially uncomfortable position, depending on the level of the retail tariffs/price cap and in that case extended periods of financial losses might occur.

Whenever we have tariffs/price caps that incorporate distortions and cross-subsidization, the parts of the retail supply market that operate under high tariffs/price caps become more attractive to new entry, if the regulatory framework allows for selective entry. Price competition that might emerge in the post-entry periods between the incumbent and new entrants can eliminate these distortions and rationalize the prices paid by the consumers by bringing them to a level that reflects the actual cost of electricity. The occurrence of such a situation would mean that the ability of these market segments to cross-subsidize unprofitable ones would be reduced and the tariff/price cap structure would be rationalized across all the customer categories of the industry, becoming more cost-reflective.

The observations regarding the level of tariffs/price caps and the implications that this has for the profitability of the industry are relevant to the Greek experience. The retail electricity tariffs that the previous form of market organization has inherited to the reformed electricity market did not encourage entry across the whole electricity industry and instead directed new entrants towards selective entry. The previous approach to tariff structure could not be maintained under the pressure of competition and the tariff levels were restructured and shifted in a more cost-reflective direction.

Chapter 4

Entry in Electricity Supply Markets

4.1 Examining the electricity supply industry with multiple suppliers

4.1.1 Introduction

In Chapter 3, we considered the case where a supplier serves a market as a monopolist under varying circumstances. In that discussion, we did not take into account the possible implications that can stem from the existence of another supplier in that market. In Chapter 4 we address scenarios where there is entry of other electricity suppliers in the market. This is done by extending the analysis presented in Chapter 3, adopting different variants that correspond to circumstances that are relevant to the Greek electricity supply market. In the first part of Chapter 4 (Sections 4.2-4.4), diagrammatic analysis is used to illustrate different conditions under which entry in the electricity supply markets might occur. In the second part of Chapter 4 (Sections 4.5-4.7), we use game theoretic approaches to describe the situations that emerge during entry into the electricity supply markets. In the third part of Chapter 4 (Sections 4.8-4.12), we take a political economics approach with reference to electricity markets. In this part, we initially examine the case of Californian market failure and its relevance to the Greek case and afterwards we examine the organization of the Greek electricity sector. In order to explain some of the interrelationships that exist within this sector, we specifically focus on the political culture in Greece.

In the Greek electricity supply sector, the incumbent firm, Public Power Company (PPC), is in a very powerful position as a retail supplier. All potential new entrants are much smaller in size when they enter the market. To reflect this, we examine models of entry that consider the interaction between two firms: the incumbent firm and the new entrant firm. The fact that in the Greek electricity supply market there has been very limited competition between the incumbent firm, PPC, and the new entrants, allows us to use relatively straightforward models in our analysis, since these model the actual situations that we are examining.

As was the case in Chapter 3, the work presented here focuses on the market issues addressed from a conceptual point of view. The novelty presented lies in the application of this approach to the case of the Greek electricity supply market, given the legal, structural, institutional, political, financial and social peculiarities of the Greek general economic setting.

The contribution of Chapter 4 to the thesis lies in offering insight, through theoretical modeling, on the interaction between market players in the Greek electricity supply market. Using the Greek experience as a starting point to the models discussed, we introduce cases that analyze the various entry scenarios under asymmetric regulation and we also examine the regulatory behaviour that might be adopted as well as what its effects are. Using the work presented in Chapter 4 in combination with that of Chapter 3 on the profit-making ability of price-capped markets, a regulator can be guided on a number of important issues. These include price-cap setting and the use of any other regulatory instruments and rules. Such a regulatory rule would be the decision to provide accommodation to potential new market entrants in order for them to be able to establish themselves before they face full competition against the incumbent. Additionally, in the third part of Chapter 4 (Sections 4.8-4.12) we look at some issues of political economics that relate to Greece and that can have a significant effect on economic activity in general and in specific sectors. We also discuss how the political culture of a country can impact on economic outcomes through the preference that might be experienced on agendas selected with non-economic criteria. That understanding can also be applied to other countries and to other sectors. Policymakers should be cautious and take politics seriously into consideration when attempting to introduce reforms in countries that present political characteristics similar to those of Greece.

4.1.2 Previous research

As we have seen in Chapter 2, the electricity supply industry is the part of the electricity market that has not been extensively researched in the literature. Research in this area has used a variety of points of view to approach the supply markets.

Kumar [2001] examines the existence of market power in supply markets, reviews the methods available for market power analysis and makes suggestions for the mitigation of market power. He proposes Oligopoly Equilibrium Analysis and refers to the various models through which it can happen: Bertrand, Cournot, Supply Function Equilibrium Model. This point of view is the one we will be adopting.

Green and McDaniel [1998] discussing the introduction of competition in the electricity industry of England and Wales conclude that competition between suppliers yields lower prices for the consumers. Steiner [2001] was also led to a similar conclusion, stating that liberalization in the supply industry that involves unbundling of electricity industry activities, prices set by the market, and privatization, results in increased efficiency. However, he goes on to state that in order for these increased efficiency results to be translated into lower prices, market power must be controlled by the market regulator. He also adds that the common pattern of market reforms involves generation being liberalized first, leaving the competition in the supply market to occur later.

Joskow [1973] refers to the issue of retail pricing by regulated utility services and attempts to put it in a behavioural framework, stating that it is difficult to model decision making on pricing. He also refers to the regulatory process of discussing price adjustments and presents a model in order to analyze the factors around the decision of a firm to ask for retail tariffs adjustment. This approach however, does not incorporate competition.

Wieringa and Verhoef [2007] present a study of the factors that lead customers to switching electricity supplier in the Dutch energy market. They refer to the classification, that comes from the loyalty literature, of customer switching behaviour as deriving either from economic concerns or social/affective ones. They also refer to the inertia explanation for non-switching behaviour in the case of monopolies that are getting liberalized, which is due to the customer's preference to keep buying as they have done in the past without considering the possibility of examining alternatives. They investigate the Dutch energy market and their findings suggest that switching is encouraged by relationship quality, switching costs, and demand for the services that the supplier is providing.

Extending the analysis to electricity markets specifically, Wieringa and Verhoef [2007] list the following as important factors that reduce switching: the familiarity with the incumbent, the fact that customers are not accustomed to switching, the relationships built over long periods of service from the incumbent, and inexperience in exploring market opportunities. We could add for the Greek case specifically: lack of information about the retail market opportunities, lack of trust on the new entrants, and a feeling of attachment that people in Greece might have to the previous monopolist. Many understand that this is a firm that has been established in the interest of the public, it has contributed to the industrialization of Greece and people feel affiliated with the firm, understanding this as being "their own". In contrast, new entrants might be perceived as opportunistic, especially after the exit from the Greek supply market of the two new entrants that had proceeded with retail supply ([RAE, 2012a], [HTSO, 2012]).

There are also a number of working papers (Newbery, 2004, 2006b; Joskow, 2000; Littlechild, 2002) which discuss the issue of electricity supply markets and adopt policy perspectives, indicating that there is an ongoing debate in this research area. Other research papers referring to electricity supply address a variety of questions such as the optimizations of bilateral contracts between suppliers and consumers [Cheng et al., 1998].

The use of game theoretic approaches is very common when analyzing player's behaviour (Tirole, 1988; Pindyck and Rubinfeld, 1996). Although deriving robust conclusions and predictions about the market outcomes is not easy and such an approach can be inconclusive [Sutton, 1990], it remains a useful instrument.

The novelty of the approach taken in Chapter 4 is that it uses economic theory to analyze developments in the Greek electricity supply market. We also discuss the issue by adopting the regulator's point of view and we examine possible regulator responses in each scenario. We discuss specific scenarios that reflect upon actual situations that could emerge in the supply industry and attempt to address the issues in hand using a perspective that incorporates a point of view of public policy and political economy.

4.2 New entry scenarios in markets served by an incumbent

4.2.1 Examining the market without considering the other suppliers

Examining how a supplier decides whether to enter in one or in multiple markets, we assume that the criterion that governs these decisions is profit maximization.

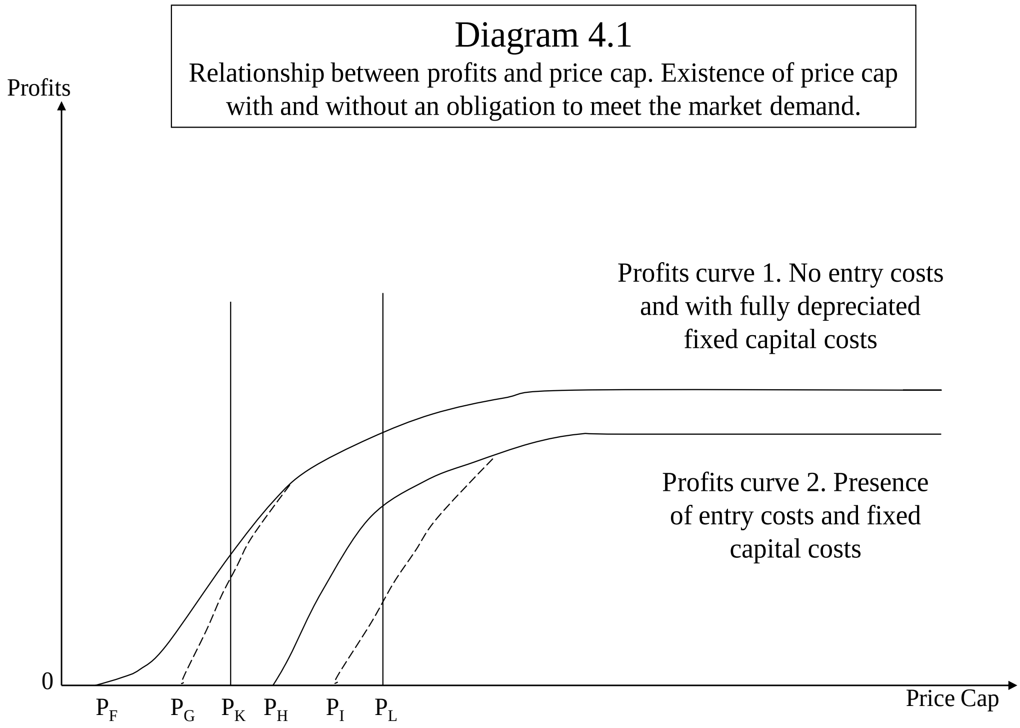
We consider a situation where there are several markets that the supplier examines as possible entry targets. The price cap and the Marginal Variable Cost (MVC) curves are not necessarily the same across the different markets. This is because each market might have its own peculiarities that affect the cost of electricity supply. As a result, each market might be facing different levels of profitability which will be determined by a combination of retail tariffs/price caps, cost structure, market demand and regulatory rules. Depending on the market setting, we will be getting profit curves discussed in the previous chapter and represented in Diagrams 3.6a, 3.6b, 3.6c and 3.6d and later verified by the simulation results in Diagrams 3.12a, 3.12b, 3.12c and 3.12d.

We assume that all costs are variable, so there is no fixed cost component. We assume however that a new entrant faces entry costs, such as paying for getting a supply licence and also endures fixed capital costs in order to build supply capacity. In our discussion, we differentiate entry cost from fixed capital costs by taking it that entry costs are the costs that refer to intangible property that cannot be recovered. Such cost could be the cost of marketing and advertising or the payments made for getting a supply licence. There is no entry cost for established suppliers and the capacity costs of the established suppliers are considered to be fully depreciated.

We consider that for the potential new entrant there is no obligation to supply the market and if the new entrant elects to do so, he does not bear an obligation to meet the market demand. Therefore, the new entrant is facing profits curves such as those seen in Diagrams 3.6a and 3.6c, depending on whether or not we have a market with price caps (or imposed tariffs) for all participants.

The incumbent firm bears an obligation to meet the market demand under the price caps/imposed tariffs set by the market regulator and its only option is to negotiate with the regulator the levels of the price caps/imposed tariffs. Therefore, the incumbent has, in each market, profits curves such as those in Diagrams 3.6b and 3.6d.

The new entrant is expected only to choose amongst these markets that are projected to be profitable for the price that he will charge and only if he considers that he can gain market capable for these profits. Market penetration is an important issue and customer switching is dependent on factors extending beyond tariffs [Wieringa and Verhoef, 2007].



In Diagram 4.1 we have four important prices: P_F , P_G , P_H , P_I . For a supplier with no entry costs and fully depreciated fixed capital costs, P_F is the price that produces zero profits if there is no obligation to meet the market demand and P_G is the price that produces zero profits if there is such an obligation. For a supplier that faces entry costs and fixed capital costs, P_H is the price that produces zero profits if there is no obligation to meet the market demand and P_I is the price that produces zero profits if there is such an obligation. In these profit curves that we present, we only graph the positive profits. The parts of the graphs that refer to cases where there is no obligation to meet the market demand do not get negative values. However, in the presence of an obligation to meet the market demand, the profit values might get negative for some price cap ranges.

- Price caps below P_F result in no profitable production for any supplier.

- Price caps between P_F and P_G result in profitable production only for a supplier without entry costs and with fully depreciated fixed capital costs, when this supplier does not bear an obligation to meet the market demand.
- Price caps between P_G and P_H result in profitable production only for a supplier without entry costs and with fully depreciated fixed capital costs, regardless of whether there is an obligation to meet the market or not.
- Price caps between P_H and P_I result in profitable production for suppliers with entry costs and having to cover fixed capital costs, regardless of whether there is an obligation to meet the market or not. This price cap range also results in profitable production for suppliers without entry costs and with fully depreciated fixed capital costs when these suppliers do not bear an obligation to meet the market demand.
- Price caps that are higher than P_I result in profitable production for all suppliers, regardless of whether they face entry costs and fixed capital costs and regardless of whether the face an obligation to meet the market demand. However, that does not mean that all these suppliers are making the same profits when facing each of the price caps.

Diagram 4.1 is constructed from Diagram 3.6a. It identifies the position for a supplier without an obligation, such as the new entrant. There are two profits curves. Profits curve 1 refers to an established supplier participating in the market who does not need to cover entry cost and who has fully depreciated fixed capital costs. Profits curve 2 refers to supplier that needs to cover entry costs and fixed capital costs associated with capacity building. The dashed lines show the profitability in each case if there was an obligation to meet the market demand.

In Diagram 4.1, for price cap P_K, a new supplier does not want to enter the market, as no profits are made when we incorporate entry costs and fixed capital costs, which is what we do when we use profits curve 2. An established supplier however that operates either with or without an obligation to meet the market demand will be profitable in that market for price cap P_K, because having sunk capital costs and no entry costs, his profits will be determined by the profitability curve 1 (either the full line or the dashed line). For price cap P_L, the new supplier wants to enter the market, as this price cap allows profits to be made whilst covering entry costs and fixed capital costs. An established supplier with or without an obligation to meet the market demand would be making more profits in this case as we can see by examining profits curve 2.

4.2.2 Competing against the established incumbent

Let's consider the case where the two suppliers, the incumbent and the new entrant, are facing identical cost and there are no entry costs or fixed capital costs. The incumbent faces an obligation to meet the market demand and the new entrant doesn't.

In each of the markets that the supplier decides to enter, another supplier is already serving the market and has set a price (subject to the price cap regulation). If the two suppliers in the market compete on price, and if there are no constraints as to the amount of electricity that each supplier can supply, then we can expect to end up with a Bertrand equilibrium, which is also a Nash equilibrium. We can also call this the Bertrand paradox, in that the competitive outcome occurs with only two firms [Tirole, 1988, pp. 209-211]. Given that we ignore all the entry costs and fixed capital costs, then the market price is set by every supplier just below the other supplier's AVC. Since we consider that both suppliers have the same AVC, the market price will be set by both suppliers at the same level. That would be at the level where demand curve D curve cuts AVC and profits are zero for both of them.

Using the diagrams that we presented in Chapter 3 when we were considering only one supplier, we now present how competition is expected to affect the market.

- For the case in Diagram 3.1, competition shifts market price from P_1 to P_A.
- For the case in Diagram 3.3a, competition shifts market price from P_1 to P_A .
- For the case in Diagram 3.3b, competition shifts market price from P_0 to P_A.
- For the case in Diagram 3.3c, competition leaves market price unaffected at P_0 (because $PC_i = P_0 \langle P_A$). That comes as a result of the existence of the obligation for the incumbent to meet the market demand. However one part of the market can potentially be taken over by the new entrant, should that be deemed profitable for him.

4.2.3 Conditions for competition

The shift in market prices that we described above is the result of the supplier competition so that price falls to the point where no super normal profits are being made. That happens for price P_A which is the price where the AVC curve intersects the demand curve. In order for this to happen and for the suppliers to end up supplying both at the same market price P_A, we require:

- The same cost structure for both suppliers, so that the Bertrand equilibrium market price, P_A , is the same for both of them. We should note that if the incumbent has lower cost than the new entrant, which could happen if we take into account entry costs and fixed capital costs, then the threat of entry and the concept that competition can be attracted in the market can result in making the incumbent establish lower prices, so as to make the market non-attractive to new entrants.
- The incumbent should be willing and able to compete against the new entrant on price. The incumbent could ultimately decide not to respond to the event of the new entry. That could be explained by the expectancy that the amount of customers switching supplier will be low. A low volume of

customer switching could occur for a variety of reasons discussed by Wieringa and Verhoef [2007]. For example, the existence of a cost for making an electricity supplier switch, high levels of customer loyalty, or because the price discount that the new entrant offers is not large enough to make the consumers decide to switch. Given the willingness of the new entrant to enter that specific market, we can think of that market as being a profitable one. So, for an incumbent that bears an obligation to meet the market demand in multiple markets where not all of them are profitable, the profitable markets will be cross-subsidizing the operation of the non-profitable markets. The incumbent might be better off keeping the initial price level, which will be decided by the relative profitability that the responding and the non-responding scenarios offer. What we are saying is that the incumbent would prefer in some scenarios to lose market share and keep the initial price rather than compete on price and also lose some profits in that second case anyway (because of the decreased price).

- The two suppliers should be in position to serve the whole market. If the market regulator restricts the quantity that the new entrant is allowed to supply, then the incumbent might ultimately not enter into price competition, knowing of the restriction to the entrant. In this asymmetric case, it could be that there is no response to the initial entry if no further entry is anticipated. In that case, a solution could be that the new entrant supplies the maximum output allowed and the incumbent faces a residual demand and corresponding marginal revenue curve for which he maximizes profits by making an equal reduction in output.

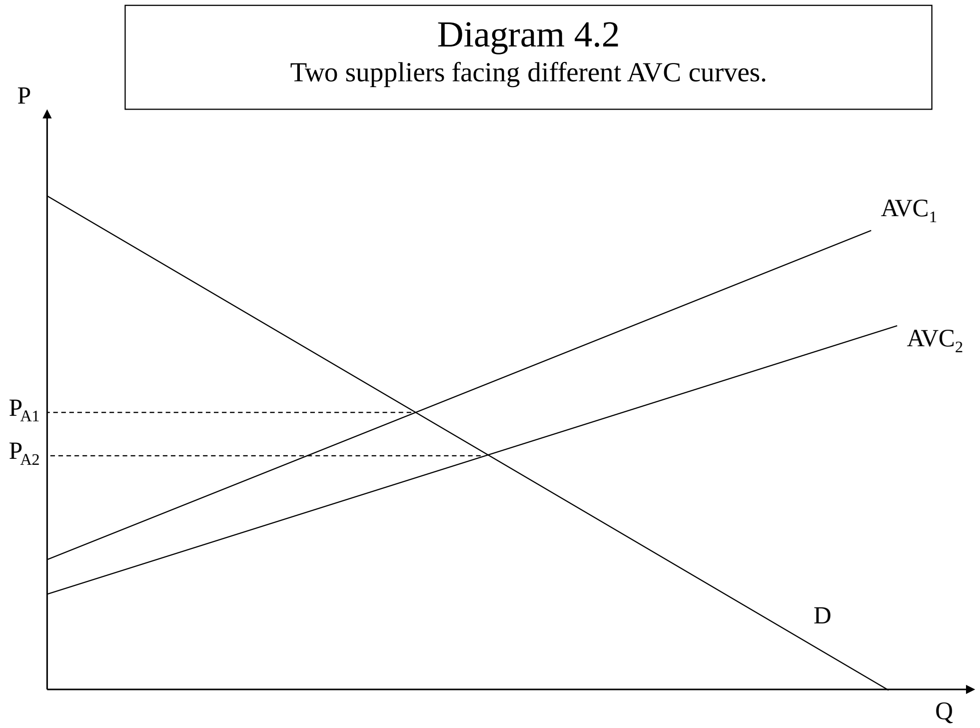
If the new entrant expects price competition to take place, then the profitability of the market should be examined using P_A as the market price, as that is the long-run price level that is expected to be the outcome of competition. In Diagram 4.1, taking two arbitrarily selected price caps P_L and P_K, we can see through profits curve 2 that a market can appear profitable with the price cap at P_L and non-profitable at price P_K . Therefore, pre-entry the profitability should be examined for the minimum price that can be set in the long-run.

4.2.4 Considering some scenarios

4.2.4.1 Different AVC curves

The analysis of the case becomes more complicated when some of our assumptions are varied. If the incumbent and the new entrant do not have the same cost structure and therefore face different AVC curves, then each will have a different P_A, in which case both of them should be examined. The price competition between them results in the supplier with the lower AVC undercutting the other supplier's price and setting a price that cannot be matched in the long-run. That case is shown in Diagram 4.2 where we can see a Bertnard price game with different AVC curves [Viscusi et al., 2005, pp 258-259]. The difference in Average Variable Cost as it is implied in Diagram 4.2 might not be solely due to differences in the cost of supplier activities (meter reading, customer service, issuing of bills) and overhead cost, but it might as well be related to the obligation of the supplier to cover the cost of capacity payments.

So, in the AVC curves presented in Diagram 4.2, the differences between the curves are due to firm specific factors. The two AVC curves are not drawn as being parallel, however there is no reason that restricts them from being so. The increasing slope of the AVC curves is due to the fact that as the quantity of electricity demanded increases, the wholesale electricity price increases as well. That is so because as the quantity demanded increases, more expensive electricity generating units are being employed and the marginal unit in the wholesale electricity market is a more expensive one.



(Based upon Viscusi et al. [2005, pp. 258-259])

4.2.4.2 Existence of a cost for supplier switching

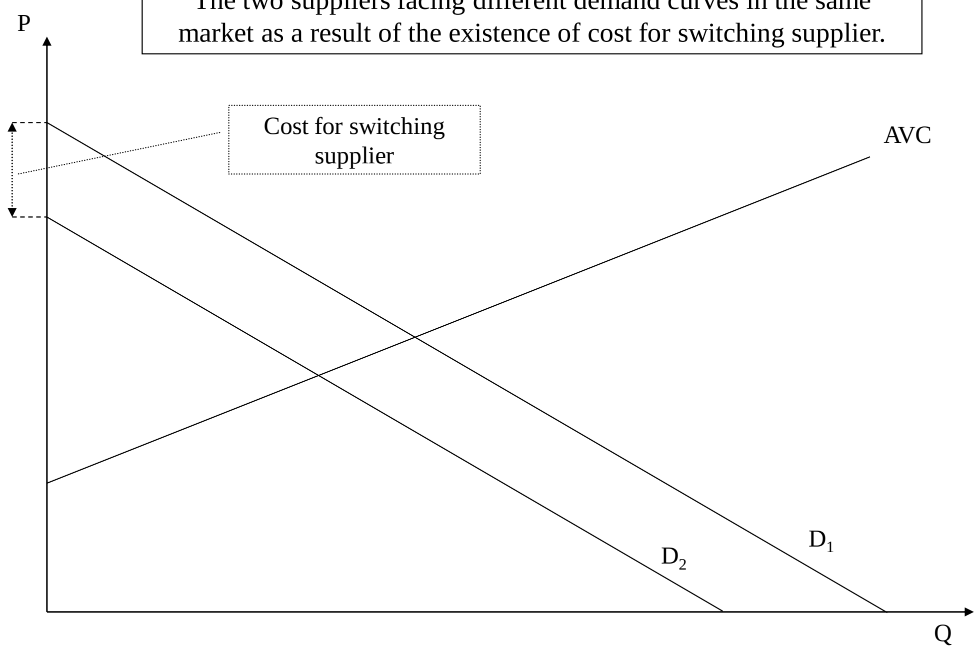
If switching costs are present in the market, then in the first period the new entrant effectively faces a different demand curve than the incumbent. The new entrant's demand curve is the result of subtracting the switching cost from the incumbents' demand curve. So, the new entrant, due to the presence of the switching cost faces a smaller market as any price offered by him will have to be increased by the switching cost that the customer needs to pay. That case is shown in Diagram 4.3, where the market demand faced by the incumbent is D_1, but the new entrant, due to the presence of the switching cost, ends up facing demand D_2.

The switching cost is to be paid by the customer only once, thereby decreasing the severity of its impact. However, using Diagram 4.3 is difficult since it only refers to the first period when each customers switches.

In the case of the Greek electricity supply market, there is no direct cost for switching supplier [Journal of the Greek Government, 2011b, page 3812]. The incumbent however asks the customers that are supplied by him to pay a deposit that will act as a guarantee. This deposit is returned to the customers if they switch supplier and stop being supplied by the incumbent. This acts in the opposite direction to a switching cost, since the customers that switch supplier get their deposit back. So, in Diagram 4.3, if we have a “revenue from switching” as described here, it could be that in the first time period for every customer that switches supplier the market demand is D_2 for the incumbent and D_1 for the new entrant.

Diagram 4.3

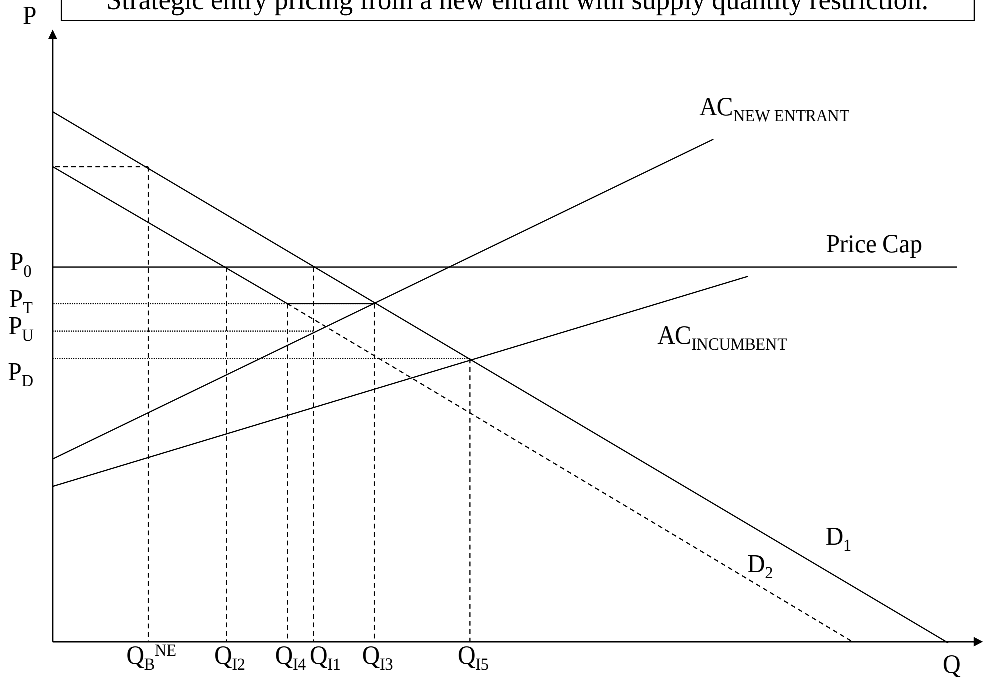
The two suppliers facing different demand curves in the same market as a result of the existence of cost for switching supplier.



4.2.4.3 Supply licence restrictions for the quantity supplied

In Diagram 4.4, we see how a new entrant that lowers its price at $P_T \langle PC_i$, can in some cases get a part of the market from the incumbent. This is done because the incumbent has set his pre-entry prices at a level that makes entry possible by undercutting his price. That means that prices are not set in entry deterring levels and these prices lead the incumbent to make super-normal profits.

Diagram 4.4
Strategic entry pricing from a new entrant with supply quantity restriction.



The analysis done using Diagram 4.4 focuses on the interreactions of market regulation, new supplier entry conditions, supply capacity restrictions and differences in the resulting efficiencies. Exactly as was the case with AVC curves in Diagram 4.2, the two AC curves are not drawn as being parallel, however there is no reason that restricts them from being so. The two AC curves have increasing slopes because as the quantity of electricity demanded increases, the wholesale electricity price increases as well. That happens because as the quantity demanded increases, more expensive electricity generating units are being employed and the marginal unit in the wholesale electricity market is a more expensive one.

What we are saying is that the incumbent and the new entrant have average cost (not considering the cost of wholesale electricity) that is different for each supplier. This cost is not necessarily fixed for each supplier, instead it might be increasing or decreasing. By adding the cost of wholesale electricity, which is positively sloped and identical for both suppliers, to the rest of the average cost of each supplier we get the full average variable cost.

We consider what happens when the new entrant has higher average cost than the incumbent and the new entrant can only supply up to a specific quantity because of licence restrictions. Electricity is bought through the pool by both suppliers. The important thing to note is that by buying electricity through the pool, the price paid for that electricity from each supplier is determined by the quantity bought by the whole market and not by the quantity bought solely by each one of them.

Supply licence restrictions apply in the Greek electricity supply market [RAE, 2012c]. The licence restriction that we are referring to could be serving risk management purposes, in order to prevent suppliers with restricted financial ability to engage in large volume of transactions without having the appropriate levels of working capital. Failing to account for this risk might lead the market in cash shortages and financial liquidity “bottlenecks” that might negatively affect the financial robustness of the other electricity market participants, causing an externality that could be of significant magnitude.

This analysis can also be applied in a different case. That would be the case instead of a licence restriction imposed by a regulator, the supplier decides to restrict the quantity supplied because of the existence of a capacity payments mechanism. Due to the obligation of the supplier to make payments in the capacity mechanism according to the maximum capacity that he is going to use in a specific time period, the supplier might decide to create a portfolio of only these customers that will be consistently using the full amount of that capacity. The supplier would aim at maximizing the efficiency of using his supply capacity. The target therefore is to maximize the use of the capacity that is paid for through the capacity mechanism. Even if the supplier ends up supplying less customers and less electricity through this policy, by doing so he is making full use of the capacity that he pays for and therefore he is able to recover these payments through retail tariffs more easily and with less risk. So, although there could be less revenue, in the same time there is much less cost, with the new entrant possibly optimizing profits.

Employing such a strategy is complex and requires extensive analysis of customer load profiles in order to be implemented. An important issue is that as this constitutes a management tool that is used voluntarily by the supplier, capacity management can be planned and executed on a short-term basis and the actual level of capacity payments that the supplier decides to make can vary across time. Accordingly, and depending on the cost advantages that the supplier gets, the supplier can vary tariffs. Therefore, in order for this approach to be adopted, the supplier should be in position to vary tariffs.

We describe three cases of entry scenarios in a market where there is an established incumbent supplying electricity under regulated tariffs. We use the approach of a two-period game to discuss these scenarios. In all three cases, because of the existence of regulation in the tariffs, there is an initial time period where the previous incumbent is unable to adjust his tariffs in response to entry. This period is period 1 in our game and the length of that period is important in determining the ability of the new entrant to enter the market and establish himself. The regulator could actually delay the adjustment of the incumbent's tariffs in order to accommodate the new entrant, given that without this initial period, entry would have been very difficult if the incumbent acts aggressively after entry.

The three cases that we present assume that predictions are made from each firm about its own cost, meaning that each firm makes assumptions about the market conditions as well. However, the actual market conditions might not be the ones projected and that could impact on the outcome of each scenario. The purpose of the new entrant in these three cases is not to maximize profits in the short run.

Instead the new entrant aims at establishing himself in the market in period 1 and then trying to stay in the market in period 2. For that reason, Diagram 4.4 is used in a descriptive manner and there are no Marginal Revenue and Marginal Cost curves.

4.2.4.3.1 Case 1-Incumbent does not respond

Case 1 is a case where the new entrant enters the market and positions himself assuming that the incumbent will not respond to entry. When we say that, we mean that the incumbent will not alter his prices and will keep supplying at the pre-entry price level. We assume that there are no switching costs. However by simply matching the incumbent's price there is no customer switching. As a result, in order for the new entrant to attract customers and gain market share, he should undercut the incumbent's price.

In Diagram 4.4, we assume that the market has a price cap set at levels that make the price cap relevant to the market price setting. Therefore, market price pre-entry was P_0, given the price cap and the obligation for the incumbent to meet the market demand. Also, market quantity pre-entry was Q_{I1} and was fully supplied by the incumbent.

The new supplier enters the market by setting his price at P_U. That price is set in such a way that it will allow the supplier to supply the market with a quantity up to the maximum that he is allowed to supply, ${Q_B}^{NE}$, and in the same time cover all costs, given that the incumbent will keep his prices at the pre-entry level. The restriction is set in terms of quantity so the new entrant is allowed to choose his price level.

Price P_U that the new entrant opts to use is the most risk-averse price in terms of ensuring higher probability for the new entrant that the desired market share will be captured. We also note that the difference between incumbent's and new entrant's price is $(P_0 - P_U)$. In order for entry to be successful, this difference should be large enough to motivate customers to switch supplier. That means that this price difference should be larger than any potential switching costs (in Diagram 4.4 we do not consider that any switching costs exist).

We expect the new entrant to enter the market by setting his price using his average cost (AC) curve, in order to be able to gain market share in the market. Although the new entrant is expected to have profit maximizing behaviour, given the market conditions and the duopolistic competition that might emerge, he has to be strategic in the decisions taken in order to gain market share first. Setting price through the AC curve, the new entrant recovers his average variable cost, his entry costs, his fixed capital costs and his cost of capital. By setting the minimum price that he can sustain in the long-run, the new entrant makes it easier to gain market share. It is also important to the determination of the strategic decisions made that each of the two suppliers might not know the AC curve of its rival(s).

This can be viewed as a two-period game, where in the first period the incumbent cannot react because of the restriction imposed by the regulator on the level of retail tariffs. In period 1 of the game, the new entrant attempts to capture the market share that he wants, without making losses. The approach that we get in period 1 is the approach that leads to capturing a specific target market share without making any super-normal profits. We should note at this point that the new entrant could attempt to enter the market using a price P_i in the range $P_0 \rangle P_i \rangle P_U$. Such a price would allow some super-normal profits to be made whilst also allowing to the new entrant to gain market share.

Quantity $Q_B{}^{NE}$ is the target market quantity for the new entrant. If the new entrant manages to get enough market share to supply this quantity, the incumbent is left to supply the rest of the market at price P_0. The market quantity is not changing and remains Q_{I1} as only a part of the consumer's base enjoys the decreased price P_U and the market is cleared at price P_0. The incumbent is supplying quantity $Q_{I2} = Q_{I1} - Q_B{}^{NE}$. The incumbent, having lost part of the market to the new entrant, now faces a residual demand curve D_2 instead of D_1. So, if the new entrant supplies all the quantity that he is allowed to, the incumbent will supply the rest of the quantity at price equal to the price cap and clear the market at price P_0.

So the result is that we get the incumbent not responding to new entry and the market is cleared at the price cap level, which is the same price level as it was in the pre-entry period. The quantity supplied remains Q_{I1} exactly as in was in the pre-entry period. The difference is that we have two suppliers splitting the market amongst themselves. In the case where the incumbent is allowed to react, by undercutting the new entrant's price the incumbent could potentially get back the lost market share.

In period 2 of the game, the new entrant could decide, as part of his strategic plan in order to maximize profitability, to raise his price after being established in the market and having captured the customer base that he was aiming for. That would make sense since there would be no incentive for his customers to switch supplier again and return to the incumbent. The new price that he can set would have to be in the range $P_U \langle P_i \leq P_0$, which is the price range that undercuts or matches the incumbent's price and still profits are made for the new entrant. The market outcome is that the market is split amongst the two suppliers and the market price is P_0.

4.2.4.3.2 Case 2-Incumbent matches the prices of new entrant

Case 2 is a case where the new entrant enters the market and positions himself assuming that the incumbent will respond to entry by matching the new entrant's tariffs. We assume that there are no switching costs, however by simply matching the incumbent's price there is no customer switching. As a result, in order for the new entrant to attract customers and gain market share, he should undercut the incumbent's price.

In Diagram 4.4, the market price pre-entry was P_0, given the price cap and the obligation for the incumbent to meet the market demand. Also, market quantity pre-entry was Q_{I1} and was fully supplied by the incumbent.

The new supplier enters the market by setting his price at P_T. That price is set in such a way that it will allow to the supplier to supply the market with a quantity up to the maximum that he is allowed to supply, $Q_B{}^{NE}$, and in the same time cover all costs, given that the incumbent will respond to entry by adjusting his prices and charging P_T as well.

We expect the new entrant to enter the market by setting his price using the point of intersection between the demand curve D_1 and his average cost ($AC_{NEW\ ENTRANT}$) curve, in order to be able to gain market share in the market. The new entrant sets a price that he will be able to sustain if the incumbent decides to match it. Setting price through the AC curve, the new entrant recovers his average variable cost, his entry costs, his fixed capital costs and his cost of capital. By setting the minimum price that he can sustain in the long-run, the new entrant makes it easier to gain market share in the time period until the incumbent eventually responds by matching the new entrant's price. It is also important to the determination of the strategic decisions made that each of the two suppliers might not know the AC curve of its rival(s).

This can be viewed as a two-period game, where in the first period the incumbent does not react because of the restriction imposed by the regulator on the level of retail tariffs. In period 1 of the game, the new entrant attempts to capture the market share that he wants, without making losses. However, understanding that the incumbent will match the price in period 2 of the game, the new entrant sets the price at the level that, if matched, the new entrants will be making zero super-normal profits. That helps the new entrant in capturing a large market share in period 1 while making super-normal profits and ensuring that when matched, this price will not lead to losses. The market is therefore split between the two suppliers depending on how long period 1 is and how attractive switching supplier is.

Quantity Q_B^{NE} is the target market quantity for the new entrant. If the new entrant manages to get enough market share to supply this quantity, as we assume to be the case in Diagram 4.4, the incumbent is left to supply the rest of the market at price P_T. The market quantity changes and becomes Q_{I3} and the market is cleared at price P_T. The incumbent is supplying quantity $Q_{I4} = Q_{I3} - Q_B^{NE}$. The incumbent, having lost part of the market to the new entrant, now faces a residual demand curve D_2 instead of D_1.

So the result is that we get the market cleared at price P_T, we have two suppliers in it and the total quantity supplied becomes Q_{I4}. This case reflects the situation that has emerged in the Greek electricity supply market after entry occurred in the start of 2009 and PPC was able to adjust its Medium and Low Voltage tariffs at 01/01/2011 [PPC, 2011c]. The lag in PPC's response to entry is what actually allowed new entrants to be in a position to gain market share. For the Greek electricity market regulator and for the Greek policymakers that operate at the political level, not allowing the new entrant the opportunity to get market share could be considered problematic by the European Union that mandates the electricity market reforms.

The residual demand curve D_2 that the incumbent faces after new entrant gets established and supplies quantity Q_B^{NE} is dependent on the assumptions that we make on customer switching behaviour. For price above P_0, the demand curve is horizontal at level P_0. For prices below P_0 it kinks at the point where quantity is Q_{I2} and starts following the residual demand curve D_2 from that point until the point where price level reaches P_T. After that point, the demand curve kinks again and becomes horizontal until the point that this horizontal line meets demand curve D_1. At that point, D_2 kinks again and becomes identical to D_1. That is so because if prices fall below P_T then the new entrant exits the market and the incumbent is left to serve the whole of it.

4.2.4.3.3 Case 3-Incumbent acts aggressively after entry

Exactly as in Case 2, in Case 3 the new entrant enters the market and positions himself assuming that the incumbent will respond to entry by matching the new entrant's tariffs. We assume that there are no switching costs. However by simply matching the incumbent's price there is no customer switching. As a result, in order for the new entrant to attract customers and gain market share, he should undercut the incumbent's price.

In Diagram 4.4, the market price pre-entry was P_0, given the price cap and the obligation for the incumbent to meet the market demand. The new supplier enters the market by setting his price at P_T. That price is set in such a way that it will allow to the supplier to supply the market with a quantity up to the maximum that he is allowed to supply, Q_B^{NE}, and in the same time cover all costs, after the incumbent responds to entry by adjusting his prices and charging P_T as well. However the incumbent might be aggressive after entry and try to retaliate, without considering the short-run implications on profits, preferring to protect its market dominance. The purpose of such a stance would be to take the new entrant out of the market by decreasing market price to P_i for which it is $P_T \rangle P_i \geq P_D$. P_D is the price where the incumbent makes zero super-normal profits. The reason why the incumbent would do so is to force the new entrant to exit the market.

The new entrant entered the market by setting his price using the point of intersection between the demand curve D_1 and his average cost ($AC_{NEW\ ENTRANT}$) curve, in order to be able to gain market share in the market. That is the minimum price that he is able to sustain if the incumbent decides to match it. Setting price through the AC curve, the new entrant recovers his average variable cost, his entry costs, his fixed capital costs and his cost of capital. However that is not possible for any price below P_T. It is also important to the determination of the strategic decisions made that each of the two suppliers might not know the AC curve of its rival(s).

The new entrant does not manage to get any market share and is forced to exit the market. So the result is that if the incumbent decides to keep market prices at the entry deterring level in order to halt any further entry, then we get the market cleared at that price P_D. We have one supplier in the market and the quantity supplied becomes Q_{I5}. In this case, the entry that occurred and the threat of possible new entry acts in a way that it forces the incumbent to reduce prices and to keep them low, thus resulting in the application of the concept of "limit pricing".

4.2.4.3.4 Some notes

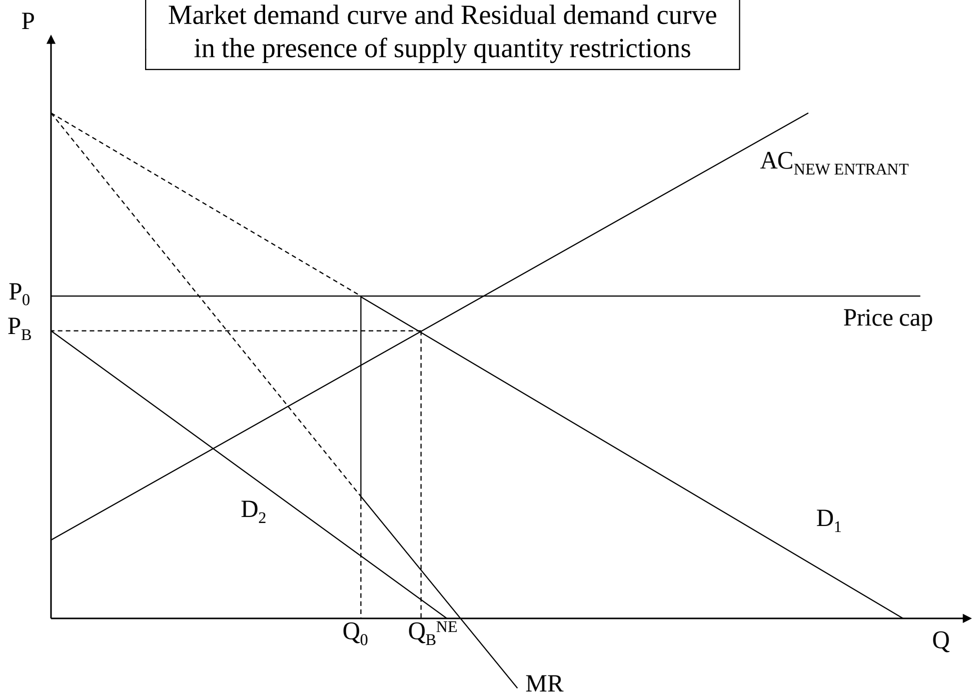
Examining these three cases, the main issues that differentiate the outcomes relate to the length of period 1 which determines how long the incumbent has to wait until he is allowed to react and to what this reaction is going to be, as well as to what it is expected to be. We note that in Cases 1 and 2, regulation can assist in getting the new entrant into the market, by delaying the adjustment of tariffs. However, as we have seen in Cases 3, that might not be enough to keep the new entrant into the market.

Another possibility for promoting competition would be to allow bilateral contracts for new entrants in the market, thus allowing them to avoid using the wholesale pool, at least for an amount of the electricity that they are supplying. However, looking at electricity supply markets, we find that the introduction of such an exception for new entrants could be a way to actually facilitate entry in the electricity supply market, if the electricity that is offered through the contracts is cheaper than that bought in the pool. This electricity can be cheaper under a bilateral agreement because in this case the generator is facing reduced risk in terms of the hours of operation and might decide that he is willing to accept less profit in exchange for reduced risk. New entrants could be allowed to operate under this framework for a period of time, so that they will have the opportunity to recover entry costs and fixed capacity costs. After that period, the new entrant would have to start buying electricity solely from the wholesale pool, however the retail electricity prices that he will be able to offer might have become more competitive.

This process, should there be generators willing to do so, could gradually lead to the development of a bilateral contracts market between independent generators and suppliers. For such a market to exist and operate efficiently though, market power issues should be addressed first. Also, in order for these contracts to be a sensible option for the generators that participate in them, they should be comparably profitable with the wholesale pool.

4.2.4.4 Supply licence restrictions

Diagram 4.5
Market demand curve and Residual demand curve in the presence of supply quantity restrictions



In Diagram 4.5, we show diagrammatically that the supply licence quantity restriction makes the existence of the price cap irrelevant to the residual demand curve only when $Q_B{}^{NE} \rangle Q_0$. What Diagram 4.5 shows is that in order for the full residual demand curve to be set below the price cap, the supply quantity restriction should be larger than the quantity supplied in the whole market, thus not being a restriction for the specific market.

In the presence of supply licence restrictions, the new entrant should examine how many markets he wants to enter and what quantity he wants to supply in each of these. A supplier could decide to sell smaller quantities to larger markets and make use of the opportunities presented in them, if these markets' retail prices are high and the average cost for supplying low quantities remains low. On the other side it would be more expensive to try to enter multiple markets as the supplier would have to cover entry costs for multiple markets. It is important to note here that the new entrant pays the same wholesale electricity price as the incumbent. However, by supplying limited quantities of electricity in each market, the degree of competition is reduced, making it more possible that we get an outcome like the one described in Case 1 of Section 4.2.4.3.1. So, the degree of entry might be a factor in determining the market outcome, since it could be that the incumbent finds it more profitable to lose a small amount of market share as opposed to trying to force all competition out of the market by undercutting the new entrants' tariffs.

4.2.5 Collusion between suppliers

In the case where the two suppliers decide to act as a monopolist and form a cartel to which both players will be loyal, we would expect the same market price and quantity as before the entrance of the new supplier. The cartel would set price and quantity in the same way as a monopolist, since that is the maximum amount of profits that can be made in the industry [Pepall et al., 2008, page 326]. The profits made in the market and the quantity supplied will be split amongst the two players.

4.3 Supply licence restrictions and the Cournot equilibrium

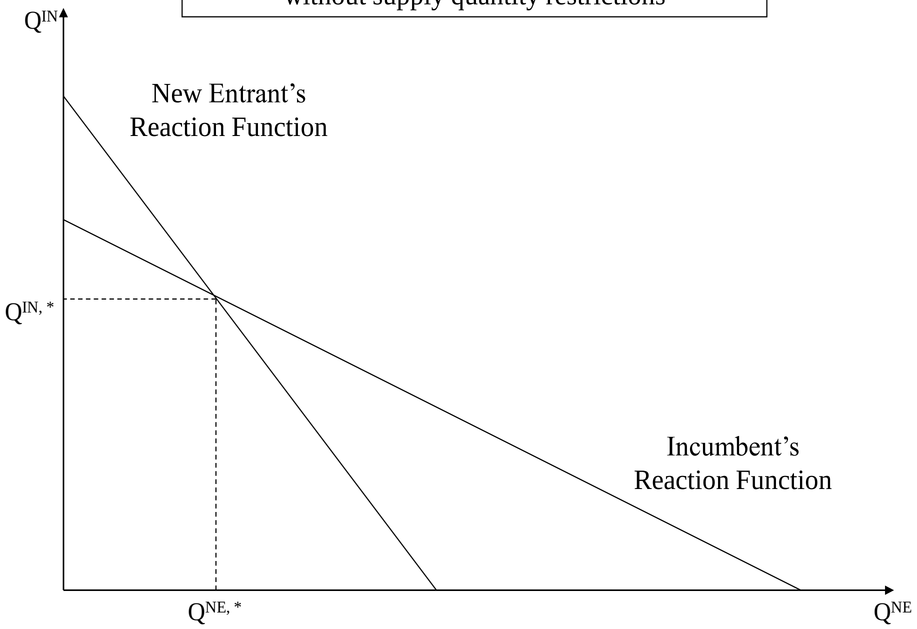
4.3.1 Cournot equilibrium without supply licence restrictions

Firms are setting prices in the market and the markets respond with quantities demanded. However, if we consider that two suppliers compete in the same market and one of them bear a quantity restrictions, we could also examine the market outcome by considering the effect of simultaneous quantity setting. The result is a Cournot equilibrium ([Varian, 1992, pp. 285-288; 2006, pp. 489-493], [Tirole, 1988, pp. 218-221]).

If two competing suppliers set quantities in a one-stage game according to their expectations about the other supplier's quantity, we have a case such as that in Diagram 4.6a. In Diagram 4.6a, the reaction functions of both suppliers are constructed and the Cournot equilibrium, which is also a Nash equilibrium, is given at the point where these two functions intersect.

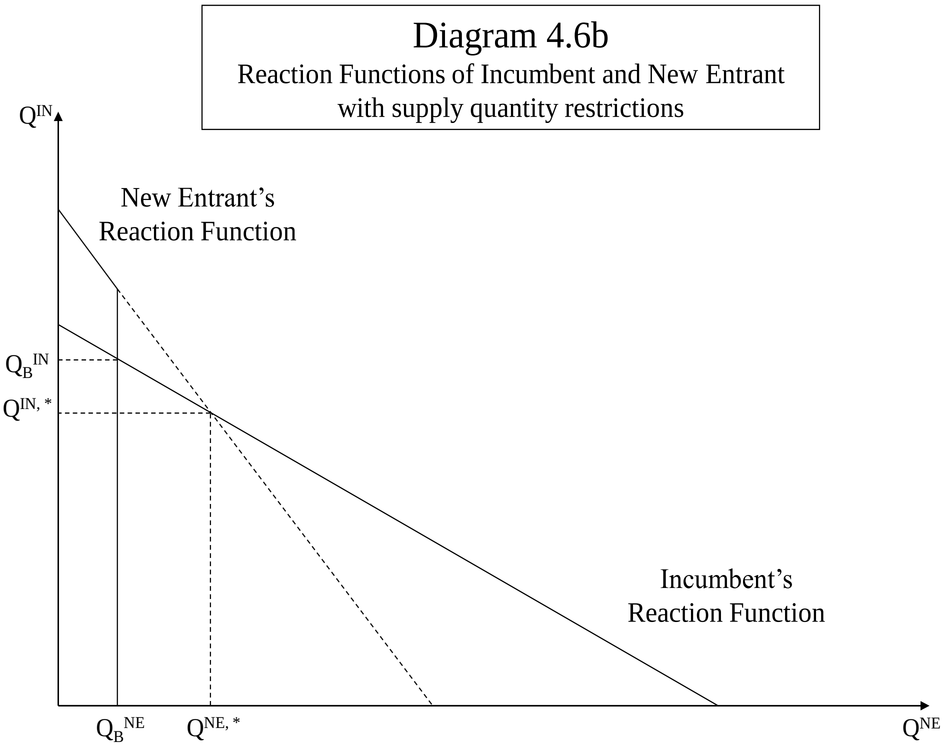
In the model presented in Diagram 4.6a, both firms are selling at the same price. However the output of the new entrant is lower because he faces higher costs. Outputs in the Cournot equilibrium reflect cost differences and the disadvantage that the new entrant has in this regard is that he faces entry costs and fixed capital costs that the incumbent does not face. The quantities supplied are $Q^{NE,*}$ for the new entrant and $Q^{IN,*}$ for the incumbent.

Diagram 4.6a
Reaction Functions of Incumbent and New Entrant without supply quantity restrictions



(Following Varian [1992, page 287], Viscusi et al. [2005, page 111])

4.3.2 Cournot equilibrium with supply licence restrictions



In Diagram 4.6b, we examine simultaneous quantity setting between two suppliers, but with a supply quantity restriction imposed on one of the two of them. The new entrant which is operating under the supply quantity restriction, has the same reaction function as before up to the level of the restriction $Q_B{}^{NE}$. At that quantity level, the reaction function becomes vertical. The equilibrium quantities for the two suppliers are defined by the points of intersections between the reaction functions and these outputs are $Q_B{}^{NE}$ for the new entrant and $Q_B{}^{IN}$ for the incumbent. If the output restriction is relevant it should affect the quantities supplied in such a way that $Q_B{}^{IN} \rangle Q^{IN,*}$ and $Q_B{}^{NE} \langle Q^{NE,*}$.

We note that in Diagram 4.6b, it seems that $(Q^{NE,*} - Q_B{}^{NE}) \rangle (Q_B{}^{IN} - Q^{IN,*})$ and as a result we expect that as compared to Diagram 4.6a, total output falls and therefore prices rise in the market. It would be interesting to consider whether as a result of the increased prices, new entrant's profits are larger under the restriction that these would be without it. And if that would be the case, one could argue that the new entrant can be motivated by this finding to restrict his output voluntarily in order to increase profitability.

4.3.3 Unsuitability of the Stackelberg competition model

The Stackelberg model of oligopolistic competition (Tirole, 1988; Varian, 1992, 2006) has been considered as a possible tool to be used for the analysis of the Greek market. Nevertheless I do not consider this model appropriately fits the characteristics of the Greek case and therefore has been rejected. The reason why the Stackelberg model is not appropriate to this discussion is because of the essential assumption for Stackelberg competition that one of the two players is able to commit to selling a specific quantity, thereby establishing quantity leadership. This assumption is not met in the Greek electricity market, as long-run commitment to quantity cannot be made by any market player. This is due to the existence of the wholesale electricity pool and to the fact that participation in the pool is mandatory for all generators and suppliers, having all transactions made at the pool price for each dispatch period. As a result there is no electricity supplier that can be buying electricity at a wholesale price that is differentiated from the pool price and therefore no supplier has the advantage of being in position to establish the quantity sold in the market. Electricity supplier switching is an option that electricity consumers have, eliminating the ability of any supplier to commit to supplying any given quantity. Additionally, the generators cannot establish quantity leadership because of the existence of the wholesale electricity pool. That is so because the generators that provide electricity to the pool are determined by the daily dispatch scheme.

The Stackelberg competition model could have been useful in modelling the Greek electricity industry if the market design had included bilateral contracts for sale of electricity between generators and suppliers. In that case, commitment to quantity could be possible for electricity suppliers. If such a market design was adopted, the previous monopolist of the Greek market would have been in a very advantageous position relative to the competition and entry could have been halted as a result. That would happen because the previous monopolist could establish contracts for the sale of electricity with all his low-cost power plants and therefore have the ability to offer some amounts of electricity for cost that is much lower than the pool price. Therefore, the previous monopolist would be able to source low-cost electricity that could be offered to consumers for tariffs that the new entrants cannot offer. The mandatory nature of the wholesale pool is the reason why the previous monopolist has such an advantage taken away.

4.3.4 Price competition with cost advantage for the new entrant

Diagram 4.7
Market is shared between Incumbent and New Entrant, in the presence of a supply quantity restriction for the New Entrant.

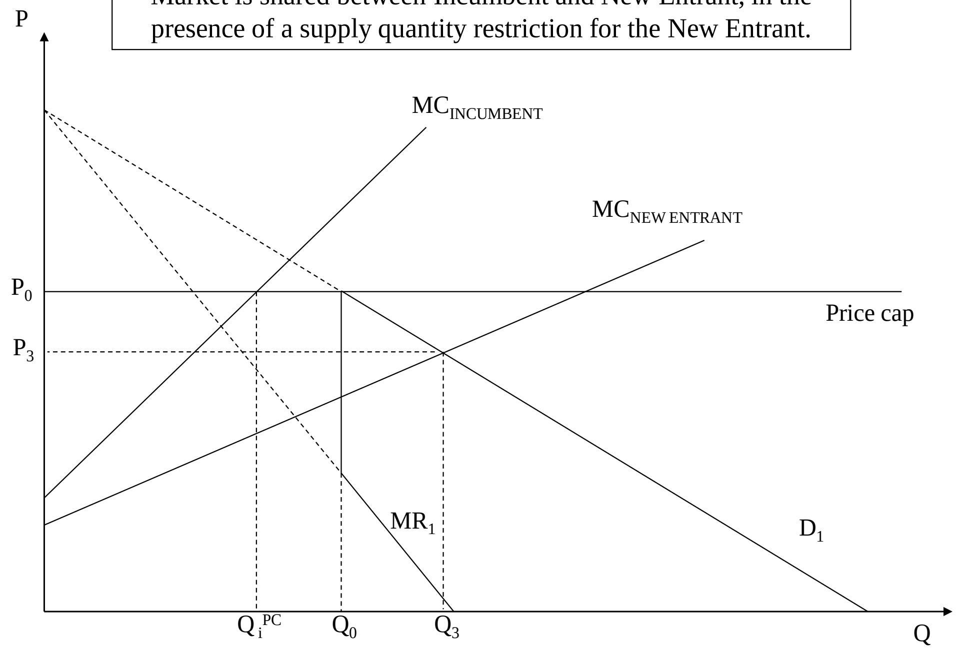


Diagram 4.7 demonstrates what happens when a new entrant shares a market with an incumbent that was forced (by the obligation to meet the market) to supply higher quantity than they would wish to. We also assume that in this market we have a supply cap that constitutes a mandatory tariff for the incumbent. The important difference in this analysis from the previous scenarios is that we assume that the new entrant faces lower costs than the incumbent.

The new entrant is restricted in the output that he can supply and therefore the incumbent decides not to engage in price competition against him, maintaining the market price that he had prior to entry. The incumbent wants to supply Q_i^{PC}, which is the quantity that leads the incumbent in making the maximum profits of the constrained case (the price-capped case), as calculated in Chapter 3. That means that from a purely profit making perspective and without considering the strategic interactions and complications stemming from allowing another supplier to enter the market, the incumbent would prefer for the additional quantity $(Q_0 - Q_i^{PC})$ to be supplied by the new entrant. In order for that to happen in such a way as described here, we make the assumption that the incumbent's cost of supplying Q_i^{PC} remains unaffected when the overall quantity supplied in the market increases. This assumption has been incorporated in Diagram 4.7. This case could approximate reality, since having the new entrant purchasing only a small quantity from a wholesale electricity pool that supplies multiple markets is very likely to have negligible effect on the wholesale electricity price. Therefore the assumption that the quantity that the incumbent wishes to supply is Q_i^{PC} even if the whole market quantity is larger than that, is realistic. We relax the assumption that the output of the new entrant has no impact on the cost of the previous incumbent later in the chapter.

In order for the incumbent to decide on the quantity Q_i^{PC}, that maximizes his profits in the constrained case whilst the market demand is met, a formula is introduced which accounts for the whole quantity supplied in the market. Instead of calculating quantity Q_i^{PC} using formula (C43) from Chapter 3 that maximizes profit of the constrained case when the market demand is not met, we should be maximizing the profits of the constrained case when the market demand is met, but not by the supplier whose profits we maximize. These profits are calculated by formula (C70). In this formula, PC_i is the price cap of the market and the wholesale price of electricity is set according to the full market quantity Q_0.

$$\pi_i^{PC} = TR - TVC = PC_i Q_i^{PC} - (V_i + P_{Ei}^W) Q_i^{PC} \qquad \text{(C39)}$$

$$\pi_i^{PC} = PC_i Q_i^{PC} - V_i Q_i^{PC} - P_{Ei}^W Q_i^{PC}$$

$$\pi_i^{PC} = PC_i Q_i^{PC} - V_i Q_i^{PC} - (a_0 + a_1 Q_0) Q_i^{PC} \qquad \text{(C70)}$$

The process of determining market outcomes in this setting is approached with a three-period game.

In period 1 in Diagram 4.7, the incumbent supplies Q_0 at price P_0 but wishes to only supply Q_i^{PC}, and get a new entrant in the market to supply the additional quantity $(Q_0 - Q_i^{PC})$ in order for the market demand to be met. Therefore the new supplier is facing an opportunity to enter a market and supply quantity $(Q_0 - Q_i^{PC})$ at price P_0.

However the new entrant also faces a supply quantity restriction because of his supply licence, that limits the maximum quantity that he is allowed to supply to Q_B^{NE}. This limitation in quantity is expected to affect the behaviour of the new entrant during period 2, when he enters the market.

If $Q_B^{NE} \langle (Q_0 - Q_i^{PC})$, then the new entrant enters the market and supplies quantity Q_B^{NE} for price P_0. The incumbent, in order for the market demand to be met, is forced to supply quantity $(Q_0 - Q_B^{NE})$ for which it is $(Q_0 - Q_B^{NE}) \rangle Q_i^{PC}$.

If $Q_B{}^{NE} = (Q_0 - Q_i{}^{PC})$, then the new entrant enters the market and supplies quantity $Q_B{}^{NE}$ for price P_0. Market demand is met, since the incumbent supplies the quantity $Q_i{}^{PC}$ that he intended to since period 1.

In these two cases above, we get an equilibrium in period 2. In period 3, no changes are introduced.

If $Q_B{}^{NE} \rangle (Q_0 - Q_i{}^{PC})$, then the new entrant enters the market and attempts to supply quantity $Q_B{}^{NE}$ since that would increase his profits. We know this because the market price is set at P_0 which is higher than the Marginal Cost of the new entrant for all quantities up to Q_0. However, for the new entrant to supply quantity $Q_B{}^{NE}$ with both suppliers using price P_0, the incumbent would have to supply less that the quantity $Q_i{}^{PC}$ that he wishes to. Therefore, the new entrant, in order to capture the market share that he wishes to, has to engage in price competition against the incumbent in period 2. The price that the new entrant sets in period 2, as well as the actual differences between $Q_B{}^{NE}$ and $(Q_0 - Q_i{}^{PC})$ and the length of period 2 are affecting the behaviour of the incumbent in period 3.

In period 3, in order to determine how the incumbent reacts to entry, we need to consider that the incumbent can either respond to the price reduction and to the loss of market share during period 2, as this reaches beyond the quantities that he is willing to allow to new entry, or he could decide not to respond and clear the market at the pre-entry price P_0. Such a decision is expected to be based upon the profitability implications of each of the two options.

As we have mentioned, if $Q_B{}^{NE} \rangle (Q_0 - Q_i{}^{PC})$ then a profit-maximizing new entrant would engage in price competition. If the new entrant is not adopting a profit-maximizing stance and is instead making business decisions by considering strategic positioning in the market, he might act otherwise. The new entrant could decide to accept to supply $(Q_0 - Q_i{}^{PC})$ for price P_0 instead of engaging in price competition, by fear of the possibility that a potential retaliation from the incumbent could force the new entrant to exit the market. Should that occur, then the outcome is the same as the one for the cases where we have $Q_B^{NE} \leq (Q_0 - Q_i^{PC})$ and where the market ends up being split amongst the two suppliers and the price remains at the pre-entry levels of P_0.

By strategic considerations, we refer specifically to the potential impact that decisions might have in the operation of other electricity markets as well as in the future. It could be that these have to do with the significance of market penetration and the impact that it might have on business performance in other markets. Of large significance would also be the concern about the establishment of reputation of the firm for being aggressive or not. Should there be no strategic level considerations, the decision of competing or not is taken on the basis of comparing the different profits that can be made in each case.

In any case where $Q_B^{NE} \langle Q_0$, the market demand will be met by the incumbent. The profits to be made by the new entrant will be determined by formula (71), which is an adjusted version of formula (70), where instead of PC_i, we use price P_i which is the price that the new entrant sets. $Q^{NE,AG}$ is the quantity that the new entrant supplies if he engages into price competition in the market and Q_M is the quantity that the whole market is being served with. In formulas (71) and (72), we calculate the cost of electricity based on the full amount of electricity that is sold in the market.

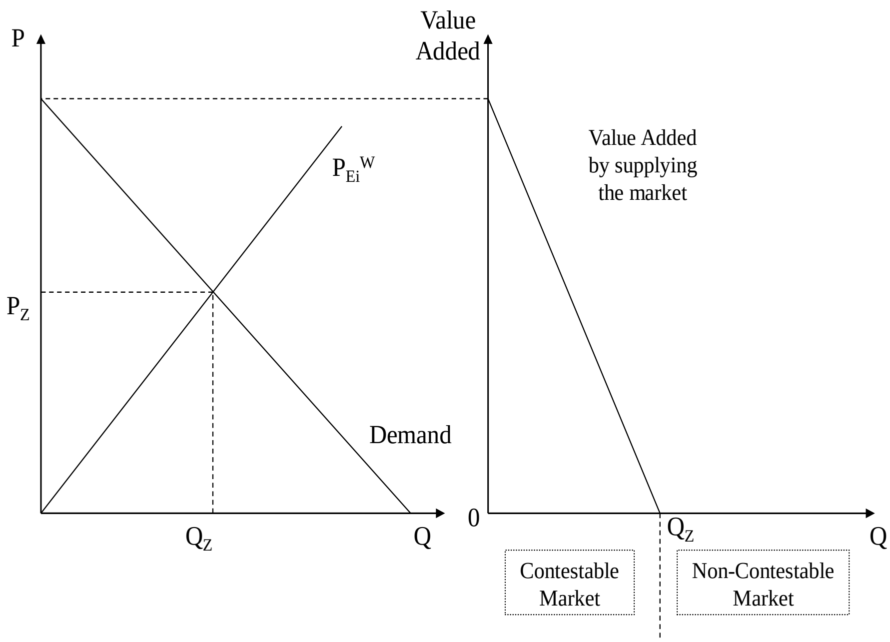
$$\pi_{i,NE,AGGRESSIVE} = P_i Q^{NE,AG} - V_i Q^{NE,AG} - (a_0 + a_1 Q_M) Q^{NE,AG} \qquad \text{(C71)}$$

In the case where the new entrant acts passively in the market and supplies quantity $Q^{NE,PA}$ which is $Q^{NE,PA} \leq (Q_0 - Q_i^{PC})$ for price P_0, the profits of the new entrant are calculated by formula (72), which is an adjusted version of formula (71). The market quantity in this case is Q_0.

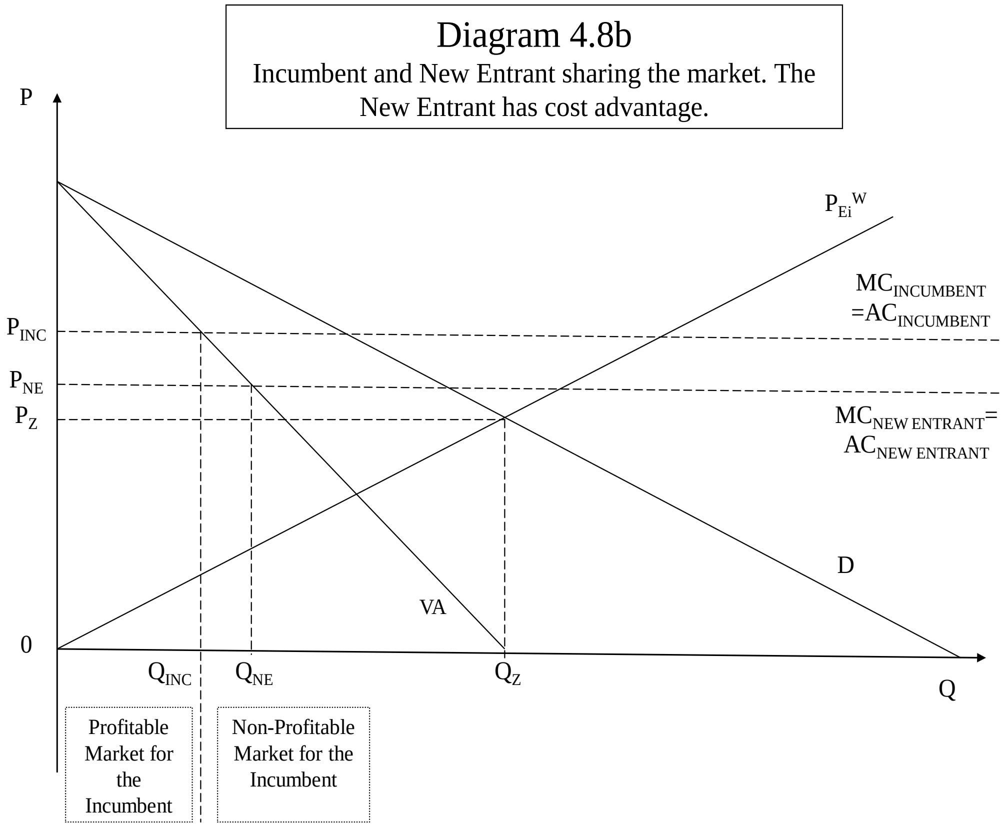
$$\pi_{i,NE,PASSIVE} = P_0 Q^{NE,PA} - V_i Q^{NE,PA} - (a_0 + a_1 Q_0) Q^{NE,PA} \qquad \text{(C72)}$$

Diagram 4.8a

Value added by supplying a market. Retail prices minus the wholesale price of electricity.



In Diagram 4.8a we can see the situation in the market through a diagrammatical setting that incorporates the wholesale electricity prices. In order to create this, we subtract the wholesale price for electricity from the retail price that we get from the demand curve and we calculate the value added that the suppliers get by supplying the market. At price P_Z we can see that the retail electricity tariffs are only covering the wholesale price for electricity, leaving zero revenue for any other cost to be recovered. That happens for quantity Q_Z. For quantities less than Q_Z, we can see that the market can attract entry (as profits might be possible) and for quantities larger than Q_Z it does not attract entry.



In Diagram 4.8b, we take the concept of the value added by supplying the market (after subtracting the wholesale electricity prices) and we combine it with the AC curves for the incumbent in the market and for a potential new entrant in order to determine the outcome of competition amongst them. For simplicity we set the AC=MC curves to be horizontal. These curves being horizontal implies the lack of economies and diseconomies of scale to both firms. Whilst such an assumption might not be entirely true, it is realistic in that most of the economies/diseconomies of scale are expected to be found in electricity generation, not in electricity supply.

The price for which each of the suppliers recovers his full average variable cost is the one that corresponds to his AC curve.

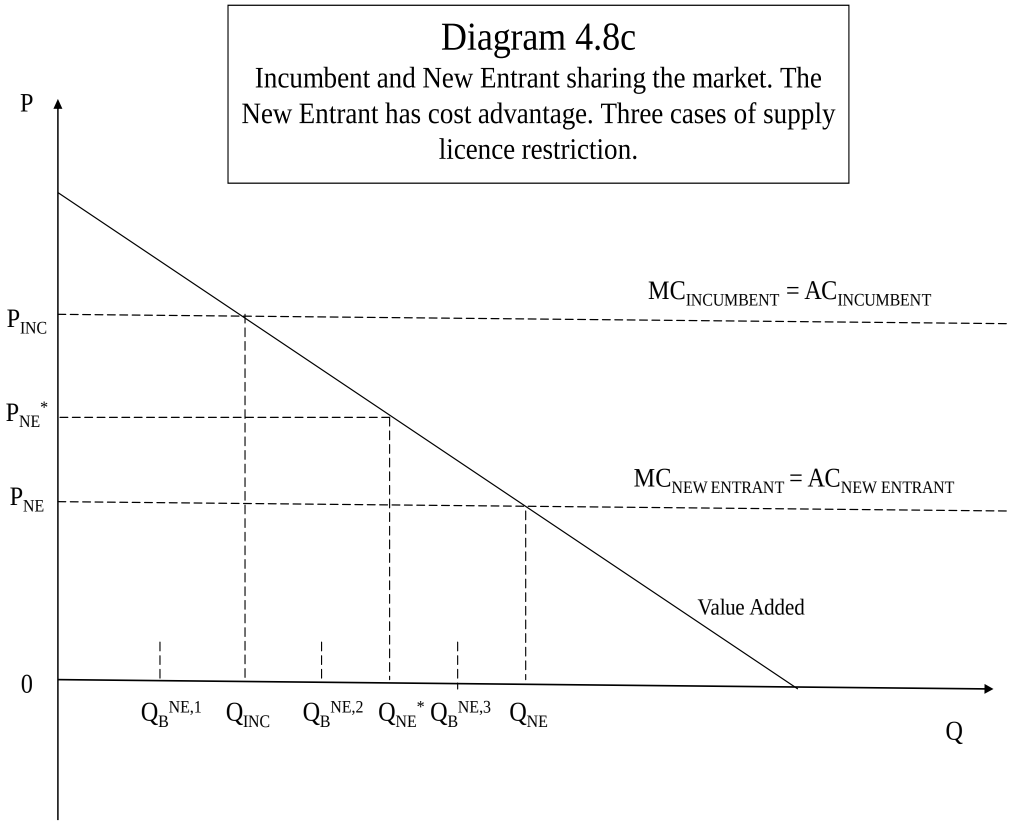
$$AC_{INC} = ATC_{INC} - P_{Ei}^{w}$$

$$AC_{NE} = ATC_{NE} - P_{Ei}^{w}$$

The AC curves and the VA curve are used for decision making in terms of deciding if a market is profitable or not. The D curve is used for market price determination for the given quantities that the supplier has decided that he wishes to supply.

Should there be competition between the suppliers for the market, the supplier with the lowest AC curve will be able to take the whole market by offering a price that is just below the average cost of the other supplier, and the other supplier will get no market share at all. That is the Bertrand equilibrium of competition amongst them and that constitutes a Nash equilibrium.

In Diagrams 4.8c and 4.8d, we present in more detail some cases of price competition between the incumbent and the new entrant.



In Diagram 4.8c, we present three cases where the new entrant faces different supply licence restriction levels. The new entrant enjoys a cost advantage over the incumbent and the profit maximizing price P_{NE}^* for the new entrant in the unconstrained case is lower than the price P_{INC} that the previous incumbent sets. Before entry, market price can get as low as P_{INC}. When it is set at this level, which is the level of the average cost and marginal cost of the previous incumbent, the previous incumbent makes no super normal profits.

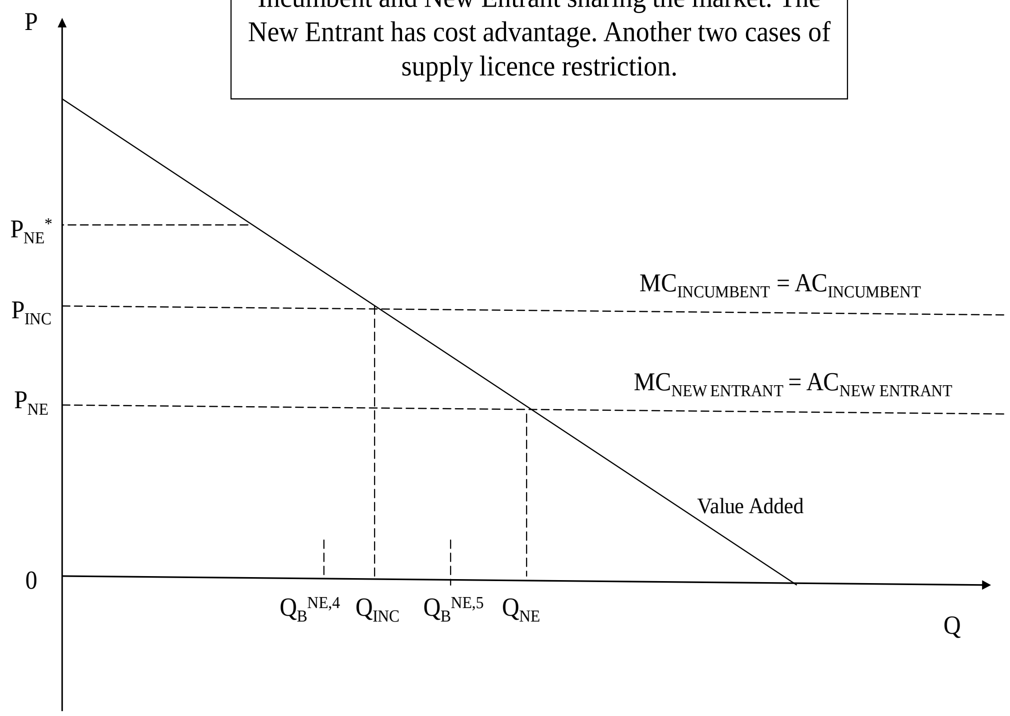
If the supply quantity restriction for the new entrant is $Q_B^{NE,1}$ for which we have $Q_B^{NE,1} \leq Q_{INC}$ then the new entrant enters the market using a price that is slightly under the incumbent's price P_{INC} and that the incumbent cannot match. The new entrant supplies quantity $Q_B^{NE,1}$ and the incumbent supplies the rest of the market. We should add at this point that this is a case that has no Nash equilibrium in pure strategies. We therefore make the assumption that the previous incumbent sets price at P_{INC} which leads to zero super-normal profits.

If the supply quantity restriction for the new entrant is $Q_B{}^{NE,2}$ for which we have $Q_{INC} \langle Q_B{}^{NE,2} \leq Q_{NE}{}^{*}$ then the new entrant enters the market using the price that corresponds to market quantity equal to the supply licence restriction $Q_B{}^{NE,2}$. $Q_{NE}{}^{*}$ is the quantity for which the new entrant makes profits at the monopolistic level. The price set by the new entrant is lower than the incumbent's price P_{INC} and the incumbent cannot match it therefore the new entrant gets all the market, supplying quantity $Q_B{}^{NE,2}$.

If the supply quantity restriction for the new entrant is $Q_B{}^{NE,3}$ for which we have $Q_{NE}{}^{*} \langle Q_B{}^{NE,3} \leq Q_{NE}$ then the new entrant enters the market using the price that corresponds to market quantity equal to $Q_{NE}{}^{*}$. The new entrant supplies the whole market making the profits of the monopolistic case and does not use his full capacity $Q_B{}^{NE,3}$.

Diagram 4.8d

Incumbent and New Entrant sharing the market. The New Entrant has cost advantage. Another two cases of supply licence restriction.



In Diagram 4.8d, we present two cases where the new entrant faces different supply licence restriction levels. The new entrant enjoys a cost advantage over the incumbent, but in contrary to what was happening in Diagram 4.8c, the profit maximizing price P_{NE}^{*} for the new entrant in the unconstrained case is higher than the price P_{INC} that the incumbent sets. Before entry, market price can get as low as P_{INC}. When it is set at this level, which is the level of the average cost and marginal cost of the incumbent, the incumbent does not make any super normal profits. As is the case in Diagram 4.8c, in Diagram 4.8d there is no Nash equilibrium in pure strategies. In subsequent analysis, later in Chapter 4, we use dynamic games to get round this problem.

If the supply quantity restriction for the new entrant is $Q_B^{NE,4}$ for which we have $Q_B^{NE,4} \langle Q_{INC}$ then the new entrant enters the market using a price that is slightly under the incumbent's price P_{INC} and that the incumbent cannot match. The new entrant supplies quantity $Q_B^{NE,4}$ and the incumbent supplies the rest of the market.

If the supply quantity restriction for the new entrant is $Q_B^{NE,5}$ for which we have $Q_B^{NE,5} \geq Q_{INC}$ then the new entrant enters the market using a price that is slightly under the incumbent's price P_{INC} and that the incumbent cannot match. The new entrant gets the whole market and does not necessarily use the full capacity $Q_B^{NE,5}$.

4.4 Summarizing Competition

We considered two supply markets, one facing a small demand and the other facing a large demand, with one incumbent supplier supplying them as a monopolist and no regulation. We also disregarded fixed costs. As we have seen on Diagram 3.2 in Chapter 3, in each of the markets a single supplier will be profit maximizing at the price where $MVC = MR$. If a new entrant attempts to enter one of these two markets by undercutting the market price, the incumbent would compete on price against the new entrant by undercutting the new entrant's price. The outcome of Bertrand competition between the incumbent and the new entrant is that the incumbent will set his price just below the new entrant's, going as far as setting it equal to the incumbent's Average Variable Cost. Although we assume that the two firms face similar cost structure, undercutting the new entrant's price is actually possible given that the new entrant faces the disadvantage of his having to recover the cost of entry (that the incumbent does not face) and the fixed capital costs (these costs are depreciated by the incumbent). In this scenario, the cost advantage of the incumbent allows him to outbid the new entrant, due to the advantage of earlier entry and established position.

However, the new entrant might still be in position to enter the market if the incumbent prior to entry uses tariffs that are high and lead to high profitability. In order for this to be a factor that facilitates entry, the regulator should restrict the incumbent from engaging in price competition against any new entrants, for a period of time. In a two-stage game theoretic approach, this period is period 1, and it provides the new entrant with the opportunity to establish himself in the market. That is something that would not be possible if the incumbent was allowed to compete on price against new entrants immediately after entry.

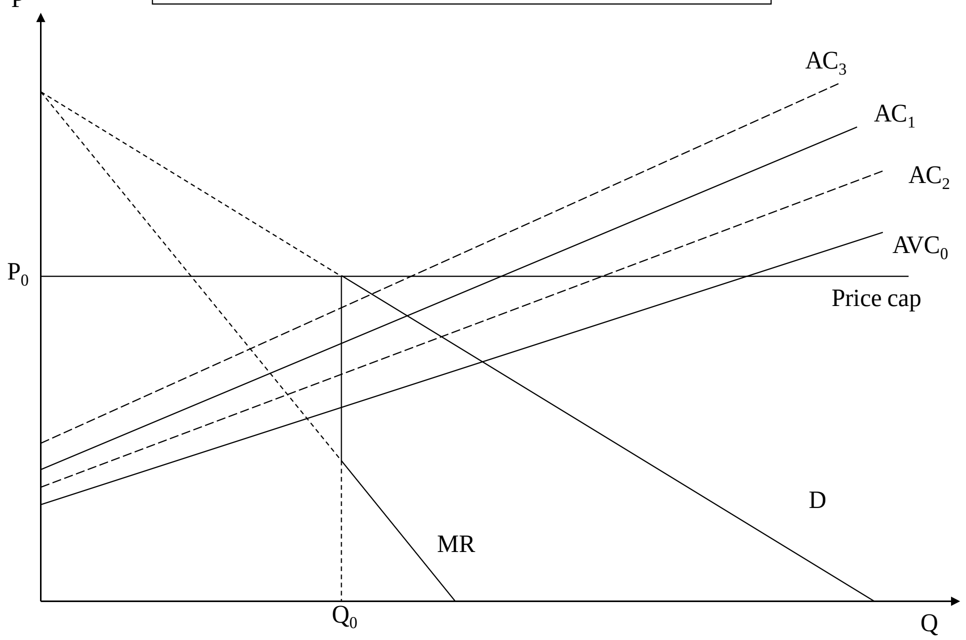
If in the two markets that we have already considered, we add the regulatory constraints of a price cap and an obligation to meet the market demand, these markets might be either profitable (Diagram 3.5b) or not (Diagram 3.5a) for the incumbent. In the case that both of the two supply markets that we examine are non-profitable, these are not attractive for entry by a new supplier. In the case that both are profitable, both of them are attractive and a new supplier might attempt to enter one of them or both. If the new supplier tries to enter the markets by undercutting the market price, the incumbent can outbid him, due to the cost advantage created by the absence of entry costs and fixed capital costs. If the new entrant decides to enter only one of the two markets (with both of them being profitable pre-entry), then the incumbent would be in a much more powerful position as he could use the profits from the one market to subsidize the other and compete aggressively on price. That would consist a credible threat for any potential new entrant in the future, since the incumbent would have signaled his willingness and will have created a reputation for protecting his market share. We will refer to these dynamic issues later in Chapter 4.

The situation gets more unstable if we have tariffs that incorporate distortions and cross-subsidizations. Under such tariffs the incumbent might be making profits in one market and losses in the other. If the incumbent makes losses in the large market and profits in the small one, then the new entrant will only want to enter the profitable market. What complicates matters is that the incumbent would be subsidizing losses in the large market by using the profits from the small one. Therefore the monopolist’s viability when providing such tariffs is maintained by the cross-subsidizations that take place. And one could argue that the monopolistic power that the incumbent might have in such a market would be related to the desire of the government to keep the cross-subsidizations when setting the tariffs.

So, although we expected that the incumbent, given similar cost structure with the new entrant, would be in a position to undercut any price offered by the new entrant, it might eventually not be so, since price competition might result in overall losses for the incumbent. That would be because the need for cross-subsidization increases the incumbent's cost in certain customer categories and reduces his ability to compete on price. This means that serving social agenda through tariffs that incorporate cross-subsidizations is difficult to maintain when we have market competition.

Diagram 4.9

The cases of different AC curves that suppliers face.



We illustrate that case in Diagram 4.9 where both the incumbent and the new entrant have similar cost structure and both of them buy electricity from the pool and are initially facing average variable cost curve AVC_0. The need for the incumbent to cross-subsidize the other unprofitable market that he is serving adds extra cost to the AVC_0 curve and the incumbent ends up with average cost curve AC_1. The new entrant faces the need to cover entry costs and fixed capital costs in addition to his average variable cost AVC_0. Depending on how high these costs are, it might be that the average cost of the new entrant is above or below AC_1. These two cases are shown by average cost curves AC_2 and AC_3. If we have the case of AC_3 and since $AC_3 \rangle AC_1$, the incumbent is in a position to offer a lower price than the new entrant and might be able to try to stop entry. If we have the case of AC_2 and since $AC_2 \langle AC_1$, the new entrant is in a position to offer a lower price than the incumbent.

The details of such a situation would be of great interest to the market regulator. The situation is unstable as the previous incumbent requires that profits made in markets with competition cross-subsidize losses made in other markets. By allowing the new entrant to undercut its price, the previous incumbent will ultimately surrender the profitable market and all of his profits. In order for that not to happen, the incumbent must match the new market price. If the incumbent does not do so, he will not be able to survive and will have to leave all markets. Given that he is not allowed to leave the market, the incumbent has no option but to undercut the new entrant's price in period 2 (when the incumbent is allowed to respond to new entry).

In that case, the incumbent might make a loss in that market or he might fail to produce enough profits to fully cross-subsidize the other market that he serves while making losses. Although that translates to a loss overall for the incumbent, considering his obligation to supply both markets, that loss might be less that the loss made if he surrendered his market share in that market by not competing on price. In that event, he would be left with supplying only the loss making market, without any source of subsidization for these losses. So by being aggressive, the incumbent keeps the new entrant out of the market and manages to make, at least partially, the revenue needed for the cross-subsidization, instead of surrendering all of it.

So, the problem that the incumbent is facing and it somehow seems like a paradox, is that while protecting his market share in the profitable market in order to be able to cross-subsidize the non-profitable one and avoid losses, his price setting leads to losses overall. Nevertheless, the incumbent is better off doing that and getting less profits from that market rather than losing the opportunity to make any profits at all in it, since these are needed to cross-subsidize, to as large an extent as possible, the losses made in the other market. The profit-maximizing decision is therefore a decision where even negative profits are possible. The critical question is how long this situation can be sustained providing social tariffs in the expense of the incumbent's profitability. The government has to decide whether it should be supporting the introduction of competition within the electricity market or supporting the "social" agendas that are put forward through the distorted retail tariffs.

That scenario constitutes a reflection of situations that have emerged in the Greek electricity supply market at the start of 2009 when entry occurred in specific tariff categories and not in others. The tariff categories that were allowing for profits to be made attracted new suppliers and the unprofitable ones were left to be served by the incumbent. The asymmetric regulatory framework included tariffs with distortions and cross-subsidizations incorporated in them [PPC, 2008a, 2010b]. This allowed new entrants to be selective about the customers that they wanted to supply. That rationale of offering to customers retail tariffs that do not reflect cost, seems to have been inherited by the regulatory culture that was relevant for the previous market condition of the vertically integrated monopoly. The fact that the tariffs were not reflecting cost in a consistent manner was evidenced by the ability of other suppliers to offer lower retail prices for the same customer categories and also by the fact that these new suppliers opted not to enter in all of the markets, signaling that some of them were less profitable that others or not profitable at all.

The fact that the response from the regulator in allowing the restructuring of retail tariffs to remove distortions and cross-subsidizations from them was delayed is concerning. This suggests that the issue of proceeding with the regulatory reform and introducing competition could have been so important to the State that the terms and conditions under which this would happen did not matter as much. It would be credible to suggest that decisions taken by the regulator are not as "independent" as one would expect, given his assigned role. The decisions on the issues of the electricity sector seem to be a matter of high political significance and as a result substantial political factors lie behind these decisions. The political element in the policymaker's approach can potentially favour social and income-distributional considerations over purely efficiency ones. That leaves us with the understanding that the deregulated electricity industry is, to some extent, driven by matters of political economy.

4.5 Modeling player's behaviour

4.5.1 Introduction

We want to look at the behaviour of players in a market. The discussion that we will engage in reflects the issues of entry in regulated electricity supply markets. We built a case with specific characteristics that make our discussion results useful in tackling the issues in the electricity supply market of Greece.

We have an incumbent monopolist in a regulated market and a new player that enters its market. The new player does so by offering lower retail tariffs. As a response to that, the incumbent also lowers its prices and matches the new lower tariffs. We examine whether this stance by the incumbent, responding to the entry of a new player in the market in this way, is "predatory". The definition of predatory pricing as can be found in Tirole [1988, page 373] is *"Predatory pricing behaviour involves a reduction of price in the short run so as to drive competing firms out of the market or to discourage entry of new firms in an effort to gain* *larger profits via higher prices in the long run than would have been earned if the price reduction had not occurred".* The idea of stopping entry before it occurs can also be expressed with the term "limit pricing". This is a concept introduced by Bain that refers to a setting where *"if there is a positive relationship between the pre-entry price and the speed or degree of entry, the established firm indeed has an incentive to cut its price"* [Tirole, 1988, pp. 367-368]. The concept of limit pricing is also presented by Shepherd [1979, pp. 288-294].

This situation becomes more complicated when we also take into consideration that it refers to multiple markets coexisting in the same time. For these markets the possibility of cross-subsidization is a credible suggestion. New entry might occur in any one of these markets and not necessarily in the largest ones, since as we have seen the price cap regulation might end up leaving some small-sized markets being more profitable than larger ones. Profits are expected to be the attraction for entry.

We have shown in Chapter 3 that, given the existence of price caps and the obligation to meet the market demand, large markets are likely to be the most difficult to enter, because of their decreased profitability. The central notion behind this discussion is that when market prices are reduced, then new entrants might be deterred from entry.

Tirole [1988, page 306] mentions the three options that incumbent firms have when facing the threat of entry:

"Blockaded entry: The incumbents compete as if there were no threat of entry. Even so, the market is not attractive enough to entrants.

Deterred entry: Entry cannot be blockaded, but the incumbents modify their behaviour to successfully thwart entry.

Accommodated entry: The incumbents find it (individually) more profitable to let the entrant(s) enter than to erect costly barriers to entry".

"Blockaded entry" would be the situation that emerges in markets that have price caps set very low, thereby entry is halted not by the incumbent, but by the market conditions. "Deterred entry" is the situation where the incumbent understands that a market is attractive to new entry and acts competitively even as a monopolist in order to deter any new entrant. The liberal approach that the market rationale incorporates within it would ask for the “accommodated entry” approach.

What we want to look into is a situation where there will be credible threat of entry in the long-run. Market power is present in the market that we are looking at because of the lack of competition. A retail tariff adjustment downwards by the incumbent that occurs post-entry, although it does actually act towards defending and preserving the market share of the incumbent, can in the same time be viewed as the result of the introduction of competition in the market. And that is what one has to look into and try to tell whether that constitutes predatory pricing or adjustment to competition.

In effect, one might argue that the notion of a market where competition exists or where there is credible threat of competition implies retail tariff adjustments in response to decreases in the retail tariffs of the competitors. The expected outcome in this case is not easily determined because of the volatility of wholesale market prices and the expectations for their long-run average level. However the retail price reductions are an expected and desired outcome of the shift from monopoly towards competition.

In order to identify what happens, we need to examine whether what we get as an outcome is consistent with models that describe the behaviour of players in a market. The decisions made at this level are strategic decisions that can have very large impact on the market shares of the supplier in each tariff category and of the profits made.

One major asymmetry derives from the obligation of the incumbent to serve the whole market demand. This becomes relevant since the incumbent has to serve all profitable and all not-profitable tariffs. That means that the incumbent will be in a difficult position trying to match all possible retail tariffs that its competitors might offer, since a part of the profits made there will be necessary to cover losses elsewhere.

The requirement to meet the market demand is a quid pro quo for the utilities that enjoy monopoly status and are being regulated. However when transitioning from the monopoly status to a competitive market, that requirement might be an asymmetry that significantly affects the market outcome.

4.5.2 Reflection in the Greek case

This case that we are discussing attempts to be a stylized presentation of the situations that emerged in the Greek electricity supply market as entry occurred at the start of 2009. That market was operating under asymmetric regulation and with distortions and cross-subsidizations incorporated in its retail tariffs [PPC, 2008a, 2010b].

PPC, before the deregulation of the market, was a vertically integrated state owned monopolist in the Greek electricity industry. That means that PPC as a competing firm found itself in an advantageous position being heavily involved in and related to all the activities in the electricity industry. It is the owner of a large part of the domestic generating capacity, which includes the large hydro-electric plants and the lignite-fired plants which are both very important from a strategic point of view. It also owns the transmission and distribution grid and is the largest retail supplier. All these characteristics place PPC in a unique position given the fact that it stands on multiple positions in the same industry and can affect the market outcomes as well as the market power of its competitors.

Any new entrant in the supply industry, contrary to what the incumbent has to do [Journal of the Greek Government, 2011b, page 3817], does not have the obligation to meet the market demand. Also, there are no imposed tariffs for the new entrant. However, the new entrant is selling electricity which is a homogeneous good and therefore the retail tariffs of the incumbent act as a price cap for new entrants since it would be irrational to charge higher prices and expect to get market share. The new entrant, on the other side, can undercut the tariffs that are set in place and can do so at great speed even being in position to go so far as to offer customized offers to individual customers. In contrary, the incumbent has difficulties in getting new tariffs approved. Tariff adjustments for the incumbent is a slow process with political implications, since these tariffs are approved by the Minister of the Environment, Energy and Climate Change. Joskow [1973] argues that the length of such a process when it refers to a monopolist requesting tariff adjustments from the market regulator, is very long.

In response to the introduction of new entrants in specific tariff categories, PPC has restructured its tariffs from 1/1/2011 [PPC, 2010b]. These new tariffs matched perfectly the tariffs chosen by one of the competitors of PPC in the supply market at that time. The new entrants were pricing below the PPC tariff in order to attract customers and earn market share. By matching their tariffs, the incumbent has taken away from the new entrants the price advantage that attracted new customers, leaving no incentive for customers to switch. That could be considered an entry deterrent stance by the incumbent, that signals to all other possible entrants its determination to keep its market share and in the same time leaves the new entrant in a position where the price cut offered to possible customers is no longer available.

Having looked at the mechanisms of how price caps affect the suppliers' profitability in Chapter 3, we can assume that the decision for the adjustment to the retail tariffs of PPC in 2011 suggests that the previous tariffs were not reflecting the overall costs of electricity accurately [PPC, 2010b] and were allowing for super-normal profits to be made in the markets where entry occurred and losses in the markets that did not attract entry. The imposition of those new tariffs implies that previously we had cross-subsidizations between markets as mentioned by PPC in its business plan for 2009-2014 [PPC, 2008, page 6]. We could be suspicious of cross-subsidizations when we have a profit-making market that allows its supplier to offer electricity in other markets for tariffs that normally result in low profits or even losses. These profit-making markets of the previous tariff structure ended up being the attracting pole that led to the introduction to the market of new suppliers.

The new tariffs, if they eliminate super normal profits in any tariff category, will lead to a situation where there will be no tariff category that offers adequate revenue to cover for losses elsewhere. As a result the market will get competitive price setting and the benefits of competition are going to be passed on to the consumers through reduced retail prices. However that will only happen for those consumers that were getting electricity for high retail tariffs. The consumers that were supplied under low retail tariffs will have to face tariffs that reflect the actual cost of electricity that they consume.

That would mean that there is less room to be exploited in the market by suppliers that are "cherry picking" the customer categories that they elect to serve. These "premium" customer categories, were not only providing higher return to the investors that elected to serve them as suppliers, but also offered greater cushion against the risks of increased wholesale electricity prices, being able to still be profitable even when facing increased and volatile wholesale electricity prices.

It is also important that PPC deciding to request for a change in its tariffs is not a decision that should be taken easily. Decisions on retail tariff adjustments, being bureaucratic, tend to be infrequent and in some occasions these also include a commitment from the policymaker that tariffs will remain unchanged for a period of time [Journal of the Greek Government, 2011a]. Joskow [1973] notes about similar cases with monopolists and regulators in USA that after being granted tariff restructuring, the next increase or decrease in the tariffs would need another 18 to 24 months as a result of the way regulatory agencies operate when dealing with these issues. This is an issue that is not restricted to the USA but rather applies to regulated industries around the world. For the Greek electricity market, this means that PPC should be very careful during tariff setting discussions, as re-adjustments are hard to make.

Another implication for the market is that PPC is not in position to make gradual tariff reductions when engaging in price competition, as it does not have the right to adjust tariffs at will. So, when tariffs are being restructured, the market gets competitive tariffs at the first adjustment that occurs. Additionally, this lag that the regulator presents in adjusting tariffs, can act in a protecting manner to new entrants in electricity supply. These new entrants enjoy a period where the incumbent is not competing against them and have the opportunity to establish themselves in the market and gain market share. If the incumbent were in a position to compete against them immediately after they entered the market, the chances that the new entrants would be forced to exit the market would be largely increased.

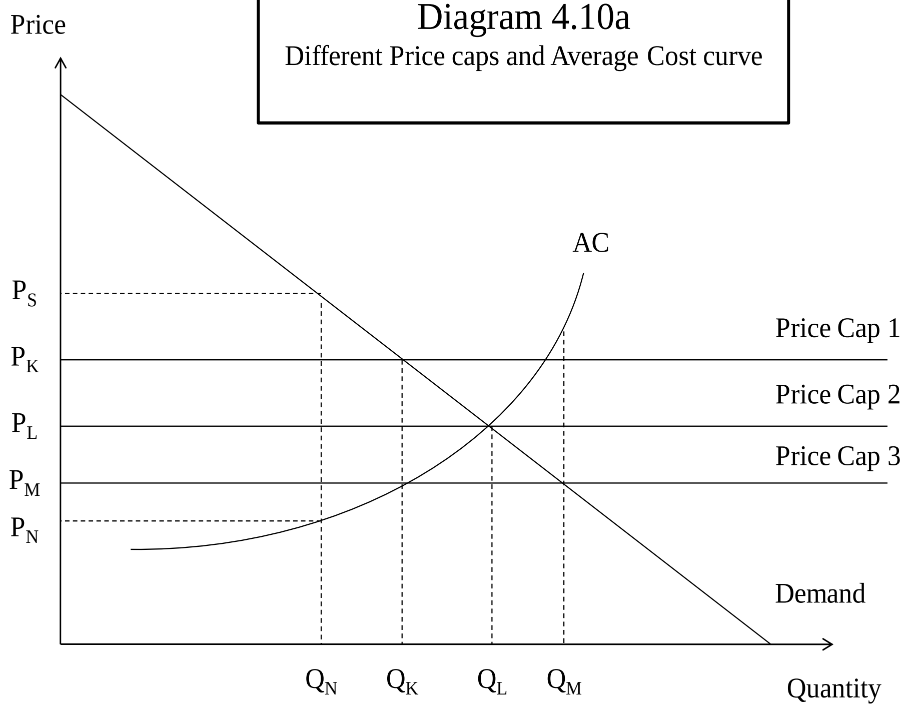
4.5.3 The case of the introduction of a supplier in one market by using imported electricity

Although in the previous model we looked at what happens when two players are in the market at the same time, we did that in an analysis that incorporated fixed price caps/imposed tariffs for the most cases. If we want to examine what a "bidding war" might look like, we should look into the situation from the viewpoint of comparing the average cost with the different possible price caps. We do this in Diagram 4.10a and we assume that the new entrant does not bear an obligation to meet the market demand and also does not need to use the wholesale market. Newbery [1998a] has investigated the idea of a wholesale electricity market that operates with an electricity pool and bilateral contracts through theoretical modeling. In our approach we combine a wholesale electricity pool with imported electricity. However, it is important to note that this approach also covers allowing bilateral contracts between generators and suppliers instead of electricity imports.

Diagram 4.10a represents a theoretical approach. This does not take into consideration some important issues of electricity markets. We assume that the new entrant can serve a part of the market by solely importing quantities of electricity. That could only be so for very large customers. Most of the other customer categories need to have their electricity demand matched on a minute-by-minute basis. Therefore the new entrant, in addition to whatever amounts of electricity he imports, he also has to buy part of the electricity that he supplies from domestic generators, just in order to be able to cover the demand volatility. Nonetheless, and given that the largest part of the electricity is bought through imports, we disregard the effect that prices paid in the pool for small amounts of electricity has on the new entrant.

Also, for simplicity we will assume that both the incumbent and the new entrant are facing identical average and marginal cost curves. However a very important point is that since the new entrant is importing electricity, the quantities supplied by the new entrant do not increase the pool price and also the output supplied through the pool does not affect the new entrant's cost. Therefore if the new entrant only imports small amount of electricity, the cost of supplying that electricity might be less than the cost of supplying electricity by buying through the pool.

Diagram 4.10a
Different Price caps and Average Cost curve



Diagrams 4.10a and 4.10b present the case where a market is served by two suppliers, with these two suppliers buying electricity from different sources. We assume that as the electricity demand increases for each supplier, the cost of wholesale electricity that these suppliers pay to their generators increases as well. However we set the model so that the wholesale electricity cost only increases in relation to the individual electricity demand faced by each supplier. A key issue in

our analysis in Diagrams 4.10a and 4.10b is that the new entrant is in position to set a price P_N and a quantity Q_N and commit to supplying this, creating conditions of Stackelberg competition ([Varian, 1992, pp. 295-298; 2006, pp. 481-487]; [Pindyck and Rubinfeld, 1996, pp. 427-428], [Estrin et al., 2008, pp. 330-333]). Although the new entrant does not enter first in the market, his ability to enter by offering lower retail tariffs and committing to the quantity that he will supply, creates Stackelberg competition conditions.

We can see on Diagram 4.10a that under the price cap regulation, the market demands for a price cap P_K that quantity Q_K be supplied. A new entrant in this market, not having to meet the market demand, might decide to enter offering a price $P_N \langle P_K$ and supplying $Q_N \langle Q_K$. The quantity Q_N is the quantity that the new entrant can import. Key to the determination of P_N is that it is a price that undercuts the current price of the incumbent. However that might not be enough. In order to the market entry to be successful, price setting should make it difficult for the incumbent to match the new entrant's price and also this price should be creating significant incentive for customers to switch electricity supplier.

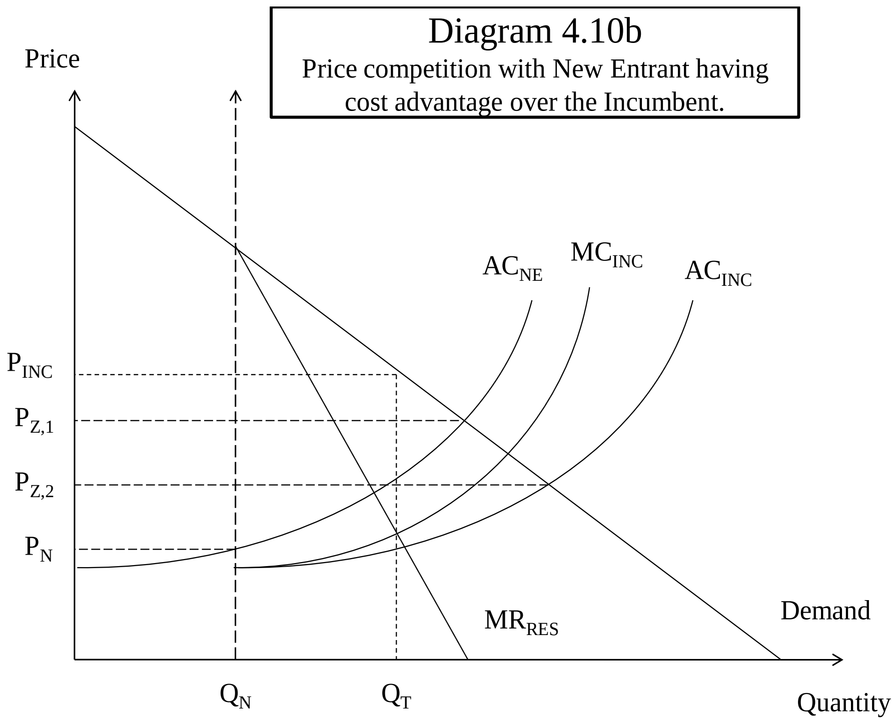
We examine whether by lowering the price cap, the incumbent gets worse off or not. In the Greek case, the price caps that we are referring to, are mandatory tariff for the incumbent. The competitive behaviour for the incumbent would be that he matches the new entrant's price. However, the incumbent has to consider the profitability implications of doing so, as well as the feasibility of such a plan, given that the cost of the incumbent is largely determined by the wholesale electricity market, whereas the new entrant is protected from the wholesale pool volatility and therefore might be in better position to offer low tariffs. Also, if the prices paid for the imported electricity are fixed, this provides the new entrant with a lower amount of risk by serving the market, as opposed to doing so by using the wholesale pool. This is because the imported electricity can be bought under terms that can be negotiated individually, whereas the pool prices cannot be controlled by the new entrant.

If the price cap is decreased at P_L which is the price level at which the average cost curve meets the demand curve, then quantity demanded in the market expands to Q_L but the new entrant remains in the market and is unaffected, supplying Q_N for price P_N. The incumbent has to supply the additional quantity $(Q_L - Q_K)$ as well as the previous quantity $(Q_K - Q_N)$, and that is done in favorable terms, as the average cost at level of output equal to $(Q_L - Q_N)$ is lower than the price P_L , given that AC is an ascending function. We need to state that when referring to "favorable terms" we mean that the incumbent is profitable. The same as those mentioned for a price cap P_L apply for any price cap within the range over $P_S \rangle P_i \geq P_L$.

For price caps $P_i \geq P_S$, there is no market left for the incumbent. The incumbent sets price P_S and quantity Q_N is demanded in the market, however all the market is cleared at price P_N by the new entrant.

The situation becomes ambiguous for reductions of the price cap to any levels lower than P_L. If the price cap is set at P_M, which falls within the range $P_L \rangle P_i \geq P_N$, quantity supplied expands to Q_M and the new entrant still remains in the market and is unaffected, supplying Q_N for price P_N. The incumbent supplies quantity $(Q_M - Q_N)$ and that is done in terms that are unspecified. In order to determine whether the incumbent is profitable, we should compare price cap P_M with the average cost of the incumbent for supplying quantity $(Q_M - Q_N)$. So, any tariff reduction below P_L should be carefully considered, given that as price caps are getting lower, the quantity demanded expands and the incumbent's cost, which is determined by the pool, increases. In this case, it could be that the incumbent might consider allowing "accommodated entry" to occur.

In Diagram 4.10b, we examine the reaction of the incumbent to the entry and establishment of the new entrant. The new entrant sets the quantity that he will be supplying at Q_N and commits to it, leaving the incumbent to serve the rest of the market. In Diagram 4.10b, for the new entrant the market starts from the start of the horizontal axis and ends at quantity Q_N. For the incumbent the market starts from Q_N and extends from there. The incumbent faces the market demand curve for quantities larger than Q_N and the residual Marginal Revenue curve MR_{RES} that corresponds to the part of the market that is left to him. The marginal cost curve MC_{INC} and the average cost curve AC_{INC} of the incumbent are drawn to be starting from quantity Q_N. The incumbent, acting in a profit maximizing way, chooses to supply quantity $Q_{INC} = Q_T - Q_N$ that is the quantity that corresponds to $MC_{INC} = MR_{RES}$. The minimum price that the incumbent can set in the market, given the position of the new entrant, is $P_{Z,2}$. This is the price for which the incumbent does not make super-normal profits. The minimum price that the new entrant can set in the market if he would attempt to serve the whole of it is $P_{Z,1}$. In a market setting such as the one of Diagram 4.10b, the new entrant is not in position to take the whole market based on price competition, since the new entrant has no cost advantage over the incumbent.



In Diagram 4.10a, the "predatory" stance from the incumbent would be to lower the price cap at P_N or even lower, deciding to endure a period of losses until the new entrant is forced out of the market. Then the incumbent would become again a monopolist and would increase the price cap again to even higher prices than before, increasing profit-making levels. In order for that to happen, the incumbent needs to be in control of the tariffs and with no regulatory monitoring of the market for anti-competitive practices.

The point here is that this constitutes an asymmetric setting that might result in splitting the market between the two suppliers and at the same time reducing the average cost, since more low cost wholesale electricity sources are used. However we should note that this reduction is not due to increased efficiencies. The incumbent could have anyhow imported the electricity himself (assuming of course that the cost of electricity is lower than the retail tariffs) and could have sold this electricity under his own tariffs, increasing his profits. And in the Greek case, the incumbent actually does so. The existence of the new entrant and the use of reduced tariffs by him results in reduced producer surplus in the market and increased consumer surplus by supplying electricity at a price which is much closer to its actual cost.

In Diagram 4.10a, we assumed that both suppliers are facing identical supply curves. That is quite unlikely to happen in the real world. However the main point was not the AC curve but the fact that the cost figures of the two suppliers were disconnected. The idea of suppliers facing different average cost curves has also been mentioned in Diagram 4.2. In terms of the determination of the cost structure of the incumbent, we need to say that although the incumbent has depreciated assets and might be expected to have a cost advantage because of that, the presence of cross-subsidization between profitable and non-profitable markets for the incumbent adds extra burden to some of the cost curves in the profitable markets (which are also the ones where competition occurs), as it has also been shown in Diagram 4.9.

As we have seen, the decision of the new entrants to use imported electricity could bring them in an advantageous position and could facilitate entry and in the same time increase consumer surplus.

In extension, this outcome could emerge if instead of imported electricity, we allow within the market for the existence of bilateral contracts for the domestically generated electricity. That could however be problematic given the size of the incumbent, since it could result in having the incumbent contracting with himself and excluding the other generators from the market, since they will not be able to dispatch their units for most of the time.

4.6 A Game Theory Approach

Modeling competition within a duopolistic market setting usually involves a game theoretic approach. Well established analyses are presented in Tirole [1988], Varian [1992, 2006], Pindyck and Rubinfeld [1996] and Estrin et al. [2008].

We consider a variety of settings in order to look into the situation that might emerge. In the Greek case we have a small number of market entrants resulting in an oligopolistic situation. This specific oligopolistic setting of the Greek electricity supply market also incorporates asymmetries that are related to the obligation of the incumbent to meet the market demand, to the ability of new entrant firms to potentially manage the quantities supplied and the load profiles of their customers with the purpose of managing their capacity payments, as well as to the established position of the incumbent and to the difficulties faced by new entrants in getting consumers to switch electricity supplier.

We approach this issue using Bertrand competition and the game of the Prisoner's Dilemma. We also examine how the outcomes of the Prisoner's Dilemma are altered by the fact that the actual market for electricity can be better approached through a repeated game. The repeated game makes the potential for collusion more possible. In doing so, we note that an important part of market analysis has to do with examining whether entry deterring strategies are employed by the incumbent. That is very difficult to determine, as prices set by competition through a Bertrand equilibrium, can also act in an entry deterring way.

Although there potentially are no predetermined market outcomes that liberalization is expected to deliver, we could approach the issue of the desired market outcome using a general estimation of what a market where competition has been successfully introduced looks like. In such a market we would expect to find a large number of suppliers that engage in price competition. This price competition is expected to drive the market price towards the direction that eliminates super-normal profits from the suppliers.

A number of factors might not allow the market to be split equally amongst those suppliers and therefore still allow the incumbent to maintain his market dominance.

Such factors could be the ones that determine electricity supplier switching behaviour by the consumers as well as pricing strategies employed by market participants.

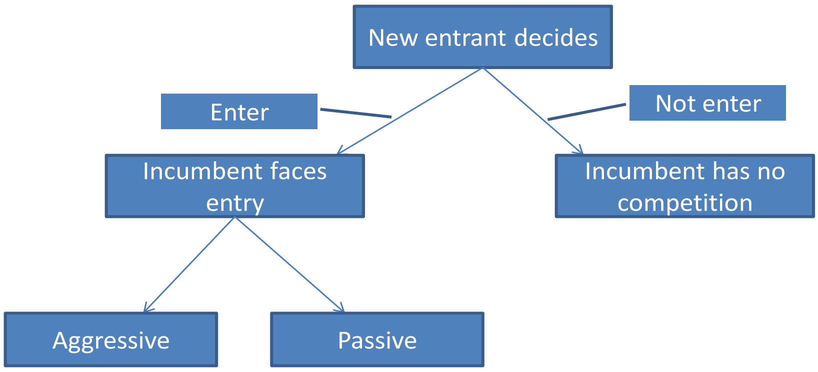
Nonetheless and even without having the market equally split amongst the market participants, the Bertrand equilibrium between the numerous electricity suppliers is expected to deliver retail prices that are formed by the forces of competition. We expect such pricing to remove cross-subsidization and for electricity prices to reflect the full cost of electricity.

4.6.1 The two-stage game

One way to approach this is to think of a two-stage sequential game with one incumbent and one possible new entrant as represented in Diagram 4.11. In the first stage the new entrant decides whether to enter or not and in the second stage, if the entrant has entered, the incumbent decides whether to act aggressively or collusively. If the incumbent acted in an entry deterring way, the incumbent would threaten to respond aggressively if entry occurred. If that threat is considered credible by possible new entrants, then the expected income to be earned by entering the market is perceived to be restricted. That is what happens at the first stage of the game. At the second stage and since the new entrant has already entered (and there is no threat of further entry), it is in the interest of the incumbent to act collusively as we will see later. Of course the best outcome for the incumbent would have been if the new entrant had stayed out of the market.

Diagram 4.11

The two-stage game



(Adjusted from Varian [2006, page 517] and Pepall et al. [2008, pp. 282, 299, 300, 303])

Below we have Table 4.1 with some proposed rewards for the players.

	Aggressive Incumbent	Passive Incumbent
No Entry	(10,0)	
Entry	(-5,-5)	(5,5)

Table 4.1: Proposed rewards for the players in the two-stage game

Since we have assumed that the game is a two period game, in the second period, the optimal strategy for the incumbent is to act collusively (passively), since that is where the game ends and the incumbent benefits from having positive rewards with a passive response as compared to the negative reward from an aggressive response. Such a concept is also suggested by Tirole [1988, page 257].

4.6.2 The repeated games approach

Acting aggressively when new entry has already occurred would require a different game setup for it to be a credible strategy. We assume a repeated game, with an infinite number of periods. Given the infinite amount of periods involved, we set the model to be that the new entrant is facing some probability that the game will continue for at least another period. The game that we are considering is between two players, the incumbent and the new entrant. The incumbent is in the market from the start and the new entrant can potentially enter. However, the new entrant can only enter once and if he exits he cannot re-enter the market. In some occasions that we will examine, forcing the competition to exit the market is the best outcome for the incumbent. In the case where we have multiple players considering entry, the behaviour of the incumbent and the outcome of forcing out the first new entrant, signals the aggressiveness of the incumbent, establishes his reputation and acts as an entry deterrent factor for the remaining possible entrants.

After a new supplier enters the market, sunk cost which is incurred makes the decision to leave harder [Viscusi et al., 2005, pp. 172-173]. In order for an exit decision to be made, the long-run average revenue has to be below the long-run average variable cost. In order for any new entrant to decide to enter, the new entrant should have a way to gain market share, and given the homogeneous nature of electricity and the lack of any differentiation, customers are expected to be mainly attracted on the basis of prices offered to them and marketing. Wieringa and Verhoef [2007] propose that other factors as well are important to customers switching supplier, however in our discussion, we will only consider prices as the method of attraction.

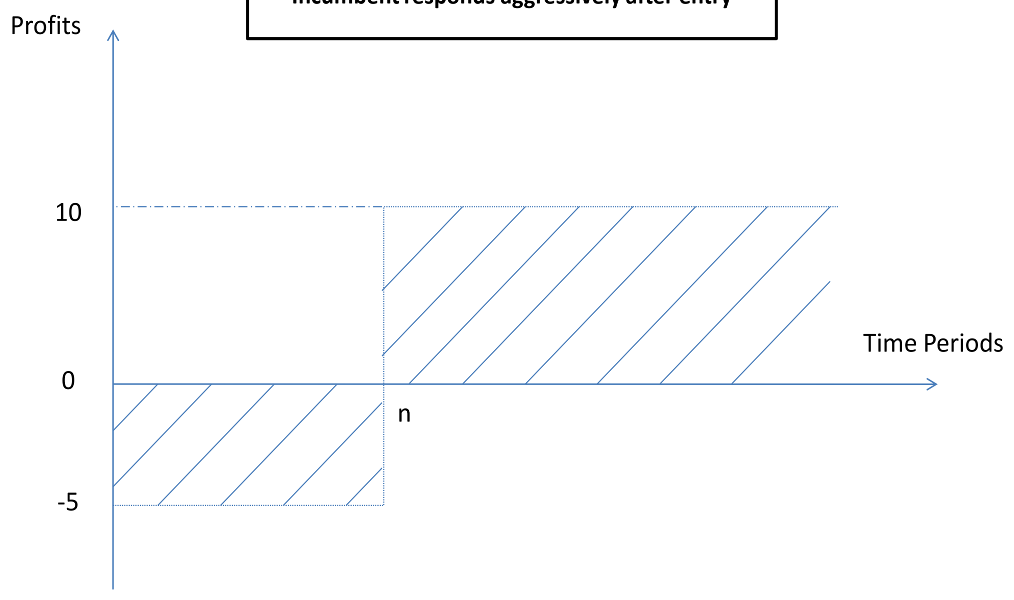
The profits of the aggressive incumbent in the case given in Table 4.1 are equal to:

$$Profit = \sum_{t=1}^{n} \frac{-5}{(1+r)^t} + \sum_{t=n+1}^{\infty} \frac{10}{(1+r)^t}$$

The r that we are using as a discount rate is the cost of capital of the incumbent. If these profits have a positive value, then it makes sense for the incumbent to consider forcing the new entrant out. The scenario where the incumbent sustains a period of losses that are made up by the increased future profits is shown in Diagram 4.12. The shaded areas below the horizontal axis are the losses and the shaded areas above the horizontal axis are profits of the incumbent in the scenario where he acts aggressively after entry. These areas are graphing the profits and losses without discounting them. That means that in Diagram 4.12, we are not taking into account the time value of money.

Diagram 4.12

Incumbent responds aggressively after entry

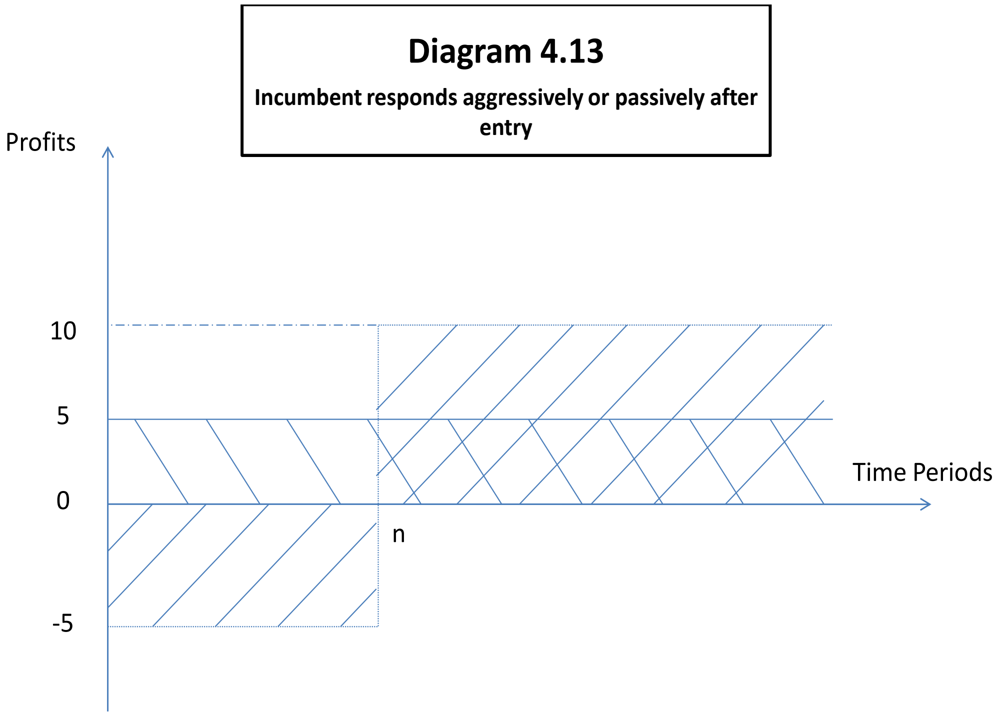


When deciding whether to be aggressive or not, the incumbent compares the profits that will be made if he is aggressive with the profits that will be made if he chooses the other possible alternative; that is to share the market by acting passively.

Expressed formally, the incumbent should act aggressively if:

$$\sum_{t=1}^{n} \frac{-5}{(1+r)^t} + \sum_{t=n+1}^{\infty} \frac{10}{(1+r)^t} > \sum_{i=1}^{\infty} \frac{5}{(1+r)^t} > 0$$

The diagrammatic presentation of this situation can be seen on Diagram 4.13. Similarly as in Diagram 4.12, the areas in Diagram 4.13 are graphing the profits and losses without discounting them. That means that in Diagram 4.13, we are not taking into account the time value of money.



(Adjusted from Viscusi et al. [2005, page 309])

The number of possible entrants is also relevant. In the way that we have looked at the situation, we have considered that there is only one possible new entrant. For two possible players, after entry occurs, the incumbent has to evaluate what is the cost of forcing out the new entrant and becoming again a monopolist and what are the profits to be gained from such a decision and then he has to compare it to the outcome if the two firms share the market. This has been shown in Diagram 4.13 in a diagrammatical fashion. The profits earned by acting aggressively are equal to the area from time period n to the later periods where profits per period $\pi = 10$ are made minus the area from time period 0 to time period n for profits per period $\pi = -5$. Of course, when doing the algebraic calculations, these values need to be appropriately discounted.

These decisions become more complex when we also consider the implications that there might be for other possible new entrants as the stance of the incumbent is of strategic significance as it creates a reputation. The signals that decisions taken on one market give to possible suppliers in other markets need to be taken into account. So in a wider context with more markets and more possible new entrants there might be a strategic interaction in the decisions taken.

This is expressed in the formula given below that describes the rewards of the incumbent in case of aggressive behaviour:

$$Profits = \sum_{t=1}^{n} \frac{-5}{(1+r)^t} + \sum_{t=n+1}^{\infty} \frac{10}{(1+r)^t} - \sum_{t=1}^{\infty} \frac{FLoM}{(1+r)^t}$$

$FLoM$ are the future losses in other markets which will not occur if the message of the aggressive incumbent convinces possible new entrants not to attempt entry. $FLoM$ takes negative values as it refers to losses so that given it has a negative sign, it increases profits. Correctly determining the actual value of $FLoM$ is very important as this might have a very large impact on decisions.

Without the existence of $FLoM$ it would be much easier for the incumbent to decide to act in a “accommodating” way. That would presume that each market is treated individually. The strategic positioning that one gets by considering $FLoM$

makes it much less likely that an incumbent would “accommodate” and increases the chances for the incumbent to decide to be aggressive.

4.7 A three-stage game

4.7.1 Introduction

We will consider this game twice, using different rules concerning the operation of the markets. This is a three-stage game that we are looking at.

- In the first period, the incumbent is in the market and the new entrant is outside of the market and is considering entry. Both firms are aware of the existence of one another and the incumbent anticipates that the new entrant firm considers entering the market. In Period 1, the incumbent decides on the level of retail tariffs. For simplicity we assume that there can only be two tariffs: an expensive tariff called High Tariff and a cheaper tariff called Low Tariff. We assume that both of the suppliers are in position to survive in the market by using any of the two available tariffs. Also, for simplicity we assume that throughout the whole game, the market demand does not change when market tariffs increase or decrease. In Period 1, only the incumbent moves.
- In the second period, after the incumbent has set his tariffs in the first period, the new entrant decides whether to enter or not. If entry occurs, the new entrant also decides on the tariffs that he is going to use. Similarly as was the case in Period 1 with the incumbent, the new entrant can choose between the two available tariffs: High Tariffs or Low Tariffs. In this period, only the new entrant moves.
- The third period is a period that is played if entry has occurred in Period 2. In this period, both the incumbent and the new entrant are moving simultaneously and are allowed to adjust their tariffs between the two options that are available in this game.

4.7.2 Rules set 1

1. When suppliers have the same tariffs, they get even shares of the market.
2. When one supplier undercuts the other supplier's tariffs: Lower tariff supplier gets the whole market. This is the standard Bertrand competition assumption.

In the Tables 4.2 and 4.3 we can see two cases where we examine the outcomes with two firms, the Incumbent that is already in the market and has selected one of the two available tariffs in Period 1 and the New Entrant firm wants to enter. As already mentioned, each firm has two options: either adopting the Low Tariff or adopting the High Tariff. We consider that the New Entrant is outside of the market and is considering entry and the Incumbent is inside the market and is charging either High Tariffs or Low Tariffs. Tables 4.2 and 4.3 show us how the outcomes look when we are examining the situation when being still in the first stage of the game that we described.

The case that we are examining at this point is a version of the game of the Prisoner's Dilemma.

	Incumbent has High Tariffs	Incumbent has Low Tariffs
New Entrant has High Tariffs	Market tariffs remain at the monopolistic level (High Tariffs). **Entry is possible** since the New Entrant can be profitable in this case. New Entrant matches the incumbents' tariffs and the two suppliers share the market evenly.	Tariffs are set (before considering entry) to Low Tariff levels, and if the new entrant is not willing to match them, then there is **no entry**. The market is affected by the threat of entry, as it gets the Low Tariffs.
New Entrant has Low Tariffs	Tariffs are at the monopolist level for the incumbent, but the New Entrant undercuts them and offers lower tariffs. **Entry is possible** and the New Entrant takes all the market.	Tariffs are set (before considering entry) to Low Tariff levels and **entry is possible** from the New Entrant, if he is willing to match the Low Tariff. The market is affected as it gets the Low Tariffs.

Table 4.2: Second stage outcomes, Rules set 1

We can see that the New Entrant needs to be charging the same tariff with the incumbent or lower than that in order to be able to enter. The Incumbent cannot do much to prevent entry since the New Entrant gains market share even when there is no price undercutting. The only thing that the Incumbent can do is set Low Tariffs in hope that the market will not be attractive for entry, because the New Entrant might be seeking higher profitability investment opportunities in order to cover his cost of capital. The New Entrant is guided by the profitability that each market presents, but also from his own ability and willingness to offer the lower tariffs, if needed. Given that the New Entrant can survive by providing a Low Tariff, the Incumbent does not have any entry deterring stance available that he can adopt.

Since no entry deterrence can exist, the suppliers in the market, given their small number, might want to consider the possibility of collusion in the periods to follow.

In a real world scenario, it could be the case that the two firms are facing different cost structure. However this has not been assumed to be the case in the game that we are examining here, as we take it that both firms can offer both tariffs and still be able to survive. A potential cost advantage would allow one of the suppliers to offer tariffs that the other cannot match, as we have seen in other cases presented earlier in Chapter 4.

If we consider that the New Entrant has entered the market and has earned a market share, then the Incumbent can only respond to that by charging either High Tariffs or Low Tariffs. The outcomes depend upon the conditions under which entry has occurred. Table 4.3 shows us how the outcomes look when we are examining the situation when being in post entry situation in Period 3.

	Incumbent has High Tariffs	Incumbent has Low Tariffs
New Entrant has High Tariffs	Both the Incumbent and the New Entrant offer High Tariffs. Both players are considering offering Low Tariffs, knowing that if one of them offers Low Tariffs and the other offers High Tariffs, the one with the Low tariffs will get the whole market, leaving no market share for the other supplier. This is a situation with properties of the Prisoner's Dilemma in a repeated game setting [Varian, 2006, pp. 509-514]. They know that if they split the market evenly by offering Low Tariffs, they will be worse off as compared to both offering High Tariffs. Best option might be to collude at High Tariffs but the issue is trust. If this would be a multiple-stage game, there is a possibility for a cartel to be formed. However, the expected outcome in our three-stage game is that both suppliers will charge **Low Tariffs**.	In this combination the Incumbent gets the whole market by offering **Low Tariffs**.
New Entrant has Low Tariffs	The **New Entrant** gets the whole market by offering **Low Tariffs**. Since the Incumbent does not respond by matching the Low Tariffs, he loses all of the market which it taken by the New Entrant.	New Entrant and Incumbent both offer **Low Tariffs** and the market is split evenly amongst them. The Incumbent cannot do anything to protect his market share, other than offer Low Tariffs and get half of the market.

Table 4.3: Third Stage outcomes, Rules set 1

A possible set of rewards for the two firms is proposed in Table 4.4.

	Incumbent has High Tariffs	Incumbent has Low Tariffs
New Entrant has High Tariffs	(6,6)	(0,8)
New Entrant has Low Tariffs	(8,0)	(4,4)

Table 4.4: Rewards, Rules set 1

In the above matrix, the New Entrant has non-zero rewards in three combinations, and these represent the three scenarios under which entry is possible.

As we have seen, in the third period of the game, the market ends up having Low Tariffs. So the market outcome in this type of setting is Low Tariffs that are offered either by one of the suppliers (that gets the whole market), or by both (and they split the market evenly). However, if instead of a three-stage game, this was a multiple stage game, then there would be a high incentive for collusion between the two suppliers, having them both set High Tariffs.

Case 1 is a classic game that adopts standard theoretical assumptions and leads to the two players sharing the market evenly under the Low Tariff, as it is a typical Prisoner's Dilemma game. The possibility of collusion in a game with more periods is also mentioned.

4.7.3 Rules set 2

1. When suppliers have the same tariffs, there is no customer switching.
2. When one supplier undercuts the other supplier's tariffs: The supplier with the lower tariff gets market share that depends upon a number of factors

(amount of discount offered, marketing expenses, time in the market) and not the whole market.

This is closer to a real world scenario, as customers need a variety of incentives in order to switch [Wieringa and Verhoef, 2007].

Tables 4.5 and 4.6 show Periods 2 and 3 of the game. We have two firms, the Incumbent that is already in the market and has selected one of the two available tariffs in Period 1 and the potential New Entrant. Each firm has two options: either offer the Low Tariff or offer the High Tariff. The New Entrant is outside of the market and is considering entry and the Incumbent is inside the market and is charging either High Tariffs or Low Tariffs.

	Incumbent has High Tariffs	Incumbent has Low Tariffs
New Entrant has High Tariffs	Market tariffs remain at the level that they were in Period 1 (High Tariffs), and **no new entry is possible** since the New Entrant does not undercut the Incumbent's price and cannot get market share.	Incumbent's tariffs are set in Period 1 at entry deterring levels for the New Entrant and therefore there is **no entry**.
New Entrant has Low Tariffs	Tariffs are at the monopolist level for the Incumbent, but the New Entrant undercuts them and offers lower tariffs. **Entry is made possible** and the New Entrant gradually takes all the market (time is a concern).	Tariffs are set in entry deterring levels for the New Entrant and therefore there is **no entry.** The New Entrants, although he is willing to match the Low Tariff, he cannot undercut it.

Table 4.5: Second stage outcomes, Rules set 2

We can see that the New Entrant needs to be charging Low Tariff in order to be able to enter and in the same time, the Incumbent should be offering High Tariff, allowing room for the New Entrant to be able to undercut the current tariffs and earn market share. The New Entrant is therefore not only guided by the profitability that each market presents, but also from his own ability to offer Low Tariffs and from the opportunities that will be present as a result of tariff setting decisions in the market during the pre-entry period. It could also be that the two firms are facing different cost structure and therefore the firm with the cost advantage might be in position to offer tariffs that the other cannot. In this game setup, the length of Period 2 is important as it determines the ability of the New Entrant to establish himself in the market without the Incumbent being able to compete on price against him. As already mentioned, the Incumbent decides on the tariffs that he is using during Period 1 and then can only make adjustments again in Period 3, where both suppliers are allowed to change tariffs simultaneously.

In the third stage we consider that the New Entrant has entered the market and has earned a small market share. The Incumbent is allowed to respond to this situation by charging either High Tariffs or Low Tariffs and in the same time the New Entrant can make tariff adjustments as well. The only possibility for entry to occur in Period 2 is with the New Entrant using Low Tariffs and the Incumbent using High Tariffs. Table 4.6 shows us how the outcomes look in Period 3 of the game that we described above.

	Incumbent has High Tariffs	Incumbent has Low Tariffs
New Entrant has High Tariffs	The New Entrant and the Incumbent both offer High Tariffs. There is **no customer switching** and the market shares remain the same as those of the time when the two suppliers started offering the same tariffs.	New Entrant offers High Tariffs, but the Incumbent undercuts them and offers Low Tariffs. **The Incumbent takes all the market** since the Incumbent has his tariffs being undercut. This happens gradually as it takes time for customers to switch supplier.
New Entrant has Low Tariffs	Incumbent offers High Tariffs, but the New Entrant undercuts them and offers Low Tariffs. **The New Entrant takes all the market** since the Incumbent has his tariffs being undercut. This happens gradually as it takes time for customers to switch supplier.	The New Entrant and the Incumbent both offer Low Tariffs. There is **no customer switching** and the market shares remain the same as those of the time when the two suppliers started offering the same tariffs.

Table 4.6: Third Stage outcomes, Rules set 2

Table 4.7 proposes some possible second-stage rewards for the two firms.

	Incumbent has High Tariffs	Incumbent has Low Tariffs
New Entrant has High Tariffs	(0,12)	(0,8)
New Entrant has Low Tariffs	(2,9)	(0,8)

Table 4.7: Second stage rewards, Rules set 2

In Table 4.7, the New Entrant has non-zero rewards only on one combination. That is, when he enters a market where High Tariffs are charged and he offers Low Tariffs. In that case however he does not take the whole market as we assumed that this takes time to occur and Period 2 is not long enough to allow for this.

As a result of the introduction of competition, market tariffs sometimes decrease, moving from High Tariffs to Low Tariffs. In these cases, the market surpluses which were previously taken by the firms are now being taken by the consumers, thus increasing consumer surplus.

Possible rewards for the third stage are seen in Table 4.8. Because of the fact that this is a three-stage game and therefore in Period 3 the game ends, the rewards that we can see in Table 4.8 are what we get in the long run. It is very important to note that in order for the game to reach the third stage, entry should have occurred in the second stage. That means that in the second stage, New Entrant offered Low Tariffs and the Incumbent offered High Tariffs. The rewards that we get in Table 4.8 get there from combination (2,9) of Table 4.7.

	Incumbent has High Tariffs	Incumbent has Low Tariffs
New Entrant has High Tariffs	(3,9)	(8,0)
New Entrant has Low Tariffs	(0,8)	(2,6)

Table 4.8: Third stage rewards, Rules set 2

We can see that in the rewards of the third stage, if both the Incumbent and the New Entrant offer Low Tariffs, then we have rewards (2,6) which are different than the rewards of the combination that allows entry in the second stage (that is: Incumbent offers High Tariffs and New Entrant offers Low Tariffs and the second-stage rewards in this case are (2,9)). For the New Entrant that has already gained a market share, the revenue generated by his market share remains unaffected even if his tariffs are matched by the Incumbent, and the rewards remain the same. However in this case, the Incumbent gets lower rewards in the third stage as he ends up offering lower tariffs than before.

Also, in the combination where the New Entrant offers Low Tariffs and the Incumbent offers High Tariffs, the rewards are 0 for the Incumbent (loses all market) and 8 for the New Entrant (gets all market). That does not happen immediately, as it takes time, however these are the long-run rewards of this combination.

The sum of rewards when the incumbent charges High Tariffs and the New Entrant Low Tariffs (0+8) is the same as the sum of rewards when both charge Low Tariffs (2+6). That is because in each case the customers are going to end up being supplied by the cheaper available tariff, which is the Low Tariff, and the total market rewards made by the customers jointly will be the same.

Also, we observe in Table 4.7 that in the second stage, when the New Entrant enters by charging Low Tariffs, the market rewards fall from (0+12) to (2+9), as a result of the fact that the customers are paying lower prices for the same electricity, depressing profitability. As we move to Table 4.8 and to the third stage of the game, customer switching continues, with the customers moving to the low tariff supplier, market rewards gradually fall even lower and in the long-run end up reaching (0+8). These rewards reflect the effect that competition has on profits, pushing electricity firms to seek efficiency improvements that can provide to the firms the advantage of increased profit margins, or the advantage of being able to decrease prices even more and gain market share by undercutting the prices of the competition.

An interesting note here is that although we consider these market shares to be at a certain level when the tariffs are matched, therefore stopping customer switching away from the incumbent, in a real case scenario would not be always the case. In the real world, we would expect market share to change even with like-for-like pricing as customer switching occurs for other factors as well [Wieringa and Verhoef, 2007].

If this were a two-stage game with no way that the New Entrant could be forced out of the market after the second stage, and also there was no threat of further entry from any other supplier, the best option for both firms in the second stage of the game would be to collude. In that way, the two firms (that for simplicity we consider to be facing similar costs) would split amongst themselves the monopoly profits instead of competitive profits, by having both of them charging High Tariffs.

The possibility of collusion is also present in Tables 4.6 and 4.8. These tables present the market outcomes and the rewards for the two suppliers in the third stage of the game with Rules set 2. In order to reach the third stage of the game, in the second stage the Incumbent has High Tariffs and the New Entrant has Low Tariffs. After entry has occurred, if this is a multiple stage game, it is possible that the two firms realize that it is to their best interest to form a cartel and both of them to offer the High Tariff. In this scenario, the rewards in the market could be like the ones presented in Table 4.8 when both suppliers offer the High Tariff. In any case, the formation of cartel should be making both of them better off as compared to the rewards that we get as a result of competition which is pushing both suppliers to offer Low Tariffs.

The case with the Rules set 2 that we have seen here is a game that adopts some realistic assumptions, as opposed to the classic game of Case 1. Nevertheless, in both games the outcome for the market is the same, as the market gets Low Tariffs and overall the joint profits of the suppliers are the same. What changes is the distribution of market shares and profits. In Case 1 the market is split evenly amongst the two suppliers, whereas is Case 2 it is split unevenly. We should also mention that if instead of a three-stage game this was a multiple stage game, we would have the possibility of collusion between suppliers and of the formation of a cartel.

4.7.4 Expressing Rewards Formally

More formally, we get to see the profits of the suppliers under the first set of rules in Table 4.9. In the first position in the brackets we get the profits of the New Entrant and in the second position we get the profits of the Incumbent. That refers to the case where they both participate in the market.

	Incumbent has High Tariffs	Incumbent has Low Tariffs
New Entrant has High Tariffs	(a,b)	(c,d)
New Entrant has Low Tariffs	(e,f)	(g,h)

Table 4.9: Rewards, Rules set 1, formally

For Table 4.9 we have:

$$a = b$$

$$g = h$$

$$c = f = 0$$

$$d = e$$

$$a + b > g + h$$

In Table 4.10 we get to see the rewards of the suppliers in the first stage of the game under the second set of rules. In the first position in the brackets we get the rewards of the New Entrant and in the second position we get the rewards of the Incumbent. That refers to the case where they both participate in the market.

	Incumbent has High Tariffs	Incumbent has Low Tariffs
New Entrant has High Tariffs	(i,j)	(k,l)
New Entrant has Low Tariffs	(m,n)	(p,q)

Table 4.10: Second stage rewards, Rules set 2, formally

For Table 4.10 we have:

$$i = k = p = 0$$

$$l = q < m + n < j$$

In Table 4.11 we get to see the rewards of the suppliers in the second stage of the game under the second set of rules. In the first position in the brackets we get the rewards of the New Entrant and in the second position we get the rewards of the Incumbent. That refers to the case where they both participate in the market.

	Incumbent keeps High Tariffs	Incumbent adopts Low Tariffs
New Entrant has High Tariffs	(r,s)	(t,u)
New Entrant has Low Tariffs	(v,w)	(x,y)

Table 4.11: Third stage rewards, Rules set 2, formally

For Tables 4.11 and 4.10 we have:

$$v + w = x + y = t + u = k + l = p + q$$

$$w = x = l = p$$

$$i = k = p = u = r = 0$$

By comparing the case for entry in the market as this evolves from the second to the third stage of the game, we get:

$$v + w < m + n < j$$

So, as the customers are switching supplier and are paying for their electricity under the Low Tariffs, joint market rewards for all suppliers decrease.

Also, in order for the Incumbent and the New Entrant to decide to form a cartel, it should be that this decision will make both firms better off. That means that in this case we have:

$$r > x$$

$$s > y$$

What we can see from the above is that the New Entrant has a dominant strategy that he should follow and that is charging Low Tariff. Given that, the dominant strategy for the Incumbent is to also charge Low Tariff. It is very interesting that this is exactly the same outcome as in a Cournot/Bertrand equilibrium [Varian, 2006, pp. 491-495].

This case that we presented here is set as a dynamic game. That means that whatever happens in later stages also affects whatever happens in earlier stages. One very important issue is the effect that entry can have in the Incumbent's profitability and the stance that he might adopt in order to deter it, if he decides that he wishes to do so. Also, the length of the second stage of the game is of very large importance as this is the period where the New Entrant can gain market share without the Incumbent being able to respond. When using the Rules set 2, the dominant strategy for the Incumbent is to charge Low Tariffs and to deter entry. In the case where entry deterrence is successful, although no movements are taking place in the market, the game is actually played and it stops at Period 1, as the New Entrant does not decide to enter in Period 2. Nonetheless, we should note that the Incumbent, for non-market reasons, might decide to adopt a different strategy than the one which we find to be the dominant. However this would suggest that the pay-offs in the game have been specified too narrowly. For example, politics could be involved.

4.7.5 Reflection of this game on the Greek case

This 3-stage game can be used, in terms of the multiple stage game that has been discussed under rules set 2, to describe past events that happened in the Greek electricity supply market. The introduction at the start of 2009 of new suppliers in the market which utilized lower tariffs in order to attract market shares has resulted in lower retail prices in the Greek electricity supply market. As the model that has been presented earlier suggests, entry occurs only in these markets where tariffs were initially set at high levels and not in those in which the tariffs were low. The fact that the suppliers appear to be selective with regards to which tariffs categories to choose to supply is indicative of the fact that this categorization of tariff levels in high tariffs and low tariffs actually existed and exists.

As a result of the pressure that competition applied on the incumbent firm, new tariffs were introduced in 2011 [PPC, 2011c] and these tariffs were adjusted again in 2012 [PPC, 2012g, 2012h, 2012j, 2012k]. Both the tariffs of 2011 and 2012 were the result of competition. Cross subsidization between tariff categories has been mitigated [PPC, 2010b, 2012i], as a result of the competition.

In Table 4.12 we present a parallelism between the 3-stage model that we introduced earlier and the actual events that happened in the Greek electricity industry. In terms of the 3-stage model, we utilize the version that corresponds to the rules set 2, as this is incorporating assumptions that are closer to the actual operation of the industry than the rules set 1. Rules set 1 is better suited to be used in purely theoretical approaches.

Phases of the 3-stage model (rules set 2)	**Greek electricity industry events**
Phase 1:Pre-entry period where the incumbent is the sole electricity supplier in the market. The new entrants are outside the market and are considering entry.	Pre-2009: PPC is the incumbent retail electricity supplier, serving the market under regulated tariffs. Independent suppliers are allowed to enter the market but do not do so.
Phase 2: The new entrant enters the market and the incumbent is not allowed to react by adjusting retail tariffs.	January 2009-January 2011: Two independent suppliers enter some parts of the market by offering tariffs that undercut those of PPC. They gain market share during that time period.
Phase 3: The incumbent is allowed to adjust tariffs and the new entrant also is in position to do so.	Post January 2011: PPC is having its retail tariffs restructured and adjusted to the levels of the tariffs of the new entrants.

Table 4.12: The 3-stage model and the Greek case

An argument can also be made here that the tariffs adjustments that took place in the Greek case were not only due to the actual competition that took place, but also due to the potential for competition and the threat of entry for specific tariff categories [Viscusi, 2005, pp. 172-173].

We could also say that the levels at which Greek electricity supply tariffs are set is such that PPC might be making (or expecting to make) profits in the long run, however these tariffs are not appealing enough to other supplier firms for them to enter in all tariff categories. This is the notion of "limit pricing" as described by Shepherd [1979, pp 288-294]. However, some selected customers categories are indeed facing entry and we assume that to be so because:

- The new entrants are targeting large consumers for whom even very small decreases in the tariffs correspond to significant savings.
- The specific customers that are targeted allow an accurate prediction of the electricity requirements. This means that the new entrant can optimize the management of capacity payments, creating for the new entrants more "room" for profits.
- These specific customer categories might have more profitable tariffs to begin with.

4.8 California's market failure

In this section, we discuss the market failure that occurred in the Californian electricity market in the summer of 2000. Research that attempts to illustrate and explain the circumstances that led to the market failure in this case has been discussed in the work of Joskow and Khan [2002], Beggs [2002, pp. 44-45], Joskow [2001], Lee [2004], Borenstein et al. [2002] and Borenstein [2002]. We compare the Californian crisis to some situations that have emerged in the Greek electricity market, pointing to the fragility of the market in Greece as well as the strong dependence of the industry operation upon PPC. That setting raises concerns over how Greece manages the strategic issue of security of supply.

4.8.1 Similarities and differences between the Greek and Californian cases

In the Greek electricity market, during periods of high demand, wholesale pool prices for electricity end up being very high due to the fact that the full generating capacity of the interconnected system is dispatched and very expensive units end up being used. At the same time, it seems that there is significant market power in the hands of the bidding parties during such periods. The mix of expensive fuels, lack of additional generating capacity, extended need for the use of imported electricity, high electricity wholesale pool prices, market power and the inability of the retail electricity supplier to set tariffs or connect the tariffs with the wholesale electricity prices could lead the Greek market to a California-type crisis. An example of how that could happen has been evidenced during June 2011, when a PPC-Union strike resulted in a number of power units being shut down and the prices in the wholesale electricity pool reached the maximum of 150 euros/MWh.

A significant difference between the Greek and the California case is that in the Greek case, there is no artificially created demand. In the previous years, capacity in the Greek electricity market has been a problem at times, especially on peak demand days. However, even with this problem addressed, as it currently is, capacity alone is not enough to result in decreased wholesale electricity prices during peak demand periods. It is also necessary for this capacity to be owned by multiple generators in order for competition to emerge in the wholesale electricity market and in the recent years the Greek electricity industry is moving in this direction.

In the case of California, the crisis was the result of market manipulations and abuse of market power by companies which participated in the market ([Borenstein et al., 2002], [Lee,2004]). No capacity had been added to the California system for a long period and also no investments in transmission capacity took place. As a result it became possible for some market participants to create electricity shortages. Suppliers were then forced to buy electricity from the pool and pool prices increased to levels much higher than the retail tariffs. Suppliers were selling at loss and in the same time were not able to fully cover demand (and supply interruptions occurred) until they went bankrupt.

4.8.2 The scenario of market manipulation

From a market power perspective, PPC is in a very powerful position, because it is the largest electricity generator in terms of owned capacity and the electricity supplier that serves a very large share of the market. Also, the fact that PPC owns power plants that generate low-cost electricity might allow PPC to keep the wholesale electricity prices at a low level during some dispatch periods. However, if as part of the liberalization effort, a decision was made that a large part of this generating capacity should be sold or rented to other generators, other risks might have emerged. If installed capacity in the interconnected electricity system of Greece is close to, or below, its peak demand levels, then there can be cases when all units and all interconnections are needed to be dispatched.

PPC, being under the control of the state and being almost the sole market supplier, is expected to respond to these high demand dispatch periods both as a supplier and as a generator. However, one cannot be assured that the same behaviour would occur if a large number of these generating units were under the control of other independent generators that might find it more profitable to shut down one or more of these units (for maintenance or by claiming damages that will take the units out of the system) during these high demand periods. That increased profitability would be the result of the increases in the wholesale electricity price which the generators will receive for the electricity sold by the rest of their power plants. It is expected that PPC, being state controlled, would not wish to see such scenario occurring. That is because PPC is highly concerned about issues of security of supply and also bears legal obligations to meet electricity demand. As a result PPC has the priority to supply the markets and does not want any disruptions in electricity supply. Also the scenario described above is not beneficial at all for PPC since by being almost the sole electricity supplier, PPC will be heavily affected by having to endure supplying high volumes of electricity at these prices.

The profits that can be made by the other generators in cases such as the one seen above are profits resulting from exploitation of market power and from taking advantage of PPC's obligation to supply the market and meet market demand as well as of the market conditions. As a result, we conclude that such "California-type crisis" risks needs to be carefully considered as part of the security of supply concerns that are considered during the design of the market.

4.8.3 Suggestions

A proposal to help prevent such an occurrence would be the provision of adequately large installed capacity so that such strategies as the one seen above will not be useful since they will not have a large impact on wholesale electricity price, or for the introduction of retail tariffs that pass on wholesale electricity costs to the consumers. Alternatively, the regulator could impose price caps instead of imposed tariffs. These price caps, whilst allowing competition, could be high enough that over time the suppliers can be compensated for having to endure high wholesale prices for certain periods.

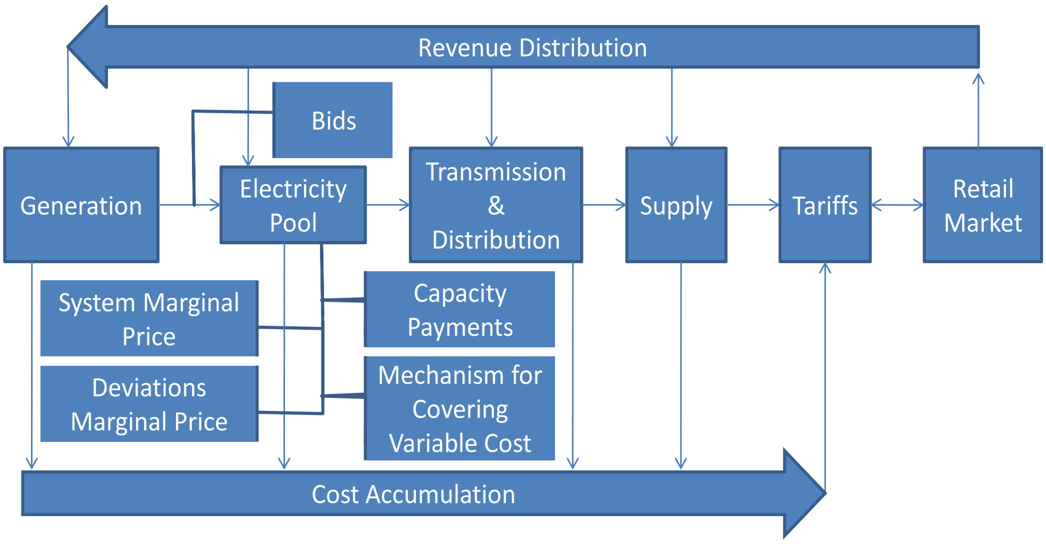
4.9 The incumbent's position

As discussed already, lowering the price caps/tariffs depresses profits, therefore this might discourage entry or lead to entrants exiting the market. In the case of the Greek electricity market, that would make PPC a monopsonist as a retail supplier and would allow it to adopt different bidding strategies as a generator when bidding in the wholesale electricity pool. The fact that this monopsonist has no market power in setting prices or in choosing the quantities of electricity that he is going to supply does not mean there is no market power at all in his position. The engagement of the incumbent in all parts of the electricity industry and its ability to affect wholesale prices, might allow the incumbent to adopt certain strategies in order to take advantage of its position.

That can be seen in the following diagrams. In Diagram 4.14 we can see the flow of revenue for the electricity industry and the direction of cost as well. Revenue is moving from the final consumers to the suppliers, then to the transmission and distribution and to the generators that sold their electricity through the pool. Cost is being accumulated from electricity generation, to transmission and distribution, to supplier costs and is finally brought against the tariffs to be covered.

Diagram 4.14

The distribution of revenue and the accumulation of cost in the Greek electricity market

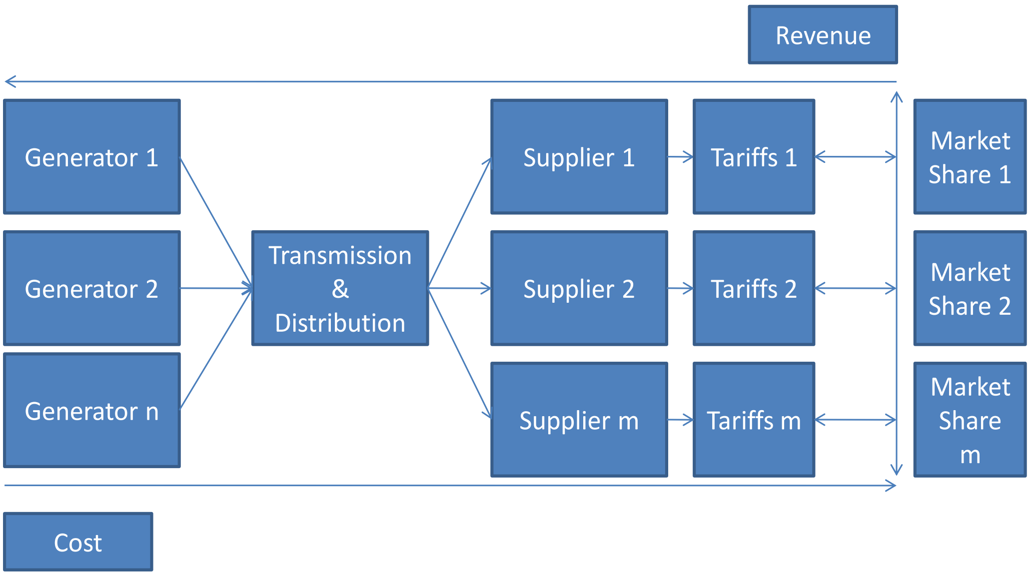


In Diagram 4.15 we can see how different generators can be selling electricity through the pool and the different suppliers can be setting tariffs, getting market share and making profits. The figure refers to one customer category, where each supplier is offering its own tariff. In a liberalized electricity market with competition fully introduced, all customer categories should appear this way. We have n generators competing in the pool (although the pool and the generators serve multiple markets) and m suppliers with each one setting his own tariffs, which are not necessarily differentiated. Accordingly, each one of these suppliers has its own market share in this specific market and these sum to 100% of the whole market.

As long as the tariffs set in a supply market make it possible for New Entrants to enter, gain market share and serve the market profitably, entry will be an attractive possibility. The attractiveness of the overall electricity supply industry (or of any parts of it considered separately) is dependent on the wholesale electricity prices and on the profit that these prices allow to be made in the supply side, for the given tariffs of each market.

Diagram 4.15

Multiple generators and suppliers in the Greek electricity market



4.9.1 Market power and pool price manipulation

With reference to situations that emerge in electricity pools with reference to competition amongst generators, Newbery [1998b] argues that competition in electricity generation calls for at least four competing generators that are facing one another in equal terms.

In another paper, he refers to the fact that market manipulations are more likely in the generation part of electricity markets than in non-electricity markets, thus negatively affecting competition. However it is difficult for the regulators to respond appropriately [Newbery, 2002, page 38].

As Kumar [2001] notes, however, collusion in the electricity supply industry is less likely to occur for a variety of reasons that are related to the technical characteristics of the electricity industry and these affect demand, cost and profits.

In order for the liberalized electricity market to be fully operational, there should be healthy competition not only in the supply market but in the wholesale pool as well.

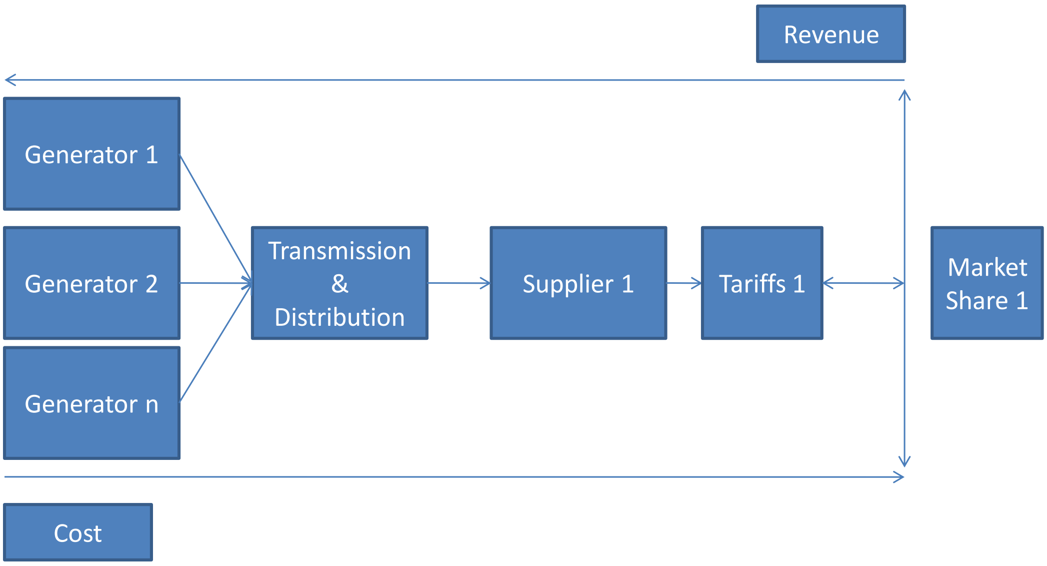
4.9.2 Pushing the pool price down

In Diagram 4.16, we see that when there is only one supplier, instead of the multiple ones that we had in Diagram 4.15, this supplier gets a market share that is equal to the whole market and he becomes a monopolist. So, this supplier receives all the revenue from the market and has to use it to cover the cost accumulated for all the activities necessary for the provision of the electricity service. If this supplier is also a generator with capacity large enough to manipulate the wholesale electricity price downwards, then by doing so the revenues that have to be given to all generators will be reduced. Even if that means that there will be less profit to be made by the dominant firm in the generation part, as all the generators income will be depressed by the low wholesale prices, the firm will be better off overall by increasing its profit margins as a supplier.

However these increased profits will be there only for as long as the firm is the sole supplier, as these constitute the outcome of the exercise of market power. Therefore these profits are not expected to attract entry from new suppliers, as the potential entrants will know that a change in the bidding strategy in the pool by the incumbent can increase wholesale electricity prices and eliminate profitability. And in addition to that, the incumbent has already signaled through his behaviour that he is willing to manipulate the system price in order to accommodate his profitability.

Diagram 4.16

Multiple generators and one supplier in the Greek electricity market



4.9.3 Taking the pool price up

In exactly the same way, one could argue that an incumbent with such extensive market power in the pool could also decide to artificially increase the wholesale electricity price. That could serve to limit the profitability of its competitors in the supply side if entry occurs and eventually take them off the market. That would come at a cost, as such a strategy would make its competitors in the generation part better off by providing them higher revenues. By reducing profits of the other supplier firms, this generator is using its market power to force exit from the market.

In the case where these new suppliers are also generators, that would make the effort for them to be taken out of the market even more complicated, as they will be receiving the increased electricity pool price for their electricity during that time and they will be enjoying increased profits as generators. So such a scenario heavily depends upon the final profitability of their decision to exit or remain in the market, taking into consideration that after the exit, in the absence of competition, the incumbent will stop keeping the wholesale price at high levels.

4.10 Bidding strategies and market power in the Greek electricity market

4.10.1 The current setting

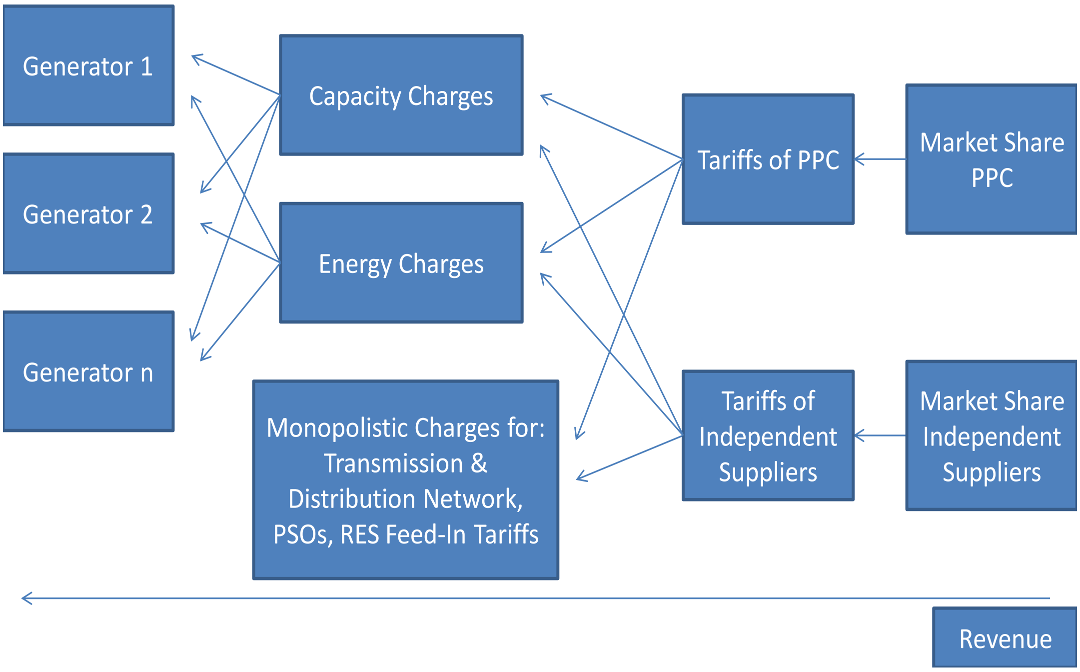
In the Greek case, the benefits of the competition in the supply side of the market were evidenced by the restructuring of retail tariffs. Despite the fact that there has been entry in the supply market to an extent, the largest part of the market is still served by PPC. PPC's market share in the Greek retail supply market was 95.8% in 2010 and 92.3% in 2011 [PPC, 2012c]. In addition, after the exit of some of its competitors in the supply market, PPC has found itself in a position that approaches even more that of a monopsonist buyer of electricity from the pool and at the same time a monopolist supplier of the market. PPC is a supplier that serves a very large part of the market and at the same time the buyer that buys a very large amount of electricity from the pool. This, together with controlling all the lignite fired generation and the large hydroelectric plants, along with other electricity generating capacity, brings PPC in a very advantageous position.

At the same time, we should note that there is competition taking place in the electricity generation part of the electricity industry. During 2010, PPC generated and imported 77.3% of the market demand, but this percentage decreased to 70.1% for 2011 [PPC, 2012c].

The revenue flow in the Greek electricity market from the final consumers to all the market participants can be seen in Diagram 4.17.

Diagram 4.17

Revenue Flow in the Greek electricity market



Given the fact that all electricity transactions take place through the pool, there seems to be some room left for market manipulation and exercise of market power. We assume that PPC's current tariffs are set at a level where profits can be made in the long run. Despite that, the tariffs make it hard for any other competitor to enter the market and compete heavily on price, as this would potentially generate negative profits in the long run.

However, competition in the Greek electricity supply market occurs. That is restricted to specific customer categories and only under specific terms. For example, Elpedison Trading is offering tariffs, which are valid for a two-month period. The low voltage tariffs refer to specific customer categories with pre-arranged maximum allowed capacities [Elpedison Trading, 2012a] and the medium voltage tariffs incorporate zonal charges (depending on whether it is day or night, working day or non-working day) whilst setting a maximum allowed annual consumption and varying the charges depending on the percentages of usage [Elpedison Trading, 2012b]. We should also note that these tariffs also include clauses that allow the firm to adjust retail prices during the length of the electricity supply contract.

Therefore we have a market where retail prices act as a barrier to entry [Viscusi et al., 2005, pp. 168]. That outcome has emerged for PPC as a result of price competition with other suppliers and it could actually be said that this competition might have led to a Bertrand equilibrium, where prices reach the competitive level [Varian, 2006, pp. 494-495].

At this point we should note that there are significant bureaucracy issues and time is needed for retail tariff adjustments for PPC to be made, approved and become effective. It is worth noting that in the Decision of the Deputy Minister of Environment, Energy and Climate Change that announced the 2012 PPC tariffs for Low Voltage, these tariffs can only be reconsidered after a six month period [Journal of the Greek Government, 2012, page 98]. That constraint does not apply for other suppliers that are free to adjust their tariffs, and that are therefore exposed to less risk. But even though new entrants don't face this risk, the issue of having limited entry in specific tariff categories in the electricity supply market could be related to other sources of uncertainty around the potential profitability.

On the other hand, even if PPC tariffs were to be rendered unprofitable, policy-makers and political forces would be very much concerned with reference to the deeply political decision to proceed with increasing electricity retail tariffs. That reluctance could be reinforced by the financial crisis that Greece faces as well as by the political instability and the inability of Greek political parties to reshape the country's economy and to lead the country out of the financial, political and, to an extension, social crisis that it faces.

After the exit of some of the electricity suppliers from the market and given the approach that current suppliers have with regards to the customers that they elect to serve, PPC's position as a supplier is strengthened in what would be approaching a monopsonistic market. In that market, the rational behaviour for PPC-generation would be to submit all of its bids in the pool at the minimum allowed levels set by the Code for Electricity Transactions [OOEM, 2012e, pages 69-70], trying to drive the wholesale pool price down.

There would be no profitability considerations in this bidding for PPC. Minimum bids are set equal to the Minimum Variable Cost for thermal units and to the Variable Cost for hydroelectric units, zero for mandatory hydroelectric, zero for imported electricity [OOEM, 2012e, page 70]. In order for PPC to manipulate pool price downwards, it could try to:

- Declare as much mandatory use of hydroelectric plants as possible for zero price, as long as the actual cost of using these plants is covered by the retail tariffs.
- Import as much low-cost electricity as it can (all prices for imported electricity covering retail tariffs would be acceptable from PPC) and sell it through the pool submitting zero offers.
- Bid the rest of the generating capacity of its dispatchable units for the minimum allowed bid.

If that strategy is successful, PPC will drive the wholesale price down. That is not necessarily a risk for PPC. As we have shown in Diagram 4.16, ignoring any other suppliers existing in the market, and in Diagram 4.17, taking other suppliers into consideration, PPC as a supplier collects revenue for the market and uses it to pay for the cost of wholesale electricity as well as for the use of transmission and distribution network, for the RES feed-in tariffs, for PSOs, as well as for capacity. The lower the amount of revenue that it pays to other parts of the market, the higher the profitability that it achieves by keeping a larger part of the revenue for the supplier. That also benefits other suppliers at the same time, since the wholesale pool price is common for all participants. However it implies very strong competition in the pool.

PPC cannot bid in the wholesale pool using bids that are lower than the minimum ones allowed under the market rules. In that way, a part of its cost for electricity generation is always covered, even if the electricity produced is bought by suppliers other than PPC. Even on the occasions where SMP is increased, this will only be a problem for PPC if the power plants that are dispatched in the daily scheme are non-PPC owned. So the act of PPC trying to decrease the wholesale pool price would not be targeting the actual pool price, but rather the amount of electricity that PPC will be generating at that price. For any given price that PPC has power plants that can offer electricity at, PPC would like to get as many as possible of its own units dispatched. If most of the electricity is generated by PPC, an artificial increase in the wholesale price will only reduce revenue to the extent that additional expenditure will have to be allocated to non-PPC generators.

On the other hand, if the increase of the SMP is not artificial and it is due to an actual increase in the cost of electricity generation, then PPC faces depressed profits and its inability to pass on this cost to the final consumer through higher retail tariffs places PPC in a very uncomfortable position where financial losses can be made.

By this discussion it is easy to be appreciated that PPC, being in the position that it is, can make use of its market power in the wholesale pool. The larger the generating capacity and imported electricity that it manages to get to the pool, the higher the degree of control that is has over the pool price.

4.10.2 Solution 1-Competition

One solution for the other generators would be to reduce their bids and try to compete with the low bids of PPC-owned power plants, so as to increase the usage rates of their power plants in the daily dispatch scheme. The competitive bidding that would come as a result would be expected to drive the pool price down. The competition does not necessarily mean that the independent generators will be bidding their minimum bids, instead it refers to the choice of an optimal bidding strategy that leads to higher payoffs [Li et al., 2011].

However that type of behaviour is the expected one from generators competing in a wholesale pool and the very existence of a problem signifies that it cannot be addressed in this way. If lower bids lead to decreased pool prices, that will actually be serving PPC even more by increasing its profits, as one can see by examining Diagrams 4.16 and 4.17.

4.10.3 Solution 2-Collusion

The other option would be for the independent generators to increase their bids instead of decreasing them. The rationale behind that option is that in the small amount of hours when their units would be dispatched in this scenario, they would have to recover any part of their cost that is not covered by the capacity mechanism and make profits that correspond to their cost of capital. In order to achieve that, the independent generators will have to form a cartel ([Varian, 2006, pp. 495-498], [Pepall et al., 2008, pp. 326-337]). In this cartel the independent generators would have to play amongst them a game similar to the prisoner's dilemma with an infinite number of repetitions. Due to the infinite number of repetitions, this game does not necessarily have the same Nash equilibrium as the standard one-shot prisoner's dilemma. So, if an appropriate trigger strategy is incorporated in the bidding strategies of cartel members to punish those that "cheat", then it could be possible that such a cartel would be able to survive for some time. [Varian, 2006, pp. 506-513].

A problem for that cartel would be the existence and activity of the regulator that could possibly anticipate this collusion and take action against it.

This type of situation would be very difficult to emerge in the pool, were it not for the large amount of generating capacity that PPC has. If the amount of capacity controlled by PPC is reduced, its market power will be lost. However reducing the market power would not be addressed by merely forcing PPC to sell some of its low cost units as the Memorandum suggests [Memorandum of Understanding on Specific Economic Policy Conditionality, 2012, page 35]. All that would be achieved would be to give the opportunity to the new owners of these plants to make the profits that these units are currently making individually.

4.11 The setting of the market tariffs-A policy perspective

The way that the tariffs are set is very important, because this reflects the purposes that the tariffs aim to serve. Tariffs set to serve specific purposes can lead to different outcomes than those expected by a policy encompassing the notion of competition.

From a competition policy standpoint, we would expect tariffs that force suppliers to increase efficiency across all electricity-related activities in order to improve profit margins. In the literature we find research done on the relationship between competition policy and efficiency improvements [Planas Raposo de Almeida Costa and Pita Barros, 2012], on the relationship between competition and productivity through management quality [Van Reenen, 2011], on the effect of electricity industry reform on the productivity and efficiency of the industry in Australia [Abbott, 2006], whereas Tanaka [2011] reviews the issue of energy efficiency in the industry sector.

Also, we would be looking for tariffs that are set by forces of competition. These tariffs are expected to approach as close as possible to the result of perfect competition. This could be achieved for a duopoly through a Bertrand equilibrium, as was suggested earlier in this chapter. In their effort to increase their market share, the suppliers could be encouraged to seek other means of attracting a client base, such as improvements in service quality [Wieringa and Verhoef, 2007].

All this would be additional to the primary benefit of competition: the delivery to the economy of decreased retail tariffs that increase consumer surplus; the increase in buying power by increasing real income through a falling price level (both directly through reductions in expenditure for electricity and indirectly through the incorporation of electricity prices in the price of other goods and services); the increase in the competitiveness of the economy through cheaper electricity which would benefit the Greek balance of payments; and the promotion of economic growth through the fact that electricity is made available to industry and to households for lower prices.

Instead of the revenue and expenditure of the electricity industry being handled exclusively through the channels established by the previous incumbent that is still state controlled, competition could be put to work to deliver the aforementioned results. Should that not happen, there is the risk of sustaining cross-subsidization between segments in the economy. This would occur not exclusively through manipulating electricity prices, but also through taxation. PPC has acted as an instrument of income distribution and welfare policies are suspected to have been put into practice through it. Having served as a platform for policy making, the previous organization of the industry is not compatible with European Integration, and with the idea of activity in the European Economic space.

Tariffs that enforce cross-subsidization and distortions have been referred to earlier. These include:

- Markets that are served with “social” tariffs. Usually that means that the tariff is lower than the tariff that we would get from a competitive setting, where price would equal average cost. Either that means that the supplier makes less than normal profits or in the extreme case, even negative profits. An example would be where electricity is supplied at a price below the wholesale cost. These tariffs make these markets appear very unattractive to possible new entrants. However this behaviour may be acceptable when these utilities serve vulnerable populations, in which case these should be recognized as Public Service Obligations (PSOs).
- Markets that are operating under a tariff that is higher than the tariff in a competitive setting in the same market, where price would equal average cost. The additional profits can subsidize the markets that are served with

"social" tariffs. These high tariff markets, given the presence of these additional profits, appear attractive to entry for new suppliers who can undercut the retail price.

International fossil fuel prices, prices for capacity payments, security of electricity supply, security of fuel supply, EU-ETS emission permits prices, taxation levels, market demand figures, general economic and political stability as well as the regulatory framework of the electricity markets are all very important factors in determining the stability and sustainability of the electricity market. Managing risk is a very important element in decision making and all factors should be weighted in.

4.12 The Greek political economy – A review of the literature

Petrakis [2012] presents an extensive overview of the Greek social, economic and political scene and puts the 2008-2010 financial crisis in this context to discuss the entry of Greece in the European Stability Mechanism. Katsimi and Moutos [2010] also describe the political and economic environment in Greece and relate this to the Greek crisis. They suggest that the crisis has resulted from a series of failures of Greek governments to deal with economic policy issues, which were instead addressed through "Greek statistics".

Bratsis [2010] notes the existence of a deep legitimation crisis in the Greek state. Such crises are identified as having occurred in the Greek political scene in the past as well. The structural issues that are highlighted are considered by the writer to be very difficult to be dealt with in the immediate future.

Lyrintzis [2005] analyses the political party system of Greece, raising questions about the details of the operation of this system, as well as the characteristics of the various Greek political parties. A presentation of the political ideologies that have emerged across the years in Greek politics is made, as well as an attempt to explain the circumstances under which the ‘modernization’ was introduced and accepted by the Greek political scene.

Kotzaivazoglou [2011] examines the extent to which the major political parties in Greece, Nea Dimokratia (ND) and Panellinio Socialistiko Kinima (PASOK), are market-oriented. He finds that both parties are very concerned with satisfying voters and society. Also, the satisfaction of, and support from, party members is considered of critical importance. Additionally, the writer notes that in Greece, voters value short-term benefits over long-term ones.

Leandros [2010] refers to a series of regulatory failures that occurred in Greece with regards to media regulation. Although this area is not related to energy sector per se, the fact that Greek authorities faced difficulties in dealing with established political interests is a useful observation that highlights the operation and interrelation between Greek politics, economic activity and regulation.

Ballas and Tsoukas [2004] investigate another sector of the Greek economy. They consider the health sector and the Greek National Health System. Their findings are useful as they extend to other sectors. They argue that in Greece political agendas tend to be prioritized in decision making over economic rationale, thus rendering measurement of performance according to technical criteria a much less significant matter than it should be.

In a book edited by Botsiou and Klapsis [2011], issued by the Konstantinos Karamanlis Institute for Democracy, a series of interesting articles are presented that largely relate to the issues of Greek politics, governance and the economy. The opinions presented by the various contributors to this edition highlight the importance of politics on the Greek economy as well as some of the peculiarities of the Greek political system.

Fakiolas [2011] refers to the Greek financial crisis that has started since 2009, as well as the borrowing of Greece from the European Union, the European Central Bank and the International Monetary Fund and to the terms of this borrowing. The effects of the crisis for Greece are also discussed, in terms of economic performance and unemployment. The writer also offers a note on the inability of political parties to respond to the circumstances and manage the social impacts of the recession.

Sklias [2011] refers to the political economics of Greece and to the interrelationships that are developed within the European Union. Problematic areas are identified in the political priorities that countries such as Greece have set, setting economic rationale aside.

Mylonas [2011] presents the causes and the consequences of the Greek financial crisis at social and economic level. As causes, the writer suggests the cultural leftovers from the Ottoman period which are related to *"...patronage politics, endemic corruption, populism and nepotism in the country."* [Mylonas, 2011, p. 79]. Also the writer, referring to previous work by Alogoskoufis, suggests as another possible cause to be the *"...strong electroral cycles, which have increased deficits and built up an enormous state debt over time."* [Mylonas, 2011, p. 79]. Additionally, in a quote taken by the work of Kaplan, we get that *"...inflexible social order,[...] which led to economic and political pathologies like statism and autocracy"* [Mylonas, 2011, p. 79]. Amongst others, the writer also suggests that the entry of Greece into the European Economic and Monetary Union (EMU) allowed Greece to borrow more which at the same time there were no appropriate regulatory controls to manage this borrowing. Lastly, the writer suggests as another cause of the financial crisis to be *"the inaction of Greek political elites"* [Mylonas, 2011, p. 80]. When discussing the consequences of this financial crisis, the writer notes in reference to the brain drain and loss of human capital that *"Sadly, another generation will face blocked scial and political mobility as a result of nepotism, clientelism and corruption."* [Mylonas, 2011, p 82].

Smith [2011] refers to the Greek financial crisis and identifies a series of political issues and disfunctionalities which are to be found in the multiple sources that he refers to. The writer highlights aspects of the political system in Greece which reveal its numerous fundamental flaws.

Savas [2011] also notes the existence in Greece of a series of cultural and "cratogenic" problems, with "cratogenic" being the ones that are *"given birth or created by the state […]: subsidies granted as political favours; overstaffed public agencies whose complacent employees engage in make-work activities; workers trapped in sheltered cocoons doing obsolete jobs because of regulations that hinder labour mobility; people's citizenship skills atrophied from disuse; and the belief that the problem is not enough revenue, whereas the real problem, more likely, is too much spending."* [Savas, 2011, pp. 117-118].

Dimas [2011] refers to Greek politics and to the way that the country has been run in recent years by the governments in office. He concludes that there are two ways in which governments act "*when the government's proposed reforms are likely to touch what the public sector or other well-organised interest groups consider to be their "vested rights""* [Dimas, 2011, p.150]. That is either by appealing to the general public and by using Europe as argument for justification or by directly addressing the EU partners and the international financial markets in an effort to enforce the notion that Greece is taking action that aligns with them. What is significant to note is the high domestic power that these stakeholders have and how difficult it is for Greek governments to deal with them.

Diagram 4.18 identifies the various parties that are involved in the decisions taken in the Greek electricity market. Each has a different agenda and a differential ability to realize its own interests. The utility functions that the different participants in Diagram 4.18 have, as well as their ability to command their will, affects the decision making that takes place in the market.

In Diagram 4.18, PPC can be found in multiple boxes and playing multiple roles. It is one of the generators in the market, one of the suppliers in the market (the larger one), the owner of the Transmission Operator (IPTO), the owner of the Distribution Operator (HEDNO) and the owner of the Market Operator (OOEM).

Pollitt and Talbot [2004], present work related to the interactions between governments and their agencies. The existence of this debate suggests that relationships between governments and their agencies might not be as straightforward as might be expected, given their legal and financial status. Similar types of interaction problems are suggested in Diagram 4.18, making the decisions on the electricity market issues hard to take.

The Greek's perception of themselves is presented by Pollis [1965]. However the Greek political, social, technological and economic environment has gone a long way since then and a lot have changed.

It is important to note the observation made by Voulgaris [2000] that Greek students have pro-European feelings, perceiving Europe as a formation shaped on a cultural and political, rather than economic, basis. Additionally, he notes that Greek students form a concept of nation that is determined by culture. The concept of democracy is very significant, being perceived as a form of expression as well as an exercise of power by the people.

This means that, at least in part, the people in Greece are pro-European in their views. This implies that the government is in position to conform to European directives and mandates without incurring significant political cost. The understanding that democracy is a means for people to express their views and put them forward might translate into increased interaction with the political parties, as these are perceived as a means of expression and participation in the Greek political life.

Featherstone et al. [2000] present the behaviour of those who acted as the negotiators on behalf of Greece in the Maastricht Treaty in 1991. Policy is analyzed on the basis of preferences, of strategies used and of the institutional context of the negotiators. What is significant is the listing from the writers of the variety of factors that affected the negotiated outcome and the understanding that the large-scale decisions in the field of politics are complex in their nature and perplexing in their consequences. Using this observation to put Diagram 4.18 into perspective, we can see how the interrelationships between the various parties identified in the diagram can become quite complicated. Interactions might go beyond those publicly stated, sometimes revealing hidden agendas.

In a paper by Arghyrou [2009], comparisons are made between the monetary policy of Greece when it had the Drachma and the policy after the Euro was introduced. The writer examines the monetary policy imposed by the European Central Bank (ECB) and how this fits the Greek economic conditions. He suggests that there is a degree of incompatibility. This understanding becomes relevant when considering the position of ECB in Diagram 4.18 and the fact that the policies that are put forward by ECB can significantly affect the Greek economy.

Weber and Schmitz [2011] discuss the economic, political and institutional determinants of the bank bail-outs that occurred during the recent financial crisis in the EU. The hypotheses that they set out at the beginning of their paper fit the characteristics of the Greek case quite well. The interconnections between the Greek Government and the European Union, the European Central Bank and the International Monetary Fund, which are the entities that provided the bail-out for Greece, are shown in Diagram 4.18.

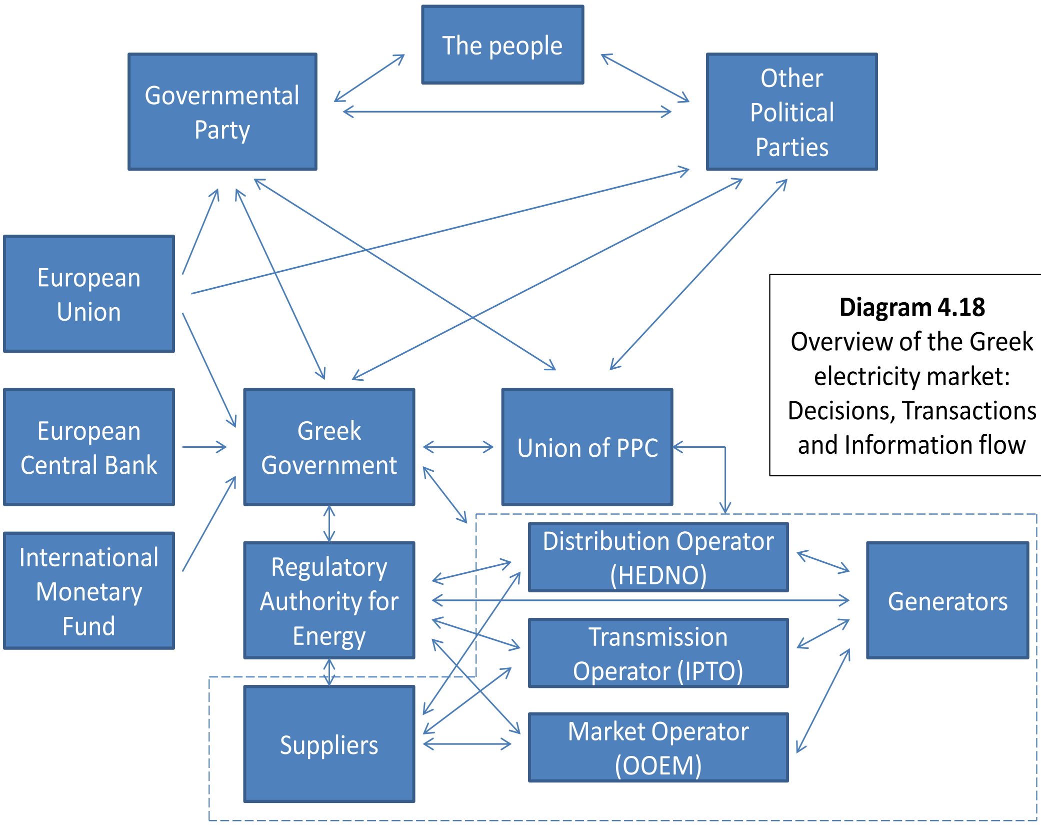
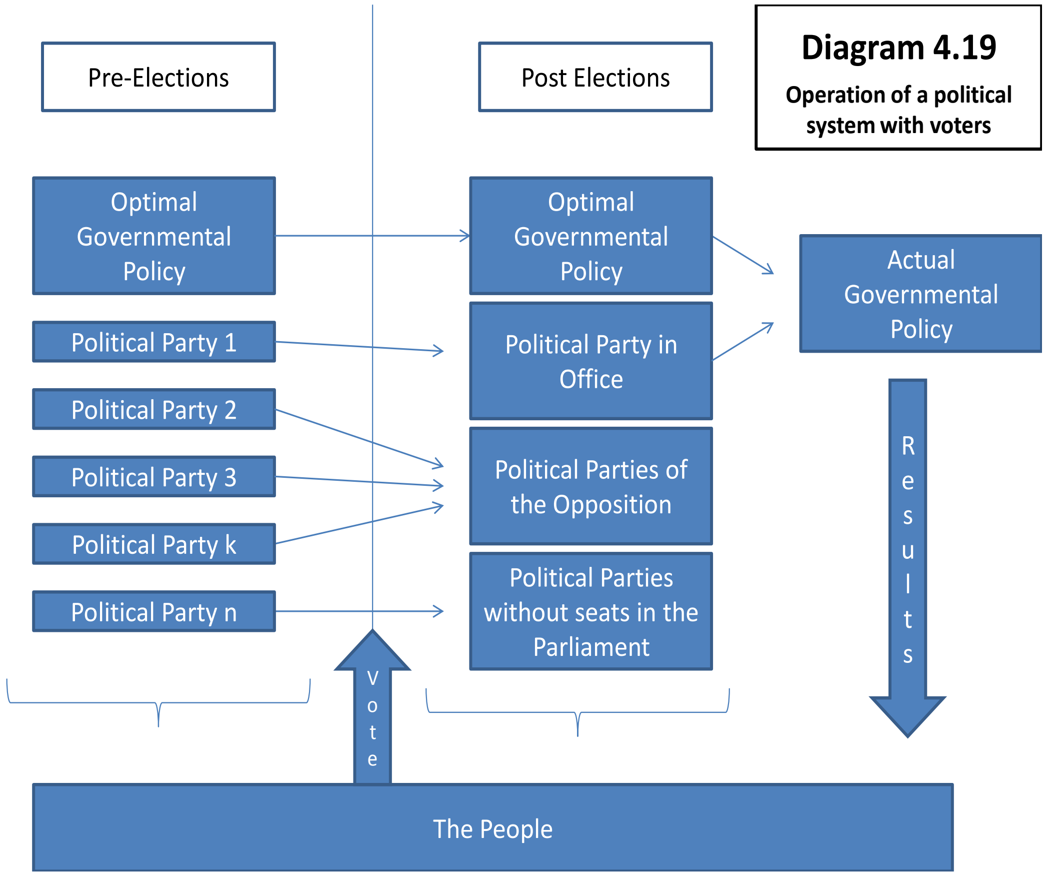


Diagram 4.18
Overview of the Greek electricity market: Decisions, Transactions and Information flow

In Diagram 4.18, PPC is the generator that holds the largest capacity, and also the sole generator that owns lignite-fired and large hydroelectric plants. Also, PPC is the supplier of the largest part of the supply market and the owner of the Distribution Operator, the Transmission Operator and the Market Operator. In order to show that, in Diagram 4.18 we have added a dashed frame that includes all the parts of the electricity market that PPC is directly related to. Also, it is expected that PPC is, to an extent, affiliated with the Union of its workers.

The Greek Government stands in the middle and is affected by many parties, especially by the governmental party which is the political party that is in office. It would be wrong to believe that the politicians that have been elected are always going to adopt the governmental policy that was included in its manifesto. After all the governmental agenda could change every time we have a new government and that is the rationale for the people voting in order to be represented [Besley and

Coate, 1997, 1998] and in order that the political program of the governing party be implemented as announced. That notion is prevailing in Diagram 4.19.



Hidden agendas in a political system can lead to vastly differentiated behaviours compared to election promises. In this case, the political forces might serve their role according to the utility function of their hidden agendas, and not of their public agendas according to which they were elected. In a setting like the one described in Diagram 4.20, we can see what happens when we assume the existence of “devoted voters” in a political system. In this case, a part of the people is strongly affiliated with particular political parties and their voting behaviour is biased towards them. Although this is to be expected between people that adopt particular views on things and political parties that express these views, things can get more complicated when this happens based upon a system of preferential treatment, financial and other transactions and exchanges. In this situation, political parties that want to participate in public politics have no other option than to adopt this practice themselves.

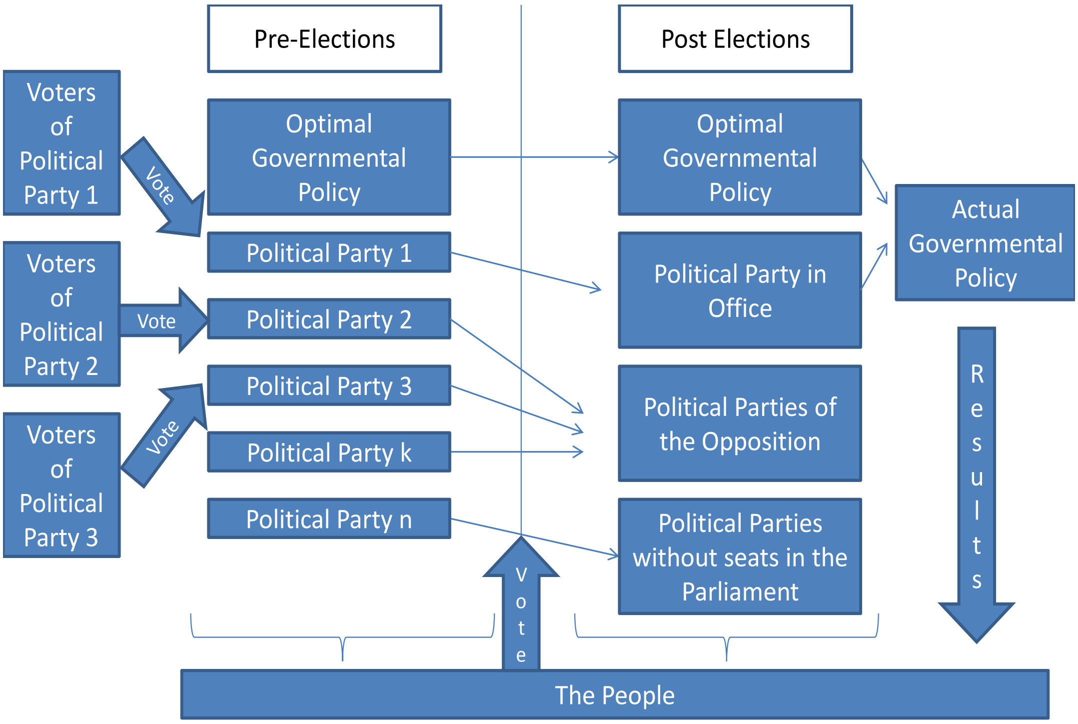


Diagram 4.20

Operation of a political system with voters closely affiliated with political parties

Were it the case that the political system in Greece was working in such a way, we may even go as far as to assume that in Diagram 4.18, the Greek Government, the Political Parties, the People and the PPC Union might have more complex relationships that the ones officially suggested. That could affect the energy policy of the country in general as well as specific issues regarding the electricity market operation.

The role of the European Union is also very important both through its role as a party that is offering bail-out funds for Greece and also as being the union of countries that Greece participates in and thereby has an effect on the country. The very decision of Greece to proceed with the liberalization was, after all, primarily the result of Greece conforming to the EU Directive 96/92/EC ([Thomas, 2006a], [Andrianesis, 2011]).

The political culture that has grown in Greece is one of networking, state paternalism, nepotism and cronyism. Cronyism is an important issue related to business performance ([Mele, 2009], [Begley et al., 2009], [Khatri et al., 2006], [Khatri and Tsang, 2003]). The people in Greece have established client-type of relationships with elected officials of the State, from local to regional to national level, and the operation of the Greek economy and of the Greek public administration seems to be heavily affected by this fact. The extent to which regulatory authorities are truly independent could be questioned and bureaucracy seems to exist in almost every transaction with the State, slowing down progress and reducing efficiency.

The Union of PPC workers is notoriously strong in its ability to strike and in some occasions, in its ability to “turn off the switch”, stopping the generation of electricity almost at will. Strongly established relations with political parties and the large number of voters that are affiliated with the Union of PPC workers allow to the PPC Union to be particularly strong whenever negotiating.

Summarizing, the challenge faced by the policymakers in the electricity sector in Greece has to do with balancing the governmental agendas with the European ones. Governmental considerations include social targets that reach beyond the boundaries of the protection of vulnerable populations and extend to the point that a more general income distribution policy is implemented through the provision of cheap electricity. Also, governments can become very concerned with the effect that liberalization decisions might have on the body of voters, as well as with the reactions that are coming from other electricity industry stakeholders, such as PPC employees and their Union. On the other hand, European Union agendas are mandating market reforms and the opening of the electricity generation and supply industries to entry by new investors. The introduction of competition and the potential efficiency improvements that come as a result, lead the electricity market tariffs to levels that eliminate cross-subsidizations and distortions. That is problematic, since such cross-subsidizations and distortions are the structural elements of tariffs that might allow the government to pursue its own aforementioned agendas. It is left to the Greek Government to decide how to balance these objectives and how to pursue its own agendas whilst satisfying the European Union requirements.

4.13 Conclusions

In this chapter we have examined entry scenarios for electricity supply markets that are supplied by an incumbent and we considered the effect that price caps have on the outcomes of entry. We discussed the issue of distortions and cross-subsidizations being present in tariff setting and we suggested that as a result of actual competition or as a result of the threat of potential competition, the Greek 2011 and 2012 PPC tariffs have resulted in reducing market surpluses. The level and structure of these tariffs appears to be the one that approaches the Bertrand price equilibrium.

We presented situations where: suppliers potentially face different cost curves; there is a cost for switching supplier; and there are potential licence restrictions on the quantity of electricity supplied by the new entrant. We also demonstrate that licence restrictions can be introduced in our analysis as self-imposed quantity restrictions by the suppliers to manage the capacity payments that they have to make. We also use the Cournot approach to analyze market setting and outcome when the quantity of electricity that can be supplied is restricted for one player.

We used approaches coming from game theory to look at player behaviour from a theoretical point of view and extended it to the Greek case. We constructed a 2-stage game and a similar repeated game. We also constructed a 3-stage game to describe scenarios with possible entry and we explained how this game relates to the Greek experience. Through analysis we demonstrated how entry is deterred when the incumbent supplier sets retail market prices at low levels.

We discussed the existence of market power in the Greek electricity market and explored potential ways that this market power can be exploited. We also investigated ideas on the potential market reactions for mitigating market power.

Recognizing the role of political agendas on the operation of energy markets and their evolution, as well as the impact that politics can have on market reforms, we review the political framework within which the Greek economy and the electricity sector operate. Focusing on the electricity sector, we show the connections and the interrelations between the different parties that participate in it. We also further extend our discussion focusing specifically on governmental agendas and on the ways that different parties determine the utility function of the government. A political situation with distortions and concealed transactions is outlined. This suggests the existence of a client-based political culture which is likely to lead to sub-optimal policy decisions.

Chapter 5

Empirical analysis

5.1 Secondary data analysis

5.1.1 Introduction

In this chapter we analyze data that refer to the Greek electricity sector. This analysis is used to show how the issues that were presented and discussed theoretically in previous chapters of this thesis correspond to the actual conditions that Greece faces. We show the dependence of electricity demand on the time of the day (day-time or night-time), the day of the week (working or non-working day), the period of the year (winter or summer) and the year under discussion. We also examine how wholesale electricity prices are dependent upon the same dimensions of time as electricity demand.

The interdependence of electricity demand and wholesale electricity prices can be related to the analysis presented in Chapters 3 and 4, where the wholesale electricity prices are key determinants of the cost curves that are presented there. Also, the introduction of competition to the Greek wholesale electricity market is shown to have an effect on the wholesale prices. This is identified through these prices with fossil fuel prices and the relevant price indices. The fuel prices examined are those for natural gas and oil. Finally, the arguments made in Chapter 4 concerning the political economy dimensions of the Greek electricity industry are supported in this chapter by demonstrating the effect that the ability of the Union of PPC workers to strike can have on the Greek electricity industry.

The empirical analysis is performed in phases. It is based on the System Load data for the Greek electricity market for the period 19/09/2001-31/10/2011, the System Marginal Price data for the same period and the Deviation Marginal Price data for the period 01/02/2002-31/10/2011. The System Load, SMP and DMP measures are defined below, together with an explanation of the need for their inclusion in this analysis.

System Load: The electricity load that is required to be produced by the generators and delivered to the final consumers through the grid. This is one of the main elements that describe an electricity sector. It constitutes the aggregate demand for electricity and, as such, needs to be examined for the Greek electricity market.

SMP: System Marginal Price is the price that is determined on an ex-ante basis to be paid from Load Representatives to Generators in the Greek wholesale electricity pool. This is also a very important element of the Greek electricity sector as it acts to largely determine the wholesale electricity cost that electricity suppliers face.

DMP (or ex-post SMP): Deviations Marginal Price is the price that is determined on an ex-post basis to be paid from Load Representatives to Generators in the Greek wholesale electricity pool. This price does not refer to electricity that is included in the scheduled operation of the market, but to additional electricity that is not scheduled or to electricity that is scheduled but which the generator fails to actually deliver. Similarly as was the case for the SMP, this is a very important element of the Greek electricity sector as it acts to determine the wholesale electricity cost that electricity suppliers face.

In Chapter 5, the available data generally cover the period 19/09/2001-31/10/2011. Some details of missing data and of the exact periods covered in each of the three datasets are given below:

- For System Load data and SMP data, the data for year 2001 only cover the part of the year 19/09/2001-31/12/2001.
- For DMP data, there are no data for year 2001. Data for year 2002 only cover the period 01/02/2002-31/12/2002.
- For System Load, SMP and DMP data, the data for the year 2011 only cover the period 01/01/2011-31/10/2011.

- For System Load, SMP and DMP data, the data for all other years refer to full years.

The data that we are using were obtained through the website of the Hellenic Transmission System Operator (HTSO) [HTSO, 2011a]. At the time when these data were obtained, HTSO was the transmission system operator and the wholesale market operator at the same time and was regularly publishing these data.

The division of the 24 hours of the day (which correspond to 24 dispatch periods, one for each hour of the day) into a day-time period (7:00-23:00 hours) and night-time period (23:00-7:00 hours) was guided by the existence of that division in the PPC tariffs [PPC, 2012g, 2012h]. Also, we identified two “peak-load” periods during the day by examining the system load data. These refer to dispatch periods 9-14 (hours 09:00-15:00) and to dispatch periods 18-21 (hours 18:00-22:00). These zones are of particular interest to us because of the fact that medium voltage tariffs and high voltage tariffs that were used in the Greek electricity market from 01/07/2008 until 01/01/2011, included in their structure varying charges for peak-load periods, non-peak load periods and night-time periods [PPC, 2008e, 2008f, 2008g]. Also, during the month of July 2005, when PPC faced very high electricity demand at specific times of the day, it asked for energy conservation during the hours 11:00-15:00, which were recognized as being “peak-load” hours [PPC, 2005a]. So, in the interest of investigating the effect that these different zones during the day have, we investigate them separately.

In this chapter we organize and present the available data in a descriptive manner. This specific approach aims at organizing and presenting these data according to the dimension of time. This is very significant for the electricity sector, given the requirement in electricity markets for demand to be met on a minute-by-minute basis and also given the non-storability of electricity. The outcomes that we were aiming at, namely to demonstrate the seasonal patterns of System Load and then relate these to temperatures and to match the SMP/DMP patterns with fuel price patterns and fuel index patterns has been possible without engaging in more complicated methods.

The use of more sophisticated analysis to address specifically the political, economic, institutional, legal, regulatory and social dimensions that are anticipated to be playing a significant role in the determination of market outcomes might have provided deeper insight to the exact role that each of these elements plays in the electricity industry. Nevertheless, the lack of relevant data that such an analysis would require, as well as the fact that changes in many elements of the electricity sector were occurring simultaneously does not allow for the successful disentanglement of the effects of those various factors. As a result, a descriptive approach has been implemented.

5.1.2 Method of analyzing data-Averages

The System Load/SMP/DMP data have been processed in an initial phase and averages have been calculated in the categories below. In presenting the calculated averages, we use the word VALUE (in capital letters) to present what we are calculating. This VALUE is alternatively the System Load, the SMP, or the DMP.

The averages that are calculated are:

1. Average VALUE per dispatch period for every one of the years for which we have available data. For every one of the 24 dispatch periods of each day, an average has been calculated using data from all days of each year. These are used to examine the changes in VALUE across dispatch periods from year to year. We have 24*11=264 observations here. These averages are graphed in Graph 5.1 for System Load, Graph 5.13 for SMP and Graph 5.25 for DMP.
2. Average VALUE per dispatch period for all the time period available. For every one of the 24 dispatch periods of each day, an average has been calculated, taking into consideration all of the days of the period we examine. We have 24 observations here. These averages are graphed in Graph 5.2 for System Load, Graph 5.14 for SMP and Graph 5.26 for DMP.

3. Average 24-hour VALUE of each of the days of the period under discussion. For every day of the period we examine, an average of the VALUEs of the 24 dispatch periods has been calculated. We have an average for each individual date. These averages are graphed in:
    - Timeline presentation - Graph 5.3a for System Load, Graph 5.15a for SMP and Graph 5.27a for DMP.
    - Presentation as annual 24-hour average VALUE profiles for the years available - Graph 5.3b for System Load, Graph 5.15b for SMP and Graph 5.27b for DMP.
4. Average night-time VALUE for each of the days of the period under discussion. For every day of the period we examine, an average of the VALUEs of the dispatch periods 0-6 and 23 (8 dispatch periods in total) has been calculated. We have chosen these dispatch periods for being the night-time ones after examining retail tariffs in Greece that were defining this time period as "night-time zone" [PPC, 2012g]. We have an average for each individual date. These averages are graphed in:
    - Timeline presentation - Graph 5.4a for System Load, Graph 5.16a for SMP and Graph 5.28a for DMP.
    - Presentation as annual night-time average VALUE profiles for the years available - Graph 5.4b for System Load, Graph 5.16b for SMP and Graph 5.28b for DMP.
5. Average day-time VALUE of each of the days of the period under discussion. For every day of the period we examine, an average of the VALUEs of the dispatch periods 7-22 (16 dispatch periods in total) has been calculated. We have an average for each individual date. These averages are graphed in:
    - Timeline presentation - Graph 5.5a for System Load, Graph 5.17a for SMP and Graph 5.29a for DMP.
    - Presentation as annual daily average VALUE profiles for the years available - Graph 5.5b for System Load, Graph 5.17b for SMP and Graph 5.29b for DMP.

6. Average VALUE of specific “high demand” dispatch periods of each of the days of the period under discussion. For every day of the period we examine, three different averages of the VALUEs of the dispatch periods 9-14 and 18-21 (10 dispatch periods in total) have been calculated. These are: an average of the dispatch periods 9-14, an average of the dispatch periods 18-21 and an average of all 10 of these dispatch periods together (9-14 and 18-21). These dispatch periods have been chosen arbitrarily by examining the average system loads per dispatch period and observing that these specific dispatch periods are those where the system load gets at higher levels than it does the rest of the day. We have three averages for each individual date. These averages are graphed in:
    - Timeline presentation for the average of 9-14 & 18-21 - Graph 5.6a for System Load, Graph 5.18a for SMP and Graph 5.30a for DMP.
    - Presentation as annual VALUE profiles of the years available for the average of 9-14 & 18-21 - Graph 5.6b for System Load, Graph 5.18b for SMP and Graph 5.30b for DMP.
    - Timeline presentation for the average of 9-14 - Graph 5.6c for System Load, Graph 5.18c for SMP and Graph 5.30c for DMP.
    - Presentation as annual VALUE profiles of the years available for the average of 9-14 - Graph 5.6d for System Load, Graph 5.18d for SMP and Graph 5.30d for DMP.
    - Timeline presentation for the average of 18-21 - Graph 5.6e for System Load, Graph 5.18e for SMP and Graph 5.30e for DMP.
    - Presentation as annual VALUE profiles of the years available for the average of 18-21 - Graph 5.6f for System Load, Graph 5.18f for SMP and Graph 5.30f for DMP.
7. Average Winter Working Day VALUE for every dispatch period of each of the calendar years under discussion. For every working day (Monday-Friday) of the period 01/01-19/05 and 21/09-31/12 of each year, an annual average has been calculated for each dispatch period. Using these averages, a 24-hour average, a night-time (dispatch periods 0-6 and 23) average, a

day-time (dispatch periods 7-22) average and three “high demand” day-time (dispatch periods 9-14; dispatch periods 18-21; and dispatch periods 9-14 and 18-21 together) averages have been calculated for each year.

- The annual averages of the VALUE per dispatch period are graphed for all available years in Graph 5.7a for System Load, Graph 5.19a for SMP and Graph 5.31a for DMP.
- The 6 different average VALUEs for every available year are graphed in Graph 5.7b for System Load, Graph 5.19b for SMP and Graph 5.31b for DMP.

8. Average Winter Non-Working Day VALUE for every dispatch period of each of the calendar years under discussion. For every non-working day (we consider Saturday and Sunday to be the non-working days, not considering any other public holidays) of the period 01/01-19/05 and 21/09-31/12 of each year, an annual average has been calculated for each dispatch period. Using these values, a 24-hour average, a night-time (dispatch periods 0-6 and 23) average, a day-time (dispatch periods 7-22) and three “high demand” day-time (dispatch periods 9-14; dispatch periods 18-21; and dispatch periods 9-14 and 18-21 together) averages have been calculated for each year.
    - The annual averages of the VALUE per dispatch period are graphed for all available years in Graph 5.8a for System Load, Graph 5.20a for SMP and Graph 5.32a for DMP.
    - The 6 different average VALUEs for every available year are graphed in Graph 5.8b for System Load, Graph 5.20b for SMP and Graph 5.32b for DMP.
9. Average Summer Working Day VALUE for every dispatch period of each of the calendar years under discussion. For every working day (Monday-Friday) of the period 20/05-20/09 of each year, an annual average has been calculated for each dispatch period. Using these values, a 24-hour average, a night-time (dispatch periods 0-6 and 23) average, a day-time (dispatch periods 7-22) and three “high demand” day-time (dispatch periods 9-14;

dispatch periods 18-21; and dispatch periods 9-14 and 18-21 together) averages have been calculated for each year.

- The annual averages of the VALUE per dispatch period are graphed for all available years in Graph 5.9a for System Load, Graph 5.21a for SMP and Graph 5.33a for DMP.
- The 6 different average VALUEs for every available year are graphed in Graph 5.9b for System Load, Graph 5.21b for SMP and Graph 5.33b for DMP.

10. Average Summer Non-Working Day VALUE for every dispatch period of each of the calendar years under discussion. For every non working day (we consider Saturday and Sunday to be the non-working days, not considering any other public holidays) of the period 20/05-20/09 of each year, an annual average has been calculated for each dispatch period. Using these values, a 24-hour average, a night-time (dispatch periods 0-6 and 23) average, a day-time (dispatch periods 7-22) and three "high demand" day-time (dispatch periods 9-14; dispatch periods 18-21; and dispatch periods 9-14 and 18-21 together) averages have been calculated for each year.
    - The annual averages of the VALUE per dispatch period are graphed for all available years in Graph 5.10a for System Load, Graph 5.22a for SMP and Graph 5.34a for DMP.
    - The 6 different average VALUEs for every available year are graphed in Graph 5.10b for System Load, Graph 5.22b for SMP and Graph 5.34b for DMP.
11. Averages of the VALUEs per dispatch period for each of the 4 Average Days that have been described above have also been calculated for the whole period that we examine. This was calculated by taking the plain average of the average annual VALUEs of all the individual years. These averages have been graphed in Graph 5.11 for System Load, Graph 5.23 for SMP and Graph 5.35 for DMP.
12. Using the averages of the VALUEs per dispatch period for each of the 4 Average Days for the whole period that we examine, we make graphs where

these averages are grouped according to the average. We get 6 graphs which refer to the 24-hour period, the night-time (dispatch periods 0-6 and 23) period, the day-time (dispatch periods 7-22) period and the "high demand" day-time (dispatch periods 9-14, dispatch periods 18-21 and dispatch periods 9-14 and 18-21 aggregated) period and where the average VALUEs are graphed by their average per year for every Average Day. These graphs are:

- Graphs 5.12a, 5.12b, 5.12c, 5.12d, 5.12e and 5.12f for System Load.
- Graphs 5.24a, 5.24b, 5.24c, 5.24d, 5.24e and 5.24f for SMP.
- Graphs 5.36a, 5.36b, 5.36c, 5.36d, 5.36e and 5.36f for DMP.

We will be discussing the graphs that we have drawn and try to provide explanations about them.

5.1.3 Method of analyzing data-Standard Deviations

After the System Load/SMP/DMP data have been processed for calculating averages, we go to the next step and calculate standard deviations for the same three datasets. In presenting the standard deviations, we again use the word VALUE (in capital letters) to present the relevant calculated values.

When calculations were being made for System Load, SMP and DMP we were respectively using System Load, SMP and DMP figures as VALUE.

We should note that the standard deviations are calculated here with the purpose of being used as a measure of volatility of System Load, SMP and DMP. We do not check our data for normality, as we are not going to go on with parametric statistical analysis. We are using these standard deviations in a descriptive way in order to find out the extent to which the data that we have vary around their means.

Our standard deviations are:

1. Standard deviation of VALUE per dispatch period for every one of the years for which we have available data. For every one of the 24 dispatch periods of each day, a standard deviation has been calculated using data from all days of each year. These standard deviations are graphed in Graph 5.37 for System Load, Graph 5.49 for SMP and Graph 5.61 for DMP.
2. Standard deviation of VALUE per dispatch period for all the time period available. For every one of the 24 dispatch periods of each day, a standard deviation has been calculated, taking into consideration all of the days of the period we examine. We have 24 observations here. These standard deviations are graphed in Graph 5.38 for System Load, Graph 5.50 for SMP and Graph 5.62 for DMP.
3. Standard deviation of the VALUE during the 24-hour period of each of the days of the period under discussion. For every day of the period we examine, a standard deviation of the VALUEs of the 24 dispatch periods has been calculated. We have a standard deviation for each individual date. These standard deviations are graphed in:
    - Timeline presentation: Graph 5.39a for System Load, Graph 5.51a for SMP and Graph 5.63a for DMP.
    - Presentation as annual profiles of the 24-hour standard deviation of the VALUE for the years available - Graph 5.39b for System Load, Graph 5.51b for SMP and Graph 5.63b for DMP.
4. Standard deviation of the VALUE during the night of each of the days of the period under discussion. For every day of the period we examine, a standard deviation of the VALUEs of the dispatch periods 0-6 and 23 (8 dispatch periods in total) has been calculated. We have a standard deviation for each individual date. These standard deviations are graphed in:
    - Timeline presentation: Graph 5.40a for System Load, Graph 5.52a for SMP and Graph 5.64a for DMP.
    - Presentation as annual profiles of the 24-hour standard deviation of the VALUE for the years available - Graph 5.40b for System Load, Graph 5.52b for SMP and Graph 5.64b for DMP

5. Standard deviation of the VALUE during the daytime of each of the days of the period under discussion. For every day of the period we examine, a standard deviation of the VALUEs of the dispatch periods 7-22 (16 dispatch periods in total) has been calculated. We have a standard deviation for each individual date. These standard deviations are graphed in:
    - Timeline presentation: Graph 5.41a for System Load, Graph 5.53a for SMP and Graph 5.65a for DMP.
    - Presentation as annual profiles of the 24-hour standard deviation of the VALUE for the years available - Graph 5.41b for System Load, Graph 5.53b for SMP and Graph 5.65b for DMP
6. Standard deviation of the VALUE of specific "high demand" dispatch periods of each of the days of the period under discussion. For every day of the period we examine, three standard deviations of the VALUEs of the dispatch periods 9-14 and 18-21 (10 dispatch periods in total) have been calculated. These are a standard deviation of the dispatch periods 9-14, a standard deviation of the dispatch periods 18-21 and a standard deviation of all 10 of these dispatch periods together (9-14 and 18-21). These dispatch periods have been chosen arbitrarily by examining the average system loads per dispatch period and observing that these specific dispatch periods (which correspond to hours of the day) are those where the system load gets values which are higher than those that we get for the rest of the day. We have three standard deviations for each individual date in our data. These standard deviations are graphed in:
    - Timeline presentation for the standard deviation of dispatch periods 9-14 & 18-21 - Graph 5.42a for System Load, Graph 5.54a for SMP and Graph 5.66a for DMP.
    - Presentation as annual profiles of standard deviation of VALUE of periods 9-14&18-21 for the years available - Graph 5.42b for System Load, Graph 5.54b for SMP and Graph 5.66b for DMP.

- Timeline presentation for the standard deviation of dispatch periods 9-14 - Graph 5.42c for System Load, Graph 5.54c for SMP and Graph 5.66c for DMP.
- Presentation as annual profiles of standard deviation of VALUE of periods 9-14 for the years available - Graph 5.42d for System Load, Graph 5.54d for SMP and Graph 5.66d for DMP.
- Timeline presentation for the standard deviation of dispatch periods 18-21 - Graph 5.42e for System Load, Graph 5.54e for SMP and Graph 5.66e for DMP.
- Presentation as annual profiles of standard deviation of VALUE of periods 18-21 for the years available - Graph 5.42f for System Load, Graph 5.54f for SMP and Graph 5.66f for DMP.

7. Standard deviation of the VALUE of the Average Winter Working Day VALUES for every dispatch period of each of the calendar years under discussion. For every working day (Monday-Friday) of the period 01/01-19/05 and 21/09-31/12 of each year, a standard deviation of the VALUEs for that given year has been calculated for each dispatch period. Also, for every day of the time period that we examine, we calculated a 24-hour standard deviation, a night-time (dispatch periods 0-6 and 23) standard deviation, a day-time (dispatch periods 7-22) standard deviation and three "high demand" day-time (dispatch periods 9-14, dispatch periods 18-21 and dispatch periods 9-14 and 18-21 together) standard deviations. Using these, we calculated an average standard deviation for each year and for each average.
    - The annual standard deviations of the VALUE per dispatch period are graphed for all available years in Graph 5.43a for System Load, Graph 5.55a for SMP and Graph 5.67a for DMP.
    - The 6 different averages of standard deviations of VALUEs for every available year are graphed in Graph 5.43b for System Load, Graph 5.55b for SMP and Graph 5.67b for DMP.

8. Standard deviation of the VALUE of the Average Winter Non-Working Day VALUES for every dispatch period of each of the calendar years under discussion. For every non-working day (we consider Saturday and Sunday to be the non-working days, not considering any other public holidays) of the period 01/01-19/05 and 21/09-31/12 of each year, a standard deviation of the VALUEs for that given year has been calculated for each dispatch period. Also, for every day of the time period that we examine, we calculated a 24-hour standard deviation, a night-time (dispatch periods 0-6 and 23) standard deviation, a day-time (dispatch periods 7-22) standard deviation and three "high demand" day-time (dispatch periods 9-14, dispatch periods 18-21 and dispatch periods 9-14 and 18-21 together) standard deviations. Using these, we calculated an average standard deviation for each year and for each average.
    - The annual standard deviations of the VALUE per dispatch period are graphed for all available years in Graph 5.44a for System Load, Graph 5.56a for SMP and Graph 5.68a for DMP.
    - The 6 different averages of standard deviations of VALUEs for every available year are graphed in Graph 5.44b for System Load, Graph 5.56b for SMP and Graph 5.68b for DMP.
9. Standard deviation of the VALUE of the Average Summer Working Day VALUES for every dispatch period of each of the calendar years under discussion. For every working day (Monday-Friday) of the period 20/05-20/09 of each year, a standard deviation of the VALUEs for that given year has been calculated for each dispatch period. Also, for every day of the time period that we examine, we calculated a 24-hour standard deviation, a night-time (dispatch periods 0-6 and 23) standard deviation, a day-time (dispatch periods 7-22) standard deviation and three "high demand" day-time (dispatch periods 9-14, dispatch periods 18-21 and dispatch periods 9-14 and 18-21 together) standard deviations. Using these, we calculated an average standard deviation for each year and for each average.

- The annual standard deviations of the VALUE per dispatch period are graphed for all available years in Graph 5.45a for System Load, Graph 5.57a for SMP and Graph 5.69a for DMP.
- The 6 different averages of standard deviations of VALUEs for every available year are graphed in Graph 5.45b for System Load, Graph 5.57b for SMP and Graph 5.69b for DMP.

10. Standard deviation of the VALUE of the Average Summer Non-Working Day VALUES for every dispatch period of each of the calendar years under discussion. For every working day (we consider Saturday and Sunday to be the non-working days, not considering any other public holidays) of the period 20/05-20/09 of each year, a standard deviation of the VALUEs for that given year has been calculated for each dispatch period. Also, for every day of the time period that we examine, we calculated a 24-hour standard deviation, a night-time (dispatch periods 0-6 and 23) standard deviation, a day-time (dispatch periods 7-22) standard deviation and three "high demand" day-time (dispatch periods 9-14, dispatch periods 18-21 and dispatch periods 9-14 and 18-21 together) standard deviations. Using these, we calculated an average standard deviation for each year and for each average.
    - The annual standard deviations of the VALUE per dispatch period are graphed for all available years in Graph 5.46a for System Load, Graph 5.58a for SMP and Graph 5.70a for DMP.
    - The 6 different averages of standard deviations of VALUEs for every available year are graphed in Graph 5.46b for System Load, Graph 5.58b for SMP and Graph 5.70b for DMP.
11. Averages of the standard deviations of the VALUEs per dispatch period for each of the 4 Average Days that have been described above have also been calculated for the whole period that we examine. This was calculated by taking the plain averages of the standard deviations of the annual VALUEs of all the individual years. We have 24 dispatch periods * 4 average days = 96 observations here. These average standard deviations have been graphed

in Graphs 5. 47 for System Load, Graph 5.59 for SMP and Graph 5.71 for DMP.

12. Using the standard deviations of the 6 combinations of dispatch periods of the VALUEs for each individual date, we calculate and average of these standard deviations for each year and for each Average Day. The 6 combinations of dispatch periods are: the 24-hour period, the night-time (dispatch periods 0-6 and 23) period, the day-time (dispatch periods 7-22) period and the "high demand" day-time (dispatch periods 9-14, dispatch periods 18-21 and dispatch periods 9-14 and 18-21 together) period. These average standard deviations have been graphed in 4 different graphs, one for each Average Day. These are:
    - Graphs 5.48a, 5.48b, 5.48c, 5.48d, 5.48e and 5.48f for System Load.
    - Graphs 5.60a, 5.60b, 5.60c, 5.60d, 5.60e and 5.60f for SMP.
    - Graphs 5.72a, 5.72b, 5.72c, 5.72d, 5.72e and 5.72f for DMP.

We will be discussing the graphs that we have drawn and try to provide explanations about them.

5.2 System Load data

5.2.1 Introduction

We assume that the System Load is primarily affected by demand for electricity and additionally by technical issues. Putting the technical issues aside, we examine the System Load of the Greek electricity system considering the factors that affect demand

Date factors: Year, Summer or Winter, Working Day or Non-Working Day

Time factors: Dispatch period (hour of the day), Day or Night

Other factors: Temperature

Putting these factors together, we can assume that the System Load is determined by the function described below:

System Load=f(year, month, day of the week, time of the day, other factors)

In the way that we examine System Load, we aim at determining in an ex-post basis how these factors affect it.

5.2.2 Presentation of the System Load data

The System Load data that we have available refer to the time period 19/09/2001-31/10/2011. That is a time period of 3,695 days. However our data list 3,692 days, indicating that there are 3 missing days. The dates of these missing dates are: 18/10/2001, 27/10/2001 and 03/01/2002. For that time period we have 24 System Load values for every day and these correspond to the 24 dispatch periods of each day (one for each hour of the day). The numbers given to describe each period correspond to the time at the start of each of the one-hour periods. That means that period 0 is between midnight and 1am, period 1 is between 1am and 2am, and so forth. We present these data in 24 separate graphs. We have one graph for each of the 24 dispatch periods and in these graphs we plot the 3,692 values of system load (one for each day) for each of the dispatch periods. These are Graphs 5.200-5.223 and can be found in Appendix B, Part 1.

All of these graphs show that in all of these timelines of system loads, there is a clear and easily identified seasonality pattern. This is perceived as being due to the fact that the demand for electricity is strongly affected by time factors that refer to specific periods of each year. That Greece has very warm summers affects the system load in specific ways, as throughout all 24 graphs we observe that the system load peaks during the summer months, where electricity consumption is expected to increase due to the extended use of air condition devices.

If we compare Graphs 5.200-5.223 one-by-one, we observe that the seasonality pattern is the same across all of them. What is changing is the level of the system load, and its volatility. So apart from the dates playing a role in the determination of the system load, the fact that the levels of system load are varying during the day in a consistent manner suggests that the hour of the day that we are examining also has its own effect on electricity demand. The fact that some hours of the day present higher volatility in system load levels than others suggests that, during these hours, the electricity consuming activities have a larger degree of unpredictability than they do in the hours with the lower volatility. That is useful when used for tariff setting purposes in conjunction with the wholesale pool prices of these hours.

The pattern that we mentioned is more evident in the mid-day hours. During these mid-day hours, the system load levels are more elevated and more volatile than the ones of the night hours.

Using the "Data Analysis" tools of the Microsoft Excel software, we have ranked the system load data for each dispatch period, in a descending order. We have graphed them in Graph 5.224 which is found in Appendix B, Part 1.

Using the ranked data, we counted the frequency of appearance of system load between certain ranges for each dispatch period and we created histograms to present these frequencies. These histograms are showing how many times we observed a system load within the specific range that each column of the histogram refers to. The ranges have been taken to be 500 MWh wide. The results are presented in Graphs 5.225-5.248 and can be found in Appendix B, Part 1.

We have also graphed all these frequencies together in Graph 5.73, to be found and discussed later in Chapter 5.

5.2.3 System Load Graphs-Actual Data

Graphs 5.200-5.223 are 24 graphs that plot the System Load for every single day of the time period that we are discussing, with each graph referring to one specific dispatch period. These are in Appendix B, Part 1.

One very important observation is that there is a strong periodical pattern that is present in the system load. This seasonal pattern is visible in all the graphs and is likely to be related to the seasonal electricity-consuming activities that take place in the country. An example of a seasonal activity is the electricity consumption use for air-conditioning devices.

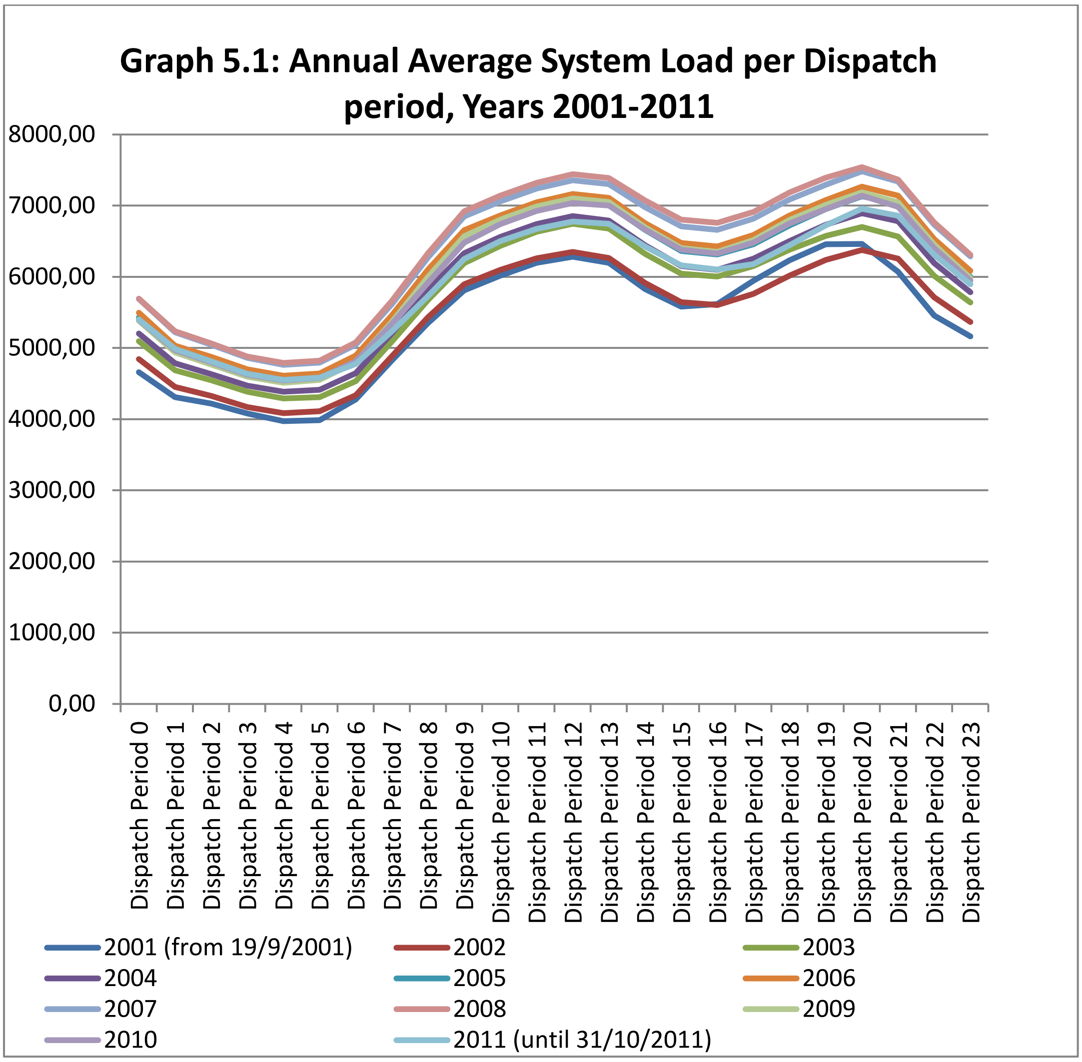
In Graphs 5.200-5.205 we can see that the line of the system loads is quite “clear”, indicating that there is small volatility in the system load during these dispatch periods (0-5) and that these increase and decrease day-by-day on a smooth manner. That can be due to the fact that these dispatch periods are night-time dispatch periods, therefore there are no reasons why any heavy volatility should be present. That volatility gets larger during the day periods, as we can see on the graphs.

This volatility could be related to everyday activities of the electricity consumers. For example, for a household, an everyday activity could be the electricity consumption for cooking. The everyday activities are expected to have their parameters (such as time in the day, duration, electricity consumption) within a specific range. The existence of this range is what creates the volatility in the system load.

By looking at the line that is formed across all the diagrams we can see that there are 20 “peaks” areas. These are 10 “high peaks” and 10 “low peaks”. The “high peaks” are peaks in the system load that happen during the summer months and the “low peaks” are peaks that happen during the winter months. In some of our graphs these can be very easily identified (5.200-5.206, 5.210-5.216, 5.221-5.223) whereas in others that is not very easily done (5.207-5.209, 5.217-5.220), as all the peaks are at similar levels. That is due to the fact that these dispatch periods are very popular for electricity consumption and this results in having the everyday activities increasing electricity consumption to levels that end up “covering” the seasonality pattern.

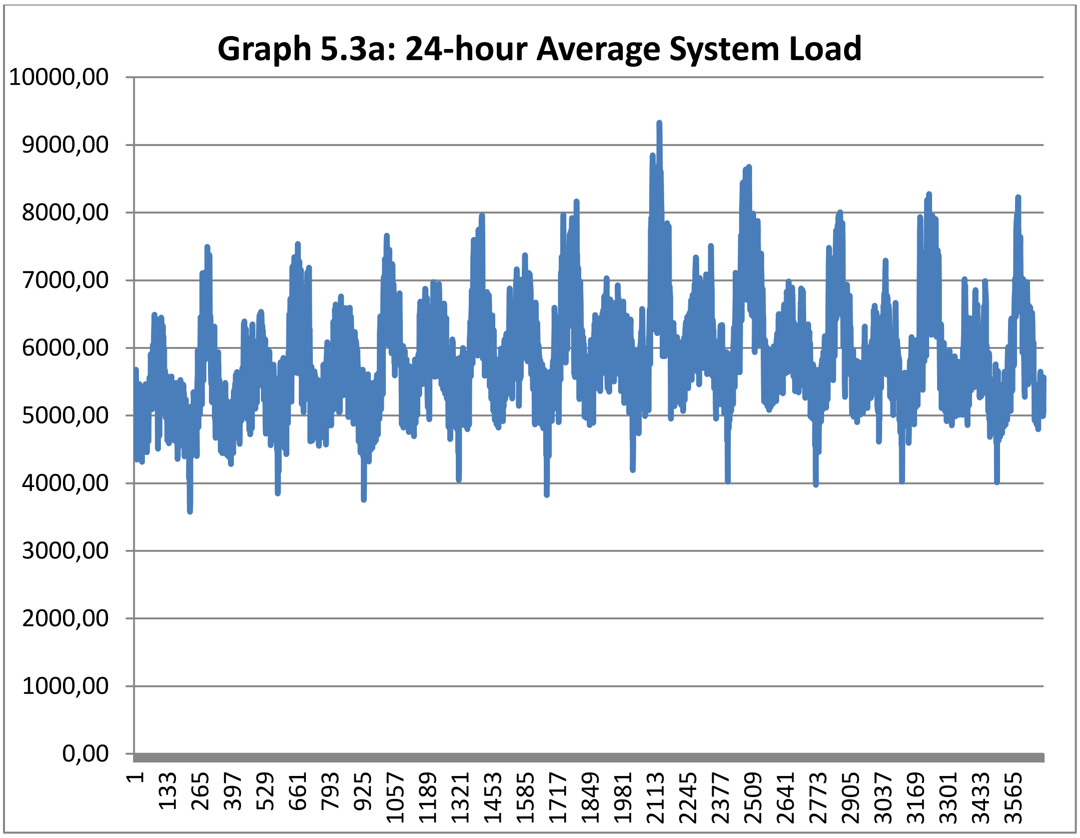
Also by observing the increases and decreases, we can see how overall demand for electricity varies though the years. That can be observed by looking at the diagrams and identifying how the seasonality pattern is affected by the incorporation of increases and decreases in the system load which are due to non-seasonal reasons. There is an increasing trend for the system load from the start of our data until the summer of 2007 (the middle of the summer 2007 is given as observation 2,123) and from that point and on there is a decreasing trend from year to year. That can be seen by taking and comparing the 10 “high peaks”, the 10 “low peaks” as well as the relevant dips that are following each of them in each of the 24 graphs.

5.2.4 System Load Graphs-Calculated Averages



In Graph 5.1 we can see the annual average system load per dispatch period for the years 2001-2011. Two very important observations here are that the pattern within the day seems to be consistent across the years. Electricity-consuming everyday activities have their parameters set within ranges that vary at different times of the year. However, when aggregated together, the effect of those ranges is eliminated, leaving the system load pattern unaffected. The second observation is that the lines increase in our graph as we move from 2001 to 2008, indicating increased demand for electricity during that period. System load averages fall from 2009 to 2011, indicating a decrease in electricity demand. These averages range throughout the years from a minimum of around 4,000 MWh/dispatch period to a maximum of 7,500 MWh/dispatch period. All these results from individual years are combined to create Graph 5.2 which is to be found in Appendix B, Part 1.

Graph 5.3a has been created by averaging all of the Graphs 5.200-5.223. For every day of the whole time period that we examine, we aggregate the figures of the system load of all 24 dispatch periods for that day. As a result we end up with one figure for each of the days of the time period under examination. We observe that the seasonality pattern that is repeated in all the graphs 5.200-5.223 has also been transferred here. Similarly as was the case with the graphs of the actual data, we have 10 “high peaks” and 10 “low peaks” as well as their respective troughs. The “high peaks” correspond to the summer peak load period and the “low peaks” to the winter peak load period. We can also see how there is an increasing trend until the summer of 2007 and a decreasing trend from that point and on. The average system load across all years and all 24 dispatch periods is calculated at 5,990.55 MWh/dispatch period and the “high peaks” get their maximum average system load around 8,000 MWh/dispatch period (and occasionally more than 9,000 MWh/dispatch period) and the “low peaks” get their minimum average system load around 4,000 MWh/dispatch period.

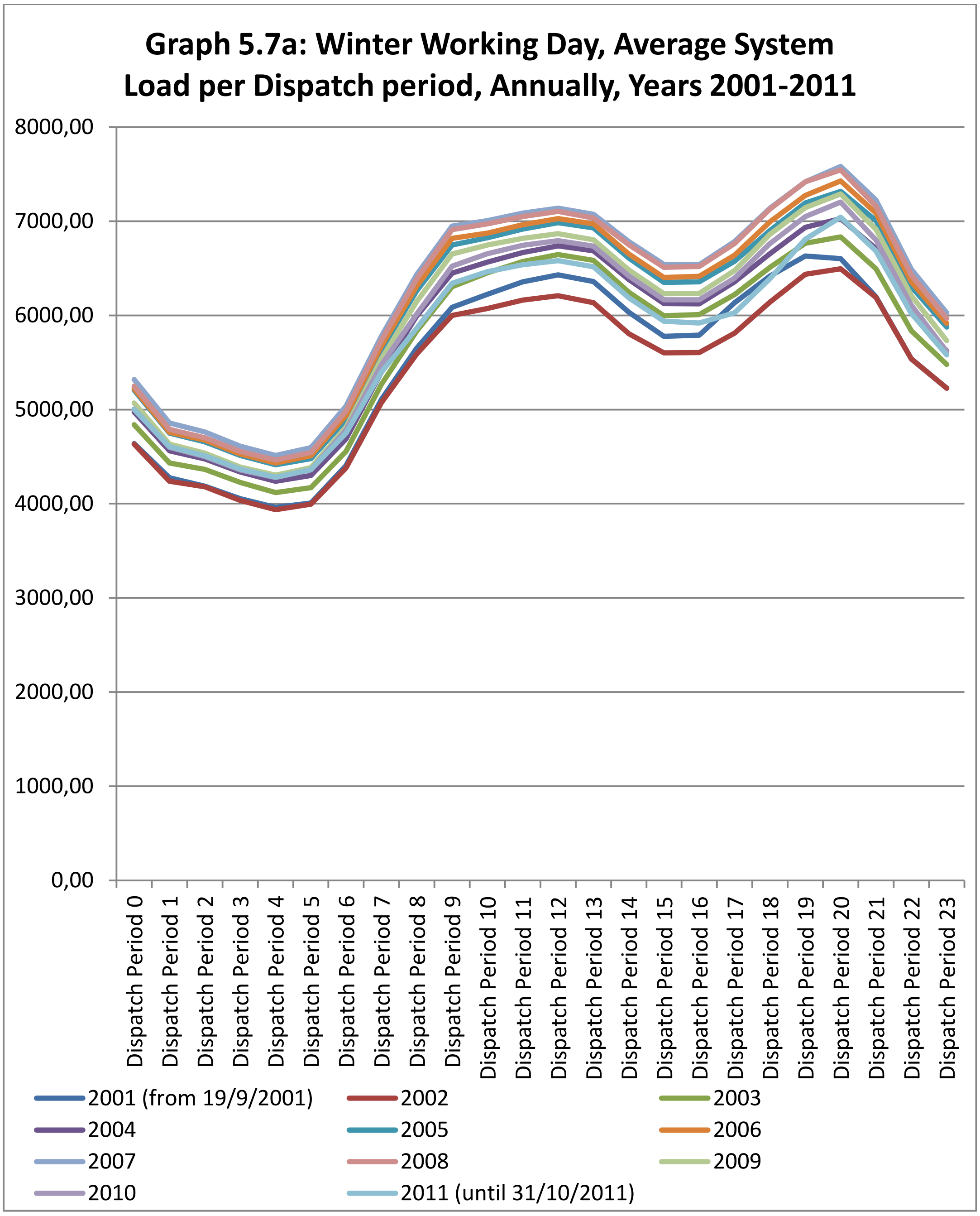


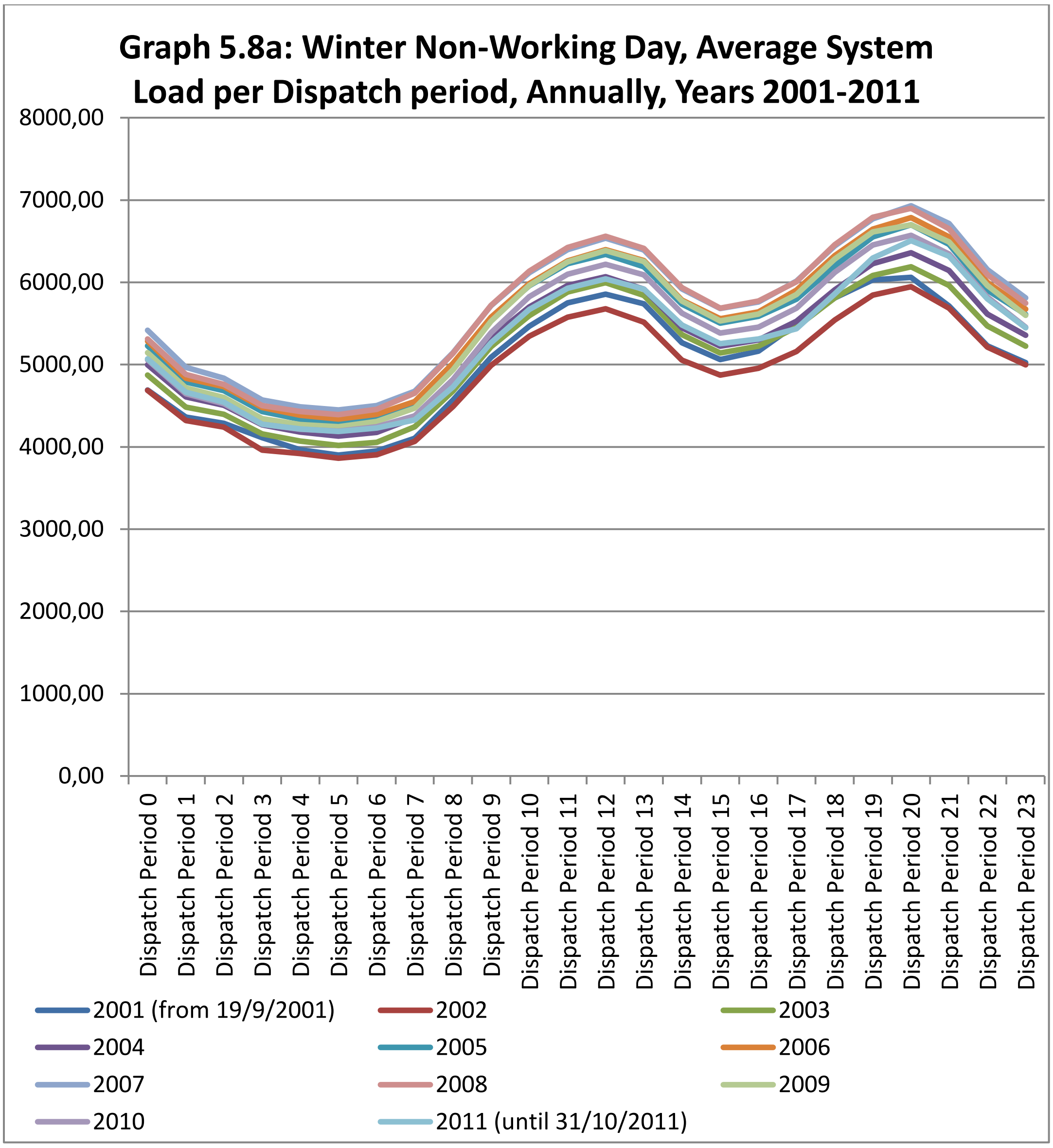
Similar to Graph 5.3a are Graphs 5.4a, 5.5a, 5.6a, 5.6c and 5.6e which refer to averages of System Load for varying combinations of the available dispatch periods. These are to be found in Appendix B, Part 1.

Graph 5.3b presents the annual 24-hour system load averages for years 2002-2011. It is hard to extract conclusions from this graph since it is very congested with lines. However we can still see the annual pattern that has been observed previously. The same happens for Graphs 5.4b, 5.5b, 5.6b, 5.6d and 5.6f which show results for the other combinations of dispatch periods that we calculated. All of these graphs and Graph 5.3b are to be found in Appendix B, Part 1.

Graphs 5.7a and 5.8a present the annual 24-hour average system load for the Average Winter Working Day and the Average Winter Non-Working Day respectively for each of the years 2001-2011. We observe that the intra-day pattern that we have identified is present and consistent throughout the years and that there do not seem to be large differences from year to year. Given the similarity of the patterns of the lines, the only thing that varies is vertical shifts in the lines over time.

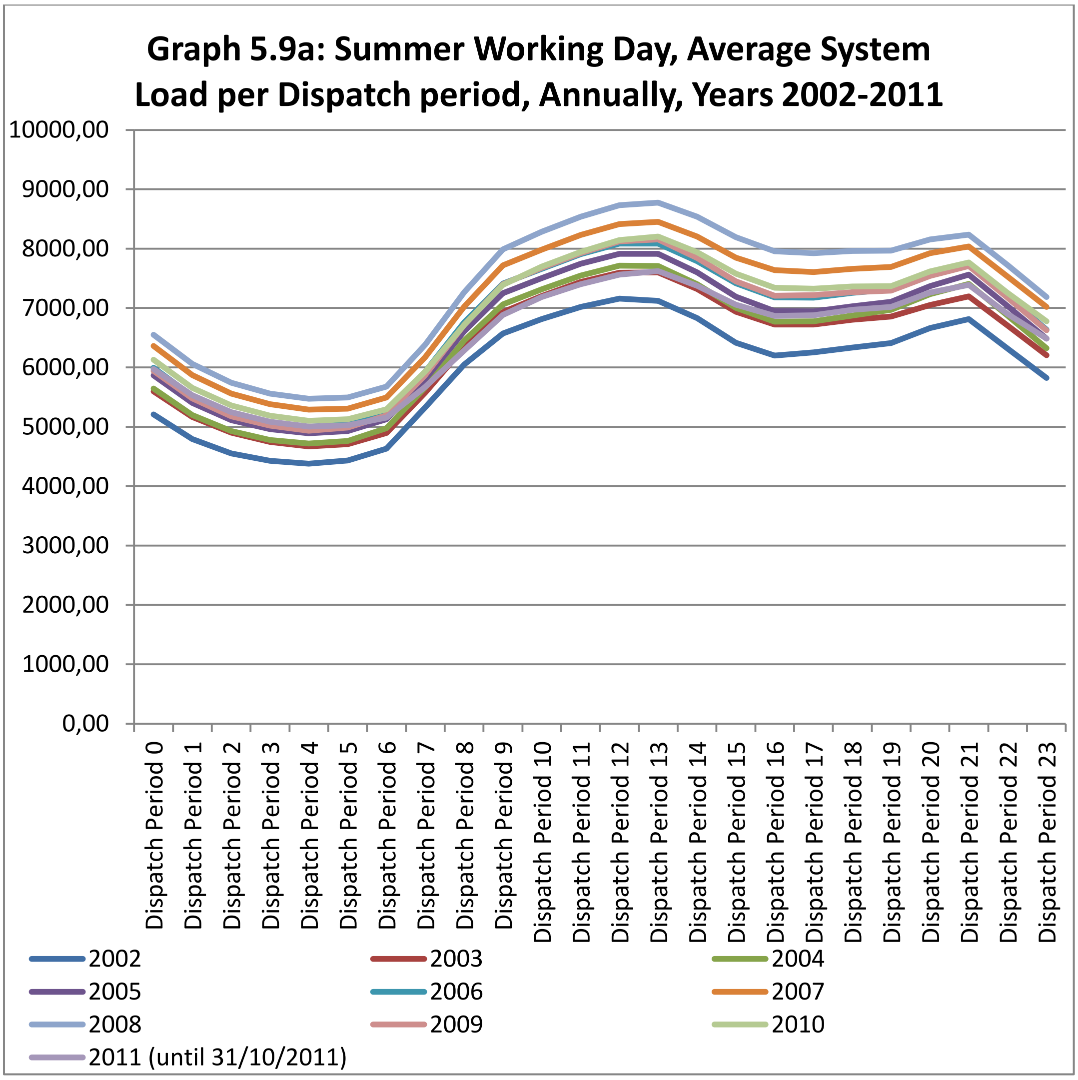
It is worth noting that there are differences between Graphs 5.7a and 5.8a when comparing the same years. The night-time dispatch periods seem to get system loads at the same levels for both Average Days, however the dispatch periods during the day have much higher system load in working days than in non-working days. That observation indicates that the day of the week is relevant to the level of electricity demand. That is so because there are certain factors that affect electricity demand in the electricity market during working days which do not operate during the non-working days.

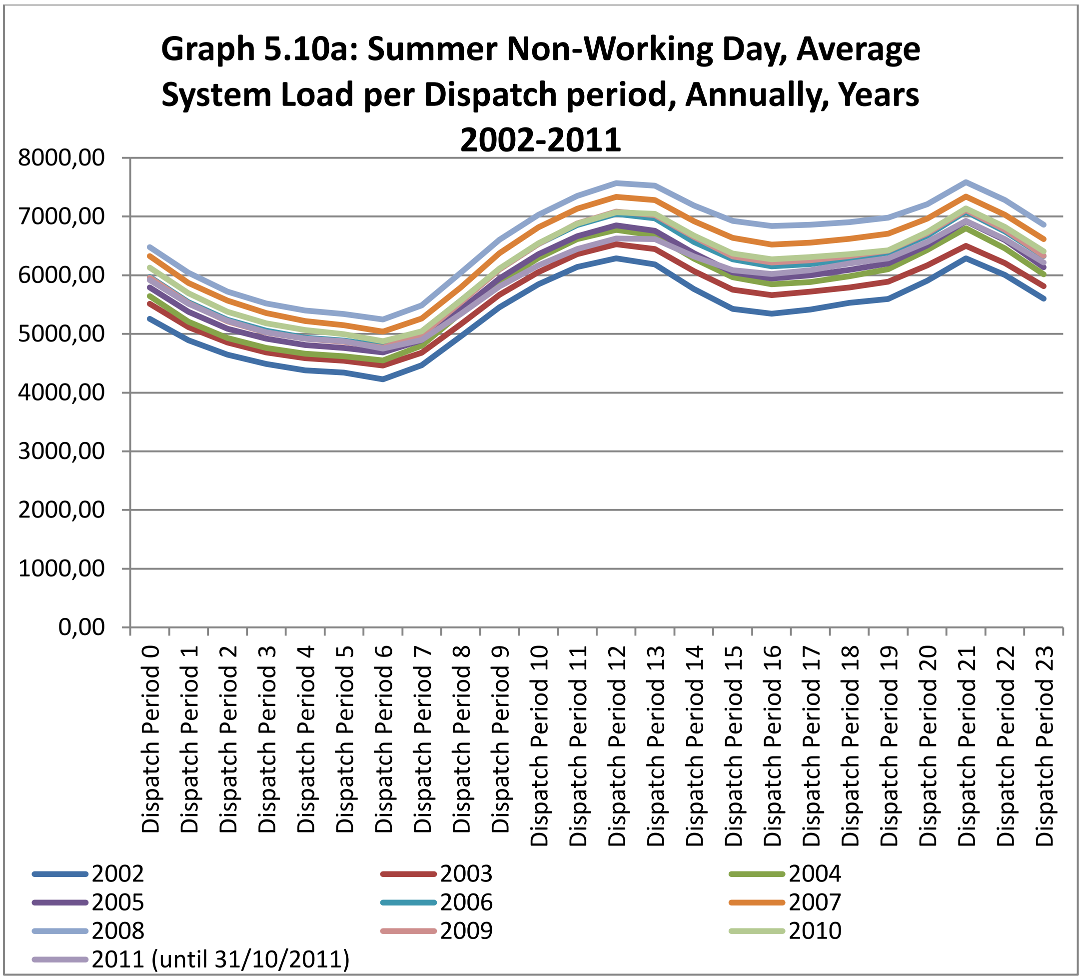

Graph 5.7a: Winter Working Day, Average System Load per Dispatch period, Annually, Years 2001-2011
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
Dispatch Period 0
Dispatch Period 1
Dispatch Period 2
Dispatch Period 3
Dispatch Period 4
Dispatch Period 5
Dispatch Period 6
Dispatch Period 7
Dispatch Period 8
Dispatch Period 9
Dispatch Period 10
Dispatch Period 11
Dispatch Period 12
Dispatch Period 13
Dispatch Period 14
Dispatch Period 15
Dispatch Period 16
Dispatch Period 17
Dispatch Period 18
Dispatch Period 19
Dispatch Period 20
Dispatch Period 21
Dispatch Period 22
Dispatch Period 23
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)



In Graphs 5.9a and 5.10a, we present the annual 24-hour average system load for the Average Summer Working Day and the Average Summer Non-Working Day respectively, for each of the years 2002-2011. As was the case for the winter period, shown in Graphs 5.7a and 5.8a, the intra-day pattern is present and consistent throughout the years and there do not seem to be large differences from year to year. The only thing that varies is vertical shifts in the lines over time.

There are also some differences when comparing Graphs 5.9a and 5.10a. The dispatch periods during the day have much higher system loads in working days than in non-working days, whereas the night-time system load levels are similar. This shows that the time of the day is relevant for determining the system load. The same holds true for the day being distinguished as working or non-working, since we can see that the elevated day-time (dispatch periods 7-22) system loads only occur during the working days. The day of the week is relevant for the level of electricity demand and how that demand changes over time. There are certain factors that affect electricity demand during the working days but not during the non-working ones.





Graphs 5.7a, 5.8a, 5.9a and 5.10a show that the average system load levels differ significantly over the years. These differences show the evolution of electricity demand and help us understand the importance of capacity planning and of attracting investments in electricity generation, as capacity requirements might grow substantially over time. Also, the fact that in some years we observe a fall in average system load levels implies that when considering investments in generation there is some uncertainty about the evolution of the market demand. When this uncertainty materializes as a decrease in demand, investors in electricity generation are unable to sell electricity in the market at the volume of sales that they projected when entering the market.

In Graphs 5.7b and 5.8b we present 6 different average system load values for the Average Winter Working Day and the Average Winter Non-Working Day respectively, for each of the years 2001-2011. In Graphs 5.9b and 5.10b, we present 6 different averages of the system load for the Average Summer Working Day and the Average Summer Non-Working Day respectively, for each of the years 2002-2011. Graphing these averages clearly indicates how any increases or decreases in the system load occur simultaneously for all 6 averages. Therefore, we identify the fact that each year has a specific effect on system load, signaling the fact that the year under discussion is always relevant to the level of electricity demand. We can also see that low average system loads apply to night-time averages (dispatch periods 23-6), then the averages increase when calculated for the 24-hour period, then they get even higher for the dispatch periods during the day (dispatch periods 7-22) and the highest averages are those of the three “high demand” periods (dispatch periods 9-14; 18-21; and 9-14 and 18-21 together).

In the Graphs that refer to the winter period (Graphs 5.7b and 5.8b), amongst the three “high demand” averages, the highest one is the winter afternoon (dispatch periods 18-21) average: in the winter, electricity demand is higher in the afternoon than it is in the morning. The morning average (dispatch periods 9-14) is the lowest of the three “high demand” averages and the aggregated one that includes both lies in between of them, as expected.

In the Graphs that refer to the summer period (Graphs 5.9b and 5.10b), amongst the three “high demand” averages, the highest one is the morning (dispatch periods 9-14) average: in the summer, electricity demand is higher in the morning than it is in the afternoon. The afternoon average (dispatch periods 18-21) is the lowest from the three high demand average. Again, the aggregated period, which includes both morning and afternoon periods, lies in between of the two, as expected. The only exception to this appears in Graph 5.10b for year 2011 when the afternoon (dispatch periods 18-21) average system load became higher than the morning (dispatch periods 9-14) one.

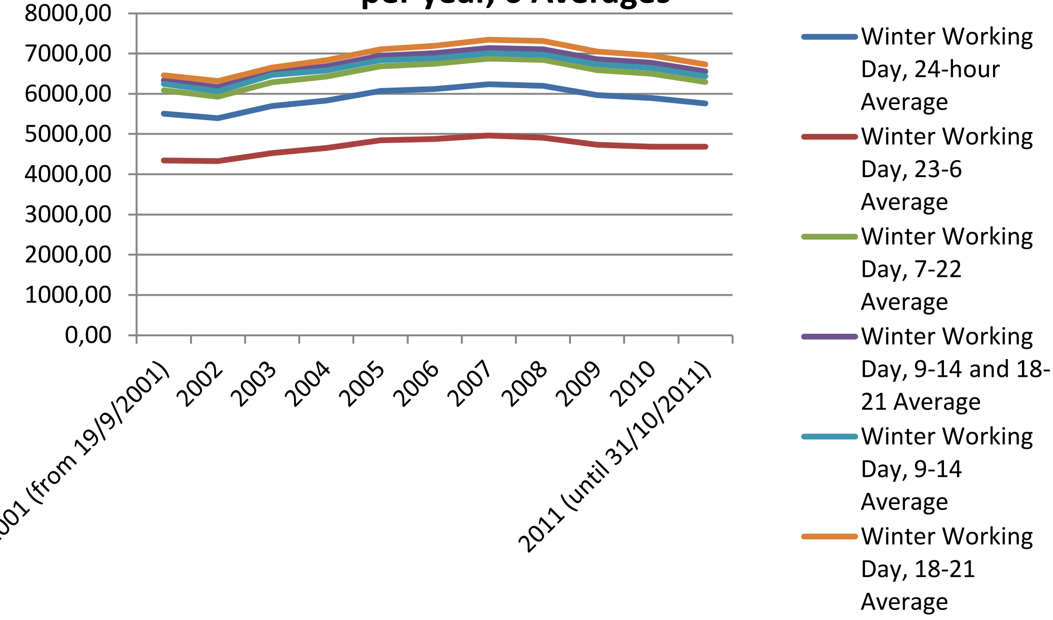
An important observation from Graph 5.10b is that the difference in system load between morning and afternoon is minor in all years. Given that this only applied to the Average Summer Non-Working Day, we can assume that this has to do with the fact that businesses are not operating in these days, so that there is not as much electricity consumption in the morning hours as there is in the working days.

When comparing Graphs 5.7b and 5.8b, we observe that the average system loads presented in them share similar patterns. This suggests that for the winter period the effect of each year on the system load is uniform regardless of whether we are examining working or non-working days. Also, the system load levels differ between the two graphs for the 24-hour, day-time (dispatch periods 7-22) and "high demand" (dispatch periods 9-14; 18-21; and 9-14 and 18-21) averages, having higher system loads during the working days as opposed to non-working days. This suggests that there is a specific effect on day-time (dispatch periods 7-22) system load depending on whether the day is a working or a non-working one. The system load averages during the night (dispatch periods 23-6) are at similar levels for both working and non-working days. This suggests that the factors that create differences between system loads of working and non-working days during the day (dispatch periods 7-22) do not affect the night-time system load. That was expected anyway as the differentiation between working or non-working days was done as a result of the recognition of the significance of having businesses working or not. From that point of view, the electricity demands in the night-time periods can be considered as the "basic" demands, considering that the electricity demand that occurs during the night does not include the day-time activities which are "built up" during the day on top of the existing night-time demand. Additionally, the differentiation of the system load between the day-time and the night-time hours shows us that there is a specific effect that the time of the day has on system load.

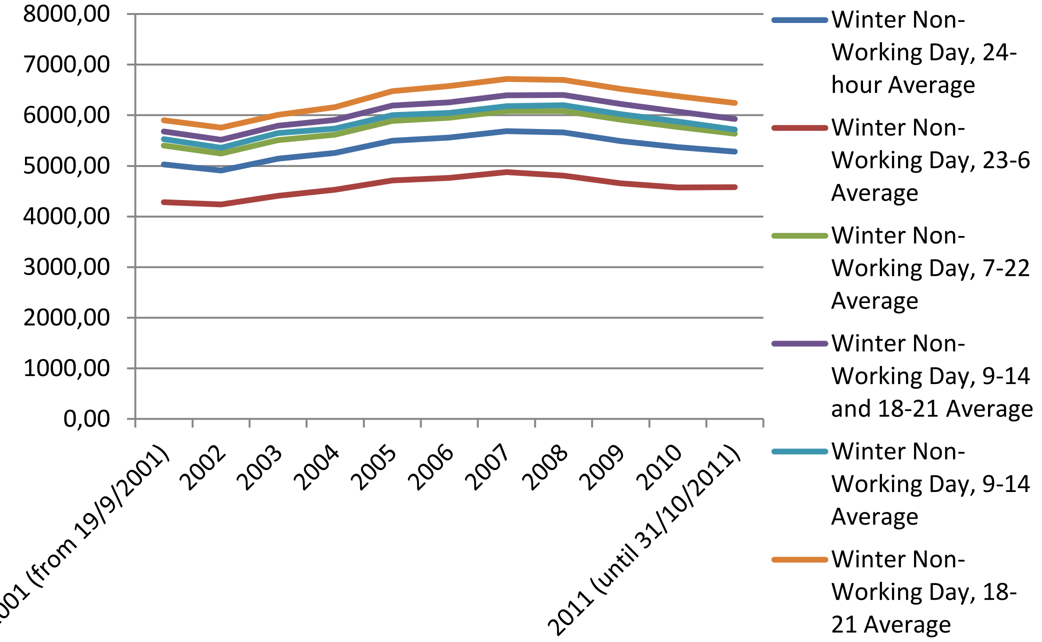
Comparing Graphs 5.9b and 5.10b gives similar results to those from a comparison of Graphs 5.7b and 5.8b. The main difference is that the pattern of average system loads that Graphs 5.9b and 5.10b share is different from the one that was found in

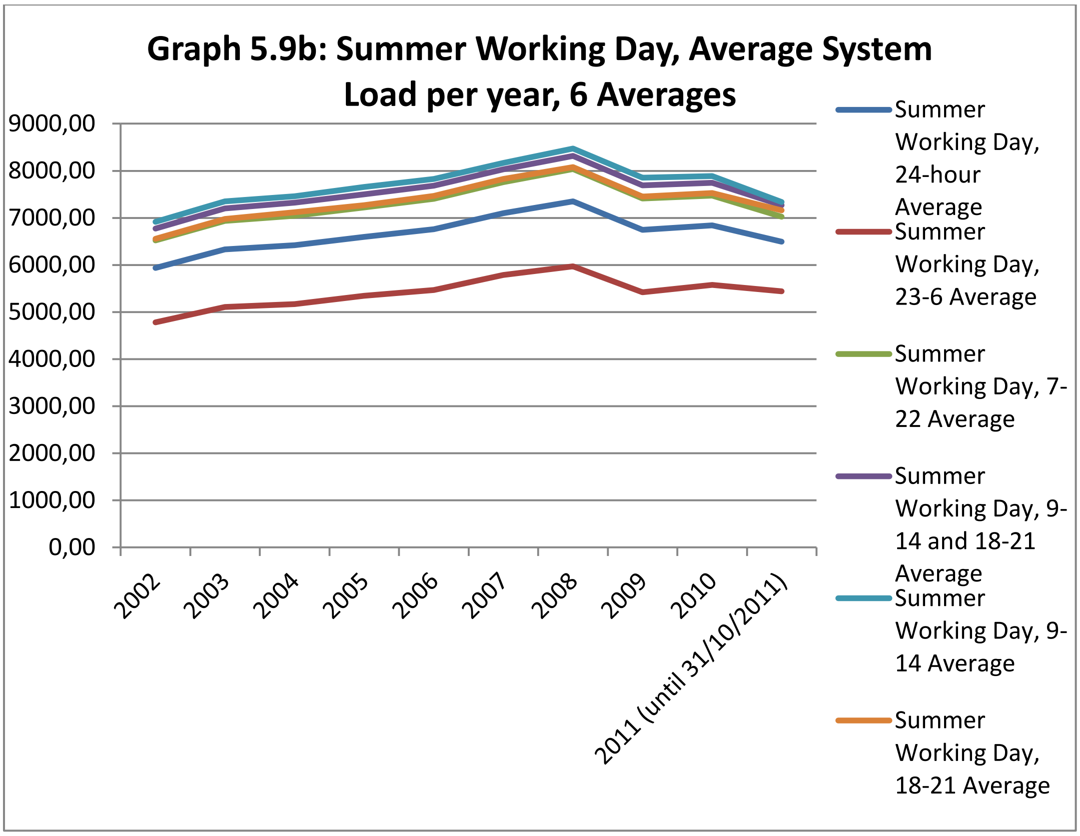
Graphs 5.7a and 5.8b. This suggests that the time of the year (winter or summer) has a different effect on the system load of the Greek electricity market.

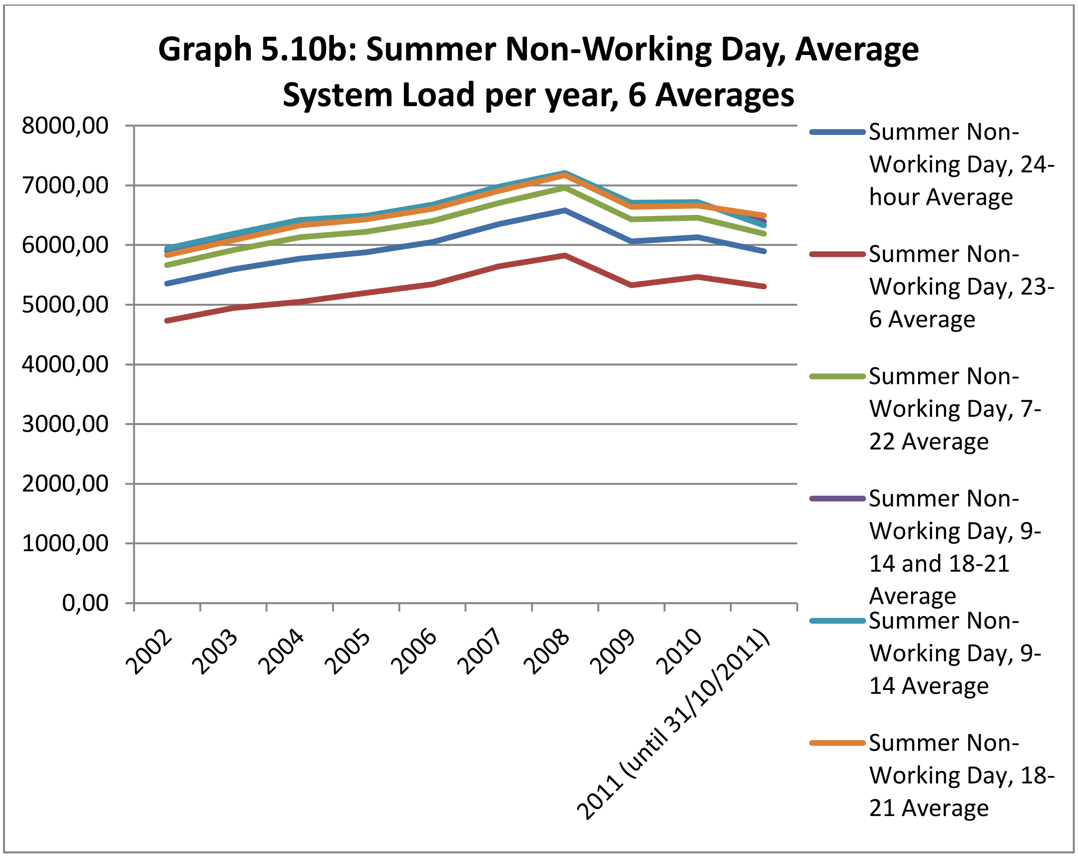
Graph 5.7b: Winter Working Day, Average System Load per year, 6 Averages



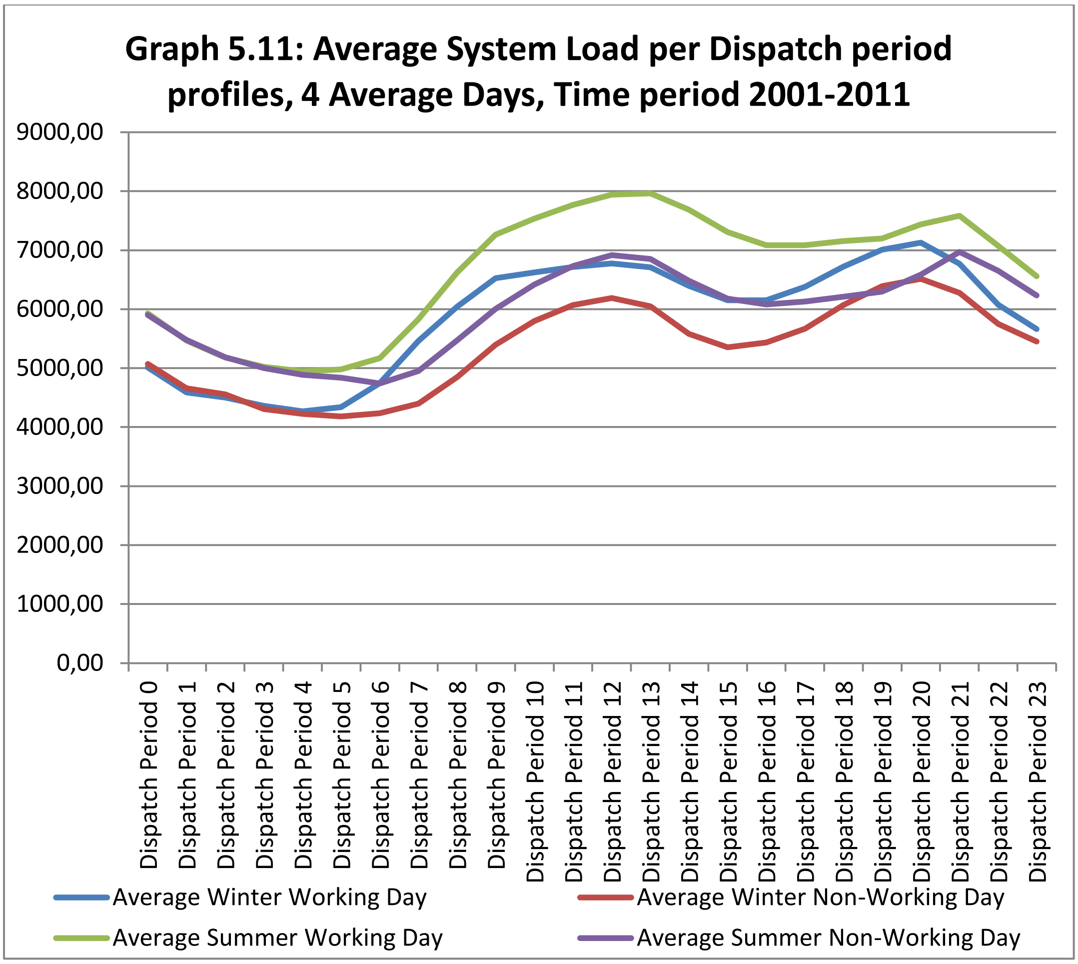
Graph 5.8b: Winter Non-Working Day, Average System Load per year, 6 Averages




Graph 5.9b: Summer Working Day, Average System Load per year, 6 Averages
9000,00
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Summer Working Day, 24-hour Average
Summer Working Day, 23-6 Average
Summer Working Day, 7-22 Average
Summer Working Day, 9-14 and 18-21 Average
Summer Working Day, 9-14 Average
Summer Working Day, 18-21 Average

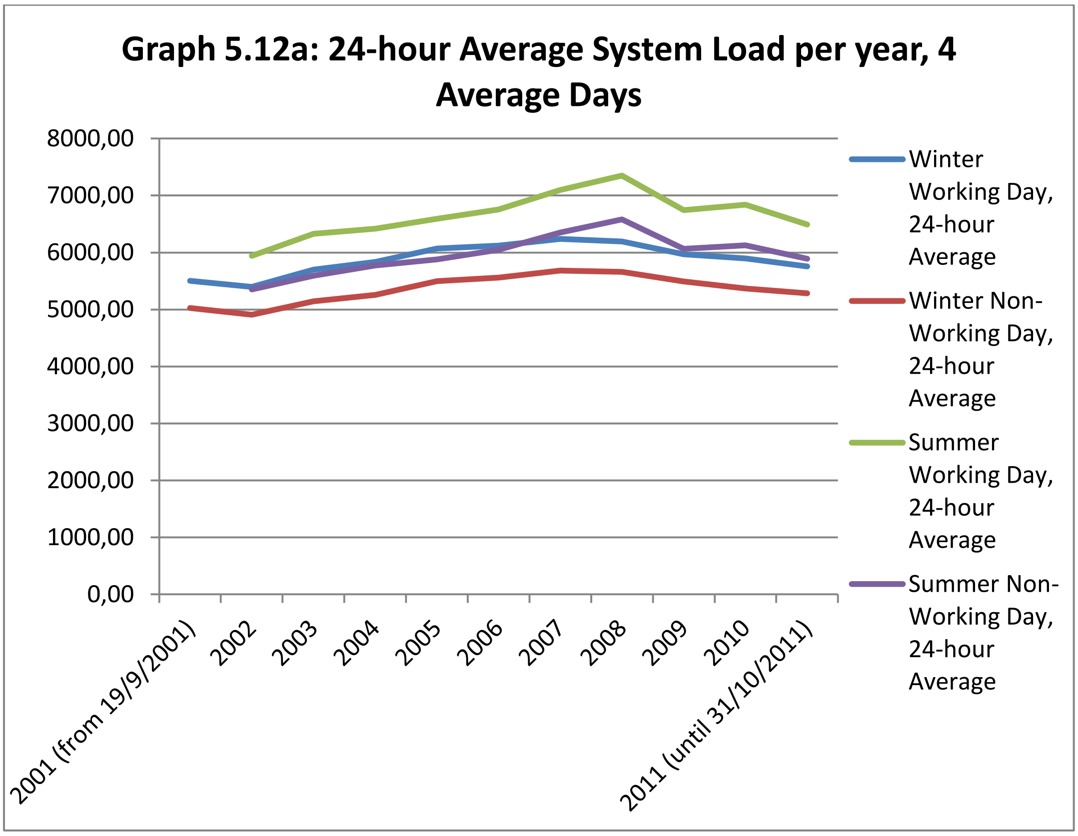

Graph 5.10b: Summer Non-Working Day, Average System Load per year, 6 Averages
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Summer Non-Working Day, 24-hour Average
Summer Non-Working Day, 23-6 Average
Summer Non-Working Day, 7-22 Average
Summer Non-Working Day, 9-14 and 18-21 Average
Summer Non-Working Day, 9-14 Average
Summer Non-Working Day, 18-21 Average

The figures shown in Graphs 5.7a, 5.8a, 5.9a and 5.10a have been averaged and plotted in Graph 5.11. In Graph 5.11 we can see that there is a pattern during the day for all of the 4 Average Days. System load is low during the night, increases in the morning hours (from dispatch period 7) reaching a peak around dispatch period 12, then decreases until dispatch period 16 and starts rising again until dispatch period 21 after which it starts decreasing until the end of the day. The winter non-working day is the one that presents the lowest system load and the summer working day the highest, with winter working day and summer non-working day being in between and roughly at the same levels. The system load seems to be increased by two factors in this case: working day activities and summer increased temperatures. When combining both of these, which is what happens in the Average Summer Working Day, we get the highest average system load. When we have none of them which is what happens when we have the Winter Non-Working Day, we get the lowest average system load, and when having only one of them we get roughly the same system load, in between of the maximum and the minimum that we referred to. The major difference between a Summer Non-Working Day and a Winter Working Day is the timing of the electricity demand around the clock as well as the existence of some extremely high demand days during the summer which cannot be identified using this graph.



The averages that we previously discussed in Graphs 5.7b, 5.8b, 5.9b and 5.10b have been rearranged into Graphs 5.12a, 5.12b, 5.12c, 5.12d, 5.12e and 5.12f where they have been grouped not by the Average Day but by the average system load that is calculated. Graph 5.12a is presented below and Graphs 5.12b, 5.12c, 5.12d, 5.12e and 5.12f are to be found in Appendix B, Part1. We do not include all of the graphs in this section as all 6 are quite similar. In these 6 graphs, we verify what has been observed in Graph 5.11. The Average Summer Working Days have the highest average system load and the Average Winter Non-Working Days the lowest.

We also can see that there are two patterns that determine the evolution of the average system load from year to year for the Average Days. The one pattern is the pattern that affects the two Summer Average Days and the other one is the pattern that affects the two Winter Average Days. Each of these patterns is consistent across the different averages in providing the same pattern, as we have seen in Graphs 5.7b, 5.8b, 5.9b and 5.10b. So, we get to realize that the effect of the summer period on the system load is specific and the effect of the winter period is specific as well.



5.2.5 Some notes on the graphs

When creating the 4 Average Days, there were no useful summer data for 2001 (only for one day - 19/09/2001). As a result, for summer working days and summer non-working days, we have observations that refer to 10 years (2002-2011) instead of the 11 years (2001-2011) that we have for the winter working days and winter non-working days.

The averages are simple and not weighted averages as we do not consider any observation to be more important that the others.

For the calculation of the 4 Average Days, the annual average system loads per dispatch period have been initially calculated for each Average Day and then these have been averaged to calculate the average system load per dispatch period of each Average Day for the time period 19/9/2001-31/10/2011. Although that is quite likely a good approximation, we have to note that the result would probably not have been exactly the same if all of the data had been averaged together. That is because the calculation of the annual averages for winter 2011 has been done with less than annual data (our data end at 31/10/2011). Also, for summer 2001 we do not have any useful data so we haven’t done it at all.

Some distortions are expected to be present in our results as a consequence of that. However, we elected to include them rather than not, since that inclusion increases the size of our dataset and the information value that we get.

The above problem is not present on the calculations of the average system loads per year or per whole period under examination, since these have been averaged directly from the actual data and not using average values.

5.2.6 Discussion of findings

The period of the year is one of the factors that determine electricity demand. In the morning hours of the summer, electricity demand is high as the temperatures are high and air conditioning devices are used extensively. These same devices are not used as heavily in the afternoon when the sun goes down and the temperatures are lower. In the winter, electricity consumption is not as high in the morning when temperatures are not very low, however there is an increase in the electricity demand as we move to the afternoon and temperatures drop. So time of the day is also an important factor that determines system load.

During the summer period, Greece typically faces high temperatures, whereas its winters are not extremely cold. The fact that there are alternative solutions to heating (such as oil-fired devices; natural gas-fired devices; as well as fireplaces where wood is burned) other than electricity consuming devices decreases the effect of the winter on electricity demand. The same does not happen for air-conditioning devices, used in the summer, that have no substitute. The effect of temperatures on system load patterns is examined more extensively in Section 5.8 of this chapter.

System load was increasing from the start of the data until 2008 where it peaks and after that it falls, indicating a decrease in the demand for electricity. That is a very important observation that has implications in many areas. In our assumptions about the factors that determine system load, the year was assumed to be one of the determining factors, and the graphs show that this is the case. The effect shown in the graphs after 2008 suggests that the issue of the country being in an economic recession and of having decreased economic activity could have affected electricity consumption, which is reduced. Also, from an energy policy perspective it is very important to monitor electricity demand and the effects that each year has on it. This information can act as input for planning in the electricity industry and of the energy industry in general. The issues that are being affected are of strategic importance and these include the security of supply and the planning for adequate electricity generation capacity.

In addition to these issues, the decreased demand impacts on the deregulation of the electricity industry and the liberalization of the market in both positive and negative ways. The positive effect is achieved through the creation of conditions that promote competition in the wholesale electricity pool. Decreased system load for the electricity pool means that the generators have fewer opportunities for market manipulation and are forced to act competitively in the pool using their actual marginal costs. In order for this to happen though, generating capacity of many types should be distributed amongst many generators. The negative effect is that the reduced economic activity after 2008 could have a negative impact on the willingness or the ability of new investors to enter new markets and therefore to the evolution of the market. New generators are less willing to enter a market than they would if there were higher demand. In a market with free tariff setting and without an obligation to meet the market demand, such as is the case for the new entrants, the higher the size of the overall market, the higher the profits made are, as we discussed in previous chapters. A shrinking market is likely to be considered as more risky and could possibly discourage new entrants.

The other important issue is the impact of decreased demand in the potential for competition in the retail supply side of the electricity market. A shrinking market might discourage potential entrants in the supply side of the market exactly as it will do on the generators. In both the case of potential generators and suppliers, the negative economic climate and the increased uncertainty, the decreased ability of the banks to fund investment through debt at favorable rates, the risk of exchange rate as the euro is fluctuating and the political instability, are all factors that discourage investors and are make the transition of the market into a deregulated liberalized market even more difficult.

The factors that we assumed at the start of this section to be affecting system load were:

Date factors: Year, Summer or Winter, Working Day or Non-Working Day

Time factors: Dispatch period (hour of the day), Day or Night

Other factors: Temperature, Economic activity

As we have seen, date and time factors actually have a specific effect on system load. In Section 5.8, we will also see what it the effect of the temperature and of economic activity on system load.

5.3 System Marginal Price (SMP) data

5.3.1 Introduction

The System Marginal Price (SMP) of the Greek wholesale electricity market is the ex-ante determined price for the quantities of electricity that are sold in the wholesale pool, according to the Dispatch Scheme of each specific day.

We assume that the SMP is affected by a number of factors. We anticipate that some of the most important would be: cost of fuels; cost of emission licences; available generation capacity at each fuel generation technology; price and quantity of imported electricity; mandatory use of hydroelectric plants; projected electricity demand; cost of capacity payments; amount of generators and market power.

5.3.2 Presentation of the SMP data

The System Marginal Price (SMP) data that we have available are for the time period 19/09/2001-31/10/2011. That is a time period of 3,695 days. However our data list 3,681 days, which means that there are 14 missing days. The dates of these missing days are: 07/11/2001-15/11/2001, 04/11/2002, 01/01/2003, 02/01/2003, 27/02/2003, 10/05/2004. Where we have data, there are 24 SMPs for every day and these correspond to the 24 dispatch periods of each day (one for each hour of the day). The number given to designate each period corresponds to the time at the start of the one-hour period. That means that period 0 is between midnight and 1am, period 1 is between 1am and 2am, etc. We have created 24 graphs that plot these data. We have one graph for each of the 24 dispatch periods and in these graphs we present the 3,681 SMPs for each of the dispatch periods. These are Graphs 5.300-5.323 and can be found in Appendix B, Part 2.

In these graphs we can see that in all of the SMP timelines, there are no obvious seasonal patterns. That means that the seasonality pattern that we observed in system load does not affect the SMP strongly enough and therefore there should be other factors that have a stronger effect.

However, that does not mean that there is nothing to observe in comparing the Graphs 5.300-5.323 one-by-one. By doing so, we observe that the values of the SMPs seem to be loosely following a pattern which does not incorporate any seasonality. So what we get is that the SMPs for the different dispatch periods are all increasing and decreasing at the same dates, forming loosely similar timelines. System load does not appear to be unrelated to SMP. That is suggested by the fact that the dispatch periods during the day, that we previously identified as having higher demand than the night-time ones, have increased SMPs. SMPs are affected by System Load through the day, but not across the year. SMPs throughout the year seem to be affected by international fuel prices, as we will see later in Chapter 5.

Using the "Data Analysis" tools of the Microsoft Excel software, we have ranked the SMP data for each dispatch period, in a descending order. Using the ranked data, we counted the frequency of having the SMP set between certain ranges for each dispatch period and we created histograms to present these frequencies. These histograms are showing how many times we observed SMPs within the specific range that each column of the histogram refers to. The ranges have been taken to be 10 euro/MWh wide. The results are presented in Graphs 5.324-5.347 and can be found in Appendix B, Part 2.

We have also graphed all these frequencies together in Graph 5.74, to be found and discussed later in Chapter 5.

5.3.3 SMP Graphs-Actual Data

Diagrams 5.300-5.323 are 24 diagrams that show us what the SMP has been for all the days of the time period that we are discussing. Each of the diagrams refers to one specific dispatch period.

In these graphs there is no clear periodical pattern in the SMP. However, what we can observe in all the graphs that as we move from the one dispatch period to another, the shape of the timeline remains roughly similar and it adjusts upwards or downwards depending on the dispatch period, whilst also incurring changes in its volatility levels. This pattern is visible in all the graphs regardless of the fact that the system loads are different for different dispatch periods.

In Graphs 5.300-5.306 the line of the SMP is quite “clear”, indicating that there is relatively small volatility in the SMPs during these dispatch periods (0-6) and that these increase and decrease day by day in a smooth manner. That can be due to the fact that these are night-time dispatch periods, where electricity-consuming activities do not present variation in their characteristics, resulting in a relatively stable electricity demand. As a result, we expect that no heavy variance should be present. Given the fact that, as we have seen earlier, system load is relatively stable during these dispatch periods and considering that the other factors that affect the SMP are not expected to be largely differentiating during these specific dispatch periods, what we actually observe is what was expected.

The important issue is to identify what the volatility throughout the day means to the electricity system and what it means to the participants in the wholesale market, both to the generators and to the suppliers. System load seems to be affecting SMPs over the course of the day, however that does not happen over the course of the year. The intra-day variation in SMP is connected with the corresponding system load variation, with the technical specifications of the system and the bids that are submitted in the electricity pool at that time. These bids incorporate a series of elements that we mentioned earlier, such as the cost of fuel, the avoidable and non-avoidable cost of operation and the bidding strategy that the generators are using, taking also into consideration any market power that they might have. What is interesting about the bidding strategies is that in the Greek electricity market, we have the Mechanism for Covering Variable Cost which ensures that the payments to generators will always cover the variable cost of their operation plus 10% [RAE, 2010a]. That allows generators to submit low bids, knowing that they are secured against operating on a financial loss. We should note that fixed costs and depreciations of the electricity generating units are being recovered through the capacity payments of the Greek electricity market.

By looking at the line that is formed across all the graphs we can see that there are 2 "peak zones". These are from May 2006 to May 2009 (the start of May 2006 is in observation 1672 and the start of May 2009 is observation 2768) and from May 2009 until the end of October 2011 (where our data end). In some of our graphs these can be very easily identified (5.300-5.306, 5.309-5.316, 5.321-5.323) whereas in others that is not very easily done (5.307-5.308, 5.317-5.320). However it is very interesting that certain peaks that we can see on some of the timelines are to be found on all graphs. Peaks like these could be the one on 27/05/2005, these on 02/08/2005 and 03/08/2005 and these on the 3 day period 11/11/2005-21/11/2005 and especial on 15/11/2005 and 16/11/2005. Also it could be the time period 22/12/2001-18/01/2002 where there have been certain days that the SMP has raised to very high levels (specifically that happened on 22/12/2001, 24/12/2001, 27/12/2001, 28/12/2001, 31/12/2001, 03/01/2002, 07/01/2002-11/01/2002, 14/01/2002, 15/01/2002, 17/01/2002 and 18/01/2002).

And very importantly, we also have the peak during the period 21/06/2011-29/06/2011 and especially on 23/06/2011. That specific time period is more extensively discussed later in this chapter. However it is important to note that this increase was due to a PPC-Union strike and to the non-availability of a number of electricity generating plants as a result of the strike. These peaks are mentioned because they can be very easily identified in most graphs and because they seem to be caused by different mechanisms than those that create the usual electricity market volatility. The fact that there are specific days during which Greece experiences very high SMPs regardless of the dispatch period that we refer to indicates that the SMP can be heavily affected by factors unrelated to hour-to-hour system load variations.

Also by observing the increases and decreases, we can see how overall prices in the wholesale electricity market vary throughout the years. That can be observed by looking at the diagrams and identifying how the seasonality pattern of the system load that we discussed earlier is impacted by the effect of the plants availability, of the cost of dispatching these plants and of bidding strategies in the wholesale electricity pool. What we get as a result is increases and decreases in the SMP which lack the seasonality of the system load data.

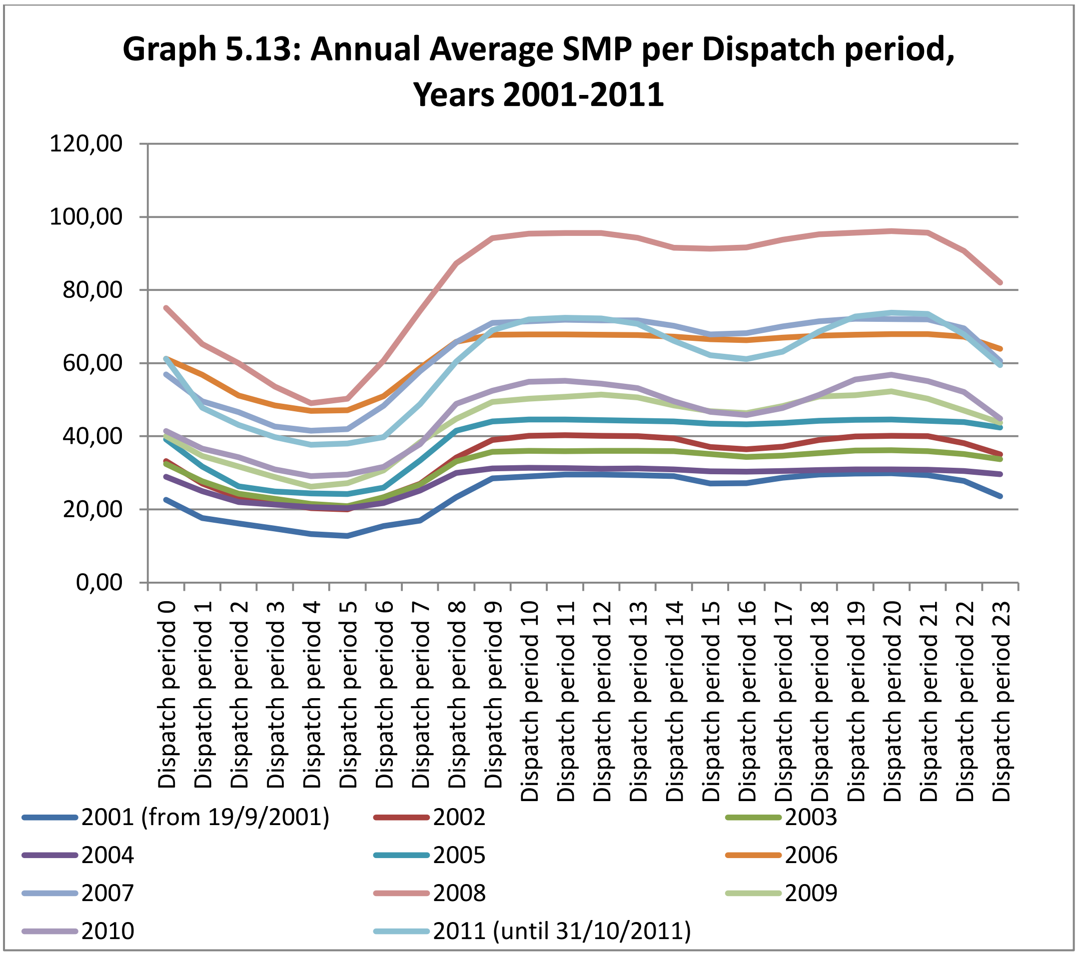
We also observe that the SMP is at an almost constant level from the start of our data until May 2006 and from that point on we experience an increase in the SMP which peaks in October 2008 and then it starts decreasing from that point and on until the end of February 2009 where it reaches a trough. That can be related to the fact that the international prices for fossil fuels, and specifically for oil, have followed a similar trend through the same time period, thus suggesting that oil prices might be heavily affecting SMP.

5.3.4 SMP Graphs-Calculated averages

In Graph 5.13 we can see the SMP per dispatch period for every one of the years in our dataset. We observe that there seems to be a pattern present in the SMP which is consistent throughout the years. As we have seen earlier, the system load in the Greek electricity system presents a consistent pattern during the day. That demand pattern seems to be affecting the SMP, since an intra-day pattern seems to exist in the SMP as well. There also seems to be an evolution in this pattern as it is not only the level of the SMP that changes from year to year (some years having significantly higher SMP than others), but also the pattern itself, especially in its part that refers to the dispatch periods 13-20.

These periods have been previously (in the part where we discussed system load) identified as being periods during the day where there is a small decrease in system load. By combing this fact and the fact that in certain years there is a decrease of the SMP during that time period and in other years there isn’t, we can conclude that there should be a reason for this. Examining the years where that happens, we find that for the dispatch periods 13-20, we have no decrease in the SMP for years 2001-

2007. From 2008, we start identifying a pattern where the SMP decreases during the periods 13-20 and that decrease becomes larger as we go through the years up until 2011. That can be perceived as being the effect of increased competition in the wholesale pool, forcing the price to adjust to the intra-day system load pattern. The increased variation of SMP represents increased competition, since competition increases the sensitivity of SMP to demand during the day. This sensitivity becomes greater over time, as competition emerges in the wholesale electricity market. That happens because within any given day, the other factors that determine pool prices should not be presenting large differentiations, thereby allowing for the effect of system load to become evident.

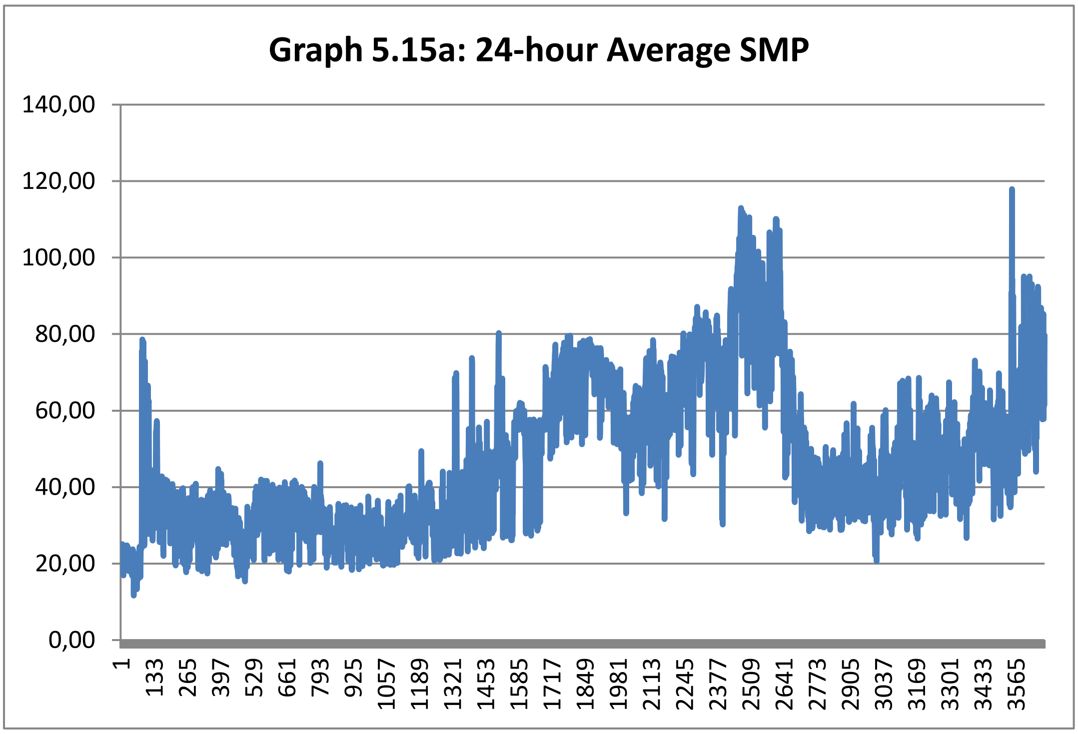


The second thing that we observe in Graph 5.13 is that the SMP levels are changing as the years pass, as we will show later more analytically. All of the averages that we see separately in Graph 5.13 are averaged together to create Graph 5.14 which is to be found in Appendix B, Part 2.

The key issue that we identify in Graph 5.13 is that there are times during the day when wholesale electricity prices are low and other times when these prices are high. Very importantly, this effect seems to become larger as we move to more recent years in our analysis. This is anticipated to be the result of the emergence of competition in the wholesale electricity market. In such a setting, the introduction of new players in an electricity pool would put pressure on the participants to adjust their bidding behaviour towards their actual marginal cost. The implication that this has for electricity suppliers, who face this wholesale electricity prices as part of their costs, is that they are presented with a need to utilize time-varying retail electricity tariffs for two reasons: electricity conservation during "peak demand" periods, shifting electricity consumption to other periods of the day; usage of retail electricity tariffs that cover the cost of electricity supply at most times, rather than using a single tariff which aims to cover average cost of electricity supply over larger periods.

Graph 5.15a, has been created by averaging all of the Graphs 5.300-5.323 that are to be found in Appendix B, Part 2. In that case, the effect of the factors that determine the SMP during peak demand periods is not very strong, however what we get is the "SMP pattern" that is incorporated in the data sets that have been used to create this graph. Similarly as was the case with the graphs of the actual data, we experience the same peaks and the same troughs. We can see that there is an increasing trend from July 2004 (start of July 2004 is observation 1,003) which turns into a sharply increasing trend from May 2006 to October 2008 (start of May 2006 is observation 1,672 and start of October 2008 is in observation 2,556) and then to a decreasing trend from that point until the end of February 2009 (end of February 2009 is in observation 2,706). We can also see the peak of the summer 2011 (observations 3,549-3,557) and the increased SMPs of the period of

September and October 2011 (the last two months of our data, observations 3,621-3,681).



The "SMP pattern" that we identified in Graph 5.15a can also be seen in Graph 5.16a for the night-time period, in Graph 5.17a for the day-time period and in Graphs 5.18a, 5.18c and 5.18e for the "peak load" periods that we have identified earlier. Graphs 5.16a, 5.17a, 5.18a, 5.18c and 5.18e are to be found in Appendix B, Part 2.

Graph 5.15b incorporates all of these SMP 24-hour averages presented in a year-by-year fashion. That diagram is hard to interpret as it is very congested with lines. The same happen for Graphs 5.16b (night-time average), 5.17b (day-time average), 5.18b (average for "peak load" period 9-14&18-21), 5.18d (average for "peak load" period 9-14) and 5.18f (average for "peak load" period 18-21). All of these graphs are to be found in Appendix B, part 2.

An important observation is that in Graphs 5.15a, 5.16a, 5.17a, 5.18a, 5.18c and 5.18e there are two large periods that we can identify. The one is the early period which is from the start of our data until the end of May 2005 (observation 1,337). Until that point, not a lot of things seem to happen in the market and the wholesale prices that we observe show very little variation. Note that the period from September 2001 until May 2005 is a period where PPC is the sole player in the market and there is actually no true competition. On May 2005, a 390 MW independently owned natural gas-fired unit is added to the system ([Iliadou, 2009], [DEPA, 2012]) and that seems to affect wholesale electricity price. Also we can see that the level of prices that we had in the first period of our data is a price level that is never again achieved. We can assume that this is in part due to the level of fossil fuel prices and to inflation, but also it could be due to the fact that due to competition, the prices in the pool should reflect actual cost of electricity generation. Therefore, we move from the previous vertically integrated state of the market to a new, more competitive, setting.

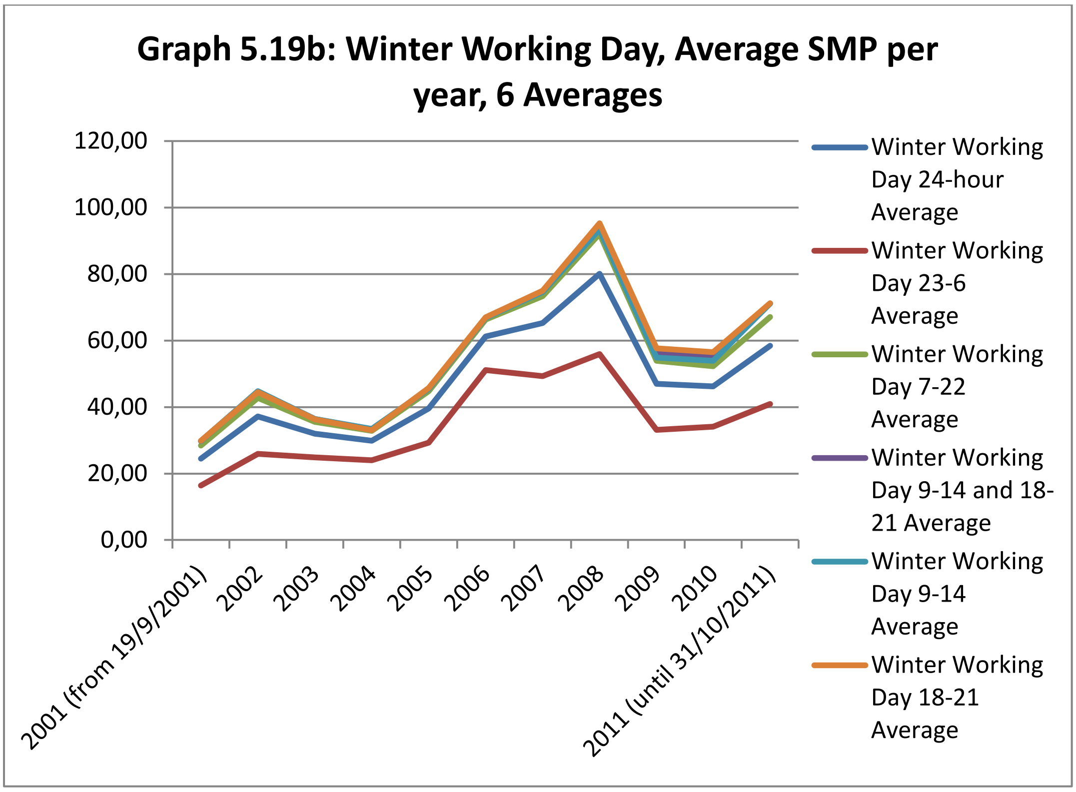
In Graphs 5.19a, 5.20a, 5.21a and 5.22a we present the annual average SMP per dispatch period for each of the Average Days, creating an "SMP profile" per year and per Average Day. These four graphs inform us that SMP tends to be lower during the night-time hours (dispatch periods 0-6 and 23) as opposed to day-time hours (dispatch periods 7-22). These graphs are to be found in Appendix B, Part 2.

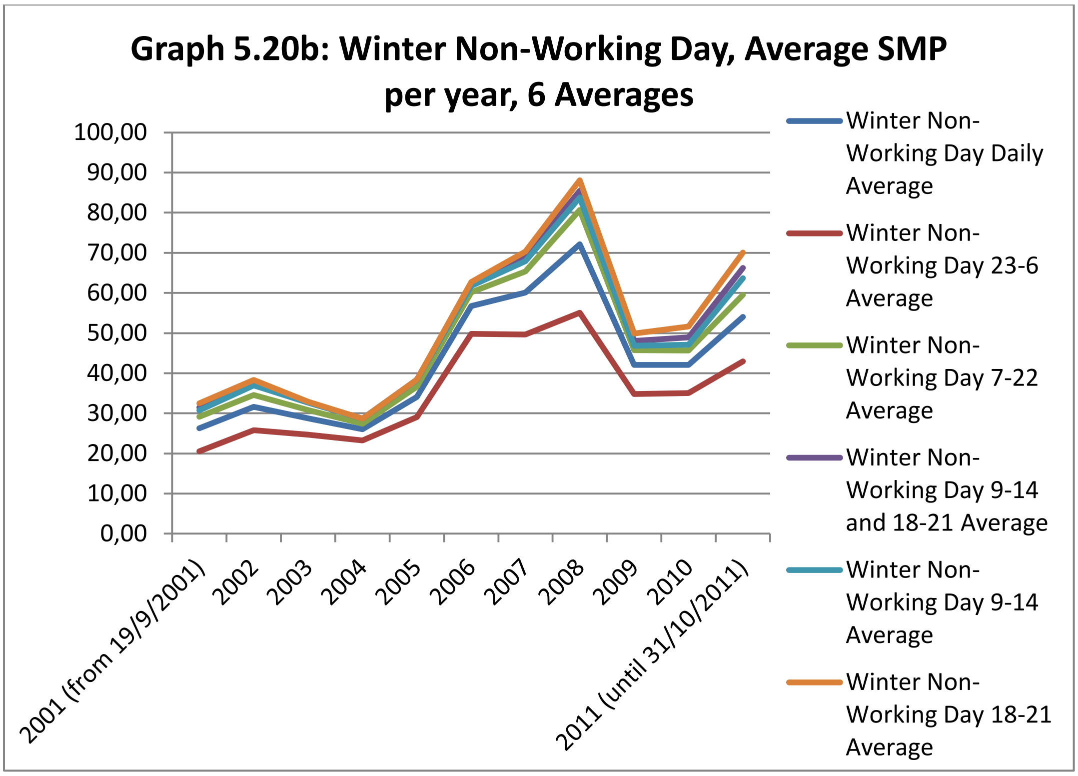
Graphs 5.19b, 5.20b, 5.21b and 5.22b present 6 different averages for the Average Winter Working Day, the Average Winter Non-Working Day, the Summer Working Day and the Summer Non-Working Day. In each of the 4 graphs, we get one average SMP for the specific period of each of years under discussion. In these averages we can see how the 6 averages that we calculate are evolving over time and we observe that all 4 graphs present similar patterns. This indicates the fact that there is a specific effect that each year has on SMP and that is visible in all of the averages and in all periods discussed (winter or summer, working or non-working), signaling the fact that the year under discussion is always relevant to the determination of the SMP in the wholesale electricity pool. By referring to the effect of each year we imply that it is not the year as such that affects the SMP but rather some other factors that vary over the specific time periods that each year refers to. We can also see that we get lower average SMPs for night-time averages (23-6), then the averages get higher when we calculate them for the 24-hour period, then even higher for the averages of the dispatch periods during the day (7-22 and all the other averages that refer to smaller periods included in this period of the day).

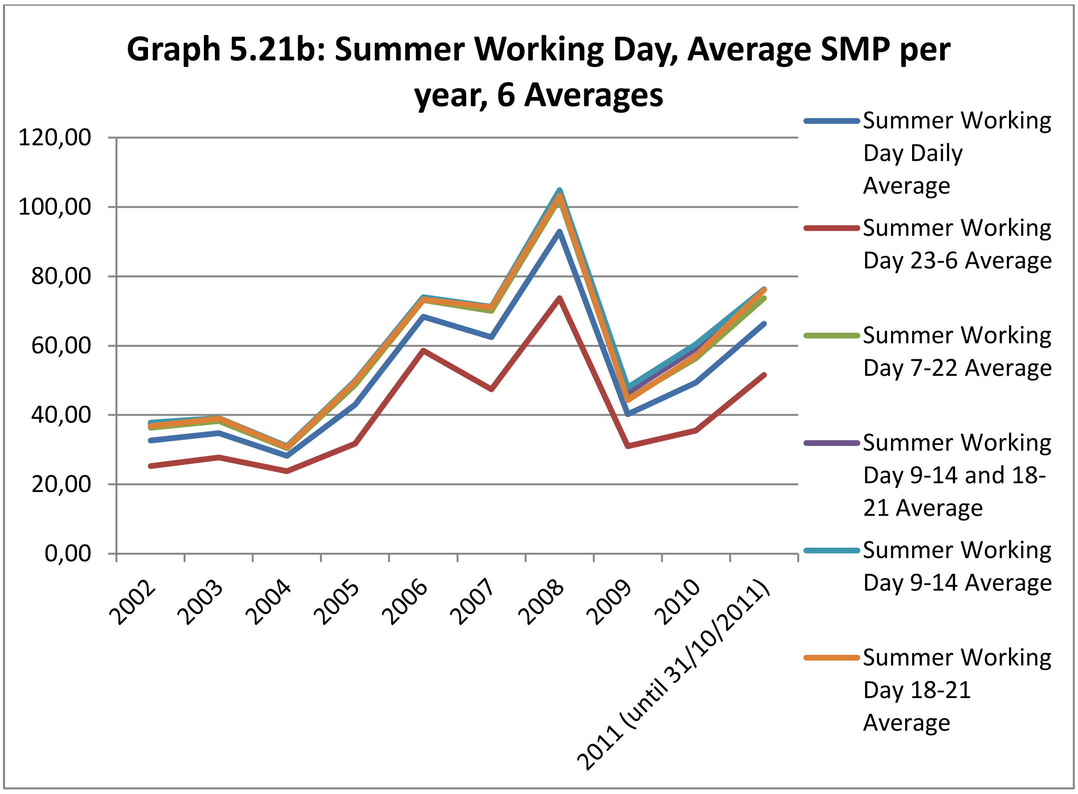
In the winter, as we discussed in the system load section, electricity demand is higher in the afternoon “high demand” period than it is in the morning and that appears to have an effect on the determination of the SMP. The afternoon (18-21) averages of SMP in Graphs 5.19b and 5.20b is the highest amongst the three “high demand” averages. In the summer, as we discussed in the system load section, we experience the relatively high demand in the morning period instead. The morning (9-14) averages of SMP in Graphs 5.21b and 5.22b are the highest from the three “high demand” averages. The effect of the time in the day on the SMP is important for us as our observations support the creation of time-varying tariffs. Retail electricity tariffs that adopt different night-time charges than day-time ones, more accurately reflect marginal cost variations and might lead to increases in consumer surplus.

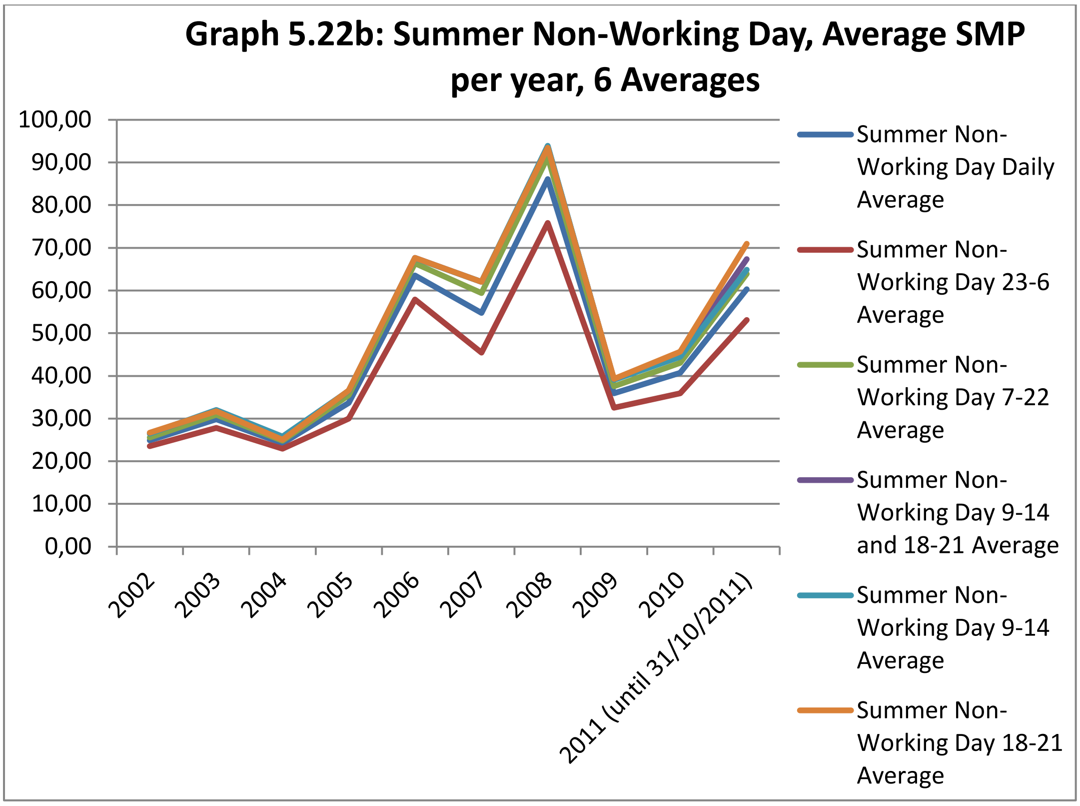
An important observation is that by comparing Graphs 5.19b, 5.20b, 5.21b and 5.22b the average SMPs in these graphs are set at different levels for the 24-hour, day-time (7-22) and “high demand” (9-14, 18-21 and both of them together) averages. In each period of the year (winter or summer) the day-time (7-22) averages of SMP of the working days are higher than those of the non-working days. The SMP averages during the night (23-6) are at similar levels for both working and non-working days. That suggests that the factors that are creating differences between the day-time SMPs of working and non-working days in each period of the year are related to activities that are carried out during the day. The fact that these activities do not seem to affect the SMP in non-working days suggests that these are business-related activities.

By comparing Graphs 5.19b, 5.20b, 5.21b and 5.22b we also observe that the SMP averages are lower in the two winter graphs (Graphs 5.19b and 5.20b) than they are in the two summer graphs (Graphs 5.21b and 5.22b). This suggest that the period of the year (winter or summer) has a specific effect on the level of the SMP and thus supports the adoption of tariffs that vary between winter and summer.

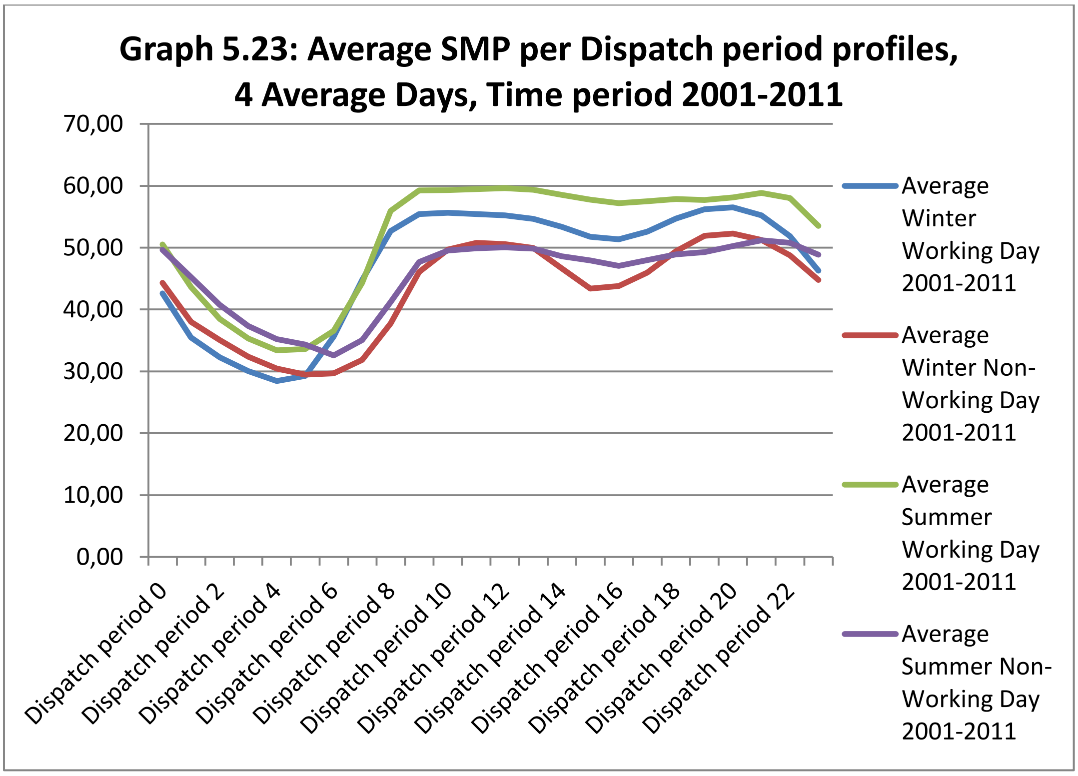



Graph 5.20b: Winter Non-Working Day, Average SMP per year, 6 Averages
100,00
90,00
80,00
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Non-Working Day Daily Average
Winter Non-Working Day 23-6 Average
Winter Non-Working Day 7-22 Average
Winter Non-Working Day 9-14 and 18-21 Average
Winter Non-Working Day 9-14 Average
Winter Non-Working Day 18-21 Average


Graph 5.21b: Summer Working Day, Average SMP per year, 6 Averages
120,00
100,00
80,00
60,00
40,00
20,00
0,00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Summer Working Day Daily Average
Summer Working Day 23-6 Average
Summer Working Day 7-22 Average
Summer Working Day 9-14 and 18-21 Average
Summer Working Day 9-14 Average
Summer Working Day 18-21 Average



Graph 5.22b: Summer Non-Working Day, Average SMP per year, 6 Averages
100,00
90,00
80,00
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Summer Non-Working Day Daily Average
Summer Non-Working Day 23-6 Average
Summer Non-Working Day 7-22 Average
Summer Non-Working Day 9-14 and 18-21 Average
Summer Non-Working Day 9-14 Average
Summer Non-Working Day 18-21 Average



Graph 5.23: Average SMP per Dispatch period profiles, 4 Average Days, Time period 2001-2011
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
Dispatch period 0
Dispatch period 2
Dispatch period 4
Dispatch period 6
Dispatch period 8
Dispatch period 10
Dispatch period 12
Dispatch period 14
Dispatch period 16
Dispatch period 18
Dispatch period 20
Dispatch period 22
Average Winter Working Day 2001-2011
Average Winter Non-Working Day 2001-2011
Average Summer Working Day 2001-2011
Average Summer Non-Working Day 2001-2011

The averages included in Graphs 5.19a, 5.20a, 5.21a and 5.22a (found in Appendix B, Part 2) have been averaged to create an average SMP per dispatch period for each of the four Average Days for the whole time period 2001-2011. These were put together in Graph 5.23. By examining Graph 5.23 we can see that there is an intra-day SMP pattern that roughly applies to all of the 4 Average Days. In all four Average Days, the SMP is lower during the time period that corresponds to dispatch periods 23-6. Therefore it is justifiable to expect that there will be tariffs capturing this market characteristic and offering lower retail prices for electricity during the night.

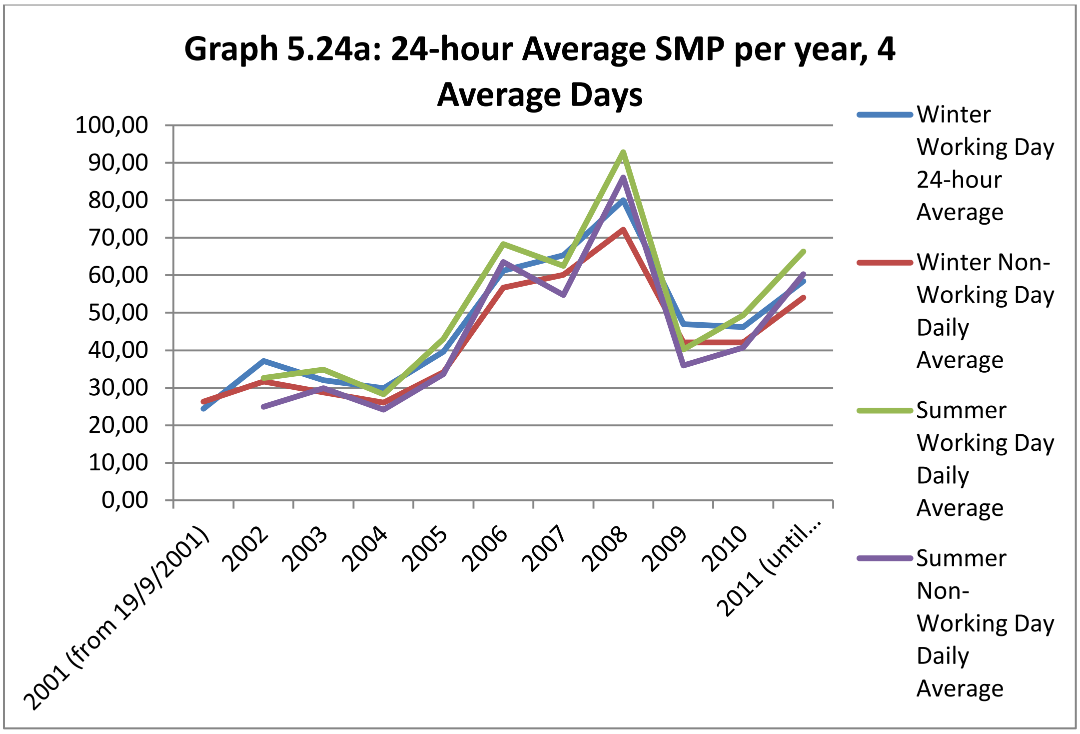
It is important to note that by comparing the levels of the SMPs that we get from Graph 5.23 for the different average days, we get similar results to those that we get from Graph 5.11. It therefore appears that the intra-day system load plays an active role in the determination of the intra-day SMP. However that is only true when we are referring to the effect of the system load during the different hours of a given day, since for that given day, other significant factors are not expected to be varying and therefore affecting the intra-day SMP. So, we conclude by comparing Graphs 5.23 and 5.11 that with all other factors kept constant, SMP is affected by the system load.

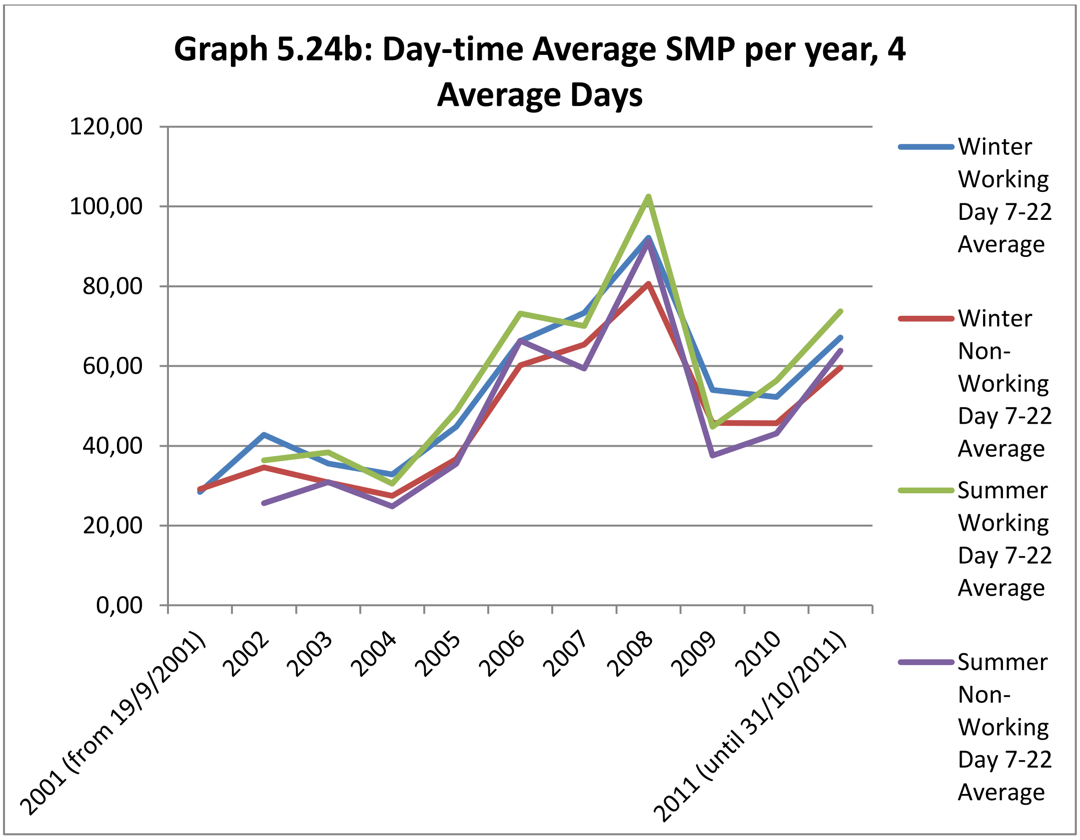
The averages that we previously discussed in Graphs 5.19b, 5.20b, 5.21b and 5.22b have been rearranged into Graphs 5.24a, 5.24b, 5.24c, 5.24d, 5.24e and 5.24f, where they have been grouped not by the Average Day but by the Average SMP that is calculated. In these 6 graphs, we look more analytically at what has been observed in Graph 5.23, by taking each of the averages separately. So we do not examine the effect of the hour of the day, since that is constant in each graph, we rather address the differences in annual average SMP by varying the time of the year (winter or summer) and the day in the week (working or non-working).

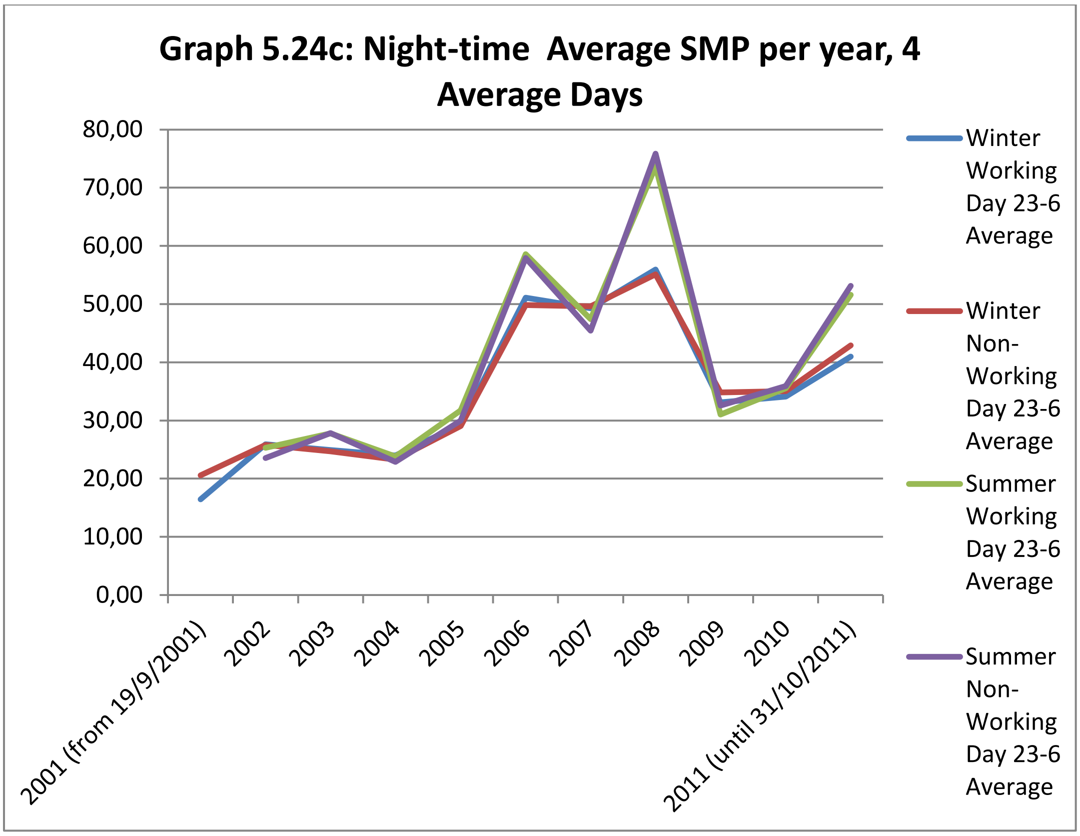
Some observations on Graphs 5.24a-5.24f:

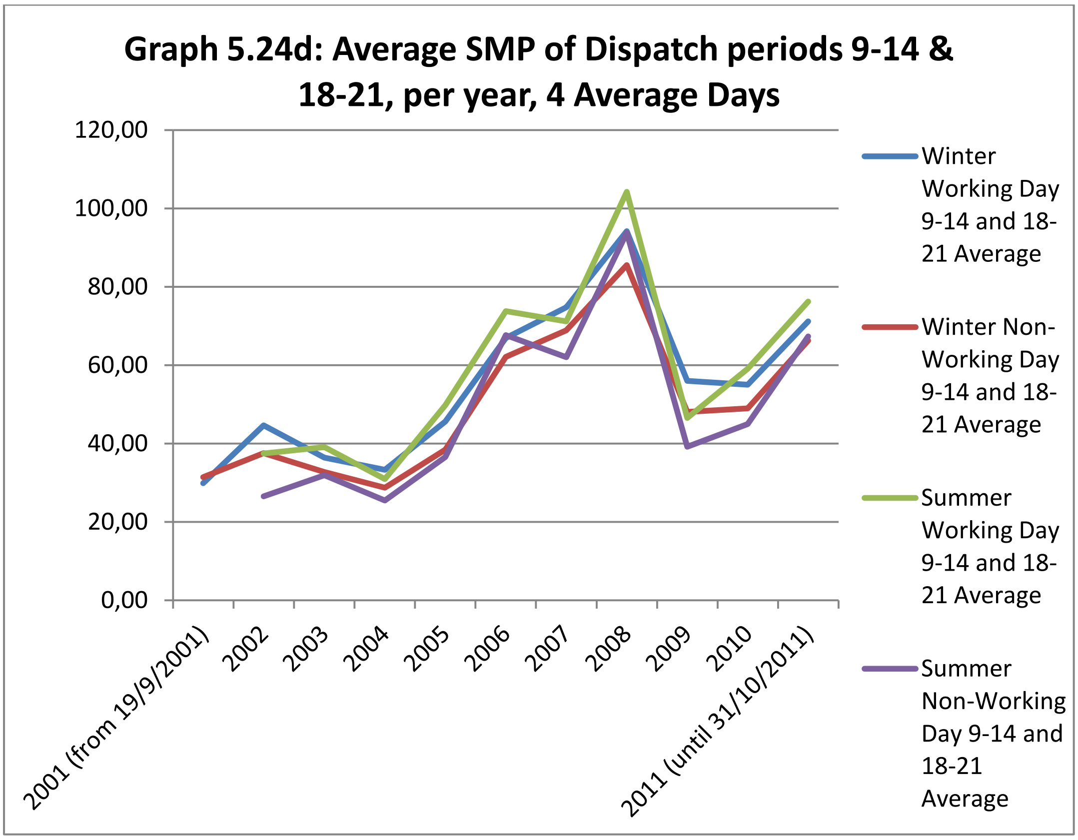
- Examining each of the years separately, the average SMPs of the day-time averages, that is to say, exclude the night-time averages, are at similar levels, regardless of which of the four Average Days we are looking at. Also, for any one of the five day-time average SMP graphs that we have (Graphs 5.24a, 5.24b, 5.24d, 5.24e, 5.24f), the average SMPs of each year are set within specific ranges regardless of the Average Day that we are looking at. These ranges are evolving through the years where we observe their levels vary, nonetheless they still exist. That suggests that there should be some factors related to each year that determine the average SMP during the dispatch periods 7-22 in both summer and winter and in both working and-non working days. Such a factor could be the international fossil fuel prices.

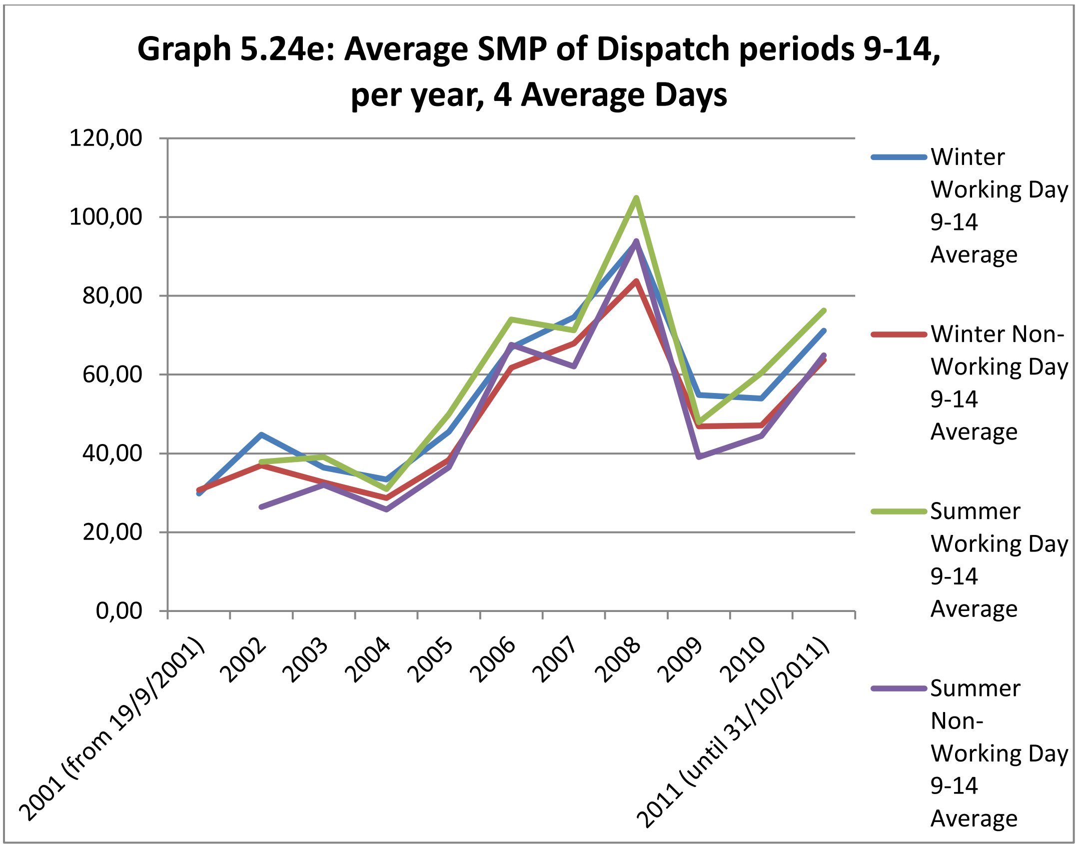
- The time of the year (summer or winter) is also very significant as we can see that we have two patterns for our averages in all graphs, one for the two Winter Average Days and one for the two Summer Average Days.
- The day of the week (working or non-working) is showing that it has a specific effect on average SMP, as by comparing working and non-working days for all averages except the night-time ones, working day average SMPs are always higher.
- The night-time average SMPs are set at lower levels that the averages of SMPs of the day-time period (dispatch periods 7-22) in all years and for all Average Days. That could be related to the tariff setting structure that allows for lower electricity prices during the night-time period.
- Also, the night-time average SMPs do not differentiate in working days and non-working days. That was expected as the differentiation between working and non-working days reflects the fact that business activities play a role in electricity demand, and that these activities do not take place during the night.

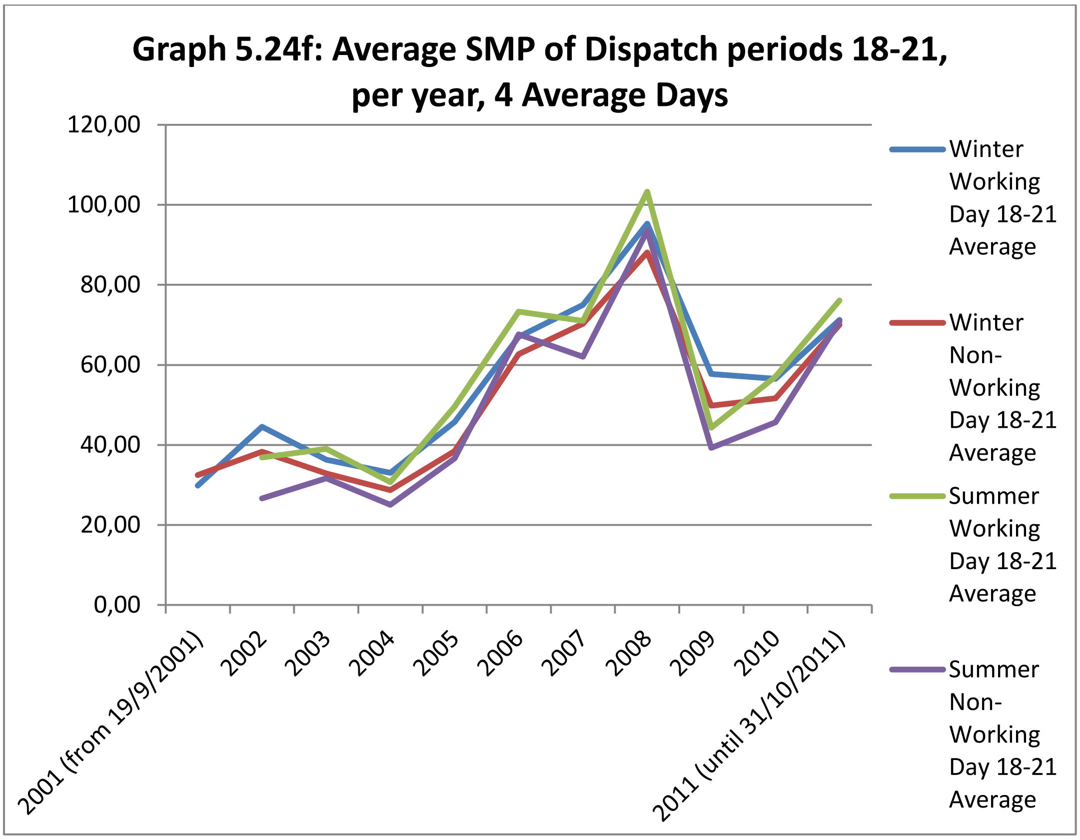

Graph 5.24a: 24-hour Average SMP per year, 4 Average Days
100,00
90,00
80,00
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until...
Winter Working Day 24-hour Average
Winter Non-Working Day Daily Average
Summer Working Day Daily Average
Summer Non-Working Day Daily Average


Graph 5.24b: Day-time Average SMP per year, 4 Average Days
120,00
100,00
80,00
60,00
40,00
20,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 7-22 Average
Winter Non-Working Day 7-22 Average
Summer Working Day 7-22 Average
Summer Non-Working Day 7-22 Average


Graph 5.24c: Night-time Average SMP per year, 4 Average Days
80,00
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 23-6 Average
Winter Non-Working Day 23-6 Average
Summer Working Day 23-6 Average
Summer Non-Working Day 23-6 Average


Graph 5.24d: Average SMP of Dispatch periods 9-14 & 18-21, per year, 4 Average Days
120,00
100,00
80,00
60,00
40,00
20,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 and 18-21 Average
Winter Non-Working Day 9-14 and 18-21 Average
Summer Working Day 9-14 and 18-21 Average
Summer Non-Working Day 9-14 and 18-21 Average


Graph 5.24e: Average SMP of Dispatch periods 9-14, per year, 4 Average Days
120,00
100,00
80,00
60,00
40,00
20,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 Average
Winter Non-Working Day 9-14 Average
Summer Working Day 9-14 Average
Summer Non-Working Day 9-14 Average


Graph 5.24f: Average SMP of Dispatch periods 18-21, per year, 4 Average Days
120,00
100,00
80,00
60,00
40,00
20,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 18-21 Average
Winter Non-Working Day 18-21 Average
Summer Working Day 18-21 Average
Summer Non-Working Day 18-21 Average

An important observation also has to do with the changes that we observe in the rankings across Graphs 5.24a-5.24f. As we mentioned, in all average SMPs except the night-time ones, the average SMPs are very close. We can also see that there isn't an Average Day that consistently has the highest or the lowest SMP. That could be due to the effect of external factors. It should be noted that although the averages are calculated for each year and graphed together, two of the averages refer to the period of the summer and two of them refer to the period of the winter. Therefore, it is not exactly the same period that these refer to, and any external factors affecting SMP during the winter of one specific year are not guaranteed to be present during the summer of that same year. Also we should note that the period referred to as the winter period in each year is made up from two non-continuous periods (01/01-19/05 and 21/09-31/12 of each year) therefore it could be that specific factors affecting the one of the two parts of the winter period are not affecting the other.

5.4 Deviations Marginal Price (DMP) data

An analysis similar to that applied to the SMP data in Section 5.3 has also been carried out with the DMP data. The results are very similar to those obtained in Section 5.3. They are not presented in the text but a report and discussion of the results can be found in Appendix D, Part 1.

5.5 System Load-standard deviations

5.5.1 Introduction

The System Load data that we have available are used to calculate standard deviations and use these to examine some parameters of the electricity market. The main purpose behind that is to show how volatile that market is during the different hours, different days, different times of the year and different years. That volatility reflects on the levels of uncertainty and risk that this market has for its participants.

Standard deviation has been used as a measure of the volatility in the Greek electricity market. Generators are interested in volatility since that could be taken into consideration when planning for new generation and they want to make decisions about capacity and technology. Suppliers on the other side are interested because system load represents their sales of electricity.

In the graphs that we have created for system loads in Section 5.2, we have seen that in all of these timelines of system loads, there are seasonality patterns that are present and easily identifiable. That is due to the fact that as seasons change, the demand for electricity is strongly affected and this happens in specific ways. That is very evident in Greece where summers are very warm and we can verify this by looking at our average system load graphs to find out where the highest system loads occur-that is in the summer months.

5.5.2 Some notes on the calculations of standard deviations

When creating the 4 Average Days, there were no useful summer data for summer 2001. As a result, for Summer Working Days and Summer Non-Working Days, we have observations that refer to 10 years (2002-2011) instead of 11 (2001-2011) that we have for the Winter Working Days and Winter Non-Working Days.

An important observation concerns the calculations of the average standard deviations per dispatch period for each Average Day:

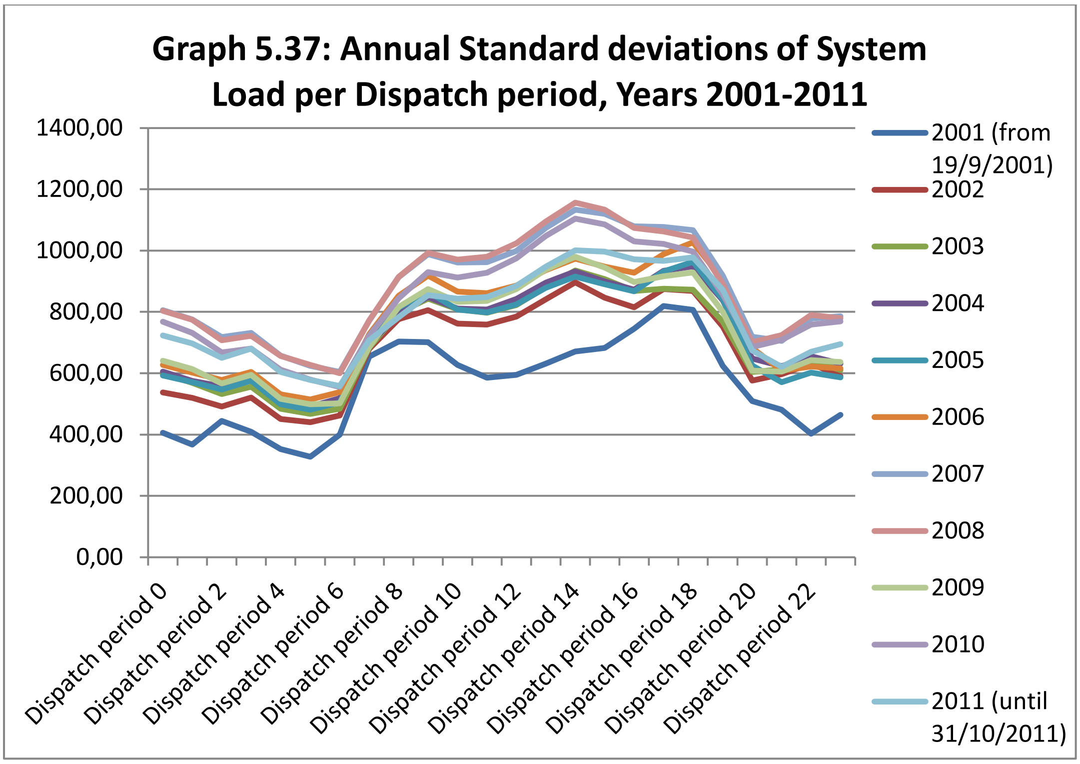
- Initially, standard deviations for annual data of each dispatch period have been calculated for every year and every Average Day
- Then, these have been averaged to calculate the average standard deviations per dispatch period and per Average Day for all the time period that we examine

However, although that is quite likely a good approximation, the result would not have been exactly the same if all of the data had been used together in order to calculate directly the standard deviation per dispatch period and per Average Day for all the time period under consideration.

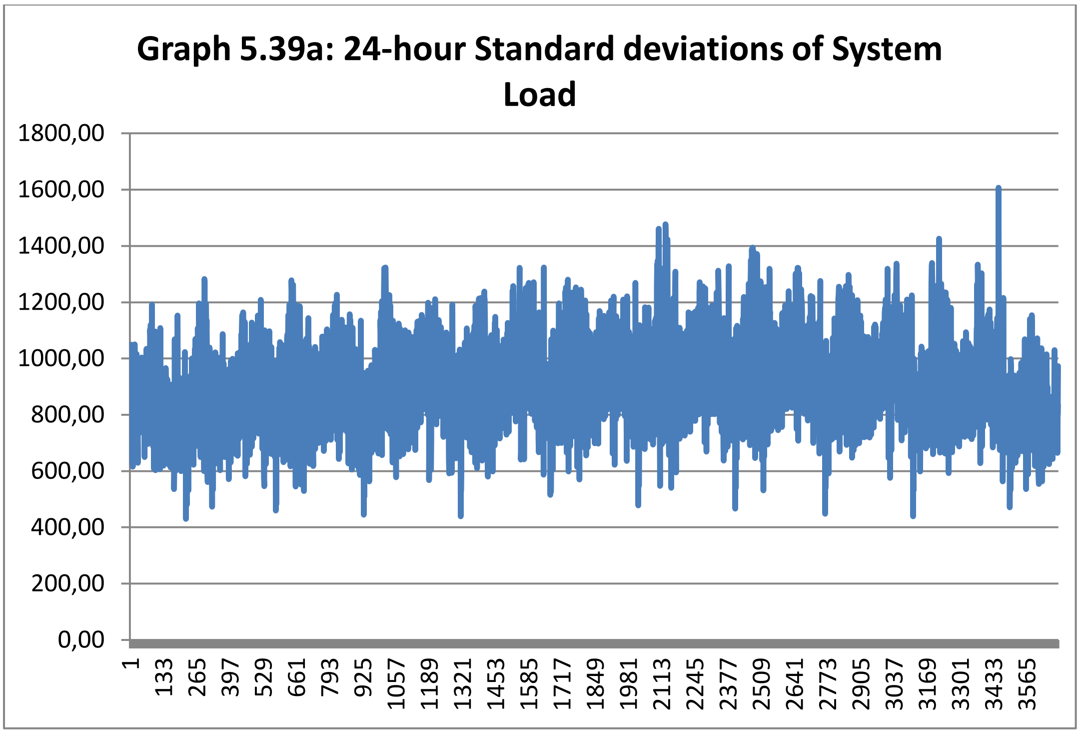
The above problem is not present on the calculations of the annual standard deviations of the system loads per dispatch period, since these have been calculated using the actual data directly. The same holds true for the standard deviations of the system loads per dispatch period for the whole time period that we examine.

5.5.3 System Load Graphs-Standard deviations

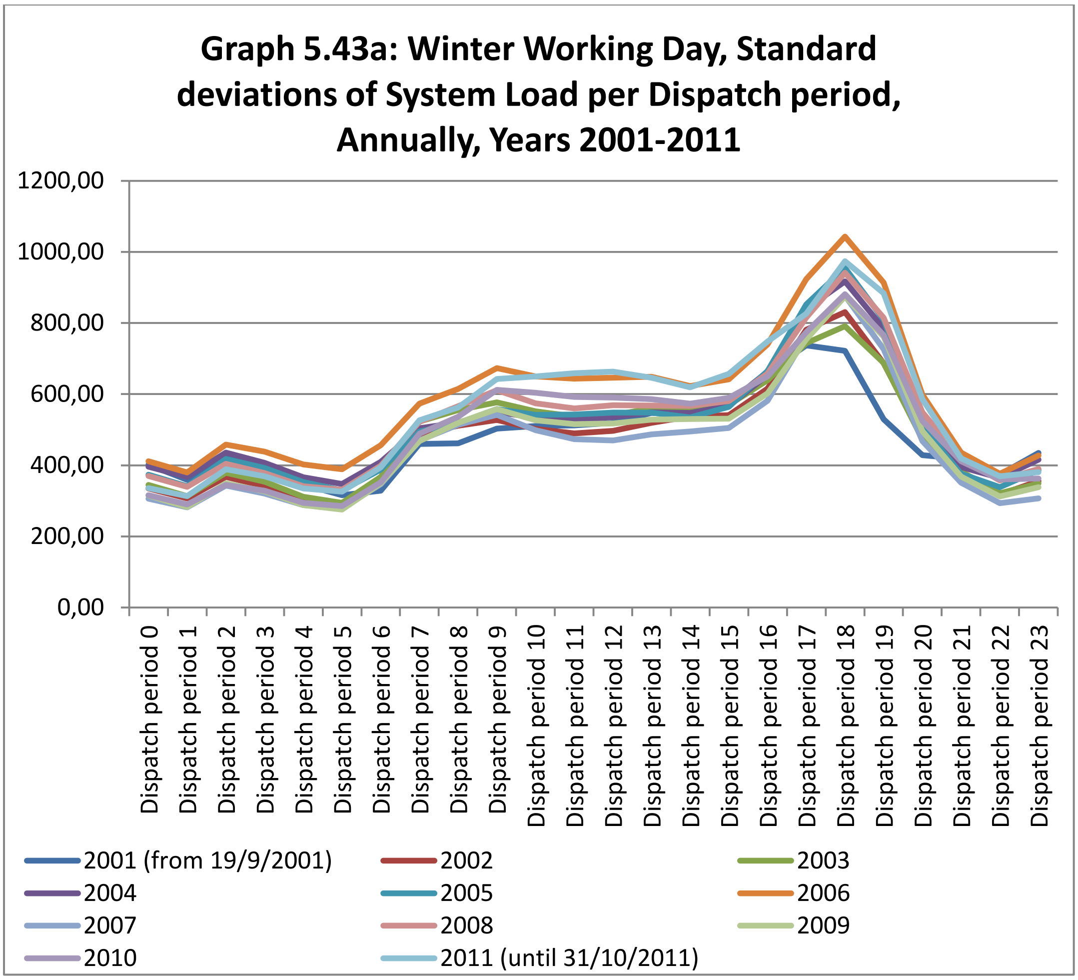
In Graph 5.37 we can see the standard deviation of the system load per dispatch period for every one of the years that we are looking at. We observe that throughout the years there is an intra-day pattern of standard deviation. That means that the system load is more volatile in specific dispatch periods than it is in others and that is mainly during the dispatch periods 8-18. These average standard deviations range throughout the years from as low as 327.64 MWh up to 1,156.15 MWh. The standard deviations of the system load of all the time period for each dispatch period is calculated and graphed in Graph 5.38 which is to be found in Appendix B, Part 4.



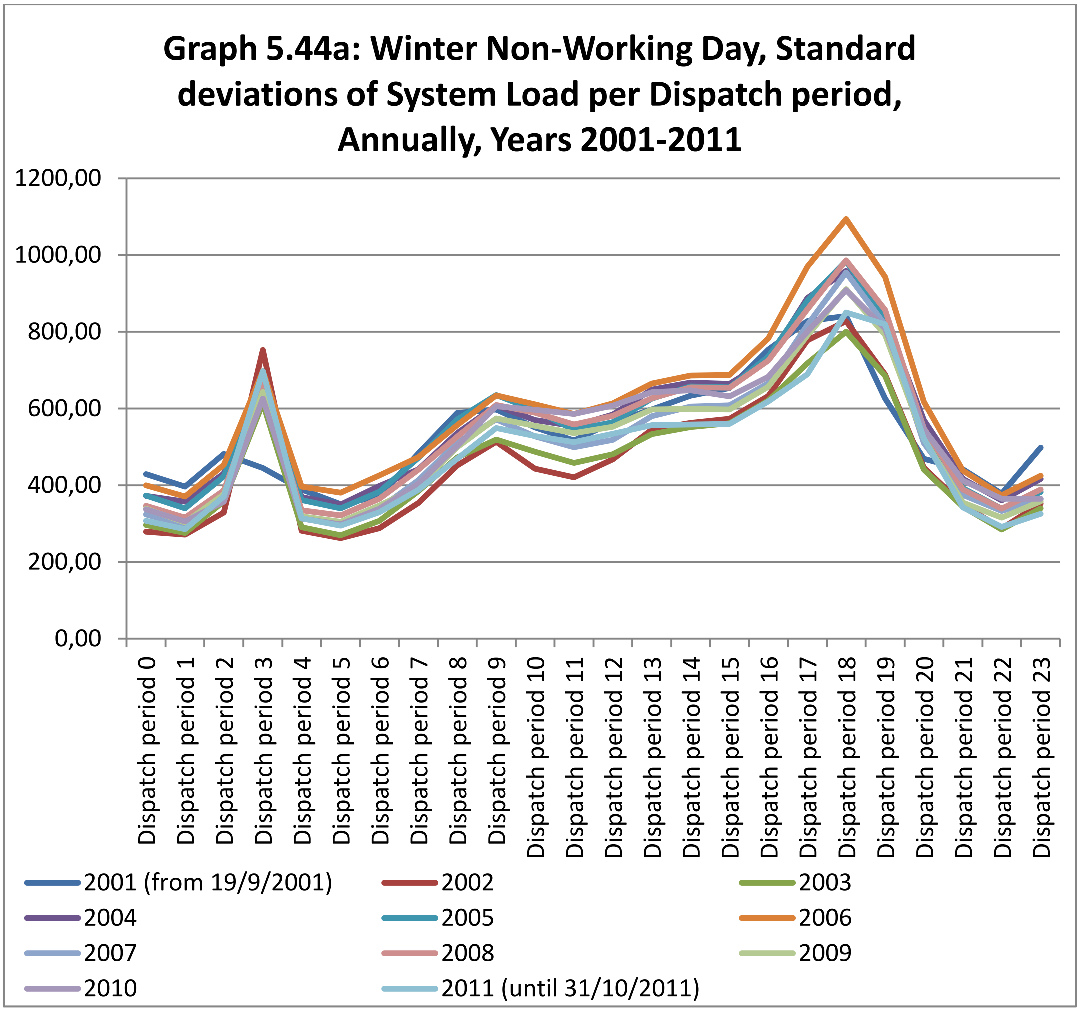
In Graph 5.39a, we present the standard deviation of the system load across all 24 dispatch periods of each day, for each day of the period that we examine. What we can see is that there is a seasonality pattern which is due to the seasonality that we also observed in the average system load in Graph 5.3a. So we get that the seasonality is not only present in the system load (as discussed in Section 5.2) but also in the standard deviation of that system load. We can also see that there is a slightly increasing trend until the summer of 2007 and a decreasing trend from that point and on. A trend similar to that one was also observed in the average system load. That was expected if we take the point of view of the respective proportions as the larger the system load, the larger the expected standard deviation. In a similar fashion as in Graph 5.39a, we present the standard deviations of the system load for the other 5 time periods that we examine. That is done in Graphs 5.40a, 5.41a, 5.42a, 5.42c and 5.42e which are all to be found in Appendix B, Part 4.



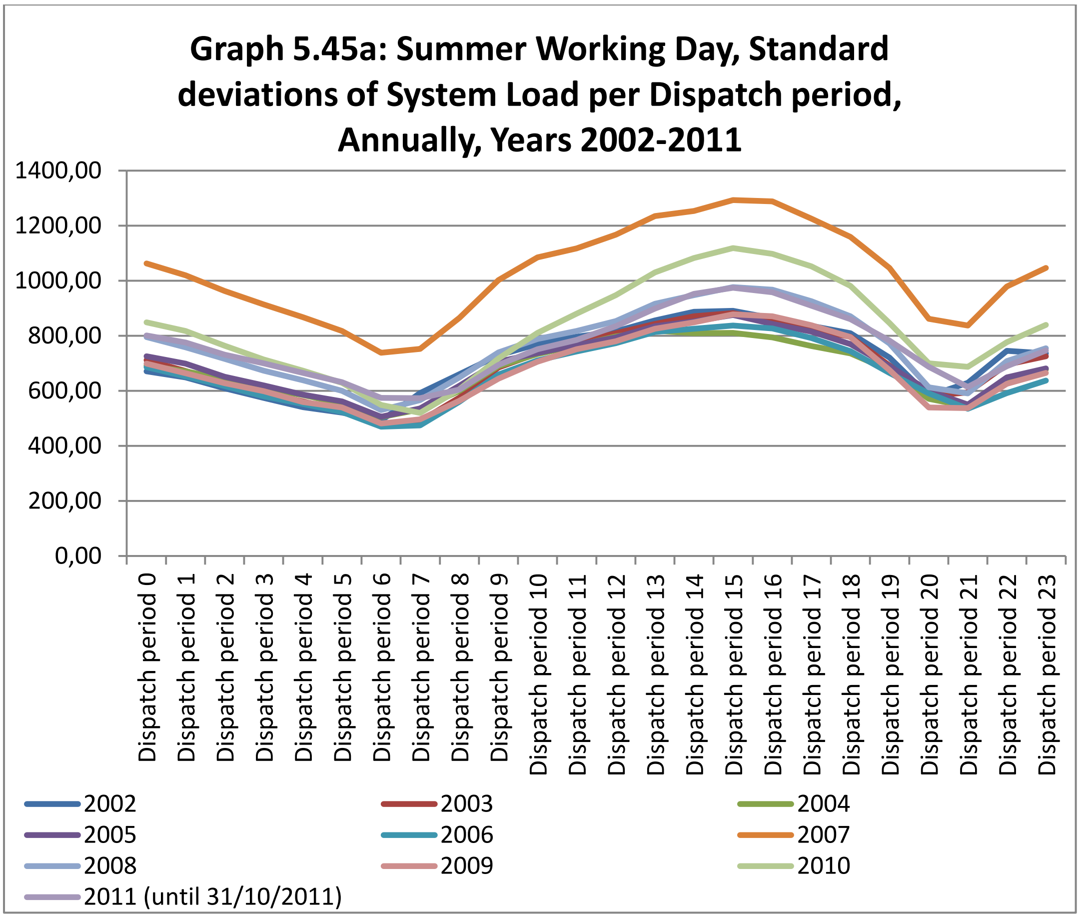
Graph 5.39b incorporates all of these 24-hour standard deviations of the system load presented in an annual basis. So what we get is annual standard deviations of the system load profiles for each of the years 2002-2011. Although it is hard to extract results from this graph since it is heavily congested with lines, we still can get to say that the annual pattern that has been observed previously is visible in this one too. Graph 5.39b is to be found in Appendix B, Part 4, along with similar graphs drawn for the other 5 standard deviations of system load. These are Graphs 5.40b, 5.41b, 5.42b, 5.42d and 5.42f. In all of them we can observe seasonality patterns which are present because of the very existence of seasonality in the respective averages of the same data.

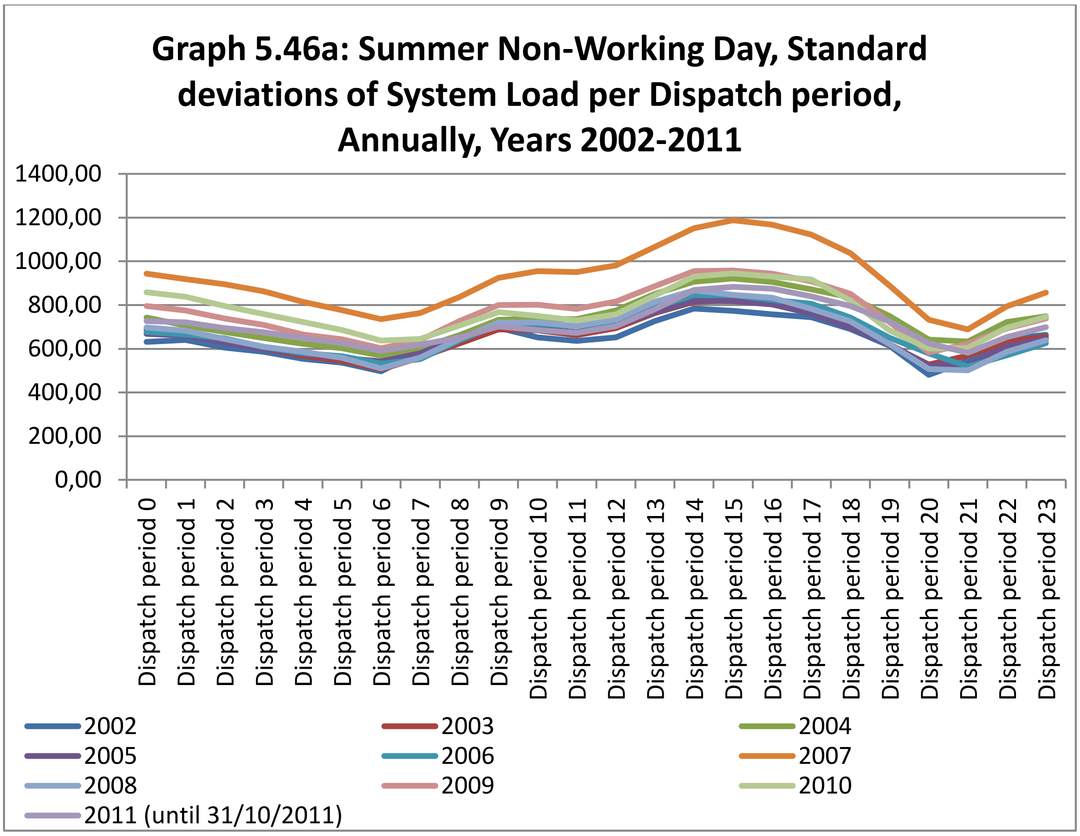


In Graph 5.43a, we have the 24-hour system load average standard deviation for the Average Winter Working Day for each of the years 2001-2011. We observe that there is a specific intra-day pattern that is present and consistent throughout the years. A similar pattern is observed in Graph 5.44a that presents the 24-hour system load standard deviation for the Average Winter Working Day for each of the years 2001-2011. The similarities between Graphs 5.43a and 5.44a are suggesting a strong intra-day seasonality in our data, as we have also seen in Graphs 5.7a and 5.8a. This is important because this seasonality is consistently present both in working and non-working days for that specific period (winter).

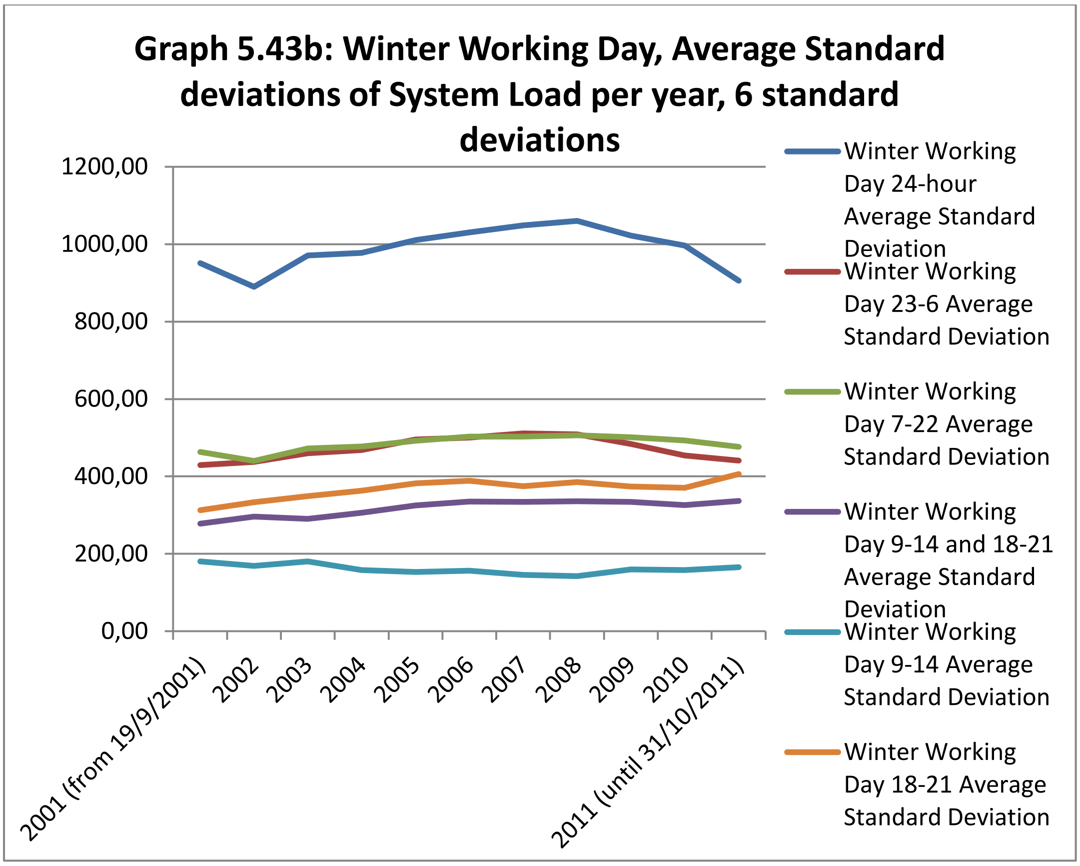


In Graphs 5.45a and 5.46a we present the 24-hour system load average standard deviation for the Average Summer Working Day and for the Average Summer Non-Working Day. Similarly as it was in Graphs 5.43a and 5.44a, there is a specific intra-day pattern that is present and consistent throughout the years, however winter and summer periods do not share similar patterns. The similarities between Graphs 5.45a and 5.46a are suggesting strong intra-day seasonality in our data, as we have also seen in Graphs 5.9a and 5.10a. This is important because this seasonality is consistently present both in working and non-working days for that specific period (summer) indicating the existence of a specific effect that the period of the year has. The suggestion that this constitutes the effect specifically of the summer period is reinforced by the fact that the winter period has its own intra-day pattern.

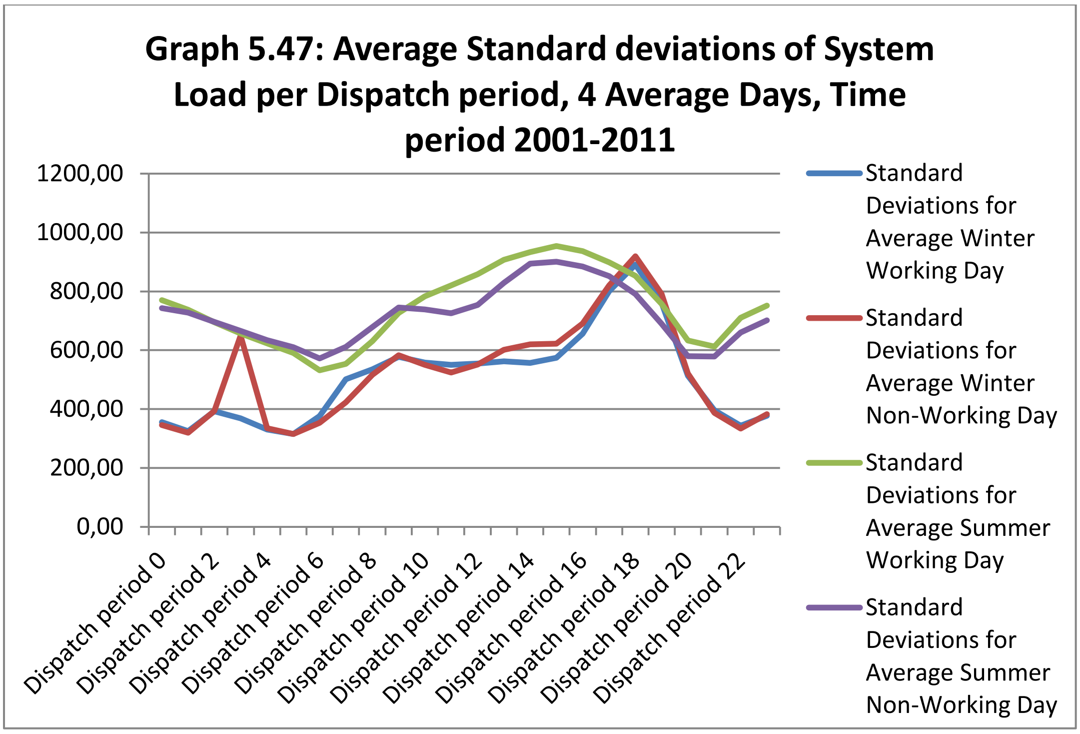

Graph 5.45a: Summer Working Day, Standard deviations of System Load per Dispatch period, Annually, Years 2002-2011
1400,00
1200,00
1000,00
800,00
600,00
400,00
200,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)



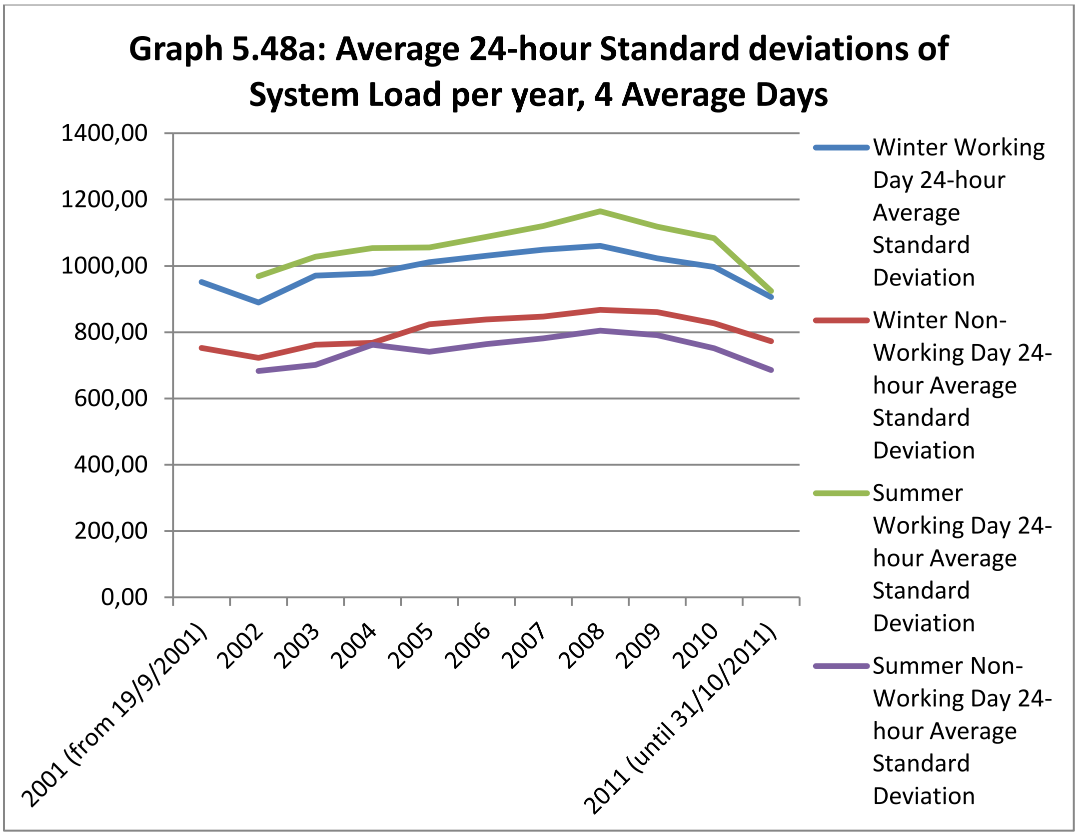
In Graphs 5.43b, 5.44b, 5.45b and 5.46b we present 6 different average standard deviations of System Load for each year and for each of the 4 Average Days. We can see that across all 4 of the graphs, standard deviations remain at constant levels for all years. The level at which the average standard deviation is set seems to be dependent on the amount of dispatch hours that are included in the calculation of each standard deviation. As a result, the 24-hour average standard deviation is set at higher levels than the night-time and the day-time average standard deviation and these are set at higher levels than the average standard deviations for the "high demand" periods. Given that these graphs are very similar, we only present Graph 5.43b below. Graphs 5.44b , 5.45b and 5.46b are all found in Appendix B, Part 4.



The standard deviations for each dispatch period that were presented in Graphs 5.43a, 5.44a, 5.45a and 5.46a have been averaged to create intra-day profiles of standard deviations for each Average day for all the time period that we examine. These are presented in Graph 5.47. By examining Graph 5.47 we can see that there are two patterns during the day for the 4 Average Days, one for the two Average Winter Days and one for the two Average Summer Days. The Average Winter Days present a pattern that is very volatile in the afternoon periods and the Average Summer Days present a pattern that has the highest standard deviation during the middle of the day (dispatch periods 9-18). The fact that there would be two patterns instead of one and that these patterns would seem to be defining the Average Days profiles according to the period of the year (winter or summer) was anticipated already by the examination of Graphs 5.43a, 5.44a, 5.45a and 5.46a, whose data acted as the source for the creation of Graph 5.47.



The average standard deviations that we presented in Graphs 5.43b, 5.44b, 5.45b and 5.46b have been rearranged into new graphs and have been now grouped not by the Average Day but by the average standard deviation that is calculated. The result is Graphs 5.48a, 5.48b, 5.48c, 5.48d, 5.48e and 5.48f. Graph 5.48a is presented below and Graphs 5.48b, 5.48c, 5.48d, 5.48e and 5.48f are to be found in Appendix B, Part 4. In these 6 graphs, there is no clear suggestion of any pattern for the average standard deviations that are calculated during the day time and most lines are flat, suggesting an almost fixed level of average standard deviation that constitutes a characteristic of the Greek electricity system, despite the changes in the system load levels that we have seen in Graphs 5.12a-5.12f.



5.6 SMP-Standard deviations

5.6.1 Introduction

The System Marginal Price (SMP) data that we have available are for the time period 19/09/2001-31/10/2011. For that time period, we have 24 SMP values for every day and these correspond to the 24 dispatch periods of each day (one for each hour of the day).

The standard deviation is used as a measure of volatility of prices in the Greek electricity wholesale market. That is very important because of the impact that this price volatility might have on profitability for electricity generators and suppliers.

A very important note that we should make is that the discussion made in Sections 5.6 and 5.7 that refer to the standard deviations of SMP and DMP is addressing risk. This risk is however the risk that the electricity suppliers are facing as they buy electricity in the wholesale market, since the generators are anyway covering their own cost, either through their bids and the wholesale markets prices, or through the Mechanism for Covering Variable Cost [RAE, 2010a].

5.6.2 Some notes on the SMP Data

One important issue is to identify what the changing levels of SMP variance mean to the electricity system and what these mean to the participants in the wholesale market-both to the generators and to the suppliers. We should be reminded that the annual seasonality pattern that was evident in the annual System Load data does not appear in the annual SMP data. That means that although System Load apparently plays a role in the determination of the SMP, this role is not large enough to make the effect of variation in the system load visible as it is always combined with the operating costs of the electricity generation plants.

However, variation in the intra-day System Load across dispatch periods does affect the intra-day SMP as we have seen earlier. That is due to the fact that during a given day, the other factors that determine SMP are not expected to vary.

5.6.3 SMP Graphs-Standard deviations

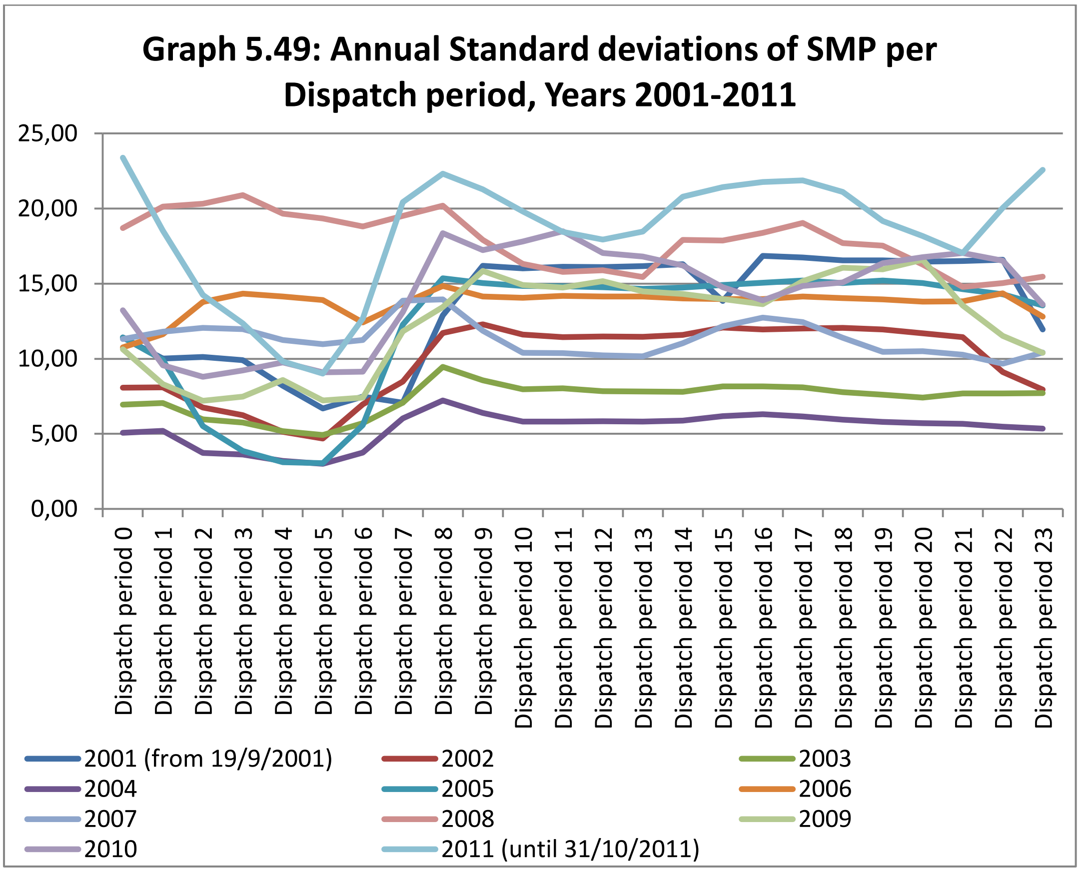
In Graph 5.49 we can see what the annual standard deviations of the SMP for every dispatch period for the years 2001-2011. The two main observations that we get from this are that:

- In some years, the SMPs of the night-time periods present lower standard deviations than the SMPs of the day-time periods.

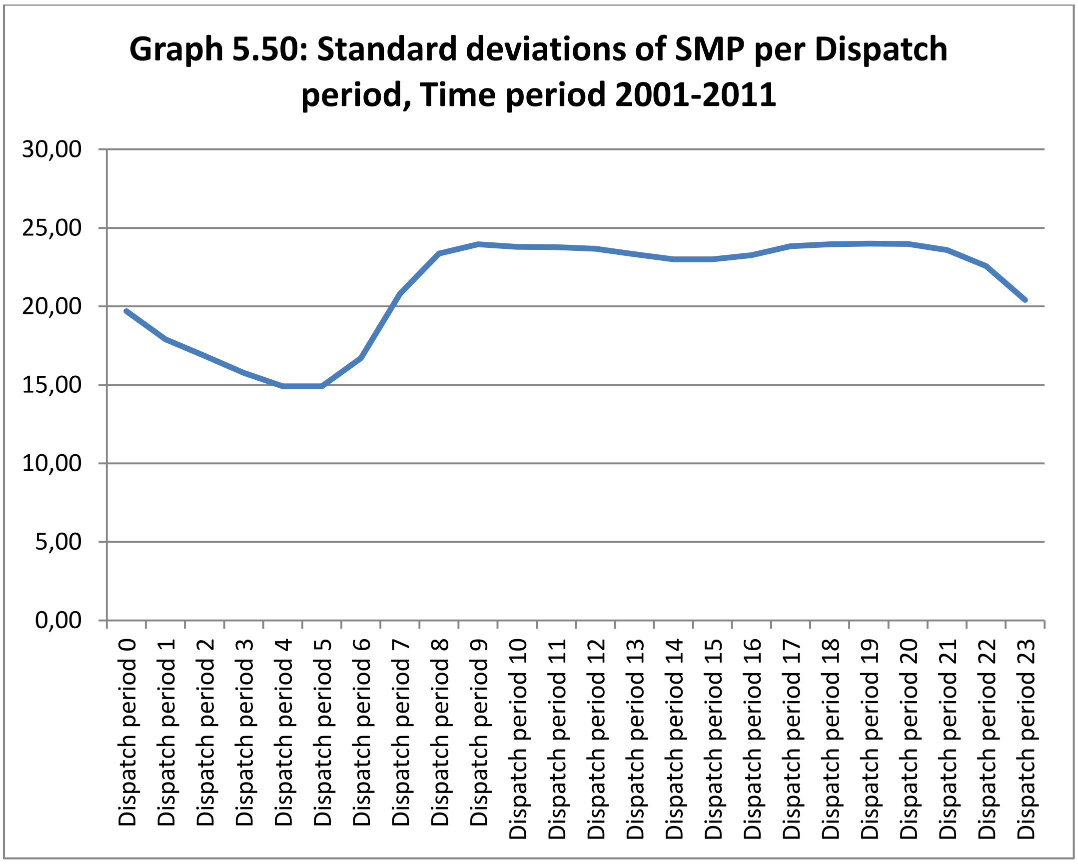
- As we move from the earlier to later years, the levels of the standard deviations of the SMPs tend to increase.

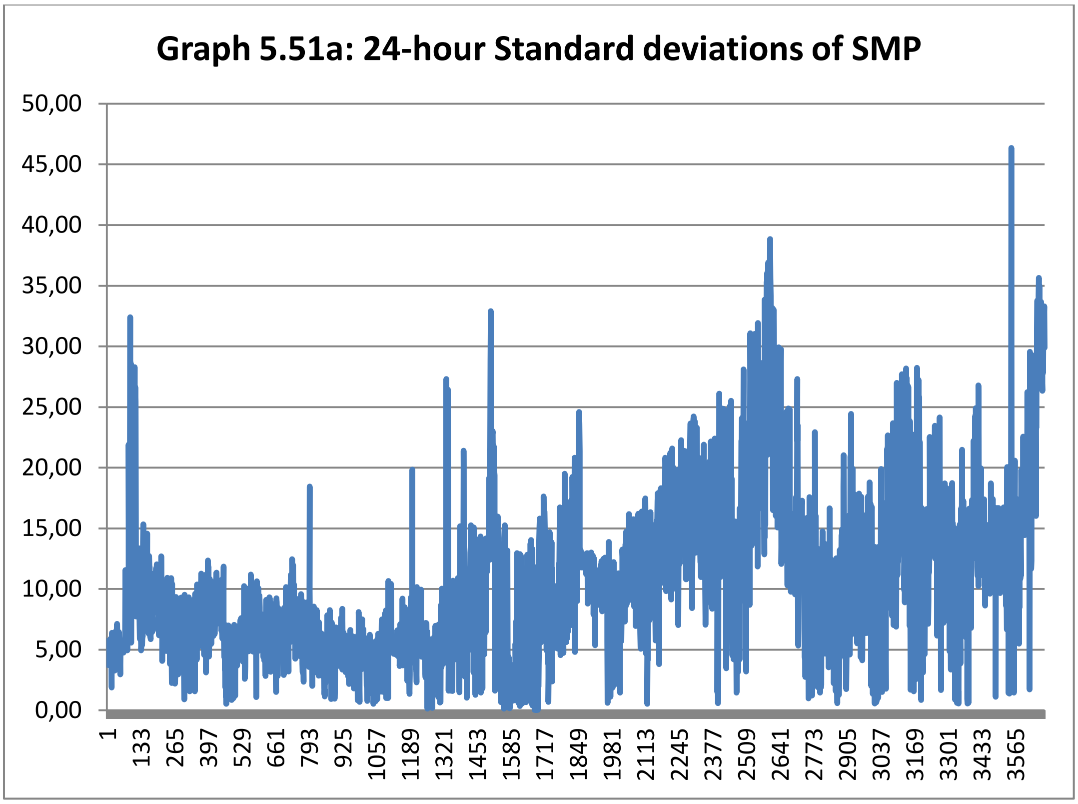
The two remarks lead us to say that for the electricity suppliers that set retail tariffs:

- There is less uncertainty concerning the wholesale price of electricity at night and therefore, accounting for these lower levels of price volatility, the retail suppliers can set night-time tariffs closer to the average wholesale cost of electricity.
- The increased overall levels of standard deviation of SMP in the later years imply that there is much larger uncertainty for market participants, in terms of their profitability.



The standard deviations for the SMPs for every dispatch period of all the time period in our dataset are presented in Graph 5.50. This graph clearly identifies that the standard deviations of SMPs of the night-time periods are lower than those of the day-time periods. This is an observation that could act in support of the argument for promoting the wider adoption of time-varying retail tariffs. Using different retail electricity prices for the various dispatch periods, or for various time zones, can result in the tariffs being more cost reflective and in increasing the consumer surplus.





Graph 5.51a presents the 24-hour standard deviation of the SMP of each day of the whole time period that we examine. We can see that the standard deviation typically takes a very low level for the initial time period up to May 2005 (observation 1,307). That also happens to be the time when an independent generator, Elpedison, introduced a 390MW natural gas-fired unit into the system ([Iliadou, 2009], [DEPA, 2012]). The increased standard deviations from that point can be considered to potentially be the result of competition in the wholesale market, in addition to other factors. From that point on, SMP becomes more volatile, and this could the result of having the electricity generators bidding according to their actual generation cost. Therefore, what we experience in the Greek electricity sector is the move from the previous vertically integrated market organization to a new, more competitive, setting.

Increased levels of standard deviation represent higher volatility and therefore higher price uncertainty and risk. One large peak period in our data is between

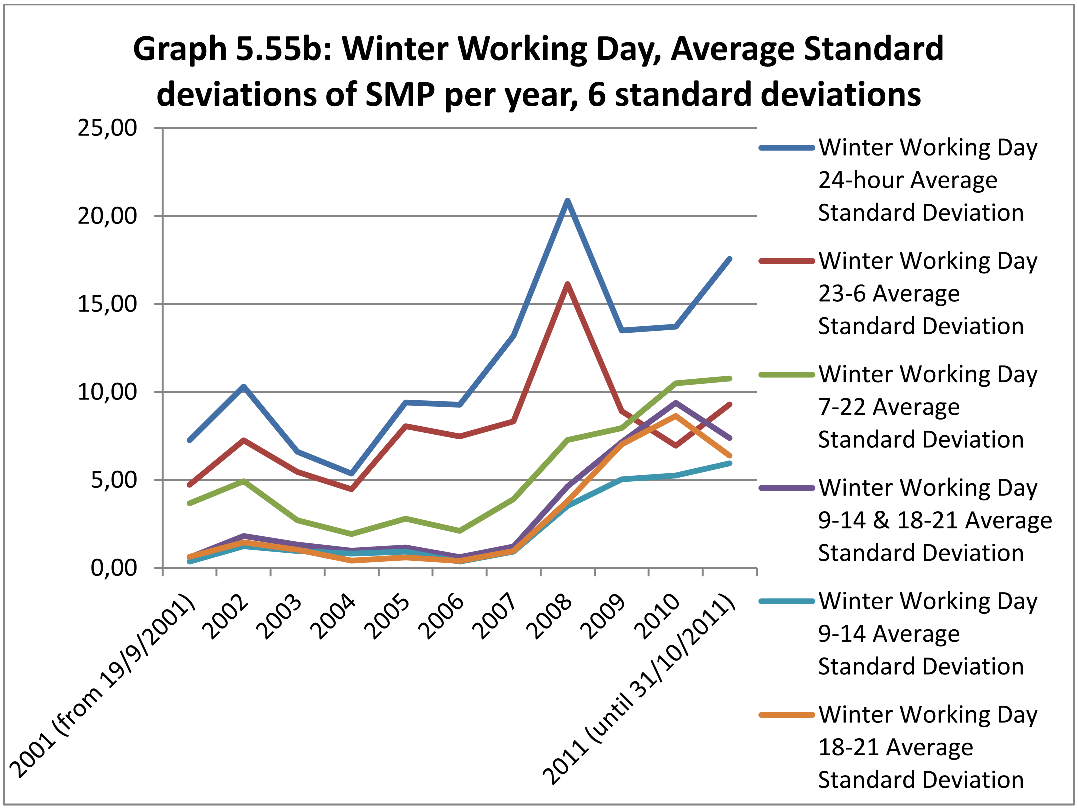
April 2007 (observation 2,007) and August 2009 (observation 2,860). During that time period, standard deviation sharply increases and then decreases, presumably due to the rise and fall that occurred in the international fossil fuel prices. Another peak period was from January 2010 (observation 3,013) to November 2010 (observation 3,317). We can also see the "spike" that was created at 21/06/2011-29/06/2011 (observations 3,549-3,557) as a result of the PPC strike, as well as the increasing trend in the standard deviation during the months September and October 2011 (observations 3,621-3,681) presumably due to the imposition of a new tax on natural gas for electricity generation.

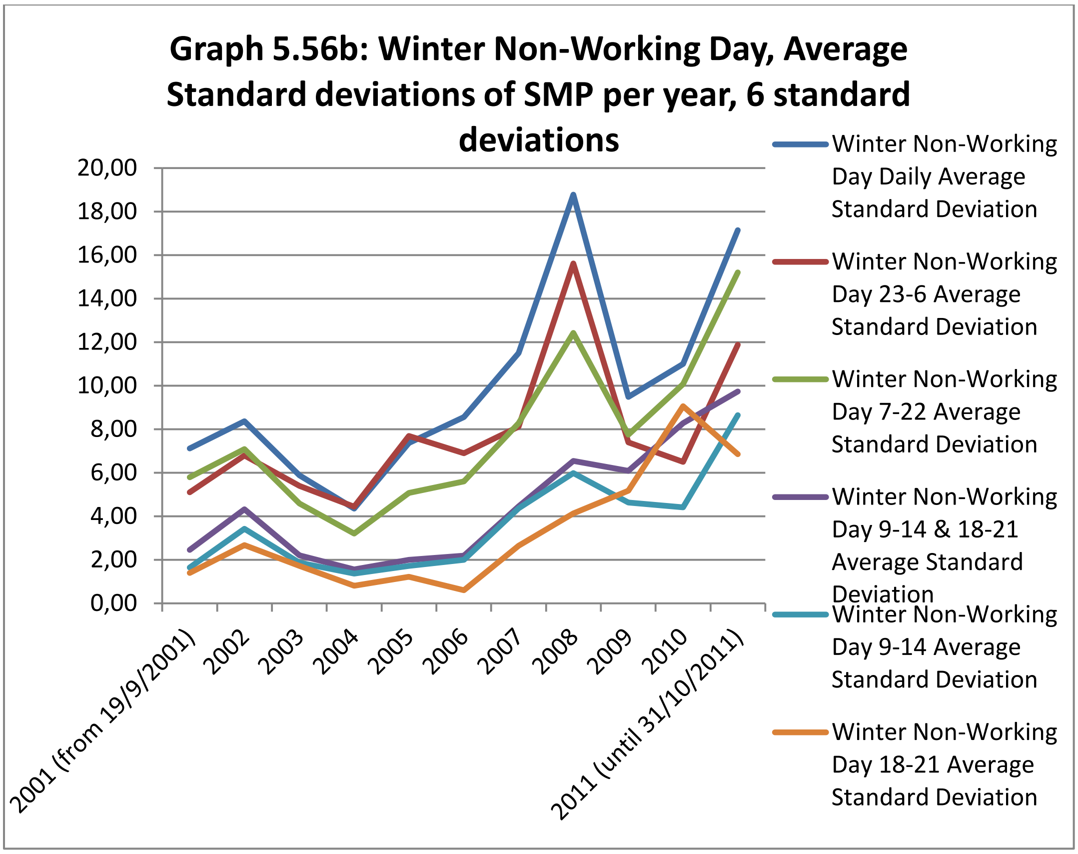
Graphs 5.52a, 5.53a, 5.54a, 5.54c and 5.54e are quite similar to Graph 5.51a. They are not presented in the text but are available in Appendix B, Part 5.

Graphs 5.51b, 5.52b, 5.53b, 5.54b, 5.54d and 5.54f present the annual standard deviations of the SMP in a year by year basis with that standard deviation calculated for 6 different time periods in the day. It is hard to extract any conclusions from these graphs, however we can say that the highest levels of standard deviation of the SMP appear to be reached only during the latest years, especially during 2011. These graphs are to be found in Appendix B, Part 5.

Graphs 5.55a, 5.56a, 5.57a and 5.58a present the annual standard deviations of the SMP per dispatch period in a year by year basis for the 4 Average Days. There are two key themes from these graphs. Firstly, the standard deviations of the SMPs are lower during the night-time dispatch periods. Secondly, there generally seems to be an increase in the level of the standard deviations of the SMPs as we go through the years. These graphs are to be found in Appendix B, Part 5.

In Graphs 5.55b and 5.56b, we present the averages of the standard deviations of the SMP of 6 combinations of dispatch periods. These are calculated and presented separately for the Average Winter Working Day in Graph 5.55b and for the Average Winter Non-Working Day in Graph 5.56b. There are two observations that we make by examining these graphs. Firstly, the standard deviations of the SMP have a low level until 2006 and volatility increases only after that period. That is anticipated as being the effect of introduction of competition in the generation part of the market that gradually occurred since the summer of 2004 ([Iliadou, 2009], [DEPA, 2012]). As the market becomes competitive, the market price starts reflecting the volatility of the cost of fuel. The second observation has to do with the patterns of evolution from year to year of the standard deviations of the SMP. These two patterns are similar for the two Average Winter Days, regardless of them being Working or Non-Working. As we have seen in Graphs 5.19b and 5.20b, the same phenomenon occurred with the average SMP of the Average Winter Days. That suggests that the year under discussion is relevant to the SMP level as well as to the SMP volatility.



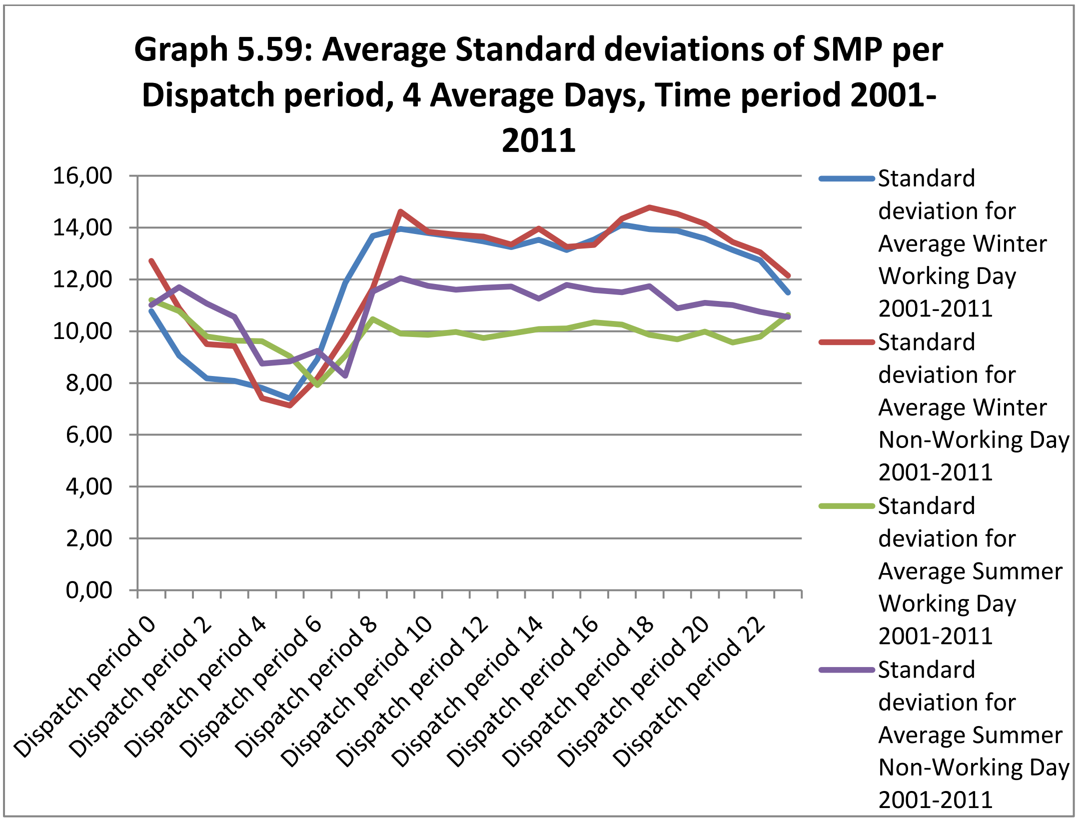


Graphs 5.57b and 5.58b are similar to Graphs 5.55b and 5.56b, with the difference that they refer to the Average Summer Working Day (Graph 5.57b) and to the Average Summer Non-Working Day (Graph 5.58b). The remarks made about them are also similar: as the market becomes more competitive, the market price starts reflecting the volatility of the cost of fuel and the year under discussion is also relevant to the SMP level as well as to the SMP volatility. Graphs 5.57b and 5.58b are to be found in Appendix B, Part 5.

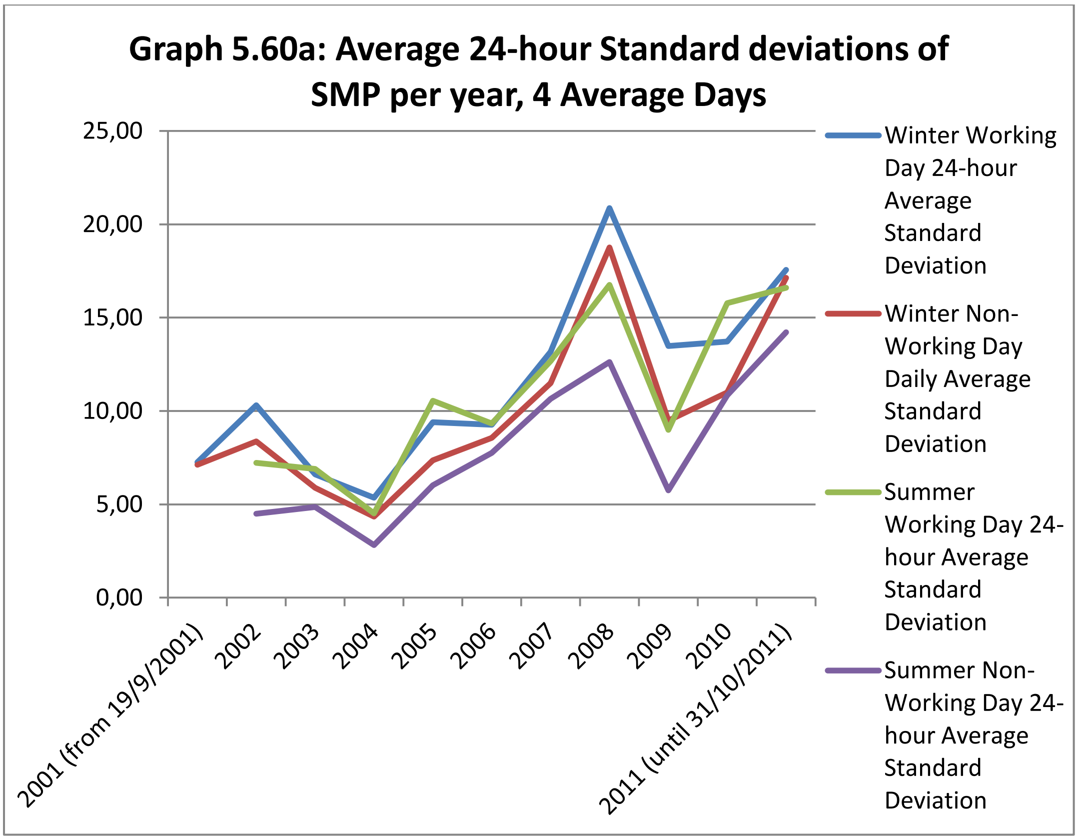
The annual standard deviations that we presented in Graphs 5.55a, 5.56a, 5.57a and 5.58a (to be found in Appendix B, Part 5) have been averaged to calculate the average standard deviation of the SMP per dispatch period for each of the 4 Average Days for the time period 2001-2011. These are presented in Graph 5.59.

By examining Graph 5.59 we can see that there is one intra-day pattern for the 4 Average Days, in contrast to what we have seen in Graph 5.47 where the average standard deviations of System Load per dispatch period were presenting 2 intra-day patterns split between the 4 Average Days. In this intra-day pattern, we observe that:

- The night-time dispatch periods present lower average standard deviations of SMP than the day-time ones.
- The day-time dispatch period present average standard deviations of SMP which are almost constant within each Average Day.
- The two Average Winter Days present higher levels of average standard deviations of SMPs that the two Average Summer Days.



The average standard deviations that we presented in Graphs 5.55b, 5.56b, 5.57b and 5.58b have been rearranged into new graphs and have been now grouped not by the Average Day but by the average standard deviation that is calculated. The result is presented in Graphs 5.60a, 5.60b, 5.60c, 5.60d, 5.60e and 5.60f. Graph 5.60a is presented below. However, Graphs 5.60b, 5.60c, 5.60d, 5.60e and 5.60f are not presented here because these are very similar to Graph 5.60a. Graphs 5.60b, 5.60c, 5.60d, 5.60e and 5.60f can be found in Appendix B, Part 5. In these 6 graphs the average standard deviations do not remain at steady levels and we can see that there are large differentiations from year to year. That contrasts with what is shown in Graphs 5.48a, 5.48b, 5.48c, 5.48d, 5.48e and 5.48f, where the average standard deviations of the corresponding System Load figures present lines that are almost flat, suggesting small changes in the level of average standard deviations from year to year. Therefore changes in average standard deviations of SMP from year to year should be attributed to factors that are affecting SMP other than the system load. Also, what all the average standard deviations of SMP in Graphs 5.60a, 5.60b, 5.60c, 5.60d, 5.60e and 5.60f share in common is that, for most of the years examined, they present increasing trends.



5.7 DMP-Standard deviations

An analysis similar to the one done for the standard deviations of the SMP data in Section 5.6 has also been done for standard deviations of the DMP data. The results are very similar to those obtained in Section 5.6 and are not presented in the text. The results and a discussion of them can be found in Appendix D, Part 2.

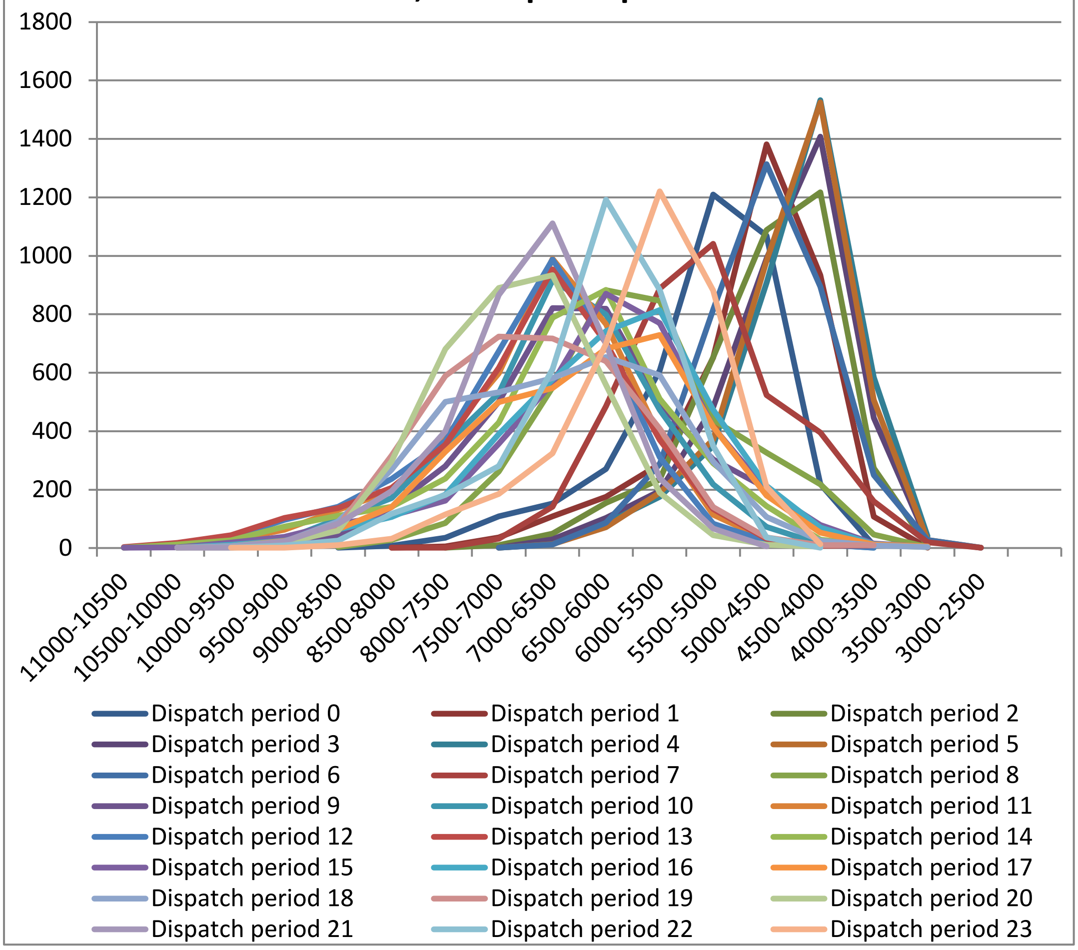
5.8 Histograms of frequencies of appearances for System Load, SMP and DMP

In order for the histograms to be created, for each dispatch period, the system loads, SMPs and DMPs have been rearranged from larger to smaller, using the “Data Analysis” tool of Microsoft Excel. Then the system loads/SMPs/DMPs have been separated into groups.

- For System Load, the ranges taken were from 11,000 MWh and were decreasing in increments of 500WMh. The number of observations in each category of System loads has been counted and in the histograms we present the population of observations for each range of System loads.
- For System Marginal Price (SMP) and Deviations Marginal Price (DMP) data, the ranges taken were from 150 euros/MWh and going down in increments of 10 euros/MWh.

The result is 24 histograms for System Load (Graphs 5.200-5.223, to be found in Appendix B, Part 1), 24 histograms for SMP (Graphs 5.300-5.323, to be found in Appendix B, Part 2) and 24 histograms for DMP (Graphs 5.400-5.423, to be found in Appendix B, Part 3). We also have gathered all of these histograms in one Graph for each dataset, where we are actually using lines in the graphs and where direct comparisons can be made. These are Graph 5.73 for System Load, Graph 5.74 for SMP and Graph 5.75 for DMP (to be found in Appendix B, Part 7).

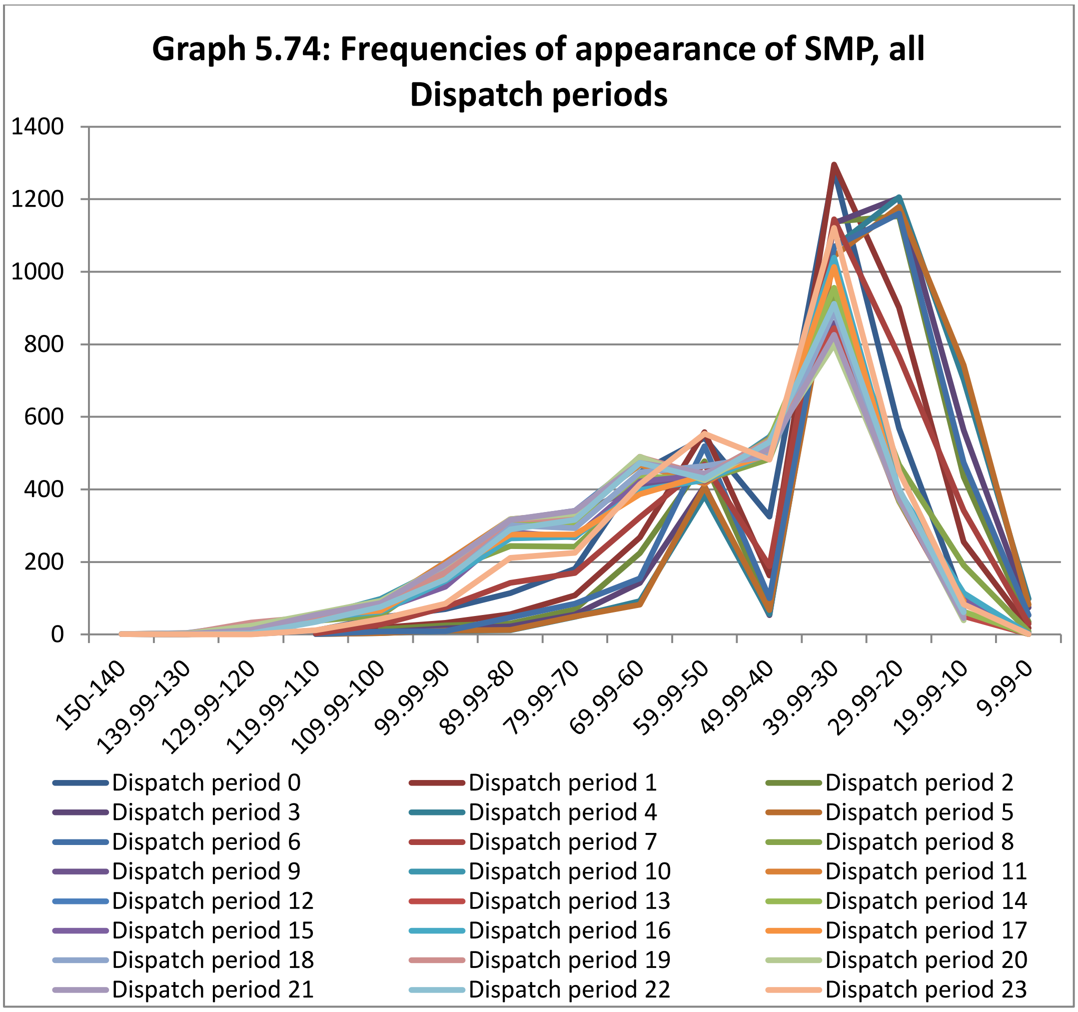
Examining Graph 5.73, we can see that the frequencies of the appearance of System Load values within certain ranges approximate a bell-shaped curve. We can see that the top of the curve, which corresponds to the system load that appears most often, is moving as we go through the dispatch periods. So, for the dispatch periods 0-7, the range with the highest frequency that the System Load will be set at is in the zone 5,500-4,000 MWh. As we move to subsequent dispatch periods later in the day, we see that the system load range that is observed most often is in the range of 7,000-5,500 MWh. That was expected anyway as more electricity-consuming activities are taking place during the day, thereby increasing electricity demand.



Graph 5.73: Frequencies of appearance of System Load, all Dispatch periods

Graph 5.74 has different patterns than Graph 5.73. Most of the curves that appear in Graph 5.74 are not bell-shaped, since these quite often have two “peaks”, meaning two SMP ranges that appear most often. The one is the range 39.99-30 euros/MWh and the other one is 69.99-50 euros/MWh. Examining the timelines of the SMPs for each dispatch period (Graphs 5.300-5.323, to be found in Appendix B, Part 2), we can see that the period from the start of our data until January 2005 (observation 1,187) - June 2005 (observation 1,338), depending on the dispatch period, does not present large volatility for the SMP. During that time, SMPs range between 39.99-30 euros/MWh. After that period, the SMPs presented larger volatility.

Assuming that the second part of our data corresponds to a market that operates under competition, we could expect that these data would provide us with a bell-shaped curve. After adding the data of the first period and graph all of them together, the result resembles to a bell-shaped curve where a “block” of observations in a specific range has been added. That “block” is the SMP data of the first period that we defined. The existence of these data has created and additional “peak” in the curve.



Graph 5.75 has similar characteristics to Graph 5.74. Graph 5.75 can be found in Appendix B, Part 7.

5.9 Temperatures and System Load

5.9.1 Method

In order to investigate the effect that different temperatures have on System Load, a set of monthly temperatures for different cities has been used. These average temperatures for certain cities in Greece have been set in a Technical Guideline of the Greek Technological Chamber [Ministry of the Environment, Energy and Climate Change, 2010, page 19].

The largest mainland Greek cities, which are served by the interconnected electricity system, have been selected. The temperatures of these cities were used weighted for the populations in the regions around these cities. These populations have been taken from the website of the governmental agency “Invest in Greece SA” [‘Invest in Greece’ Agency, 2012].

The cities and the regions around them, the population of these regions and the percentage of the population in each city (accounting only for the cities that we use) are presented in Table 5.1 below:

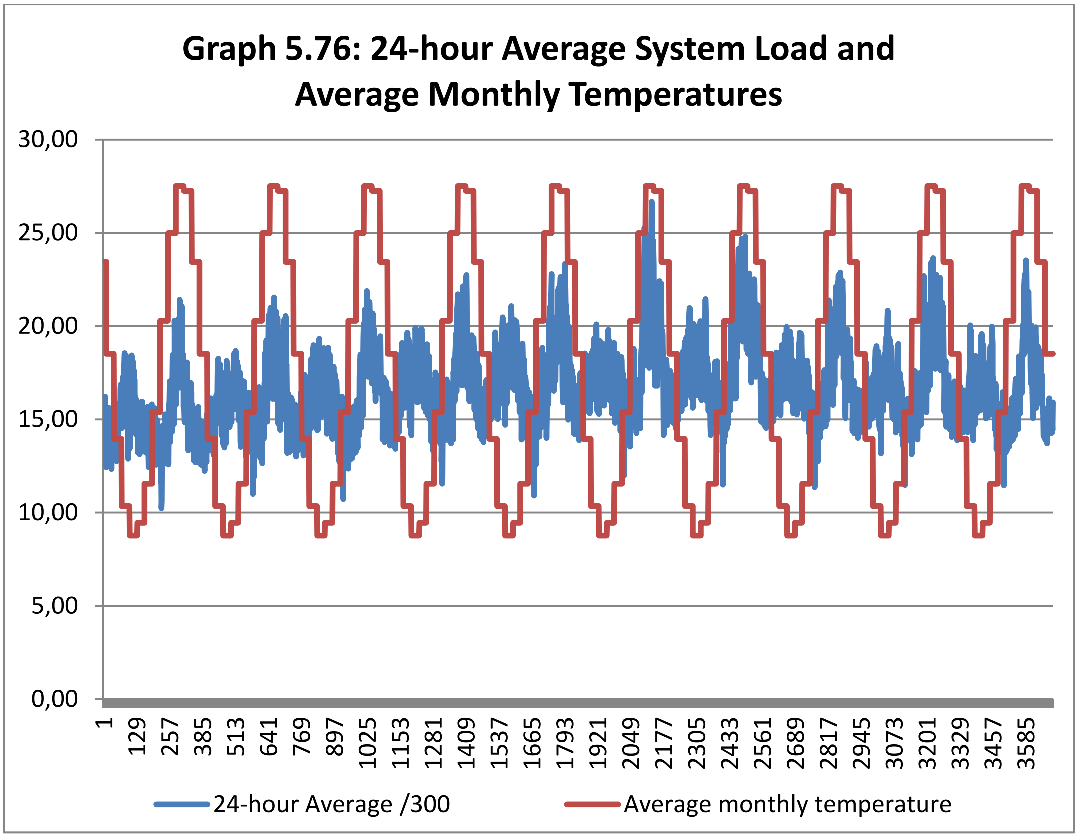
City/Region	**Population of the region (not just the city)**	**Percentage of the population that we examine that lives in each city**
Athens/Attiki	4,088,447	58.64%
Thessaloniki	1,153,959	16.55%
Patra/Achaia	345,380	4.95%
Larisa	286,505	4.11%
Agrinio/Aitoloakarnania	217,497	3.12%
Pirgos/Ilia	179,161	2.57%
Serres	186,782	2.68%
Lamia/Fthiotida	165,954	2.38%
Kalamata/Messinia	163,675	2.35%
Ioannina	184,925	2.65%
Sum	**6,972,285**	**100,00%**

Table 5.1: Greek Cities and Population of Regions around them. Constructed using data collected from ‘Invest in Greece’ Agency [2012].

For each month, the average temperature in each city (in Celsius degrees) is multiplied by the percentage of the population that lives in that city. Then the results are all summed together and we get the weighted average temperature for each month. The results can be seen on Table 5.2.

Month	Weighted Average Temperature
January	8.77
February	9.46
March	11.55
April	15.39
May	20.28
June	24.98
July	27.5
August	27.25
September	23.44
October	18.51
November	13.95
December	10.34

Table 5.2: Average Temperature in Greek mainland cities of Table 5.1, weighted for populations. Source: ‘Invest in Greece’ Agency [2012] and a Technical Guideline of the Greek Technological Chamber [Ministry of the Environment, Energy and Climate Change, 2010, page 19].



5.9.2 Graphing System Load and Temperatures

By using these temperatures we create Graph 5.76 where we combine the timeline of the 24-hour Average System Load, divided by 300, with the Average Temperatures. These temperatures are not evolving as we go through the years: rather the temperature pattern is repeated on an annual basis. This is because we do not have temperature data for different years. The 24-hour Average System Load was divided by 300, in order for us to be able to get it at a comparable size with the Average Temperatures. In that way, we are able to focus on the patterns and how these are interrelated.

In Graph 5.76, during the months June-September when we get increased temperatures, the 24-hour Average System Load is also increasing and during the months December-March that the temperatures are falling, the 24-hour Average System Load is increasing again, but not to the same levels it was when we had high temperatures. These increases constitute the “high peaks” and the “low peaks” that we have mentioned when discussing the seasonality pattern of the System Load.

A possible explanation for that link between temperatures and Average System Load could be found in the extended use of air-conditioning devices during the warm summer months and to the use of electricity for heating of building during the winter, in addition to the extended use of electricity for lighting during the winter.

5.10 Fossil fuel prices and wholesale electricity prices

5.10.1 Datasets used

In terms of fossil fuel prices, we use five sets of data.

The price of Natural gas imported from Russian Federation via pipeline: They are sourced from the International Energy Agency [2012]. These are monthly prices and the period covered is from September 2001 until August 2011. However, there are some gaps in our data, since we do not have prices for all the months of this period. The use of these data is relevant because these are the prices that are paid for natural gas that is imported from the Russian Federation through pipelines in Greece. Natural gas is a very important fuel in the Greek electricity sector and therefore we examine these data in order to reveal the existence of relationships between natural gas prices and wholesale electricity prices.

Price for Natural gas imported to Greece in Liquefied Natural Gas (LNG) form from various origins: These prices are sourced from the International Energy Agency [2012]. These are monthly prices and the period covered is from September 2001 until August 2011. However, there are some gaps in our data, since we do not have prices for all the months of this period. The use of these data is relevant because these are the prices paid in Greece for natural gas in LNG form. Natural gas is a very important fuel in the Greek electricity sector and therefore we examine these data in order to reveal the existence of relationships between natural gas prices and wholesale electricity prices.

Wholesale natural gas index in Greece: These are sourced from the International Energy Agency [2012]. These are prices that refer to three-month periods (meaning that we get one price for every three months). The period covered is from September 2001 until the end of October 2011, which is the whole period that we examine. These data are identified to be the sub-indices for energy products as used by national statistical services to compile Producer Price Indices (PPI). The use of these data is relevant because these are the indices of prices that are paid for natural gas in Greece. Natural gas is a very important fuel in the Greek electricity sector and therefore we examine these data in order to reveal the existence of relationships between natural gas indices (and in extension, natural gas prices) and wholesale electricity prices.

Wholesale oil product index in Greece: These are sourced from the International Energy Agency [2012]. These are prices that refer to three-month periods (meaning that we get one price for every three months). The period covered is from September 2001 until the end of October 2011, which is the whole period that we examine. These data are identified to be the sub-indices for energy products as used by national statistical services to compile Producer Price Indices (PPI). The use of these data is relevant because these are the indices of prices that are paid for oil products in Greece. Oil is an important fuel in the Greek electricity sector and therefore we examine these data in order to reveal the existence of relationships between oil indices (and in extension, oil product prices) and wholesale electricity prices.

Price for Brent oil in Europe: These prices are sourced from the US Energy Information Administration [2012]. These are daily prices that refer to working days (Monday-Friday) for the time period from September 2001 until the end of October 2011. There are some gaps with some missing dates in this dataset, however that happens to a very small extent. These prices, being in US dollars, had to be expressed in euros before being used, so as these would not be affected by fluctuations in the exchange rates between the euro and the US dollar. Exchange rates are available by the European Central Bank [European Central Bank, 2012]. The use of these data is relevant because they refer to the prices that are paid for Brent oil in Europe and these are expected to affect Greece as Greece is part of the European Economic Area. Oil is an important fuel in the Greek electricity sector and therefore we examine these data in order to reveal the existence of relationships between oil prices and wholesale electricity prices.

5.10.2 Graphs of Natural gas prices and SMP

The three sets of data that refer to natural gas prices and indexes are used in combination with the System Marginal Price (SMP) data.

In Graph 5.77 we present the 24-hour average SMP along with the prices that we have for imports of natural gas from the Russian Federation to Greece through pipelines.

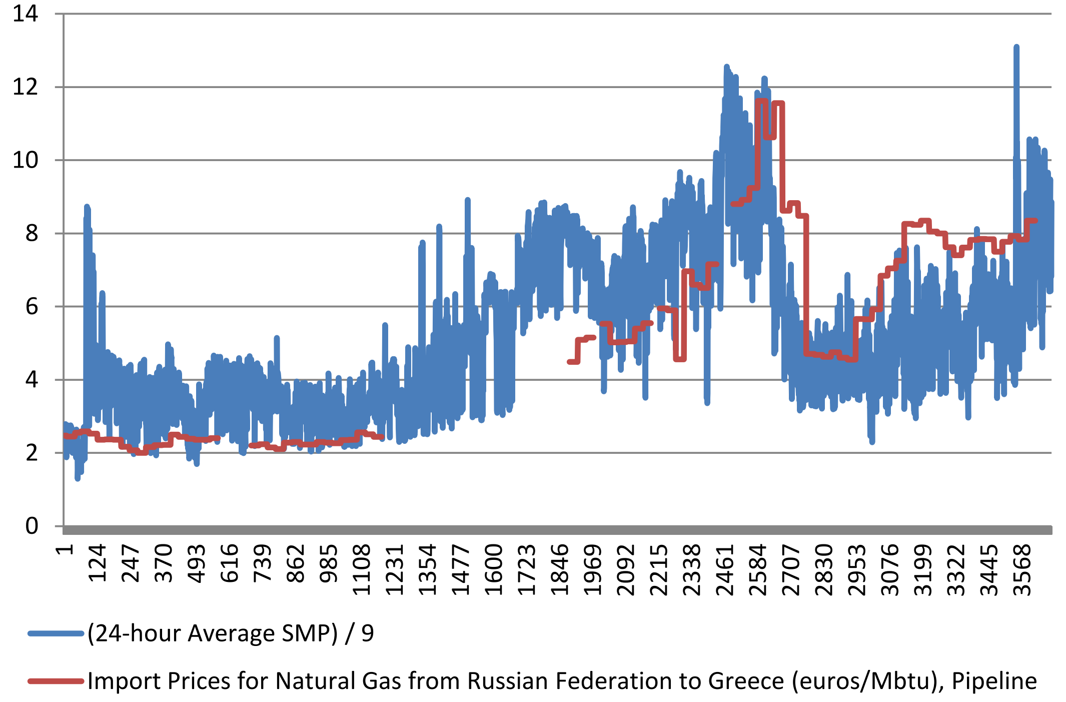
In Graph 5.78 we present the average SMP of dispatch periods 7-22 along with the prices that we have for imports of natural gas from the Russian Federation to Greece through pipelines.

In Graph 5.79 we present the 24-hour average SMP along with the prices that we have for imports of natural gas from all origins to Greece, in the form of Liquefied Natural Gas (LNG).

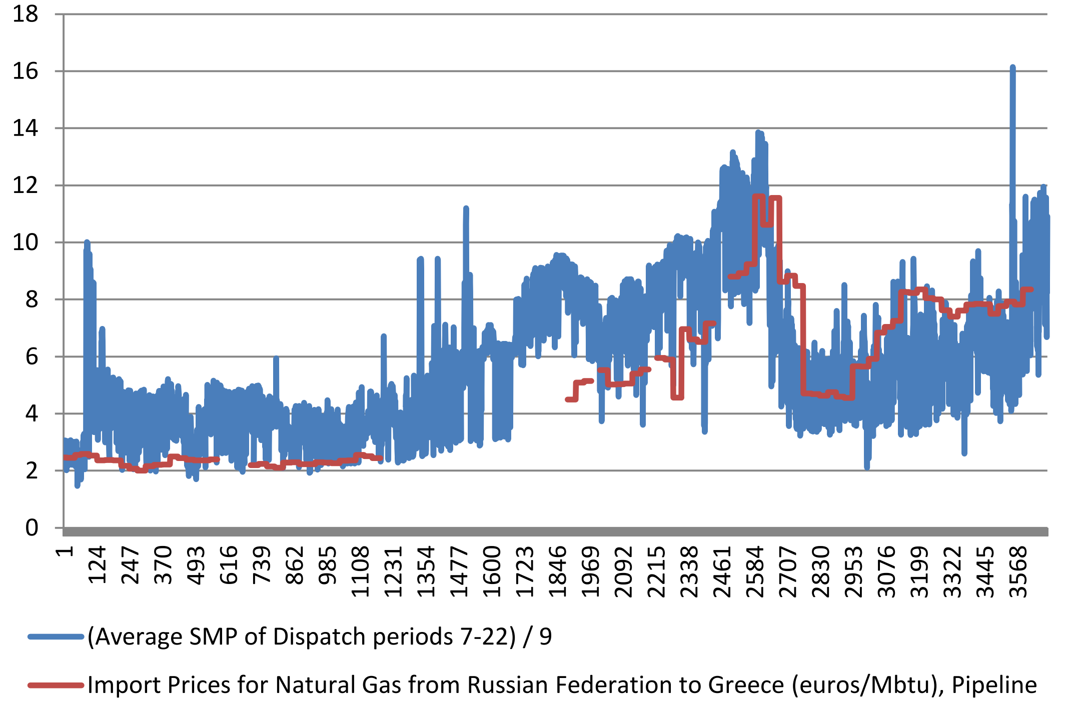
In Graph 5.80 we present the average SMP of dispatch periods 7-22 along with the prices that we have for imports of natural gas from all origins to Greece, in the form of Liquefied Natural Gas (LNG).

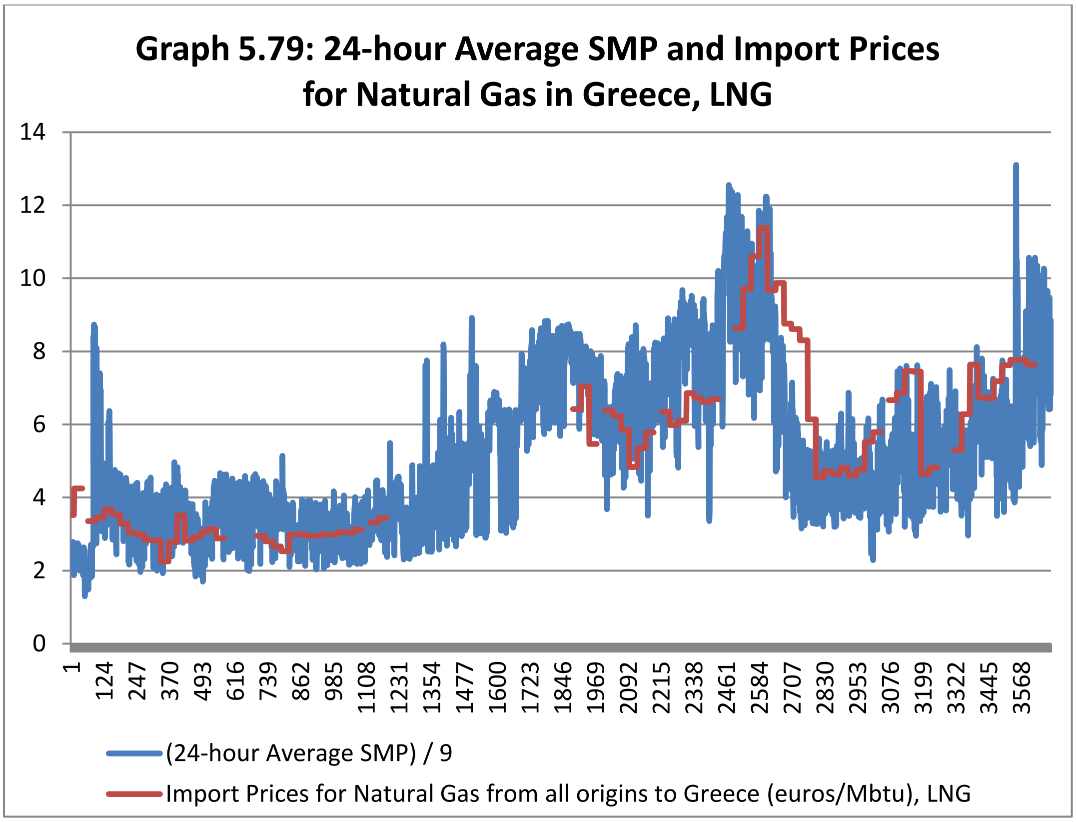
In Graphs 5.77, 5.78, 5.79 and 5.80, the averages of the SMPs have been divided by 9 in order to bring them in a comparable size with the natural gas prices, in order for us to be able to examine the patterns in them.

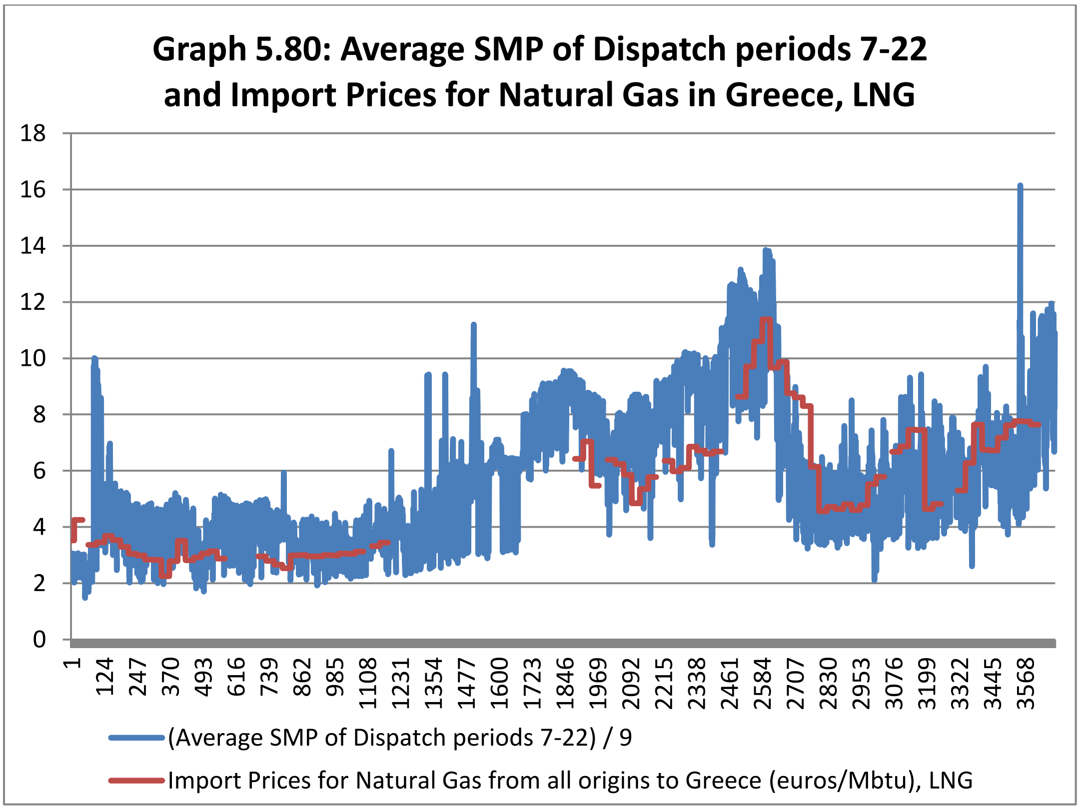
Graph 5.77: 24-hour Average SMP and Import Prices for Natural Gas in Greece, Pipeline



Graph 5.78: Average SMP of Dispatch periods 7-22 and Import Prices for Natural Gas in Greece, Pipeline



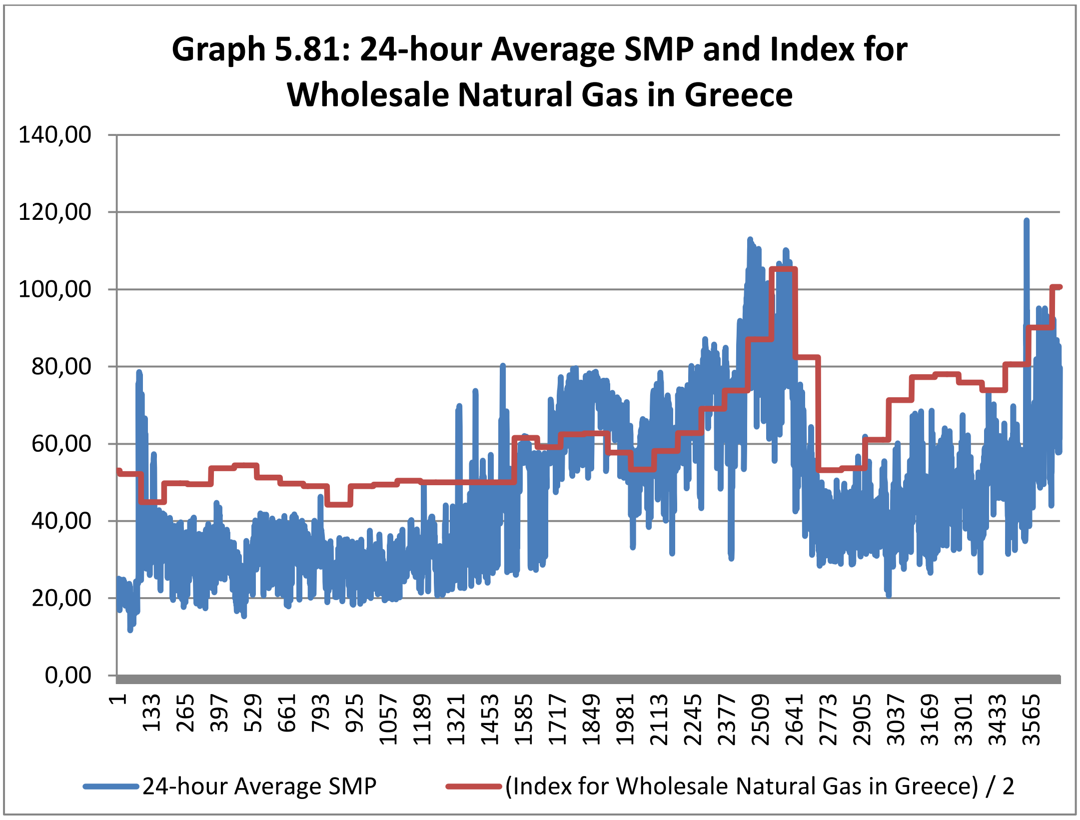

Graph 5.79: 24-hour Average SMP and Import Prices for Natural Gas in Greece, LNG
14
12
10
8
6
4
2
0
1
124
247
370
493
616
739
862
985
1108
1231
1354
1477
1600
1723
1846
1969
2092
2215
2338
2461
2584
2707
2830
2953
3076
3199
3322
3445
3568
(24-hour Average SMP) / 9
Import Prices for Natural Gas from all origins to Greece (euros/Mbtu), LNG

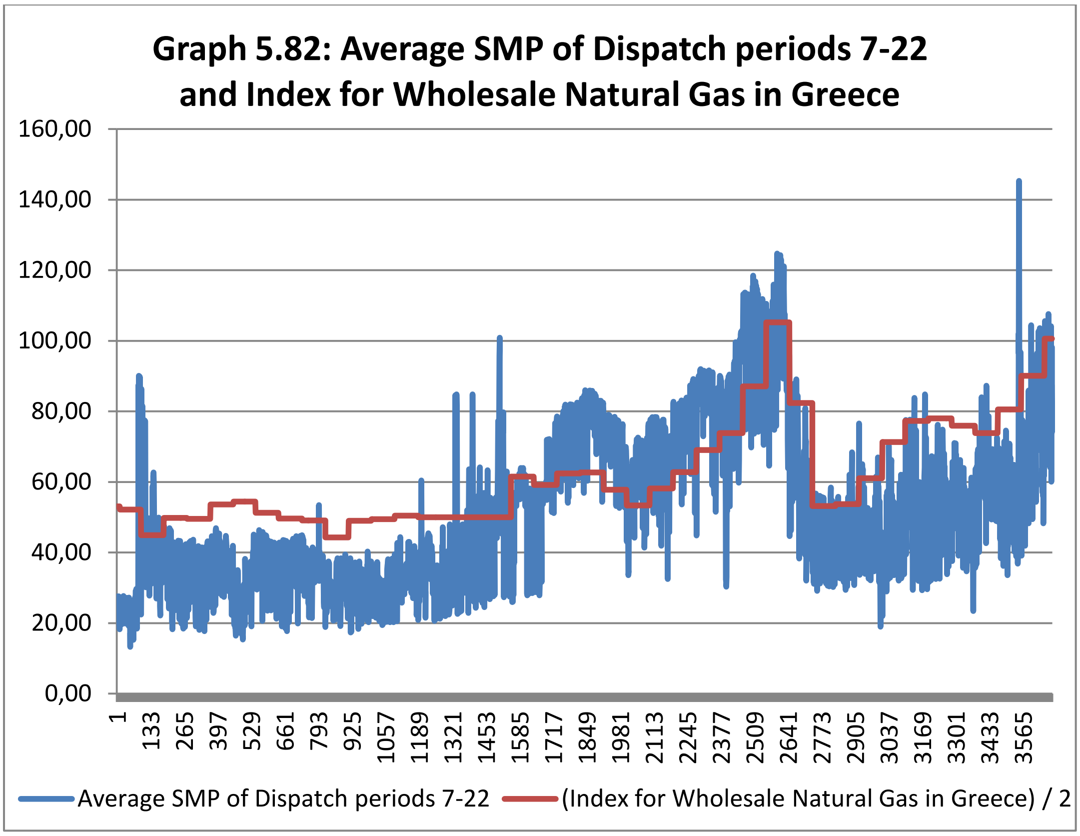

Graph 5.80: Average SMP of Dispatch periods 7-22 and Import Prices for Natural Gas in Greece, LNG
18
16
14
12
10
8
6
4
2
0
1
124
247
370
493
616
739
862
985
1108
1231
1354
1477
1600
1723
1846
1969
2092
2215
2338
2461
2584
2707
2830
2953
3076
3199
3322
3445
3568
(Average SMP of Dispatch periods 7-22) / 9
Import Prices for Natural Gas from all origins to Greece (euros/Mbtu), LNG

In Graph 5.81 we present the 24-hour average SMP along with the indexes for wholesale natural gas in Greece.

In Graph 5.82 we present the average SMP of dispatch periods 7-22 along with the indexes for wholesale natural gas in Greece.

In Graphs 5.81 and 5.82 the indexes for wholesale natural gas have been divided by 2 in order to bring them in a comparable size with the average SMPs in order for us to be able to examine the patterns in them.





5.10.3 Natural gas prices and SMP-Discussion of Graphs

In Graphs 5.77, 5.78, 5.79 and 5.80, despite the fact that some prices are missing, we can identify that the "SMP pattern" that we referred to earlier in this chapter when discussing SMP averages, seems to be very closely related to the pattern of the natural gas import prices. Also, important information shown is that the natural gas import prices in the early period of our data, from the start until the end of 2004 (observation 1,186), are at relatively steady levels.

In Graphs 5.81 and 5.82, as in Graphs 5.77, 5.78, 5.79 and 5.80, the "SMP pattern" seems to be very closely related to the pattern of the indexes for wholesale natural gas. Also, we observe that the indexes for wholesale natural gas in the early period of our data, until the end of 2005 (observation 1,551), are at relatively steady levels.

The fact that both import prices for natural gas and indexes for wholesale natural gas are at steady levels for the early period of our data, suggests that a potential explanation for the average SMPs during that period being set at steady levels could be that these SMPs are determined by the actual cost of fuel. As mentioned earlier in this chapter, the lack of competition can also be an explanation for the relatively stable ranges that SMP gets. We should note that competition was non-existent in the early period of our data.

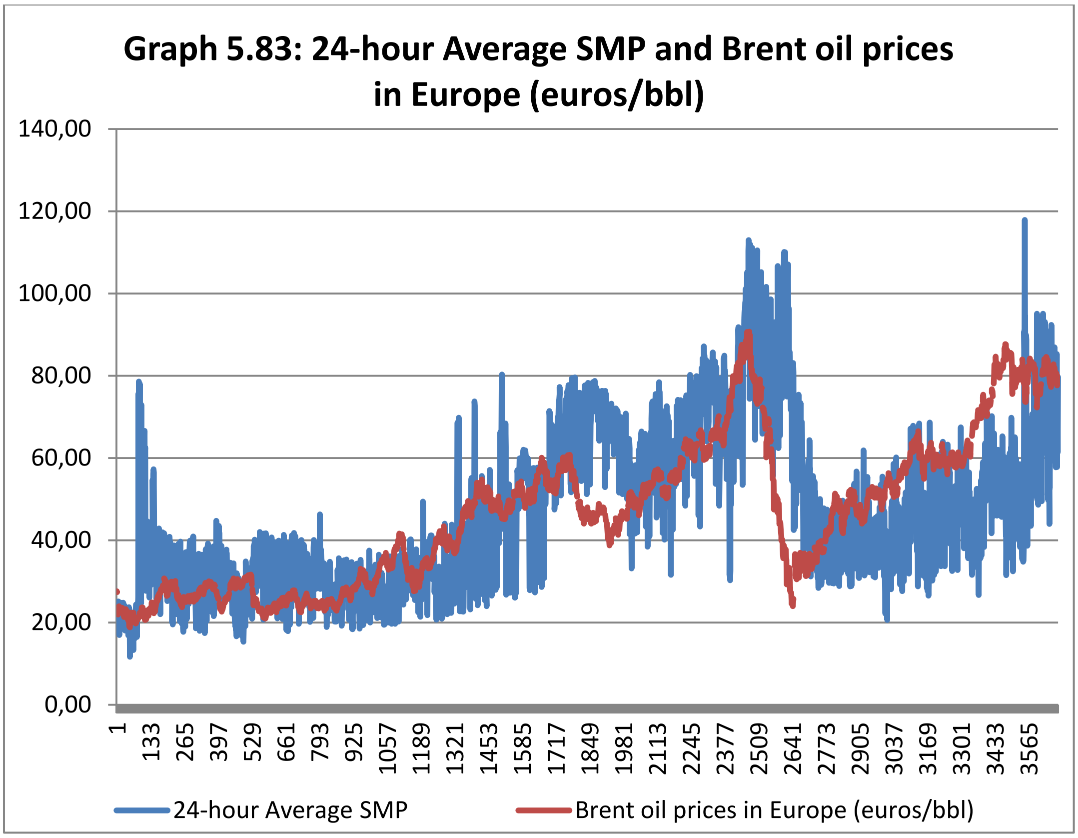
So what we get is a situation where the relatively steady range of SMP values can be explained both by the lack of competition and the steady level of input prices. Although it is a fact that competition did not exist in the early period of our dataset, that does not ensure that the incumbent generator was submitting bids that were not reflecting electricity generation cost. The wholesale electricity prices can serve the incumbent as an instrument to argue for potential tariff adjustments and as a result these should be cost-reflective. Even in this case though, because of the fact that the input prices that we get are at steady levels, the average SMPs are not varying. So we can see how it could be that getting average SMPs within a certain range could be the result of both lack of competition and steady input prices.

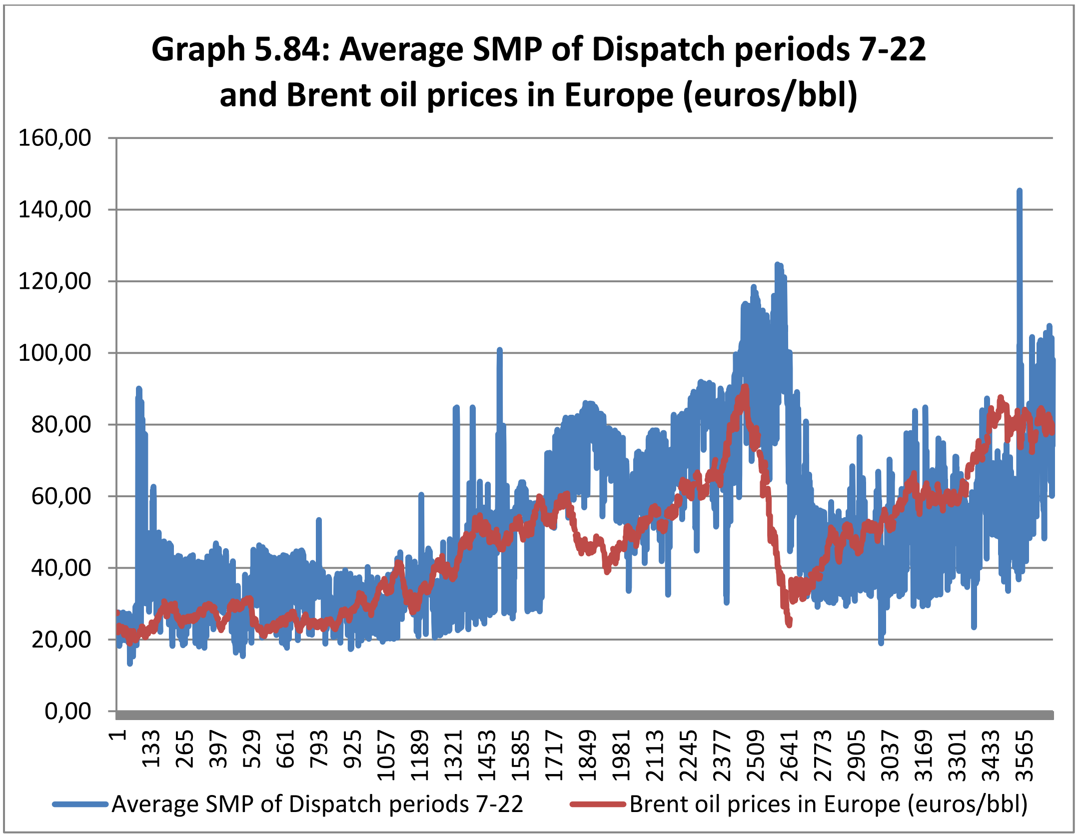
5.10.4 Graphs of Oil prices and SMP

The two sets of data that refer to oil prices and indexes are used in combination with the System Marginal Price (SMP) data.

In Graph 5.83 we present the 24-hour average SMP along with the prices that we have for Brent oil in Europe.

In Graph 5.84 we present the average SMP of dispatch periods 7-22 along with the prices that we have for Brent oil in Europe.

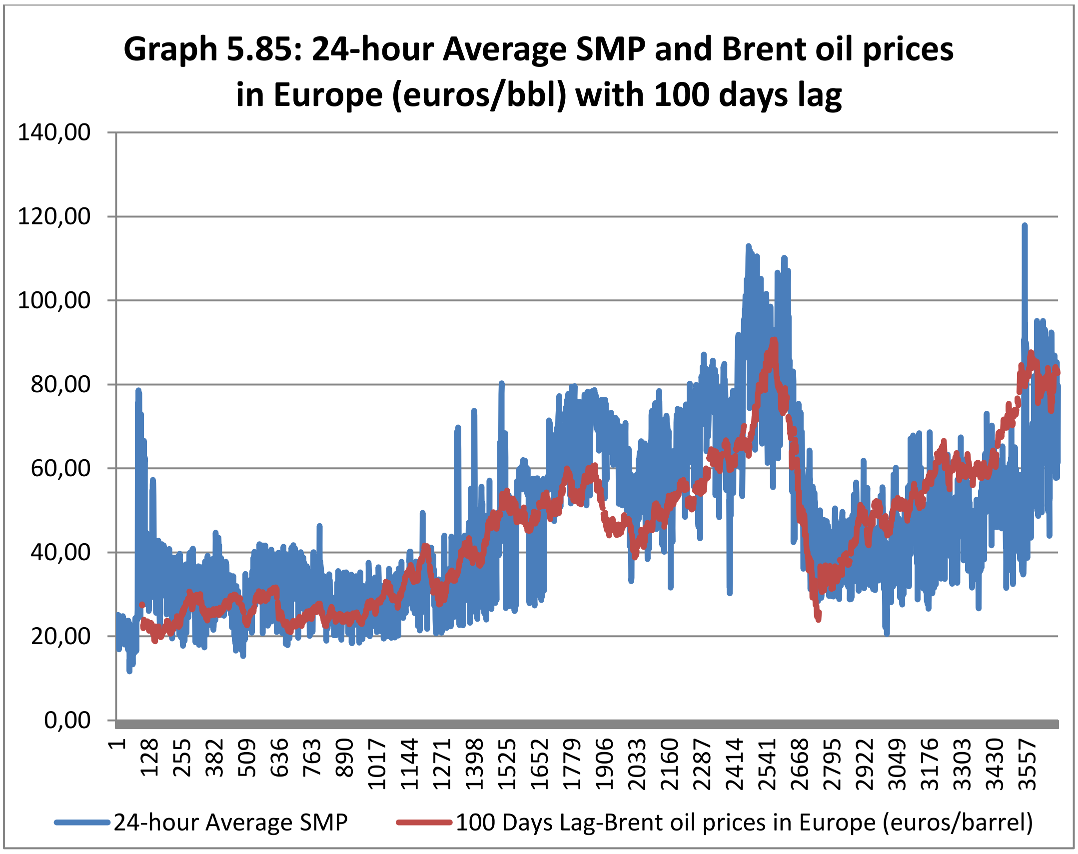

Graph 5.83: 24-hour Average SMP and Brent oil prices in Europe (euros/bbl)
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565
24-hour Average SMP
Brent oil prices in Europe (euros/bbl)

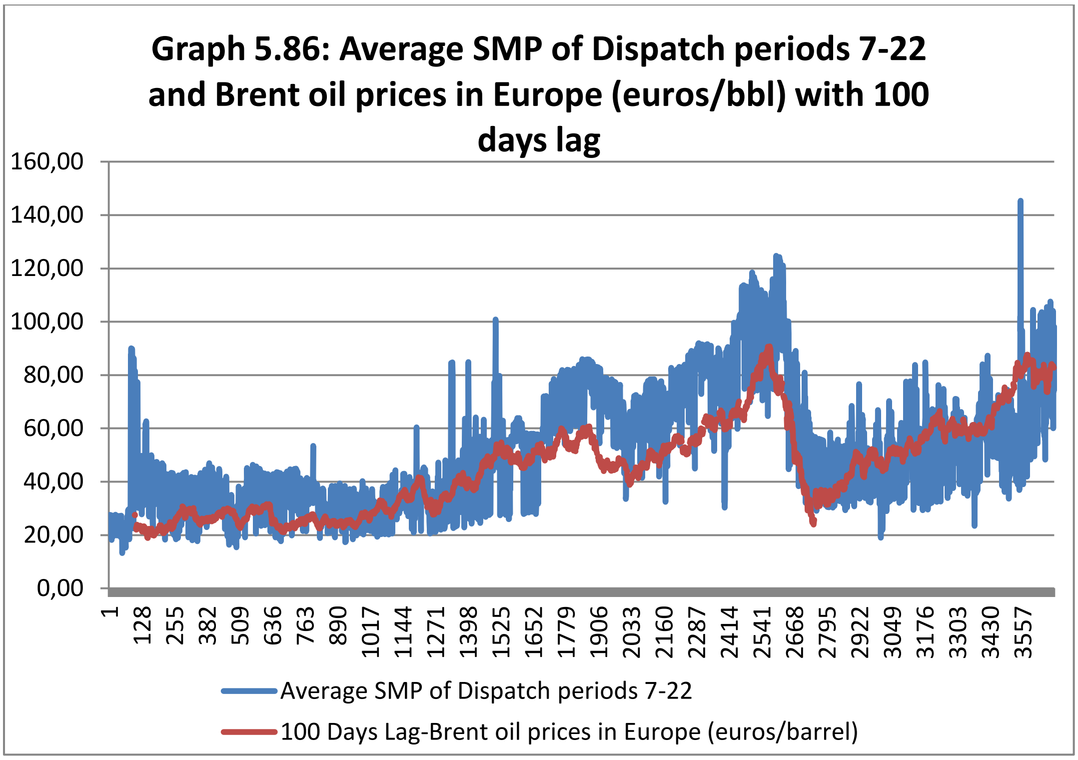

Graph 5.84: Average SMP of Dispatch periods 7-22 and Brent oil prices in Europe (euros/bbl)
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565
Average SMP of Dispatch periods 7-22
Brent oil prices in Europe (euros/bbl)

In Graph 5.85 we present the 24-hour average SMP along with the prices that we have for Brent oil in Europe, with 100 days lag.

In Graph 5.86 we present the average SMP of dispatch periods 7-22 along with the prices that we have for Brent oil in Europe, with 100 days lag.

Deciding to “move” the oil prices by 100 days in Graphs 5.85 and 5.86 is related to the patterns that we see in Graphs 5.83 and 5.84 and to the lack of timing between them. That difference in timing between the two patterns can possibly be explained by the requirement from the Ministry of Environment, Energy and Climate Change for all importers of oil, refineries and Large Customers to be keeping safety inventories of at least 90 days of the consumption level recorded in the previous year [RAE, 2012d]. As a result, and assuming that these firms use a First In-First Out cost accounting system, the oil prices would become effective at least 90 days after they occur in fuel markets.





In Graph 5.87 we present the 24-hour average SMP along with the indexes for wholesale oil products in Greece.

In Graph 5.88 we present the average SMP of dispatch periods 7-22 along with the indexes for wholesale oil products in Greece.

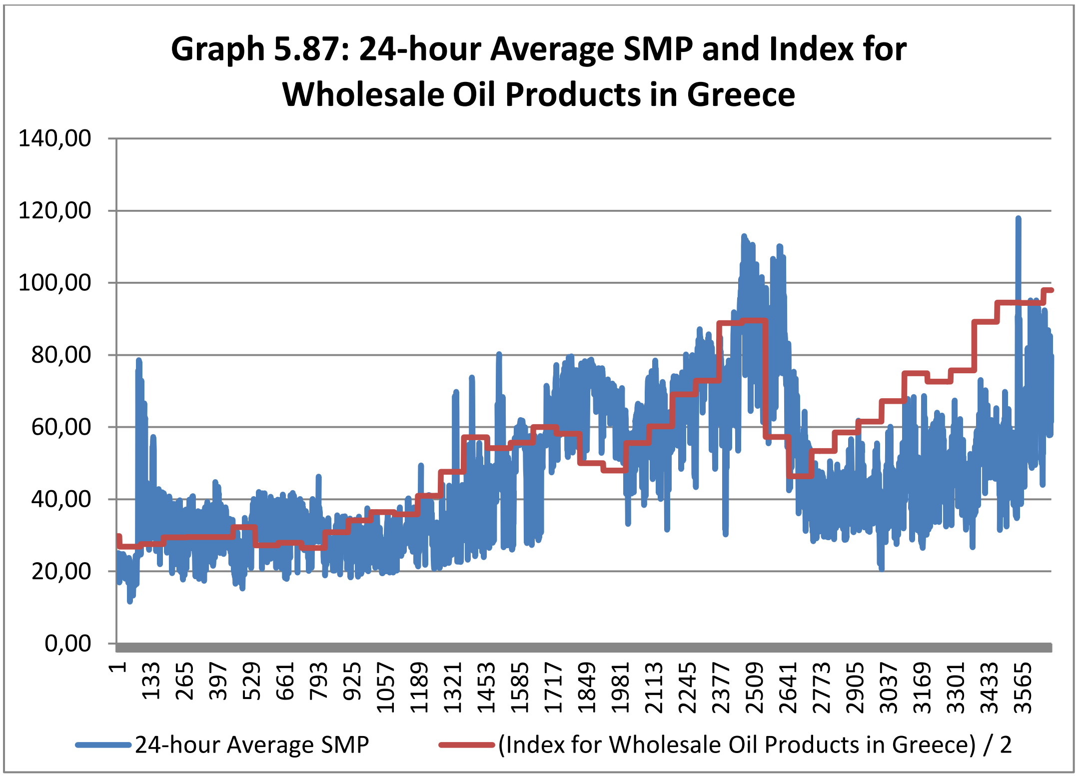
In Graph 5.89 we present the 24-hour average SMP along with the indexes for wholesale oil products in Greece, with 100 days lag.

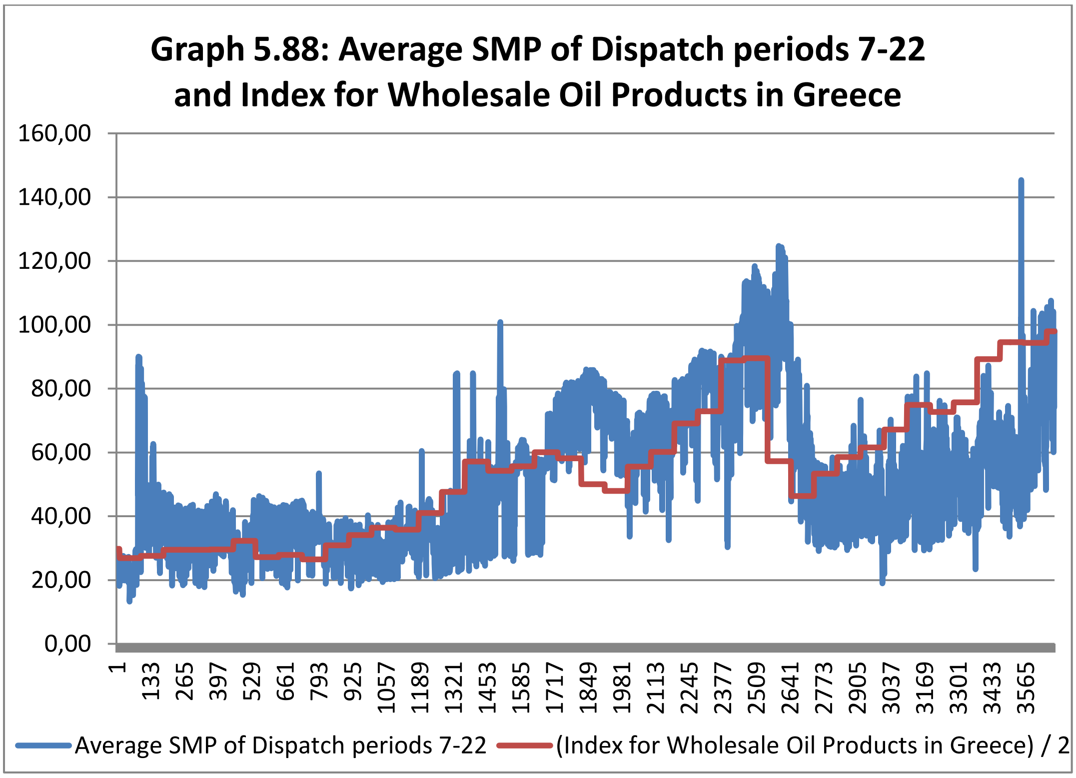
In Graph 5.90 we present the average SMP of dispatch periods 7-22 along with the indexes for wholesale oil products in Greece, with 100 days lag.

In Graphs 5.87, 5.88, 5.89 and 5.90 the indexes for wholesale oil products have been divided by 2 in order to bring them in a comparable size with the average SMPs in order for us to be able to examine the patterns in them.

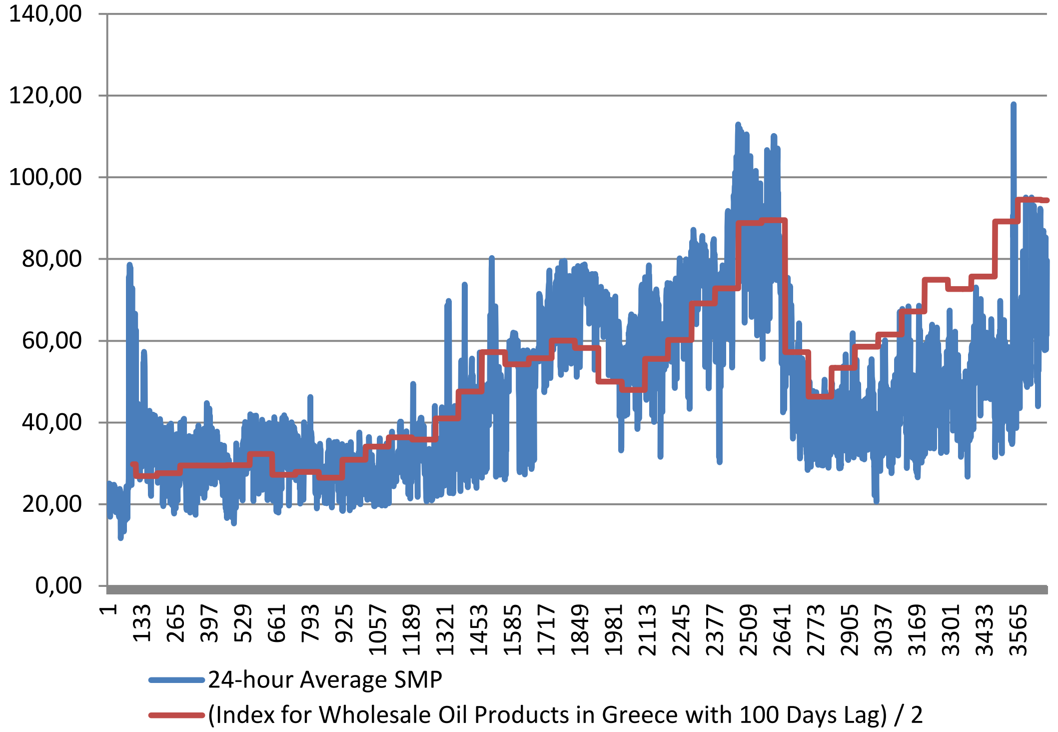
This "movement" of indexes for wholesale oil products was done in a similar manner as in Graphs 5.85 and 5.86 in order to accommodate for the lack of timing between the two patterns, which is related to the requirement for buffer inventories

[RAE, 2012d] and to the assumed use of First In-First Out cost accounting systems as we mentioned earlier.

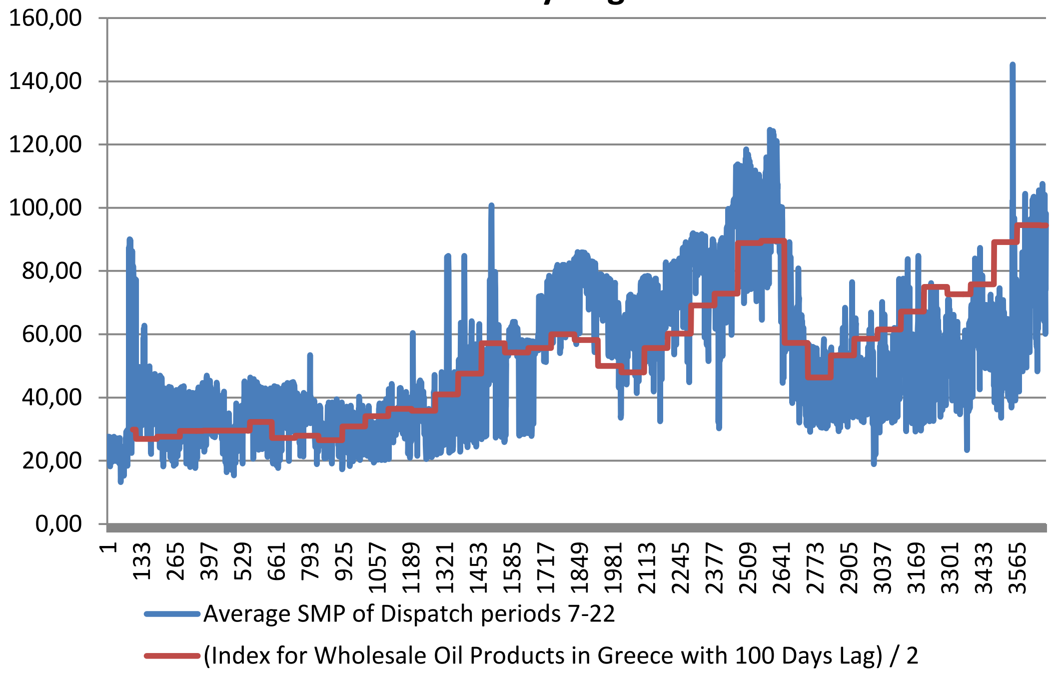




Graph 5.89: 24-hour Average SMP and Index for Wholesale Oil Products in Greece, with 100 days lag



Graph 5.90: Average SMP of Dispatch periods 7-22 and Index of Wholesale Oil Products in Greece, with 100 days lag



5.10.5 Oil prices and SMP-Discussion of Graphs

In Graphs 5.85 and 5.86, the pattern of Brent oil prices in Europe, after being "moved" for a time period of 100 days which we assumed that corresponds to the delay after each price becomes effective, seems to be well aligned with the evolution of the average SMPs in the Greek electricity market. The same holds true for Graphs 5.89 and 5.90. The "SMP pattern" that we referred to when discussing average SMPs, seems to be very strongly related to the pattern of oil prices and indexes.

Also, important information is that the Brent oil prices in the early period of our data, from the start until May 2005 (observation 1,307), are at relatively steady levels. The same holds true for indexes of wholesale oil products in Greece for the period from the start of our data until April 2005 (observation 1,276).

The fact that both Brent oil prices in Europe and indexes for wholesale oil products in Greece are at steady levels for the early period of our data, suggests that a potential explanation for the average SMPs during that period being set at steady levels could be that these SMPs are determined by the actual cost of fuel, and not necessarily solely by the lack of competition, exactly as was the case in Section 5.10.3 for natural gas and SMP. PPC, even when being the sole generator would find it useful to submit bids in the electricity pool that reflect the actual cost of electricity generation. Using the wholesale electricity prices that are set in the pool, PPC would be in position to use these to support any effort that it could make for retail tariff adjustments.

In Graphs 5.85, 5.86, 5.89 and 5.90 we note that after the start of April 2007 (observation 2,007) the oil prices and indexes appear to be affecting the SMPs in two different ways. From the start of April 2007 until the start of April 2009, the oil prices and index lines are positioned in the middle and lower band of the SMP pattern, whereas from the start of April 2009 until the end of our data in the end of October 2011 (observation 3,681) the oil prices and indexes lines are positioned in the upper band of the SMP pattern or over it. This differentiation could be the result of a number of factors such as: system load variation (system load is decreasing during that period); decreased market power in the wholesale electricity market; and an increase in the number of generators. These factors result in increased levels of competition in the market and the outcome is that for any given oil price or index level, the SMP gets lower than it did before. This suggests that competition operates in this market and affects the market outcome by creating lower market prices.

5.10.6 Fossil Fuel prices and Deviations Marginal Price (DMP)

The same approach as the one taken for averages of SMP, has been taken for averages of DMP. Given the similarity of SMP and DMP patterns, the results from comparing natural gas data and oil data with averages of DMP are the same as those when using averages of SMP. The patterns of the DMP averages seem to be very well explained by the patterns of prices of imported natural gas and of the indexes for wholesale natural gas in Greece, as well as from the patterns of Brent oil prices in Europe and of the indexes for wholesale oil products in Greece.

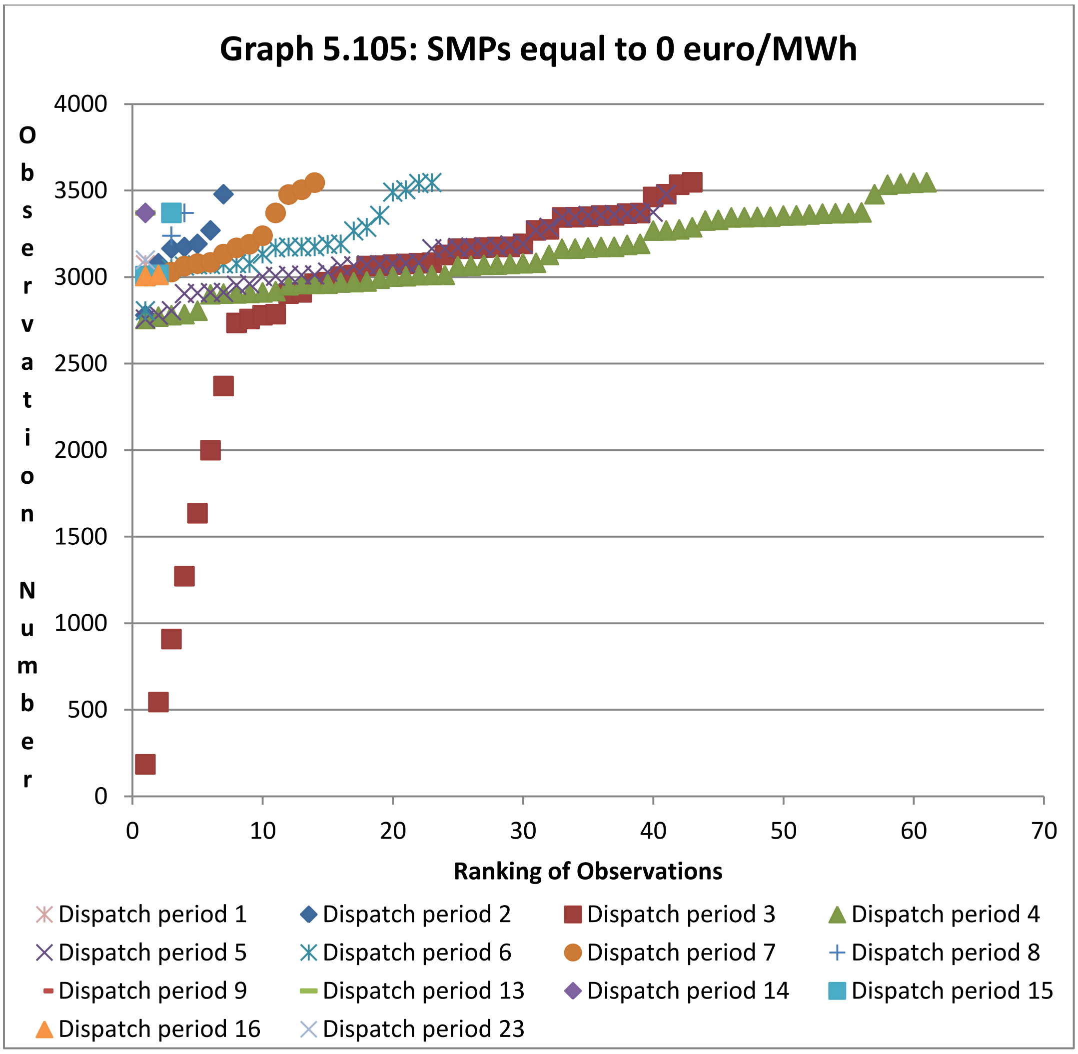
The Graphs of the DMP averages that correspond to the analysis done for SMP averages in Sections 5.10.2 and 5.10.3, are presented in Appendix B, Part 7. These are Graphs 5.91, 5.92, 5.93, 5.94, 5.95, 5.96, 5.97, 5.98, 5.99, 5.100, 5.101, 5.102, 5.103 and 5.104.

5.11 An observation on low wholesale electricity prices

Graphs 5.300-5.3023, to be found in Appendix B, Part 2, show that from April 2009 we start observing the existence of SMPs that are as low as zero euros/MWh. These low SMPs are present mostly in the night-time dispatch periods rather that the day-time ones.

Using the "Data Analysis" tool of Microsoft Excel, we ranked the SMPs for every dispatch period from the highest to the lowest. Selecting the lower ones, we can see which ones of them are set at exactly 0 euro/MWh. These are presented in Graph 5.105. The observations are ranked according to date, from earliest to latest as we read the graph from left to right. Each observation corresponds to a date when for some dispatch period, SMP falls to 0 euro/MWh.

We can see that all of these observations occur on the upper part of Graph 5.105, meaning that this only occurred in the later part of our data, starting from April 2009. The observations that we get for dispatch period 3 that start earlier than that date, do not correspond to actual dispatch periods but to the hours when time changes from winter time to summer time.



The fact that these low prices occur only after a specific date and not earlier might suggest that this is part of the strategic positioning that the electricity generators were employing at the time. According to this positioning, a more aggressive bidding behavior is being used and electricity generators are possibly trying to reduce the wholesale electricity price. The same situation could occur if only a few of the generators were adopting this strategy, on the occasions where they control a large enough amount of generating capacity to be able to produce this effect.

Being aggressive and keeping SMP at low levels can potentially help the previous monopolist protect the profits made on the supply side of the market, by having to distribute as little revenue as possible to the other generator firms. The existence of the Mechanism for Covering Variable Cost [RAE, 2010a] ensures that the electricity generators cannot find themselves involved in electricity generation activity that leads to financial losses. According to the provisions of this mechanism, whenever the daily payment to a generator is set below its variable cost of operation increased by a certain percentage, the mechanism is activated and additional payments are made to the generator so that its revenue will reach that level. These payments are recovered through the Deviations Clearance.

In all of these periods where the SMP was set at very low prices, the corresponding DMP was not zero, as can be seen from an examination of the respective DMP data. This is due to the fact that DMP refers to deviations in the amounts of electricity produced. Therefore these deviations in quantity cannot be covered through the imported electricity or the mandatory operation of hydroelectric plants (which are the only cases where bids can be zero). These deviations can only be offered by units that submit offers to the electricity pool which are larger than zero, since these offers have to be larger than the Administratively Set Minimum Energy Offers [OOEM, 2012, page 70]. Additionally, through the DMP, a variety of other costs are being covered [Journal of the Greek Government, 2005a, pp. 9459-9467], therefore increasing the levels of DMP above zero.

5.12 PPC Strike on June 2011

During the time period 20/06/2011-29/06/2011, a strike organized by the Union of PPC resulted in a series of PPC plants being switched off. In Graphs 5.300-5.323 and 5.400-5.423 (to be found in Appendix B, Parts 2 and 3) we can see the effect that these strikes had on SMP and DMP. In Graphs 5.106 and 5.107, the effect of these strikes is isolated as we present the SMPs and the DMPs of these dispatch periods. The strike occurred in days 11-20 of Graphs 5.106 and 5.107 and we can see that its effect was very large.

In addition to the financial effect that the strike had for PPC, it also affected all the other suppliers that had to endure the increased pool prices. In that regard, we can say that this strike constituted a negative externality for the electricity supply market.

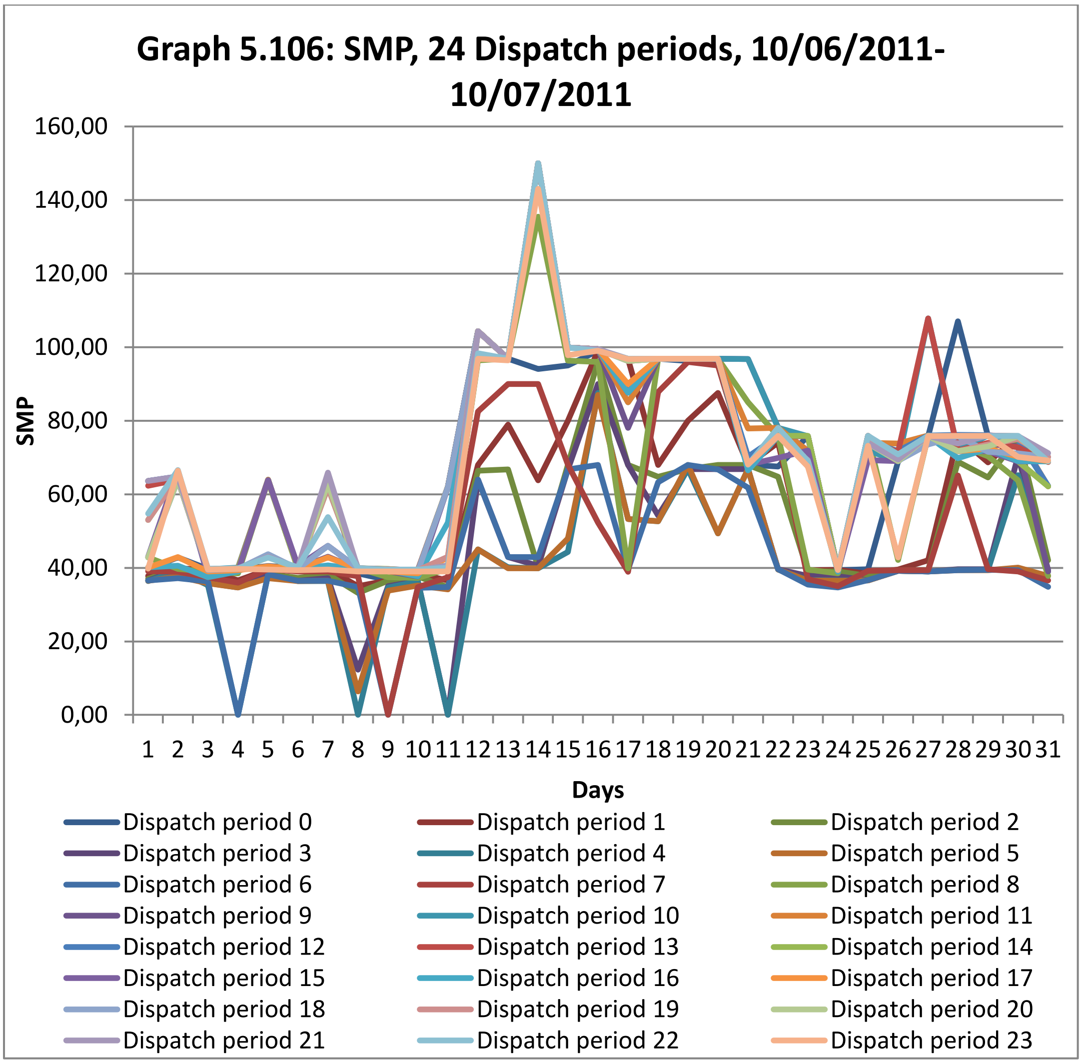
In addition, the supply of electricity to consumers has been heavily disrupted, as evidenced by the 14 press releases by PPC announcing the scheduled supply interruptions [PPC, 2011b], in addition to other press releases by PPC referring to the details of the strike.

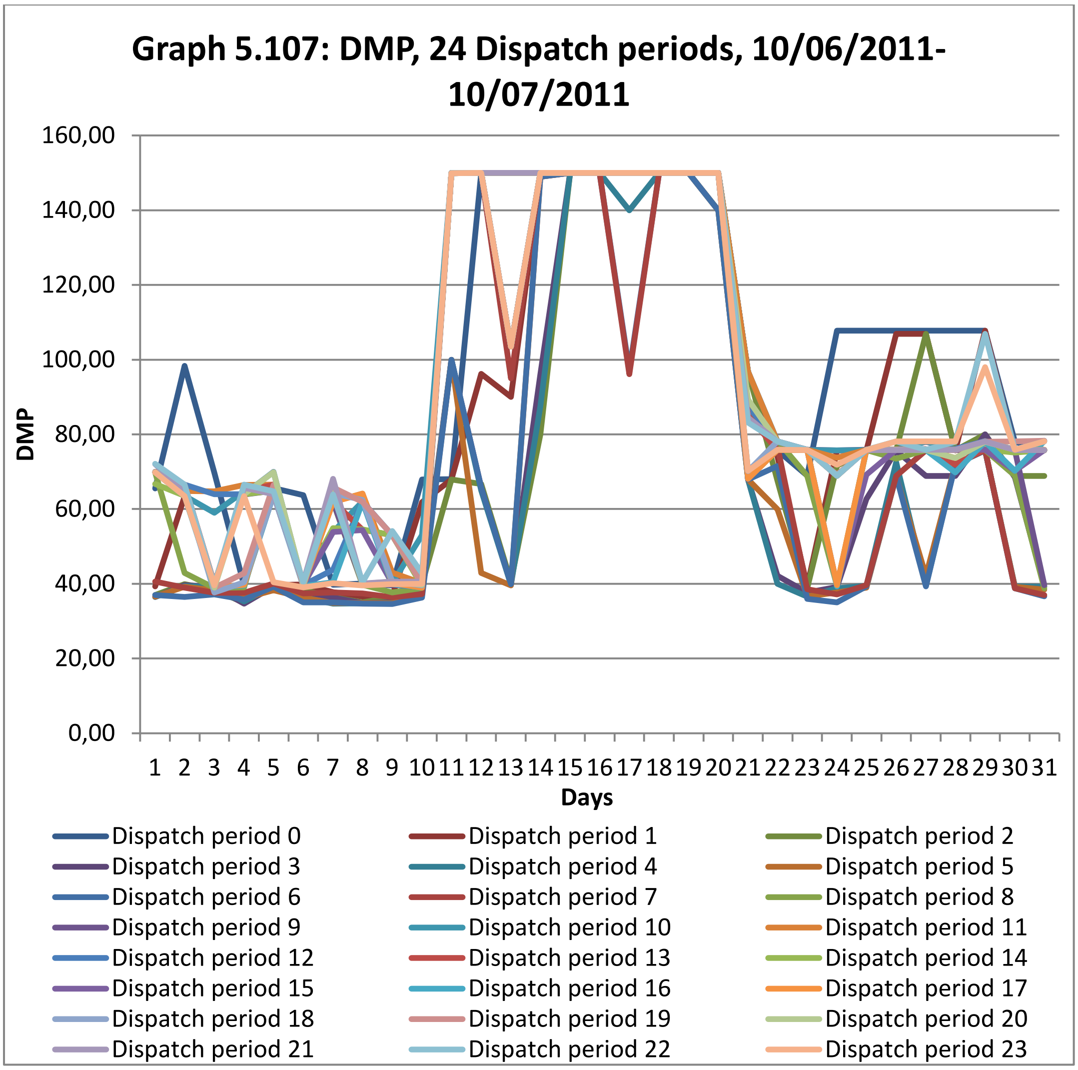
The ability of the Union to organize strikes of such magnitude and affect on the operation of the market demonstrates that:

- PPC's size relative to the market and to its competitors is very large. As a result, the electricity market's daily scheduling relies on the operations of PPC in order to be fulfilled, thus becoming vulnerable to the potential use of market power that PPC has.
- Its size as an electricity generator, and its role in the market renders PPC very important in terms of security of electricity supply.
- The power of the Union within PPC to close down PPC power plants is a cause of concern.
- The reliability and structural integrity of the liberalized deregulated electricity market where investors are expected to enter, is put into question.

Asymmetric risks are shown to be present for other potential new entrants, without the market being able to manage them.

- Political parties might be able to use the Union of PPC workers in order to exercise political pressure through such acts.





That event did not only showcase the power of the Union of PPC workers in controlling the operations of the firm, but also showed the extent to which the liberalization of the electricity market has progressed, as a strike within PPC resulted in people being left without electricity and in lack of any alternative being available for the electricity market to be in a position to cover the demand. The programmed electricity supply interruptions suggest the acceptance of that situation on behalf of the system operator (HTSO).

The liberalization process in the Greek electricity sector has a long way to go until it can reach the point where there are enough firms participating in the competitive parts of the market (generation and supply). Had it been so at the time of the strike, the impact of such an event on the electricity supply of final consumers would have been diminished, given that the market would be able to meet the demand through other electricity generators.

The fact that such a large part of electricity generation takes place through PPC empowered the Union of PPC, since that fact brought the electricity market under its control and left no options to the consumers. The rest of the market participants have their own interests as well and these have to be respected by the market operator. Having one firm that uses its market position and market power in order to serve political and economic agendas should not be allowed. The market design should incorporate mechanisms that prevent such occurrences. One way to do so would be to control market shares and therefore the ability of each firm to impact the market in such a way.

PPC workers are not being represented by industry-wide unions and have instead created a union that is solely dedicated to their representation. This ensures that this union will be specifically focused and dedicated on the specific issues of PPC workers and will not compromise their interests in order to serve other groups. That could have been the case if PPC workers were represented by an industry-wide union.

5.13 Comparing Retail Tariffs of PPC with wholesale electricity prices

In this part, we will be examining PPC tariffs. The tariffs that were used from 01/07/2008 did not have separate charges for monopolistic activities (transmission and distribution) and competitive activities (generation and supply). However the tariffs used from 1/1/2011 have separate charges for these activities [PPC, 2011c] and the same thing happens in the tariffs used from 1/1/2012 for low voltage [PPC, 2012k] and from 1/2/2012 for medium voltage [PPC, 2012g, 2012h, 2012j]. So, the 2011 and 2012 retail tariffs, have a two-part tariff structure, with the one part of the tariff referring to the transmission and distribution charges (this is the part of the monopolistic charges) and the other part referring to the charges for the generation and supply of electricity. Amongst the competitive charges, we isolate the Energy Charges in the tariffs (some customer categories also have to pay Capacity Charges in the competitive part of the tariffs). The competitive charges also incorporate capacity charges in some customer categories, through which PPC aims at recovering fully or partially the cost of the capacity payments. Two-part tariff structures with separate energy and capacity payments categories are faced by tariff categories B1, B2, B1B, B2B, C22 and C22B. In the first columns of Tables 5.3 and 5.4 these tariff notations are explained as to the customers categories that they correspond to. The other customer categories are apparently paying for capacity through the Energy charges.

We separated the charges applied to different customer categories according to the time in the day at which these charges occur. According to the tariffs, the night-time period is the period 23:00-07:00, which corresponds to dispatch periods 23-6, and the day-time period is the period 07:00-23:00, which corresponds to dispatch periods 7-22. The interruptible farming tariffs are tariffs that have the electricity supply interrupted whenever PPC decides to do so.

Table 5.3 shows the tariffs that refer to electricity consumption during the whole day. With these tariffs we can see the energy charges for these categories. We should note that 1,000kWh=1MWh (we note this because the actual tariffs are expressed in kWh). We also calculate the average SMP from the market data that we have. The 24-hour Average SMP was 45.66 euros/MWh in 2010 and 60.06 euros/MWh in the period 1/1/2011-31/10/2011. For these average SMPs it is apparent that when the 2011 tariffs were being set, all tariff categories in Table 5.3 would be covering their average SMP and potentially their capacity cost if the average SMP level would have remained in the 2010 levels (Commercial Tariffs C22 and Industrial tariffs C22B also included a capacity charge in the tariff to address this cost).

However, when considering the actual average SMP of 2011 (until 31/10/2011), there was much less “room” for capacity cost coverage and profit making. By saying so, we mean that the average SMP during 2011 was higher than it was in 2010. We consider this to be relevant, since at the time of tariff setting for the 2011 tariffs, the 2010 average SMPs were the most recent information available on SMP levels. It is also worth noting that according to the Residential Tariff C1 electricity would be supplied for 54 euros/MWh, which is less that the average SMP of 60.06.

In the 2012 tariffs, this problem is partially addressed, by incorporating increased charges that in most cases go well beyond the level of 60.06 euros/MWh, allowing for the capacity charges to be covered and for potential profits to be made.

	Energy charge 2011 (euros/MWh)	**Energy Charge 2012 (euros/MWh)**
Tariffs with "All day charges"		
LOW VOLTAGE		
Commercial Tariff 2011 (C21)	87	93
Industrial Tariff 2011 (C21B)	79.9	85.48
Commercial Tariff 2011 (C22)	65.4	71.1
Industrial Tariff 2011 (C22B)	65.4	71.1
Lighting of Streets and Squares	64.62	68.25
Residential Tariff (C1)		
0-800 kWh	54	56.25
801-1000 kWh	68.6	78.5
1001-1200 kWh	71	81.5
1201-1600 kWh	72.7	81.5
1601-2000 kWh	72.7	81.5
more than 2001 kWh	81.74	91.55

Table 5.3: Tariff categories with charges that apply for the whole day, and Energy Charges for the 2011 and 2012 PPC Tariffs. Made from information from [PPC, 2011c, 2012k]

Table 5.4 gives the tariffs that refer to electricity consumption that occurs during the day-time hours. For these tariffs we can see the Energy charges for these categories. We also calculated the average SMP from the market data that we have and we have found that the Average SMP for dispatch periods 7-22 was 51.09 euros/MWh in 2010 and 67.17 euros/MWh in the period 1/1/2011-31/10/2011. Given these average SMPs we can see that when the 2011 tariffs were being set, all tariff categories in Table 5.4 would be covering the average SMP during the day, if the average SMPs had remained in the 2010 levels. We should note that customer categories B1&B2 and B1B &B2B are also including a capacity charge, so it remains for the energy charge to only cover the wholesale pool price, the allocated general expenses of the firm and also make profit.

With the actual average SMP of 2011 (until 31/10/2011), there was much less “room” for profit making than there would have been if the SMP had remained at the 2010 levels. The Commercial Tarrifs (B1&B2) and the Industrial Tariffs (B1B&B2B) were supplying electricity for 61.83 euros/MWh and 60.83 euros/MWh respectively, that being less that the average SMP of 67.17. Commercial Tariffs C23 were supplying for 100.95 euros/MWh and Industrial Tariffs C23B were supplying for 85.05 euros/MWh, having however to also cover capacity cost through these charges.

In the 2012 tariffs, increased charges are applied for all four tariff categories.

	Energy charge 2011 (euros/kWh)	**Energy Charge 2012 (euros/kWh)**
Tariffs with “Day-time Charges”		
Medium Voltage Commercial Tariff 2011 (B1 & B2)	61.83	63.88
Medium Voltage Industrial Tariff 2011 (B1B & B2B)	60.83	63.88
Low Voltage Commercial tariff 2011 (C23)	100.95	105
Low Voltage Industrial Tariff 2011 (C23B)	85.05	88.46

Table 5.4: Tariff categories with charges that apply during the day-time hours, and Energy Charges for the 2011 and 2012 PPC Tariffs. Made from information from PPC [2011c, 2012k, 2012g, 2012h].

In Table 5.5, we can see the tariffs that refer to electricity consumption occurring during the night-time. For these tariffs we can see the energy charges for these categories. We also calculated the average SMP from available market data revealing that the Average SMP for dispatch periods 23-6 was 34.79 euros/MWh in 2010 and 45.79 euros/MWh in the period 1/1/2011-31/10/2011. Given these average SMPs we can see that when the 2011 tariffs were being set, all tariff categories in Table 5.5 would be covering the average SMP during the day, should the average SMPs have remained in the 2010 levels. We should note that customer categories B1&B2 and B1B &B2B also include a capacity charge. As a result, in these customer categories, the energy charge should only cover the wholesale pool price, the allocated general expenses of the supplier firm and also some profit.

With the actual average SMP of 2011 (until 31/10/2011), there was much less “room” for profit making than there would have been if the SMP had remained at the 2010 levels. The Commercial Tariffs (B1 & B2) and the Industrial Tariffs (B1B & B2B) were supplying electricity for 51.03 euros/MWh and 50.03 euros/MWh respectively, which was more than the average SMP of 45.79. Commercial Tariffs C23, Industrial Tariffs C23B and Residential Tariffs C1N were supplying for 54 euros/MWh, needing however to also cover capacity cost through these charges.

In the 2012 tariffs, decreased charges applied for tariff categories B1&B2 and B1B &B2B, whereas C23, C23B and C1N remained unchanged to the 2011 charges.

	Energy charge 2011 (euros/kWh)	Energy Charge 2012 (euros/kWh)
Tariffs with "Night-time Charges"		
Medium Voltage Commercial Tariff 2011 (B1 & B2)	51.03	50.15
Medium Voltage Industrial Tariff 2011 (B1B & B2B)	50.03	50.15
Low Voltage Commercial tariff 2011 (C23)	54	54
Low Voltage Industrial Tariff 2011 (C23B)	54	54
Low Voltage Residential Tariff (C1N)	54	54

Table 5.5: Tariff categories with charges that apply during the night-time hours, and Energy Charges for the 2011 and 2012 PPC Tariffs. Made from information from PPC [2011c, 2012k, 2012g, 2012h].

In Table 5.6 we can see the tariffs that refer to electricity consumption during all hours of the day except at the times when PPC asks for supply interruption. For these tariffs we can see the energy charges for these categories. We cannot calculate an average SMP, given the fact that there is a supply interruption option that can be used whenever the wholesale electricity price increases or whenever there are generation capacity issues. However, given that there is no specific zone defined for it, we can use the 24-hour Average SMP that was calculated at 45.66 euros/MWh in 2010 and 60.06 euros/MWh in the period 1/1/2011-31/10/2011.

Given these average SMPs it is clear that when the 2011 tariffs were being set, all tariff categories in Table 5.6 would be covering the average SMP during the day, should the average SMPs have remained in the 2010 levels. That would leave some small surplus for coverage of capacity cost, allocated general expenses, and firm profits. That surplus could be enlarged (for these specific tariff categories) by interrupting supply whenever the wholesale pool price becomes very high.

With the actual 24-hour average SMP, which is 60.06 euros/MWh, it becomes very difficult for PPC to maintain tariffs at the 2011 levels. Given that the night-time SMP averages of 2011 were at 45.79 euros/MWh, being able to use these tariffs to cover wholesale electricity pool price and capacity cost as well becomes very difficult. As a result, in the 2012 tariffs, the two interruptible Tariffs were both set at higher levels.

	Energy charge 2011 (euros/kWh)	**Energy Charge 2012 (euros/kWh)**
Medium Voltage Tariff for Farming-Interruptible	49.46	59.33
Low Voltage Tariff for Farming-Interruptible	55.56	55.56

Table 5.6: Tariff categories with charges that apply for all day except at the times when PPC asks for electricity supply interruption, and Energy Charges for the 2011 and 2012 PPC Tariffs. Made from information from PPC [2011c, 2012k, 2012j].

The 2011 PPC tariffs were set at levels that, although they were formed from the pressure of competition, they presumably allowed for profitability when these have been set, given the 2010 average SMP levels. The adjustment of tariffs could be said to constitute an adjustment to competition and not an act of predation. The subsequent increase in 2012 seems a necessary adjustment in order for PPC to be able to supply the market in terms that allow PPC to recover at least the wholesale electricity cost. Therefore the 2012 tariffs constituted an adjustment to rising wholesale electricity costs.

In the same time, one could argue that PPC might be importing electricity through the interconnections for prices lower than its tariffs or using its lignite-fired units to generate electricity that costs less than the average SMP. However that only means that PPC is making profits as a generator or electricity trader. It should also be that each of the firms that supply the electricity market is able to also make profits as an electricity supplier as well, without cross-subsidizations between the different electricity industry segments.

Note at this point that RAE has put forward the Opinion [RAE, 2011b] that the average revenue allowed for PPC from its competitive activities should be set according to the middle column of Table 5.7. The initial suggestion of PPC is shown on the left-hand column of Table 5.7. We note that according to RAE [2011b], the overall Average Allowed Revenue for competitive activities by PPC was proposed by RAE to be set at 78.68 euros/MWh for 2012, whereas for 2011 it was set at 69.78 euros/MWh.

However by a Decision of the Deputy Minister of Environment, Energy and Climate Change [Journal of the Greek Government, 2011a], the Average Competitive Revenue (euros/MWh) was set according to the right column of Table 5.7. That was done in the interest of mitigating the economic consequences for some consumers from the tariff adjustments, taking into consideration the adverse economic climate in Greece at the start of 2012.

	Average Allowed Competitive Revenue (euros/MWh) for 2012, as suggested by PPC	Average Allowed Competitive Revenue (euros/MWh) for 2012 by RAE	Average Competitive Revenue (euros/MWh) for 2012 by the Ministry of Environment, Energy and Climate Change
Residential Customers	94.1	89.8	78.6
Professional Customers at Low Voltage	97.9	93.7	89.9
Rest of Customers (Farmers at Low Voltage/Interruptible, Lighting of Streets and Squares)	81.6	77.9	61.5

Table 5.7 Average Competitive Revenue (euros/MWh) of PPC for 2012. [RAE, 2011b], [Journal of the Greek Government, 2011a].

Examining the details of Table 5.7, we can see that for 2012, PPC was asking for larger average allowed revenue from competitive activities than the ones suggested by RAE and that the final average revenues were set at even lower levels than the ones RAE suggested. That would lead us to conclude that:

- RAE is not a strong regulator since important decisions, such as tariff setting or average revenue setting, are not taken by the regulator.
- Recent decisions by the Ministry of Environment, Energy and Climate change have been oriented towards serving social agendas and PPC can be potentially used as an instrument for income redistribution and welfare improvements.
- PPC as a firm is quite unlikely to be following "predatory pricing" or "limit pricing" practices since, in the presence of competition in the electricity supply markets, the company asked for retail tariffs upwards adjustments that were much larger than the ones that actually occurred.

5.14 Imposition of Tax on Natural Gas

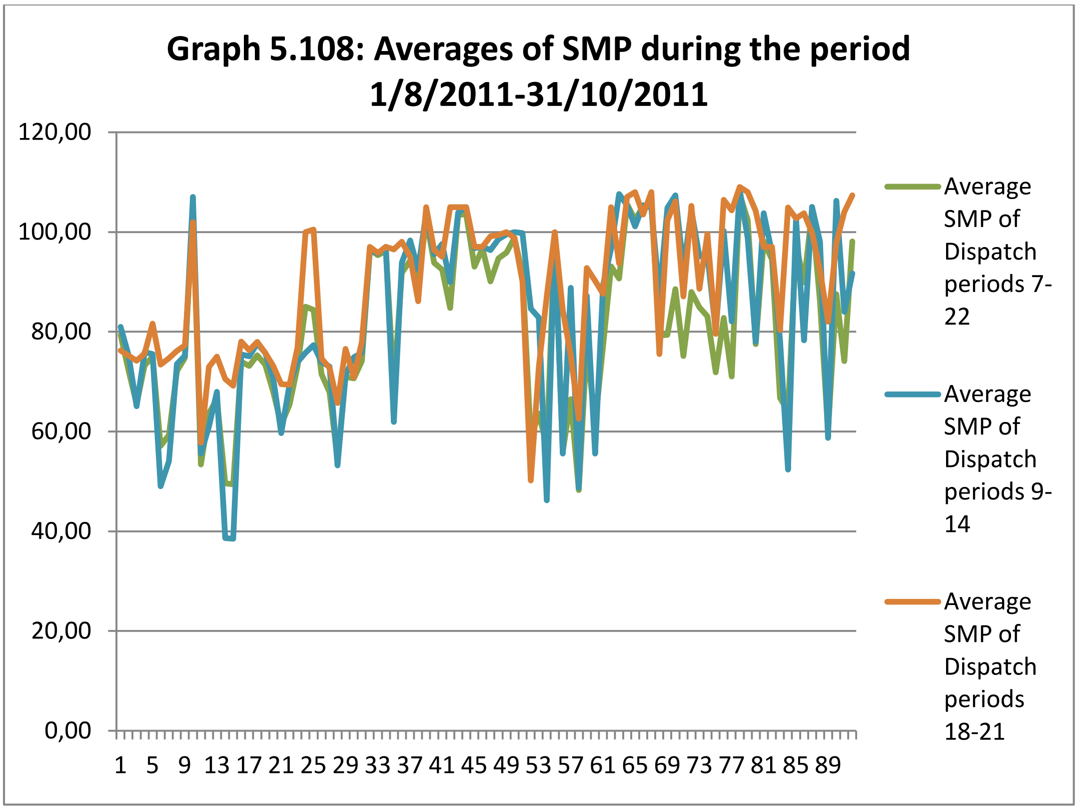
From 01/09/2011 a tax was imposed in Greece for the use of natural gas [PPC, 2012c]. The extended use of natural gas as a fuel for electricity generation has resulted in increase in the wholesale electricity prices. One could say that the design of the Greek system is such that it cannot absorb shocks in international or domestic fuel prices. This does not imply that an electricity system should definitely be in the position to do so. However, the point here is that the inability to absorb these shocks indicates that there is inflexibility in the electricity system. That means that it is very hard for alternative solutions to be found in the short run which would have allowed the wholesale prices to remain at low levels. That specific inflexibility is a systemic problem and is rooted in the generating capacity structure and its fuel mix design.

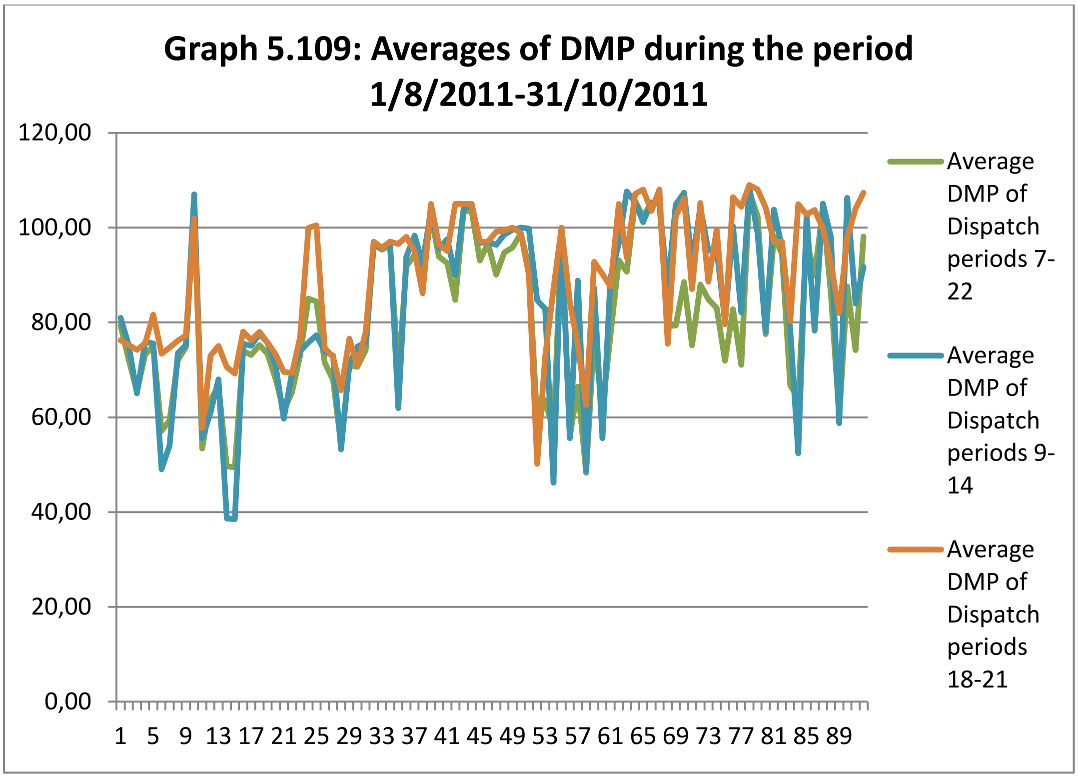
RAE recognized the magnitude of the effect that this tax had on the SMP and the fact that this created asymmetries in the competitiveness of natural gas-fired units and increased the profitability of all other electricity generating units thereby depressing the profitability of electricity suppliers to a much larger extent than the tax itself would justify. That was done in a Decision issued by RAE on 15/12/2011 [RAE, 2011a] where it was decided that the payments for this tax would not be included in the Minimum Variable Cost of the natural gas-fired units as described in the article 44 of the Code for Electricity Transactions [OOEM, 2012e, pp. 34-39]. This implies that this tax would not be affecting the wholesale pool price and would instead be recovered through the "Account of Increases-3" used for recovering the cost of ancillary services and cost of various reserve units [Journal of the Greek Government, 2005, page 9461]. This account is being paid through the Deviations Clearance Mechanism, which means that this cost will be recovered through the DMP.

That effect that we are discussing can be seen in Graphs 5.108 and 5.109. These graphs are set for the period 01/08/2011-31/10/2011, whereas the period that the tax is imposed is 01/09/2011-31/10/2011. In that way, we can see the effect in the days where the tax is in place in comparison to the days that it wasn't. On our graphs, the tax is active from day 32 until the end.

In Graphs 5.108 and 5.109 we are using the average SMPs and DMPs of the dispatch periods 7-22, 9-14, 18-21. We choose these because the time periods during the day seem to be the ones that have been affected the most.

Examining Graphs 5.108 and 5.109 we can see that after the tax imposition, the average SMPs and DMPs during the day-time period generally increase. More specifically the SMPs were previously for the most part under 80 euros/MWh and after the tax imposition we can see that a lot of these prices are close to 100 euros/MWh for September and 105 euros/MWh for October.





5.15 Regulatory Policy Implications

In the Greek electricity market, competition has emerged in the generation sector, whilst the transmission and distribution sectors are natural monopolies run respectively by their operators and the retail electricity supply sector faces very limited competition. The retail electricity supply has seen some developments in the past, when new entrants have identified the potential for profitable entry in small segments of the market. This entry potential has emerged as a result of the combination of tariff structure at the time. This tariff structure incorporated social concerns and agendas, the existence of an obligation to meet the market demand for the previous monopolist and the resulting cross-subsidizations between tariff categories.

From a policy point of view, an important concern has to do with the issue of the behaviour of the market players: the previous monopolist, the new entrants and the regulator. Examining the stance of the previous monopolist towards the event of new entry, the issue is whether the response of the previous monopolist constitutes competitive behaviour or predatory behaviour. It should be noted that when a powerful incumbent acts competitively, it is very difficult for a new entrant to compete against this incumbent. The role of the regulator in such a situation involves the regulator allowing competition or restricting it in order to protect the new entrants and allow them to enter the market.

A solution for a setting such as the one in the Greek electricity market could involve a market without entry restrictions where there will be the previous monopolist and potentially some fringe firms. The important element of this market setting is the existence of the small supplier firms as well as the threat of potential further entry. The outcome could be that the previous monopolist would act competitively in the long run providing a Bertrand market equilibrium as a result of the threat of entry and of the threat posed by the small retail suppliers that can take advantage of any opportunity that can exist in the market if the previous monopolist attempts to increases retail prices.

5.16 Conclusions

This chapter presents empirical work. Secondary data collected from the website of the previous transmission system operator (HTSO) is shown. These data comprise the System Load, System Marginal Price and Deviations Marginal Price (the ex-post System Marginal Price). Data cover a time period from the end of 2001/start of 2002 until 31/10/2011.

Each variable is analyzed separately, in timeline form for each of the dispatch periods. Six different averages are calculated and presented for each day of the period under discussion. Annual averages for every dispatch period are calculated as well as averages for the whole time period. Four average days are created in order to show the effect that time has on the determination of the System Load and of the SMP and DMP. Annual averages are calculated for these average days as well as for the whole time period.

We show how system load, SMP and DMP, are dependent on time variables, as we observe a specific effect that the hour of the day, the day in the week (working or non-working day), the period of the year (winter or summer) and the year (by comparing annual averages) has on them.

We also calculate standard deviations and adopt the same approach as we did with averages, drawing graphs that present our results.

We assume that temperature is a factor that affects system load which through this, has an effect on SMP and DMP. We use an annual pattern of monthly temperatures that is population weighted. There is a close fit between the system load and the temperature pattern, suggesting that temperature guides the prices, a finding that was suggested also in the literature.

Fossil fuel price data are also used. These are the monthly import prices for natural gas through pipelines from the Russian Federation to Greece, the monthly import prices of natural gas in Liquefied Natural Gas form from all origins to Greece, the three month period index for wholesale natural gas in Greece, the daily Brent oil spot prices in Europe and the three month period index for wholesale oil products in Greece. The SMP and DMP patterns seem to be well explained by the natural gas prices as well as by the oil prices, when we adjust them for the buffer inventory period.

We find indications that System Load, SMP and DMP are affected in ways that can be summarized as:

System Load is determined by the function:

System Load=f(year, month, day of the week, time of the day, other factors)

Wholesale electricity prices SMP and DMP are determined by the function:

Wholesale electricity prices=f (cost of generation per dispatchable unit, generating capacity per dispatchable unit, system load, other factors)

In this wholesale electricity prices formula function, prices are linked with marginal cost. We should note that the "cost of generation per dispatchable unit" includes the cost of fuel for each unit.

We present the competitive charges for energy in PPC tariffs for Medium and Low Voltage in 2011 and 2012 and compare them with the average SMP of years 2010 and 2011 (until 31/10/2011). We use SMP averages that correspond to the dispatch period that each of the charges refers to. We argue that the 2011 tariffs were potentially set at profit making levels and that the increases recorded in the 2012 tariffs were the result of increases in the wholesale price of electricity. This strengthens the argument that PPC is not acting in a predatory manner, but rather is engaged in healthy price competition adjusting for the market conditions.

That suggestion is strengthened by the fact that PPC was asking for larger tariff increases than the ones finally approved. Also, the fact that the approval of the level of allowed revenues per customer category for PPC from the Ministry of Environment, Energy and Climate Change did not adopt the suggestion of RAE but instead adjusted it downwards, demonstrates the willingness of the political forces to use PPC as an income redistribution instrument. Should that be so, the sustainability of the operation of the electricity supply market could be put at risk by these political decisions, given that competition will take place against tariffs set using social criteria.

We present the evolution of SMP and DMP averages of dispatch periods during the day for the time period 01/08/2011-31/10/2011 to demonstrate the effect that an imposition of a tax on natural gas consumption had after 01/09/2011. In this way, we demonstrated the vulnerability of the wholesale electricity prices to domestic and international fuel price fluctuations.

We also present the SMP and DMP levels during the time period 10/06/2011-10/07/2011 in order to show the effect that a strike of the PPC Union during the period 20/06/2011-29/06/2011 had on the operation of the wholesale market given that PPC power plants were forced to shut down. In this way we showed that the electricity market operation faces an additional risk which, although directly related to PPC, also constitutes an externality for the rest of the market participants. This event not only highlights the market dominance of PPC in electricity generation. It also shows the fact that the Greek electricity system has not managed to move away from its domination by the previous monopolist or to establish mechanisms to manage such crises.

The analysis presented in this chapter highlights specific aspects of the operation of the electricity market that we have argued for in the earlier chapters of the thesis. We found that if the system load gets close to the maximum system capacity, wholesale electricity prices increase and that the market power of the generators increases as well. System load levels can be a problem when these get close to the maximum generating capacity. That situation results in increased market power for the wholesale pool bidders, since they might be able to bid strategically, submitting higher bids than they would under normal circumstances. If this strategy ends up being successful, it results in higher wholesale electricity prices being paid to the generators.

By examining tariffs, we see that these have been set by PPC in 2011 at potentially profit-making levels. These have been readjusted in 2012 to levels that protect PPC's profitability, but for the given SMPs of the time that the adjustment occurred, do not suggest abuse of market power. The very existence of retail suppliers that elect not to compete against PPC in many of these customer categories strengthens the argument that there are no significantly large profits to be made in these so that entry would be attracted.

In an electricity sector with high wholesale prices, the value of the lignite-fired power plants increases because of their increased ability to make profits. That is so because the wholesale electricity price is the selling price of the electricity that these plants generate, whilst the actual cost of electricity generation for these plants is quite low. The increased wholesale pool price implies that there could be a high asking price for these power plants, should they be sold by PPC to independent investors. Should these remain under PPC ownership, PPC will have assets with increased market value, regardless of the book value of these assets.

Chapter 6

Conclusions

In this thesis we have examined the Greek electricity market, focusing on the operation of the electricity supply.

6.1 The unique characteristics of the Greek case

The unique characteristics of the Greek electricity industry that have been identified throughout the thesis are presented in this section.

- The market was previously organized as a vertically integrated state-owned monopoly. That is to say, the Public Power Company (PPC), was the owner of the full generating capacity, the transmission and distribution network and the sole supplier in the market. There was no market regulator and policymaking duties for the energy sector were fulfilled directly by the government and the Minister that was responsible for the energy sector.
- The decision for the implementation of the market reform came externally, through Directives from the European Union.
- As a result of the previous monopolistic market setting and the previous close integration of PPC with the Greek State, a significant amount of Greek lignite sources are given to PPC by the Greek State for no price. PPC is the sole firm that is accessing and using these. Such an arrangement was made so that low tariffs could be applied, allowing industrial development and income redistribution policies to be pursued.
- In the same way PPC is the only firm that has large hydro-electric power plants. Specific rules apply for the use of these plants and their incorporation in the wholesale electricity pool.
- The Greek State in the majority owner of PPC even after the liberalization process. The Greek State has control over the decisions of PPC and in this manner it has control of a large part of the electricity industry.

- Through ownership of PPC, the Greek State also has control of the Independent Power Transmission Operator (IPTO), the Hellenic Electricity Distribution Network Operator (HEDNO) and the Operator Of Electricity Market (OOEM).
- The Greek State maintains a significant level of control over the energy market regulator, Regulatory Authority for Energy (RAE).
- Although the Greek electricity market regulator, RAE, possesses a wide range of responsibilities, it does not have large powers. The most significant energy industry powers remain with the government.
- The Greek government has very large legal and executive powers, given the structure of the Greek political system. In order for the government to stay in office, it has to be supported by a majority of the Members of the Parliament to allow most legislative voting acts to proceed successfully.
- The Greek political culture leans heavily towards state paternalism which leads to adoption of social electricity retail tariffs as well as to serving agendas of more general social considerations. That fact, coupled with the adoption in the Greek political system of an exchange-based political culture, leads to State-owned assets, such as public firms, being employed in a potentially economically inefficient manner in order to serve political agendas and the interests of specific groups.
- The above characteristics imply that successful liberalization would require a major resetting of the Greek electricity industry and possibly a large resetting of the way that the Greek economy operates in general. The fact that policymakers in Greece elected to avoid addressing these issues and attempted to go around them, appears to be one of the major reasons for the problems that the electricity reform effort has faced.

6.2 List of findings

In this section we present a list of all the findings that came through the thesis.

1. The reform of the Greek electricity market is an ongoing process which is yet to be completed. Regulatory mechanisms are still evolving and adjustments are made so as to promote competition and to successfully transfer the benefits from the increased efficiency to the consumers.
2. Increased efficiency has been evidenced in observing that after the start of April 2009, we get lower average SMPs for given levels of input prices. This differentiation occurred after the increase of the level of competition in the market, the resulting increase of generating capacity and the decrease of electricity demand.
3. There are similarities between the Greek case and other South East European countries in the ways that the economy operates and in the way that the electricity market reforms take place.
4. In the presence of imposed tariffs or price cap regulation the wholesale electricity prices can render unsustainable the existence of supplier firms in the market. That effect is much stronger when these tariffs do not include mechanisms that connect wholesale electricity prices with retail tariffs.
5. Tariff setting is a critical issue as it determines whether each tariff category will be profitable or not. Differences in profitability levels attract entry in selected tariff categories, whereas these also suggest cross-subsidizations between tariff categories for the firm that serves the whole market.
6. Price competition between market participants in the Greek supply market might result in decreases in the electricity supply prices. That would mean larger consumer surpluses and smaller producer surpluses.
7. New entrants might be able to compete against the previous monopolist by managing their tariff structures and their capacity payments in the same time. This can lead new entrants to restricting their market shares limiting the ability and motivation of the previous monopolist to respond.
8. The Greek electricity generation market demonstrates the existence of market power for PPC, given its installed capacity, the amount of electricity generated and imported by PPC and the fact that it exclusively owns and controls lignite-fired units and large hydroelectric plants.

9. The market power of PPC in the electricity generation part can be used to increase profitability. This happens when combining the market power in the wholesale market with the very large market share that PPC has in the electricity supply market.
10. The governmental decisions seem to be affected by multiple parties such as the EU and the Greek political parties and that happens in complex ways. Governmental decision making is affecting the energy policy, and that happens in decisions such as the tariff setting ones as well as the ones on managing strikes.
11. System Load in the Greek electricity industry presents an intra-day seasonality pattern.
12. System Load in the Greek electricity industry presents an annual seasonality pattern that seems to be correlated with annual temperature pattern.
13. System Marginal Price (SMP) and Deviations Marginal Price (DMP) in the Greek wholesale market present an intra-day seasonality pattern.
14. SMP and DMP in the Greek wholesale market do not present annual seasonality patterns, instead these seem to be correlated with the patterns of evolution of fossil fuel prices.
15. SMP and DMP seem to be very closely related to one another in both their intra-day and annual seasonality as well as in their levels.
16. There seems to be a specific effect that the day of the week, being working day or non-working day, has on System Load, SMP and DMP.
17. There seems to be a specific effect that the period of the year, being winter or summer, has on System Load, SMP and DMP.
18. There seems to be a specific effect that each year has on System Load, SMP and DMP.
19. Examining SMP levels and tariffs for 2011 and 2012, we concluded that PPC is not engaging in predatory behaviour. Instead, it engages in normal competition for the given market conditions.

20. The same finding is reinforced by the fact that PPC asked for its allowed revenues per customer category for 2012 to be higher than the ones suggested by RAE and higher than the ones finally approved.
21. The decision of the Ministry of Environment, Energy and Climate Change to approve allowed PPC revenues per customer category for 2012 that were not following the suggestion of RAE but were adjusting it downwards, demonstrates the fact that political forces are using PPC as an income redistribution instrument. This also suggests that political agendas might be prioritizing social concerns over the sustainability of the electricity supply market.
22. The magnitude of the effect of the strike organized by the PPC Union demonstrated the importance of the current position of PPC for the market operation as well as the fragility of the market to external shocks.
23. The effect of taxation on domestic natural gas prices was demonstrated, highlighting the strong correlation between fossil fuel prices and wholesale electricity prices. The large risks involved for any electricity supplier could be mitigated by the introduction of a retail price adjustment mechanism connected either with a fuel prices index or with the wholesale electricity prices directly.

6.3 Lessons learned

With regards to the Greek policymakers and their effort to proceed with the liberalization of the Greek electricity market, the lessons learned from this thesis are centred around six key points. These are:

- Proceeding with liberalization requires a strong political preference in favour of the market reform and in support of the removal of any obstacles that are halting liberalization.
- Asymmetric regulation should be used with caution as a regulatory instrument.

- In retail electricity supply markets that are regulated through the use of price-caps (or tariffs), the level of these price caps is crucial as it determines the ability of the suppliers to make profits in each of these markets. That mean that retail price-caps or tariffs determine the attractiveness of the markets for potential new entry.

- The introduction of competition in electricity supply markets that bear the characteristics of the Greek case leads to tariff adjustments that are directed towards eliminating cross-subsidizations between customer categories.

- Wholesale electricity prices in Greece seem to be strongly related to natural gas and oil prices. Given the analysis presented in Chapter 3 for the ability of electricity supply markets to make profits for various cost levels and price caps, we understand that international fuel price volatility could bring these market in a very difficult position financially. This issue can be addressed by the introduction of fuel clauses in retail tariffs, allowing for increases in fuel prices to be transferred to the final consumers.

- Also, wholesale electricity prices in Greece seem to peak during specific hours of the day where electricity demand is very high, leaving retail suppliers in the position of having to serve the markets on unprofitable terms for some dispatch periods (as seen in Chapter 3). A solution to this issue could come from the use of time-varying tariffs (which also require that customers have smart meters installed) which can have a double effect: they make customers move their electricity consuming activities to the zones of lower tariffs; and the customers that consume electricity during the "high demand" periods pay higher prices for that electricity to the suppliers.

The need for the political will to proceed with the market reform appears to be the most crucial of the lessons learned. Without commitment to the reform from policymakers, the expected market outcomes might not emerge. In a setting like the Greek one, fundamental issues inherited from the past can have a significantly large impact and therefore policymakers should plan and prepare for these to arise.

When policymakers implement policies in the future, they should learn from the experiences in the past. In particular, they should not encourage new entry which will end in financial failure. Tighter controls in both the operational and the financial dimensions should be imposed on the markets and the firms that participate in these markets. That is because when asymmetries are being introduced to potentially accommodate new entrants in electricity supply, then a form of short-run protectionism is introduced which, when removed, could result in these new entrants being unable to remain in the market.

To help towards the stable operation of electricity markets that face the introduction of competition, a very important element is the existence of transparency across the whole electricity sector. This transparency aims to decrease the concerns of potential investors and thereby encourage them to enter the market. If policymakers wish to create liberalized electricity markets that appear attractive to new investors, all rules, all arrangements, all firms, all transactions, all retail tariffs and all charges applied to firms should be known to all parties. Being open and sharing all this information with market participants, as well as having publicly known plans on future policies which are consistently put into practice, facilitates market operation. That comes as a result of the combination of enhanced trust in these markets and of the ability of potential new entrants or of already existing suppliers to identify reliably the full benefits that they can have from entering and/or supplying any given market.

These “lessons learned” that are identified in this section can also be applied to other countries that have similar characteristics to Greece and which plan to introduce reforms in their electricity sector. In this way, these experiences are turned into transferable knowledge that can be employed in various settings, including the application to other network utilities.

6.4 Future research

Further research in the area could examine more closely the interactions between the electricity generation and supply market. That could be done through the use of a model that describes the full electricity sector and which incorporates competition which is developed in electricity generation but very limited in retail electricity supply.

Further research can apply econometric techniques on the data that were used in this thesis. By doing so, a better establishment of the relationships between the figures that we presented could be achieved, by disentangling the effect that the each of the various factors has on the market.

Also, the relationship between temperatures and system load can be examined again incorporating year-to-year trends in the annual temperature profile that we used or even actual daily average temperatures. The incorporation of heating degree days and cooling degree days could also add some insight to the effect that temperature has on electricity demand and system load.

Additionally, a large scale simulation of the supply market could be drawn. This could be incorporating the actual retail tariffs used by all the market participants, the percentages on the market shares of each participant, the system load profiles for each given day and the corresponding average wholesale electricity prices for specific years. That would be leading to production of estimates of profitability of each individual category and would allow us to use comparative statics to estimate the ability of each participant to compete on prices.

Research can also be done in examining the bidding behaviour of the participants in the wholesale pool, in order to determine the amount of market power that they have as well as the specific circumstances that allow for this market power to be put into use.

Further research could also examine the effect that the different governments have in the market operation, meaning how much these affect market outcomes. That means that research on Energy Policy issues could focus on the impact that political decisions have on the electricity market. Also, the effect that the different governments that have been in office had produced during the time period that we examine, can be examined using the timeline of the values for System Load, SMP and DMP. That could be done using dummy variables for periods that correspond to different governments in office.

6.5 Limitations of the Study

Although every possible effort has been made to make this research as up-to-date as possible, it could be that this effort has been hindered by the fact that some information sources were less up-to-date than others.

Also, given that a desk analysis approach was selected, the accuracy of the qualitative and quantitative inputs that were used is definitely a factor that could have hindered the results produced. That also applies for the availability of certain parts of information.

In order to present the data, we elected to use a descriptive approach. Other approaches that would incorporate statistical analysis and econometric techniques were also amongst the possibilities, which could potentially have established more robust and more explanatory relationships between the different datasets. Nevertheless, the lack of data and the difficulty in isolating the effect of each of the variables individually has directed the research to the use of descriptive methods.

6.6 Epilogue

The process of reforming an electricity market has been shown by experience to be a long one. The presence of peculiarities in the structure of the economic and political system in Greece coupled with the adversity of the economic conditions faced by the country during a critical phase of the reform effort seem to have affected the outcome of this reform effort. Nonetheless, progress is being made and the liberalization of the Greek electricity industry is progressing.

A large number of structural changes seem to be necessary in order for the Greek economy to be able to recovery from the financial recession that it faces since the end of 2009/start of 2010. The introduction of competition in the Greek electricity market could be beneficial in promoting efficiency improvements and delivering increased consumer surpluses and increased welfare. The removal of cross-subsidizations and distortions from all sections of the market (excluding PSOs and potentially RES) and the introduction of flexible tariff mechanisms, such as zonal charges for all customers, combined with an environment of increased competition and with market monitoring for anti-competitive practices, could result in the supply of electricity that fully reflects its costs to all customers.

However, ambiguity reflecting the different interests at the political level is present. It remains to be seen how the market will progress in the future.

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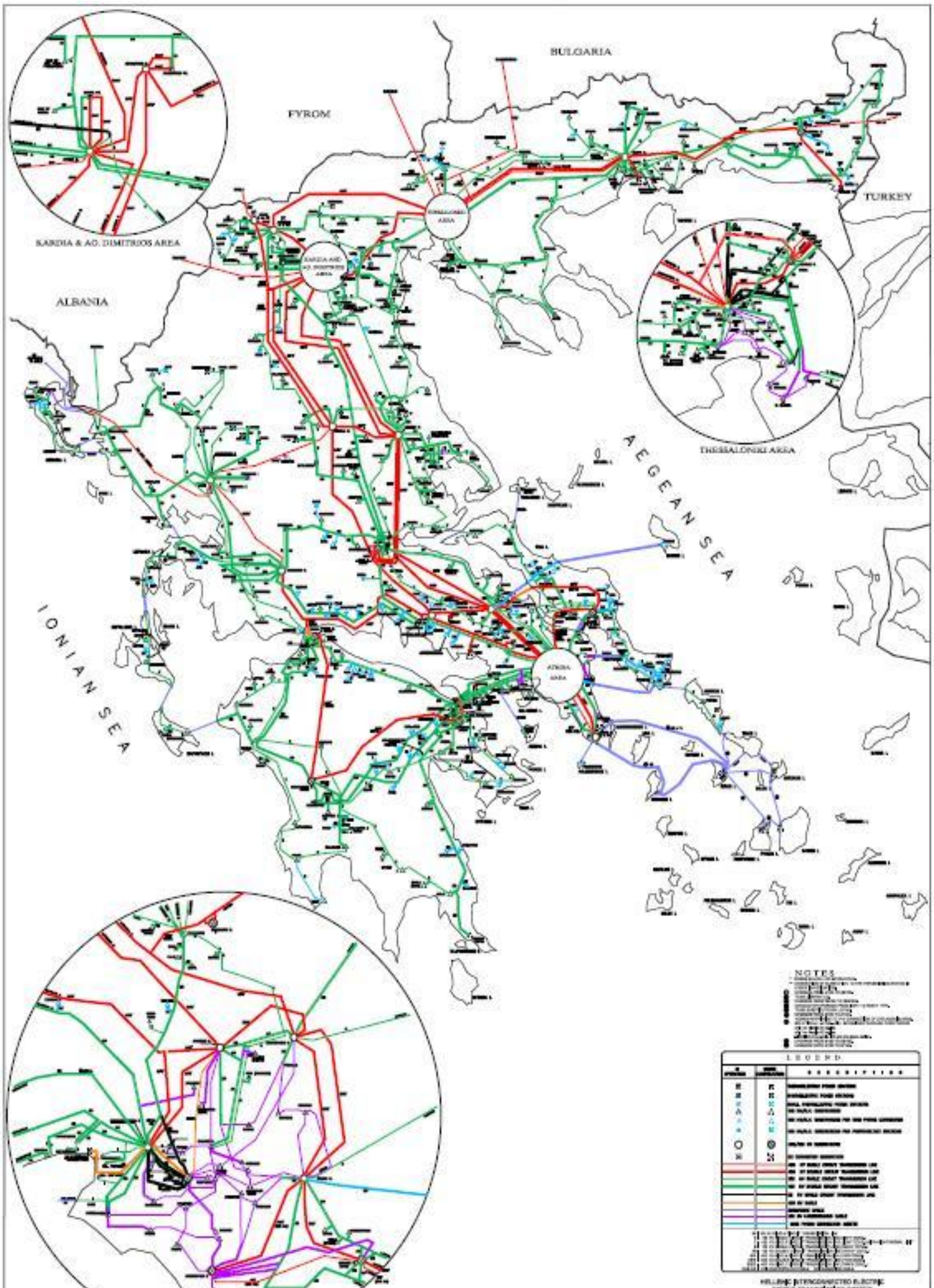
Appendix A

Part 1

Map of the Greek Electricity Transmission System [HTSO, 2010a]

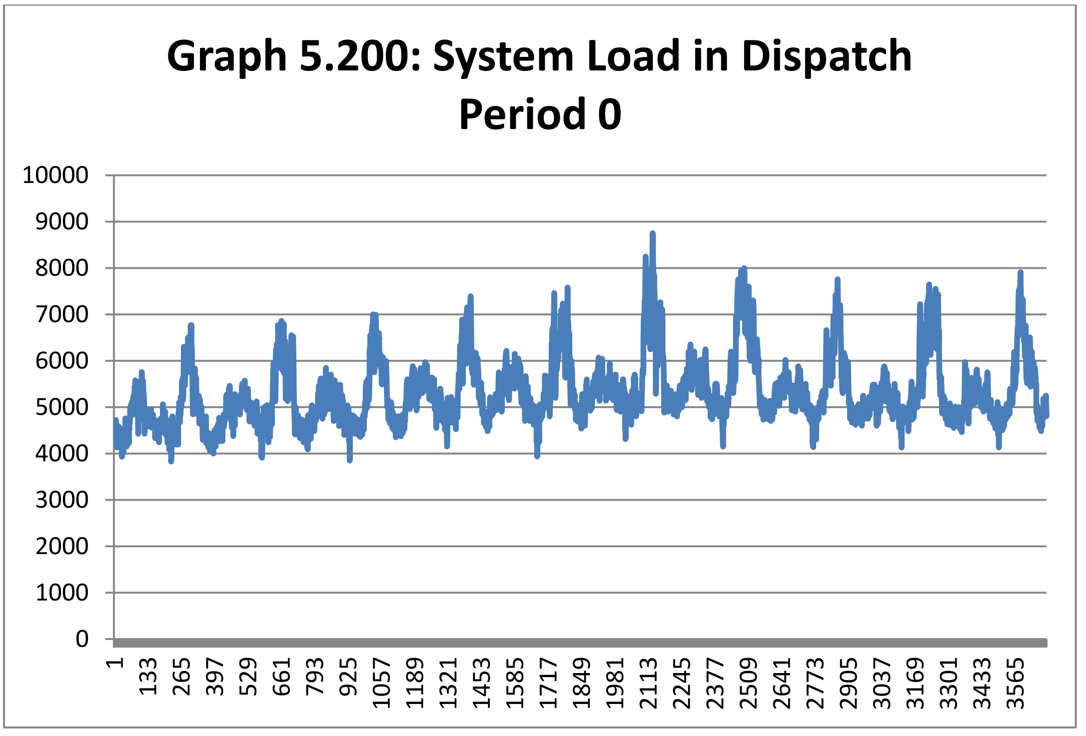
Hellenic Transmission System Operator (HTSO), (2010a), “Hellenic Interconnected Electric Power Transmission System 2010-2014”, 11/06/2010, Available at: http://www.desmie.gr/fileadmin/user_upload/Files/masm/masm2010_2014_Eng.pdf , Accessed 28/05/2012.

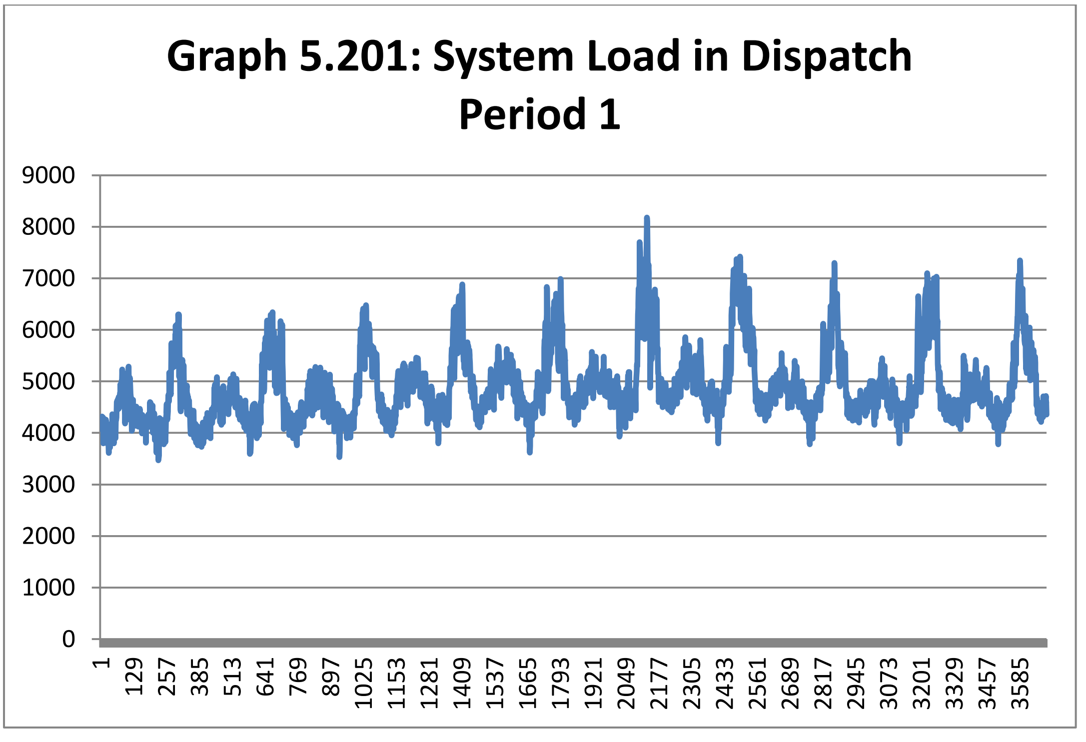

BULGARIA
FYROM
TURKEY
ALBANIA
KARDIA & AG. DIMITRIOS AREA
THESSALONIKI AREA
AEGEAN SEA
IONIAN SEA
ATHINA AREA
NOTES
LEGEND

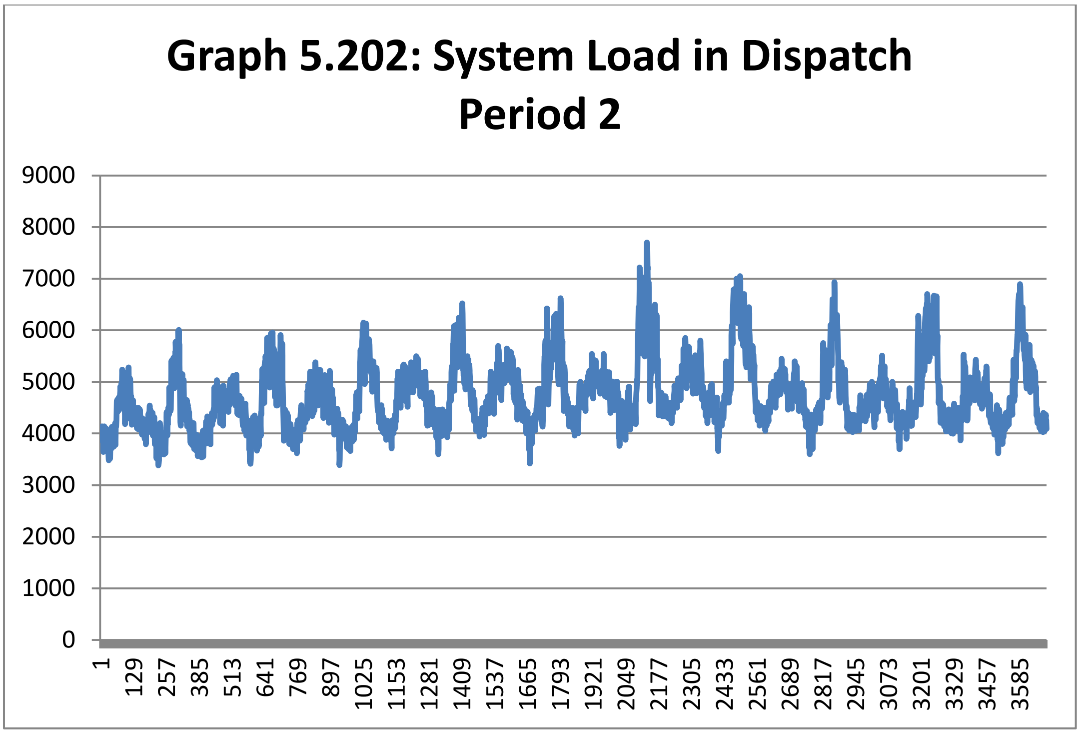
Appendix B

Part 1

System Load Data are presented in this part.






Graph 5.202: System Load in Dispatch Period 2
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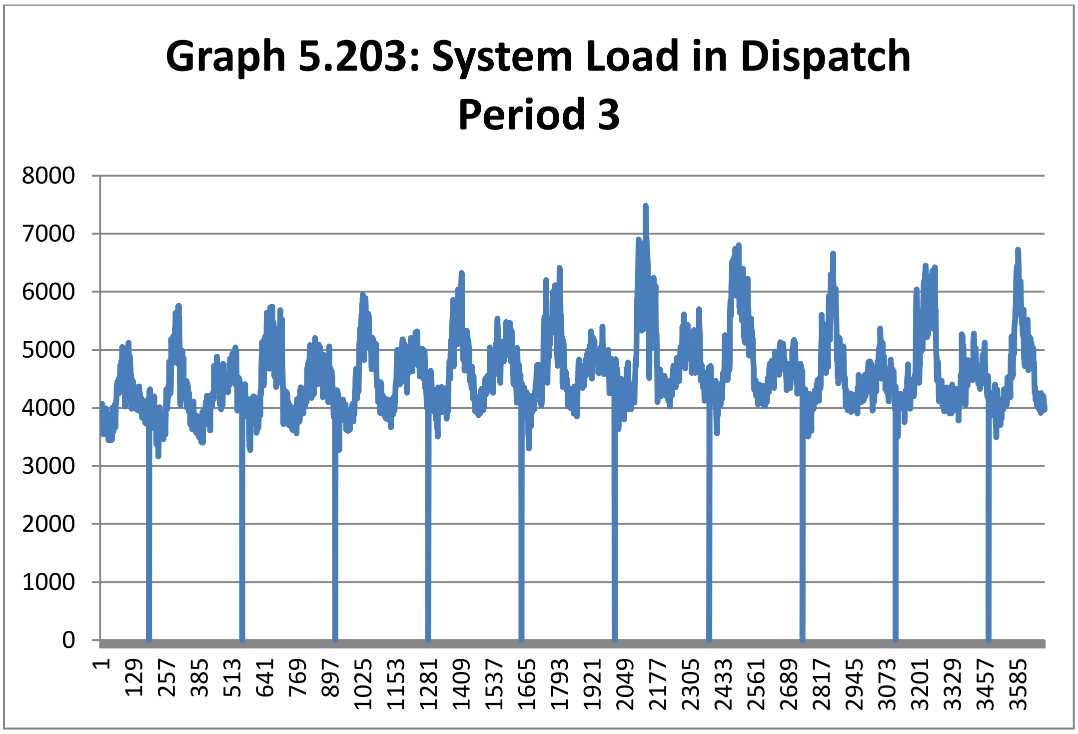
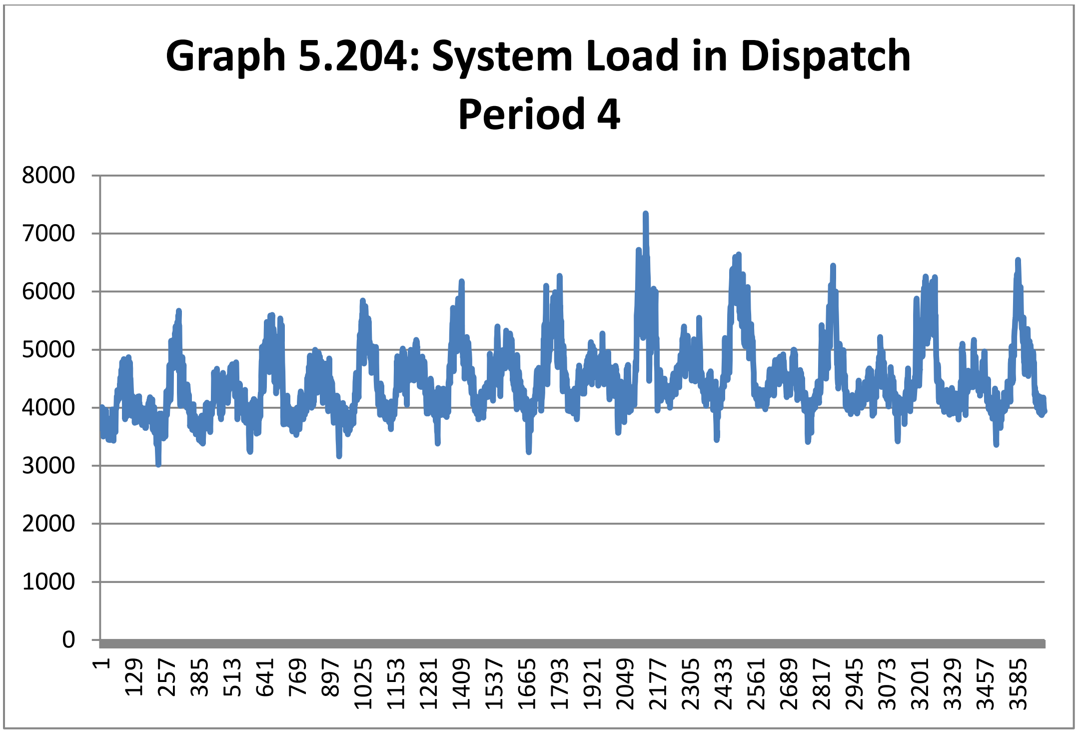
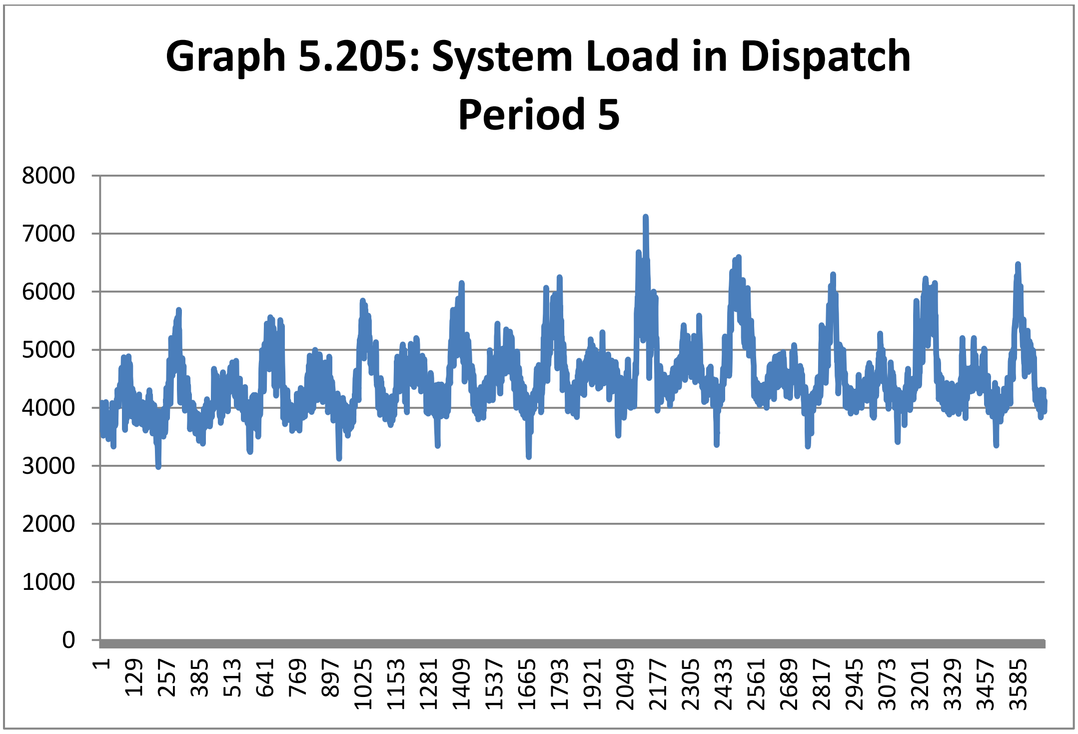
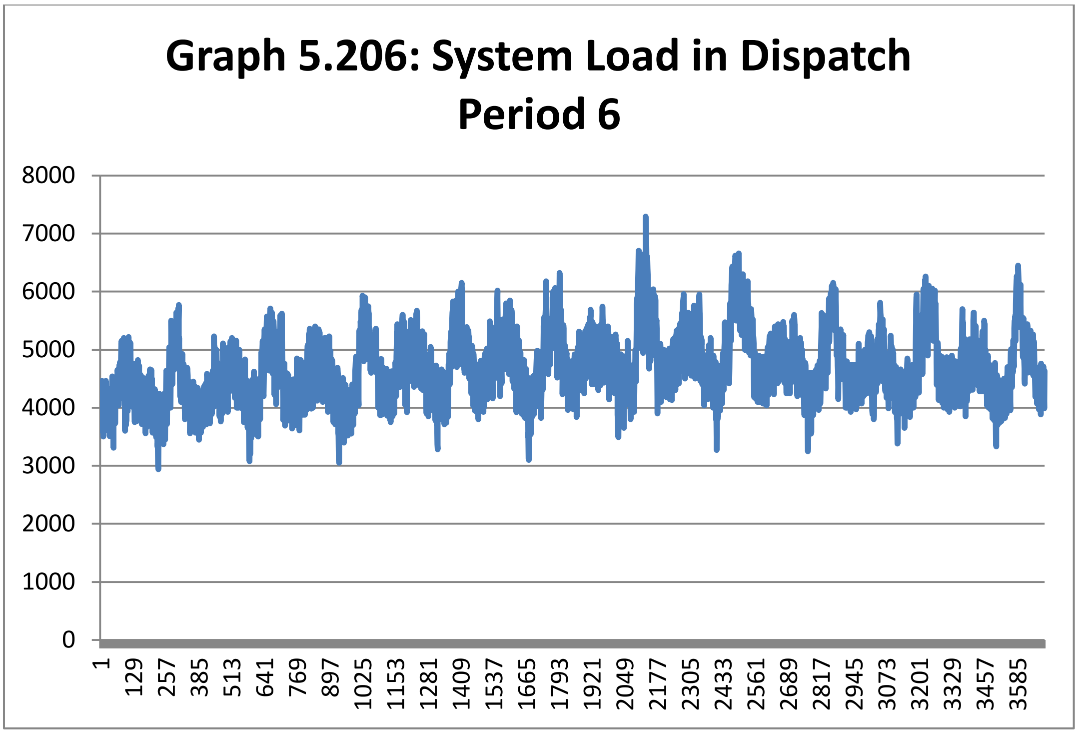
8000
7000
6000
5000
4000
3000
2000
1000
0
1
129
257
385
513
641
769
897
1025
1153
1281
1409
1537
1665
1793
1921
2049
2177
2305
2433
2561
2689
2817
2945
3073
3201
3329
3457
3585

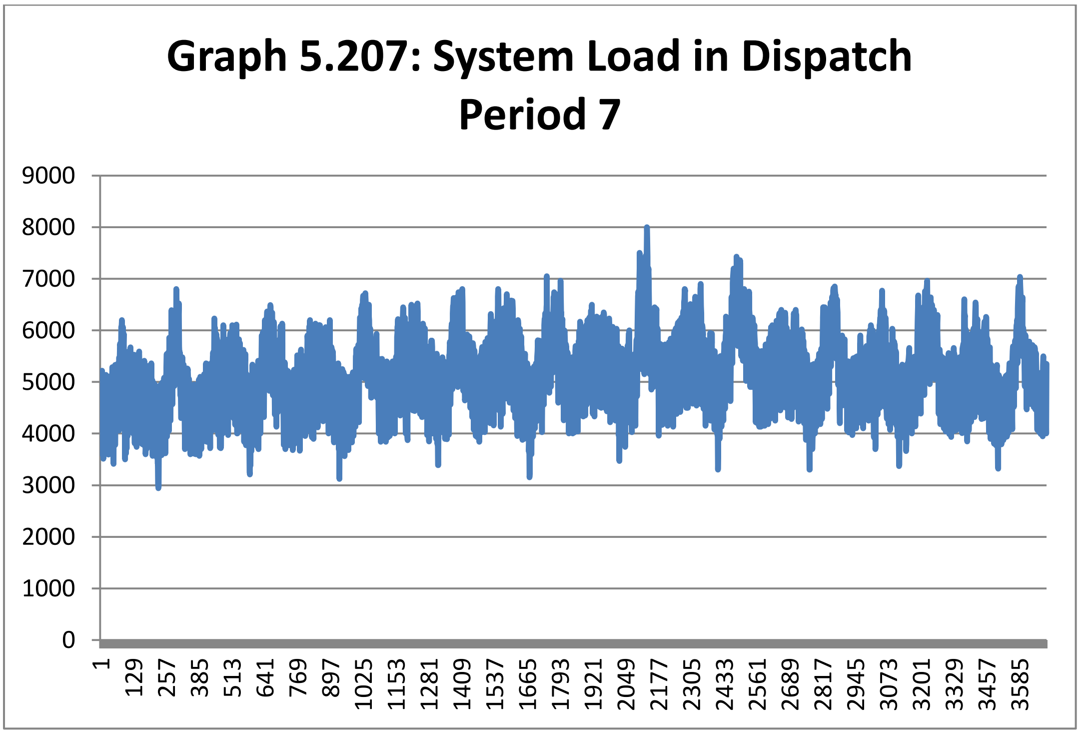

Graph 5.203: System Load in Dispatch Period 3
8000
7000
6000
5000
4000
3000
2000
1000
0
1
129
257
385
513
641
769
897
1025
1153
1281
1409
1537
1665
1793
1921
2049
2177
2305
2433
2561
2689
2817
2945
3073
3201
3329
3457
3585


Graph 5.204: System Load in Dispatch Period 4
8000
7000
6000
5000
4000
3000
2000
1000
0
1
129
257
385
513
641
769
897
1025
1153
1281
1409
1537
1665
1793
1921
2049
2177
2305
2433
2561
2689
2817
2945
3073
3201
3329
3457
3585

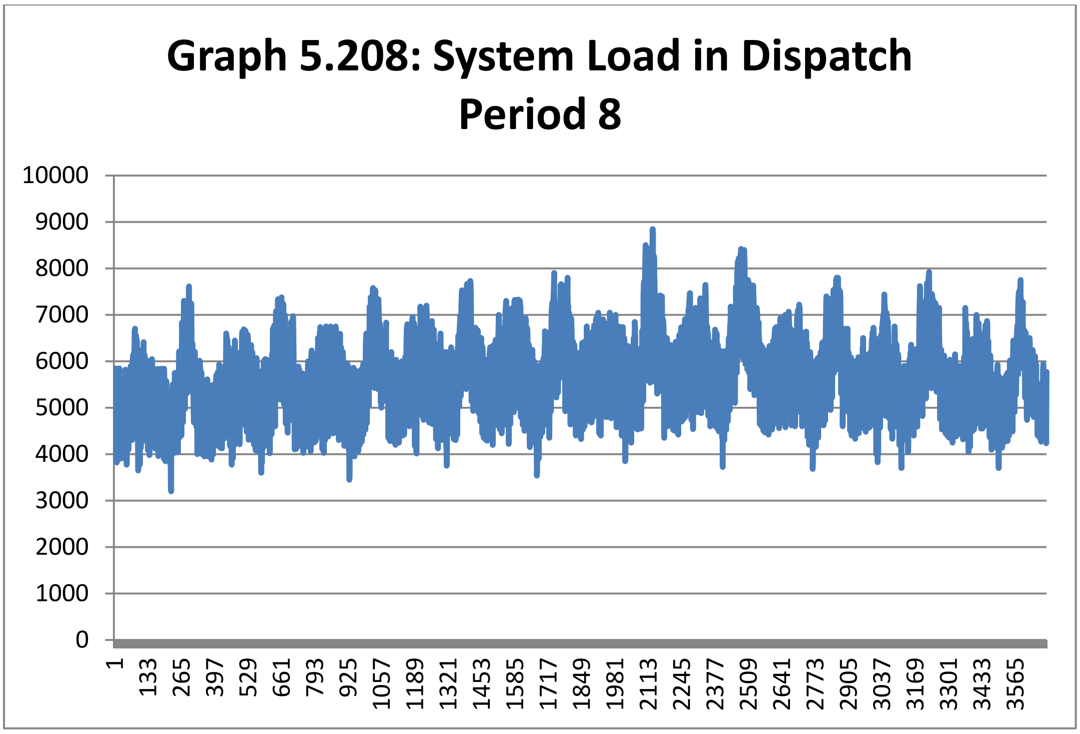

Graph 5.205: System Load in Dispatch Period 5
8000
7000
6000
5000
4000
3000
2000
1000
0
1
129
257
385
513
641
769
897
1025
1153
1281
1409
1537
1665
1793
1921
2049
2177
2305
2433
2561
2689
2817
2945
3073
3201
3329
3457
3585

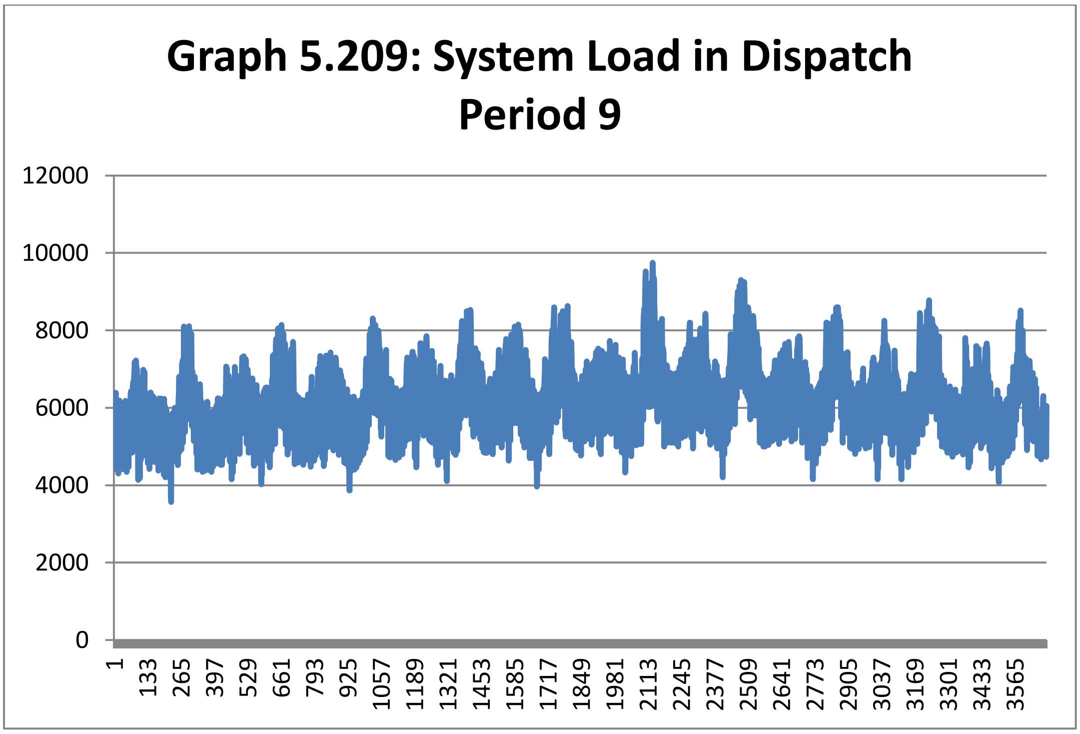


Graph 5.206: System Load in Dispatch Period 6
8000
7000
6000
5000
4000
3000
2000
1000
0
1
129
257
385
513
641
769
897
1025
1153
1281
1409
1537
1665
1793
1921
2049
2177
2305
2433
2561
2689
2817
2945
3073
3201
3329
3457
3585

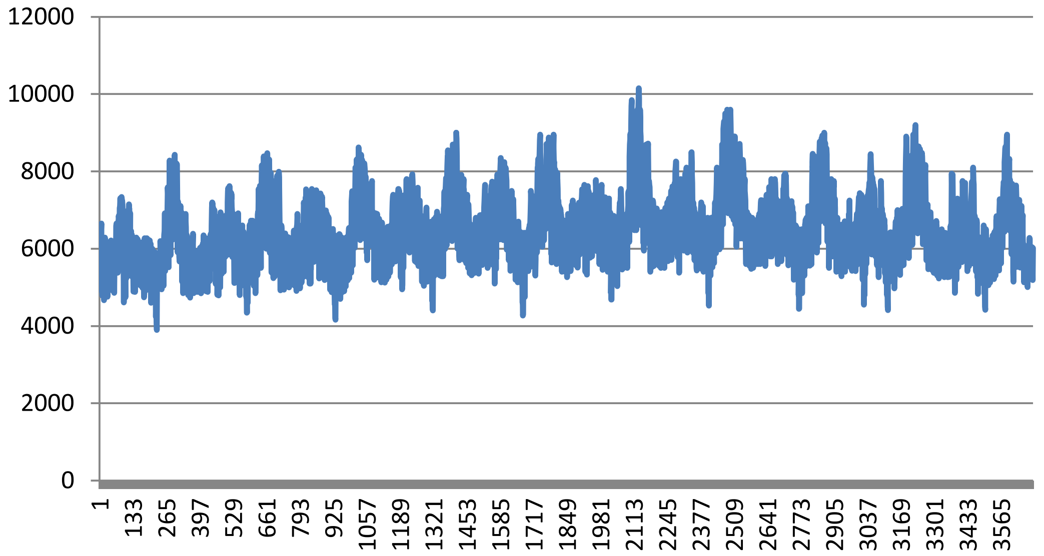


Graph 5.207: System Load in Dispatch Period 7
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
1
129
257
385
513
641
769
897
1025
1153
1281
1409
1537
1665
1793
1921
2049
2177
2305
2433
2561
2689
2817
2945
3073
3201
3329
3457
3585

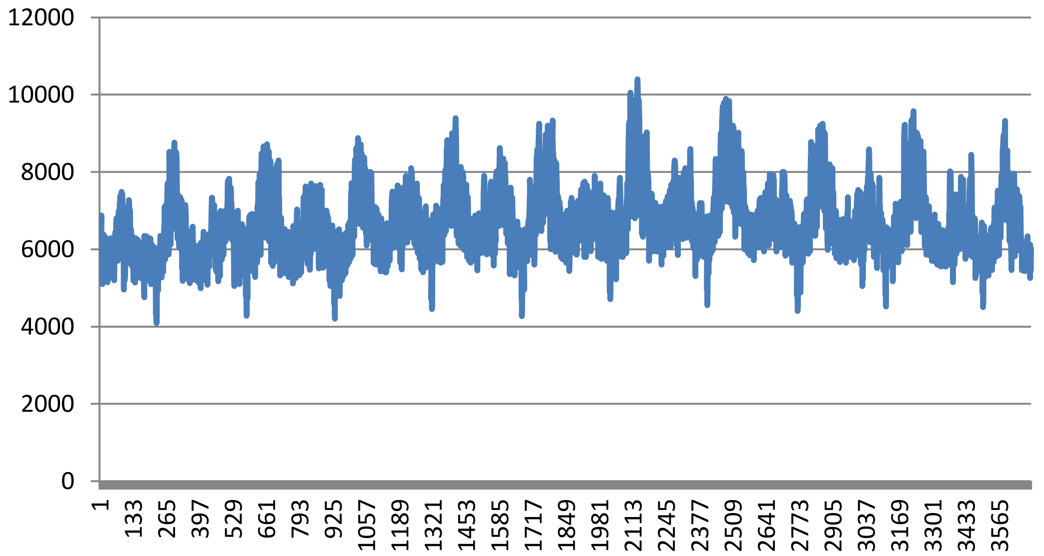

Graph 5.208: System Load in Dispatch Period 8
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

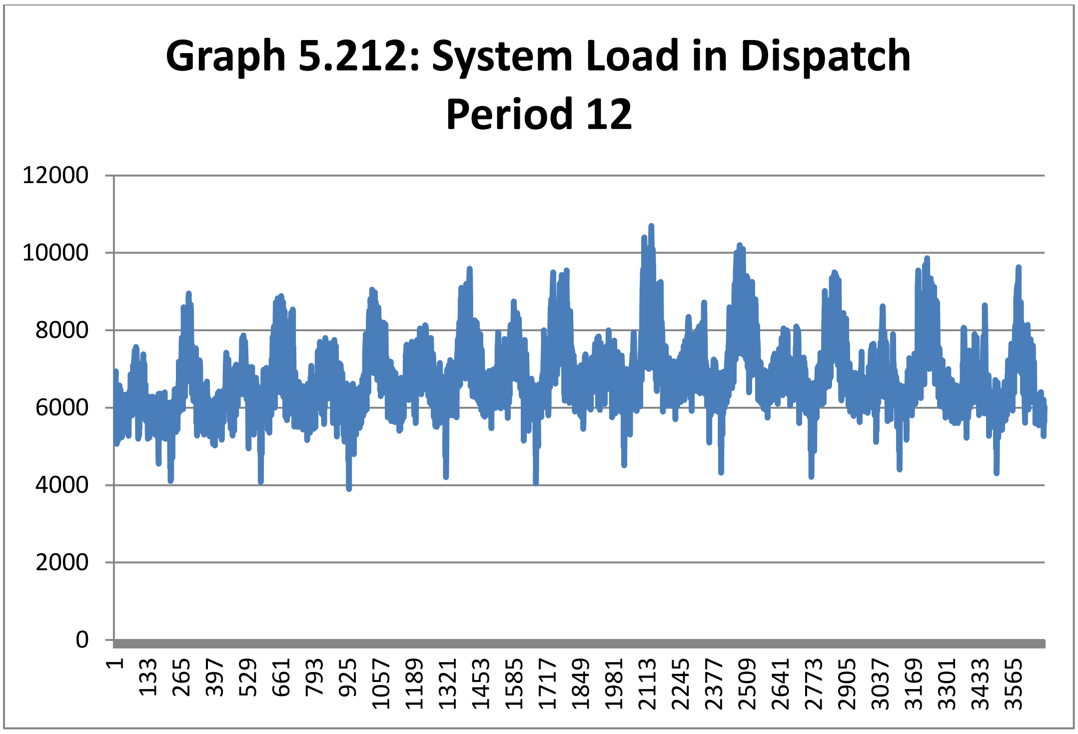

Graph 5.209: System Load in Dispatch Period 9
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

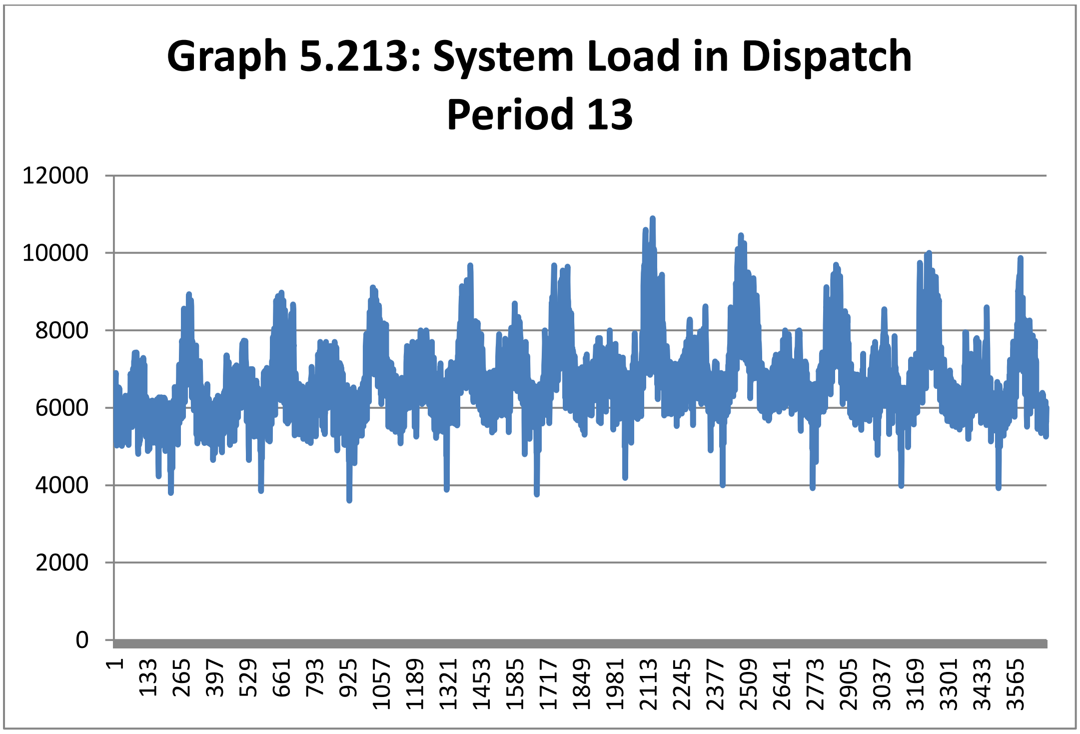
Graph 5.210: System Load in Dispatch Period 10



Graph 5.211: System Load in Dispatch Period 11




Graph 5.212: System Load in Dispatch Period 12
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565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12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
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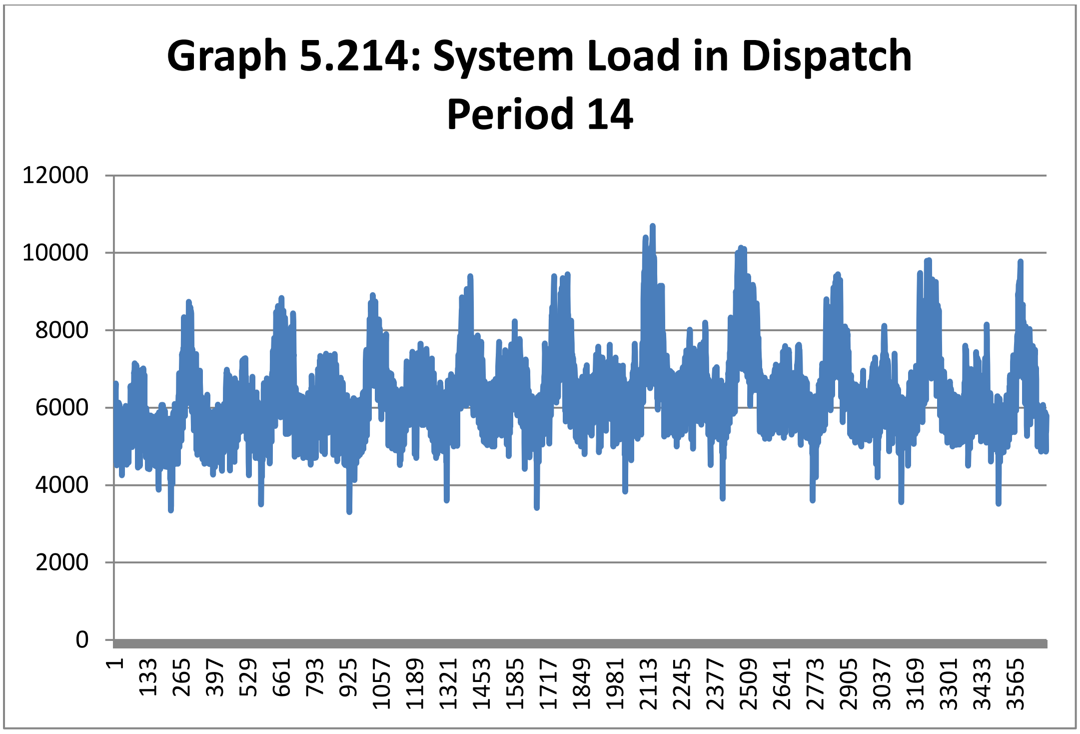
Graph 5.214: System Load in Dispatch Period 14
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
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2113
2245
2377
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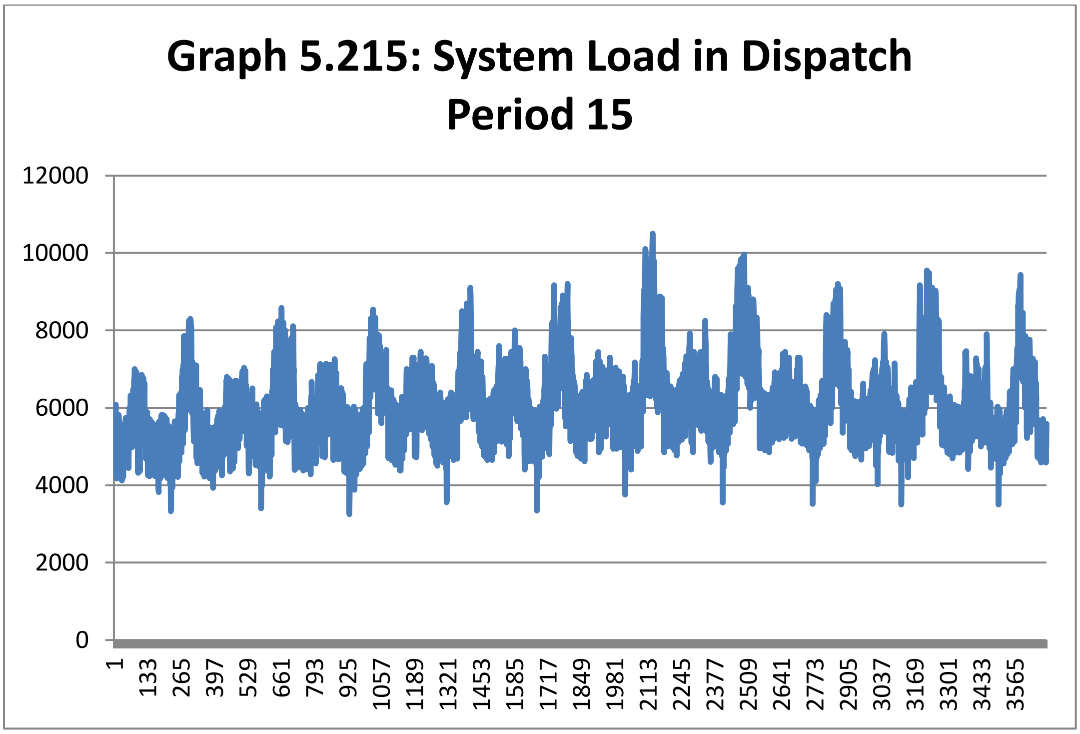
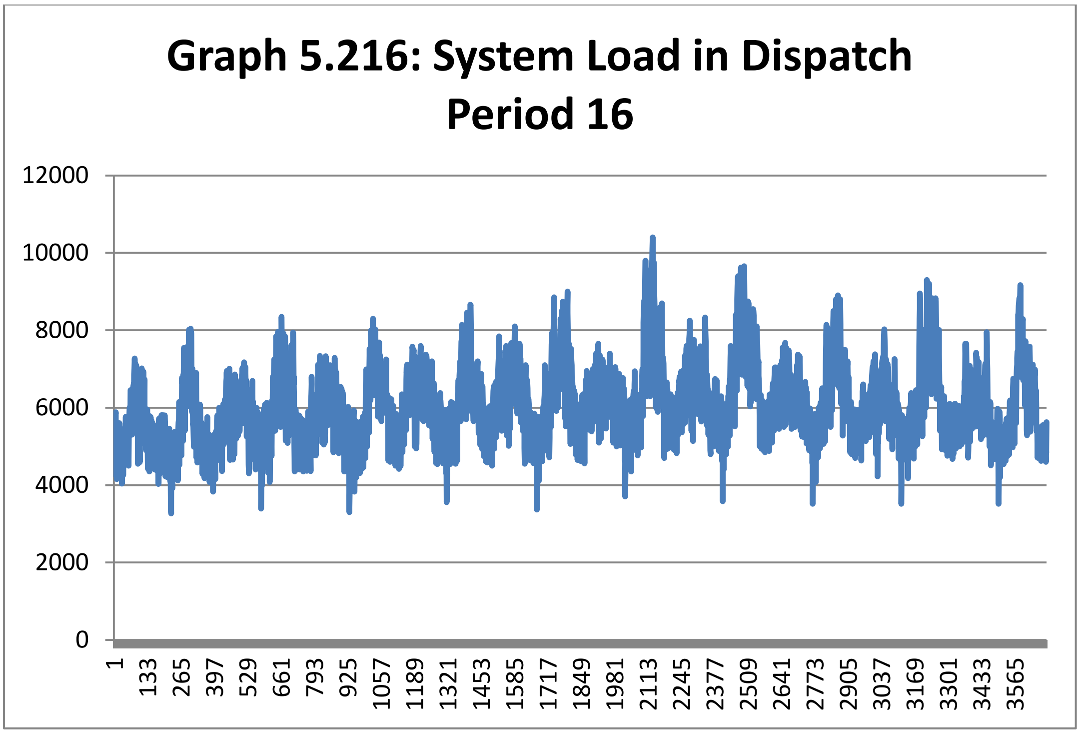
2905
3037
3169
3301
3433
3565


Graph 5.215: System Load in Dispatch Period 15
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.216: System Load in Dispatch Period 16
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
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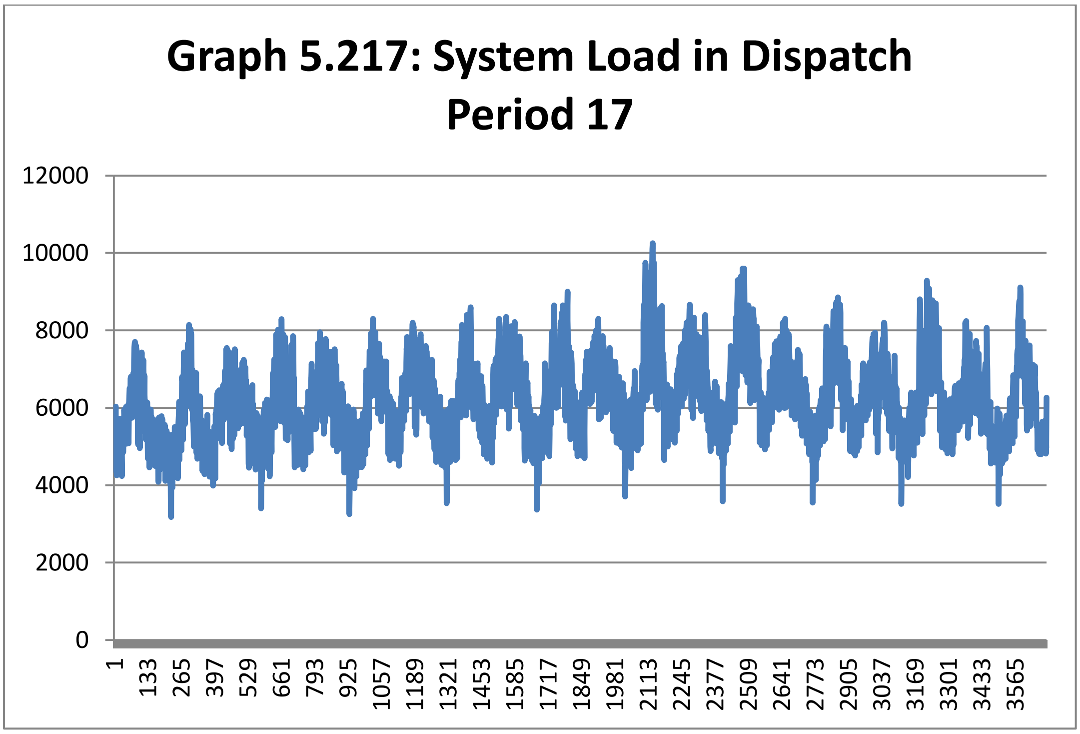
Graph 5.217: System Load in Dispatch Period 17
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
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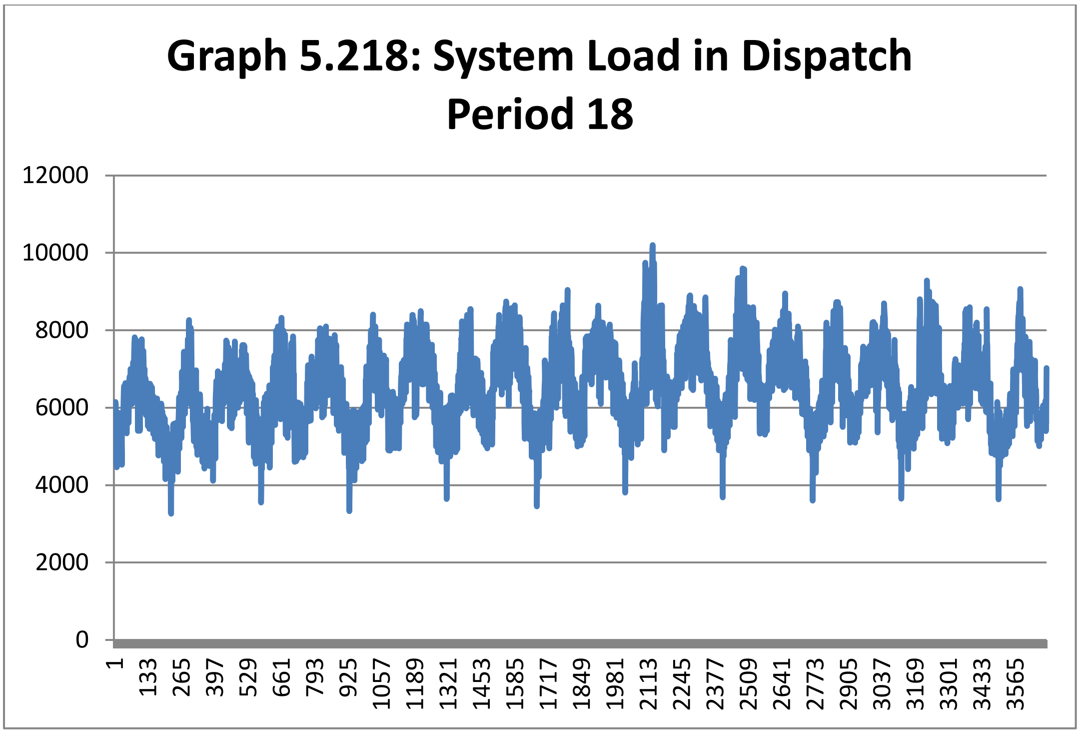
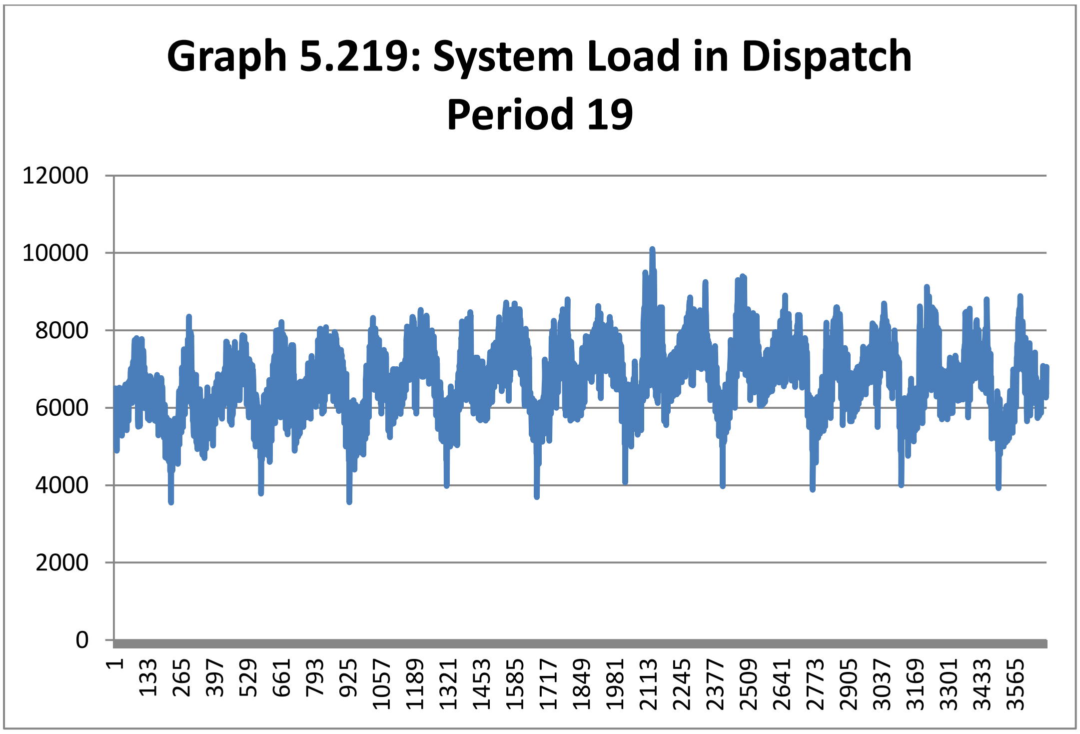
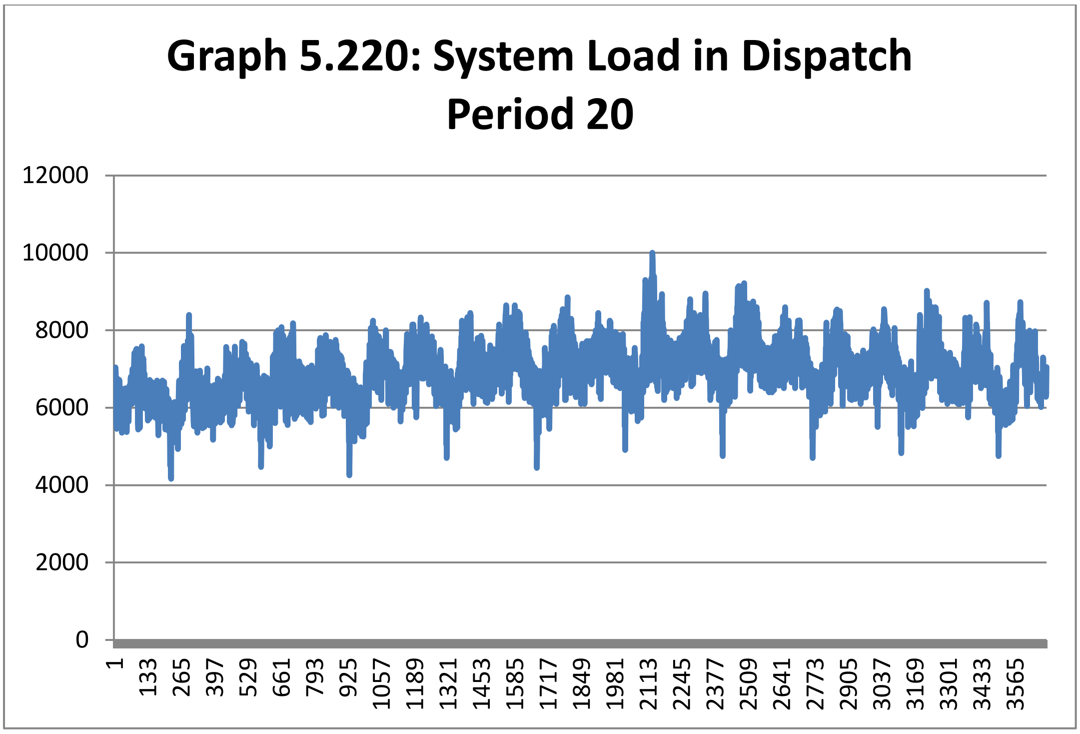
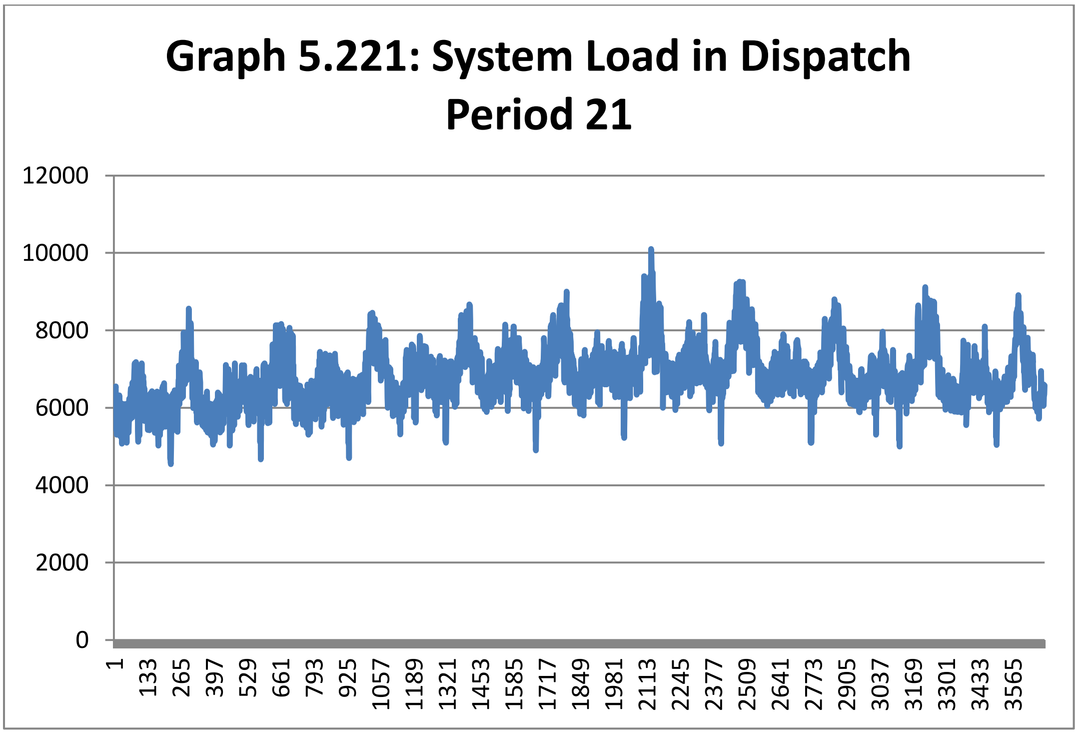
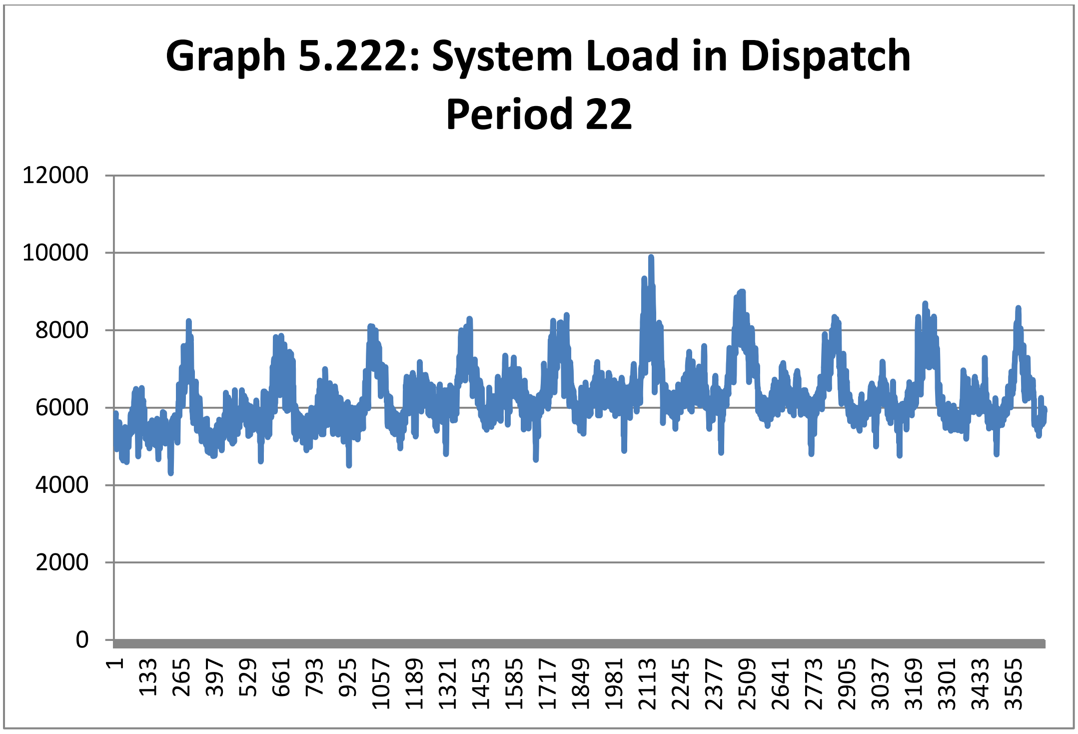
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.218: System Load in Dispatch Period 18
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.219: System Load in Dispatch Period 19
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.220: System Load in Dispatch Period 20
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.221: System Load in Dispatch Period 21
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.222: System Load in Dispatch Period 22
12000
10000
8000
6000
4000
2000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
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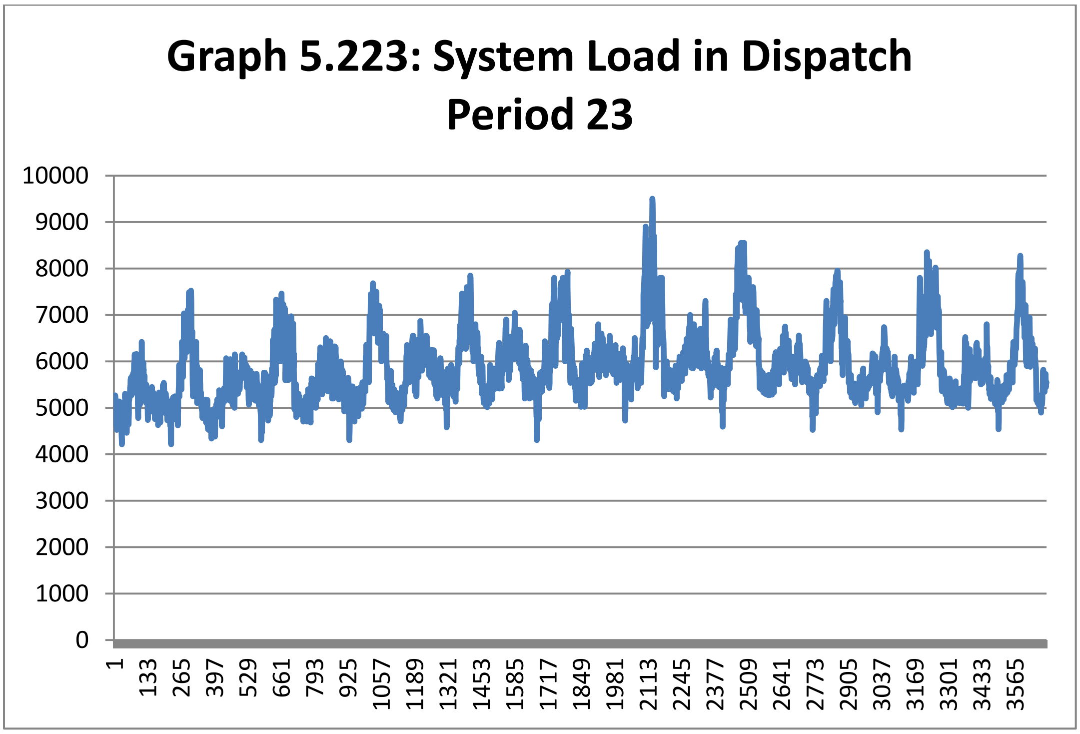
Graph 5.223: System Load in Dispatch Period 23
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
1
133
265
397
529
661
793
925
1057
1189
1321
1453
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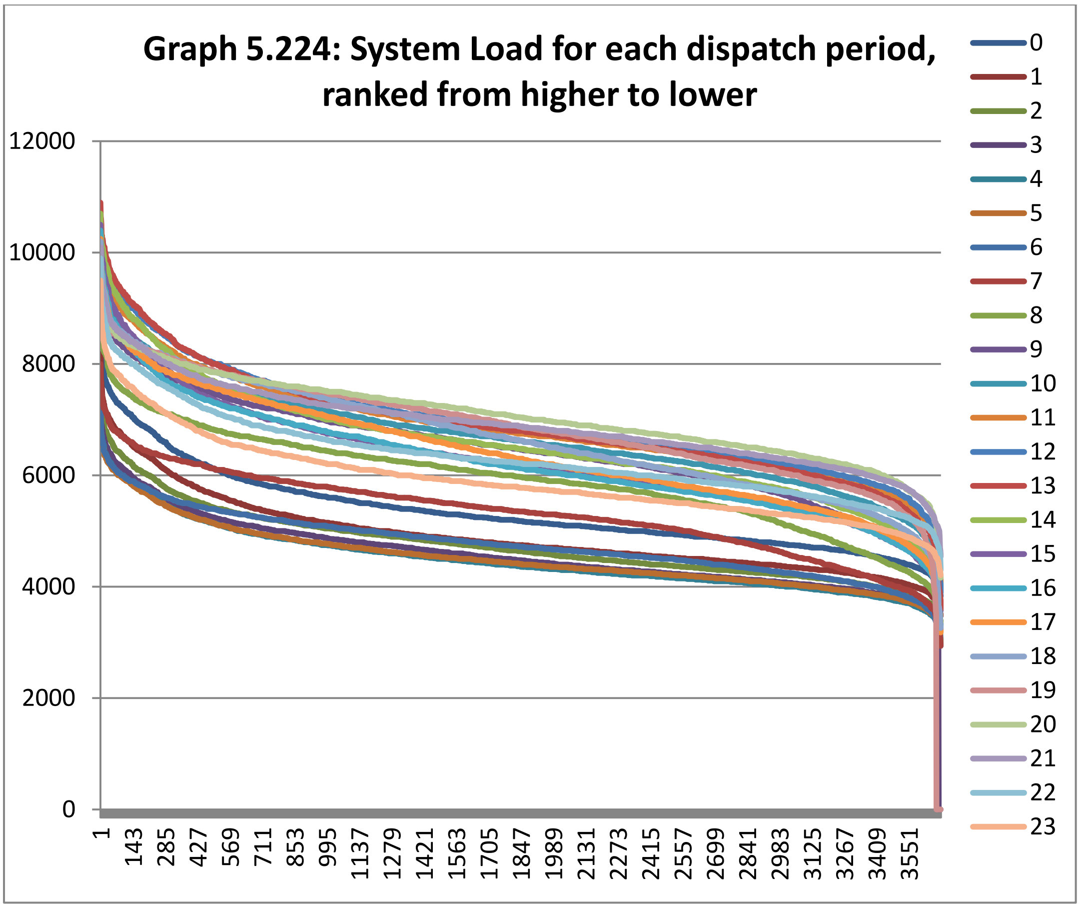
3301
3433
3565



Graph 5.224: System Load for each dispatch period, ranked from higher to lower
12000
10000
8000
6000
4000
2000
0
1
143
285
427
569
711
853
995
1137
1279
1421
1563
1705
1847
1989
2131
2273
2415
2557
2699
2841
2983
3125
3267
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2
3
4
5
6
7
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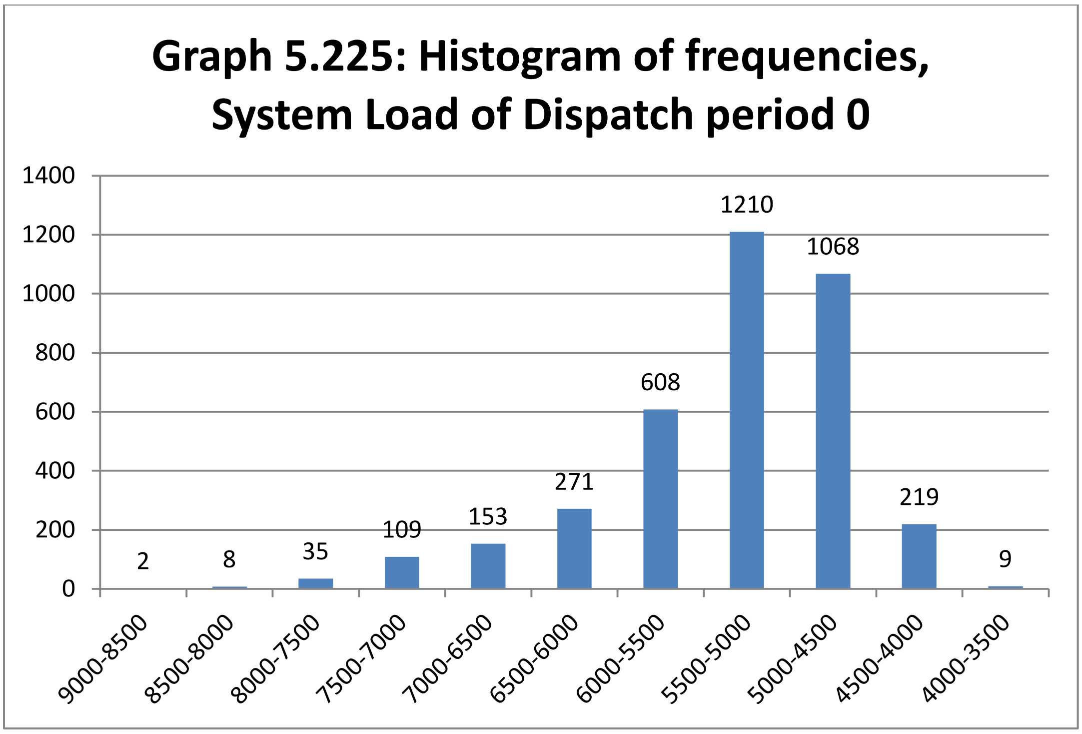
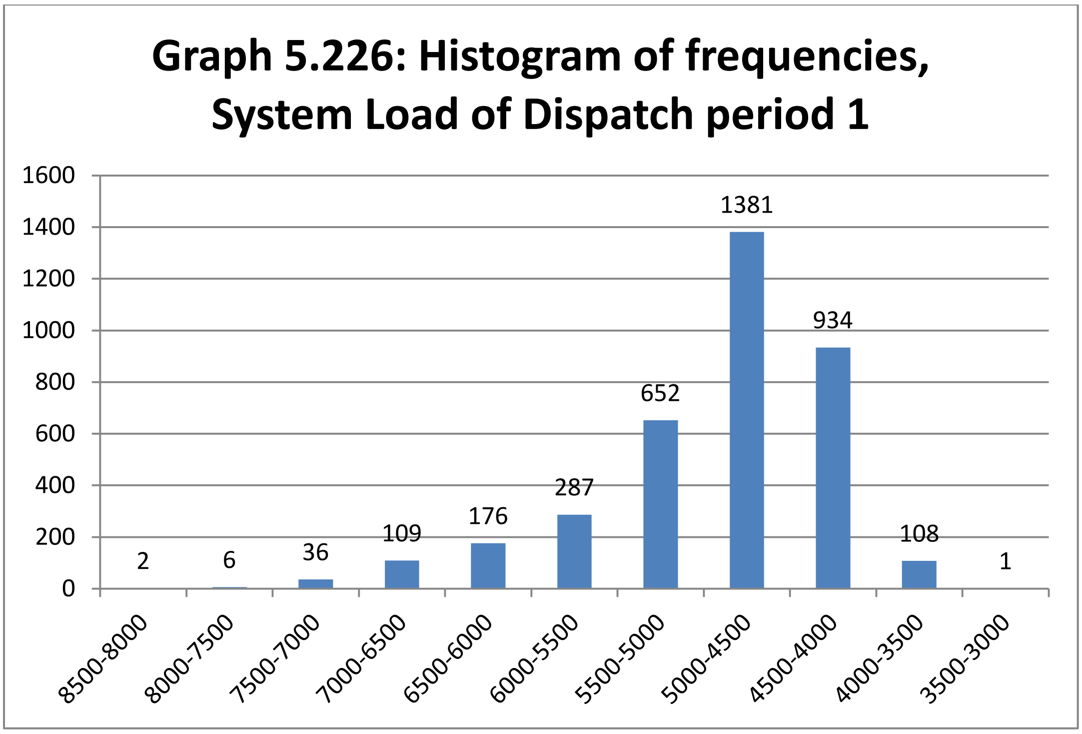
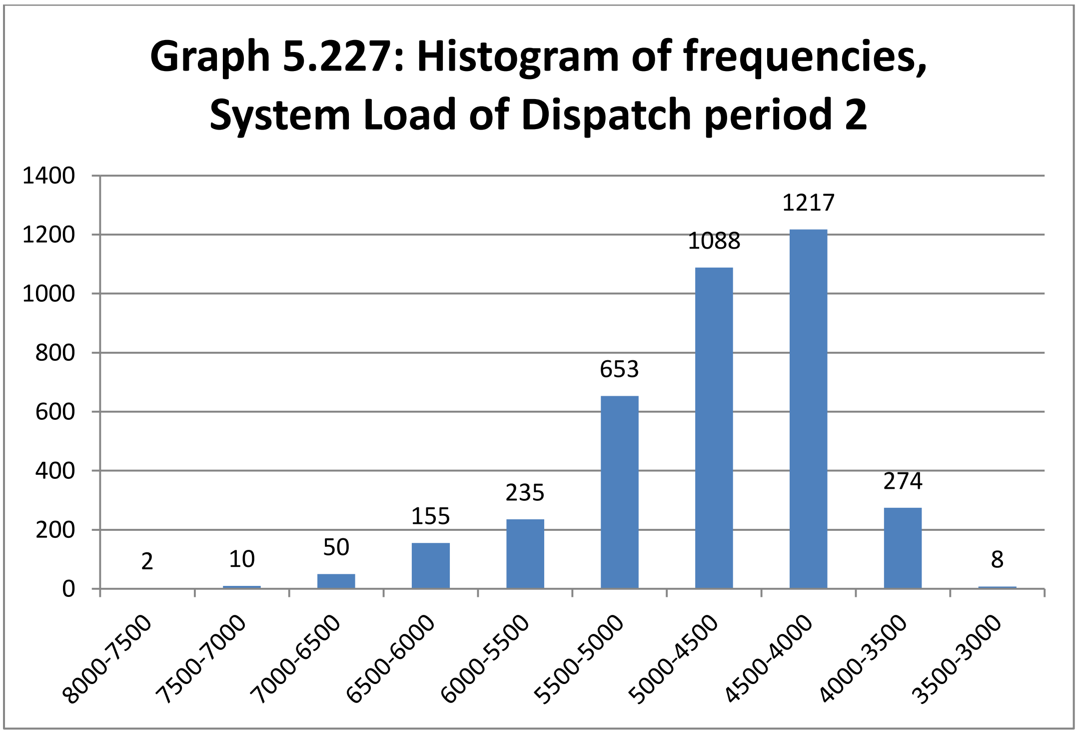
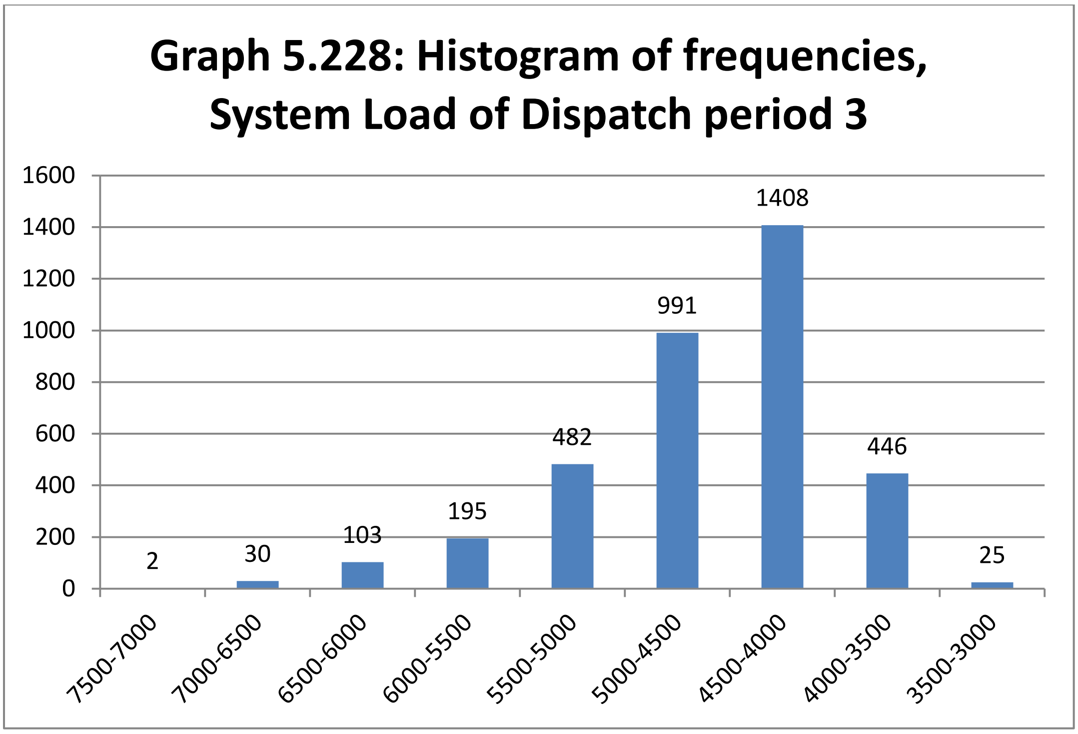
22
23

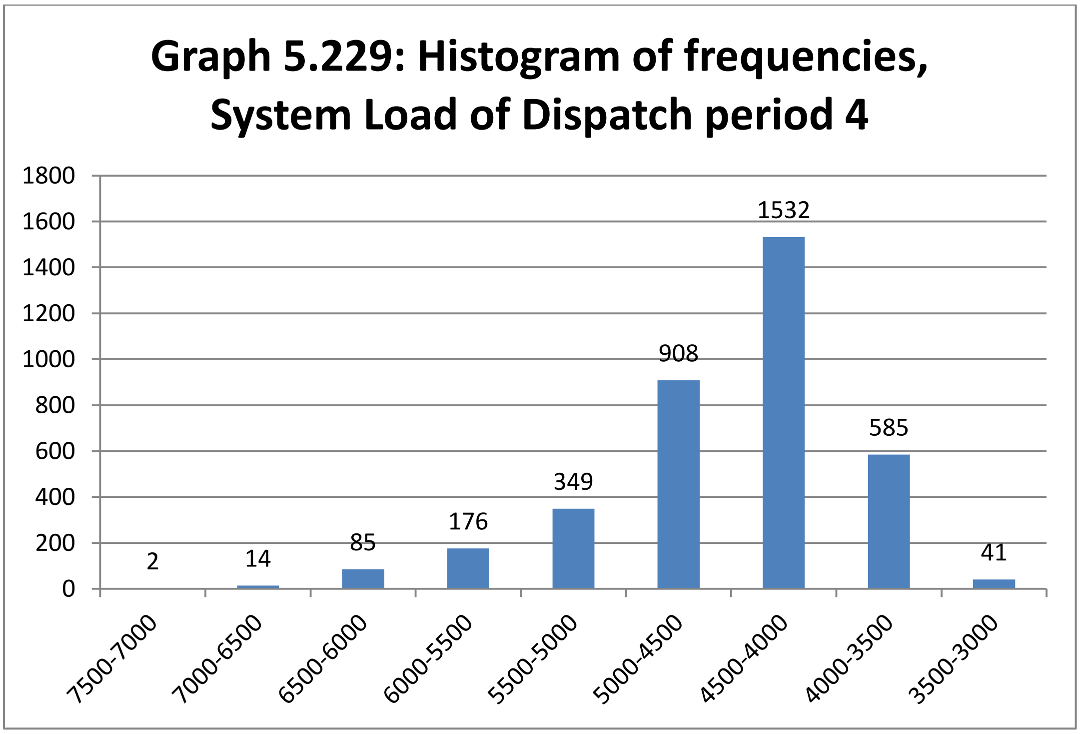


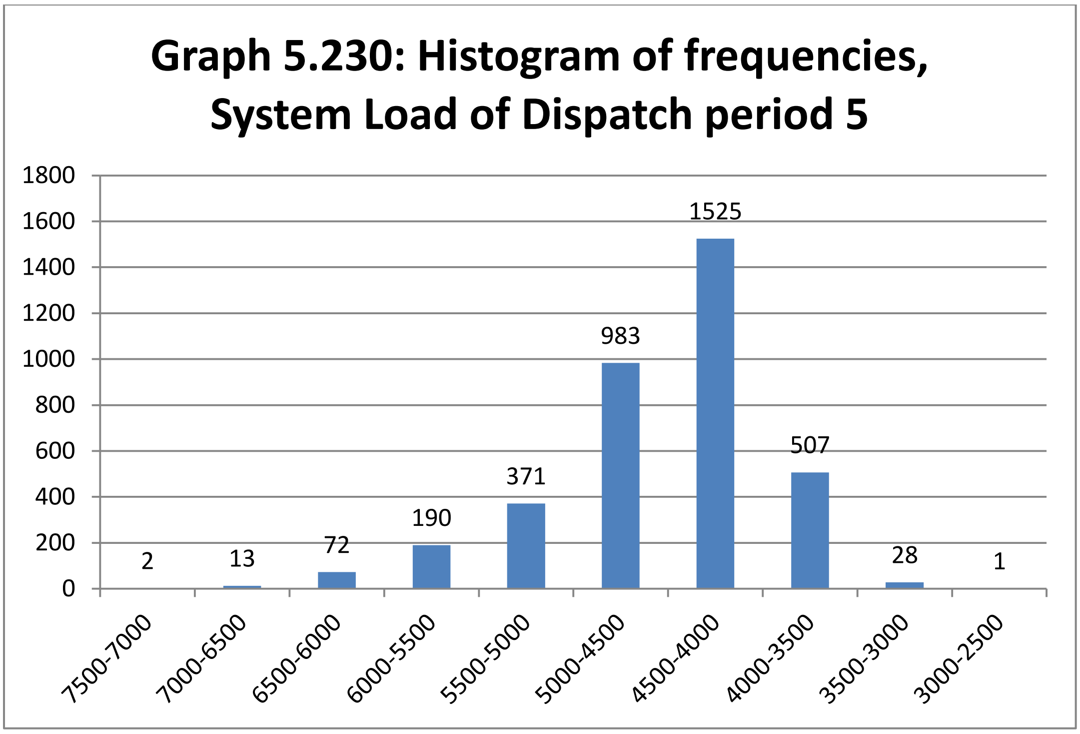
Graph 5.225: Histogram of frequencies, System Load of Dispatch period 0
1400
1200
1000
800
600
400
200
0
2
8
35
109
153
271
608
1210
1068
219
9
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500

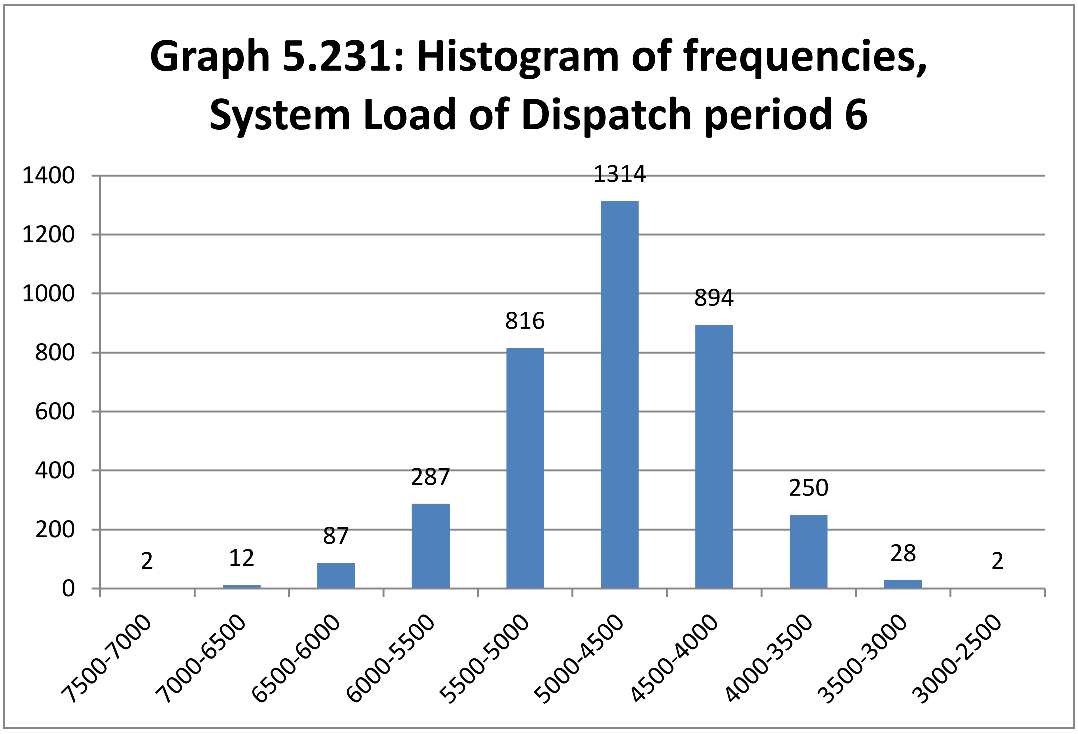

Graph 5.226: Histogram of frequencies,
System Load of Dispatch period 1
1600
1400
1200
1000
800
600
400
200
0
2
6
36
109
176
287
652
1381
934
108
1
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

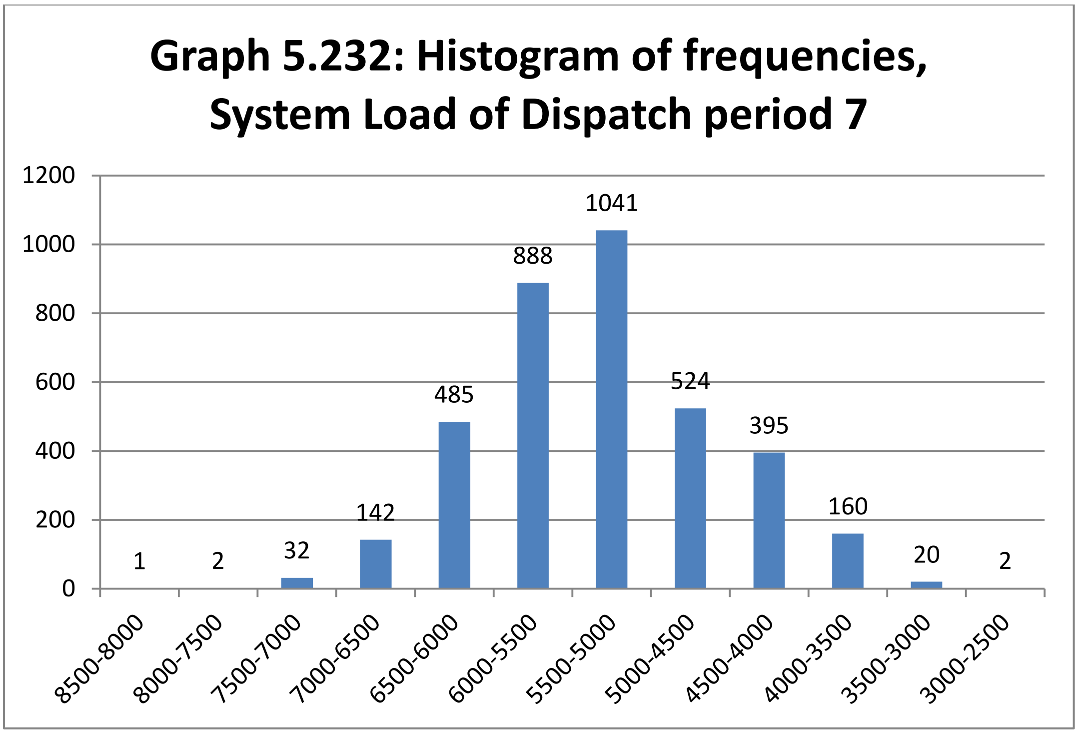

Graph 5.227: Histogram of frequencies,
System Load of Dispatch period 2
1400
1200
1000
800
600
400
200
0
2
10
50
155
235
653
1088
1217
274
8
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

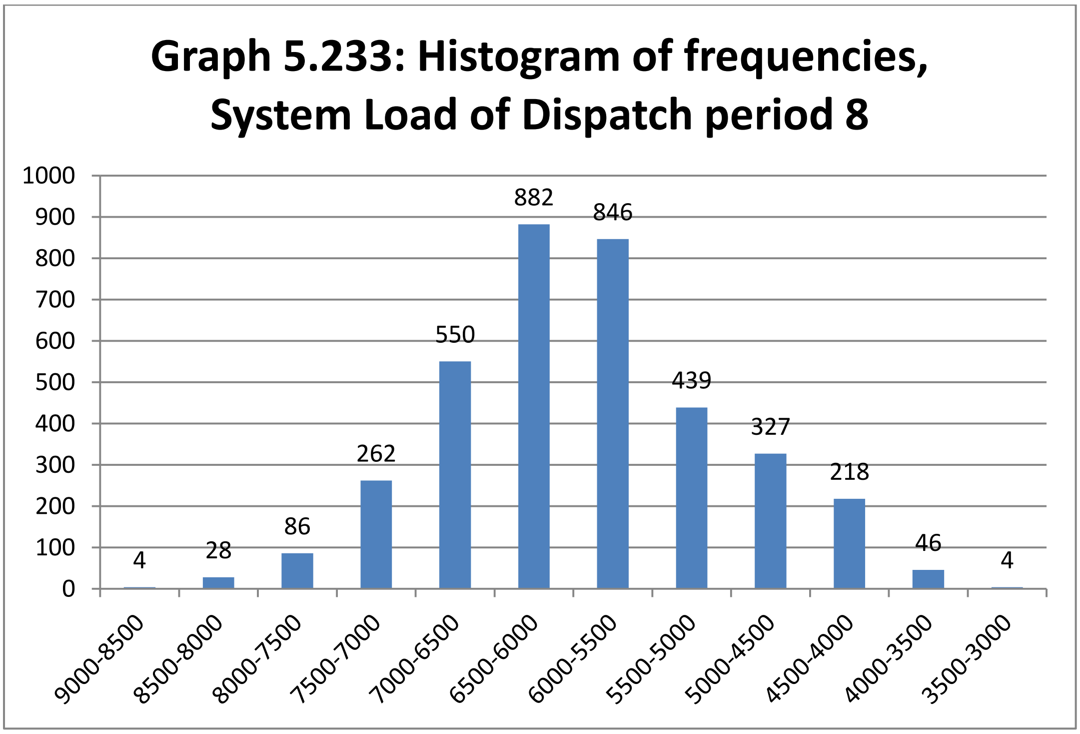

Graph 5.228: Histogram of frequencies, System Load of Dispatch period 3
1600
1400
1200
1000
800
600
400
200
0
2
30
103
195
482
991
1408
446
25
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

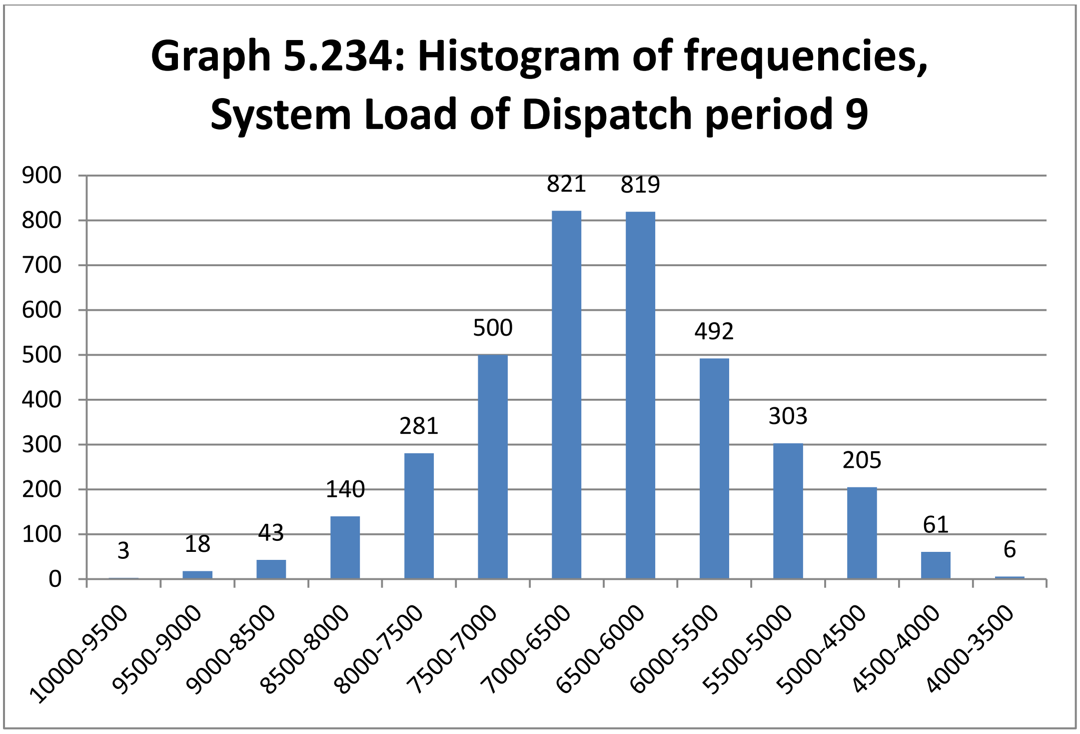

Graph 5.229: Histogram of frequencies, System Load of Dispatch period 4
1800
1600
1400
1200
1000
800
600
400
200
0
2
14
85
176
349
908
1532
585
41
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

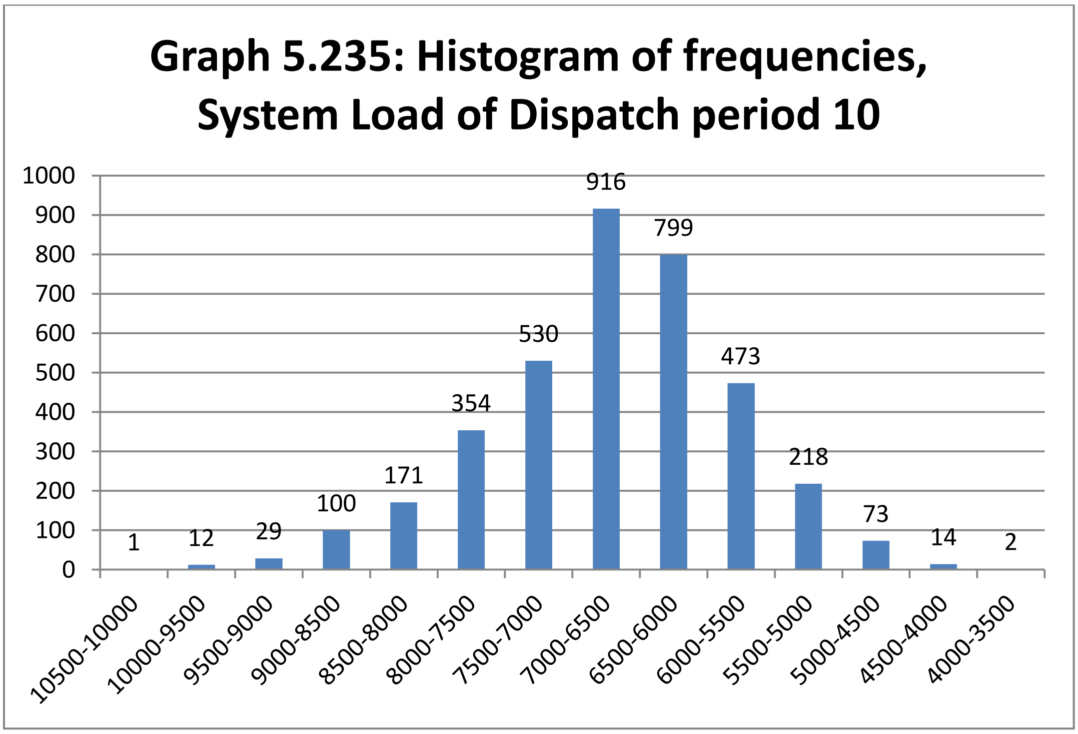

Graph 5.230: Histogram of frequencies, System Load of Dispatch period 5
1800
1600
1400
1200
1000
800
600
400
200
0
2
13
72
190
371
983
1525
507
28
1
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000
3000-2500

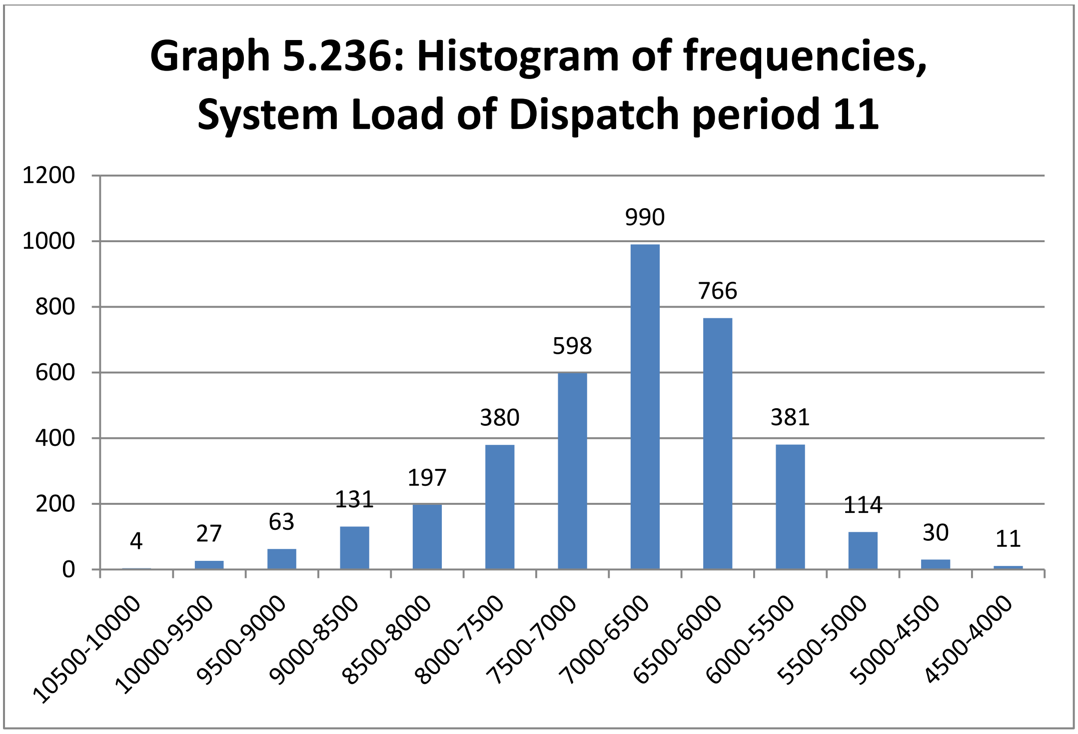

Graph 5.231: Histogram of frequencies, System Load of Dispatch period 6
1400
1200
1000
800
600
400
200
0
2
12
87
287
816
1314
894
250
28
2
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000
3000-2500

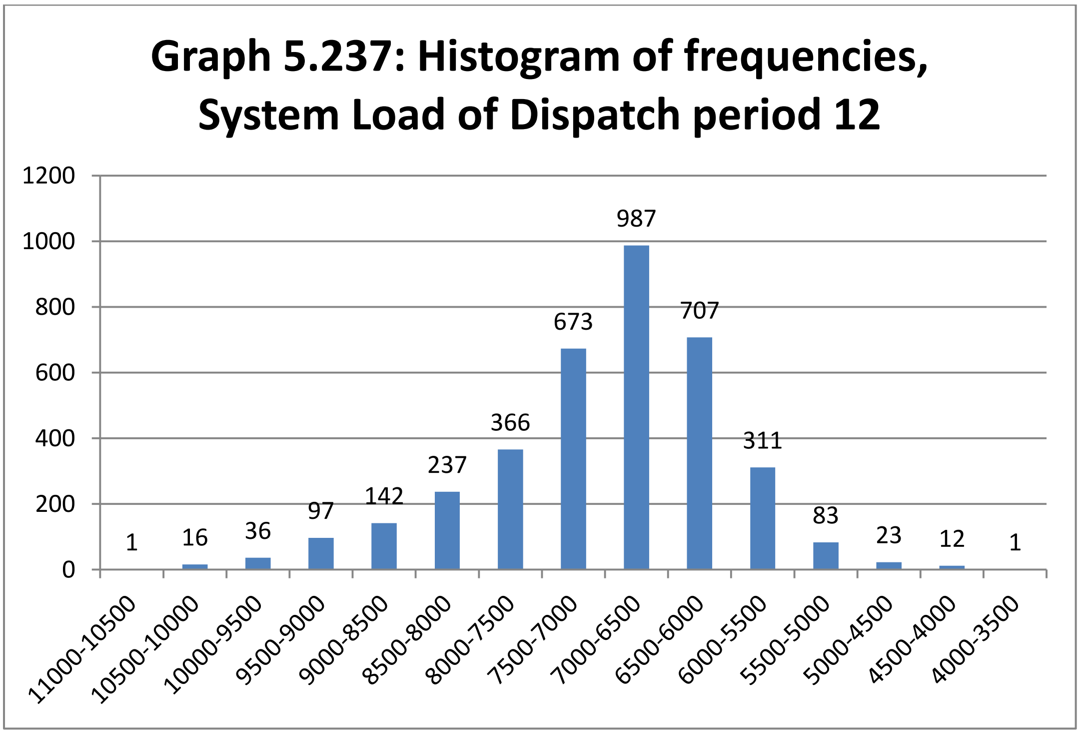

Graph 5.232: Histogram of frequencies, System Load of Dispatch period 7
1200
1000
800
600
400
200
0
1
2
32
142
485
888
1041
524
395
160
20
2
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000
3000-2500

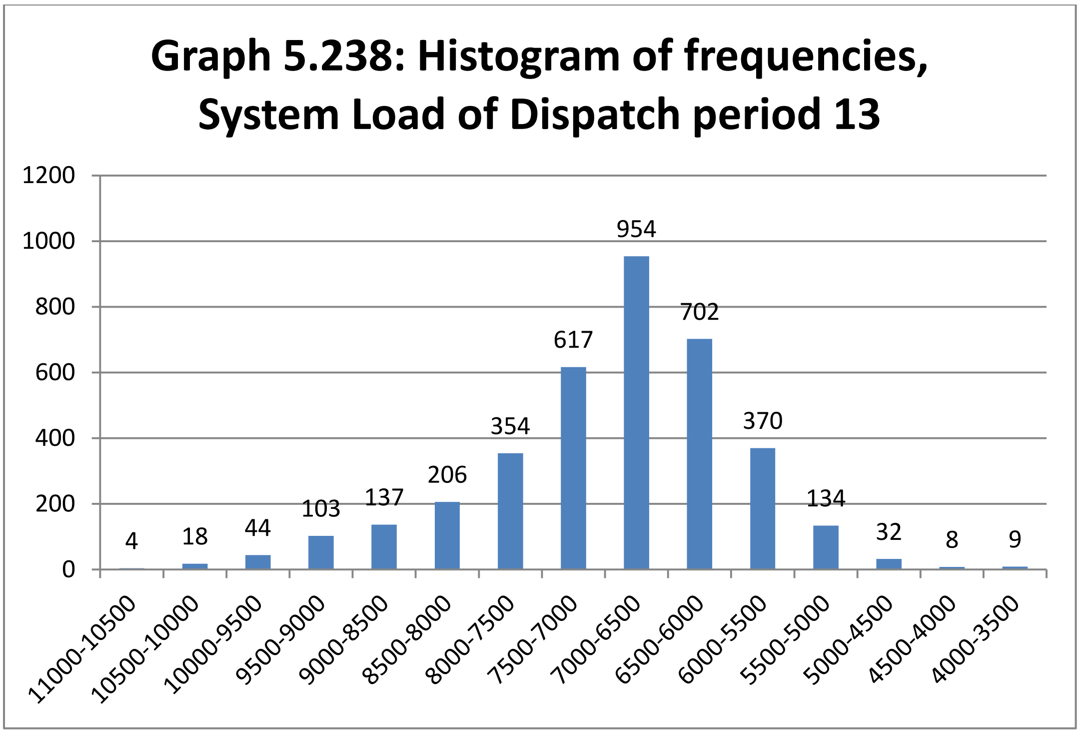

Graph 5.233: Histogram of frequencies, System Load of Dispatch period 8
1000
900
800
700
600
500
400
300
200
100
0
4
28
86
262
550
882
846
439
327
218
46
4
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

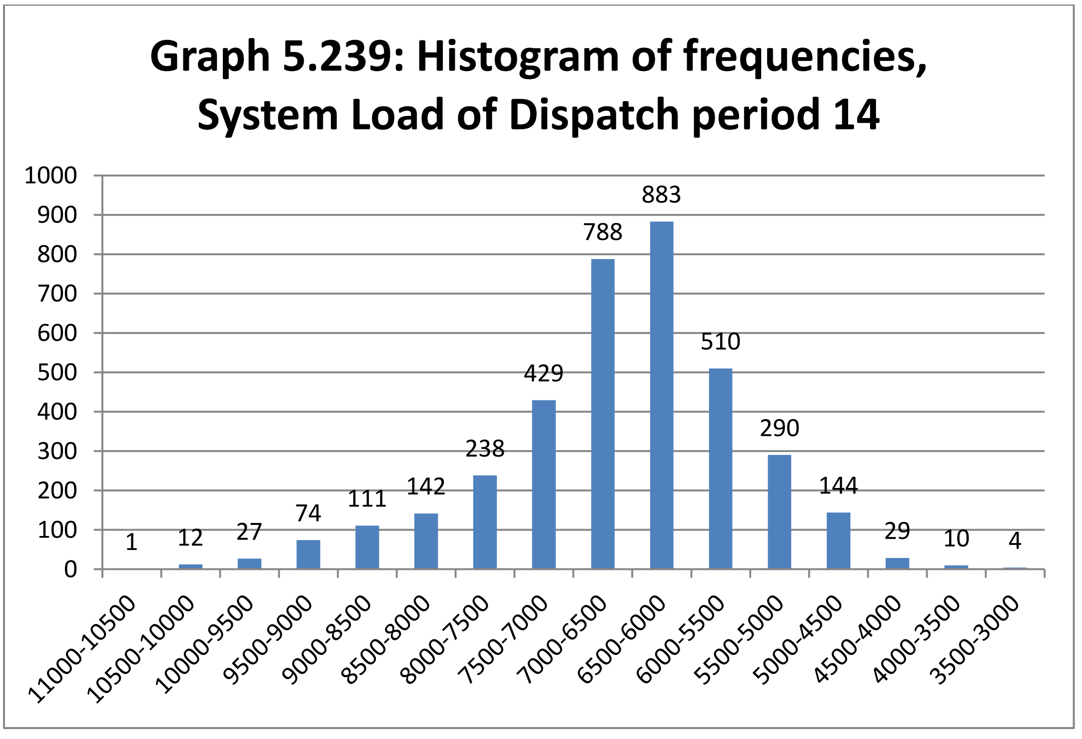

Graph 5.234: Histogram of frequencies, System Load of Dispatch period 9
900
800
700
600
500
400
300
200
100
0
3
18
43
140
281
500
821
819
492
303
205
61
6
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500

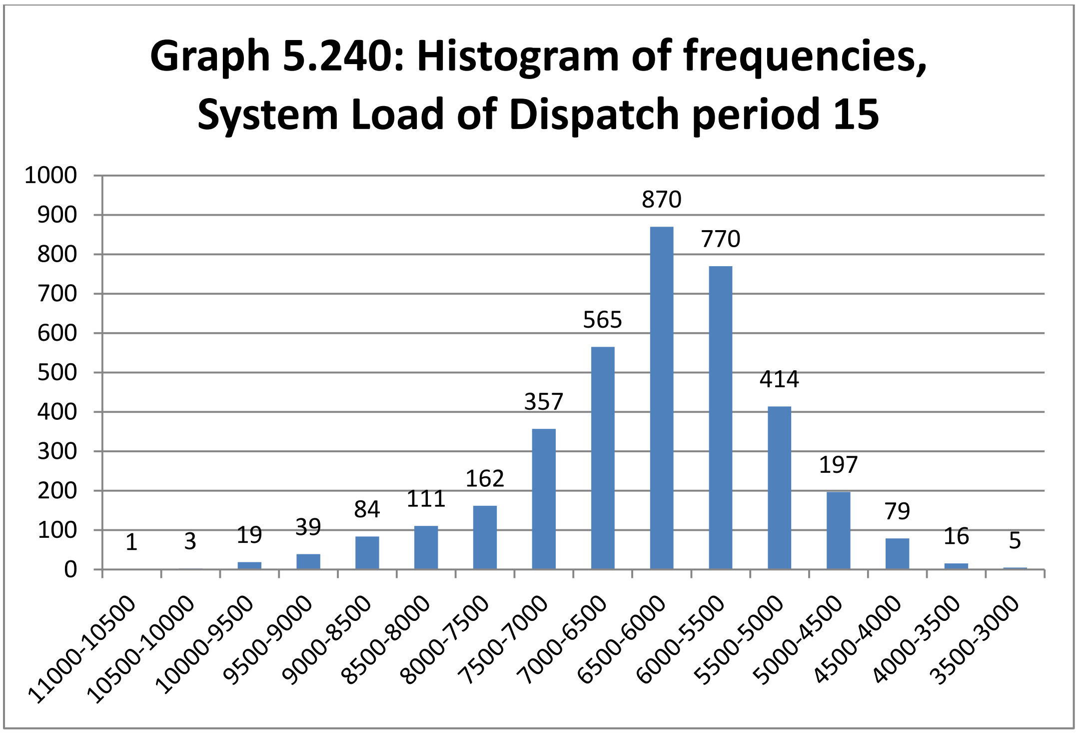

Graph 5.235: Histogram of frequencies, System Load of Dispatch period 10
1000
900
800
700
600
500
400
300
200
100
0
1
12
29
100
171
354
530
916
799
473
218
73
14
2
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500

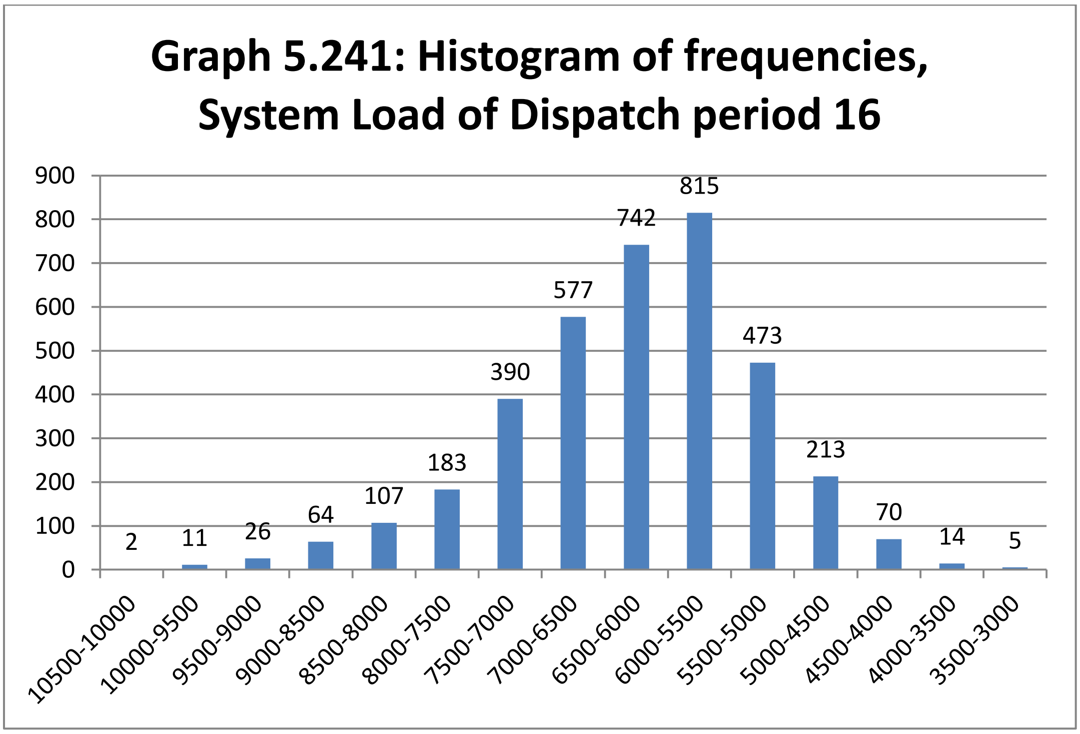

Graph 5.236: Histogram of frequencies, System Load of Dispatch period 11
1200
1000
800
600
400
200
0
4
27
63
131
197
380
598
990
766
381
114
30
11
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000

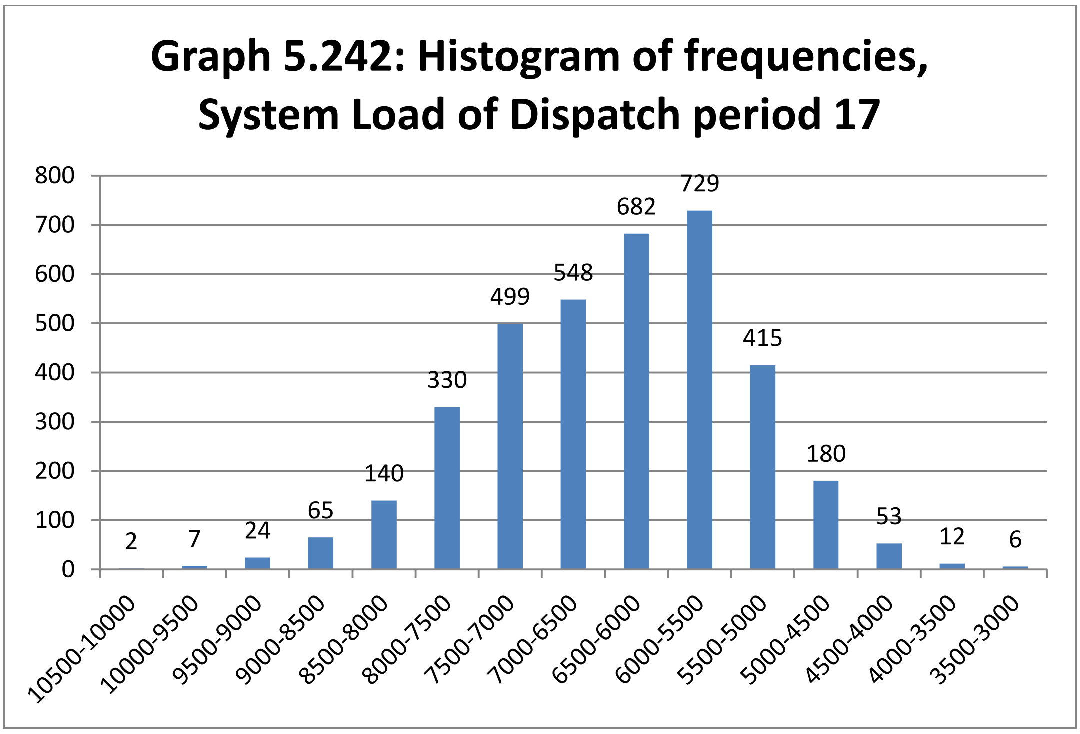

Graph 5.237: Histogram of frequencies, System Load of Dispatch period 12
1200
1000
800
600
400
200
0
1
16
36
97
142
237
366
673
987
707
311
83
23
12
1
11000-10500
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500

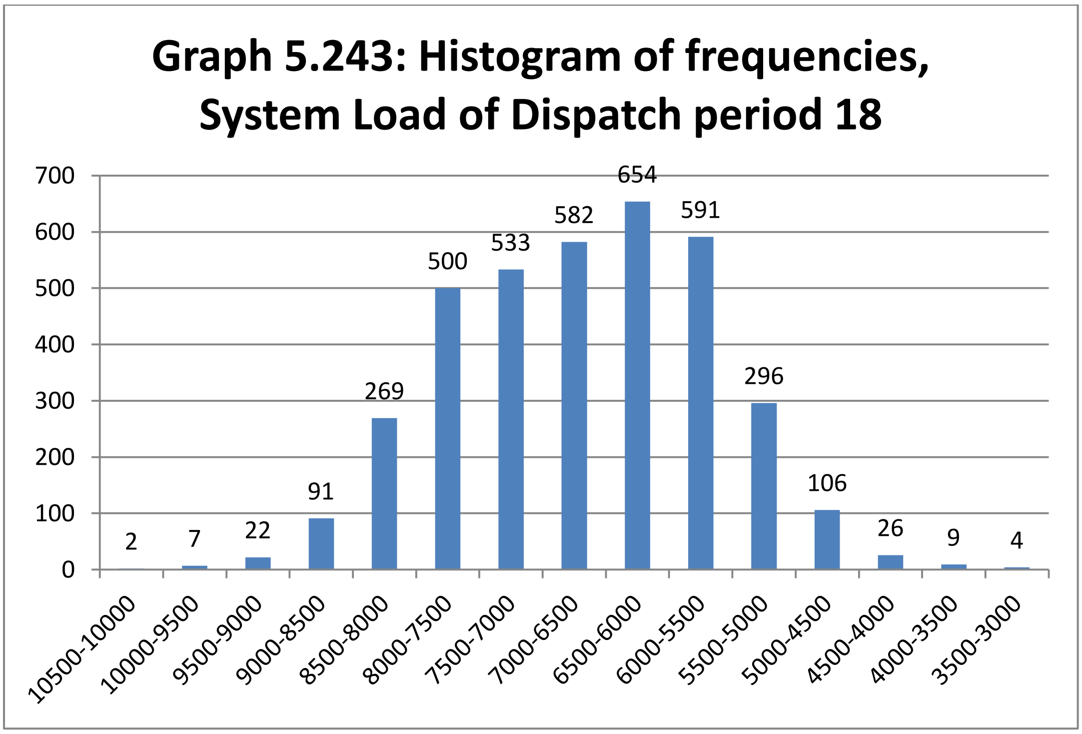

Graph 5.238: Histogram of frequencies, System Load of Dispatch period 13
1200
1000
800
600
400
200
0
4
18
44
103
137
206
354
617
954
702
370
134
32
8
9
11000-10500
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500

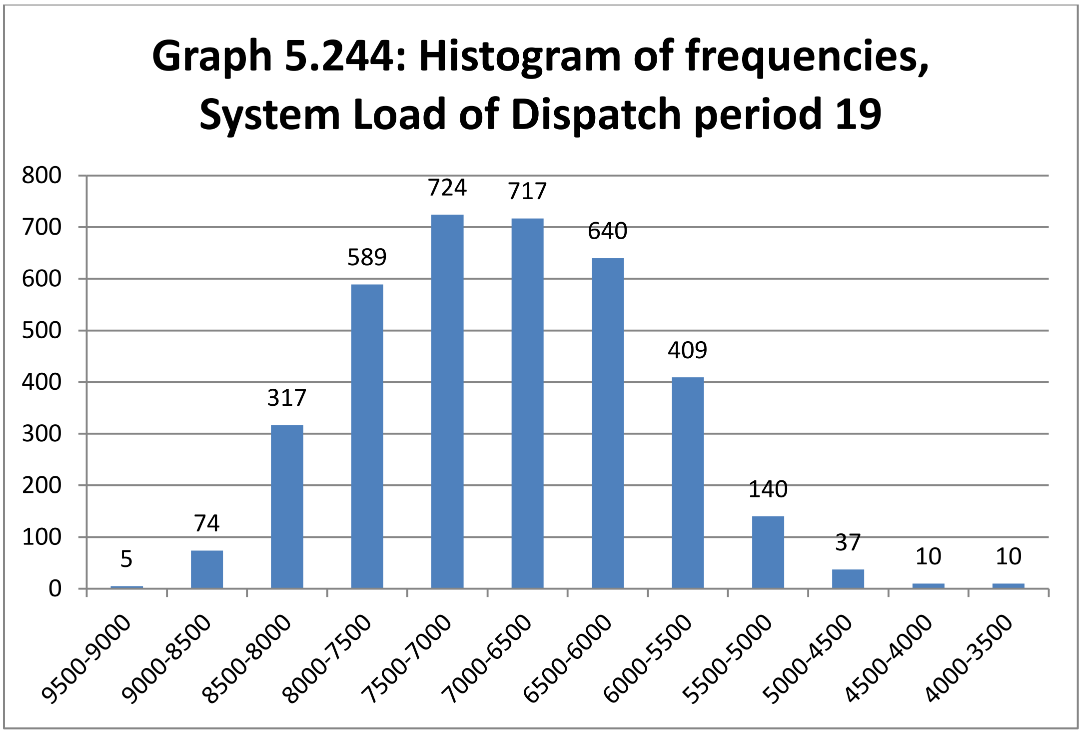

Graph 5.239: Histogram of frequencies, System Load of Dispatch period 14
1000
900
800
700
600
500
400
300
200
100
0
1
12
27
74
111
142
238
429
788
883
510
290
144
29
10
4
11000-10500
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

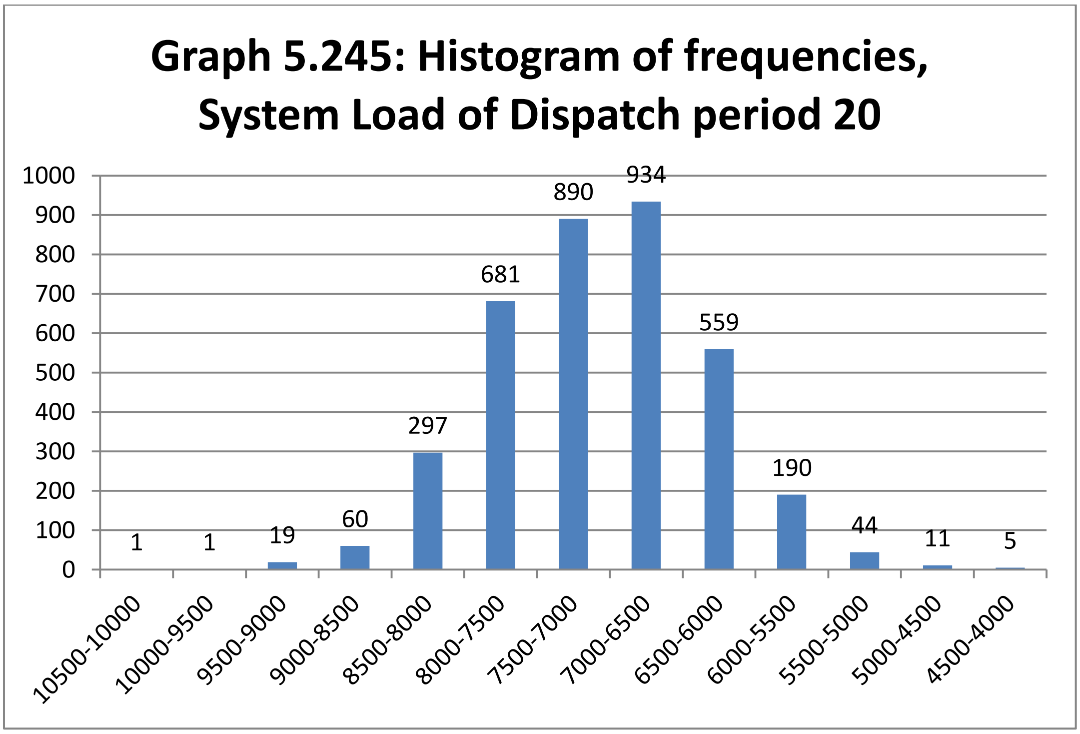

Graph 5.240: Histogram of frequencies, System Load of Dispatch period 15
1000
900
800
700
600
500
400
300
200
100
0
1
3
19
39
84
111
162
357
565
870
770
414
197
79
16
5
11000-10500
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

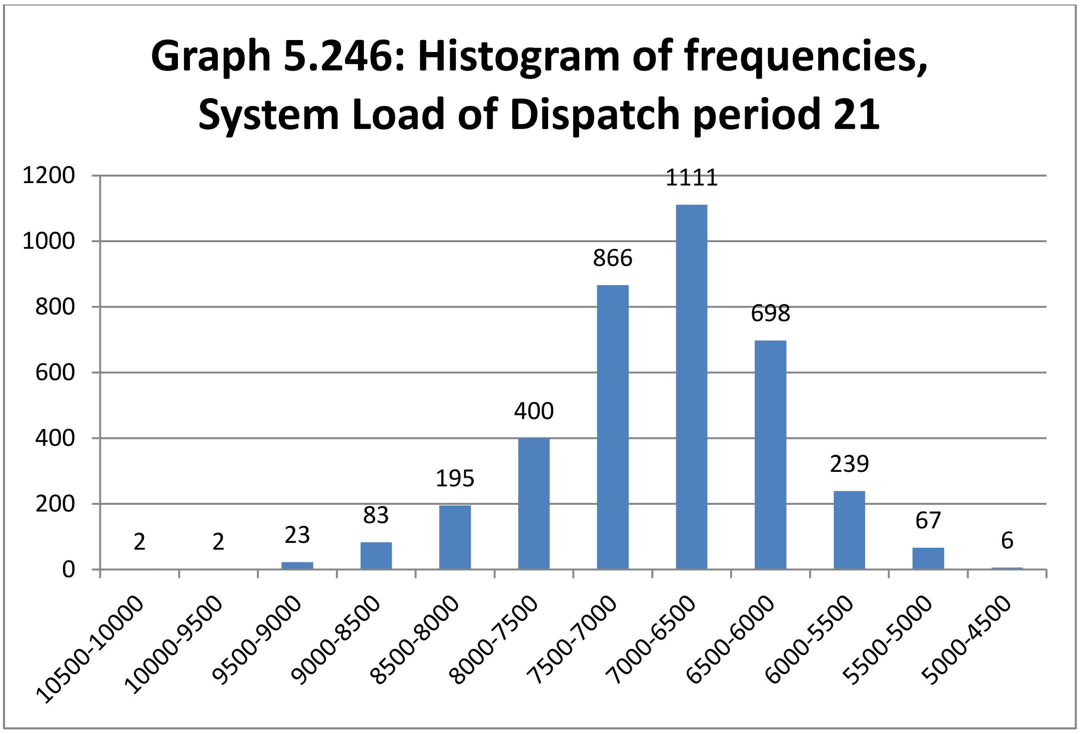

Graph 5.241: Histogram of frequencies, System Load of Dispatch period 16
900
800
700
600
500
400
300
200
100
0
2
11
26
64
107
183
390
577
742
815
473
213
70
14
5
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

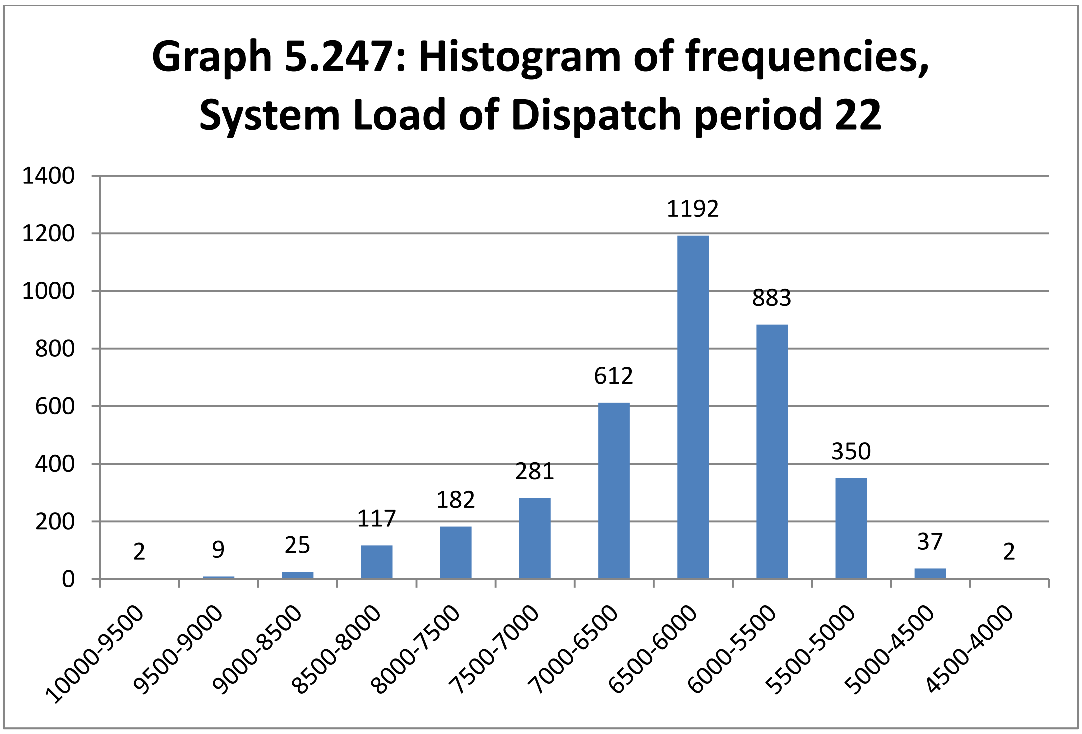

Graph 5.242: Histogram of frequencies, System Load of Dispatch period 17
800
700
600
500
400
300
200
100
0
2
7
24
65
140
330
499
548
682
729
415
180
53
12
6
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

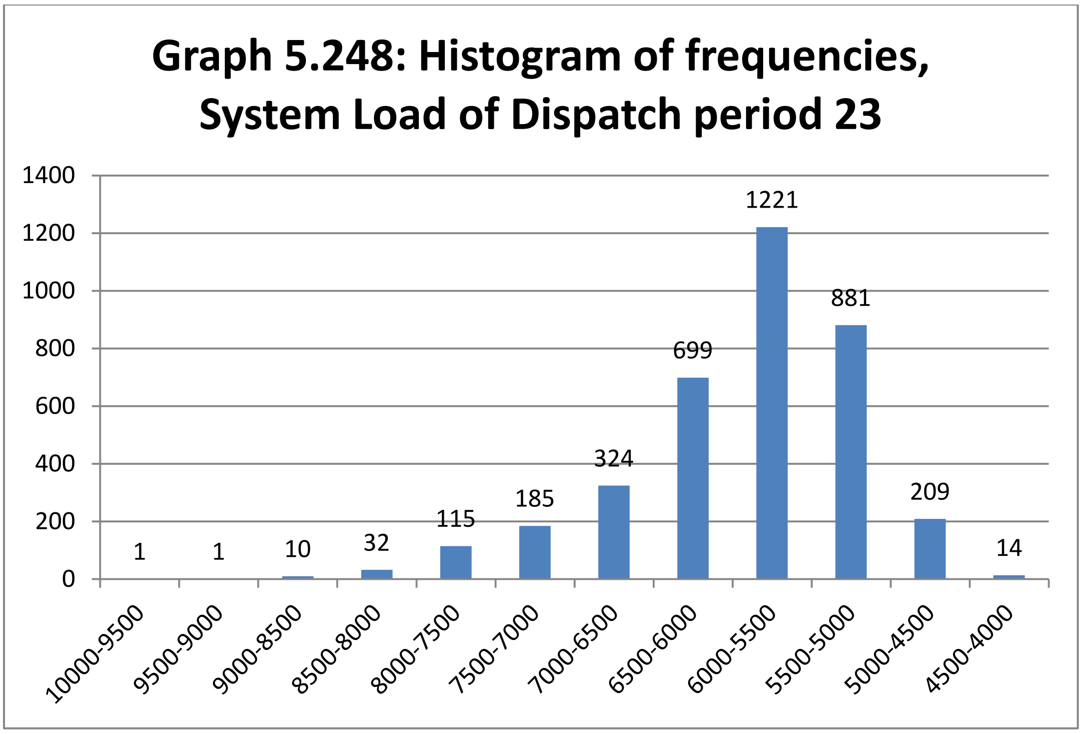

Graph 5.243: Histogram of frequencies, System Load of Dispatch period 18
700
600
500
400
300
200
100
0
2
7
22
91
269
500
533
582
654
591
296
106
26
9
4
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500
3500-3000

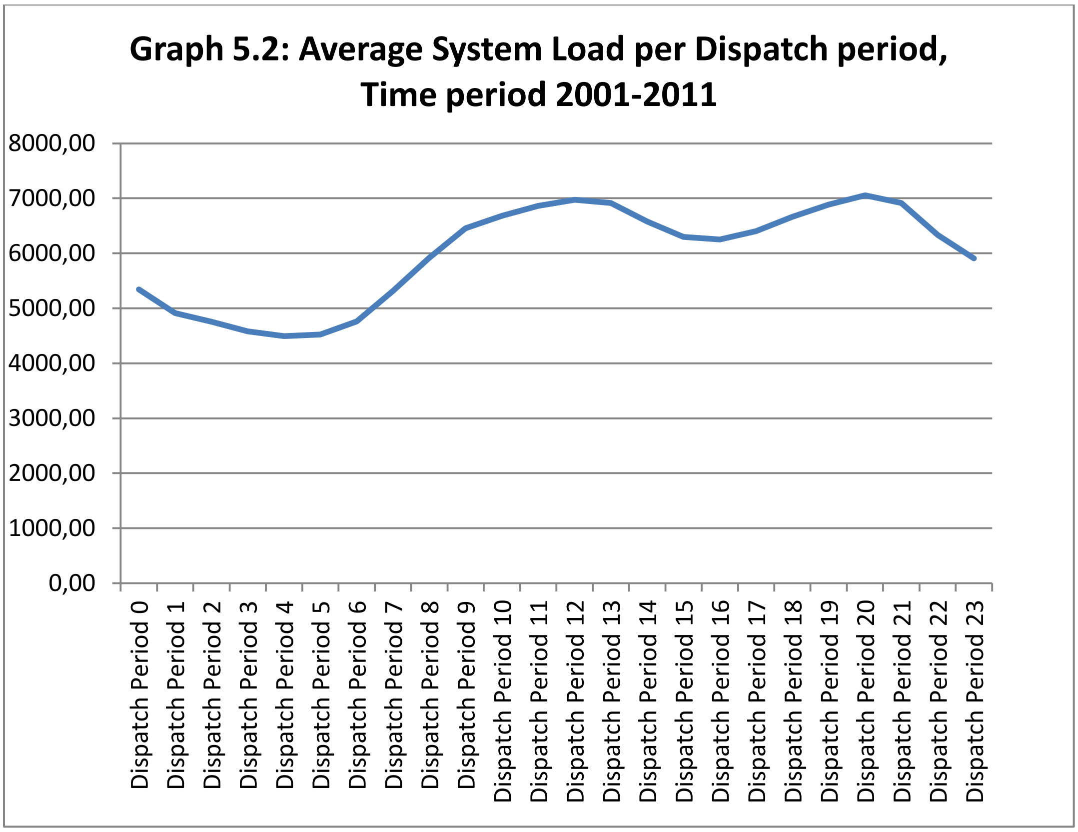

Graph 5.244: Histogram of frequencies, System Load of Dispatch period 19
800
700
600
500
400
300
200
100
0
5
74
317
589
724
717
640
409
140
37
10
10
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000
4000-3500

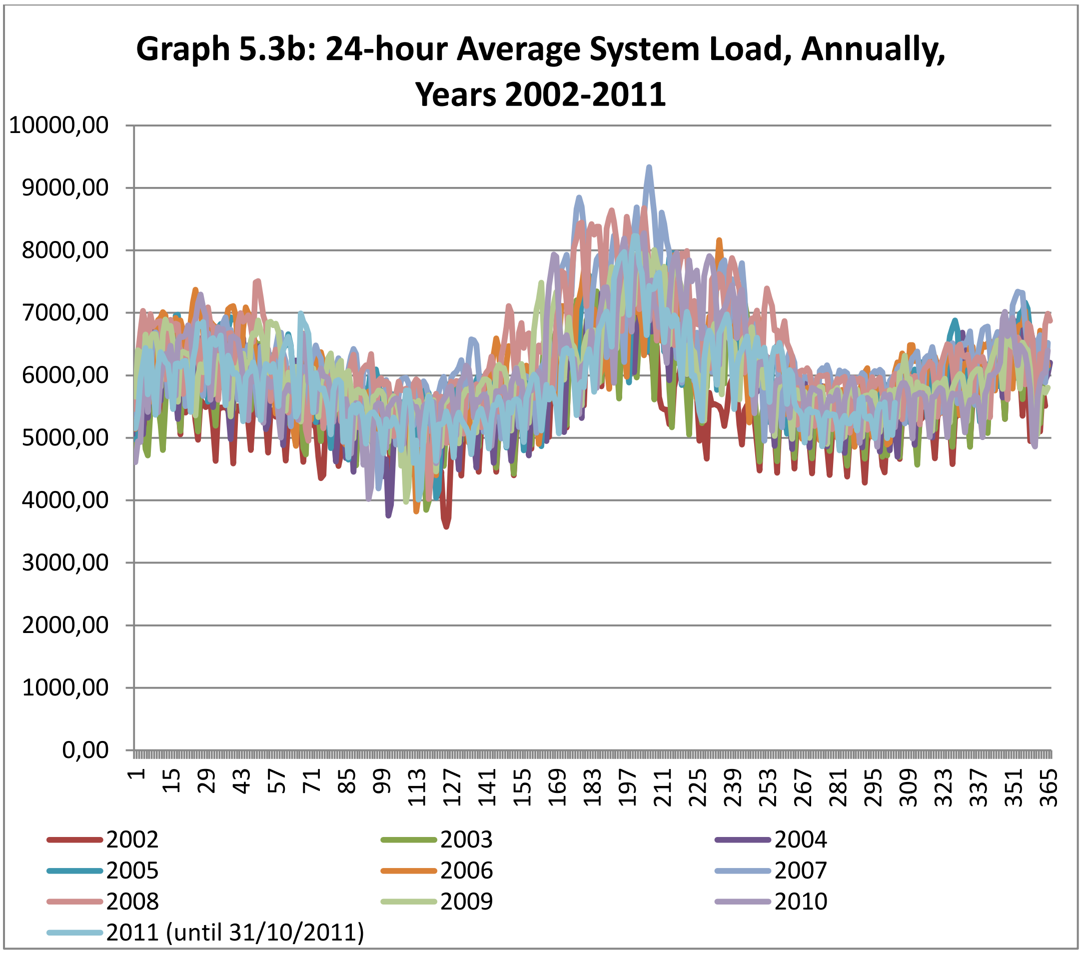

Graph 5.245: Histogram of frequencies, System Load of Dispatch period 20
1000
900
800
700
600
500
400
300
200
100
0
1
1
19
60
297
681
890
934
559
190
44
11
5
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000

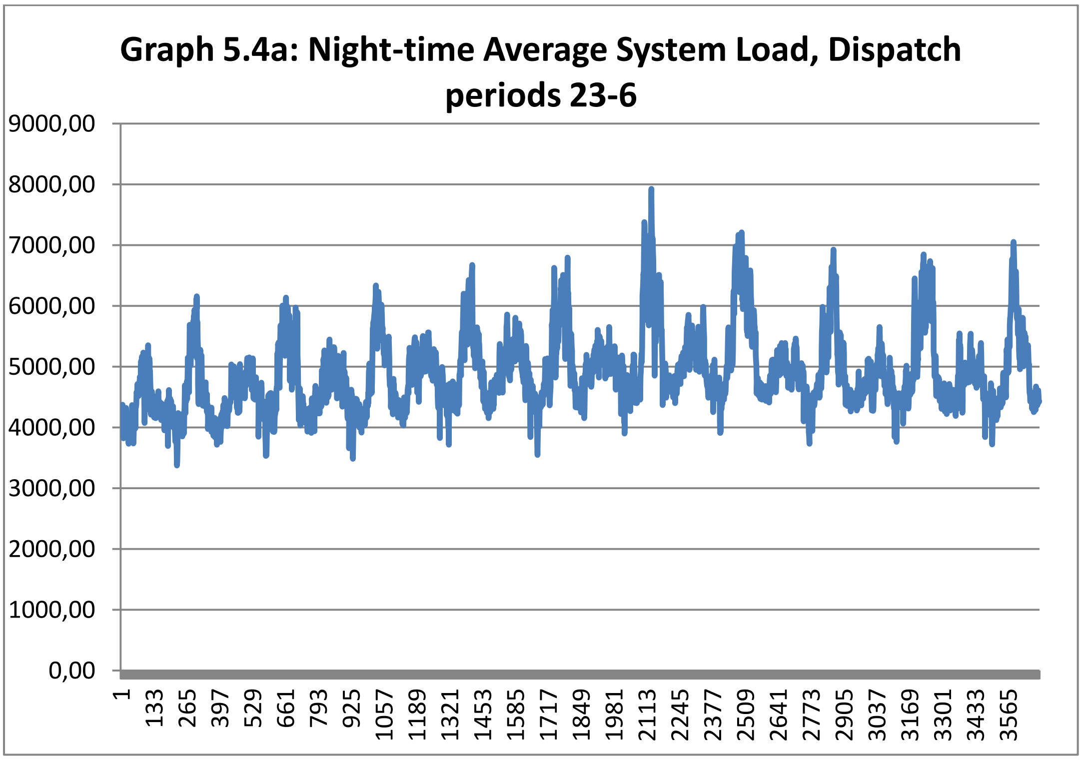

Graph 5.246: Histogram of frequencies, System Load of Dispatch period 21
1200
1000
800
600
400
200
0
2
2
23
83
195
400
866
1111
698
239
67
6
10500-10000
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500

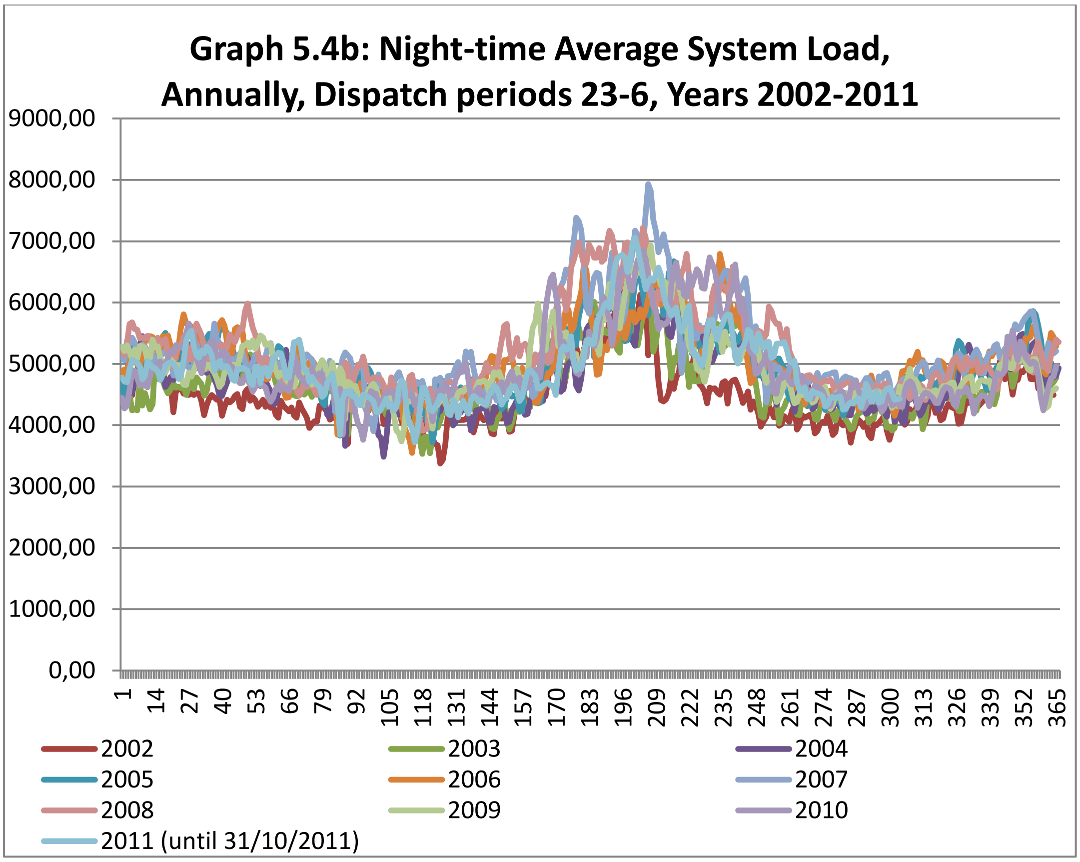

Graph 5.247: Histogram of frequencies, System Load of Dispatch period 22
1400
1200
1000
800
600
400
200
0
2
9
25
117
182
281
612
1192
883
350
37
2
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000

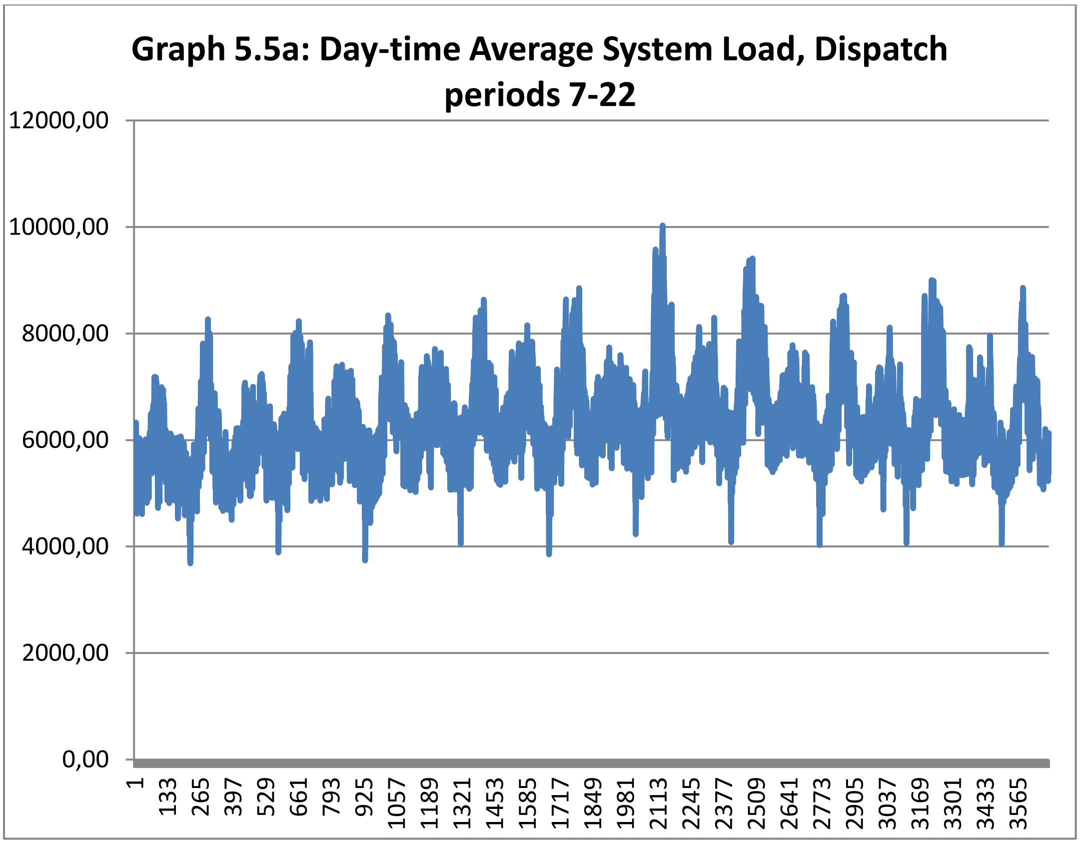

Graph 5.248: Histogram of frequencies, System Load of Dispatch period 23
1400
1200
1000
800
600
400
200
0
1
1
10
32
115
185
324
699
1221
881
209
14
10000-9500
9500-9000
9000-8500
8500-8000
8000-7500
7500-7000
7000-6500
6500-6000
6000-5500
5500-5000
5000-4500
4500-4000

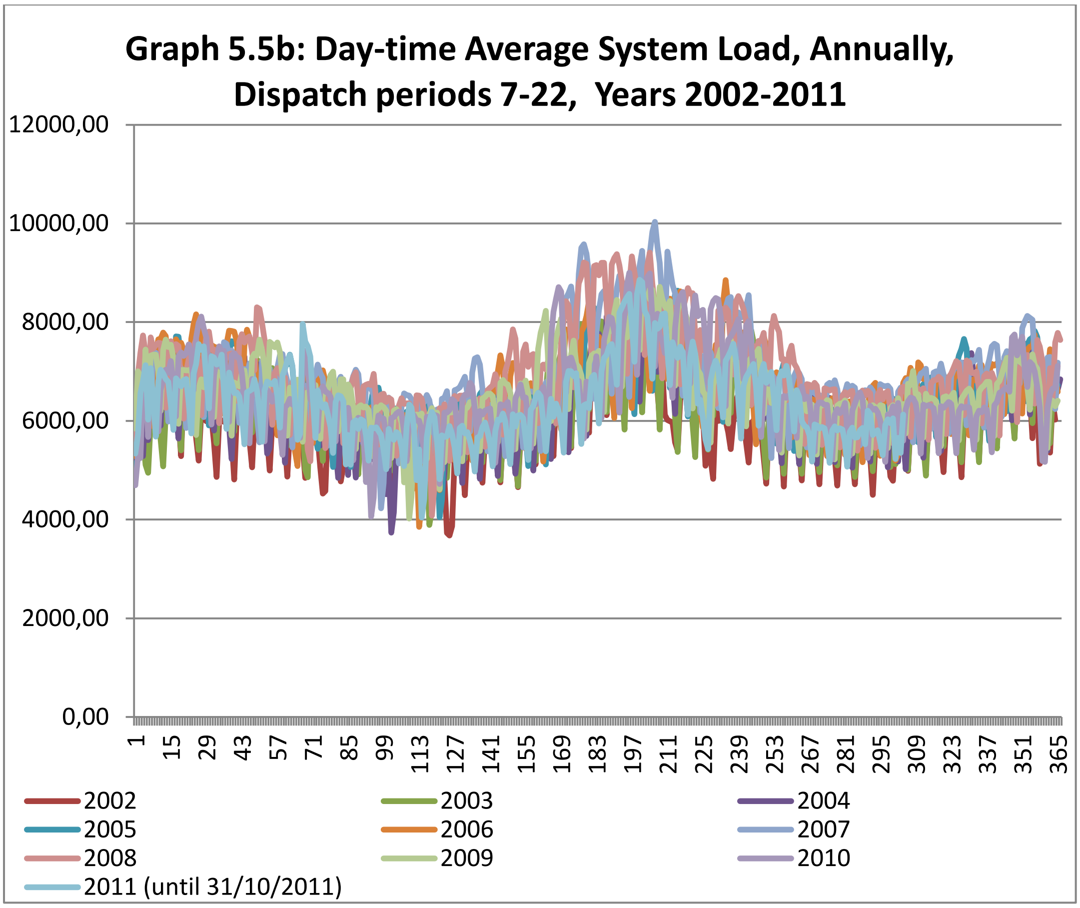

Graph 5.2: Average System Load per Dispatch period, Time period 2001-2011
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
Dispatch Period 0
Dispatch Period 1
Dispatch Period 2
Dispatch Period 3
Dispatch Period 4
Dispatch Period 5
Dispatch Period 6
Dispatch Period 7
Dispatch Period 8
Dispatch Period 9
Dispatch Period 10
Dispatch Period 11
Dispatch Period 12
Dispatch Period 13
Dispatch Period 14
Dispatch Period 15
Dispatch Period 16
Dispatch Period 17
Dispatch Period 18
Dispatch Period 19
Dispatch Period 20
Dispatch Period 21
Dispatch Period 22
Dispatch Period 23

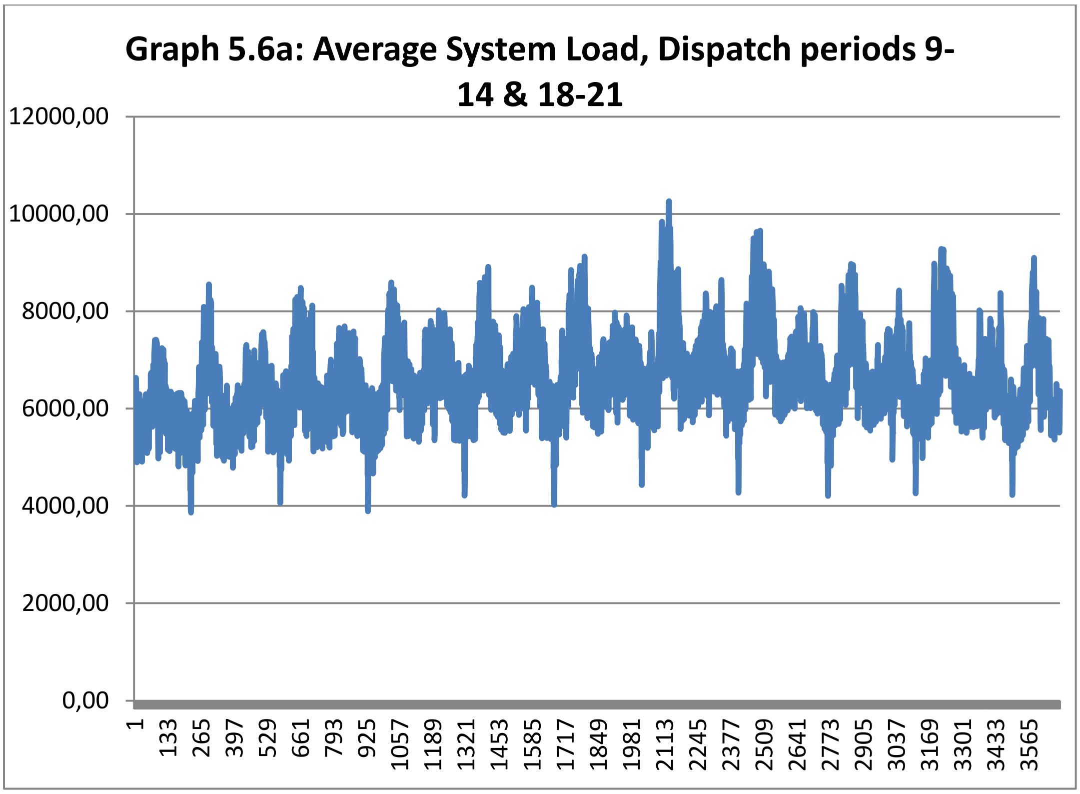

Graph 5.3b: 24-hour Average System Load, Annually, Years 2002-2011
10000,00
9000,00
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
1 15 29 43 57 71 85 99 113 127 141 155 169 183 197 211 225 239 253 267 281 295 309 323 337 351 365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.4a: Night-time Average System Load, Dispatch periods 23-6
9000,00
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
1 133 265 397 529 661 793 925 1057 1189 1321 1453 1585 1717 1849 1981 2113 2245 2377 2509 2641 2773 2905 3037 3169 3301 3433 3565


Graph 5.4b: Night-time Average System Load, Annually, Dispatch periods 23-6, Years 2002-2011
9000,00
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
1 14 27 40 53 66 79 92 105 118 131 144 157 170 183 196 209 222 235 248 261 274 287 300 313 326 339 352 365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.5a: Day-time Average System Load, Dispatch periods 7-22
12000,00
10000,00
8000,00
6000,00
4000,00
2000,00
0,00
1 133 265 397 529 661 793 925 1057 1189 1321 1453 1585 1717 1849 1981 2113 2245 2377 2509 2641 2773 2905 3037 3169 3301 3433 3565


Graph 5.5b: Day-time Average System Load, Annually, Dispatch periods 7-22, Years 2002-2011
12000,00
10000,00
8000,00
6000,00
4000,00
2000,00
0,00
1
15
29
43
57
71
85
99
113
127
141
155
169
183
197
211
225
239
253
267
281
295
309
323
337
351
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.6a: Average System Load, Dispatch periods 9-14 & 18-21
12000,00
10000,00
8000,00
6000,00
4000,00
2000,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
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2641
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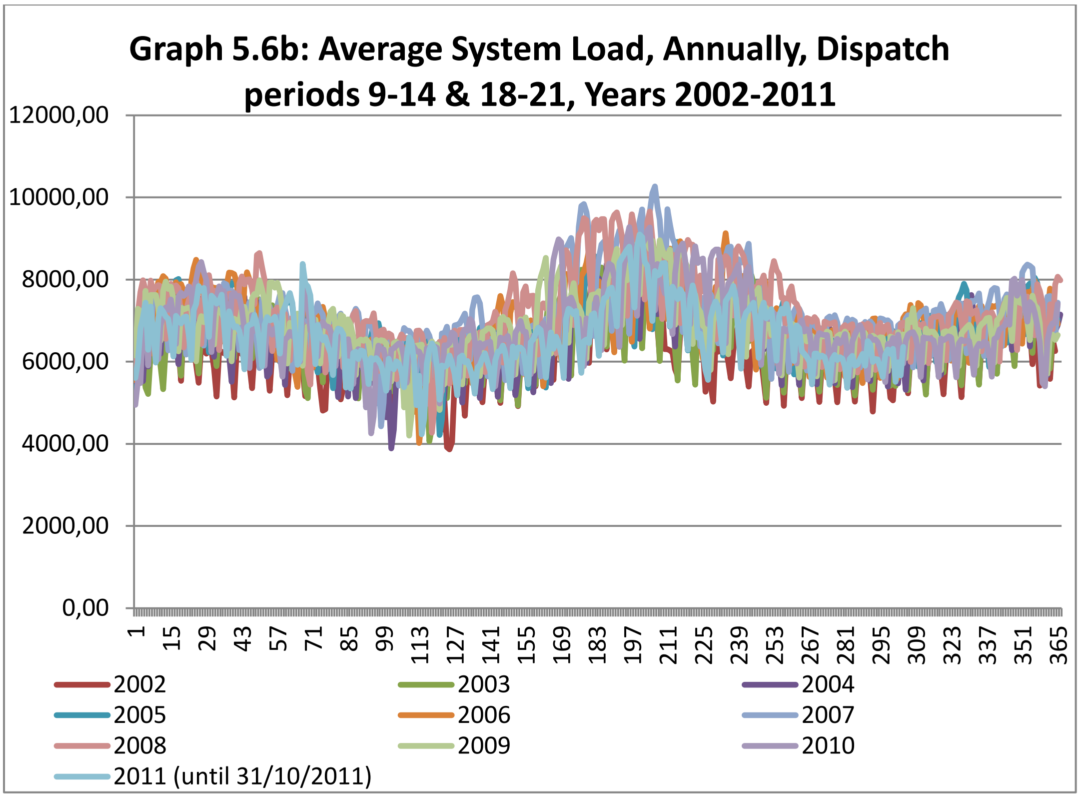
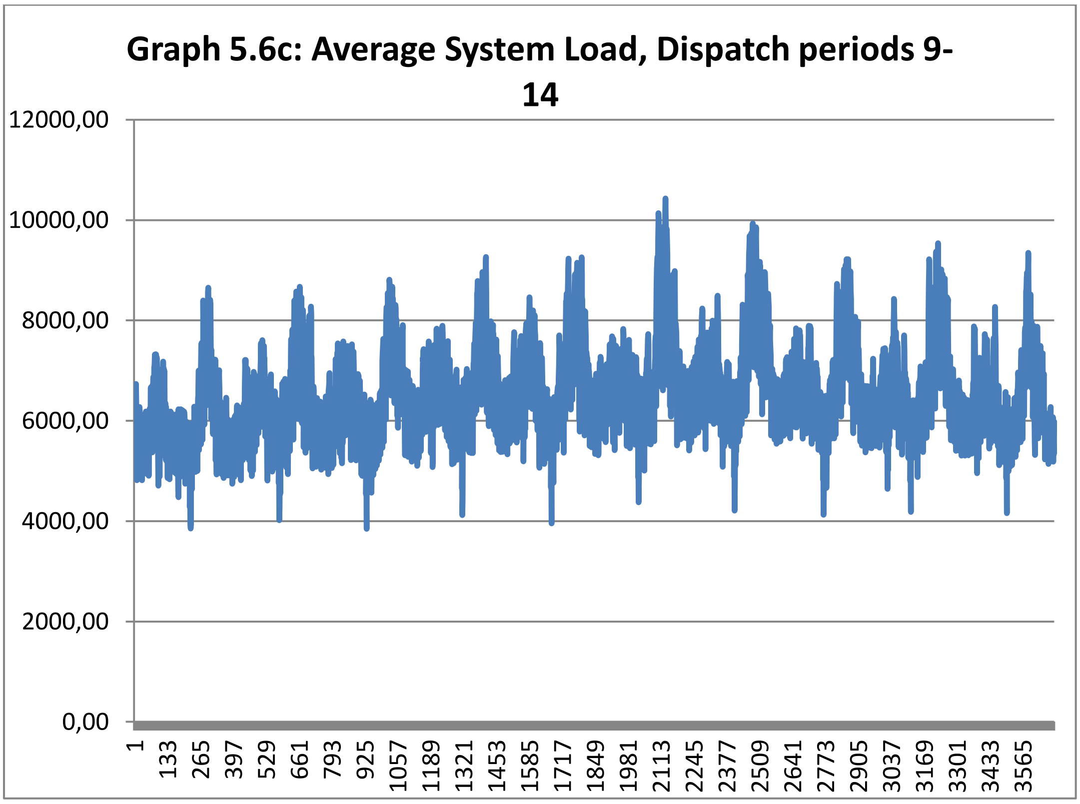
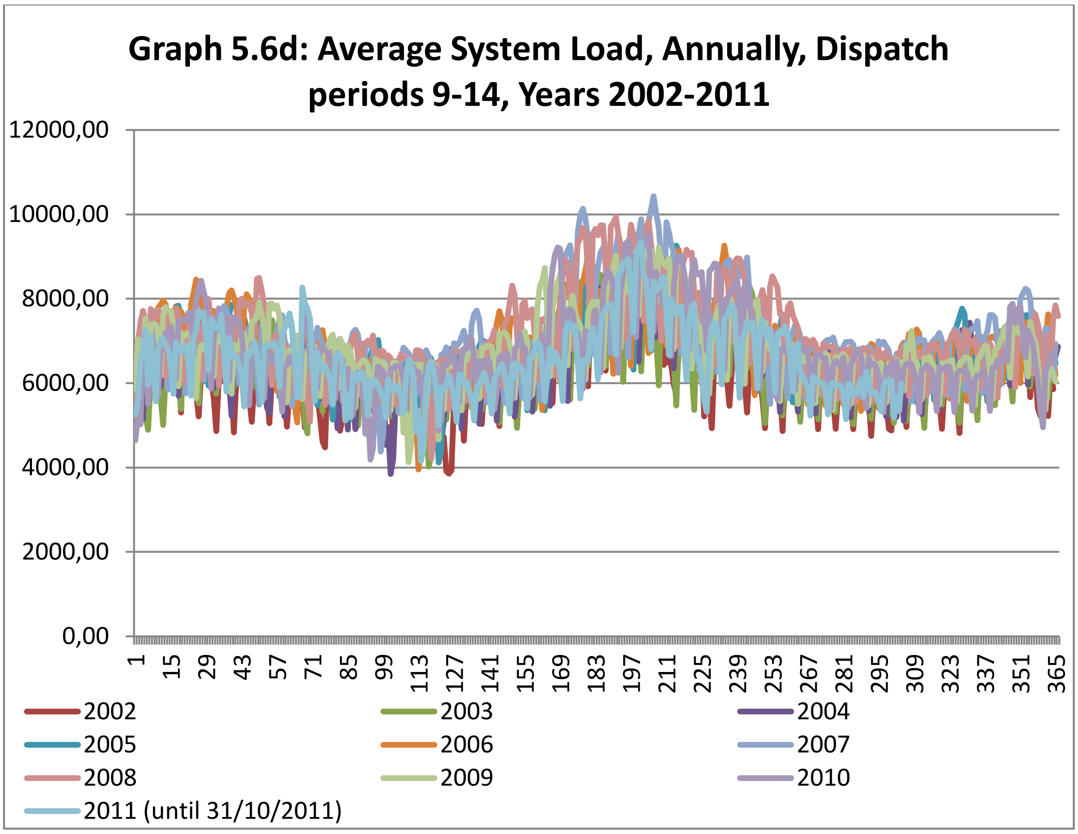
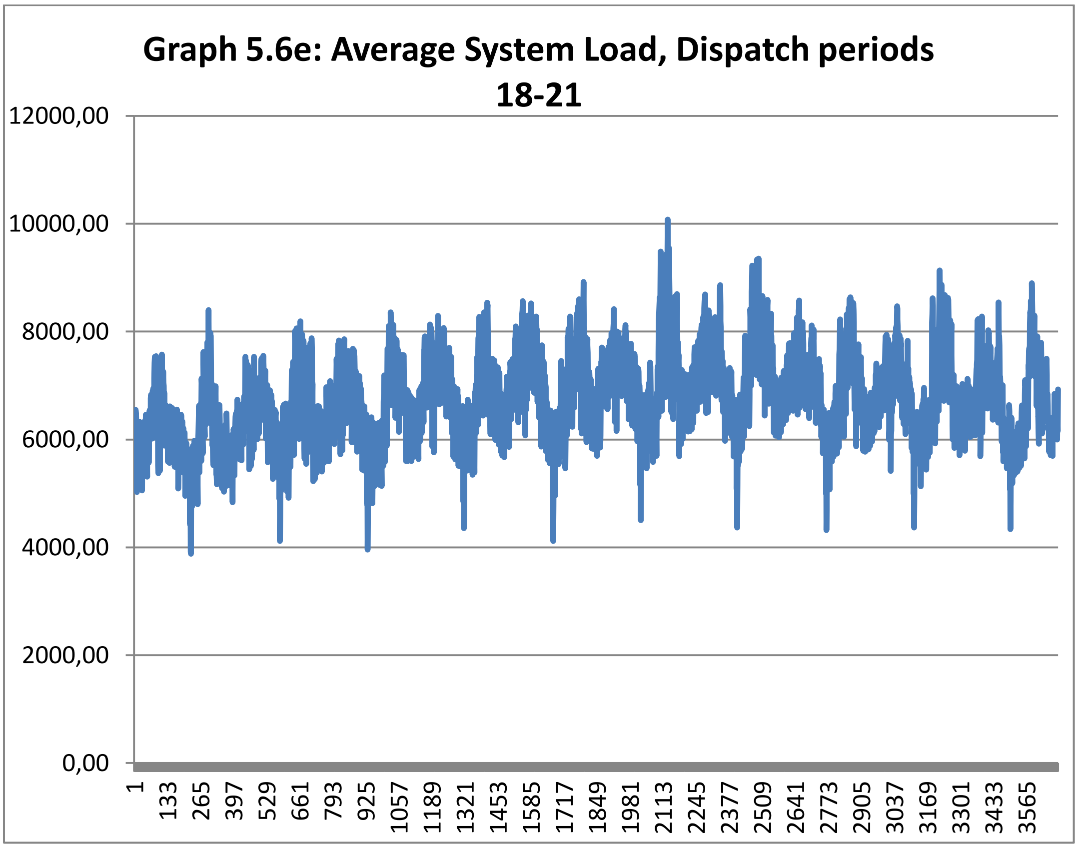
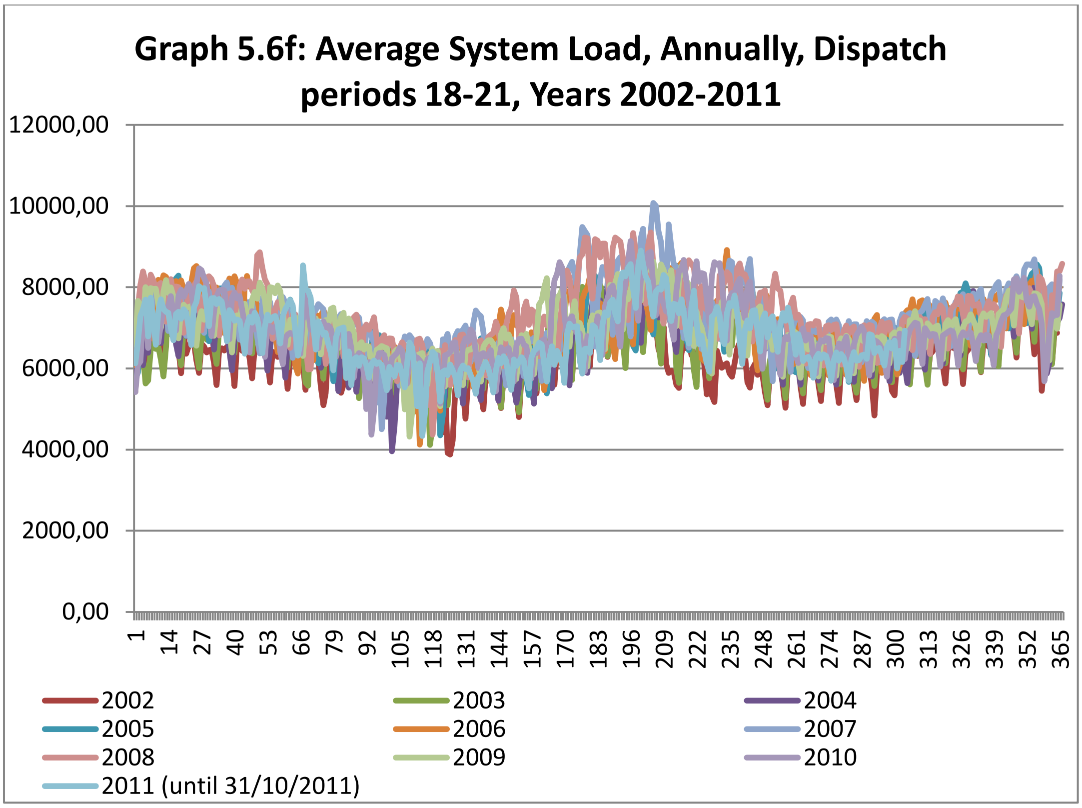
3037
3169
3301
3433
3565

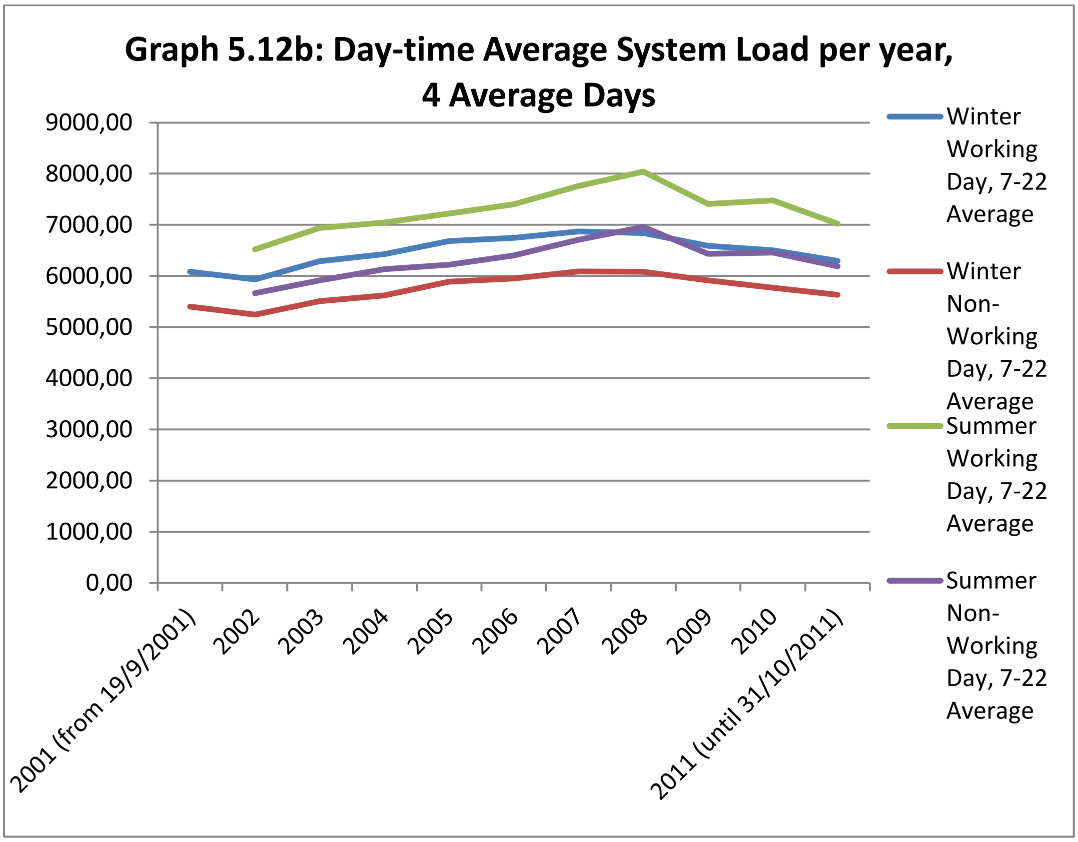

Graph 5.6b: Average System Load, Annually, Dispatch periods 9-14 & 18-21, Years 2002-2011
12000,00
10000,00
8000,00
6000,00
4000,00
2000,00
0,00
1
15
29
43
57
71
85
99
113
127
141
155
169
183
197
211
225
239
253
267
281
295
309
323
337
351
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

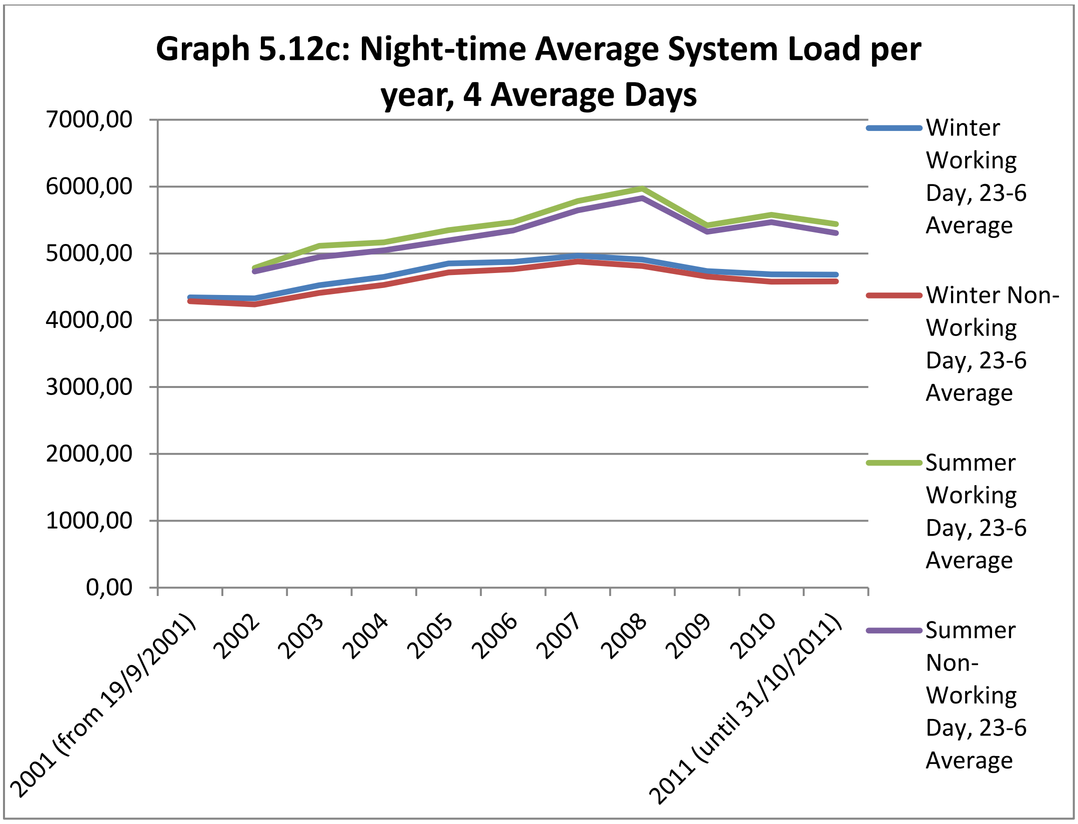

Graph 5.6c: Average System Load, Dispatch periods 9-14
12000,00
10000,00
8000,00
6000,00
4000,00
2000,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

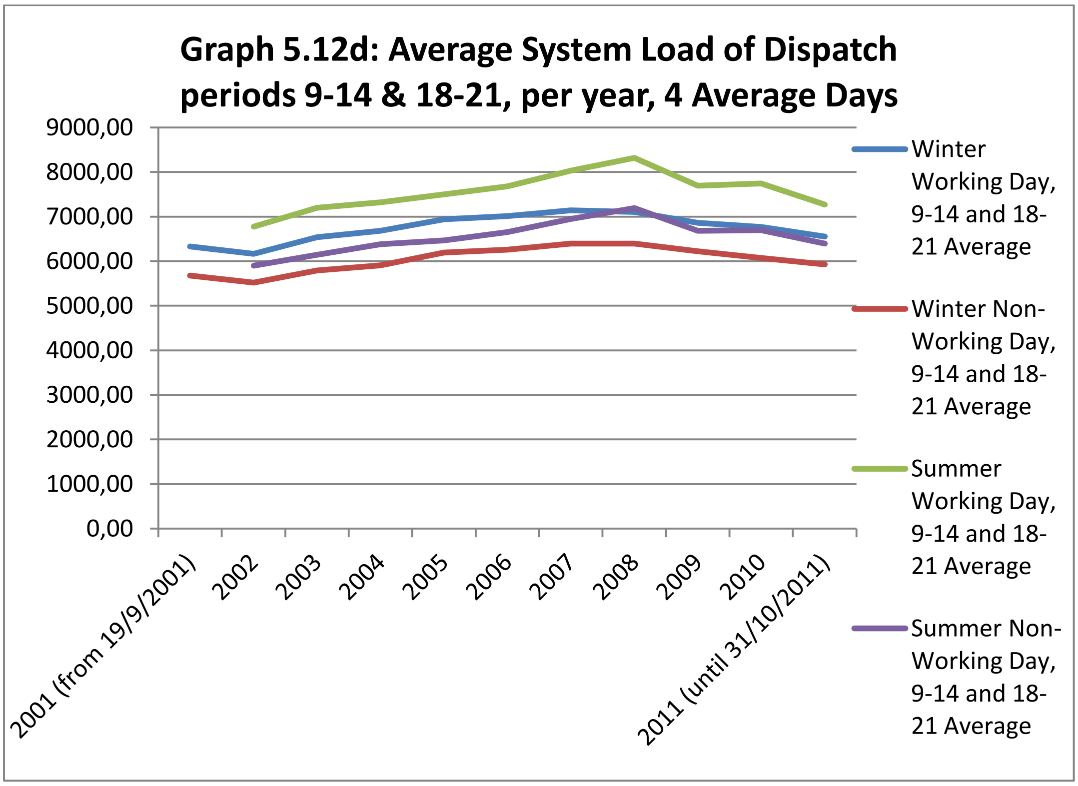

Graph 5.6d: Average System Load, Annually, Dispatch periods 9-14, Years 2002-2011
12000,00
10000,00
8000,00
6000,00
4000,00
2000,00
0,00
1
15
29
43
57
71
85
99
113
127
141
155
169
183
197
211
225
239
253
267
281
295
309
323
337
351
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

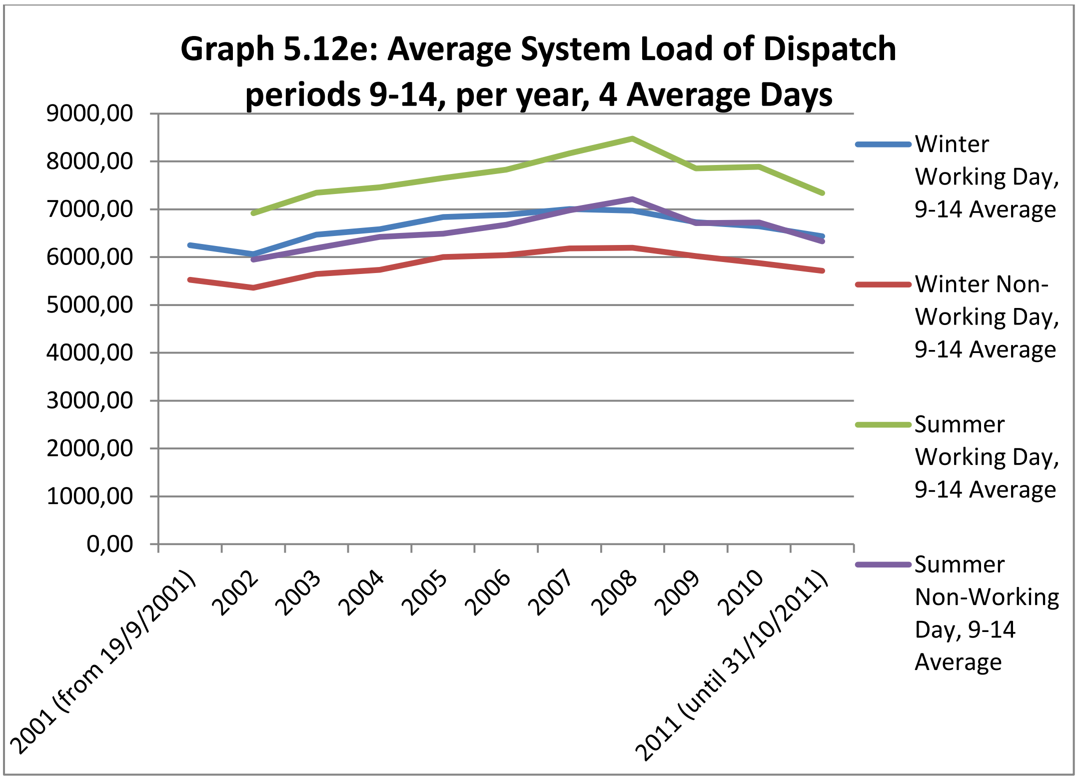

Graph 5.6e: Average System Load, Dispatch periods 18-21
12000,00
10000,00
8000,00
6000,00
4000,00
2000,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

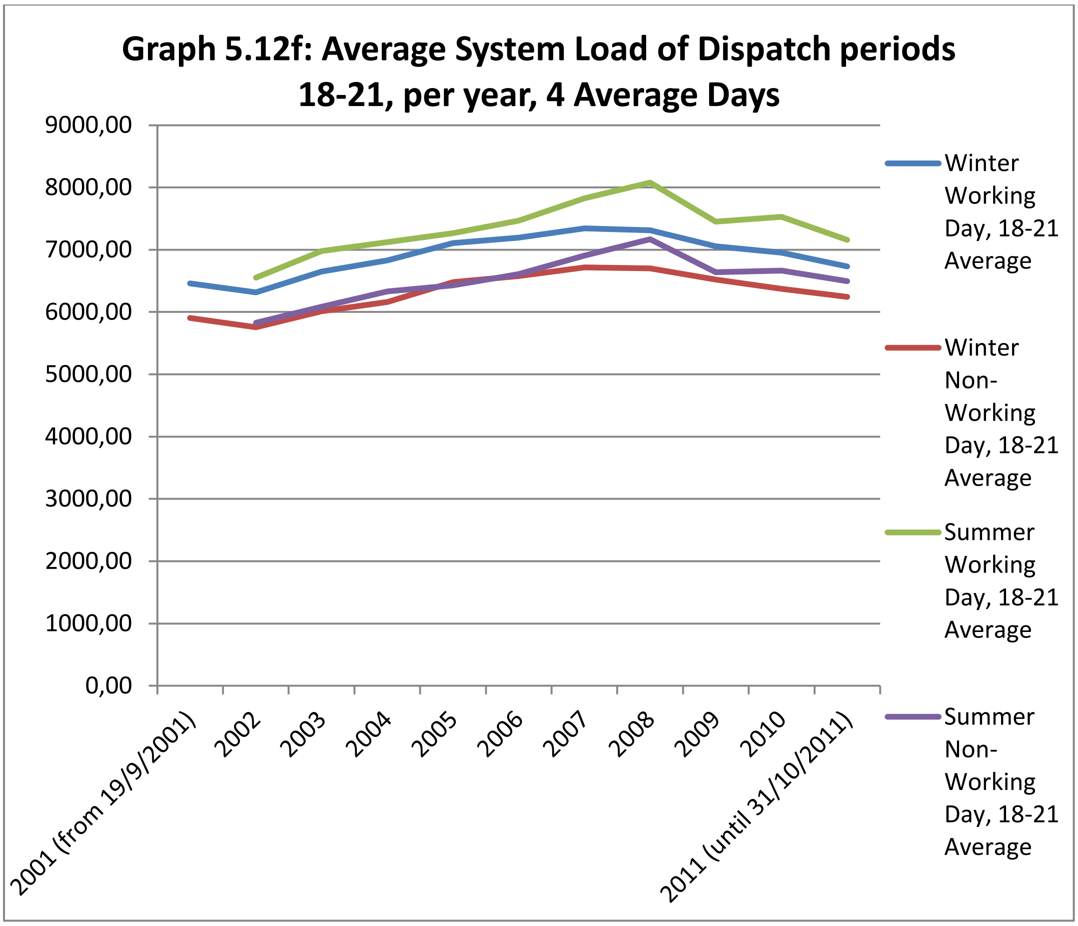

Graph 5.6f: Average System Load, Annually, Dispatch periods 18-21, Years 2002-2011
12000,00
10000,00
8000,00
6000,00
4000,00
2000,00
0,00
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.12b: Day-time Average System Load per year, 4 Average Days
9000,00
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day, 7-22 Average
Winter Non-Working Day, 7-22 Average
Summer Working Day, 7-22 Average
Summer Non-Working Day, 7-22 Average


Graph 5.12c: Night-time Average System Load per year, 4 Average Days
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day, 23-6 Average
Winter Non-Working Day, 23-6 Average
Summer Working Day, 23-6 Average
Summer Non-Working Day, 23-6 Average

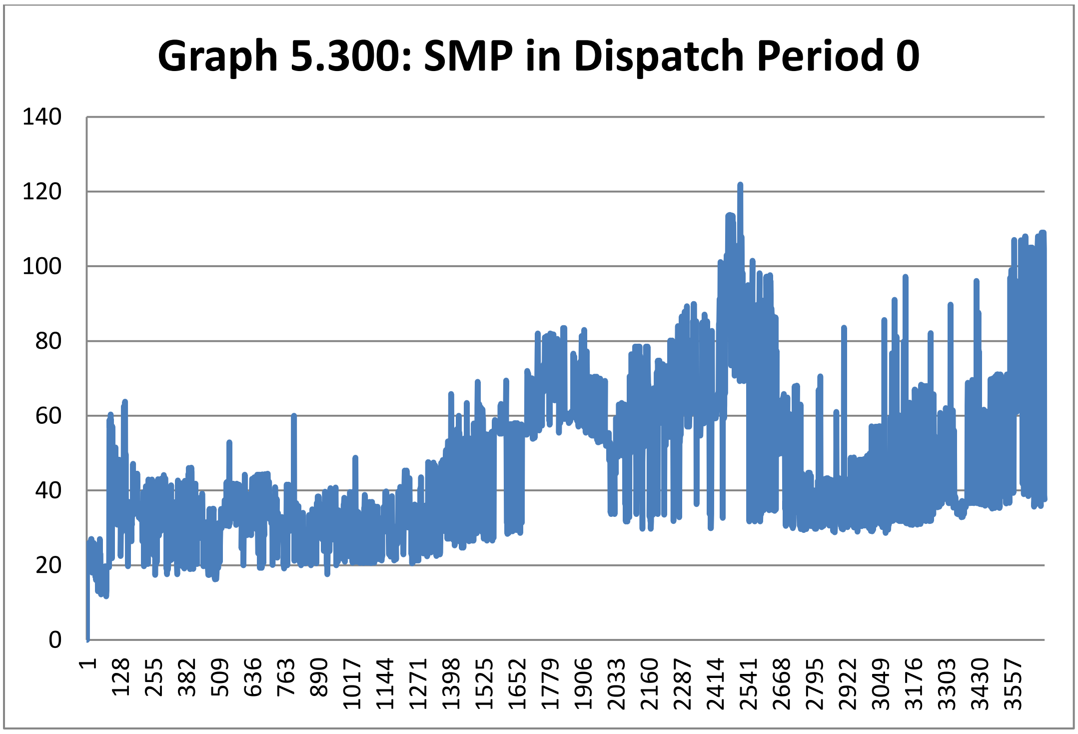

Graph 5.12d: Average System Load of Dispatch periods 9-14 & 18-21, per year, 4 Average Days
9000,00
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day, 9-14 and 18-21 Average
Winter Non-Working Day, 9-14 and 18-21 Average
Summer Working Day, 9-14 and 18-21 Average
Summer Non-Working Day, 9-14 and 18-21 Average

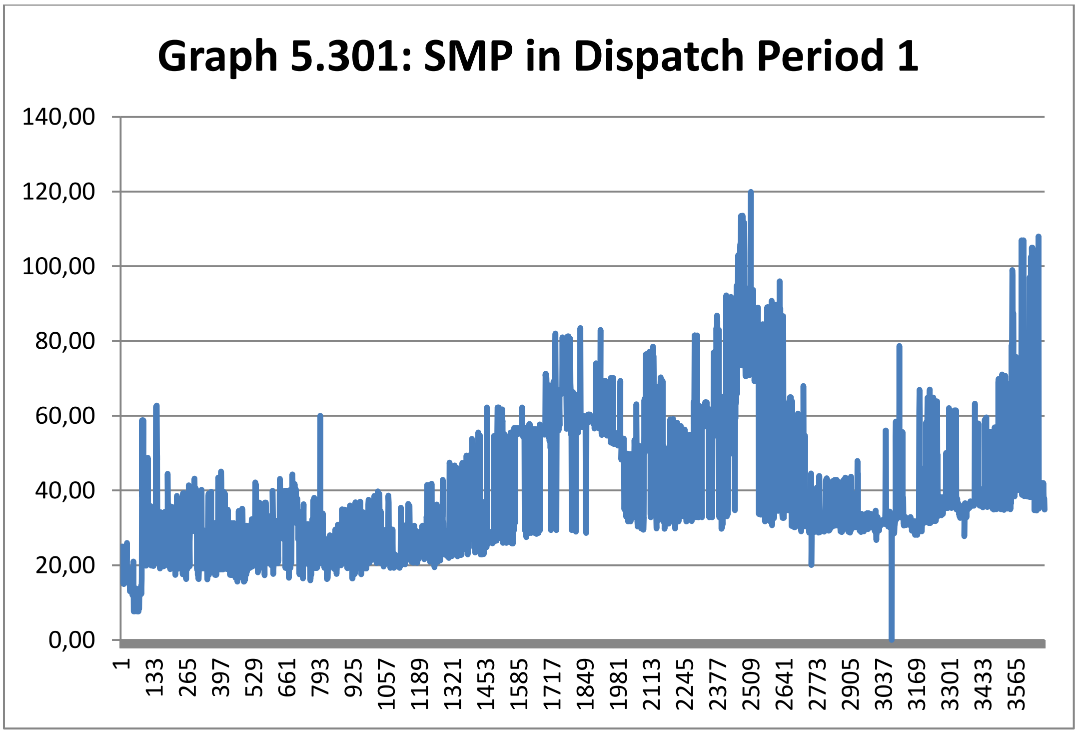

Graph 5.12e: Average System Load of Dispatch periods 9-14, per year, 4 Average Days
9000,00
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day, 9-14 Average
Winter Non-Working Day, 9-14 Average
Summer Working Day, 9-14 Average
Summer Non-Working Day, 9-14 Average

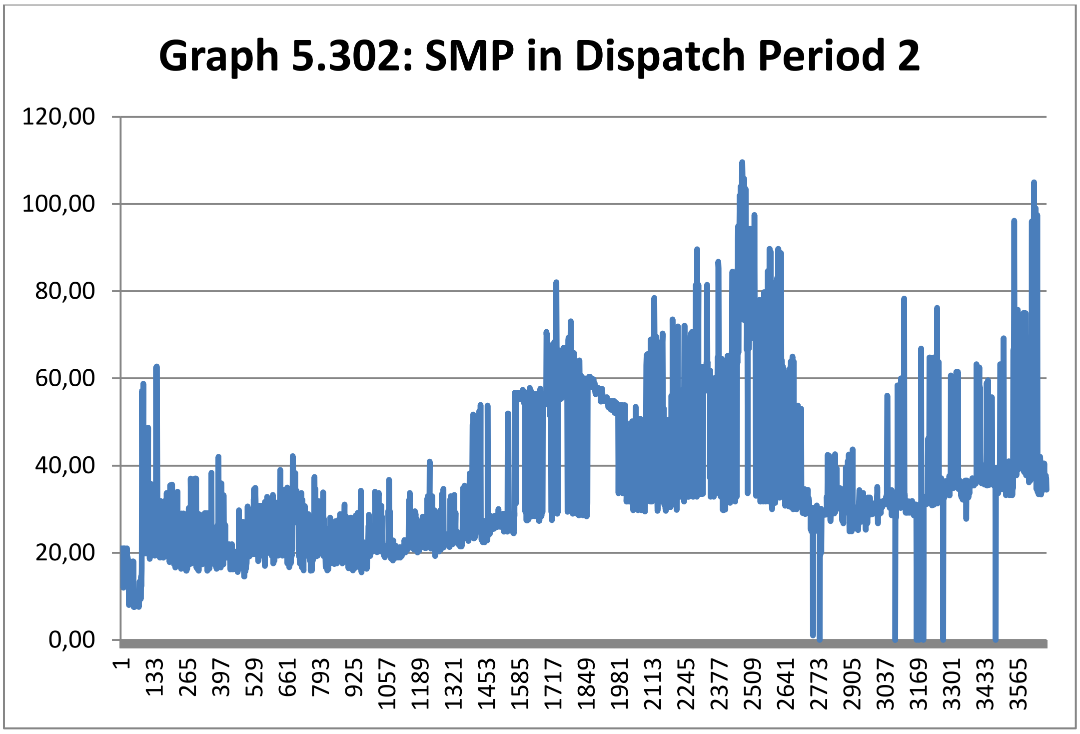

Graph 5.12f: Average System Load of Dispatch periods 18-21, per year, 4 Average Days
9000,00
8000,00
7000,00
6000,00
5000,00
4000,00
3000,00
2000,00
1000,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day, 18-21 Average
Winter Non-Working Day, 18-21 Average
Summer Working Day, 18-21 Average
Summer Non-Working Day, 18-21 Average

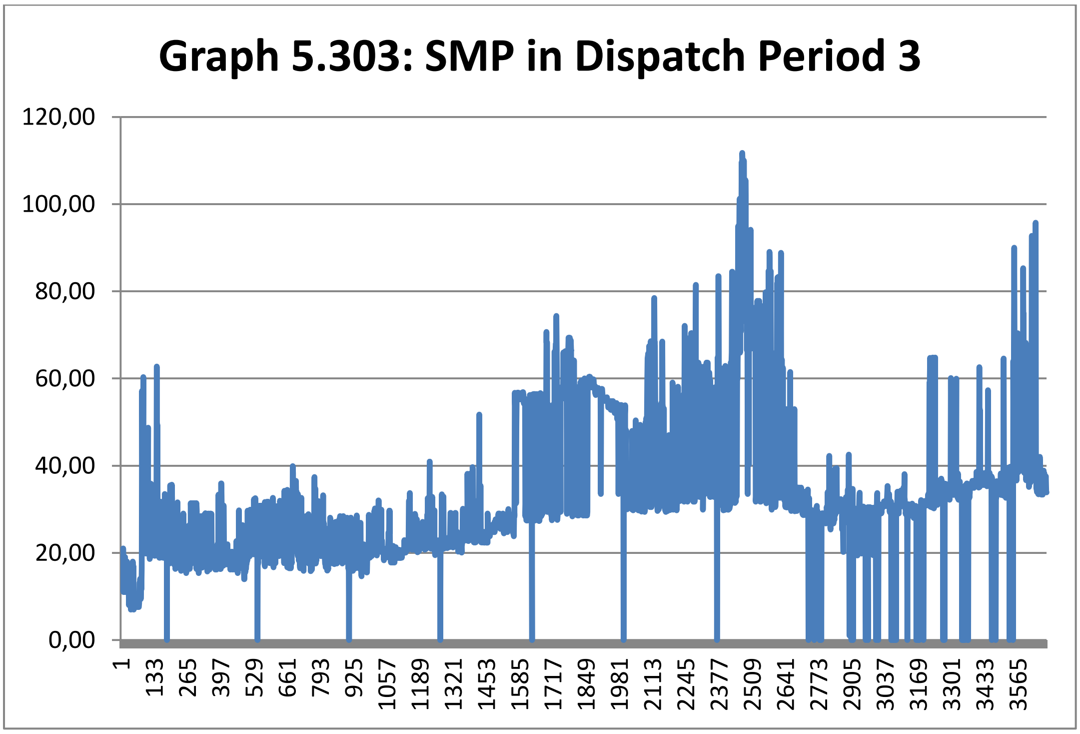
Part 2

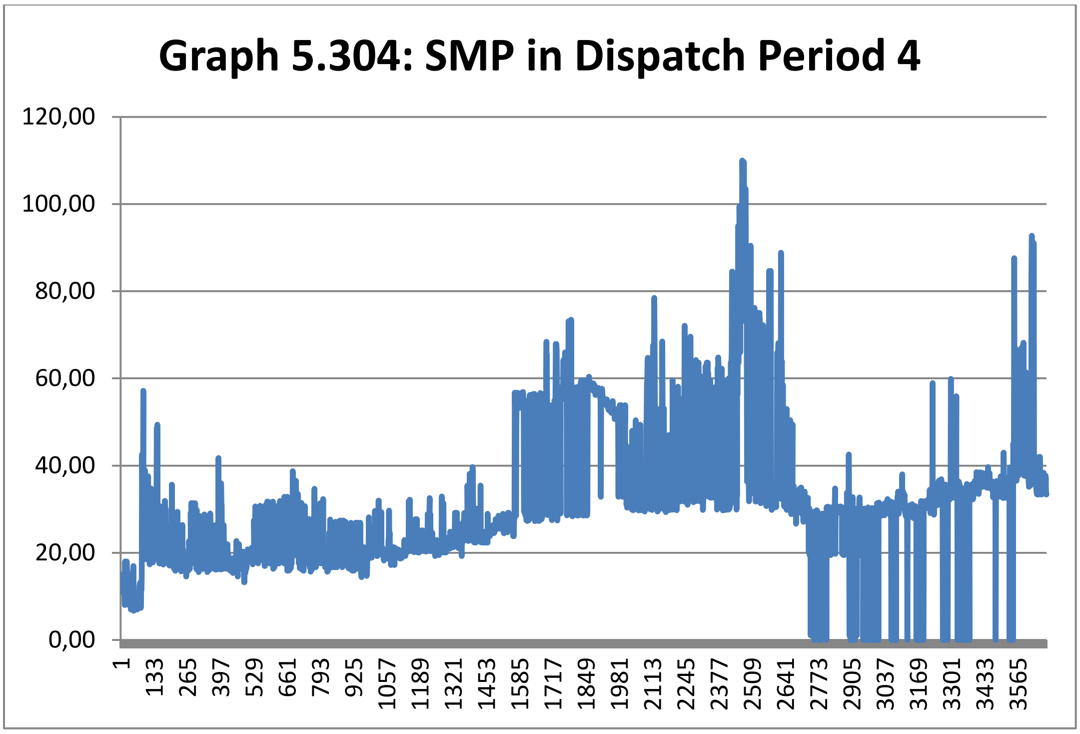
System Marginal Price (SMP) Data are presented in this part.

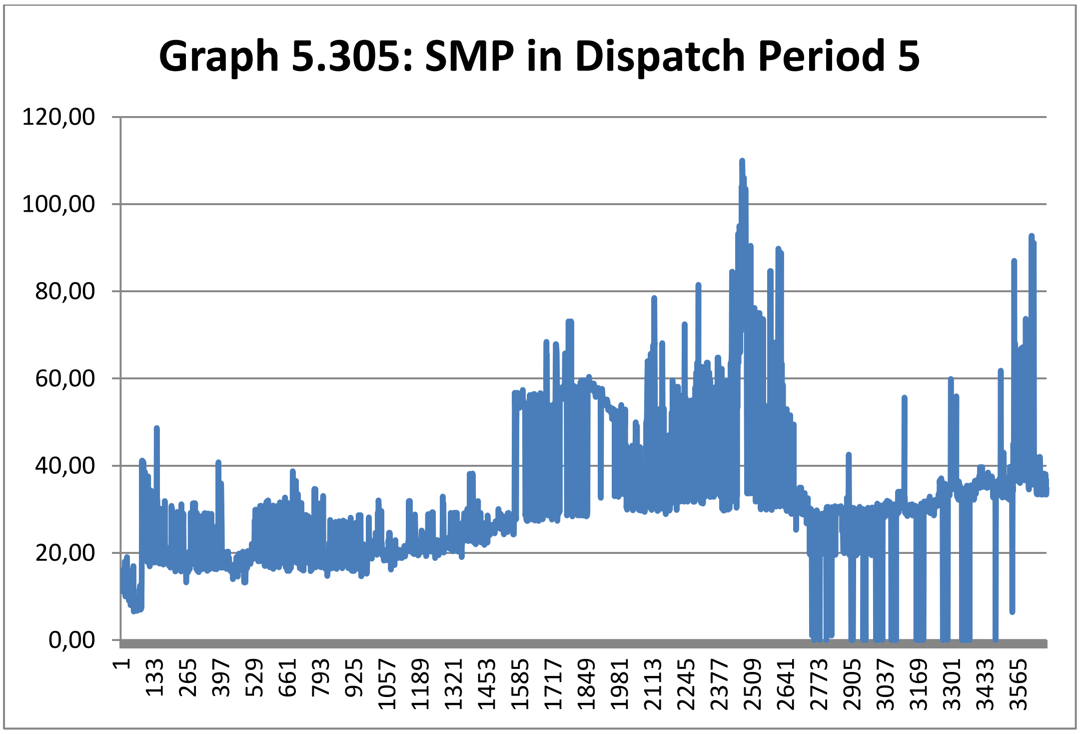


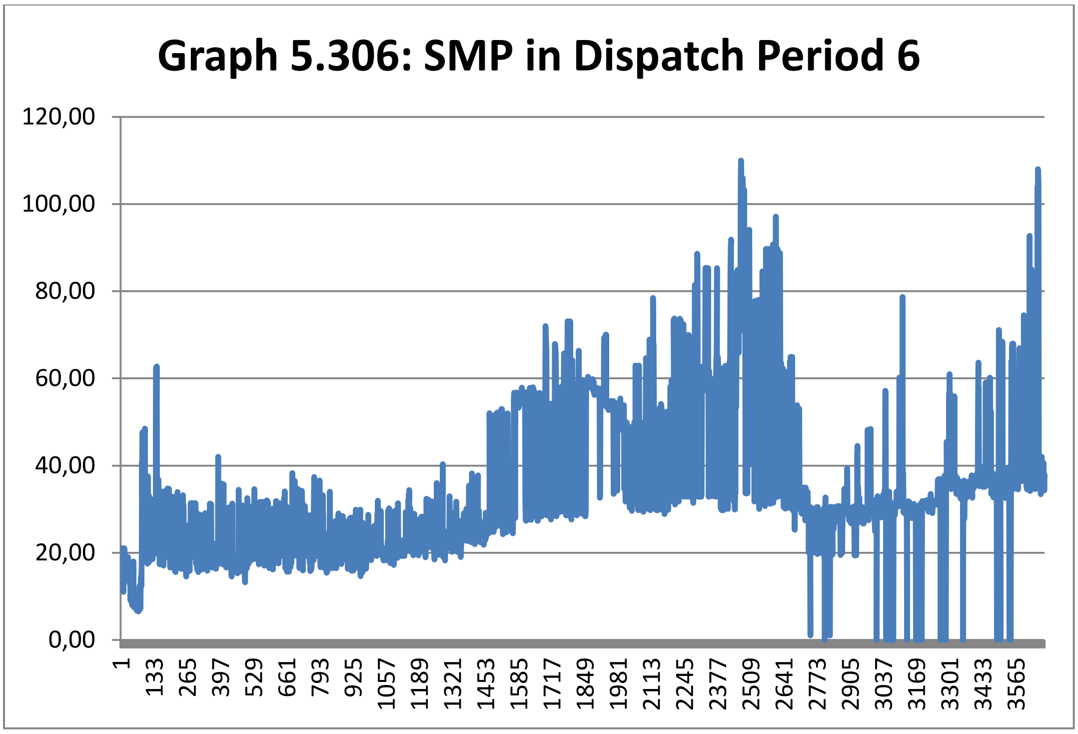


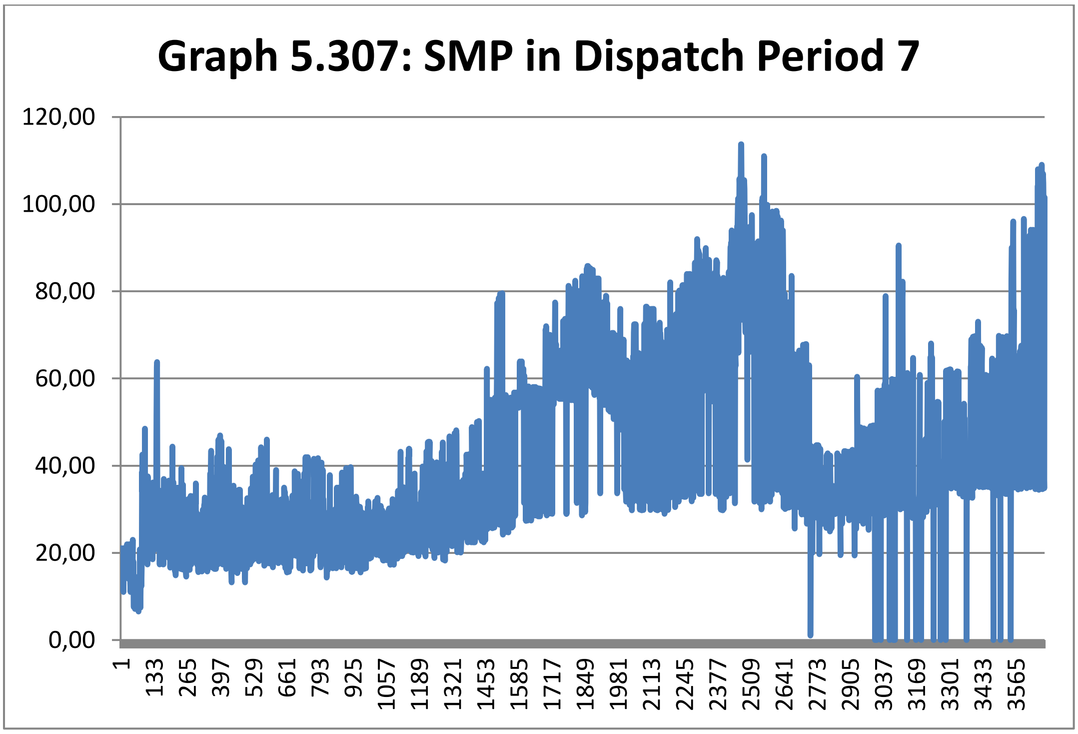

Graph 5.302: SMP in Dispatch Period 2
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

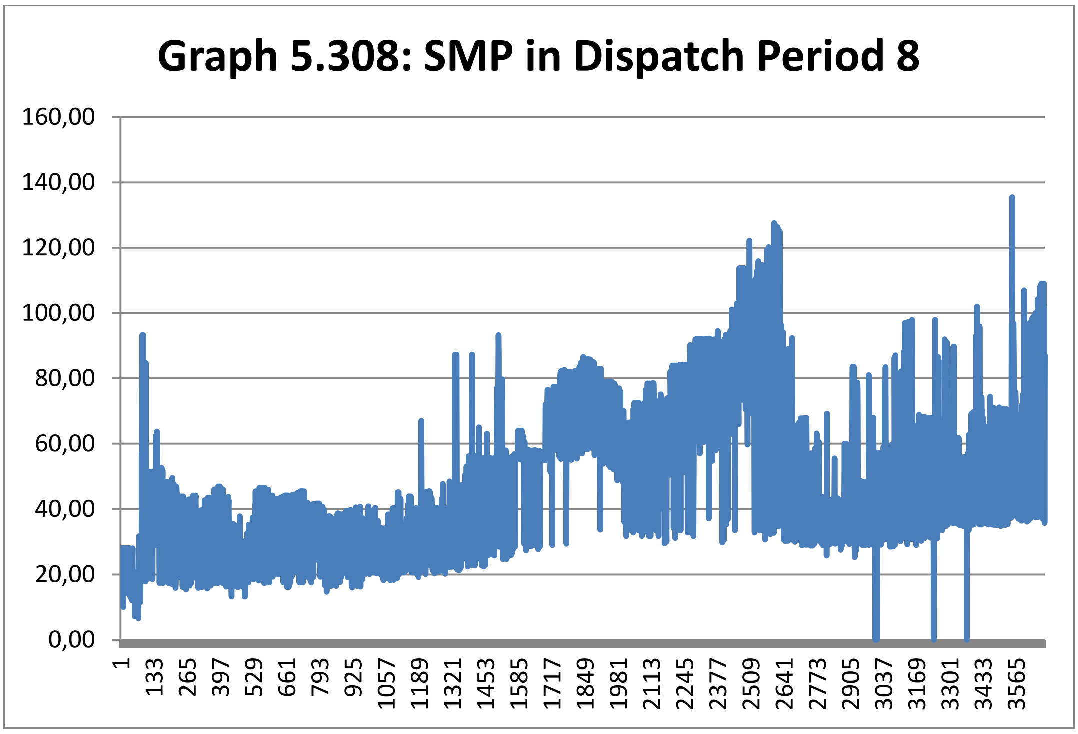

Graph 5.303: SMP in Dispatch Period 3
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

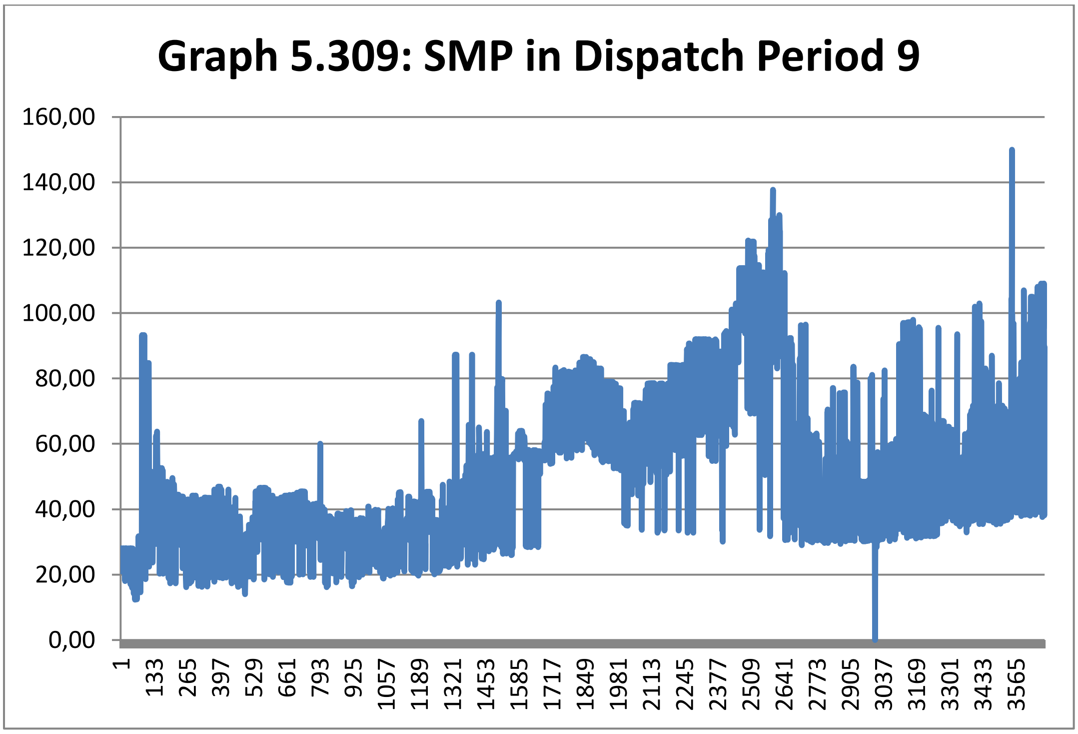

Graph 5.304: SMP in Dispatch Period 4
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.305: SMP in Dispatch Period 5
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.306: SMP in Dispatch Period 6
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.307: SMP in Dispatch Period 7
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.308: SMP in Dispatch Period 8
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.309: SMP in Dispatch Period 9
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
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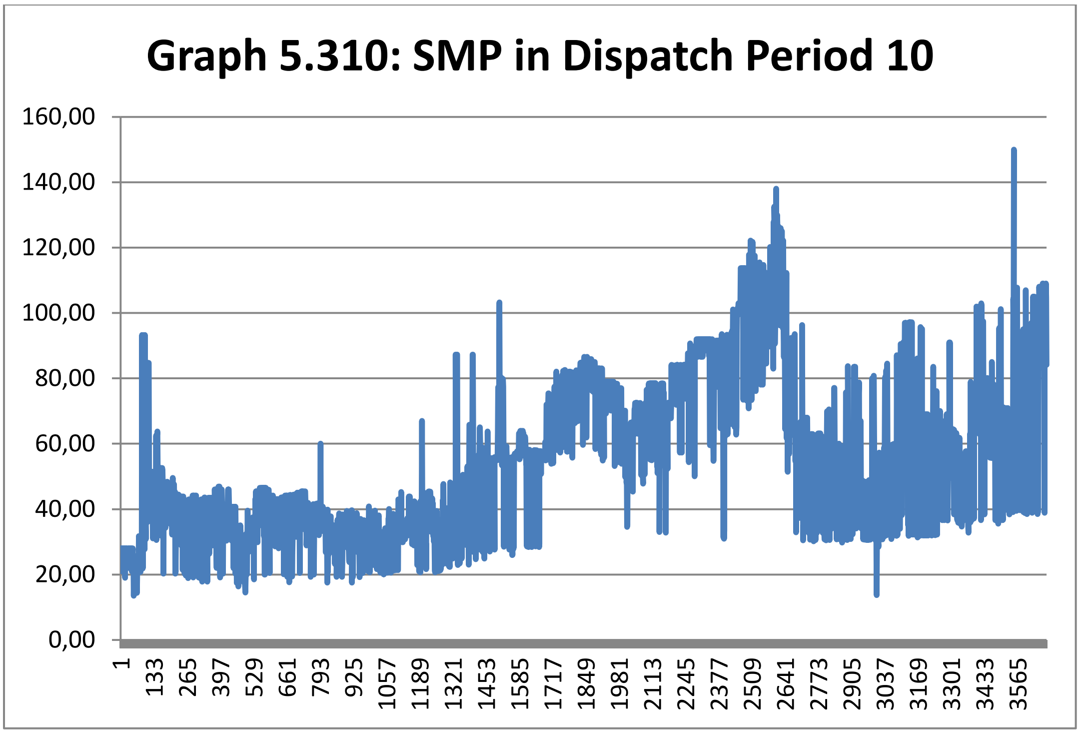
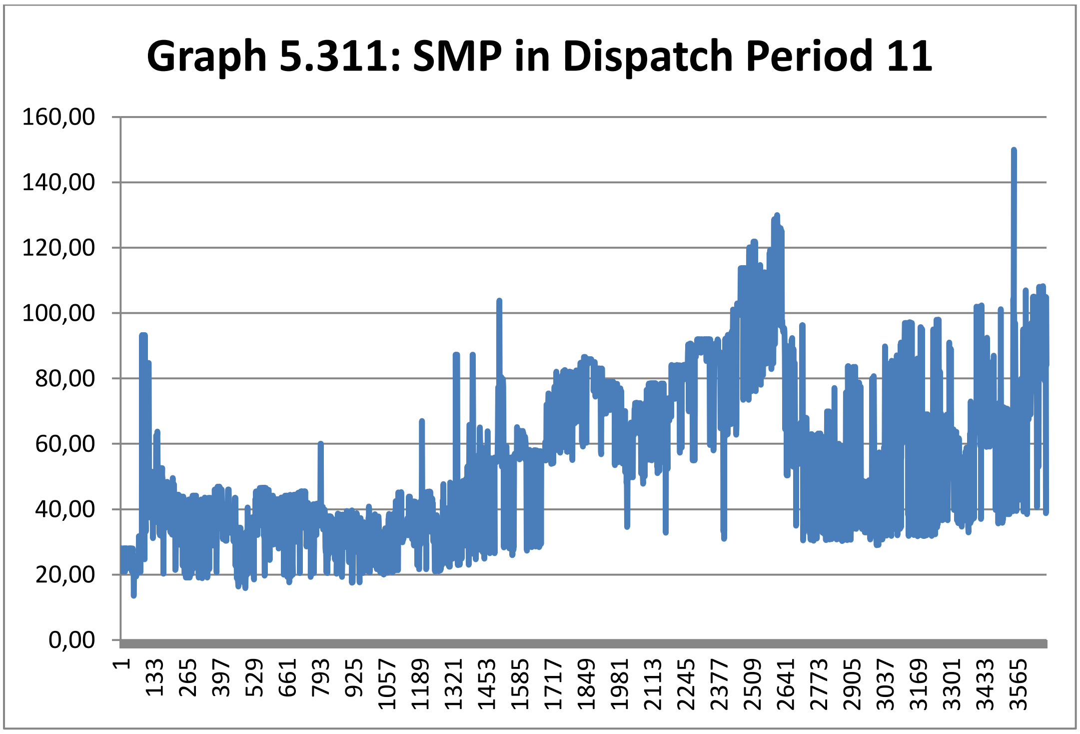
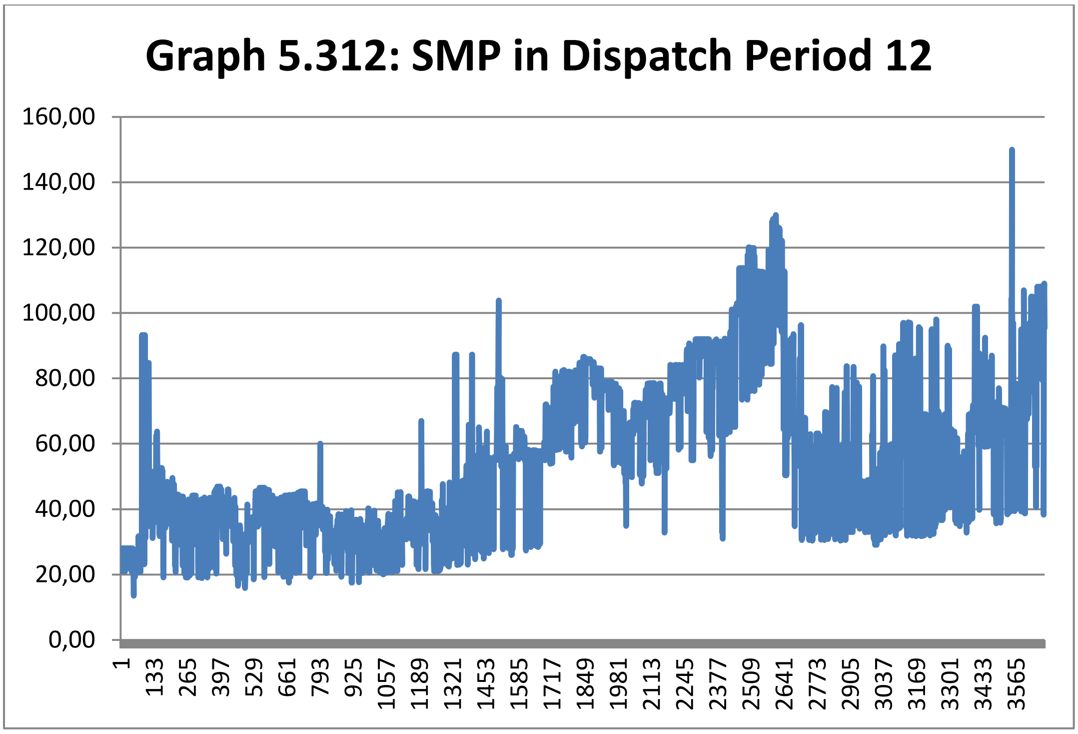
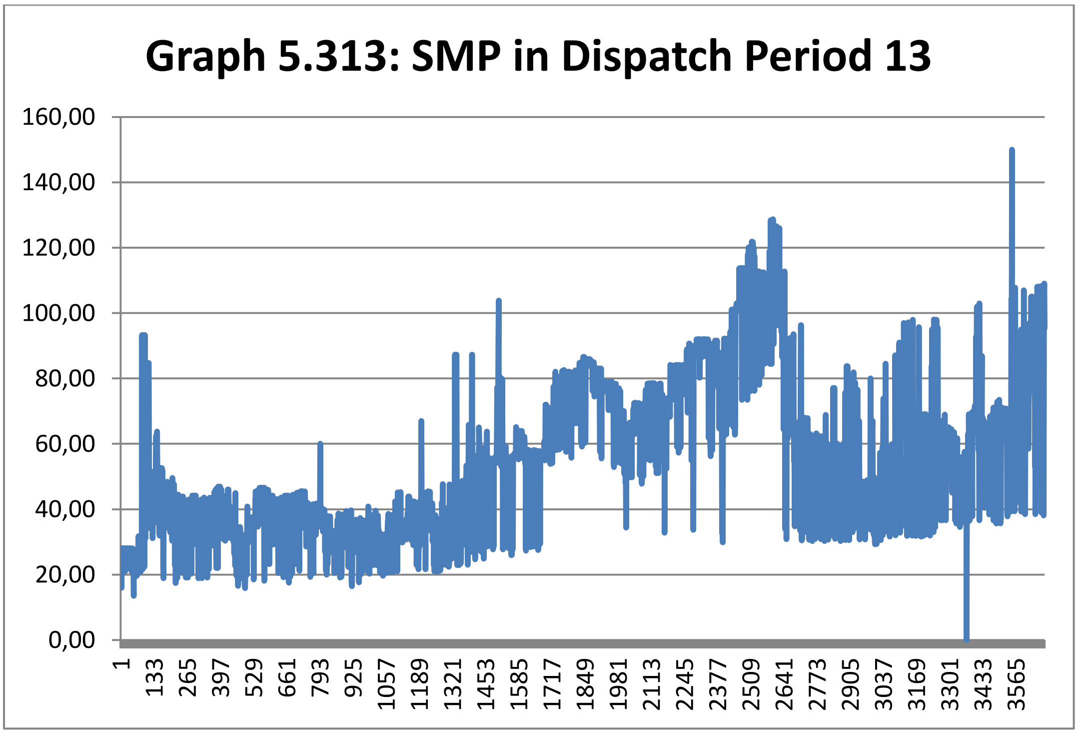
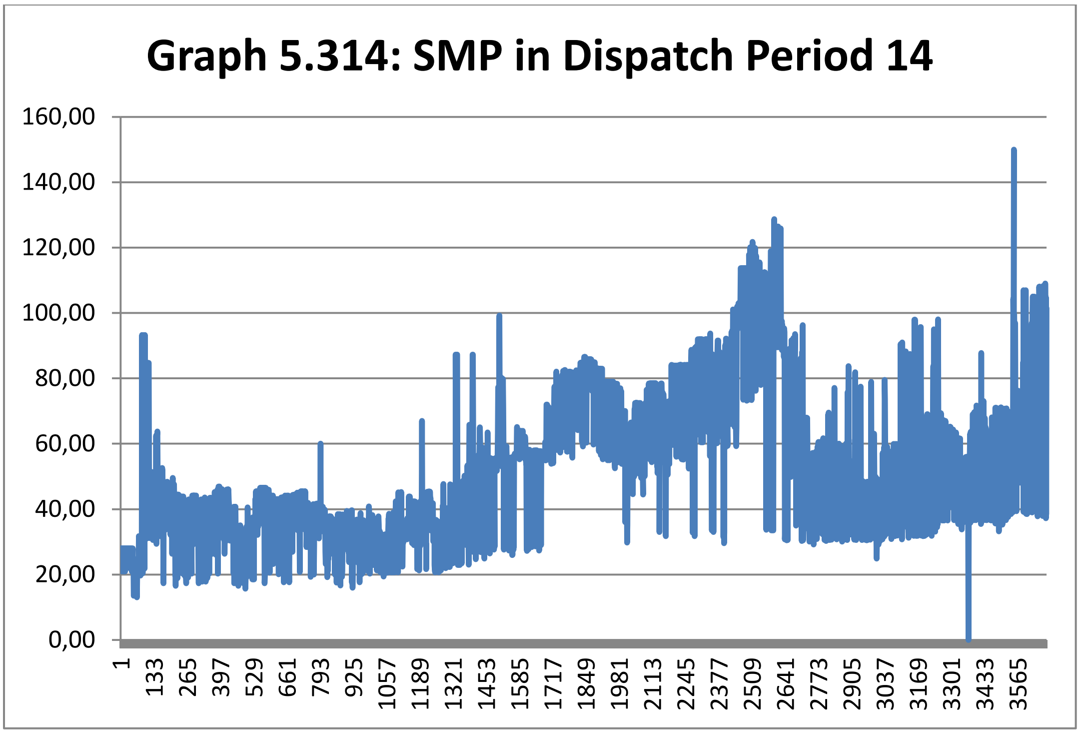
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

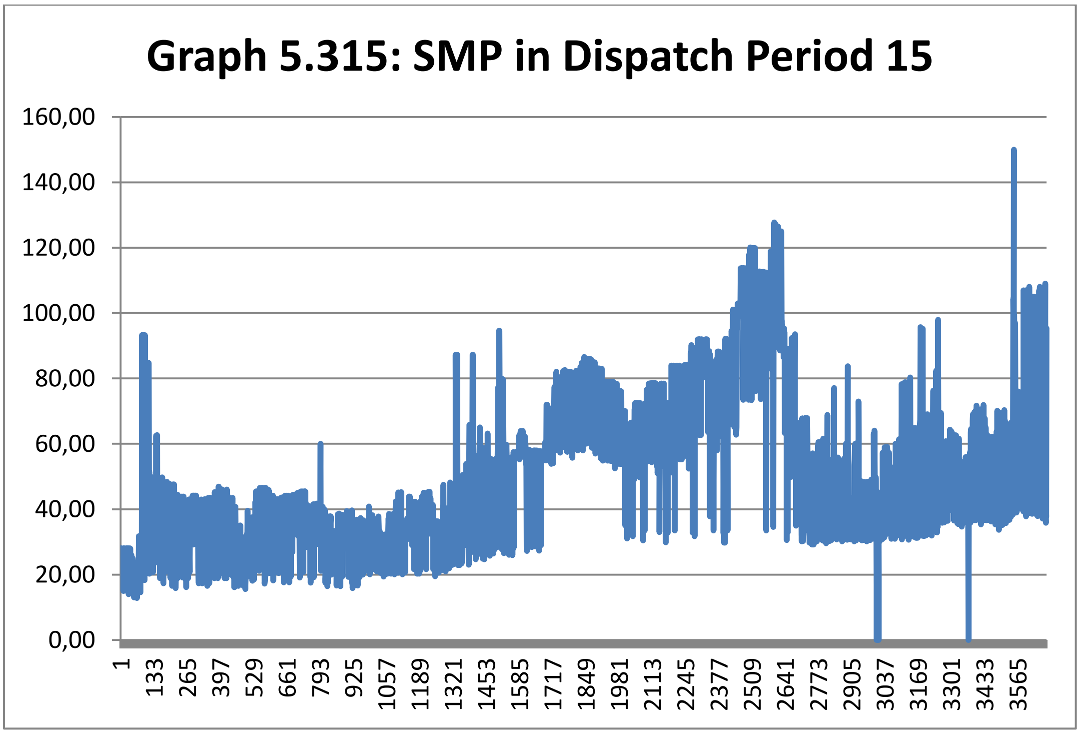

Graph 5.310: SMP in Dispatch Period 10
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.311: SMP in Dispatch Period 11
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.312: SMP in Dispatch Period 12
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.313: SMP in Dispatch Period 13
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.314: SMP in Dispatch Period 14
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.315: SMP in Dispatch Period 15
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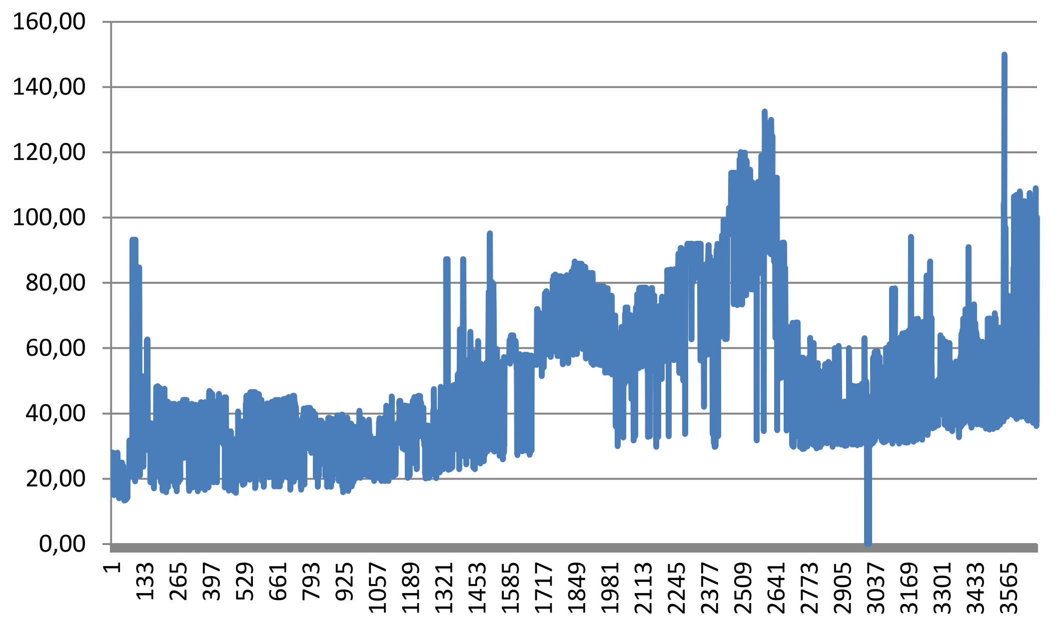
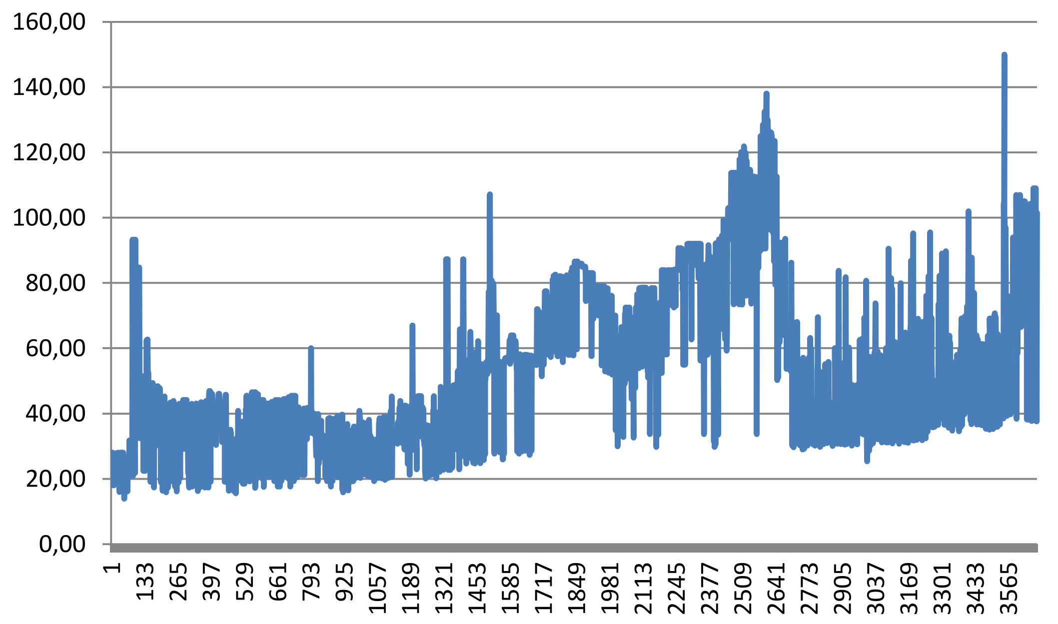
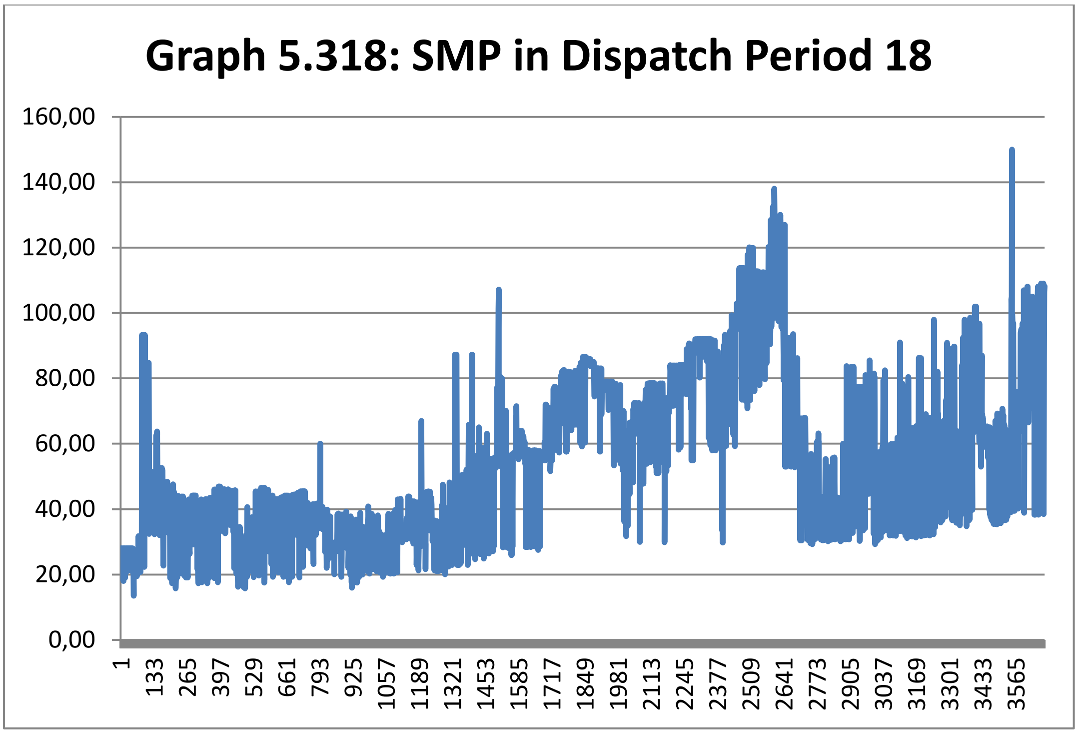
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

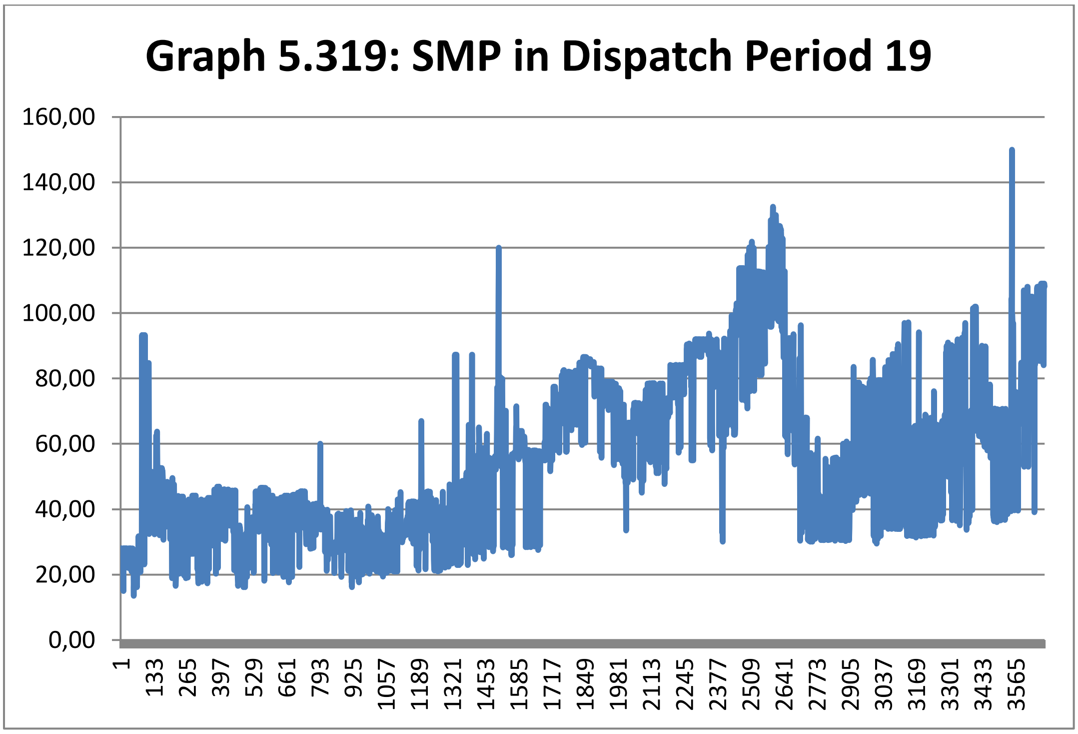
Graph 5.316: SMP in Dispatch Period 16

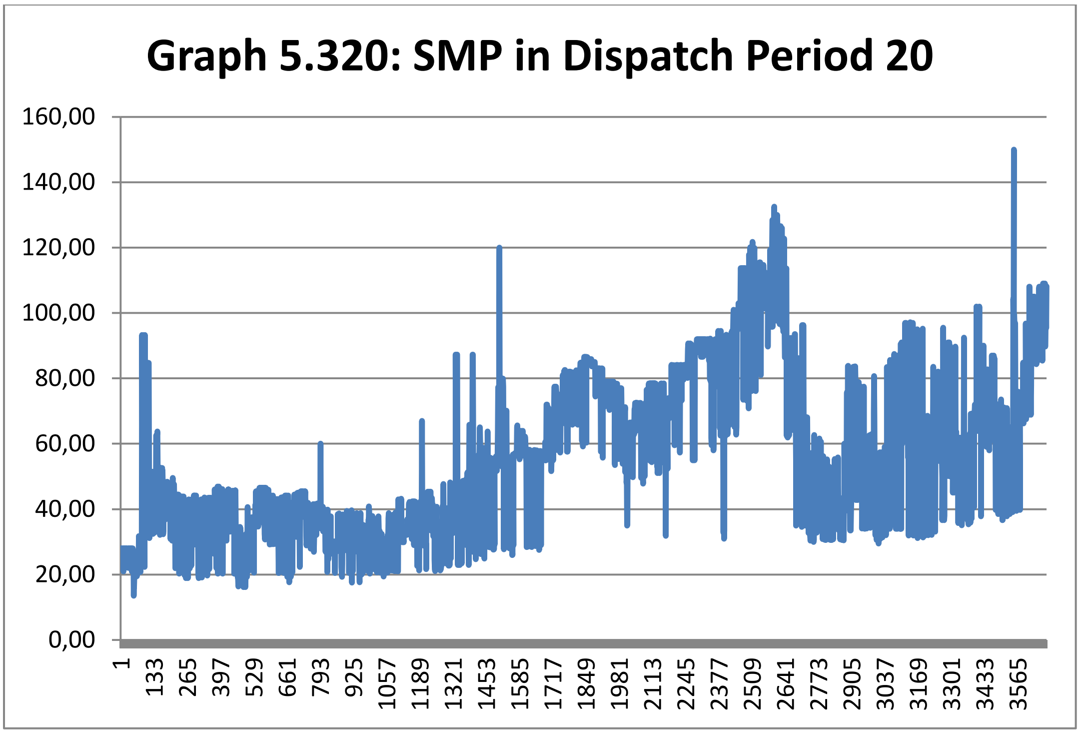


Graph 5.317: SMP in Dispatch Period 17

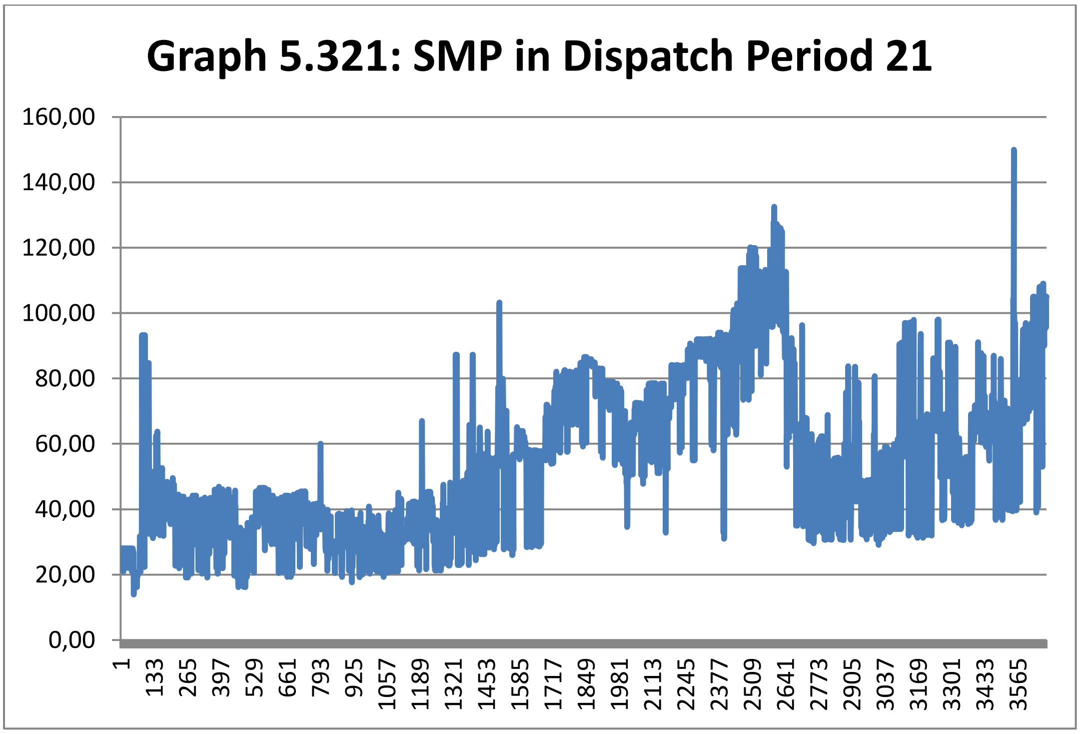



Graph 5.318: SMP in Dispatch Period 18
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.319: SMP in Dispatch Period 19
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565



Graph 5.320: SMP in Dispatch Period 20
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565



Graph 5.321: SMP in Dispatch Period 21
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
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1849
1981
2113
2245
2377
2509
2641
2773
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3301
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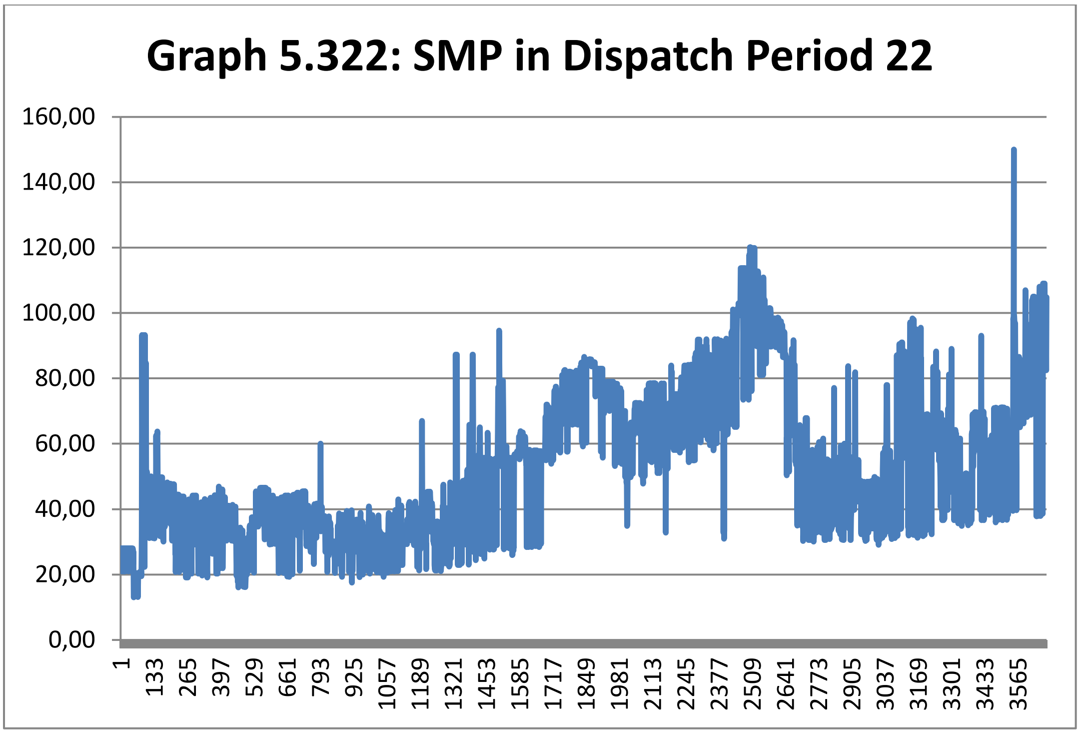
Graph 5.322: SMP in Dispatch Period 22
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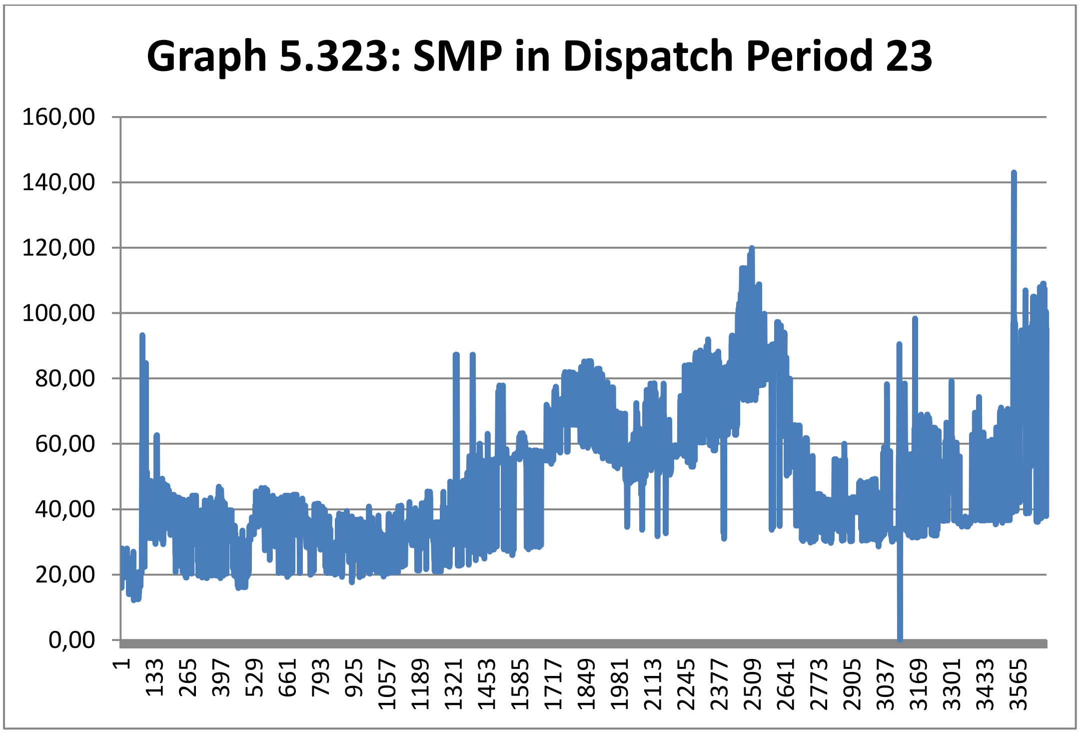
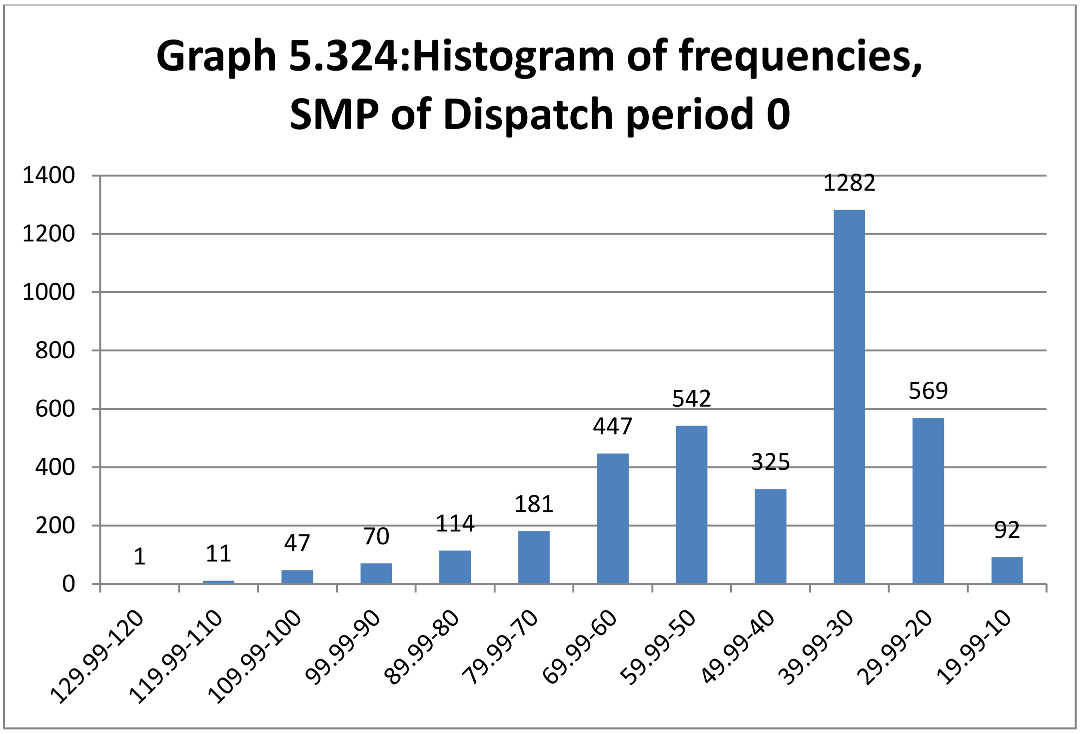
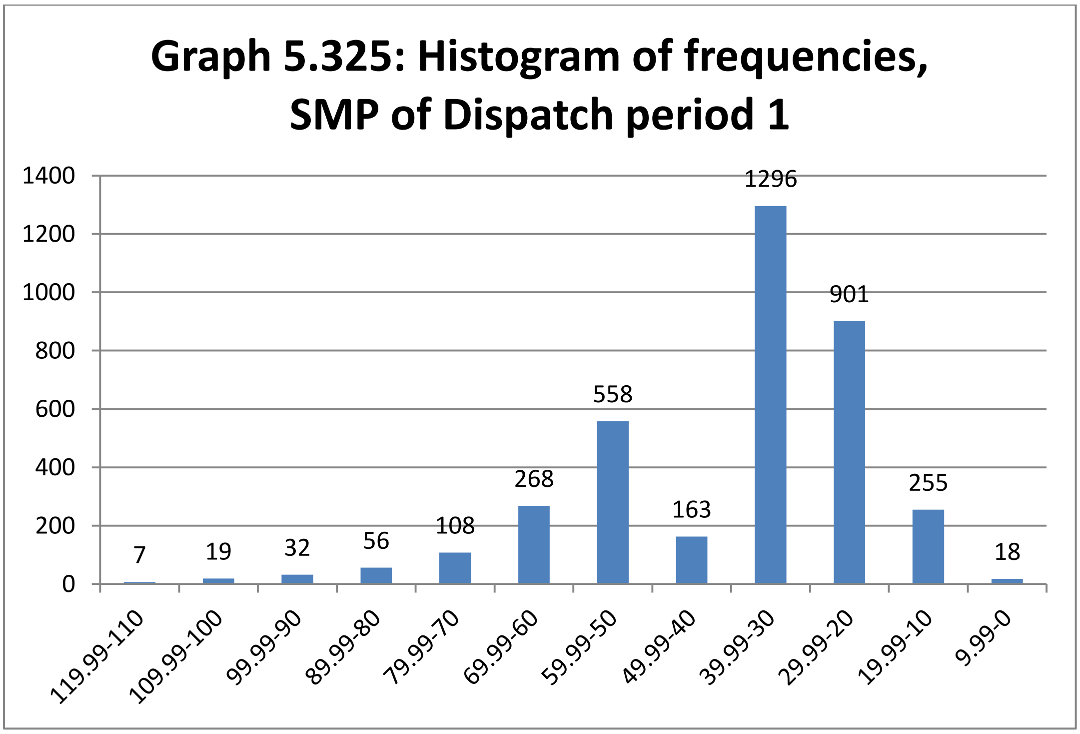
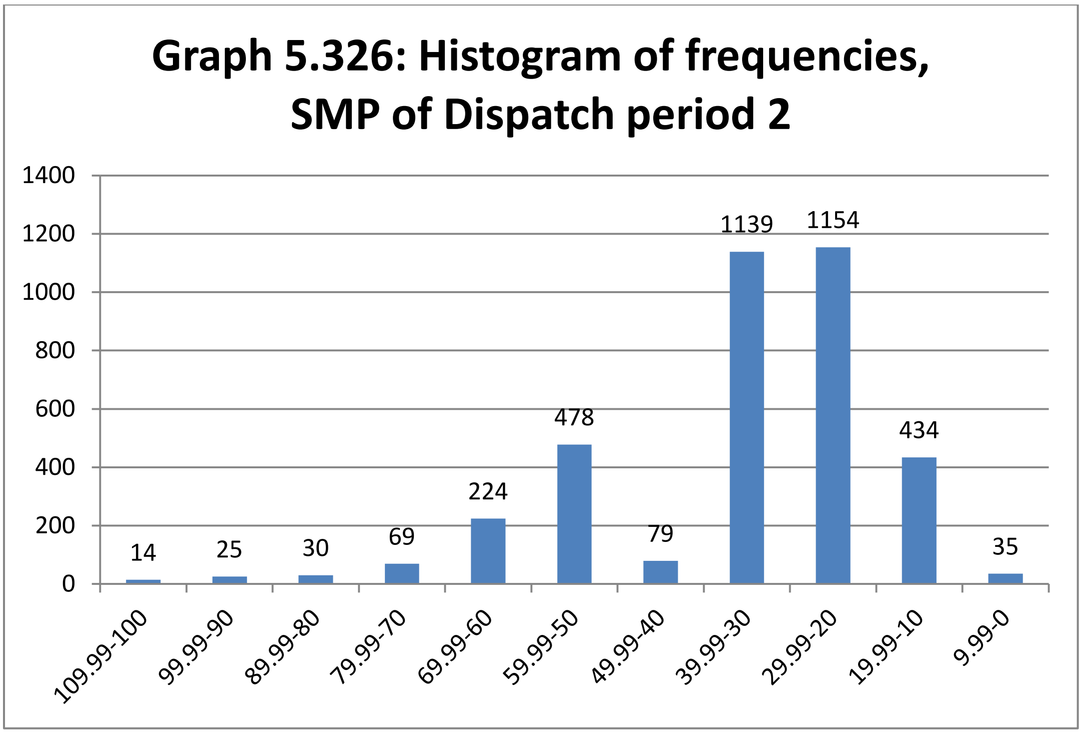
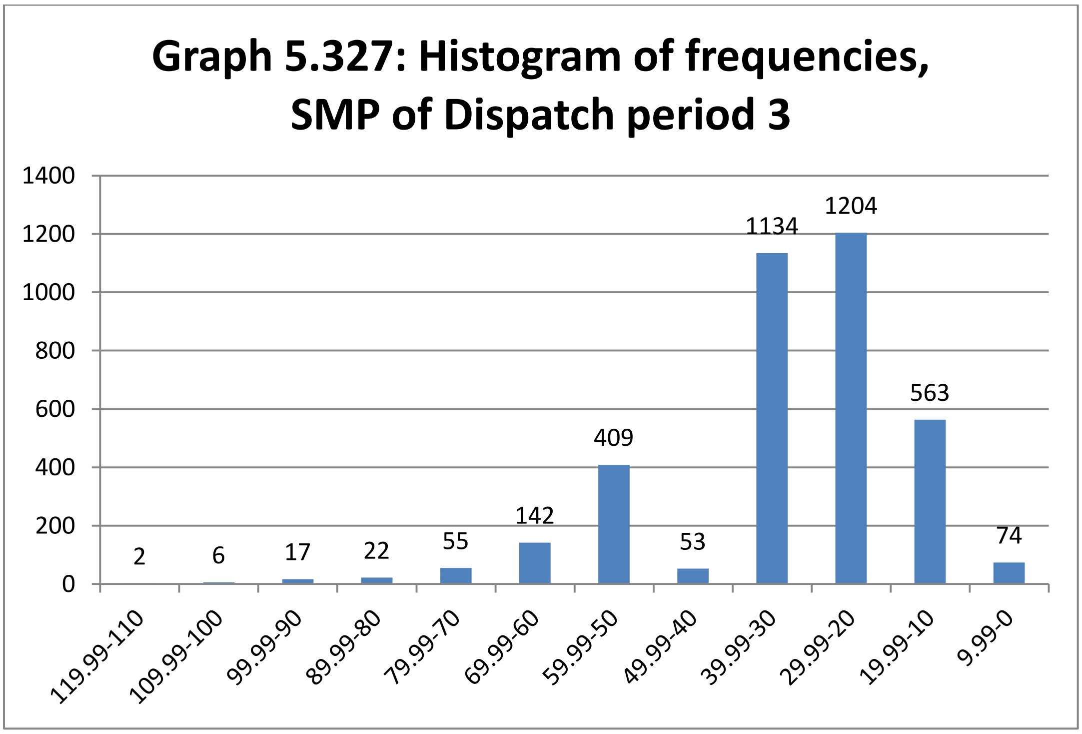
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.323: SMP in Dispatch Period 23
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

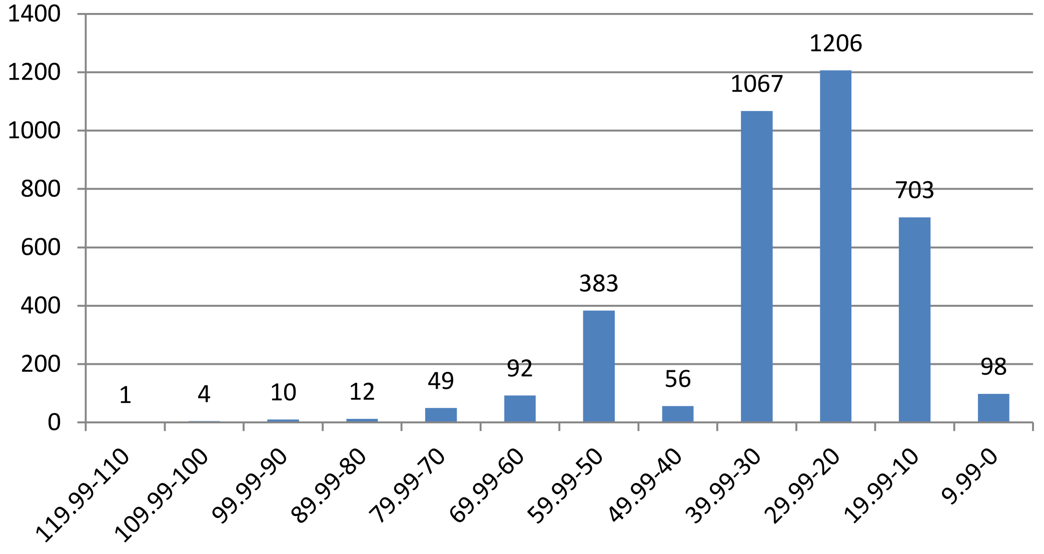

Graph 5.324:Histogram of frequencies, SMP of Dispatch period 0
1400
1200
1000
800
600
400
200
0
1
11
47
70
114
181
447
542
325
1282
569
92
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10


Graph 5.325: Histogram of frequencies, SMP of Dispatch period 1
1400
1200
1000
800
600
400
200
0
7
19
32
56
108
268
558
163
1296
901
255
18
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0

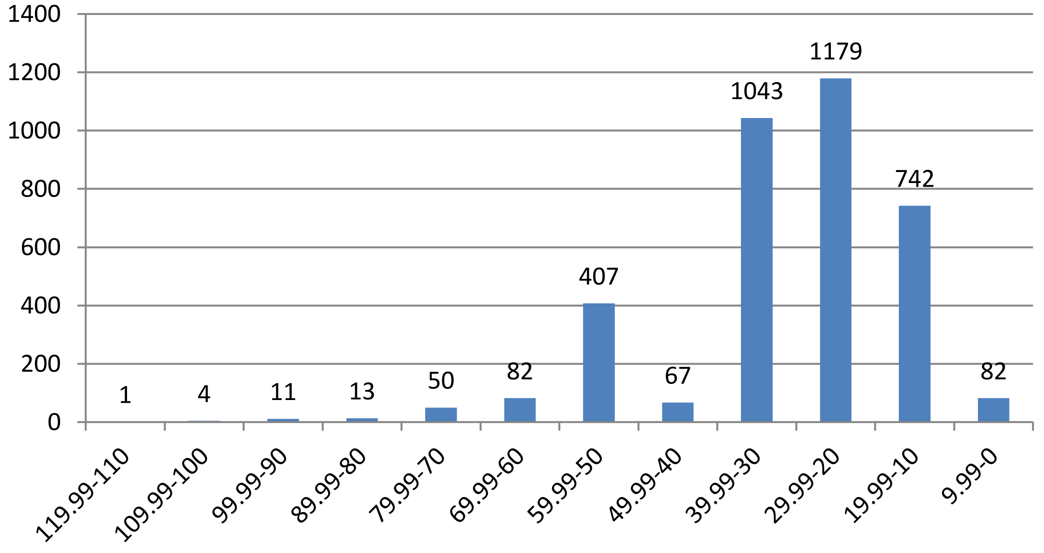

Graph 5.326: Histogram of frequencies,
SMP of Dispatch period 2
1400
1200
1000
800
600
400
200
0
14
25
30
69
224
478
79
1139
1154
434
35
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0


Graph 5.327: Histogram of frequencies,
SMP of Dispatch period 3
1400
1200
1000
800
600
400
200
0
2
6
17
22
55
142
409
53
1134
1204
563
74
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0

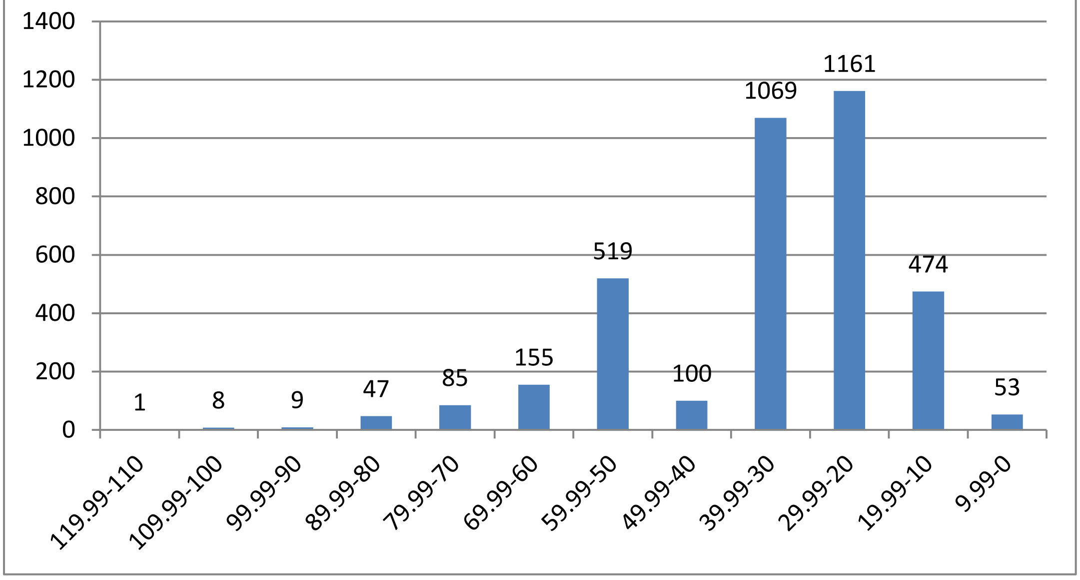
Graph 5.328: Histogram of frequencies, SMP of Dispatch period 4



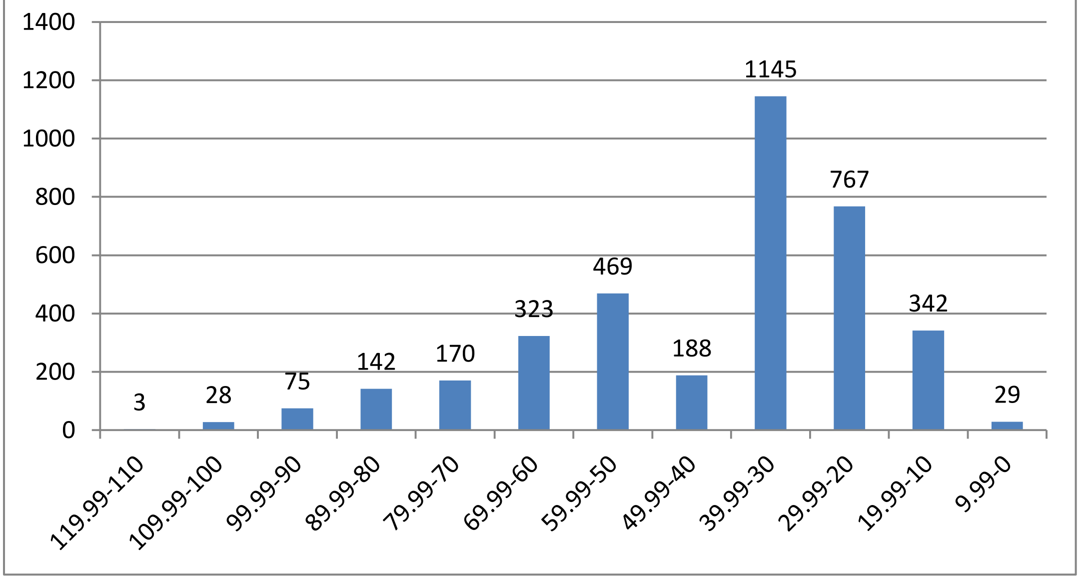
Graph 5.329: Histogram of frequencies, SMP of Dispatch period 5

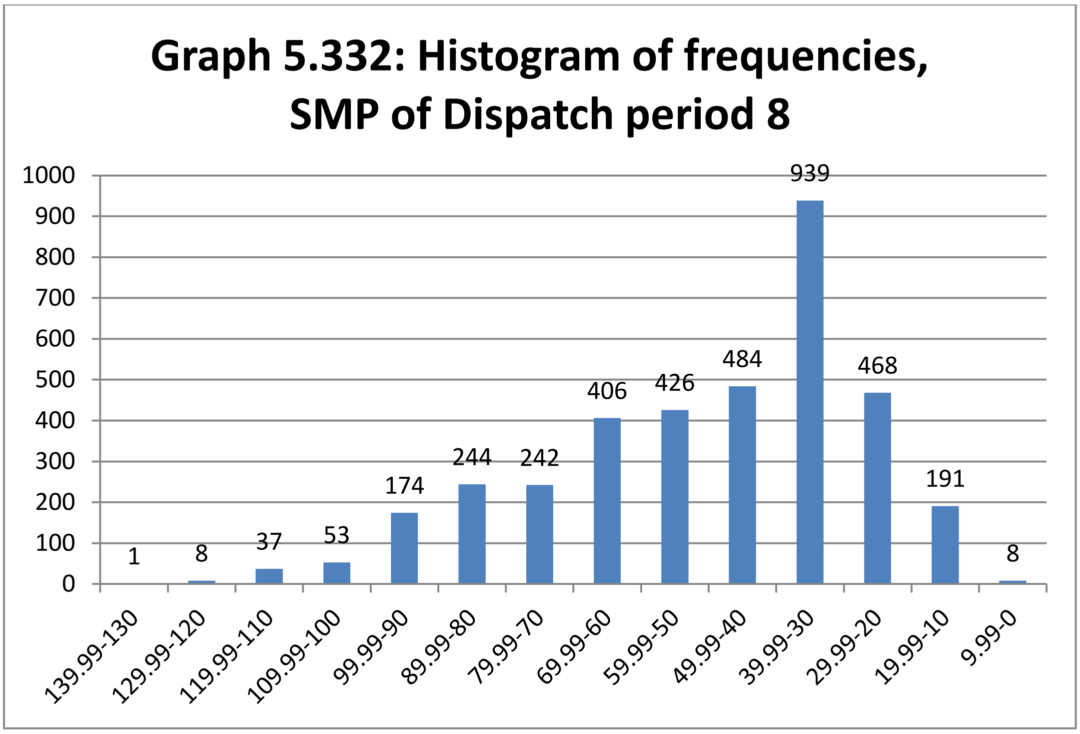


Graph 5.330: Histogram of frequencies, SMP of Dispatch period 6

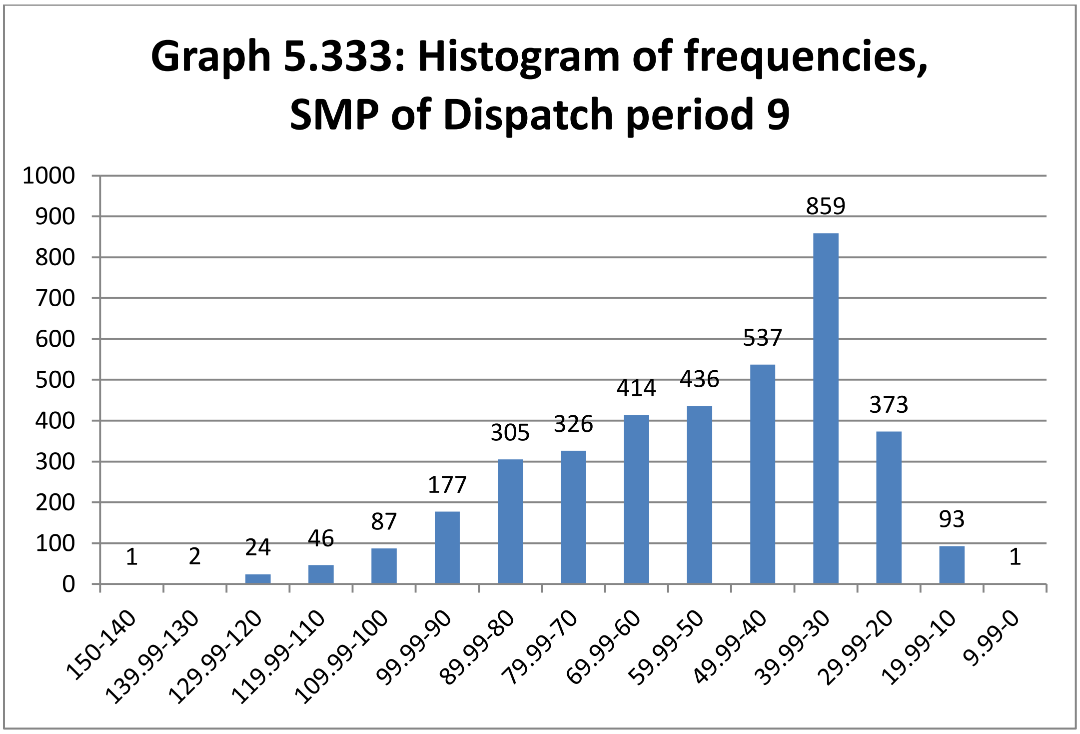


Graph 5.331: Histogram of frequencies, SMP of Dispatch period 7

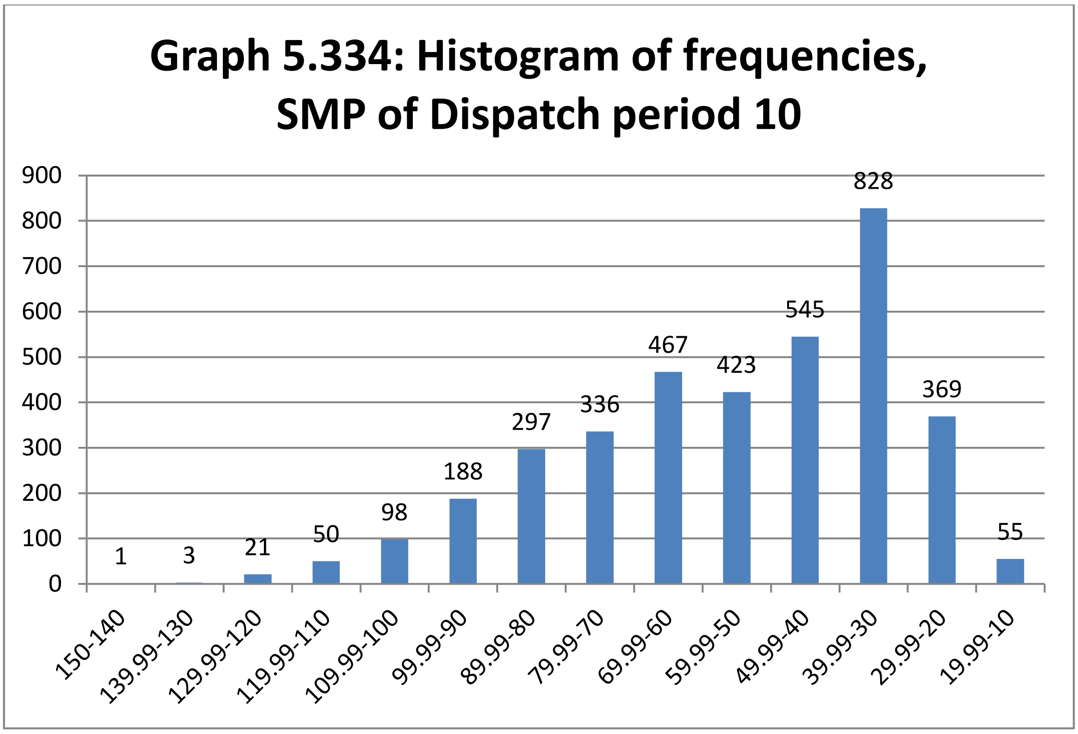


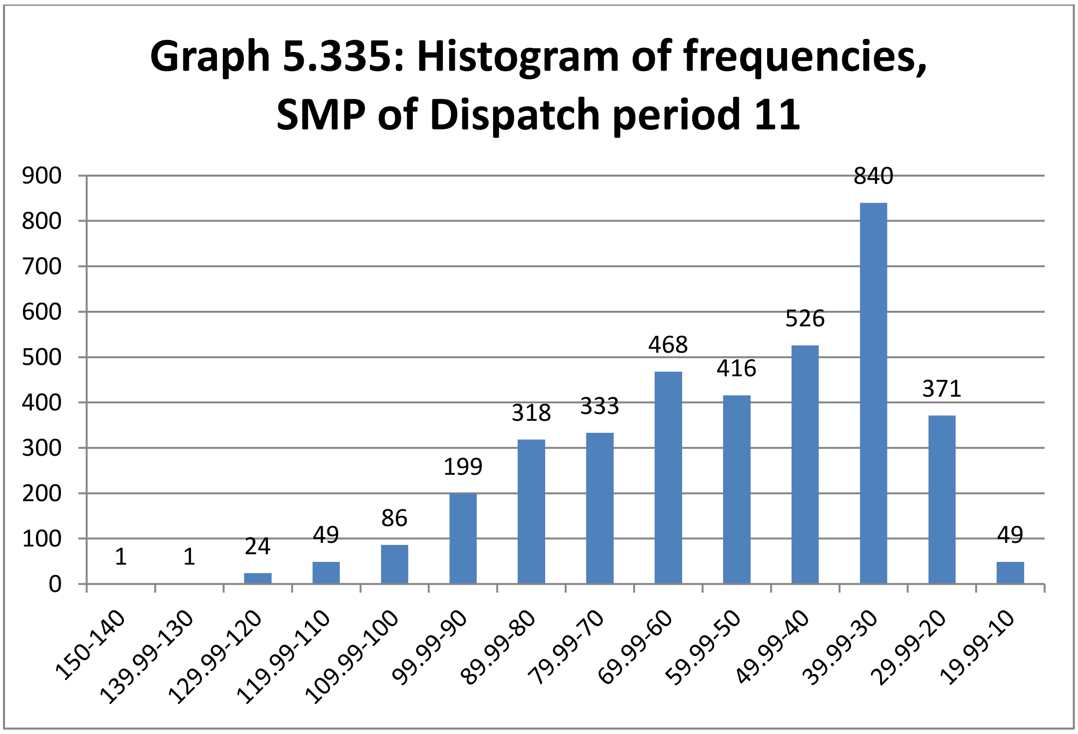


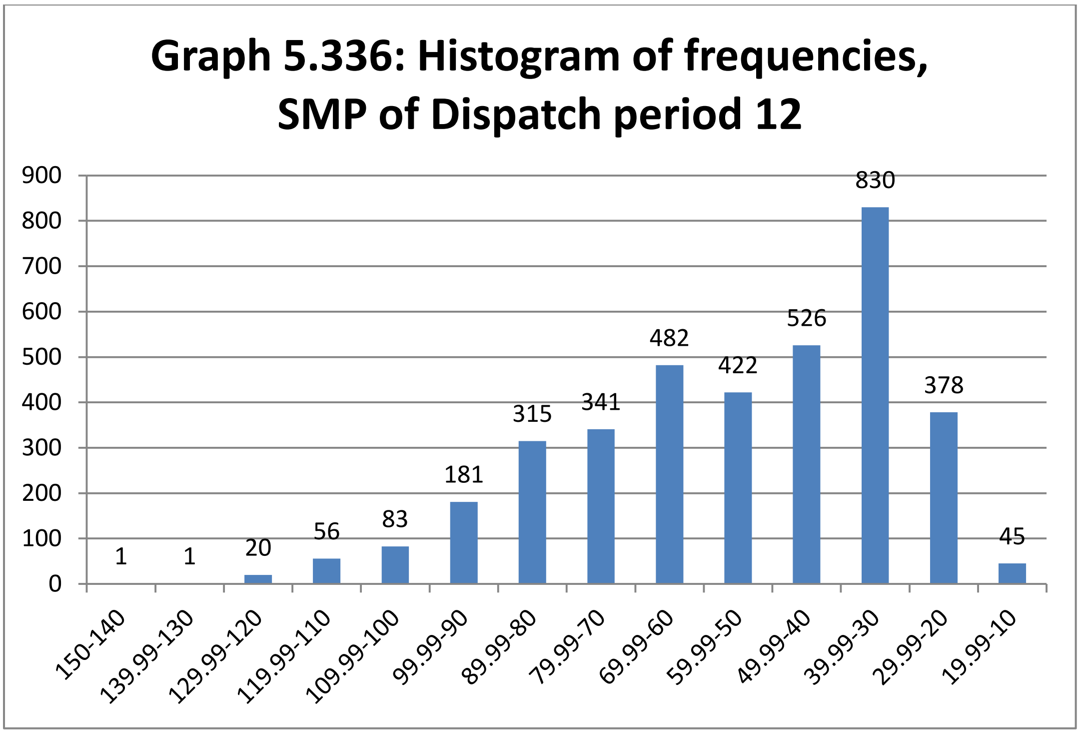
Graph 5.332: Histogram of frequencies,
SMP of Dispatch period 8
1000
900
800
700
600
500
400
300
200
100
0
1
8
37
53
174
244
242
406
426
484
939
468
191
8
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0



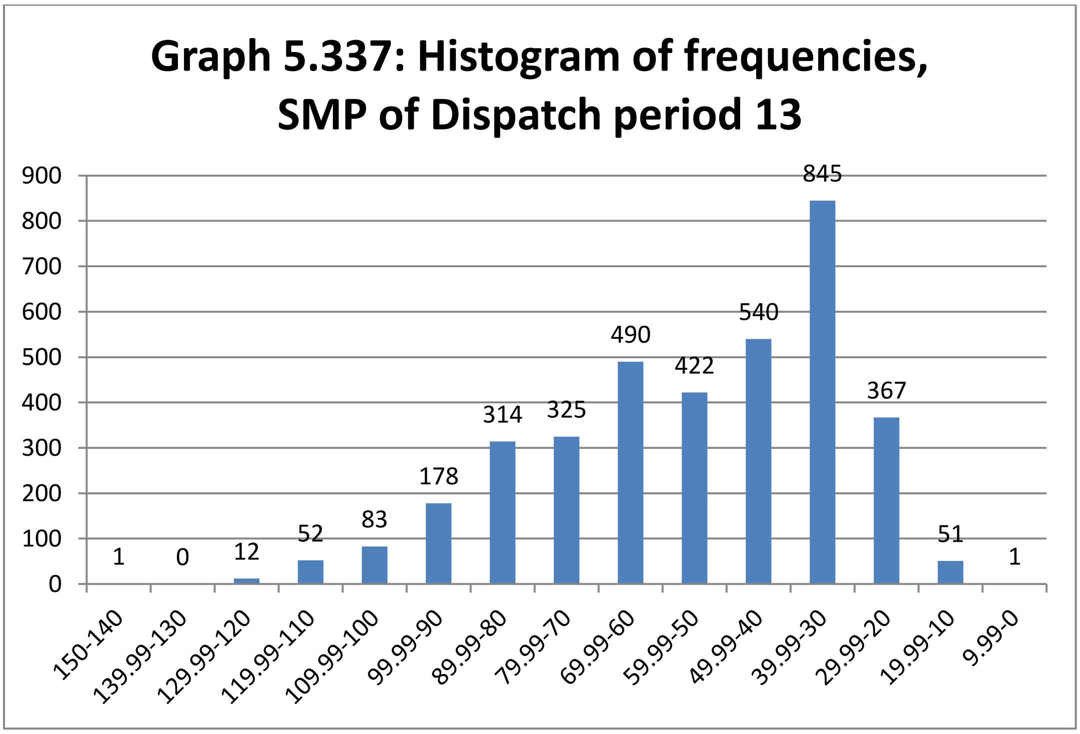
Graph 5.333: Histogram of frequencies,
SMP of Dispatch period 9
1000
900
800
700
600
500
400
300
200
100
0
1
2
24
46
87
177
305
326
414
436
537
859
373
93
1
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0


Graph 5.334: Histogram of frequencies, SMP of Dispatch period 10
900
800
700
600
500
400
300
200
100
0
1
3
21
50
98
188
297
336
467
423
545
828
369
55
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

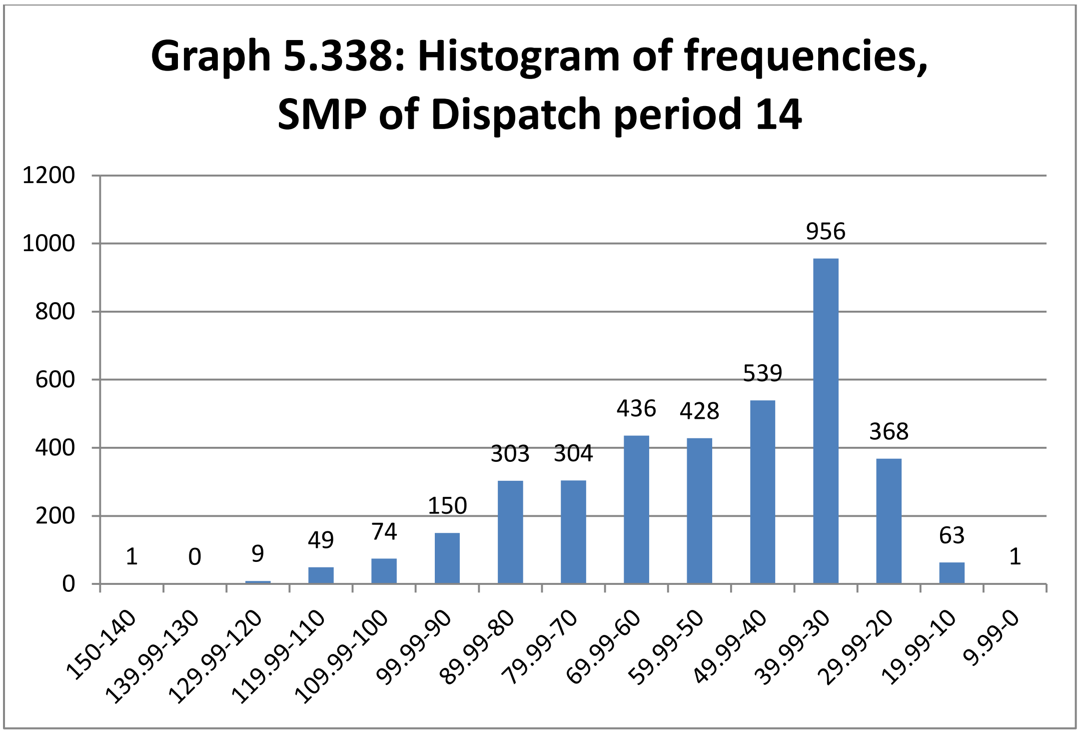

Graph 5.335: Histogram of frequencies, SMP of Dispatch period 11
900
800
700
600
500
400
300
200
100
0
1
1
24
49
86
199
318
333
468
416
526
840
371
49
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

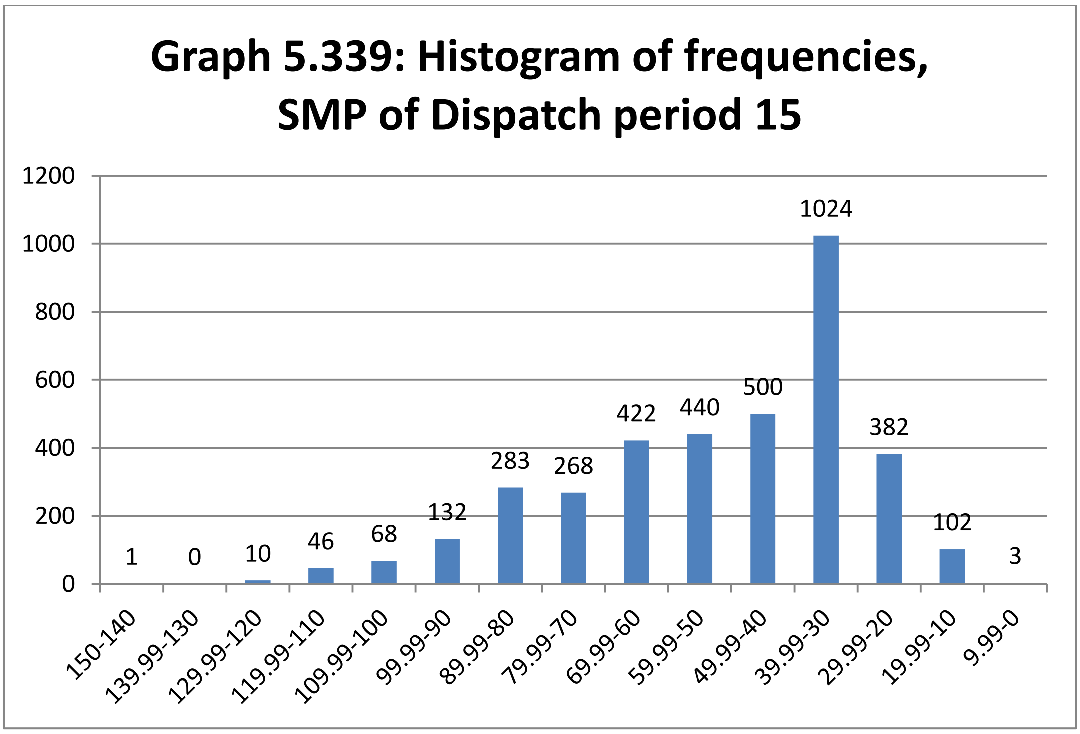


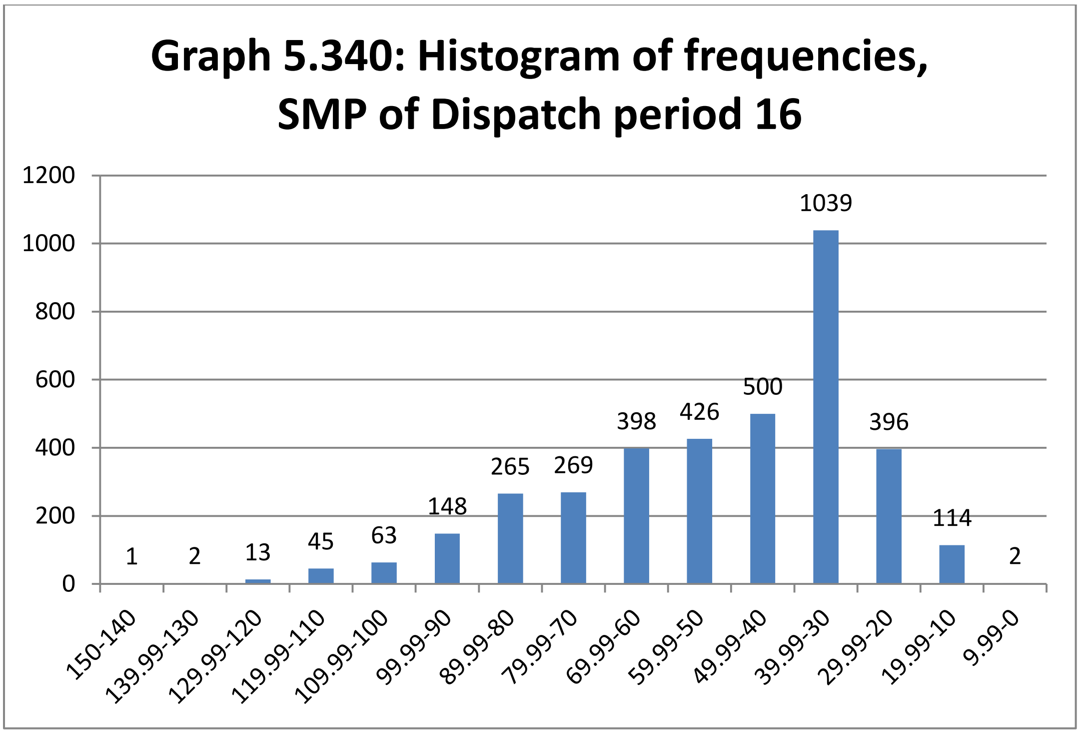
Graph 5.336: Histogram of frequencies, SMP of Dispatch period 12
900
800
700
600
500
400
300
200
100
0
1
1
20
56
83
181
315
341
482
422
526
830
378
45
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

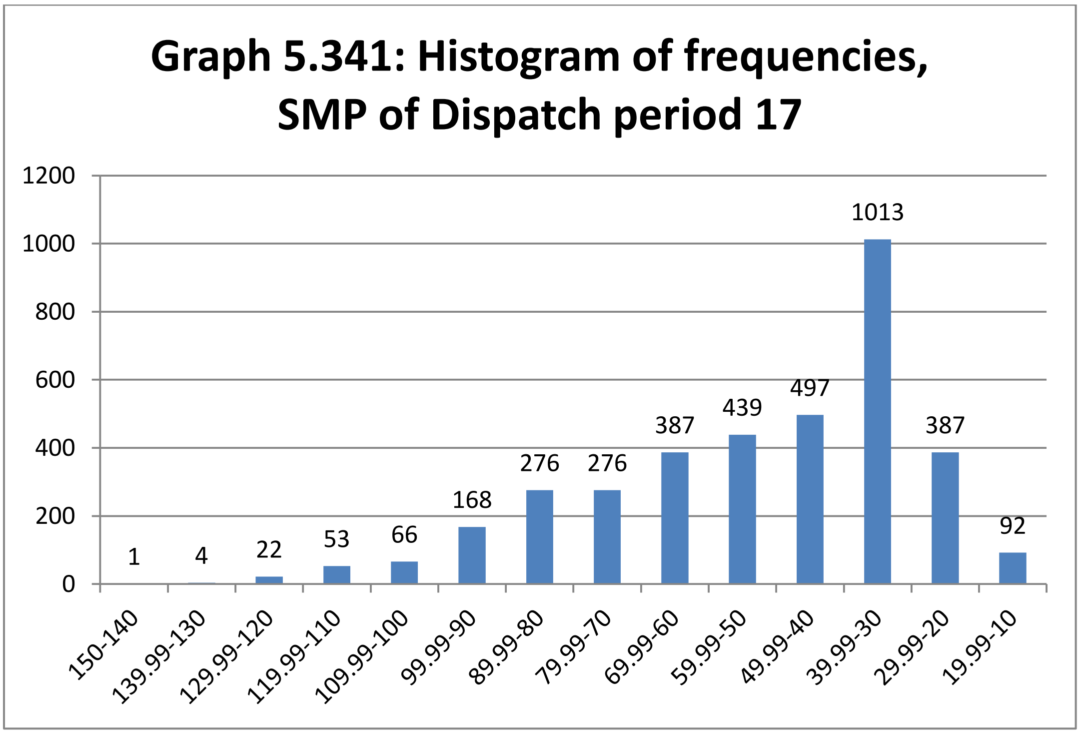


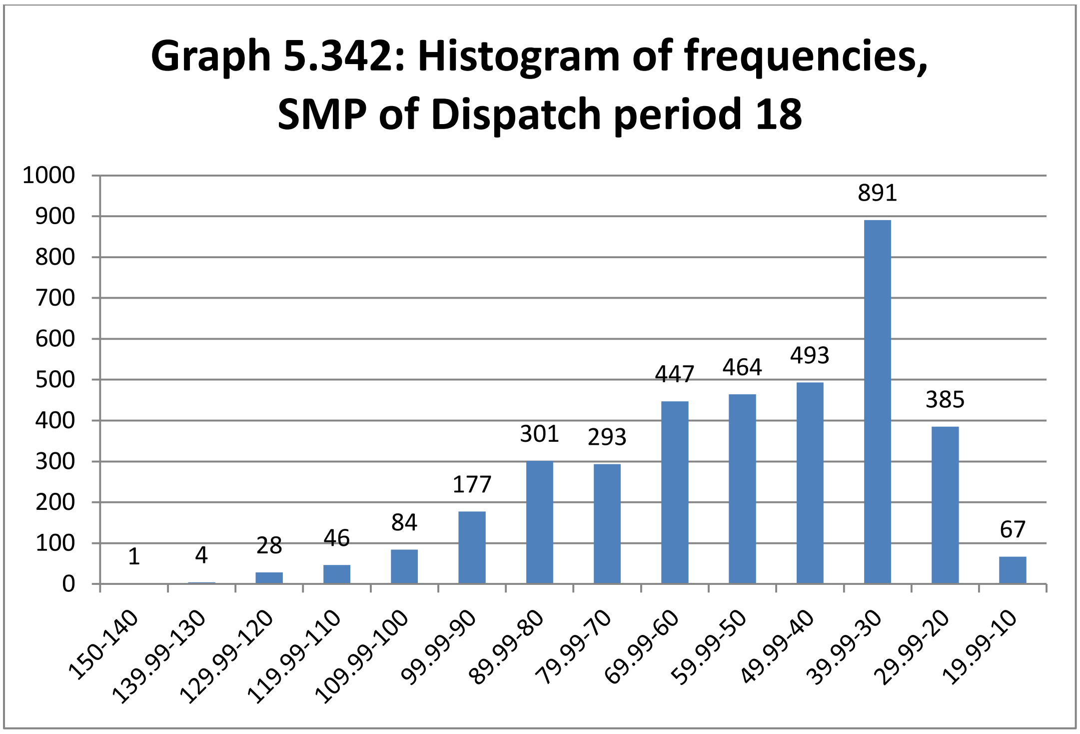
Graph 5.337: Histogram of frequencies, SMP of Dispatch period 13
900
800
700
600
500
400
300
200
100
0
1
0
12
52
83
178
314
325
490
422
540
845
367
51
1
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0

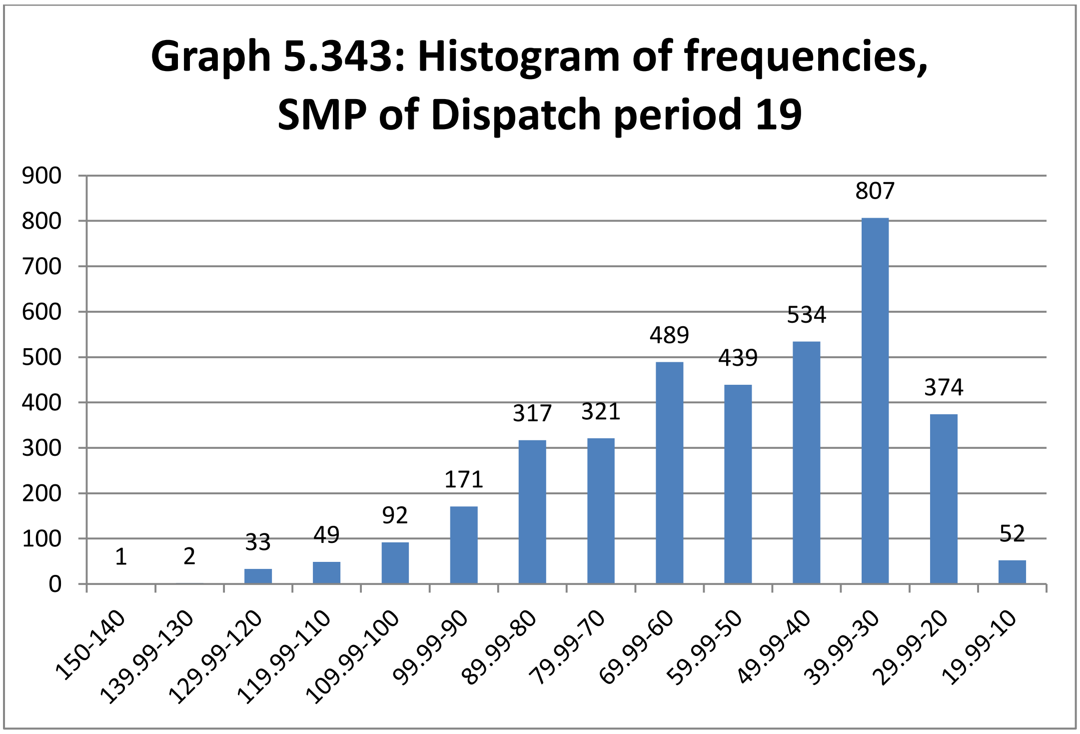

Graph 5.338: Histogram of frequencies, SMP of Dispatch period 14
1200
1000
800
600
400
200
0
1
0
9
49
74
150
303
304
436
428
539
956
368
63
1
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0

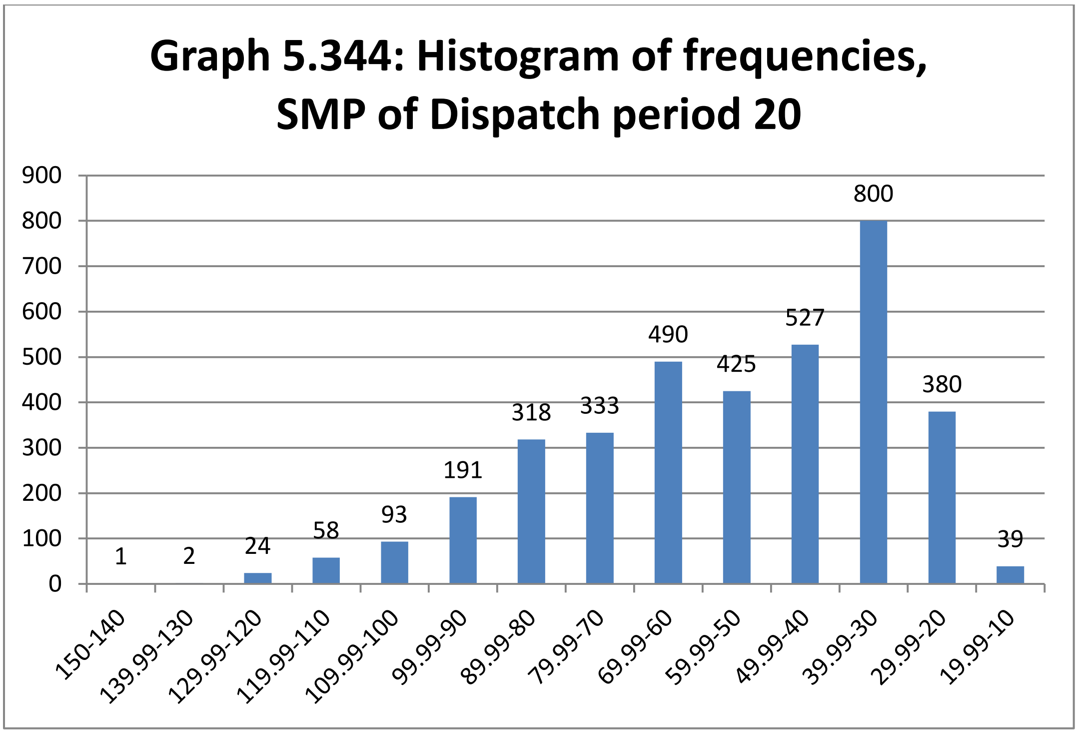

Graph 5.339: Histogram of frequencies, SMP of Dispatch period 15
1200
1000
800
600
400
200
0
1
0
10
46
68
132
283
268
422
440
500
1024
382
102
3
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0

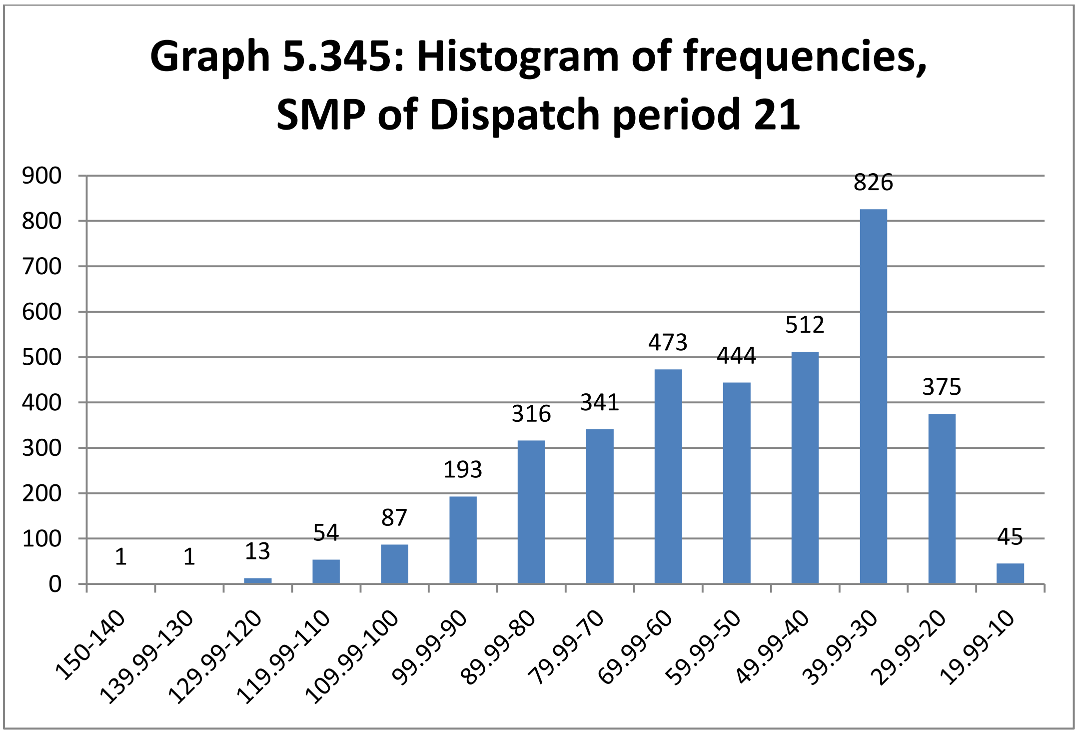

Graph 5.340: Histogram of frequencies, SMP of Dispatch period 16
1200
1000
800
600
400
200
0
1
2
13
45
63
148
265
269
398
426
500
1039
396
114
2
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0

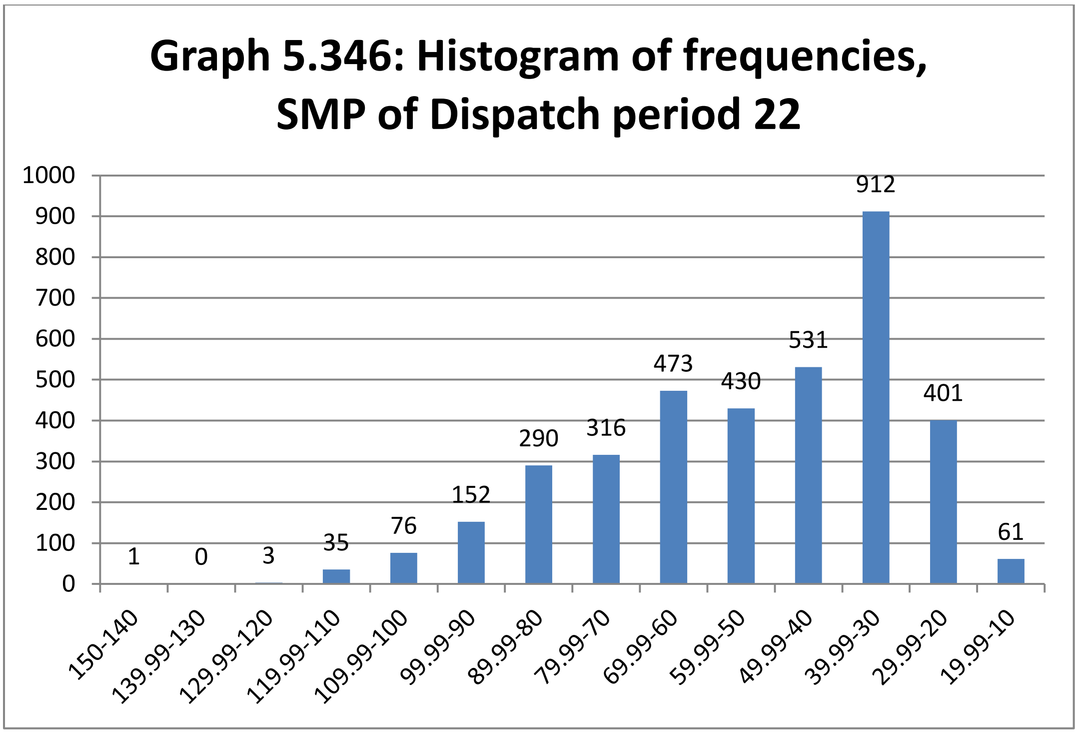

Graph 5.341: Histogram of frequencies, SMP of Dispatch period 17
1200
1000
800
600
400
200
0
1
4
22
53
66
168
276
276
387
439
497
1013
387
92
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

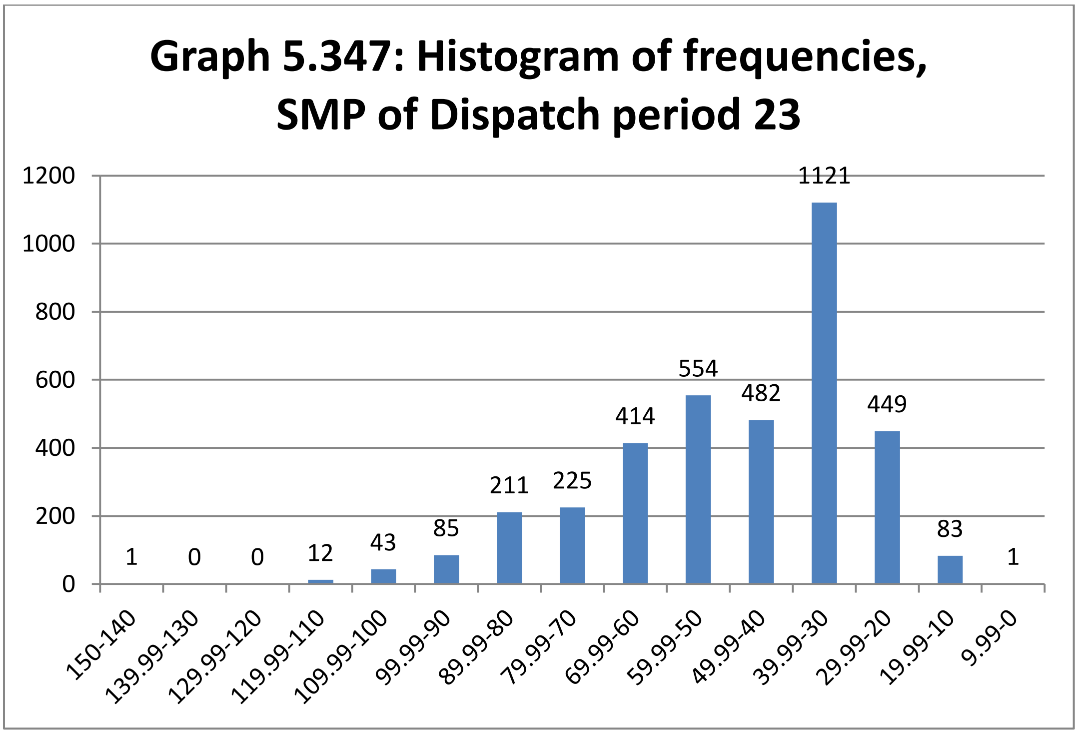

Graph 5.342: Histogram of frequencies, SMP of Dispatch period 18
1000
900
800
700
600
500
400
300
200
100
0
1
4
28
46
84
177
301
293
447
464
493
891
385
67
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

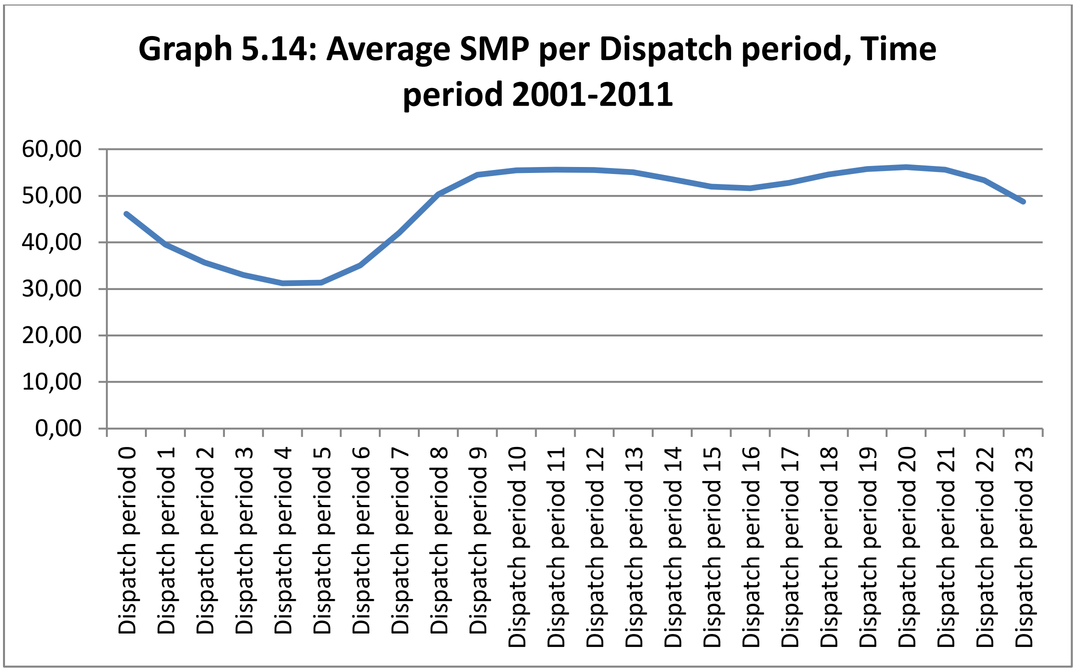

Graph 5.343: Histogram of frequencies, SMP of Dispatch period 19
900
800
700
600
500
400
300
200
100
0
1
2
33
49
92
171
317
321
489
439
534
807
374
52
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

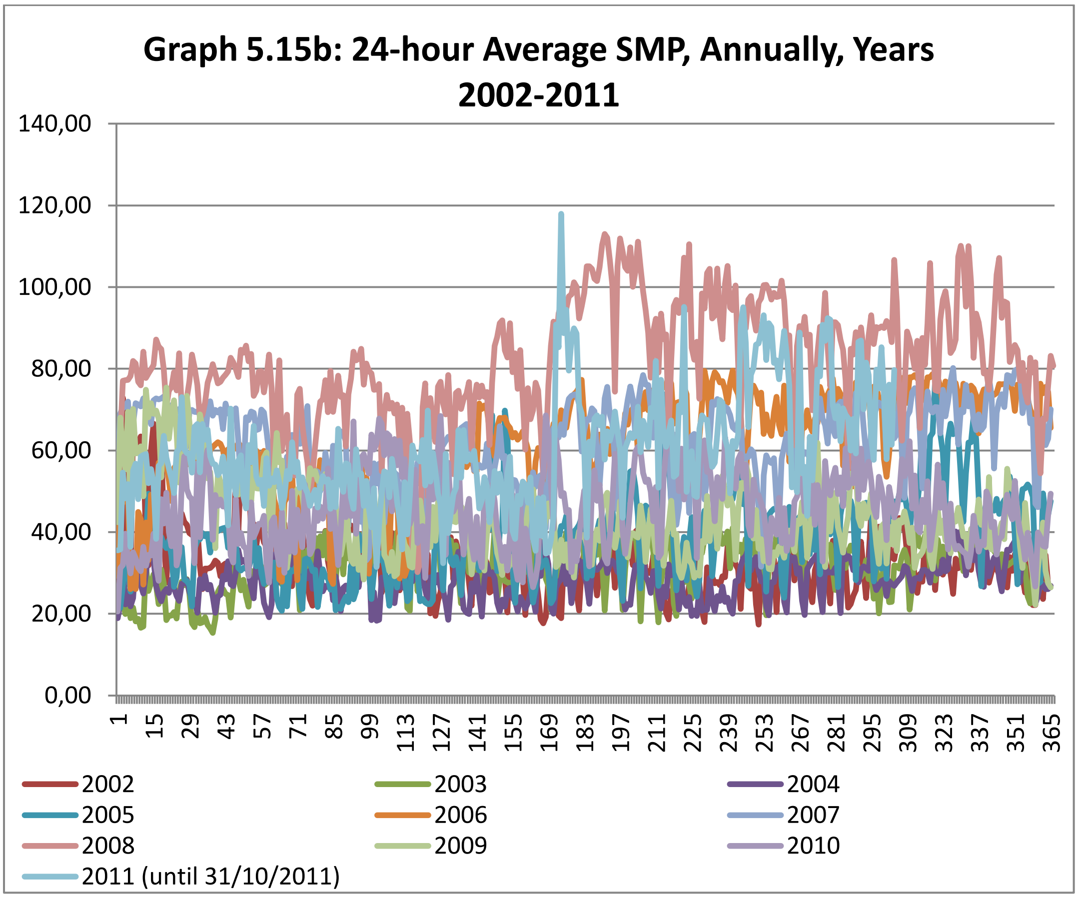

Graph 5.344: Histogram of frequencies, SMP of Dispatch period 20
900
800
700
600
500
400
300
200
100
0
1
2
24
58
93
191
318
333
490
425
527
800
380
39
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

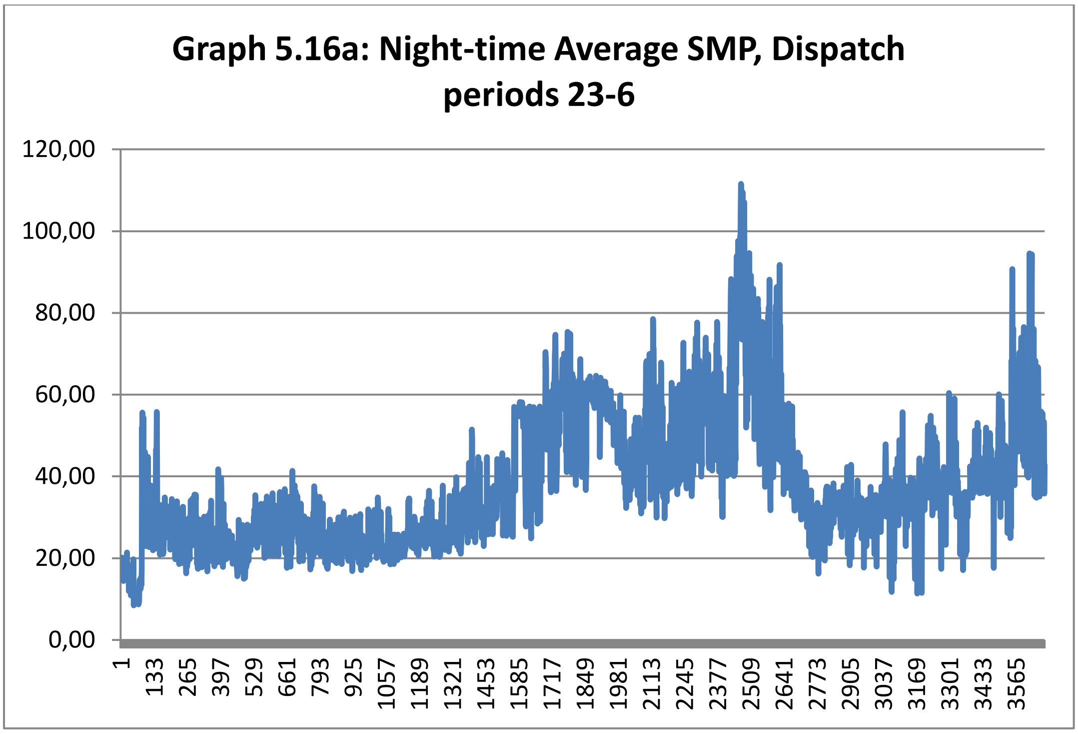

Graph 5.345: Histogram of frequencies, SMP of Dispatch period 21
900
800
700
600
500
400
300
200
100
0
1
1
13
54
87
193
316
341
473
444
512
826
375
45
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10


Graph 5.346: Histogram of frequencies, SMP of Dispatch period 22
1000
900
800
700
600
500
400
300
200
100
0
1
0
3
35
76
152
290
316
473
430
531
912
401
61
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

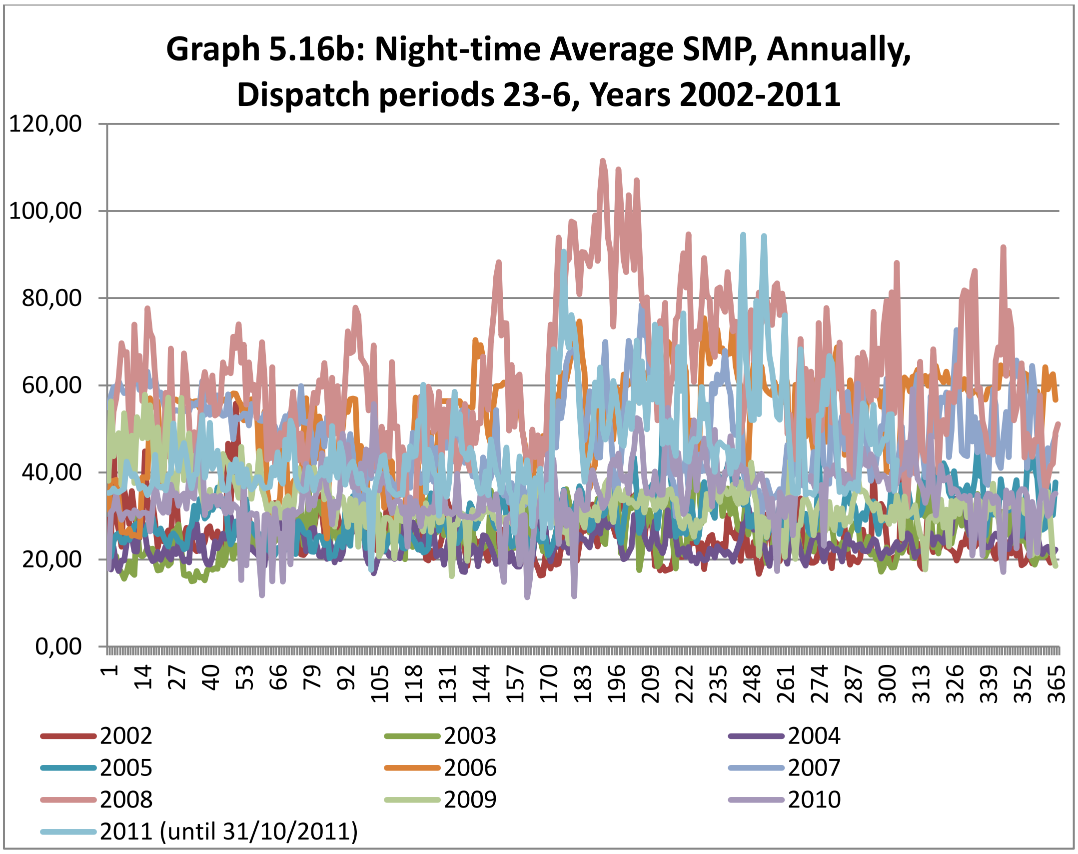

Graph 5.347: Histogram of frequencies, SMP of Dispatch period 23
1200
1000
800
600
400
200
0
1
0
0
12
43
85
211
225
414
554
482
1121
449
83
1
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0


Graph 5.14: Average SMP per Dispatch period, Time period 2001-2011
60,00
50,00
40,00
30,00
20,00
10,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23

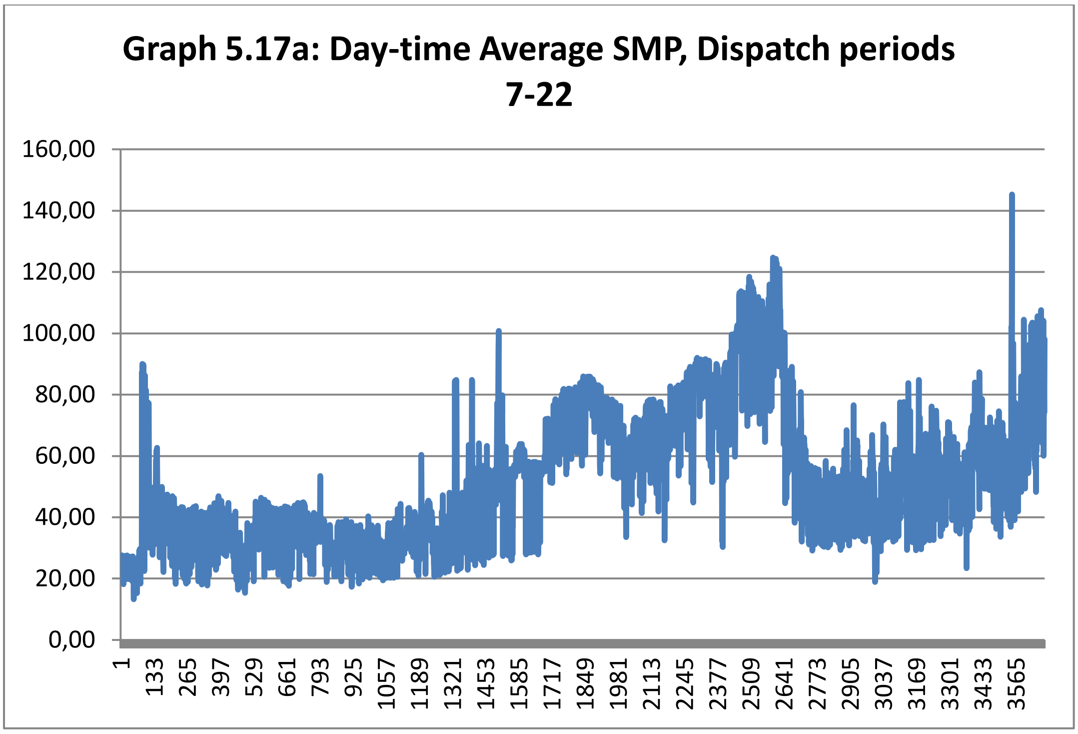

Graph 5.15b: 24-hour Average SMP, Annually, Years 2002-2011
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
15
29
43
57
71
85
99
113
127
141
155
169
183
197
211
225
239
253
267
281
295
309
323
337
351
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

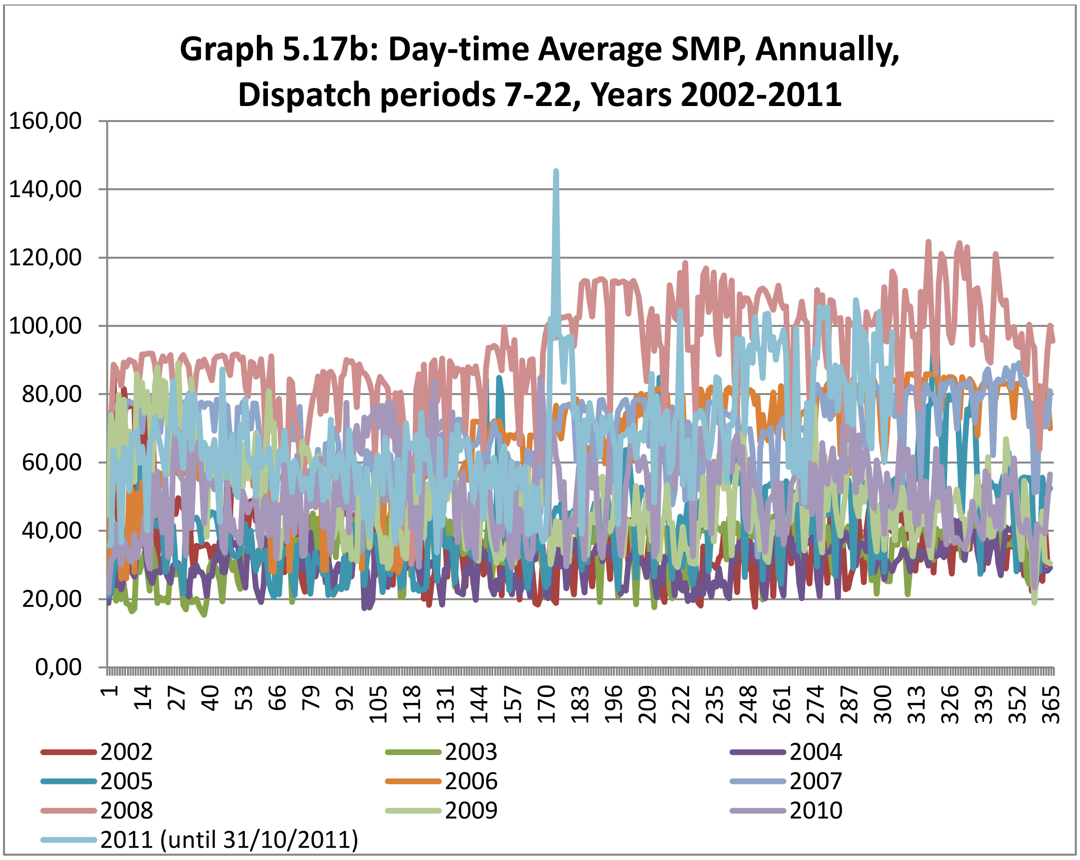


Graph 5.16a: Night-time Average SMP, Dispatch periods 23-6
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565



Graph 5.16b: Night-time Average SMP, Annually, Dispatch periods 23-6, Years 2002-2011
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.17a: Day-time Average SMP, Dispatch periods 7-22
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.17b: Day-time Average SMP, Annually, Dispatch periods 7-22, Years 2002-2011
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
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326
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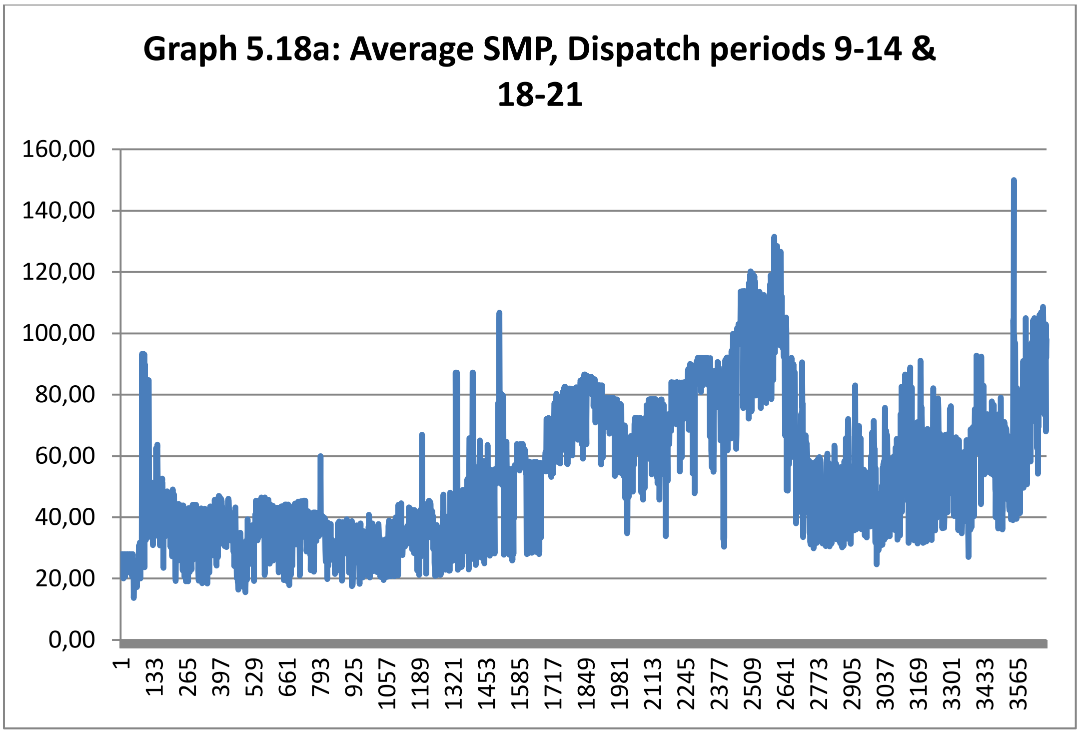
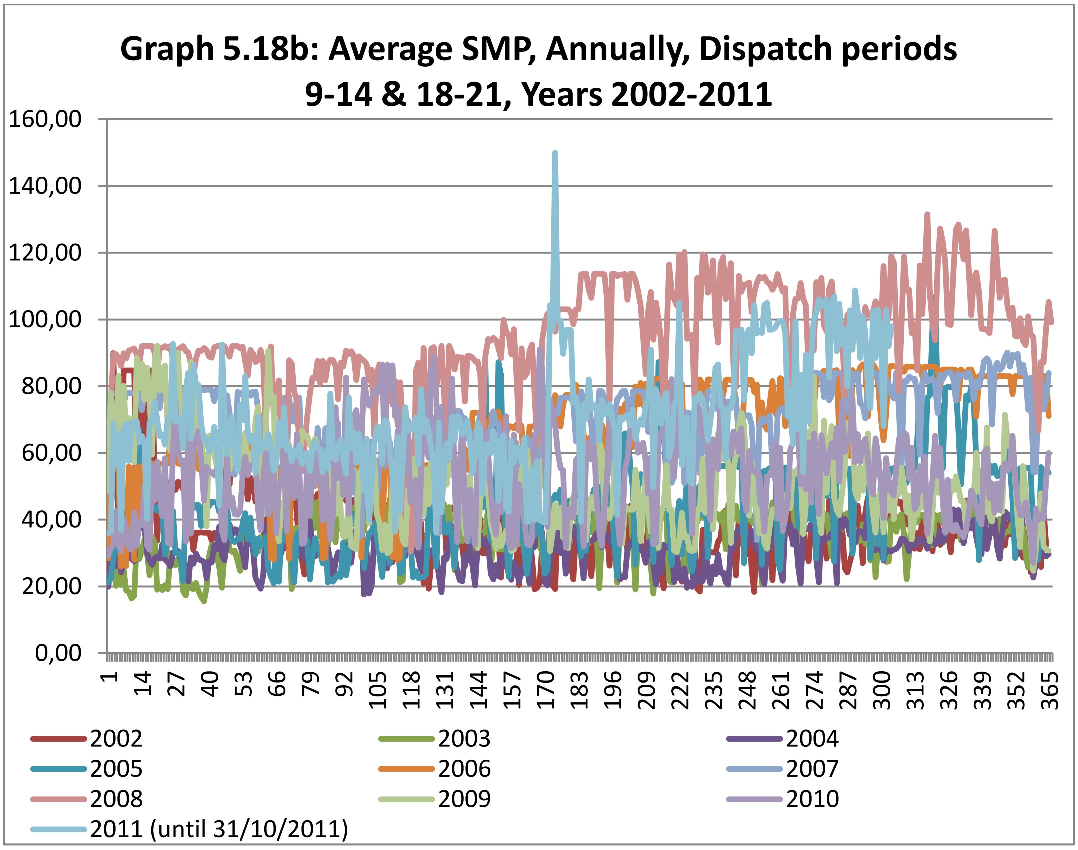
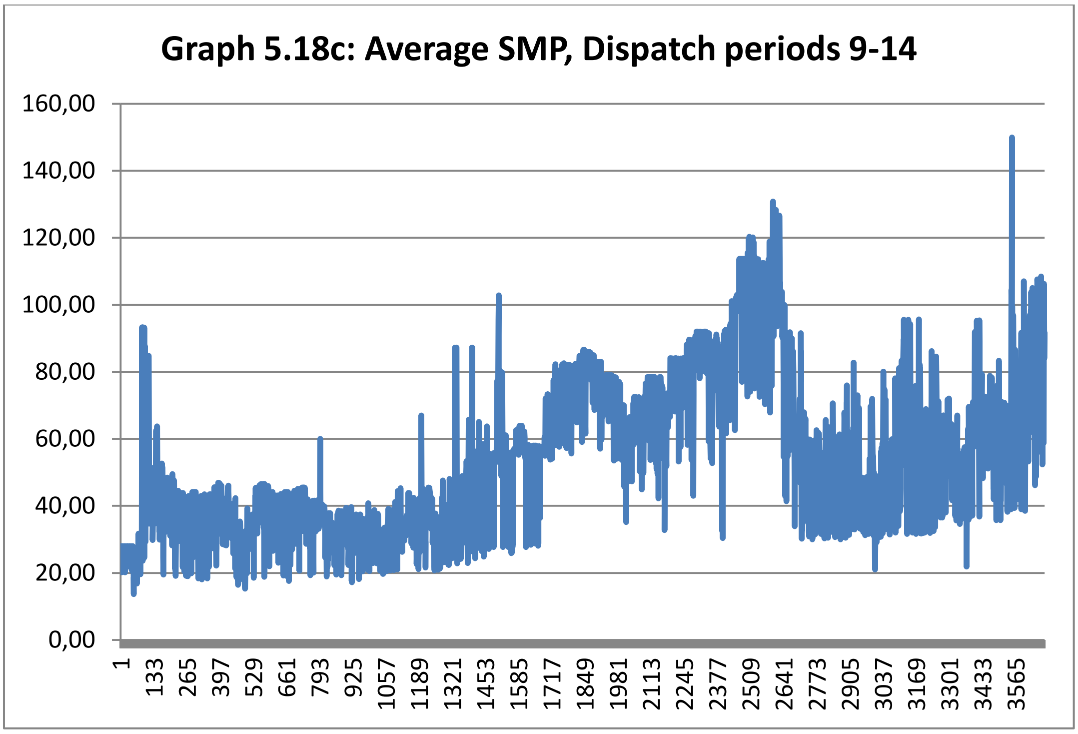
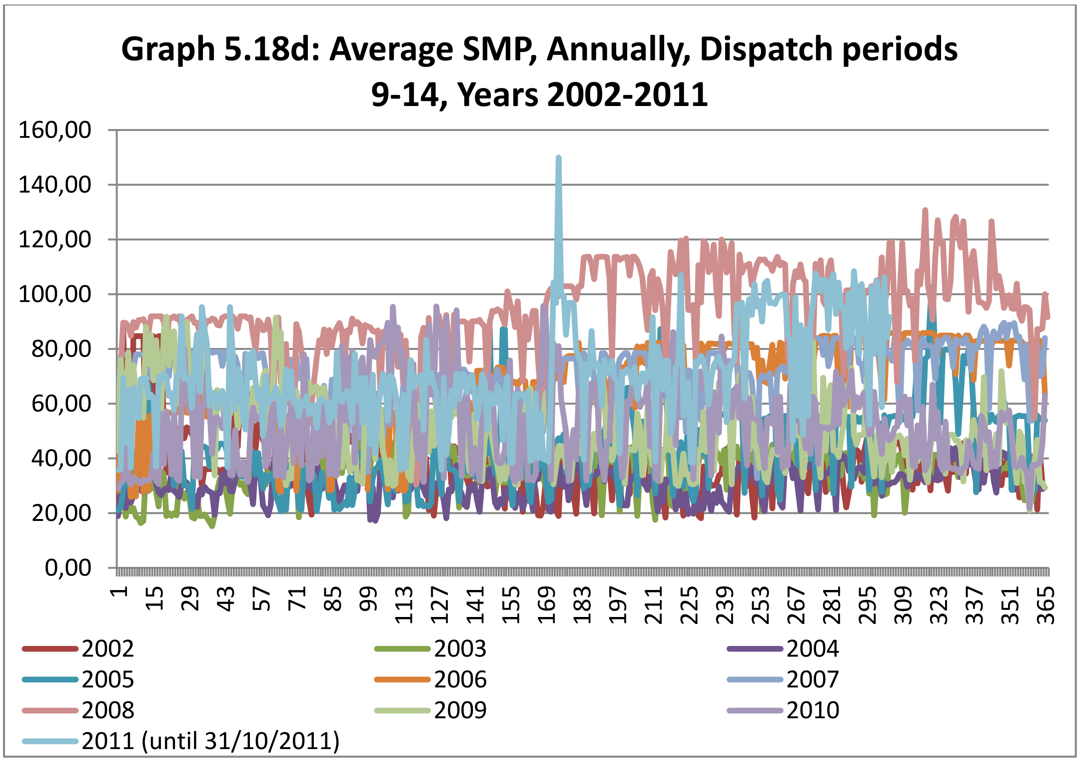
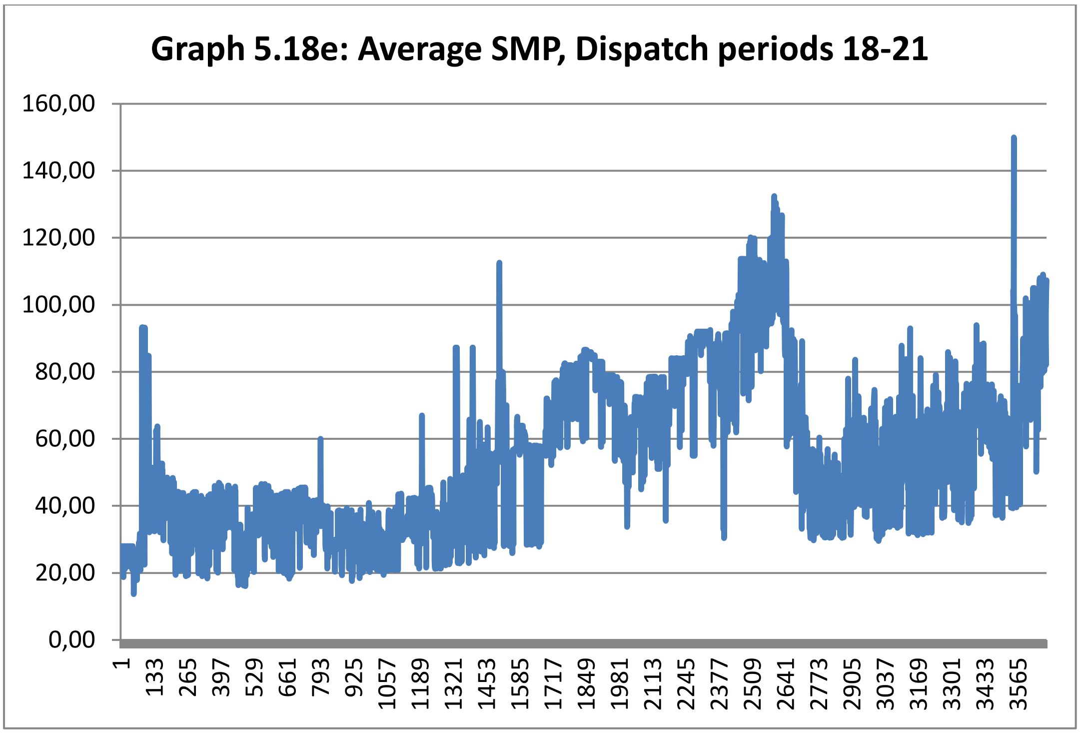
352
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

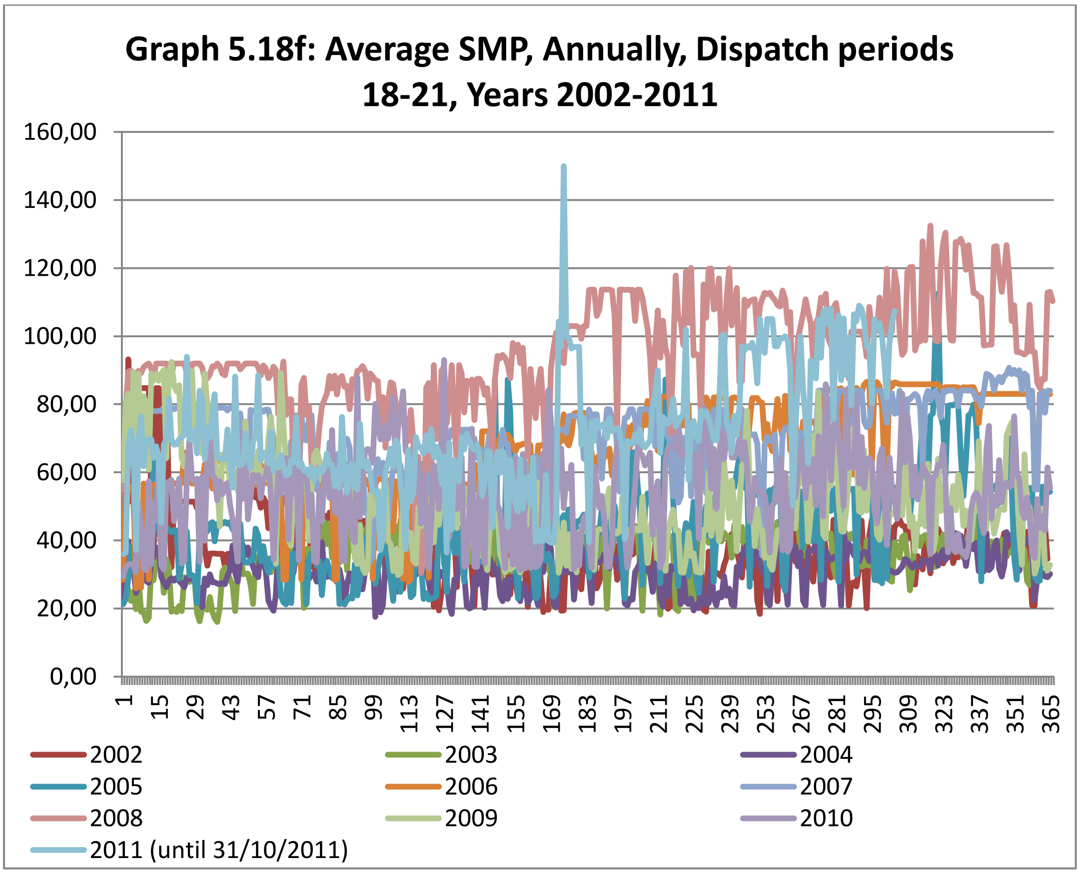

Graph 5.18a: Average SMP, Dispatch periods 9-14 & 18-21
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.18b: Average SMP, Annually, Dispatch periods 9-14 & 18-21, Years 2002-2011
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

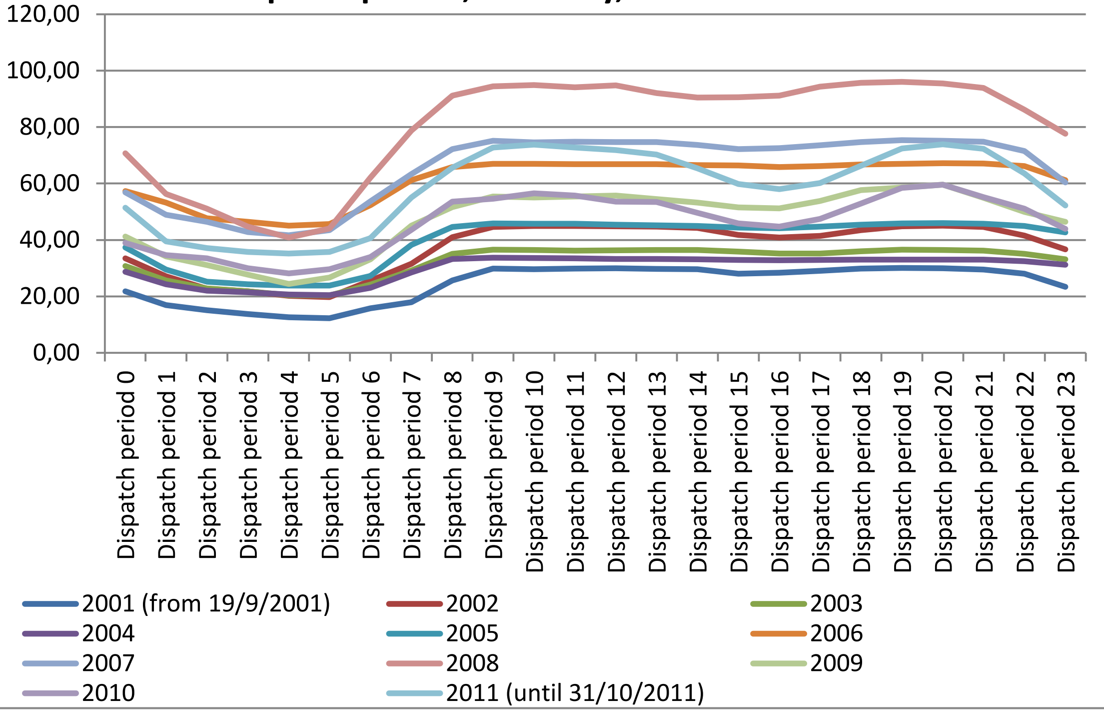

Graph 5.18c: Average SMP, Dispatch periods 9-14
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.18d: Average SMP, Annually, Dispatch periods 9-14, Years 2002-2011
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
15
29
43
57
71
85
99
113
127
141
155
169
183
197
211
225
239
253
267
281
295
309
323
337
351
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

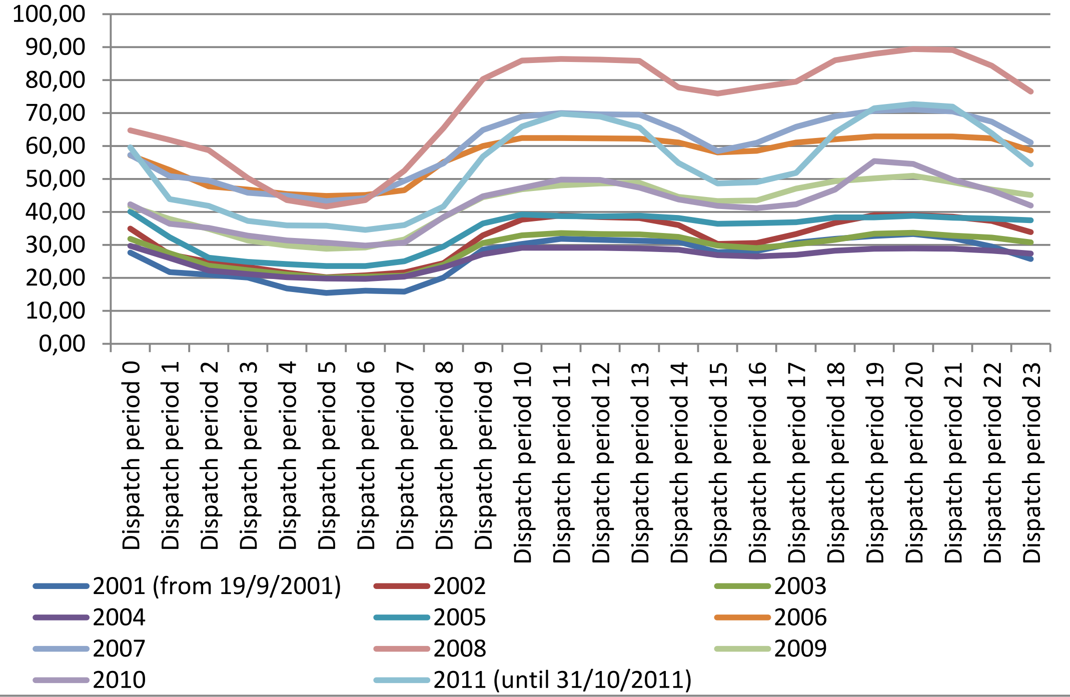

Graph 5.18e: Average SMP, Dispatch periods 18-21
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

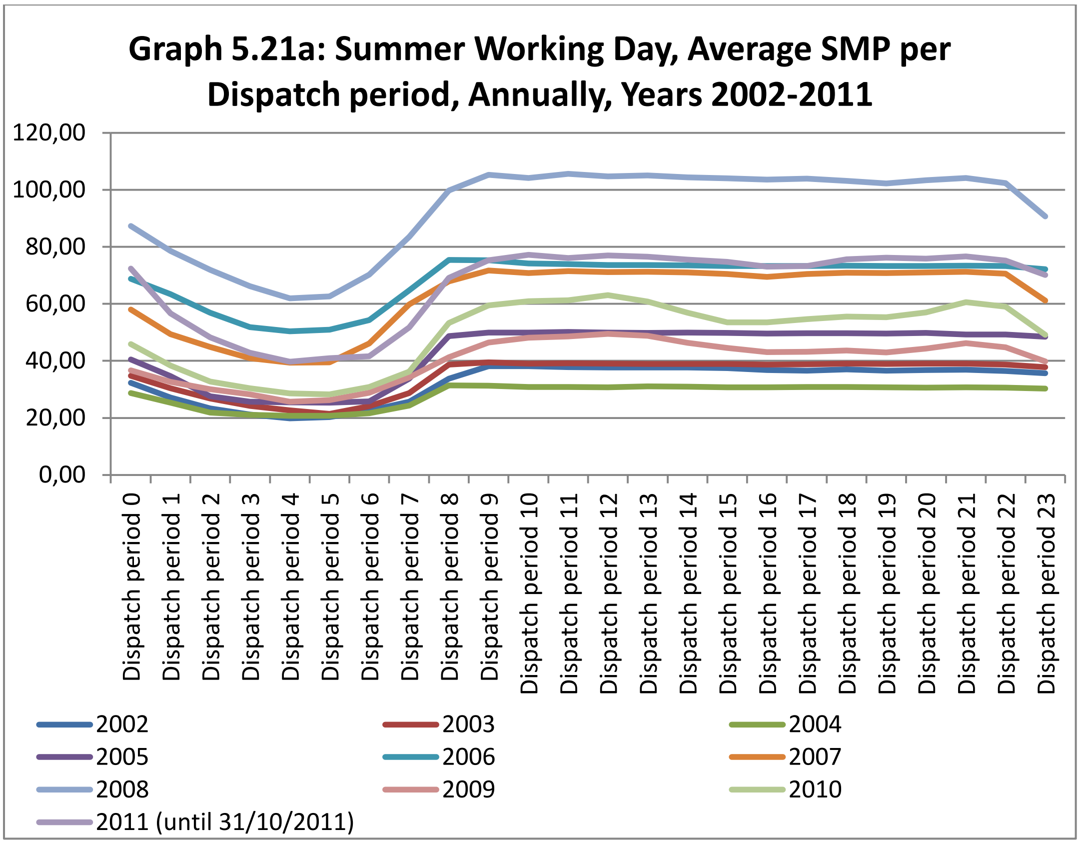

Graph 5.18f: Average SMP, Annually, Dispatch periods 18-21, Years 2002-2011
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
15
29
43
57
71
85
99
113
127
141
155
169
183
197
211
225
239
253
267
281
295
309
323
337
351
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

Graph 5.19a: Winter Working Day, Average SMP per Dispatch period, Annually, Years 2001-2011

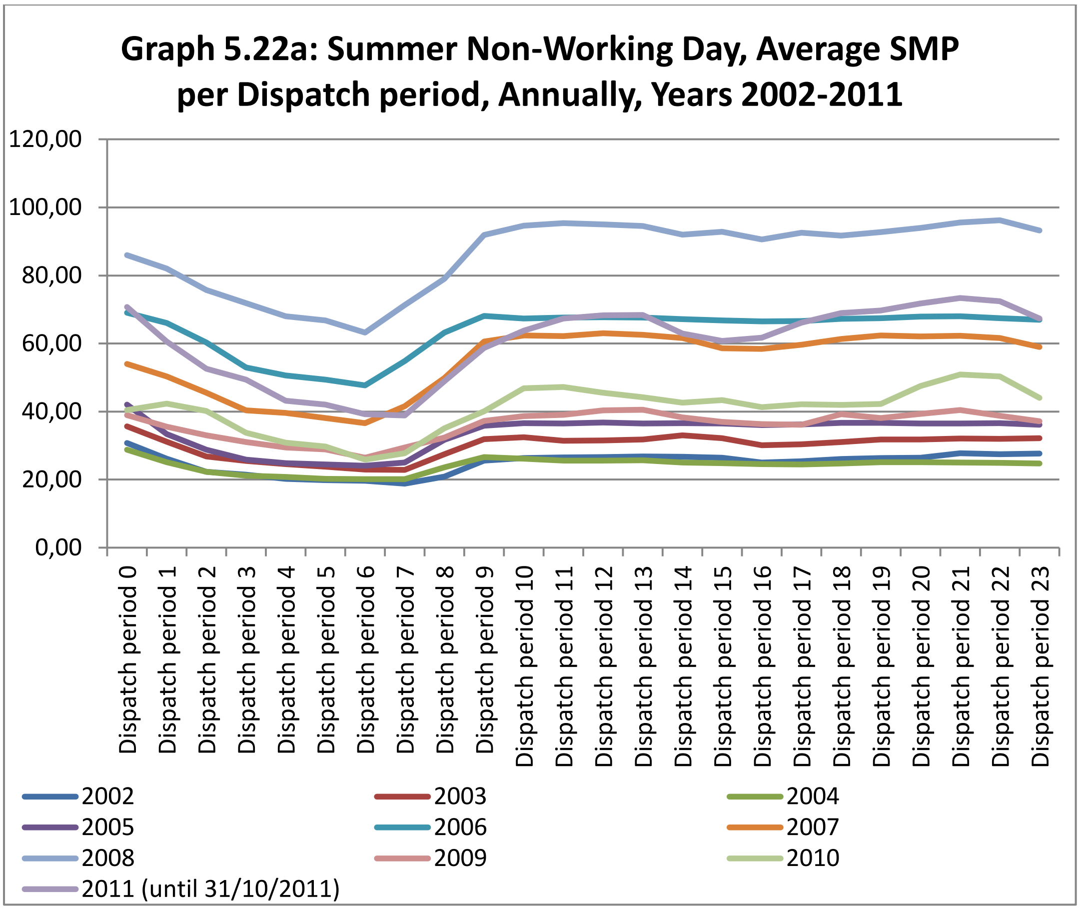


Graph 5.20a: Winter Non-Working Day, Average SMP per Dispatch period, Annually, Years 2001-2011



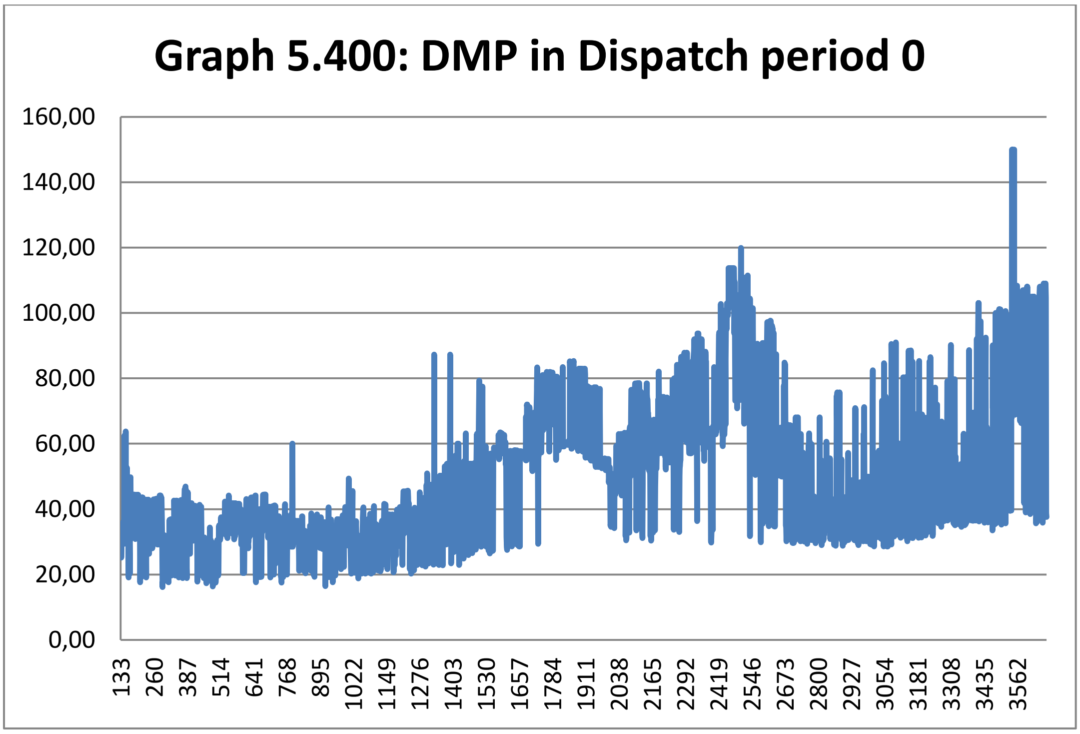


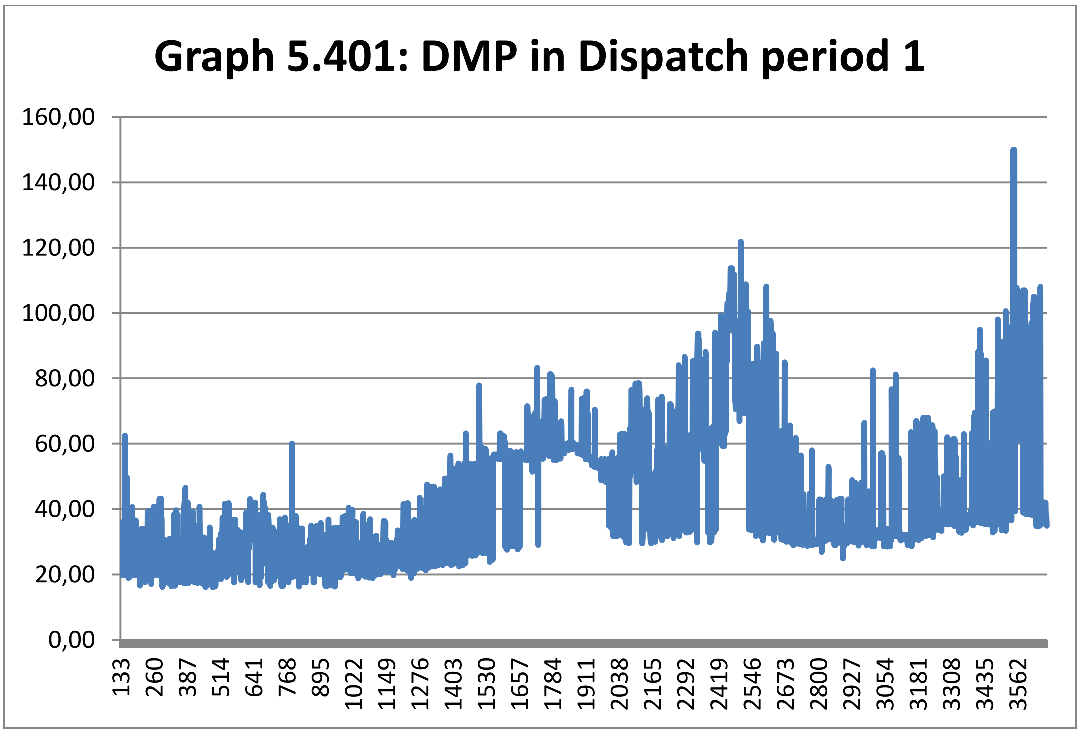
Graph 5.21a: Summer Working Day, Average SMP per Dispatch period, Annually, Years 2002-2011
120,00
100,00
80,00
60,00
40,00
20,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

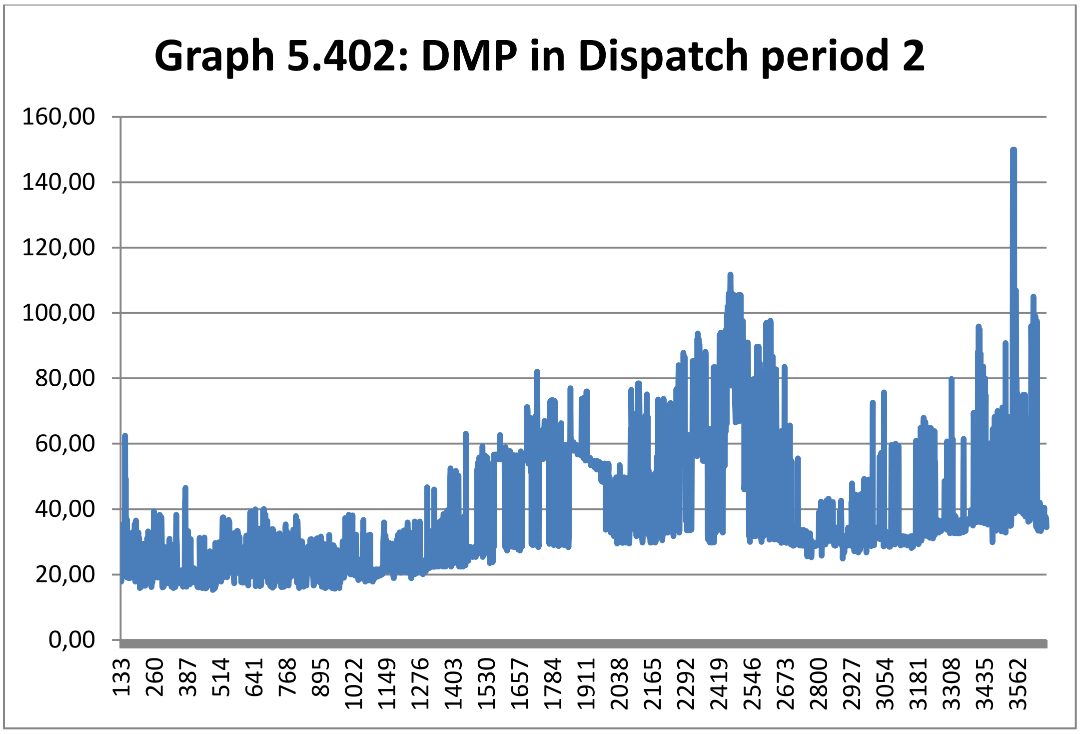

Graph 5.22a: Summer Non-Working Day, Average SMP per Dispatch period, Annually, Years 2002-2011
120,00
100,00
80,00
60,00
40,00
20,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

Part 3

Deviations Marginal Price (DMP) Data are presented in this part.







Graph 5.402: DMP in Dispatch period 2
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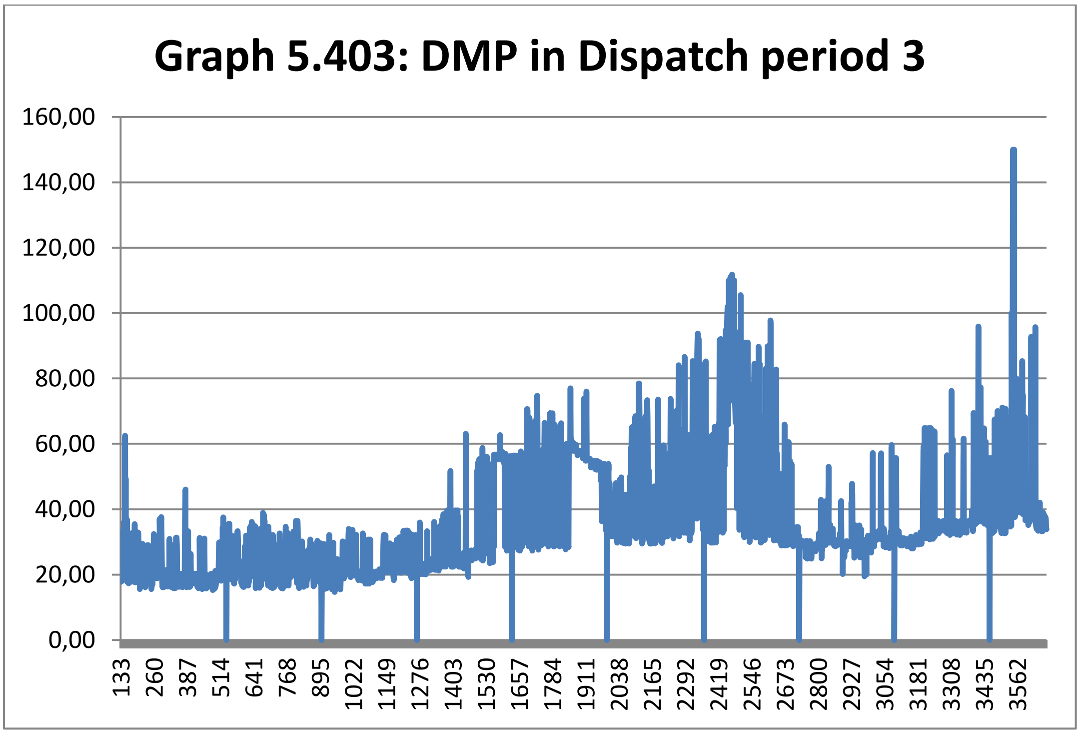
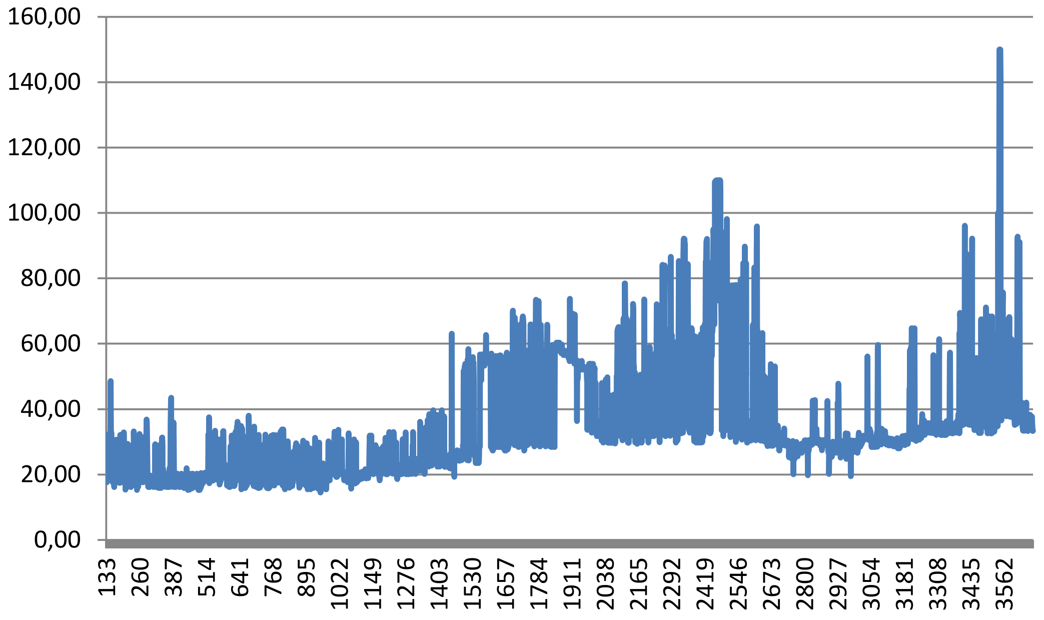
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562

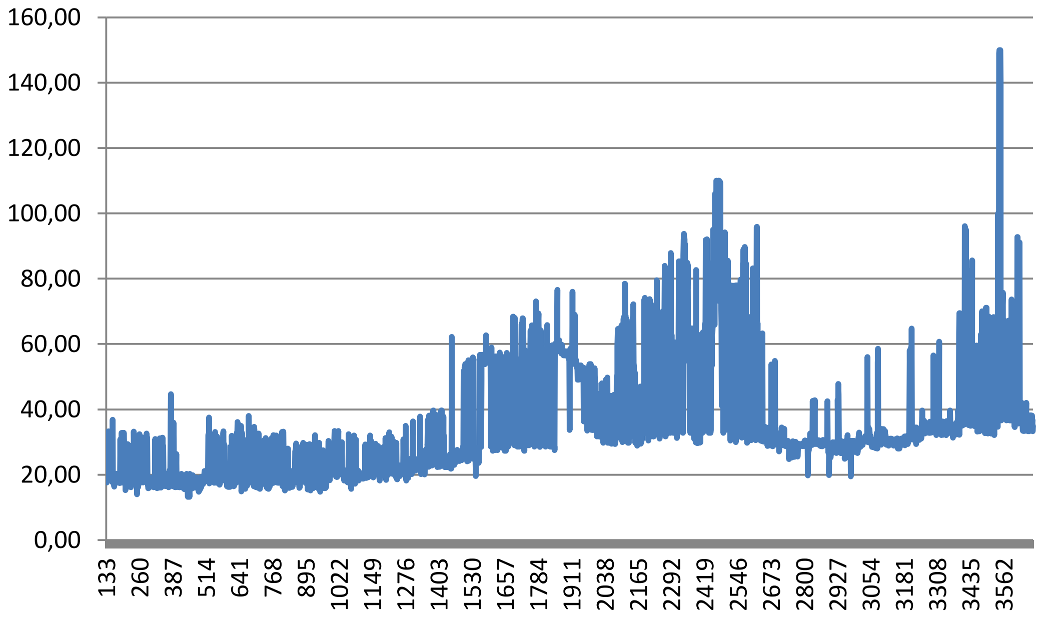


Graph 5.403: DMP in Dispatch period 3
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562

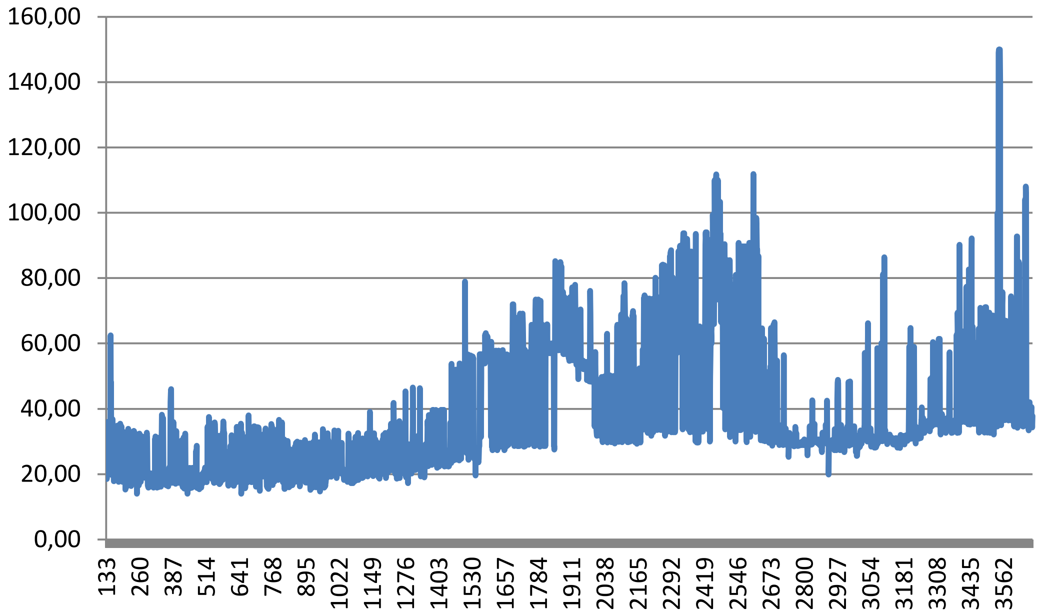
Graph 5.404: DMP in Dispatch period 4



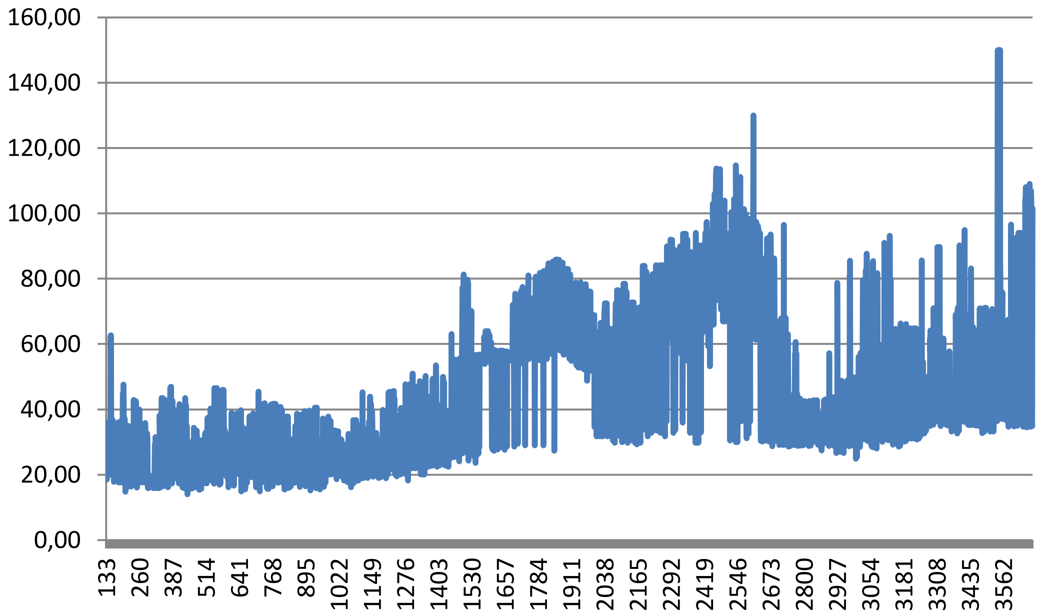
Graph 5.405: DMP in Dispatch period 5

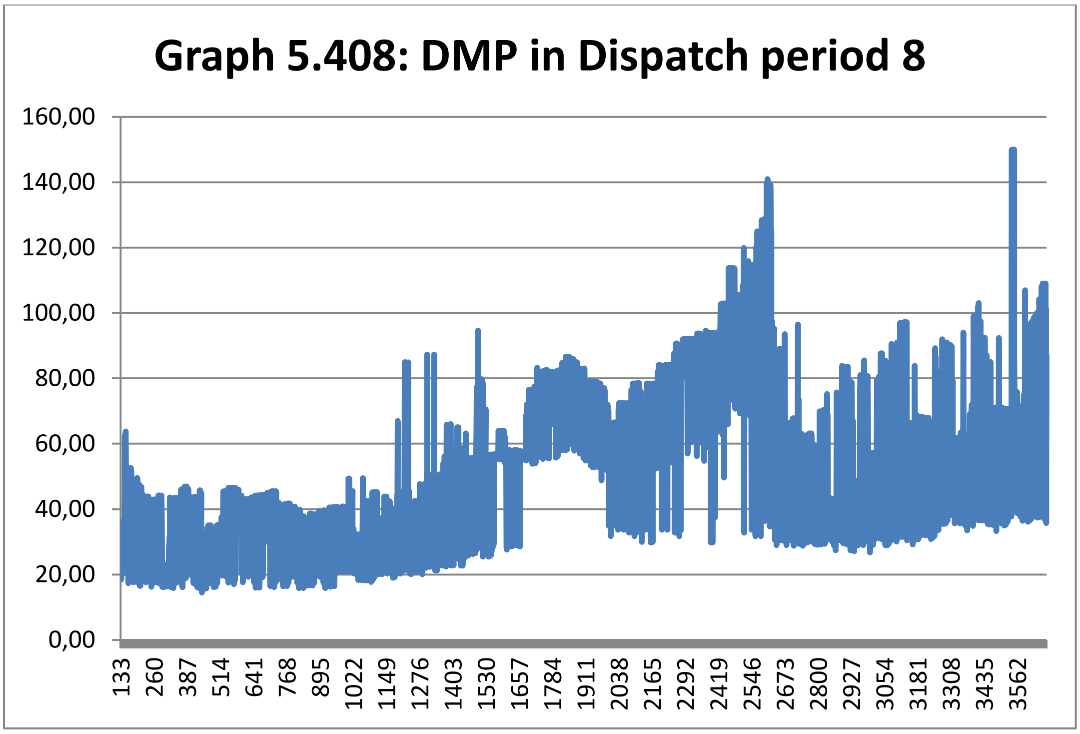


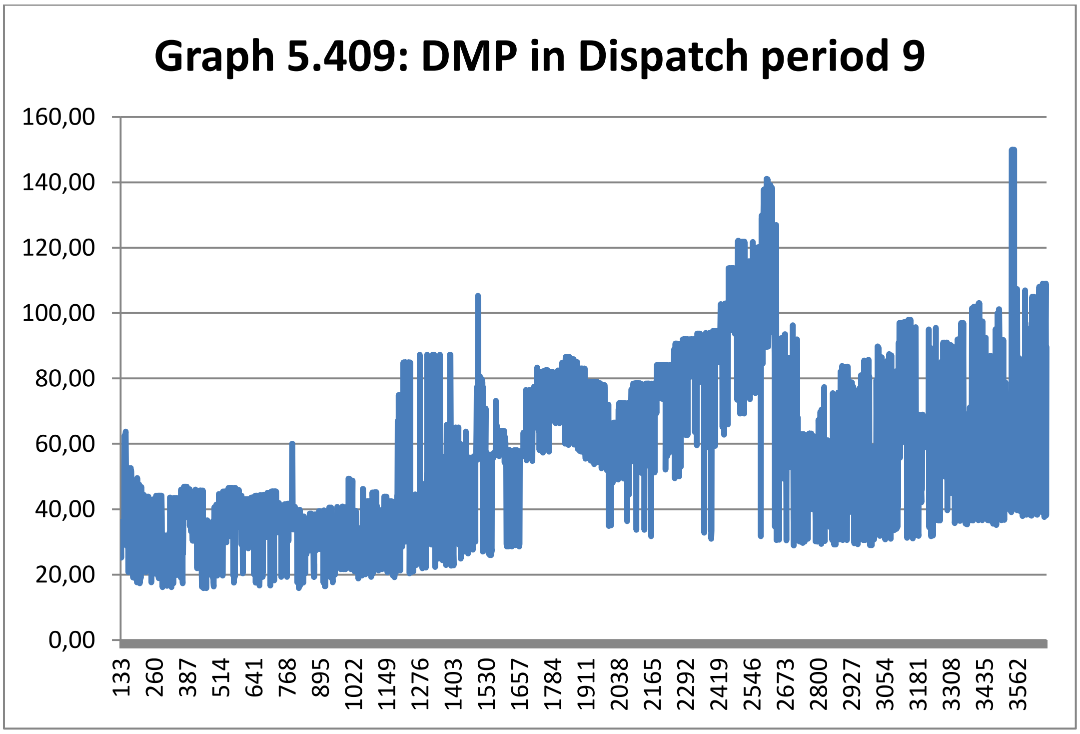
Graph 5.406: DMP in Dispatch period 6



Graph 5.407: DMP in Dispatch period 7




Graph 5.408: DMP in Dispatch period 8
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.409: DMP in Dispatch period 9
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
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1911
2038
2165
2292
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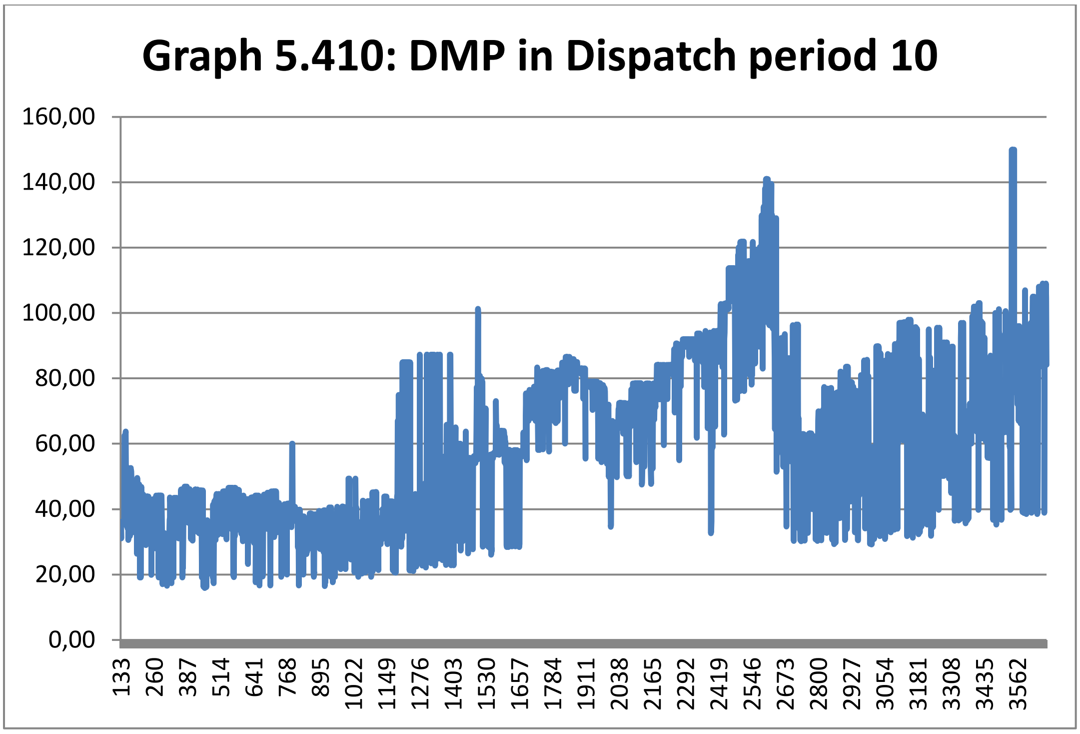
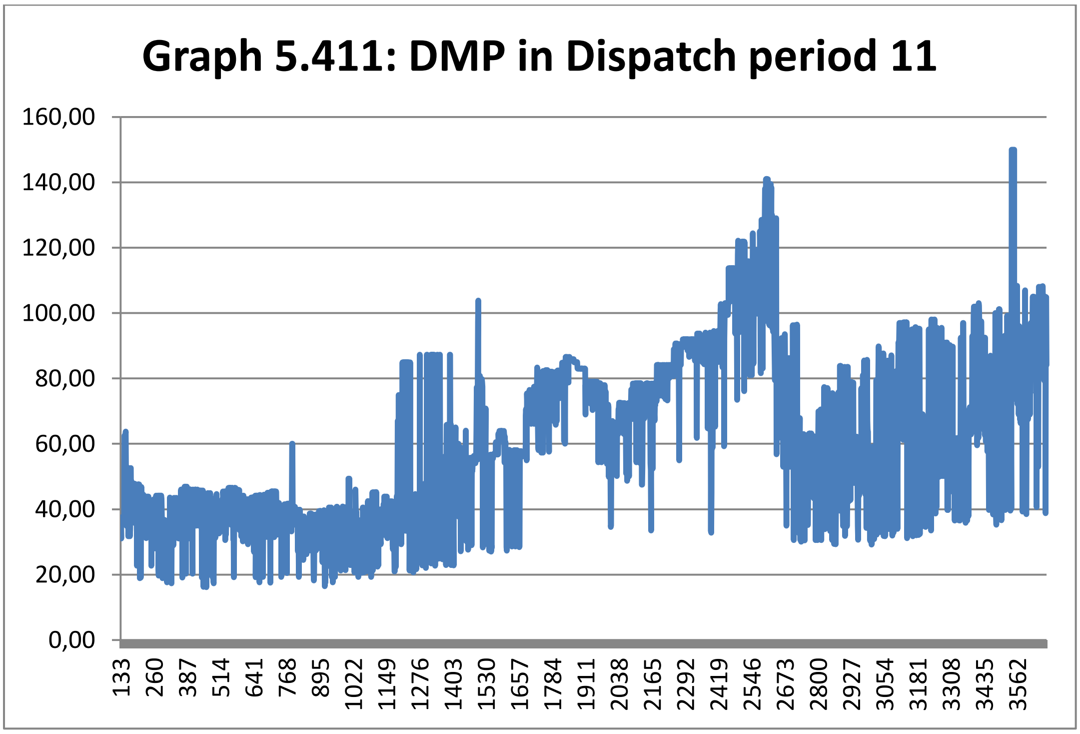
3181
3308
3435
3562


Graph 5.410: DMP in Dispatch period 10
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.411: DMP in Dispatch period 11
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
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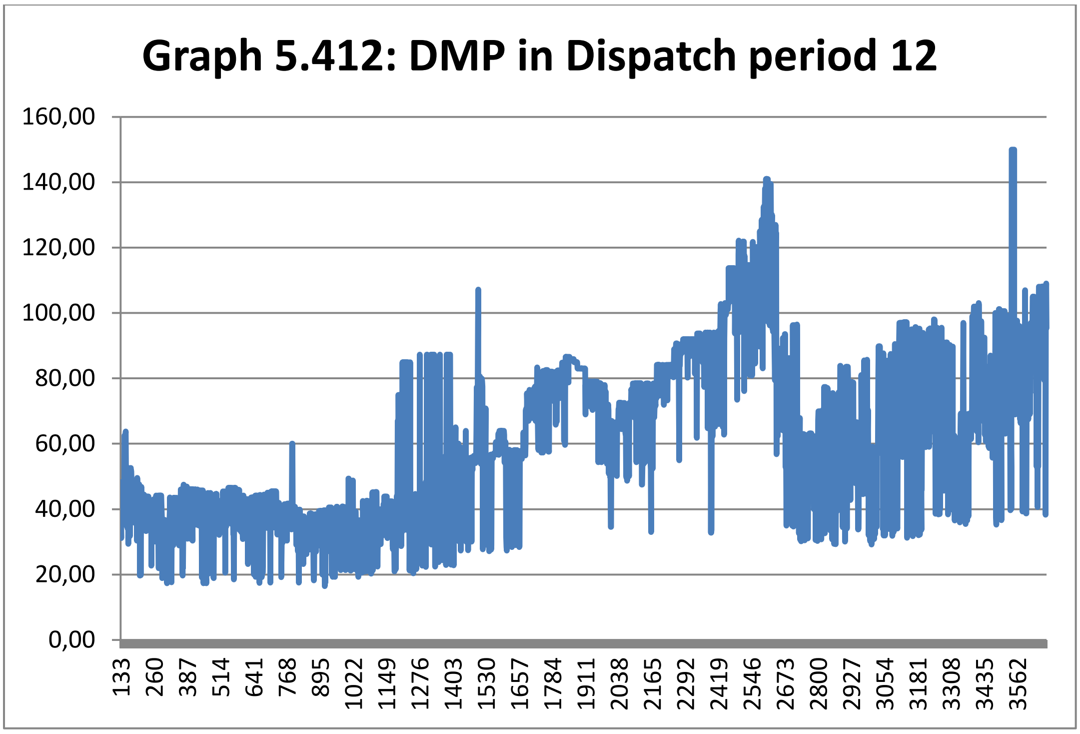
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.412: DMP in Dispatch period 12
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140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
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1911
2038
2165
2292
2419
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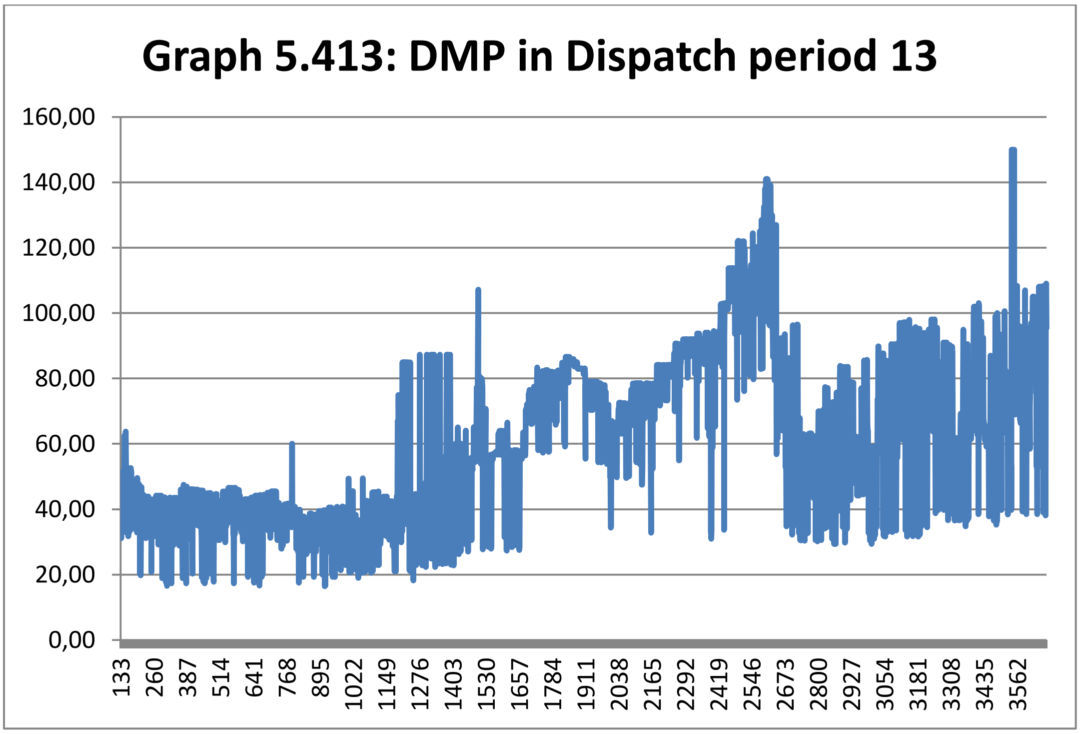
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.413: DMP in Dispatch period 13
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
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2038
2165
2292
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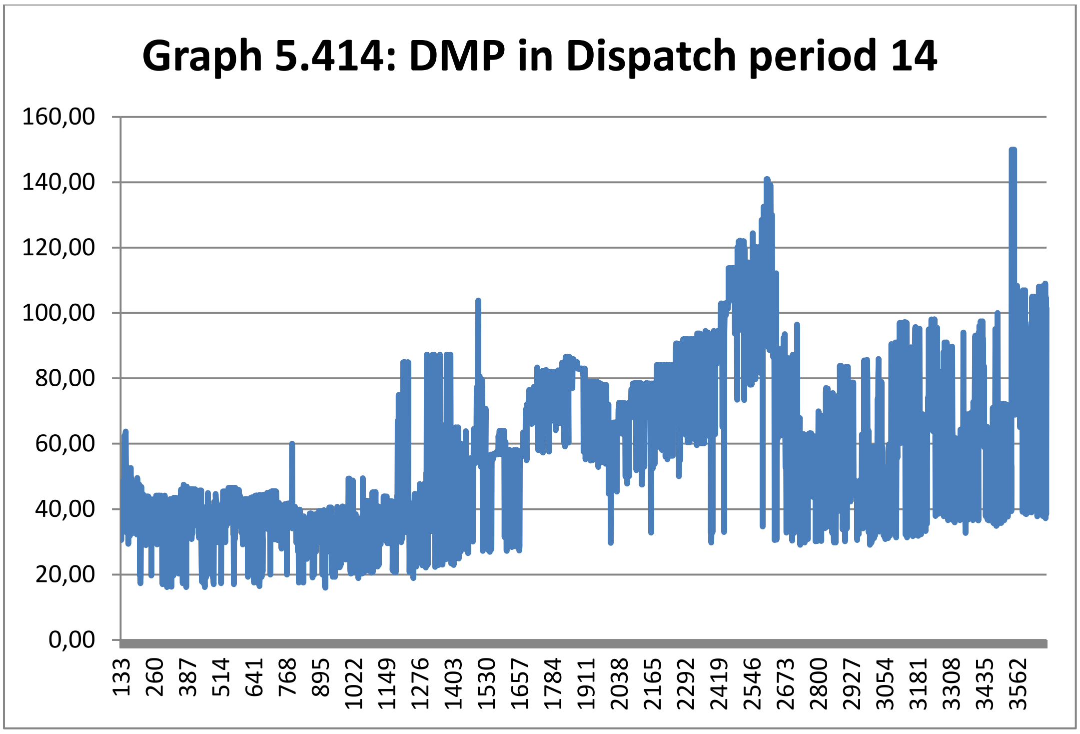
2927
3054
3181
3308
3435
3562


Graph 5.414: DMP in Dispatch period 14
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
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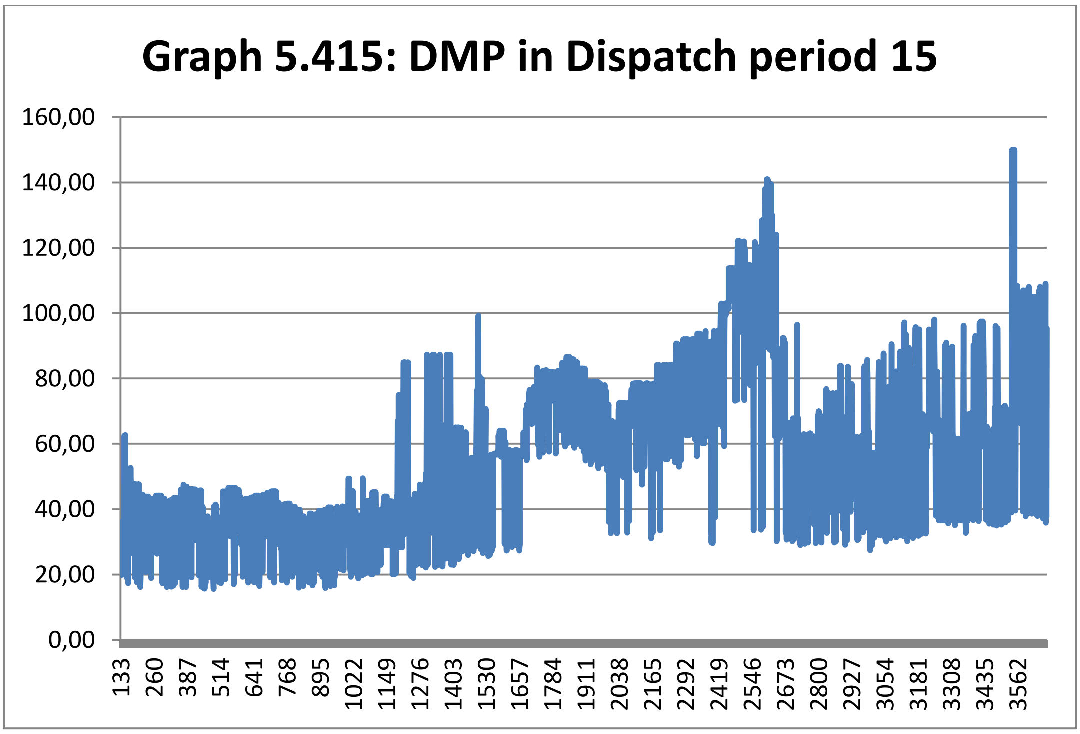
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.415: DMP in Dispatch period 15
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
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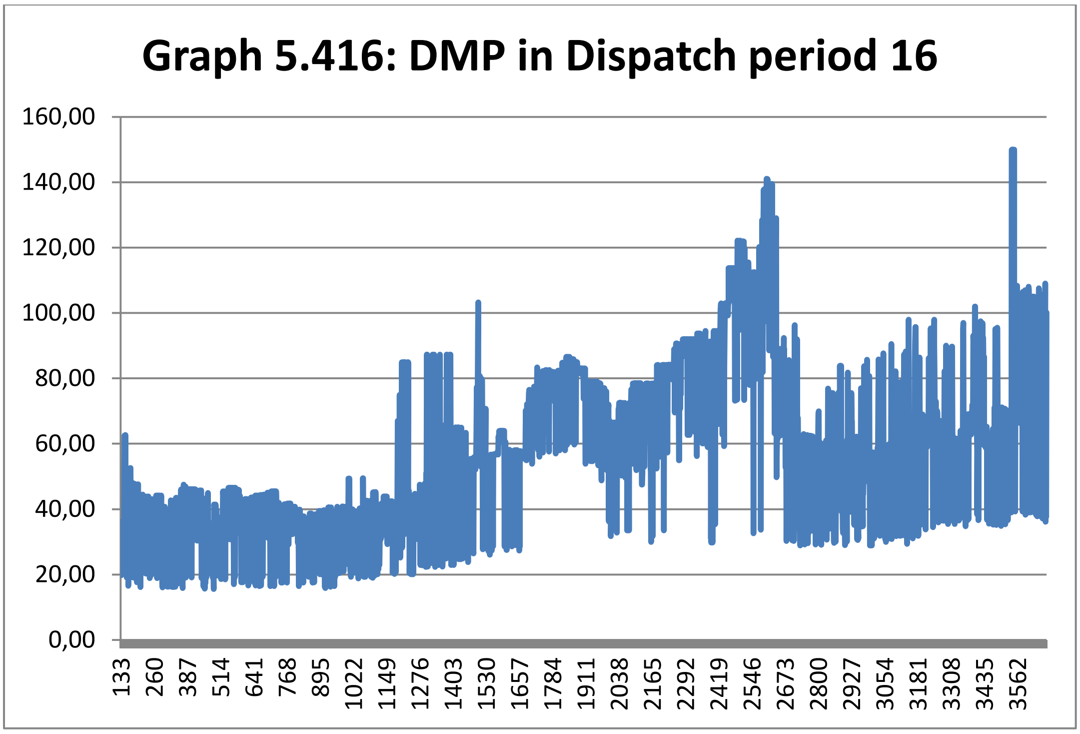
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.416: DMP in Dispatch period 16
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
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133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
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1911
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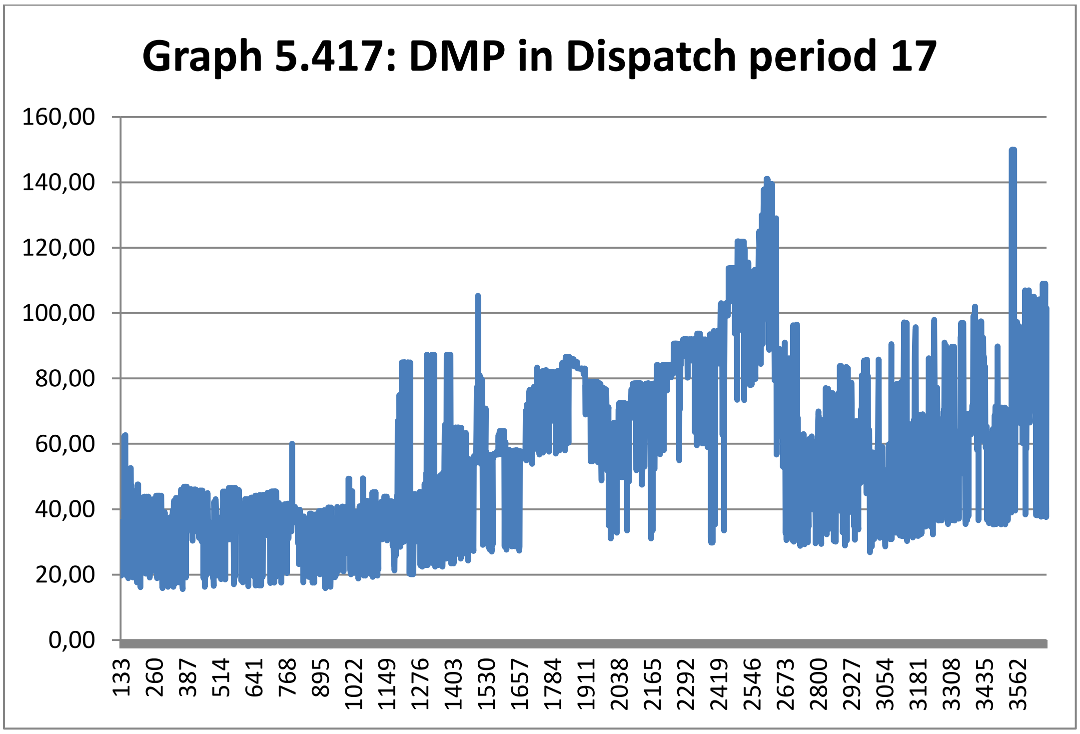
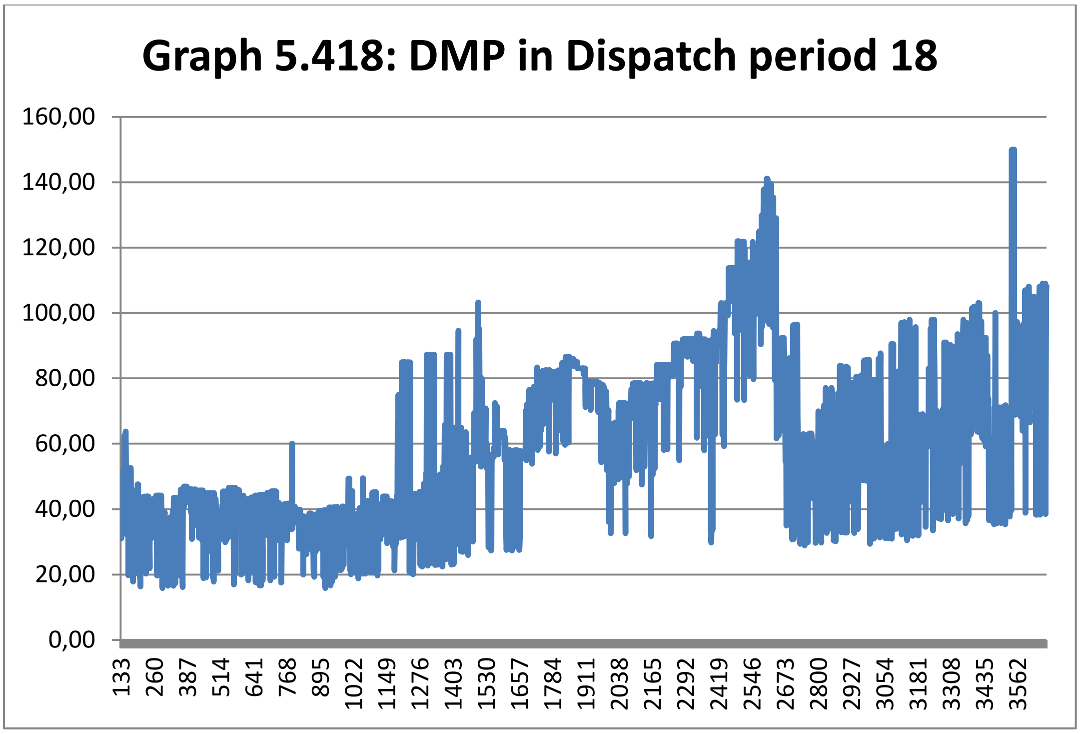
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.417: DMP in Dispatch period 17
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.418: DMP in Dispatch period 18
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
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2292
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2546
2673
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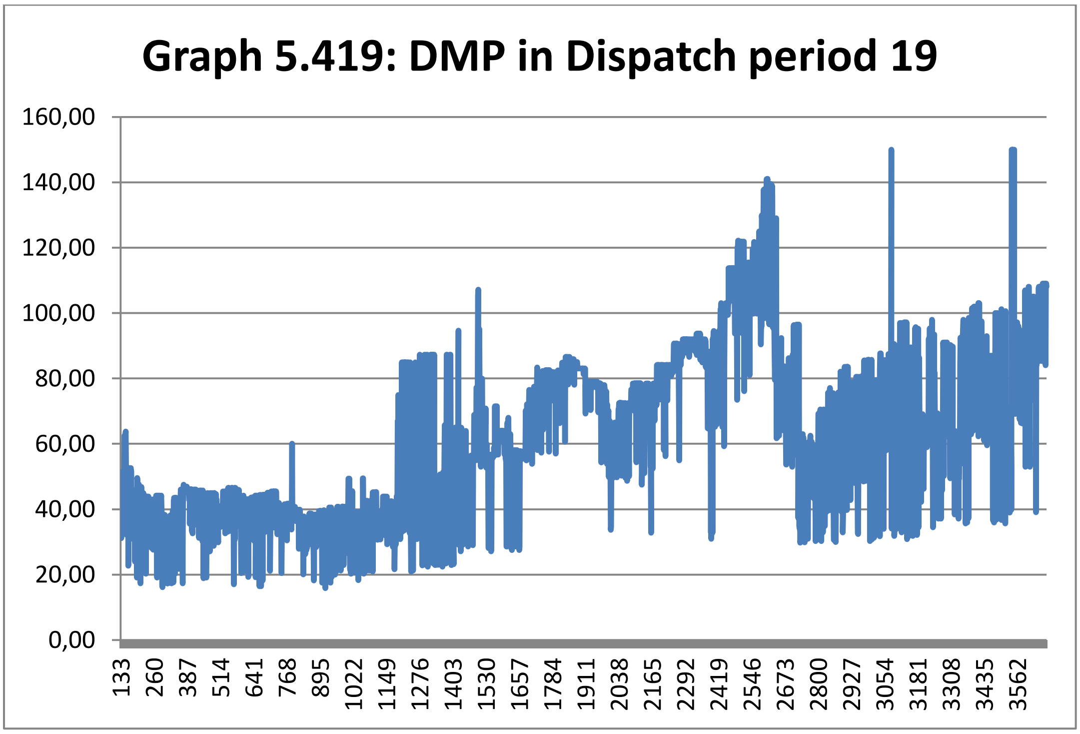
2927
3054
3181
3308
3435
3562


Graph 5.419: DMP in Dispatch period 19
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
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2038
2165
2292
2419
2546
2673
2800
2927
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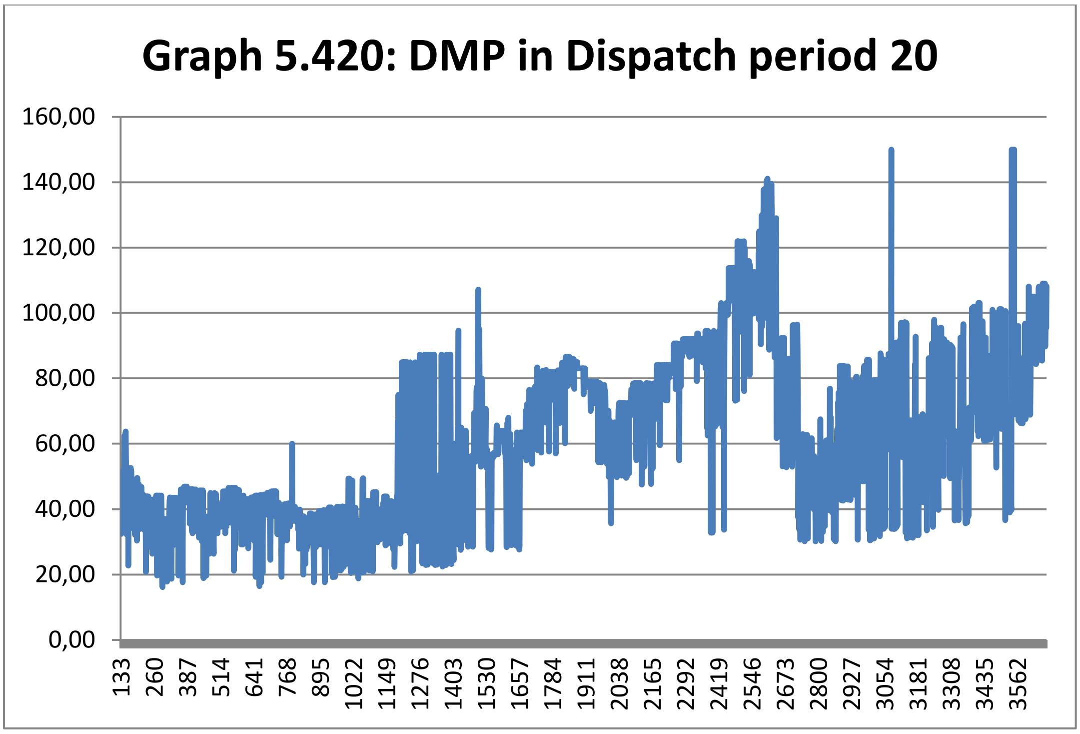
3181
3308
3435
3562


Graph 5.420: DMP in Dispatch period 20
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
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2038
2165
2292
2419
2546
2673
2800
2927
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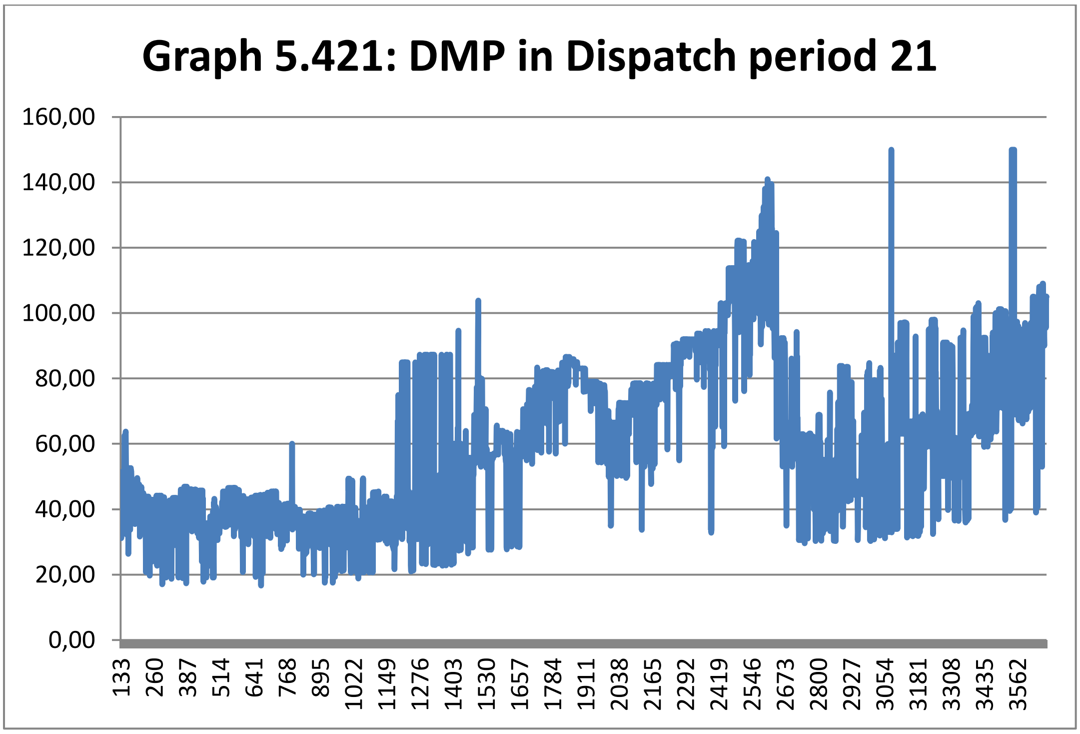
3181
3308
3435
3562


Graph 5.421: DMP in Dispatch period 21
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
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2038
2165
2292
2419
2546
2673
2800
2927
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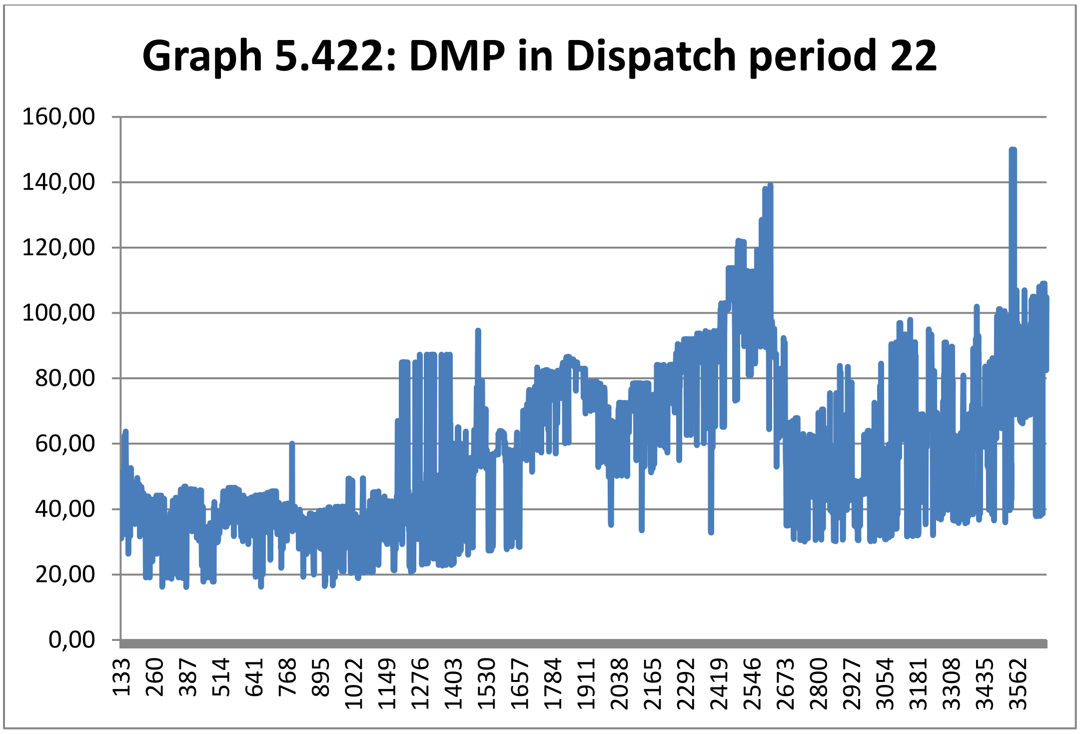
3181
3308
3435
3562


Graph 5.422: DMP in Dispatch period 22
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120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
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2292
2419
2546
2673
2800
2927
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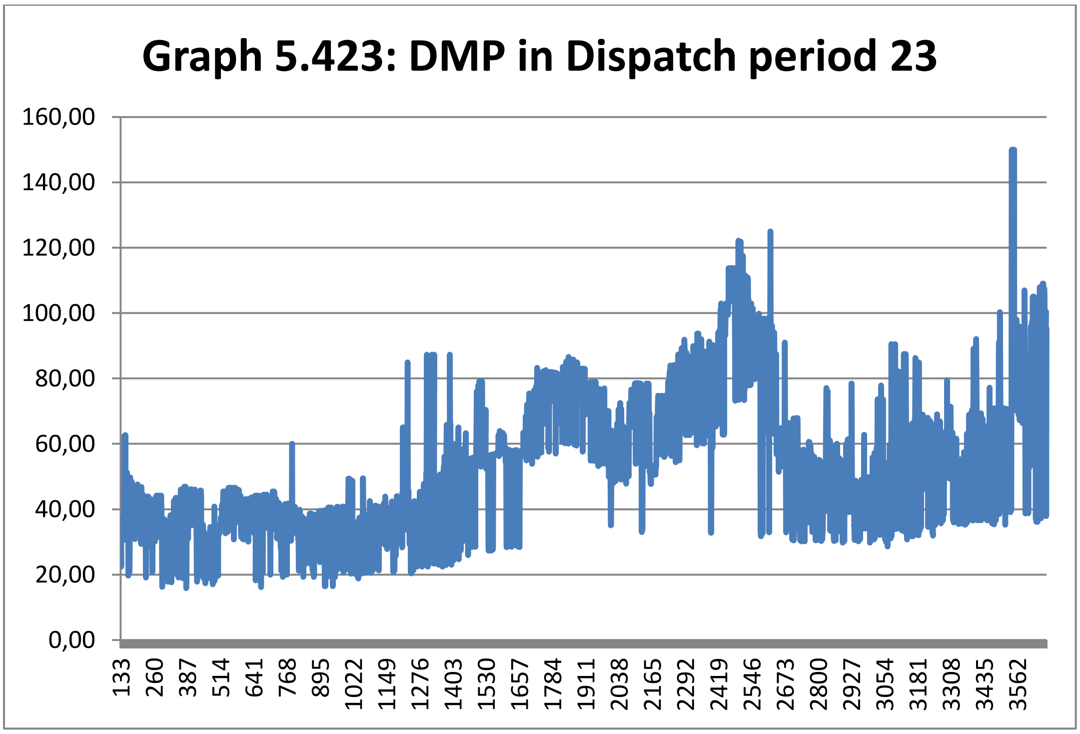
3181
3308
3435
3562


Graph 5.423: DMP in Dispatch period 23
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
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1911
2038
2165
2292
2419
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2673
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3181
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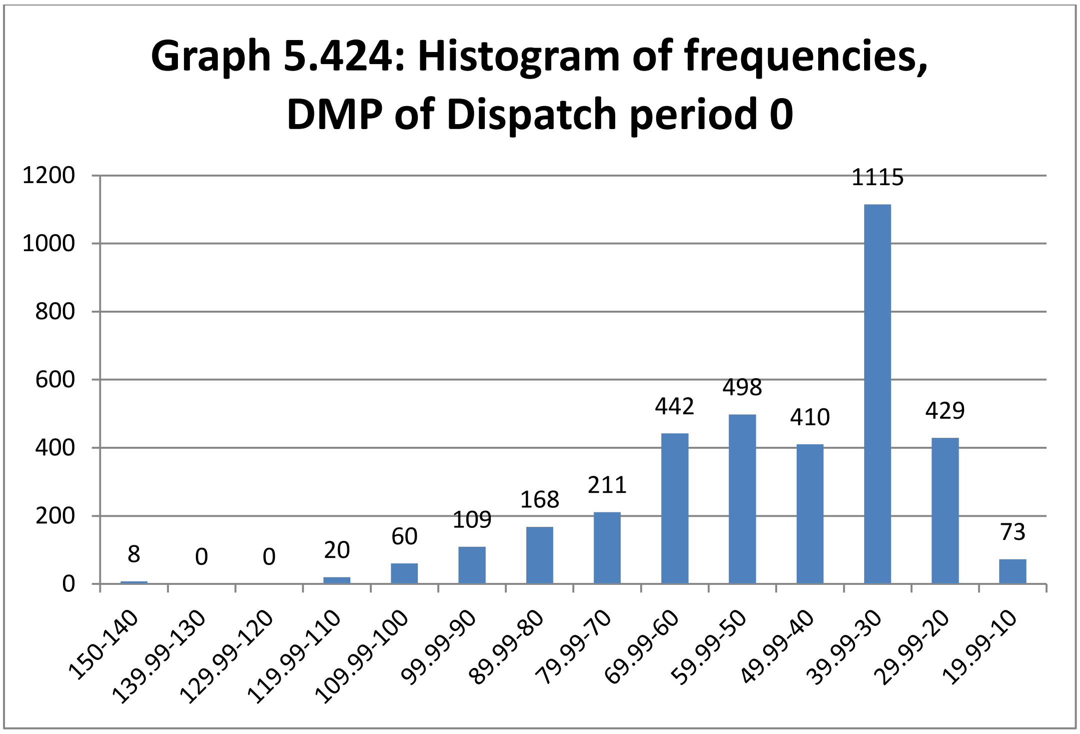
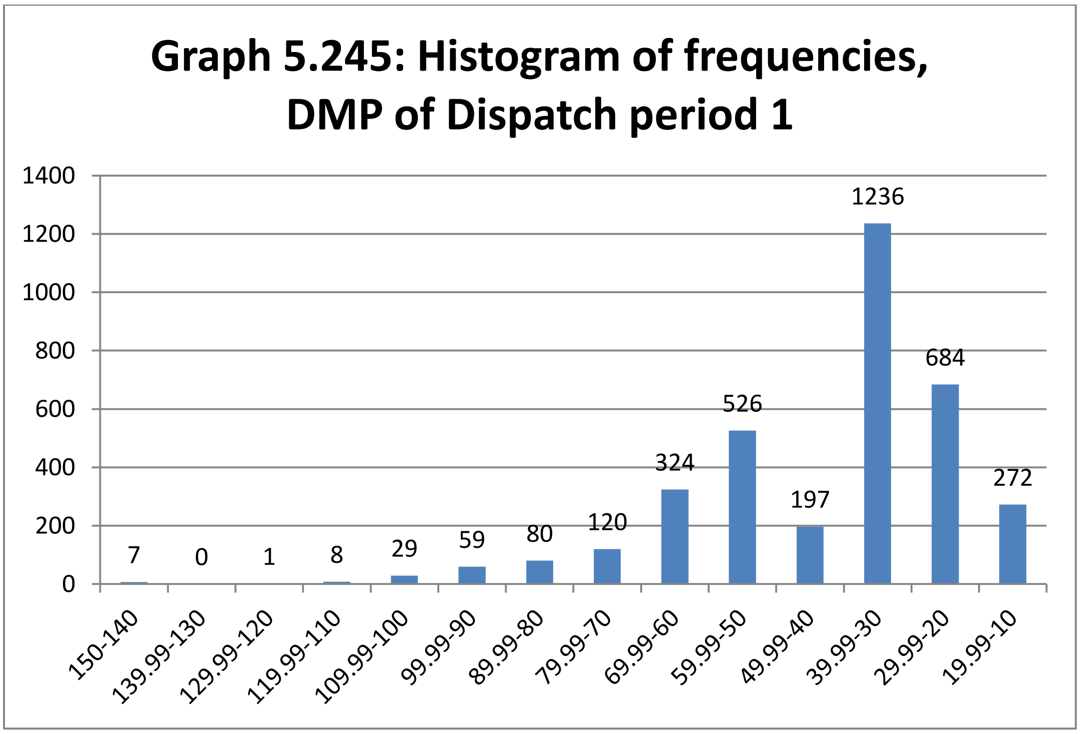
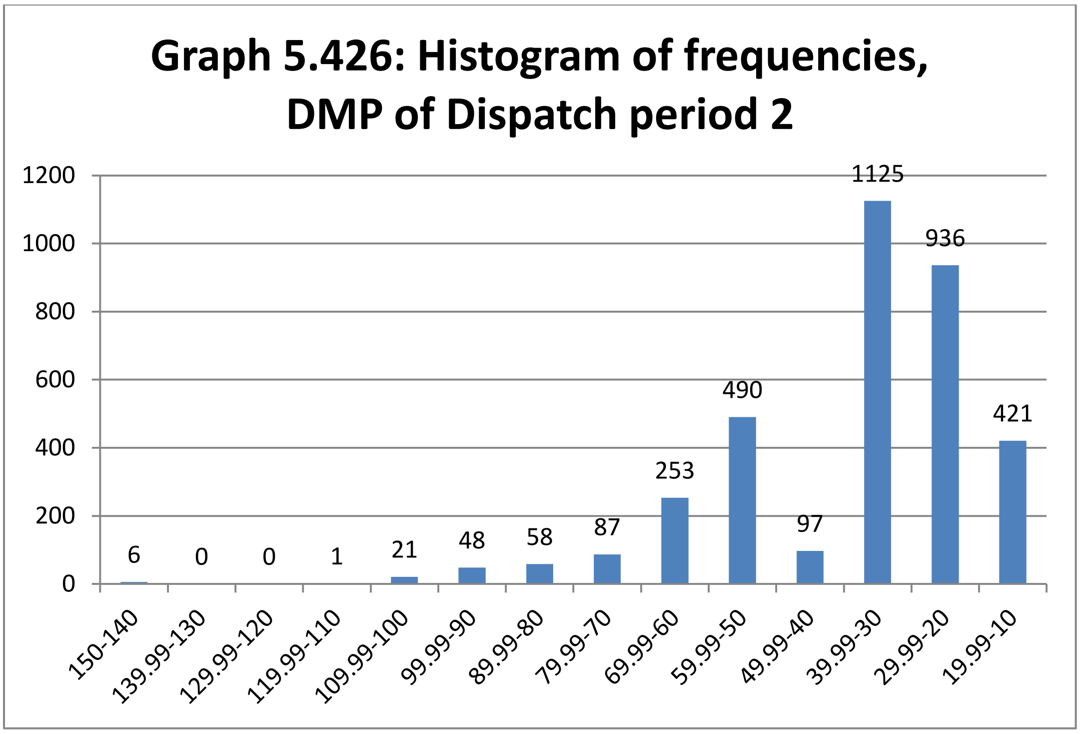
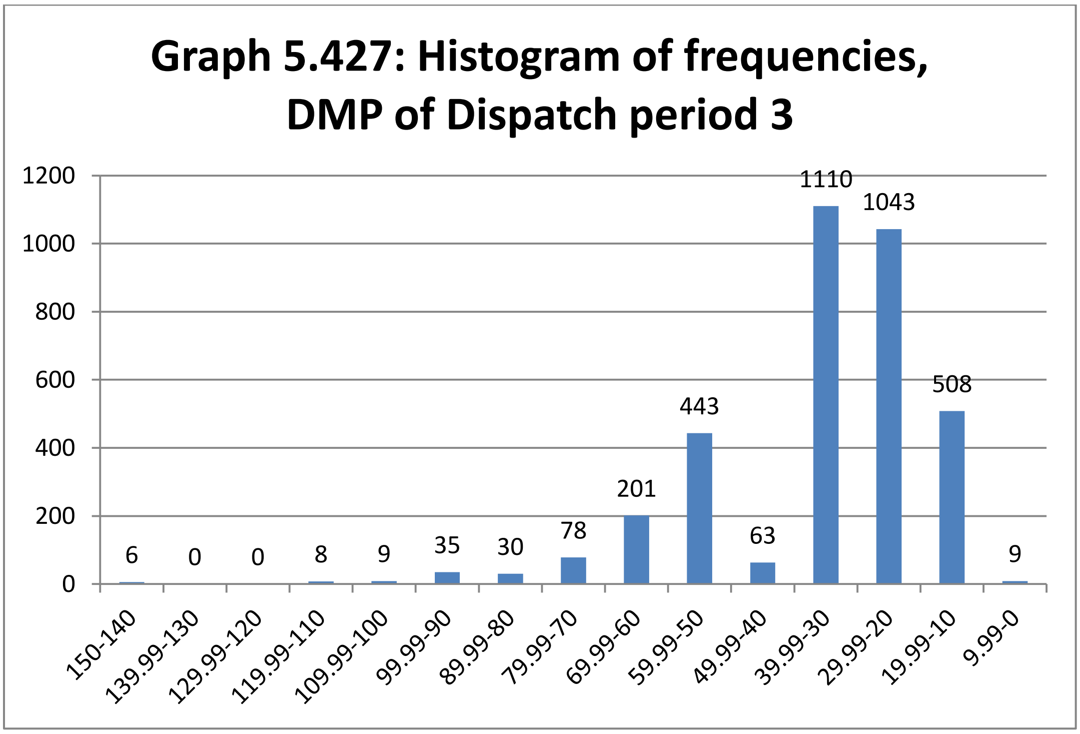
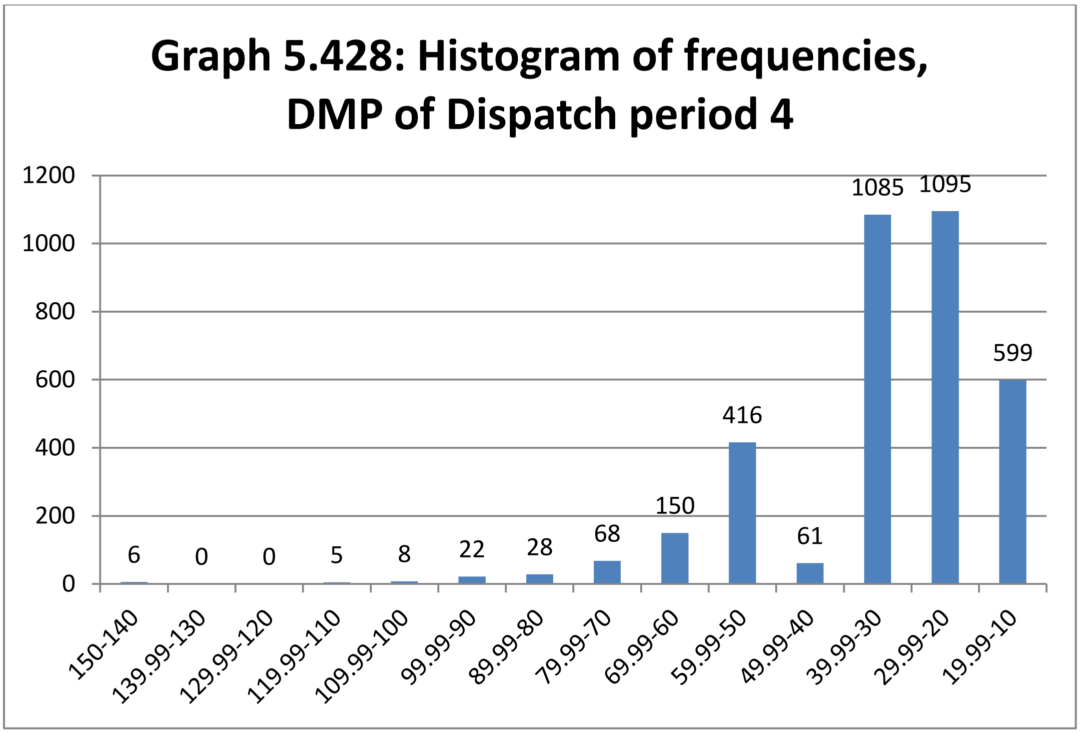
3562

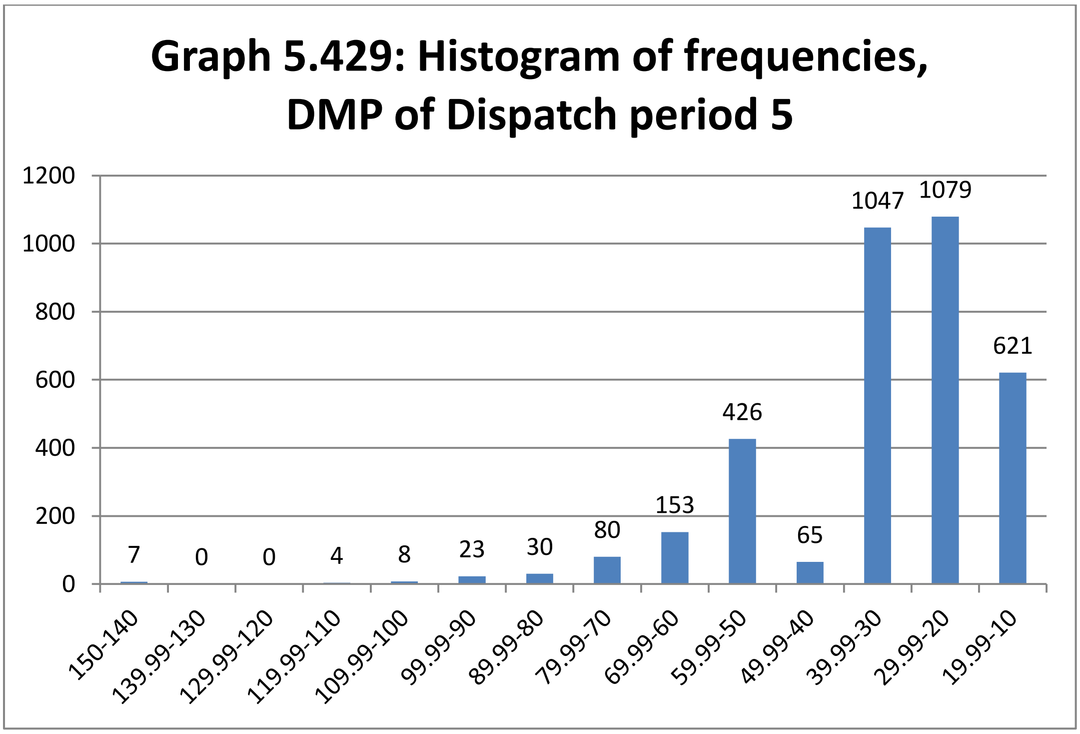

Graph 5.424: Histogram of frequencies, DMP of Dispatch period 0
1200
1000
800
600
400
200
0
8
0
0
20
60
109
168
211
442
498
410
1115
429
73
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

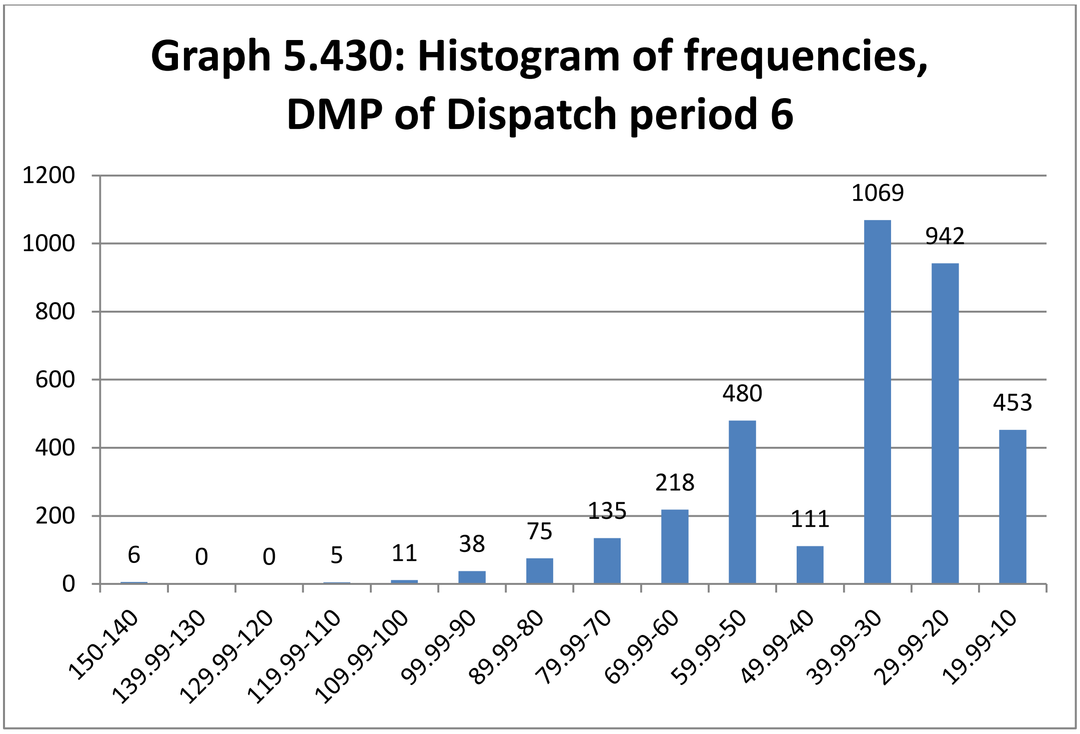

Graph 5.245: Histogram of frequencies, DMP of Dispatch period 1
1400
1200
1000
800
600
400
200
0
7
0
1
8
29
59
80
120
324
526
197
1236
684
272
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

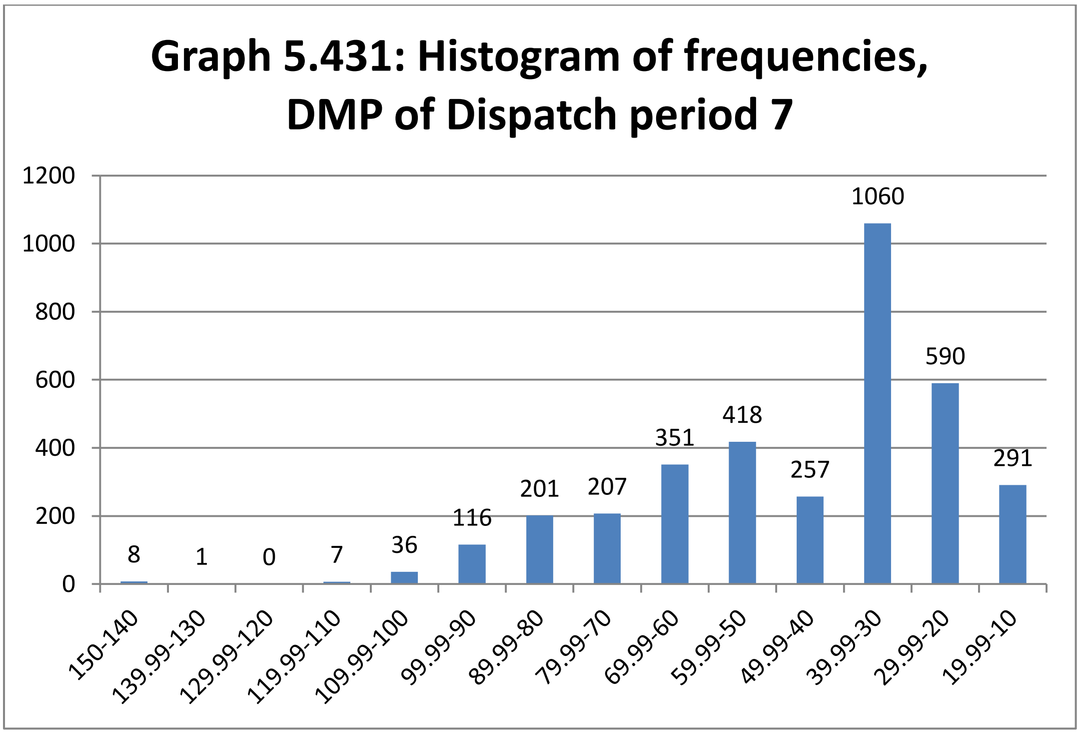

Graph 5.426: Histogram of frequencies, DMP of Dispatch period 2
1200
1000
800
600
400
200
0
6
0
0
1
21
48
58
87
253
490
97
1125
936
421
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10


Graph 5.427: Histogram of frequencies, DMP of Dispatch period 3
1200
1000
800
600
400
200
0
6
0
0
8
9
35
30
78
201
443
63
1110
1043
508
9
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10
9.99-0

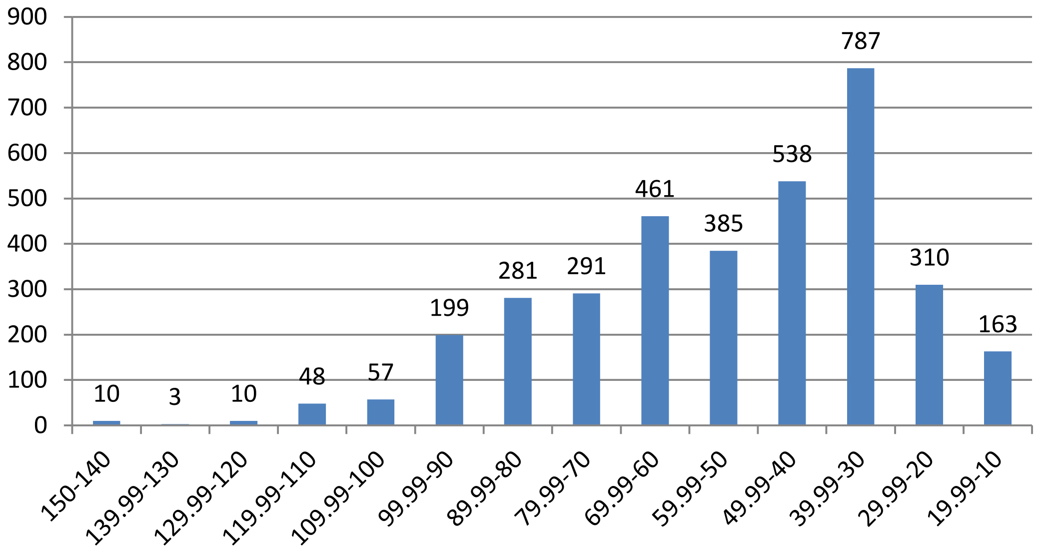

Graph 5.428: Histogram of frequencies, DMP of Dispatch period 4
1200
1000
800
600
400
200
0
6
0
0
5
8
22
28
68
150
416
61
1085
1095
599
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10


Graph 5.429: Histogram of frequencies, DMP of Dispatch period 5
1200
1000
800
600
400
200
0
7
0
0
4
8
23
30
80
153
426
65
1047
1079
621
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

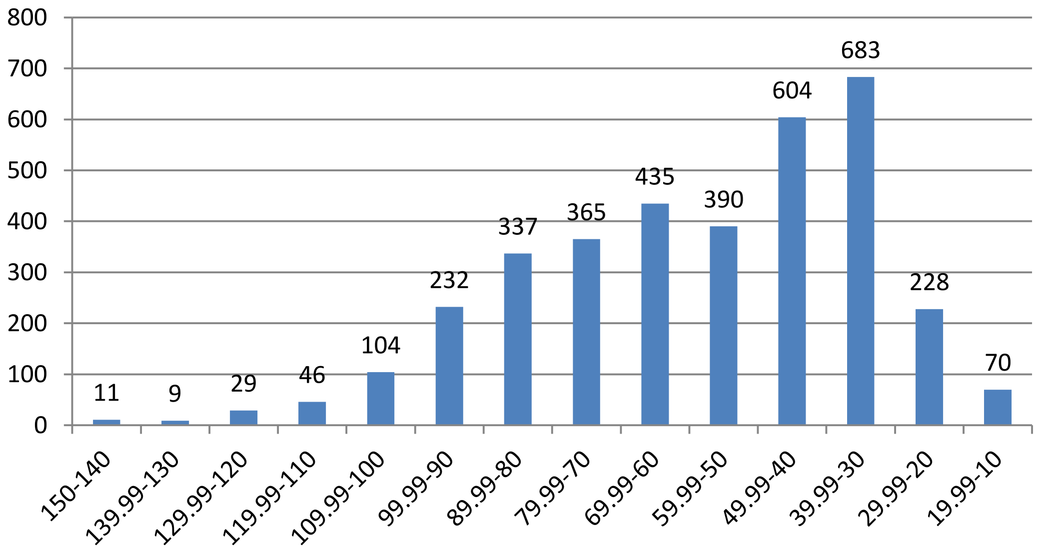

Graph 5.430: Histogram of frequencies, DMP of Dispatch period 6
1200
1000
800
600
400
200
0
6
0
0
5
11
38
75
135
218
480
111
1069
942
453
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

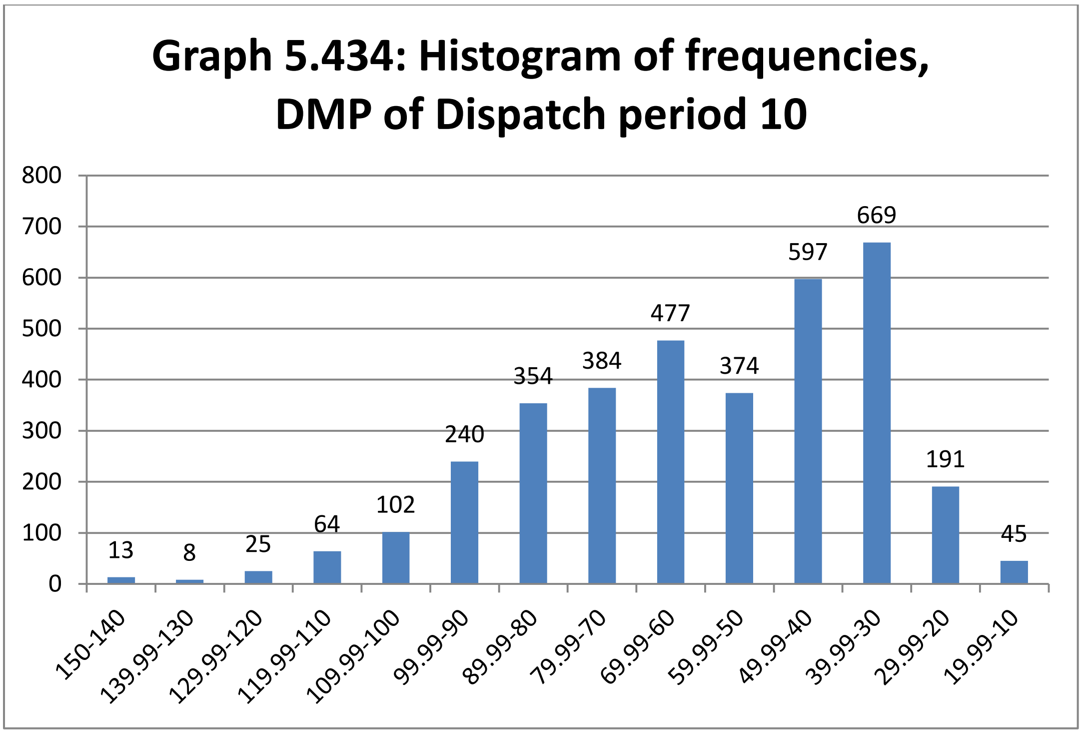

Graph 5.431: Histogram of frequencies, DMP of Dispatch period 7
1200
1000
800
600
400
200
0
8
1
0
7
36
116
201
207
351
418
257
1060
590
291
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

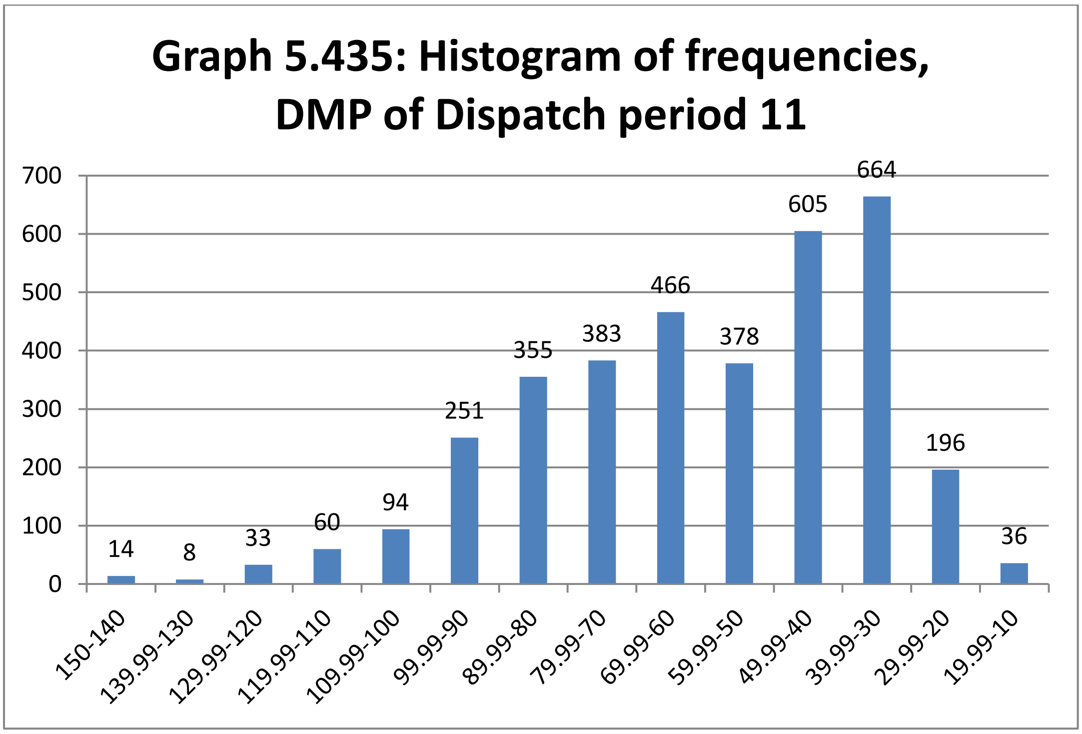
Graph 5.432: Histogram of frequencies, DMP of Dispatch period 8

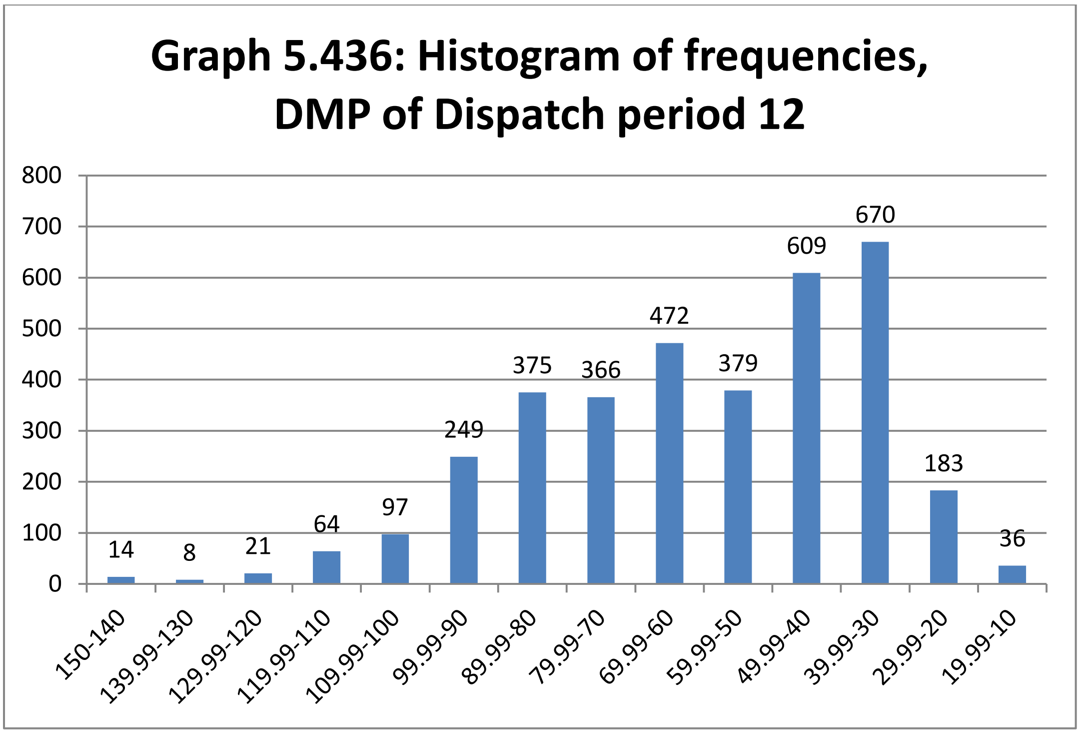


Graph 5.433: Histogram of frequencies, DMP of Dispatch period 9

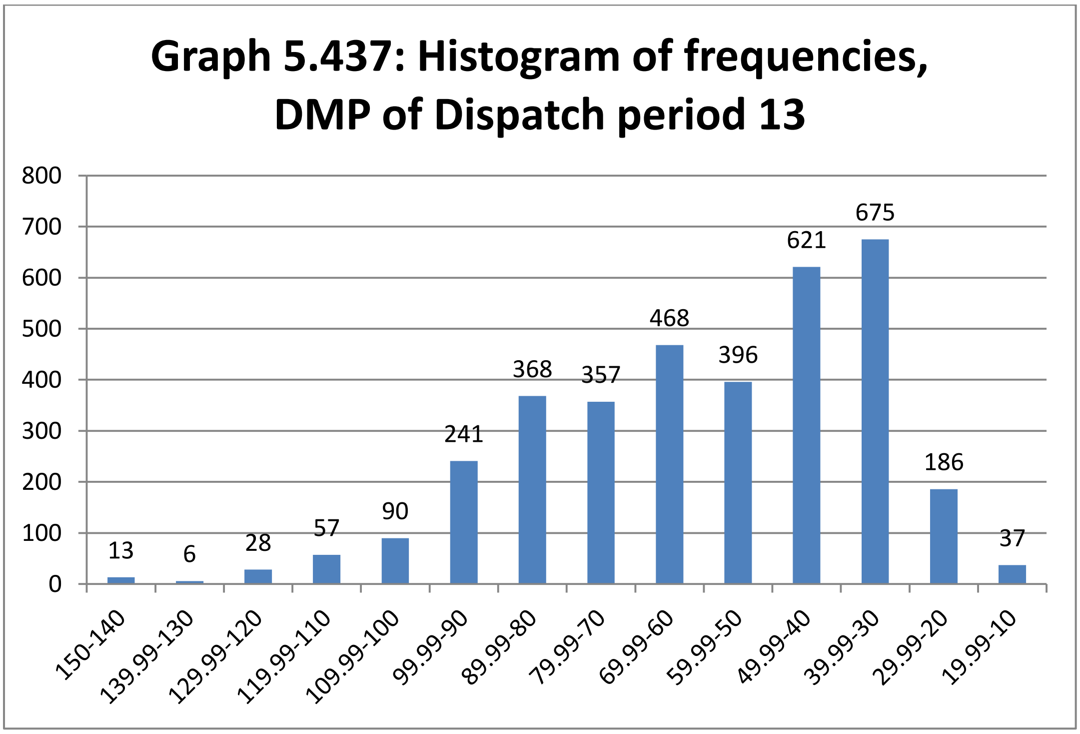



Graph 5.434: Histogram of frequencies, DMP of Dispatch period 10
800
700
600
500
400
300
200
100
0
13
8
25
64
102
240
354
384
477
374
597
669
191
45
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

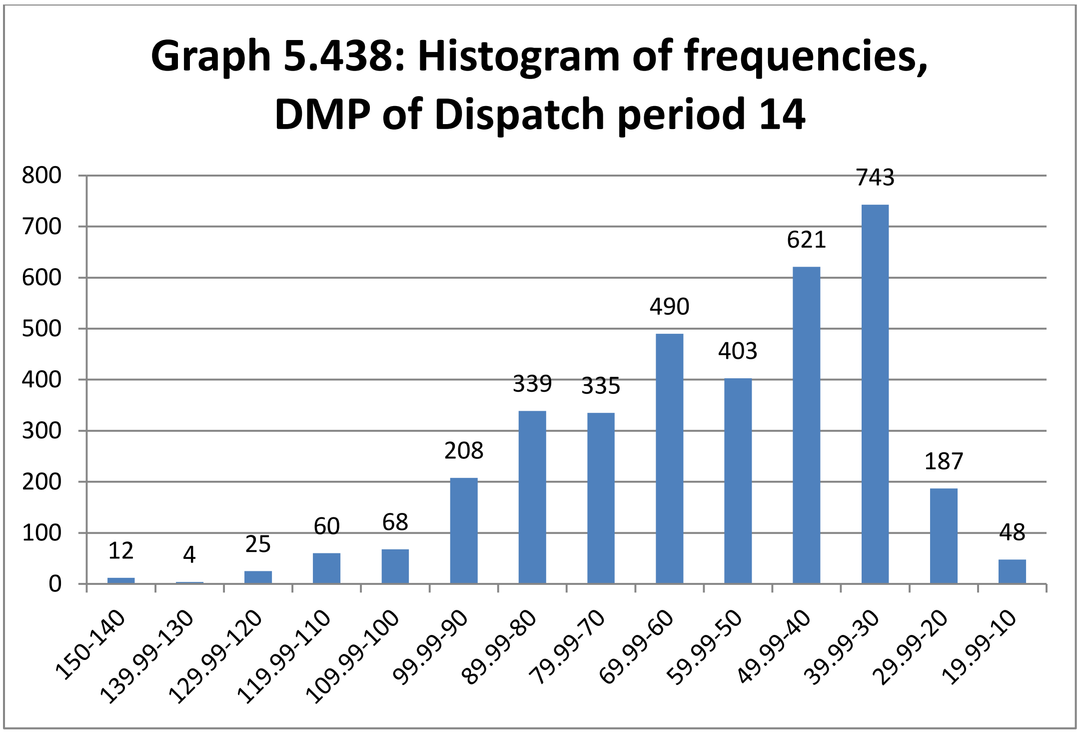

Graph 5.435: Histogram of frequencies, DMP of Dispatch period 11
700
600
500
400
300
200
100
0
14
8
33
60
94
251
355
383
466
378
605
664
196
36
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

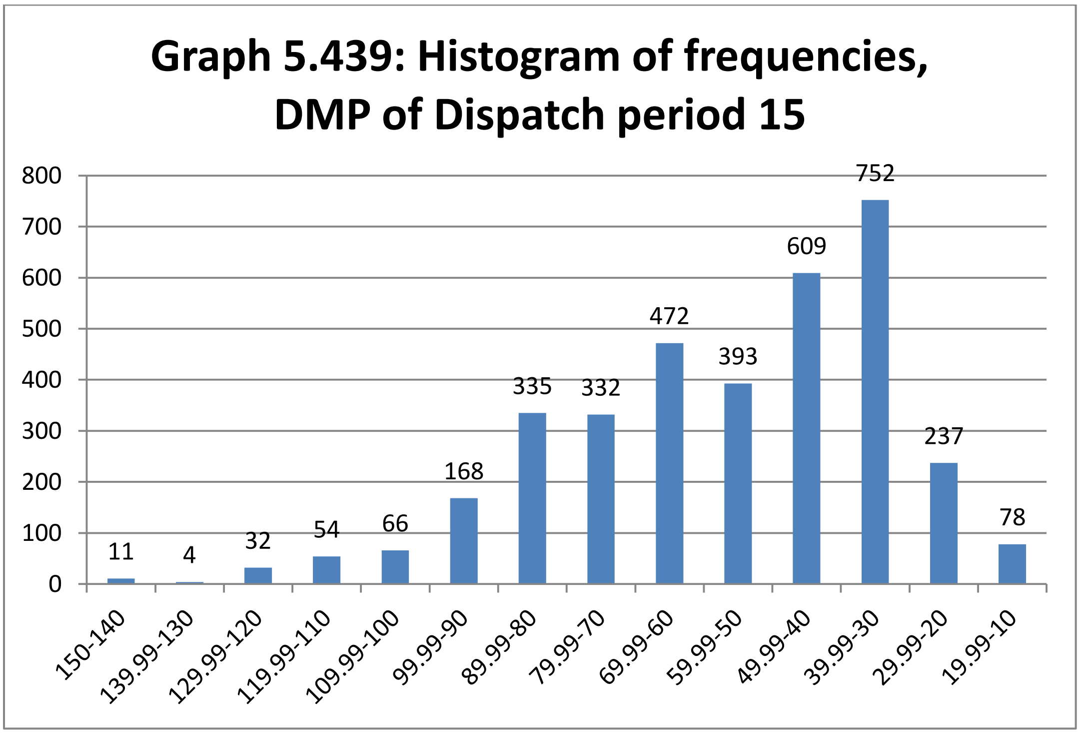


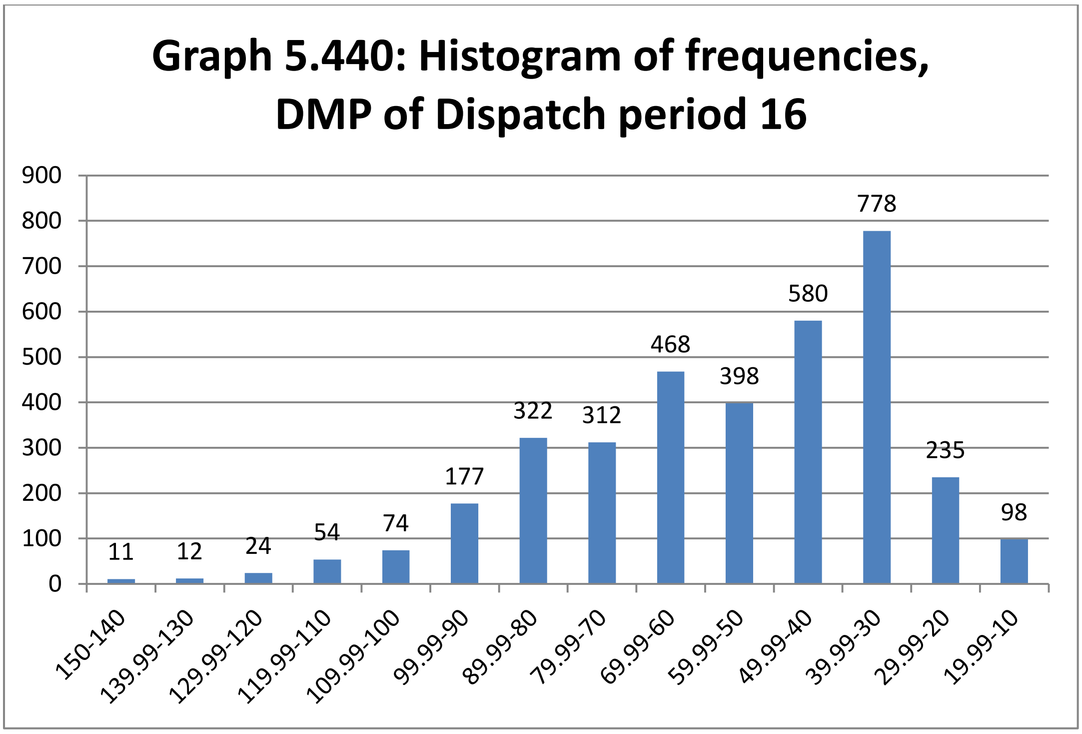
Graph 5.436: Histogram of frequencies, DMP of Dispatch period 12

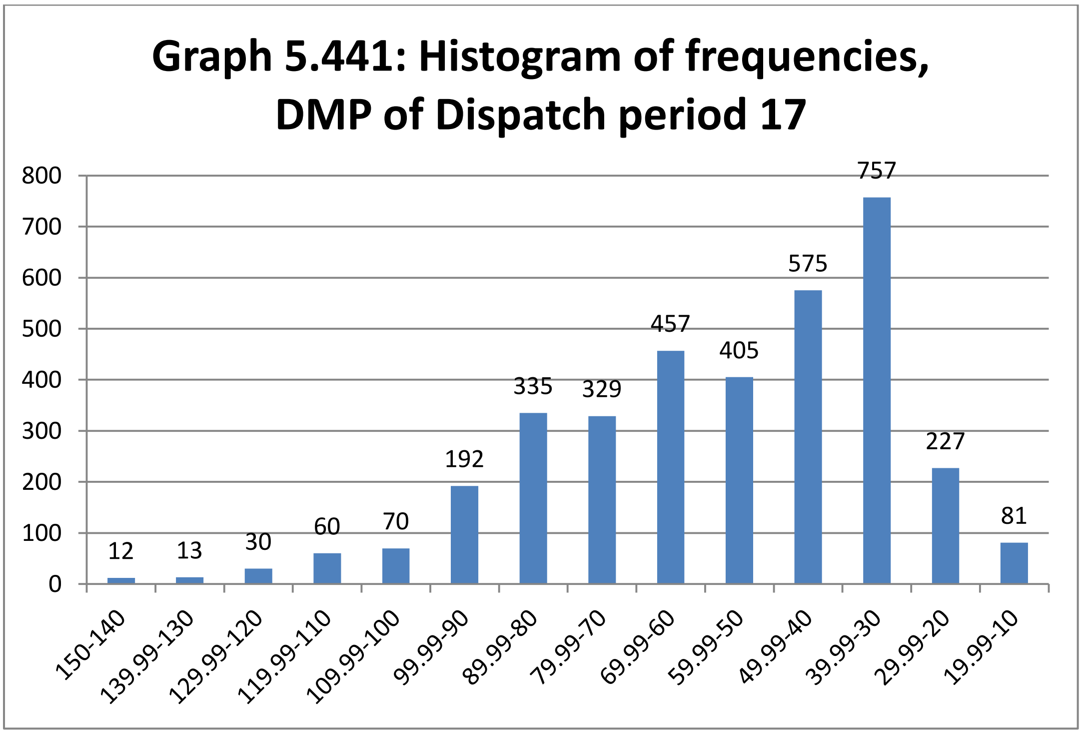


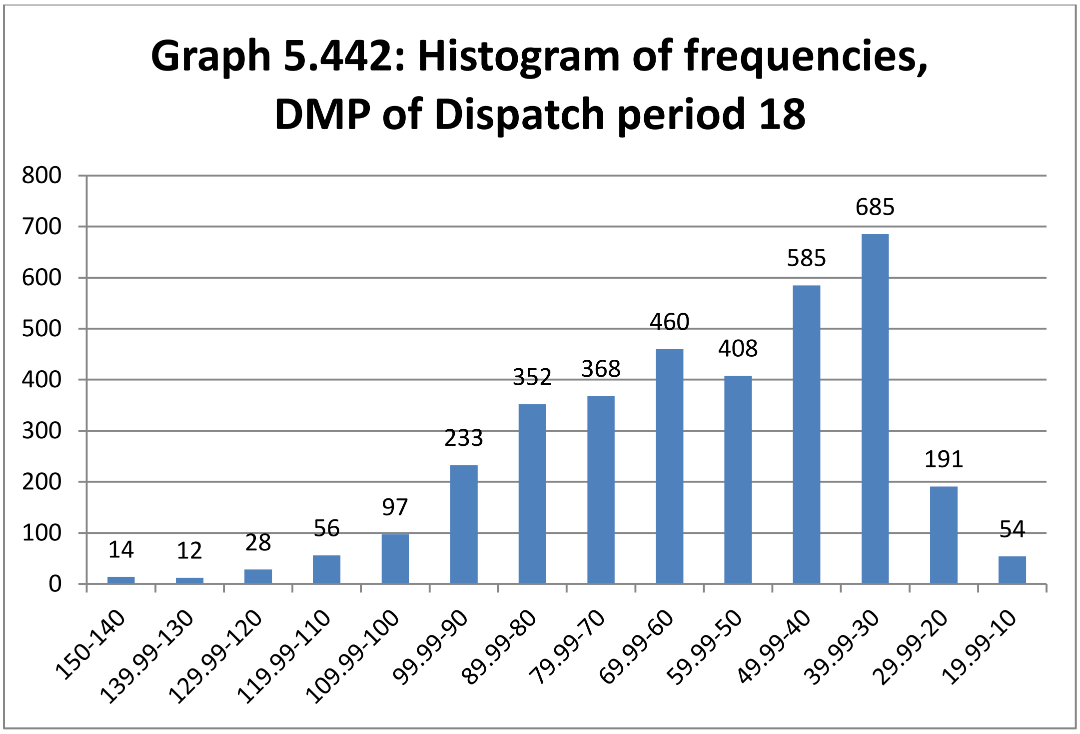
Graph 5.437: Histogram of frequencies, DMP of Dispatch period 13

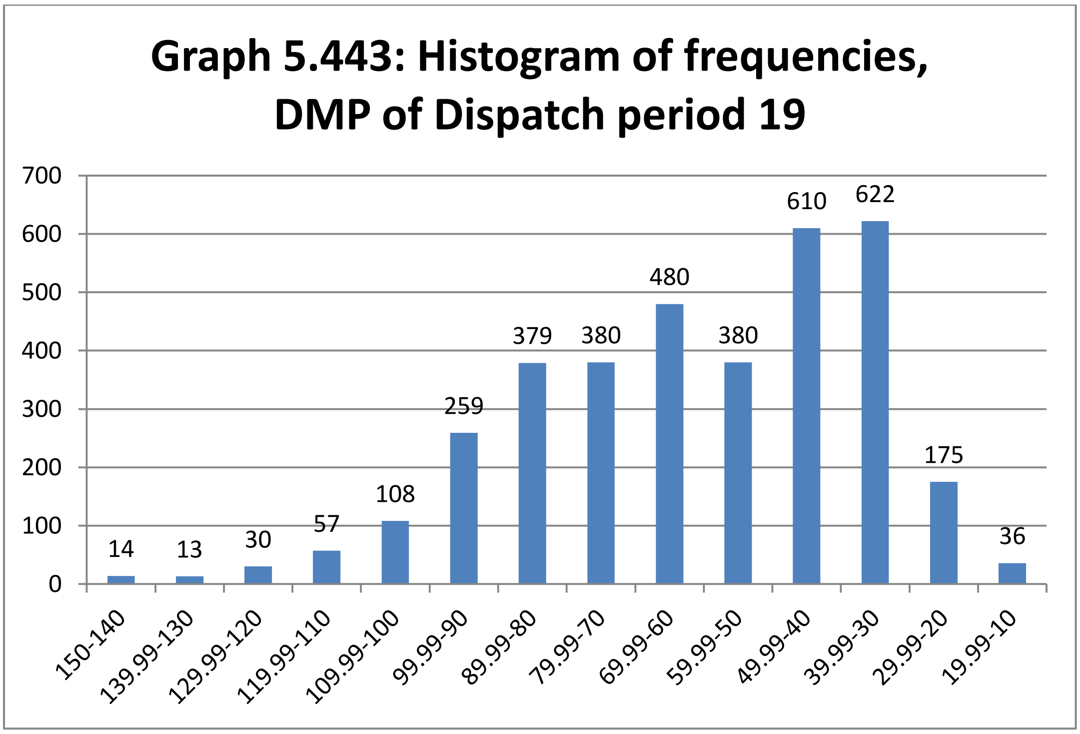

Graph 5.438: Histogram of frequencies, DMP of Dispatch period 14
800
700
600
500
400
300
200
100
0
12
4
25
60
68
208
339
335
490
403
621
743
187
48
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

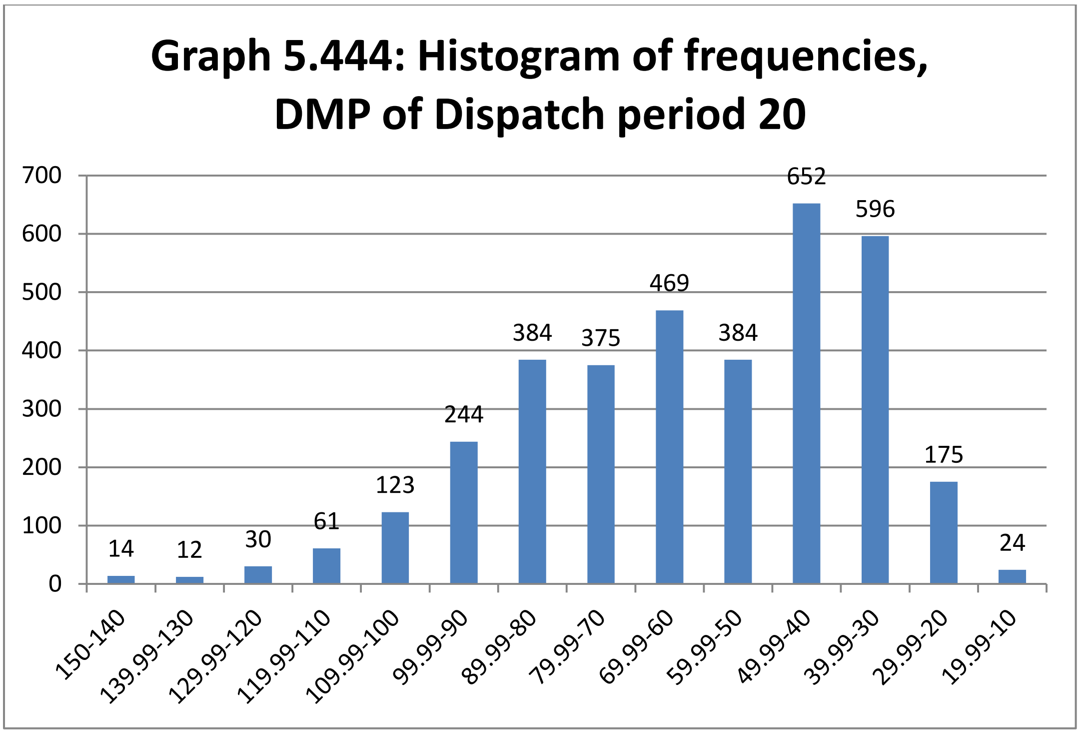

Graph 5.439: Histogram of frequencies, DMP of Dispatch period 15
800
700
600
500
400
300
200
100
0
11
4
32
54
66
168
335
332
472
393
609
752
237
78
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

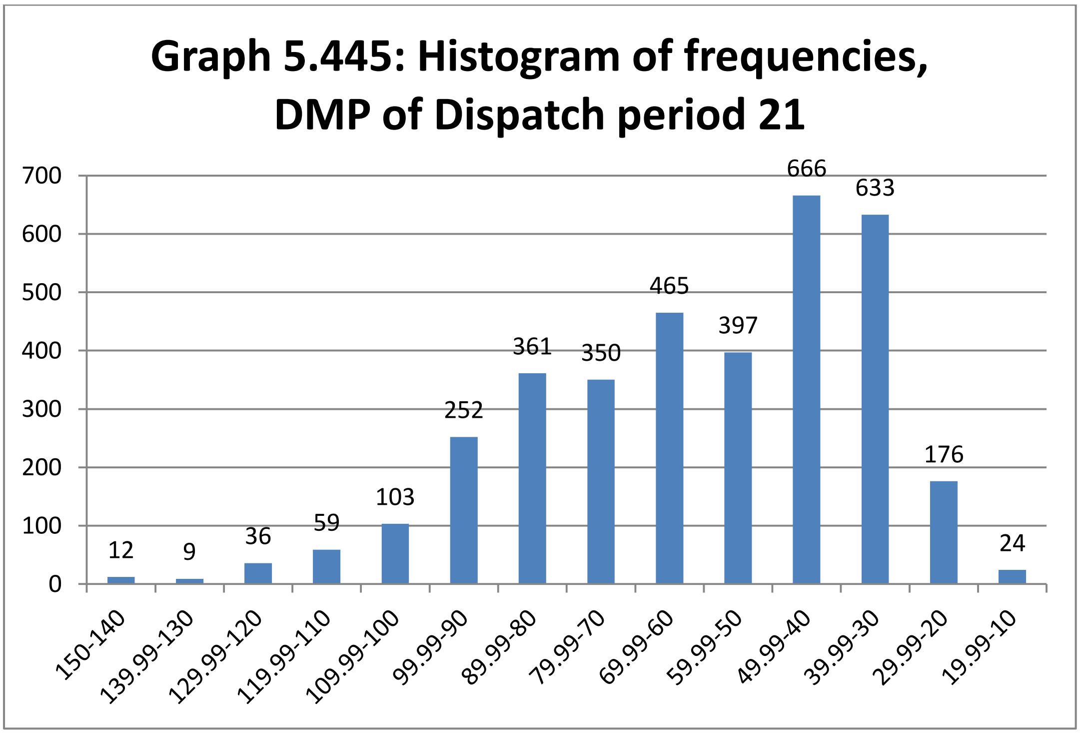

Graph 5.440: Histogram of frequencies, DMP of Dispatch period 16
900
800
700
600
500
400
300
200
100
0
11
12
24
54
74
177
322
312
468
398
580
778
235
98
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

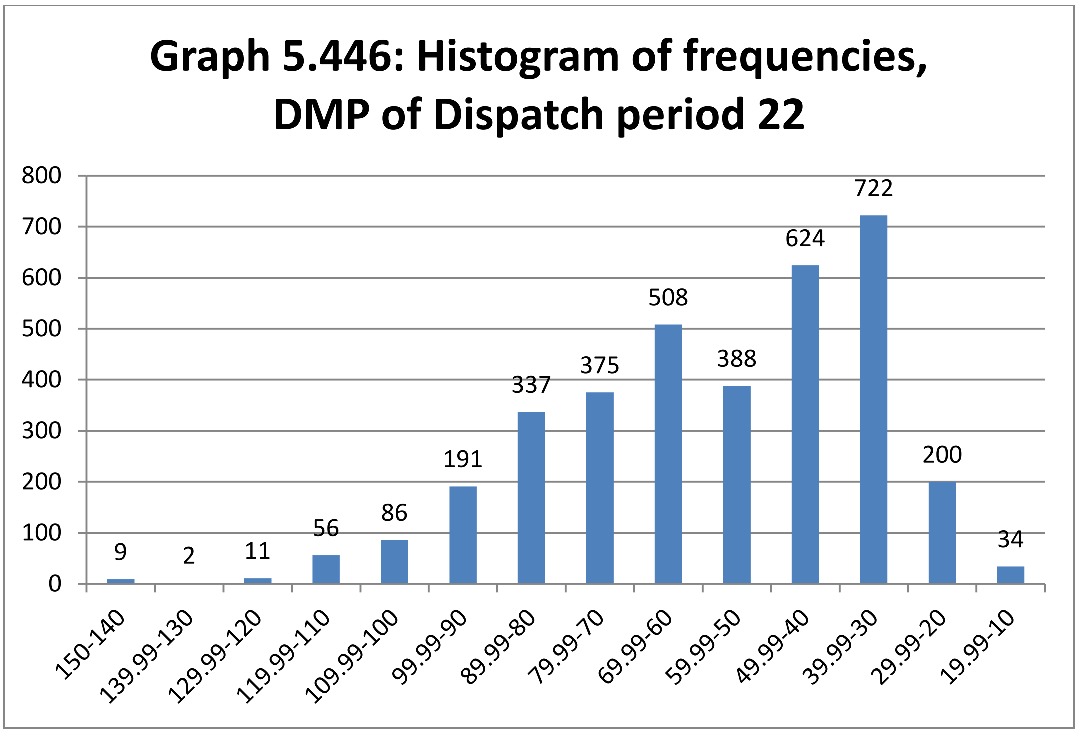

Graph 5.441: Histogram of frequencies, DMP of Dispatch period 17
800
700
600
500
400
300
200
100
0
12
13
30
60
70
192
335
329
457
405
575
757
227
81
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

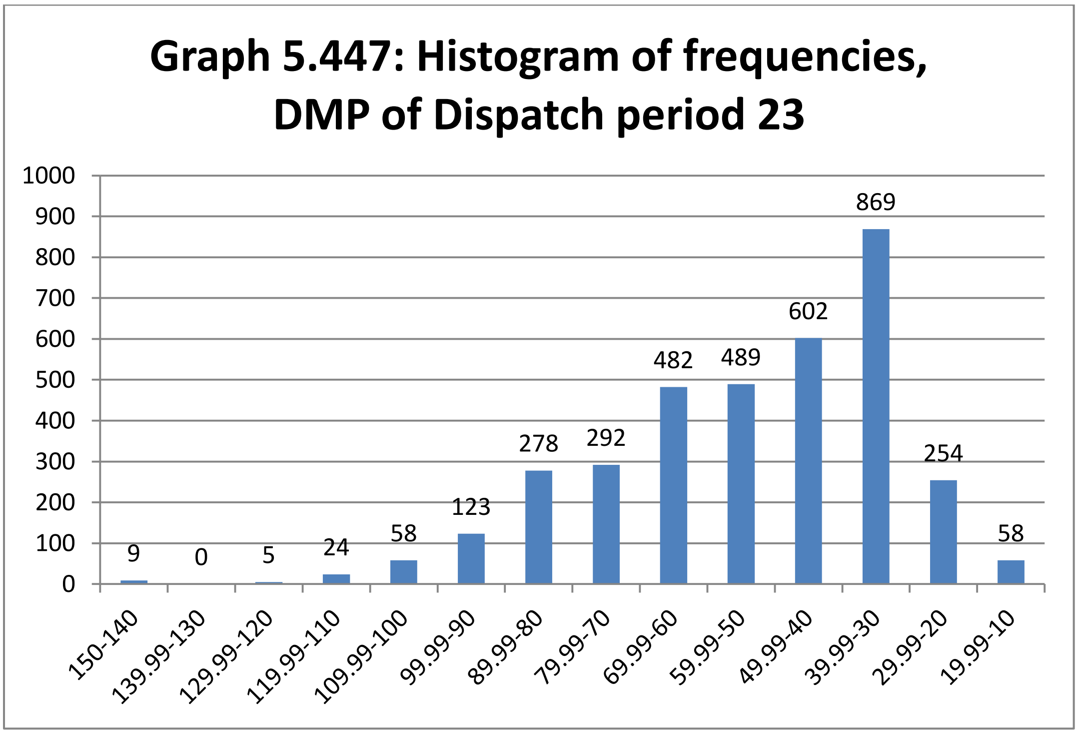

Graph 5.442: Histogram of frequencies, DMP of Dispatch period 18
800
700
600
500
400
300
200
100
0
14
12
28
56
97
233
352
368
460
408
585
685
191
54
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

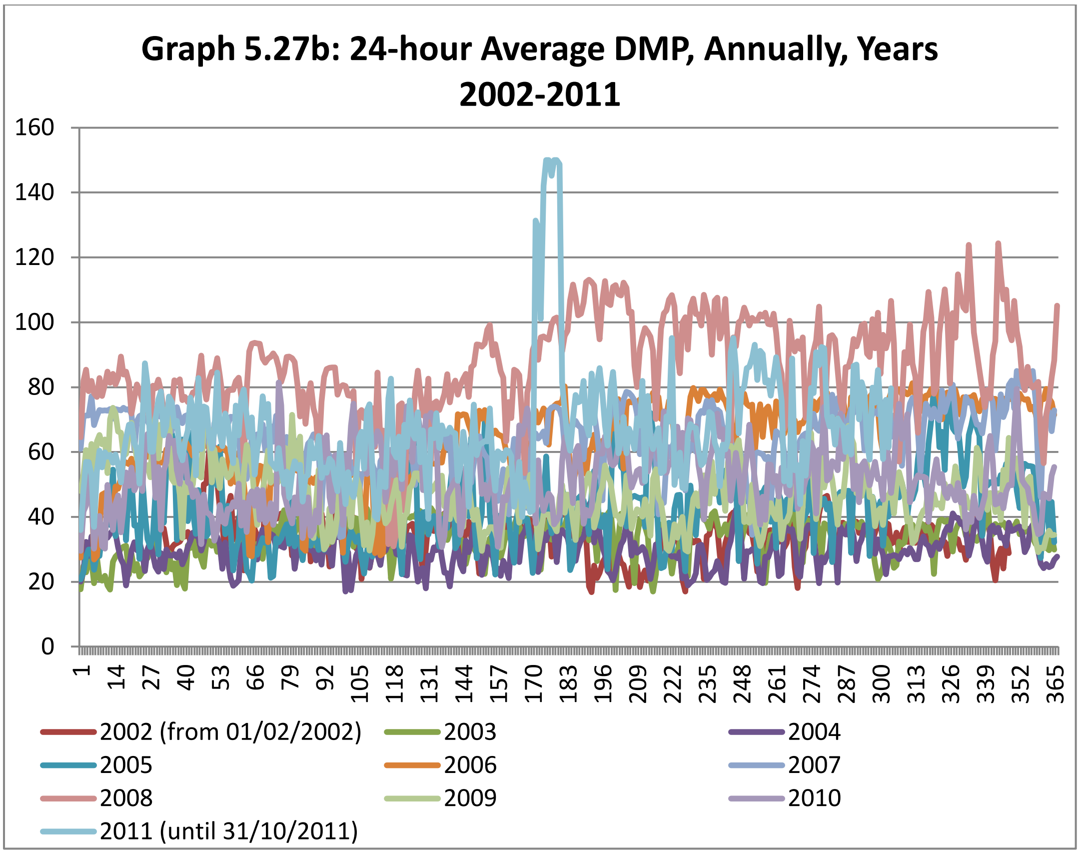

Graph 5.443: Histogram of frequencies, DMP of Dispatch period 19
700
600
500
400
300
200
100
0
14
13
30
57
108
259
379
380
480
380
610
622
175
36
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10


Graph 5.444: Histogram of frequencies, DMP of Dispatch period 20
700
600
500
400
300
200
100
0
14
12
30
61
123
244
384
375
469
384
652
596
175
24
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

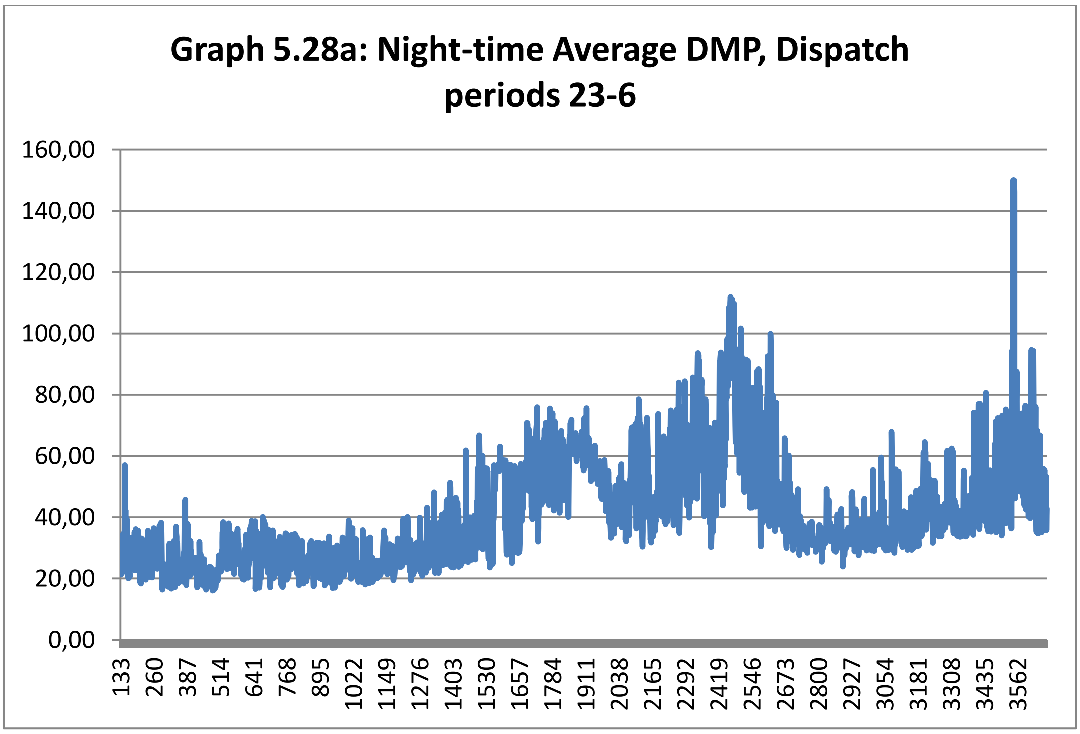

Graph 5.445: Histogram of frequencies, DMP of Dispatch period 21
700
600
500
400
300
200
100
0
12
9
36
59
103
252
361
350
465
397
666
633
176
24
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10


Graph 5.446: Histogram of frequencies, DMP of Dispatch period 22
800
700
600
500
400
300
200
100
0
9
2
11
56
86
191
337
375
508
388
624
722
200
34
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

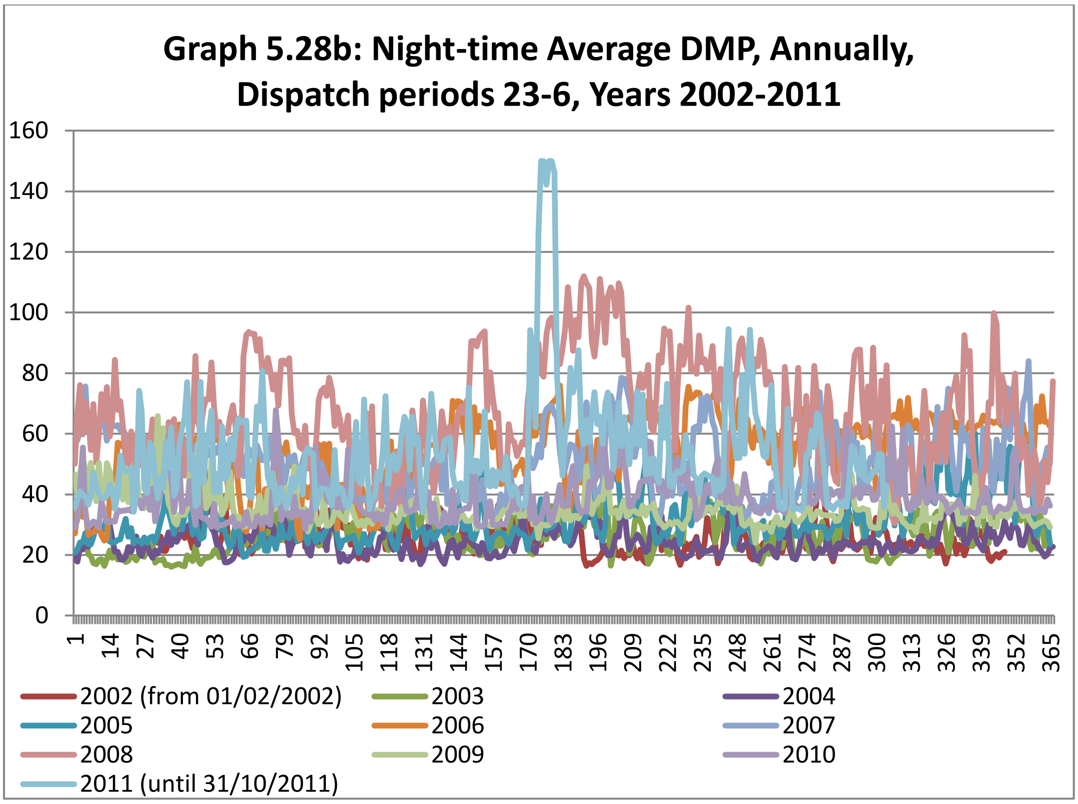

Graph 5.447: Histogram of frequencies, DMP of Dispatch period 23
1000
900
800
700
600
500
400
300
200
100
0
9
0
5
24
58
123
278
292
482
489
602
869
254
58
150-140
139.99-130
129.99-120
119.99-110
109.99-100
99.99-90
89.99-80
79.99-70
69.99-60
59.99-50
49.99-40
39.99-30
29.99-20
19.99-10

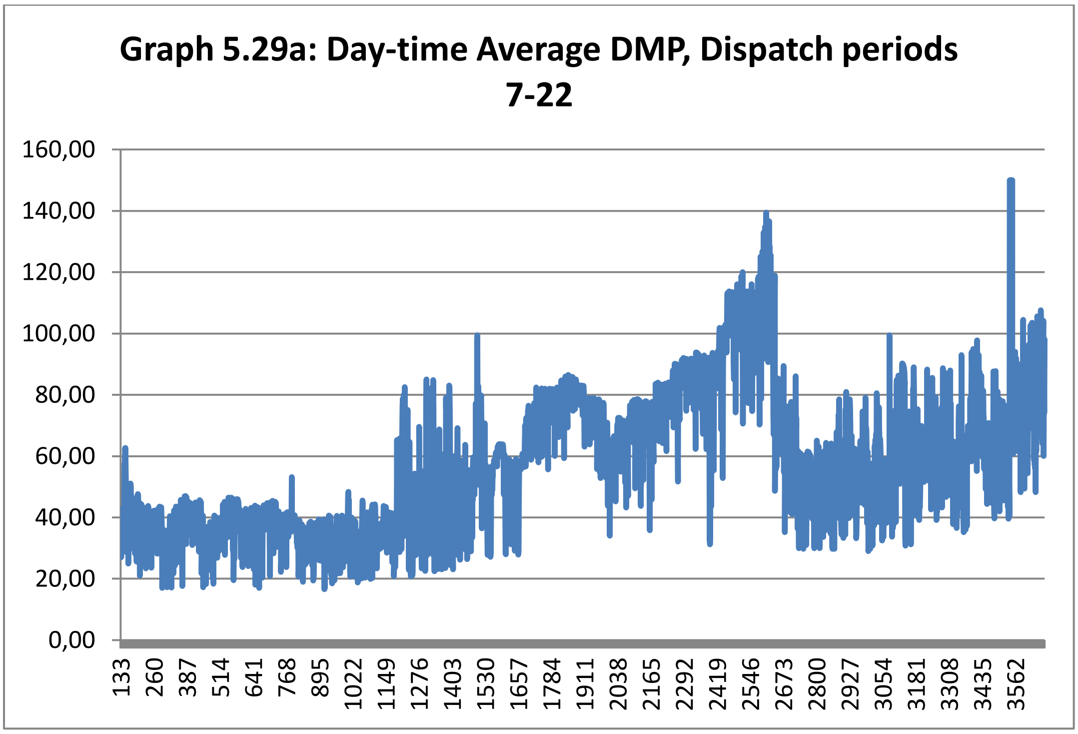


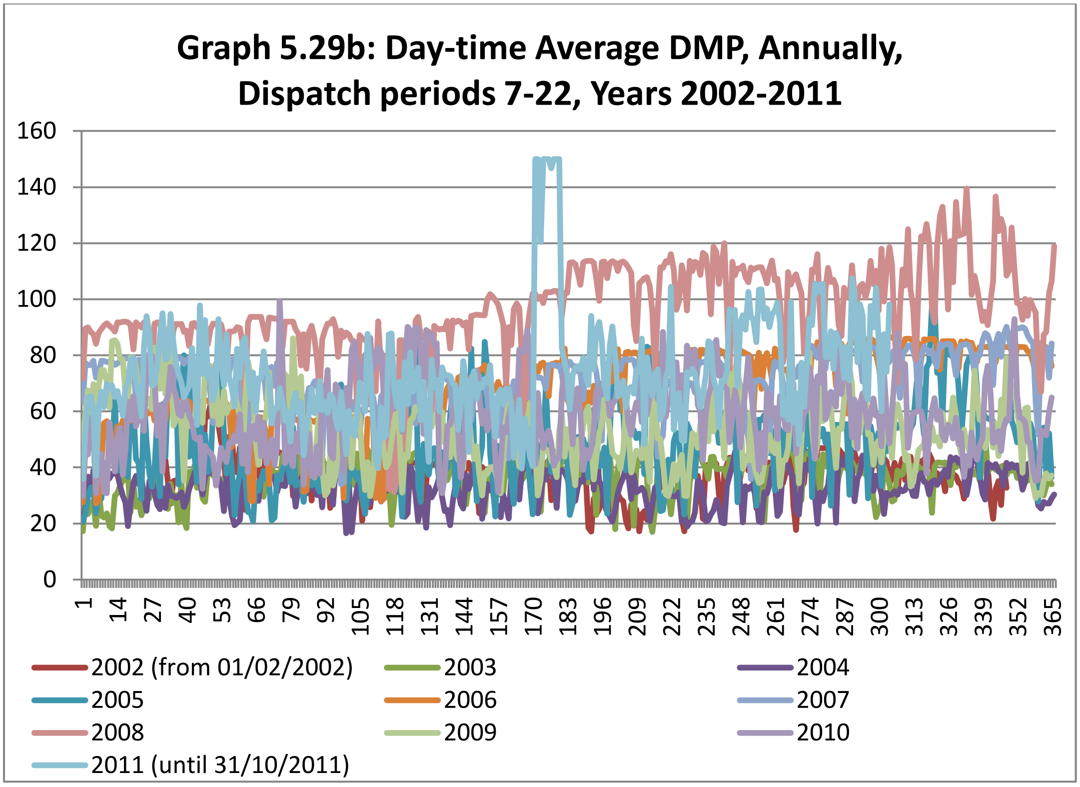
Graph 5.27b: 24-hour Average DMP, Annually, Years 2002-2011
160
140
120
100
80
60
40
20
0
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)



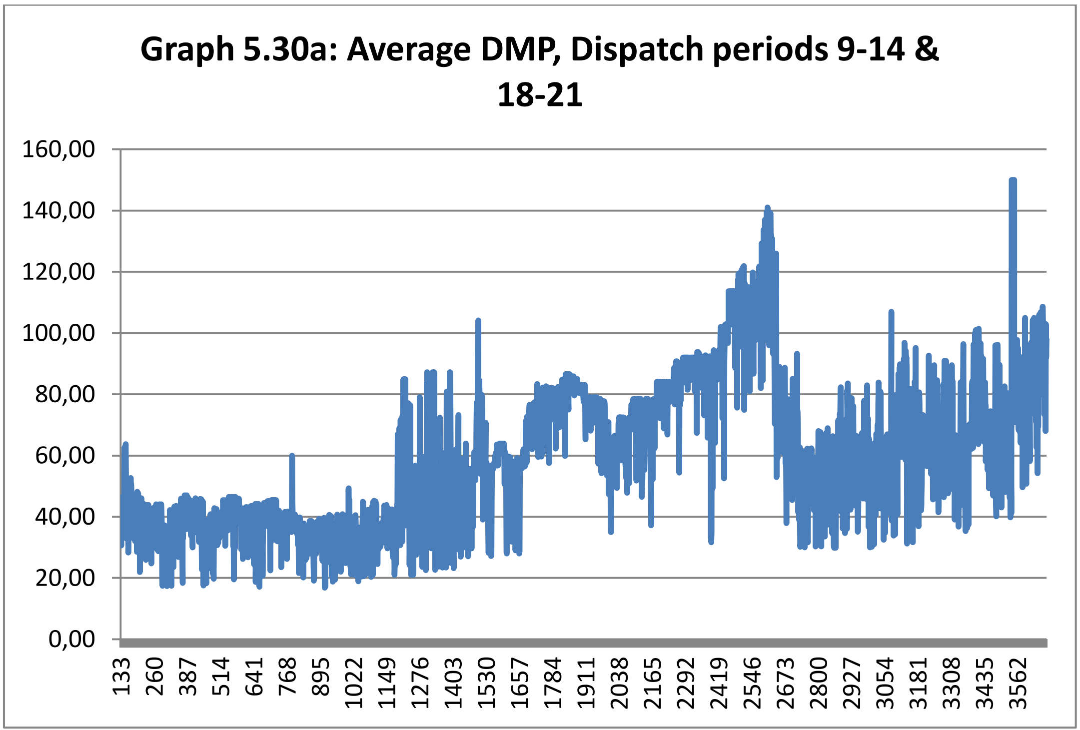
Graph 5.28a: Night-time Average DMP, Dispatch periods 23-6
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.28b: Night-time Average DMP, Annually, Dispatch periods 23-6, Years 2002-2011
160
140
120
100
80
60
40
20
0
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

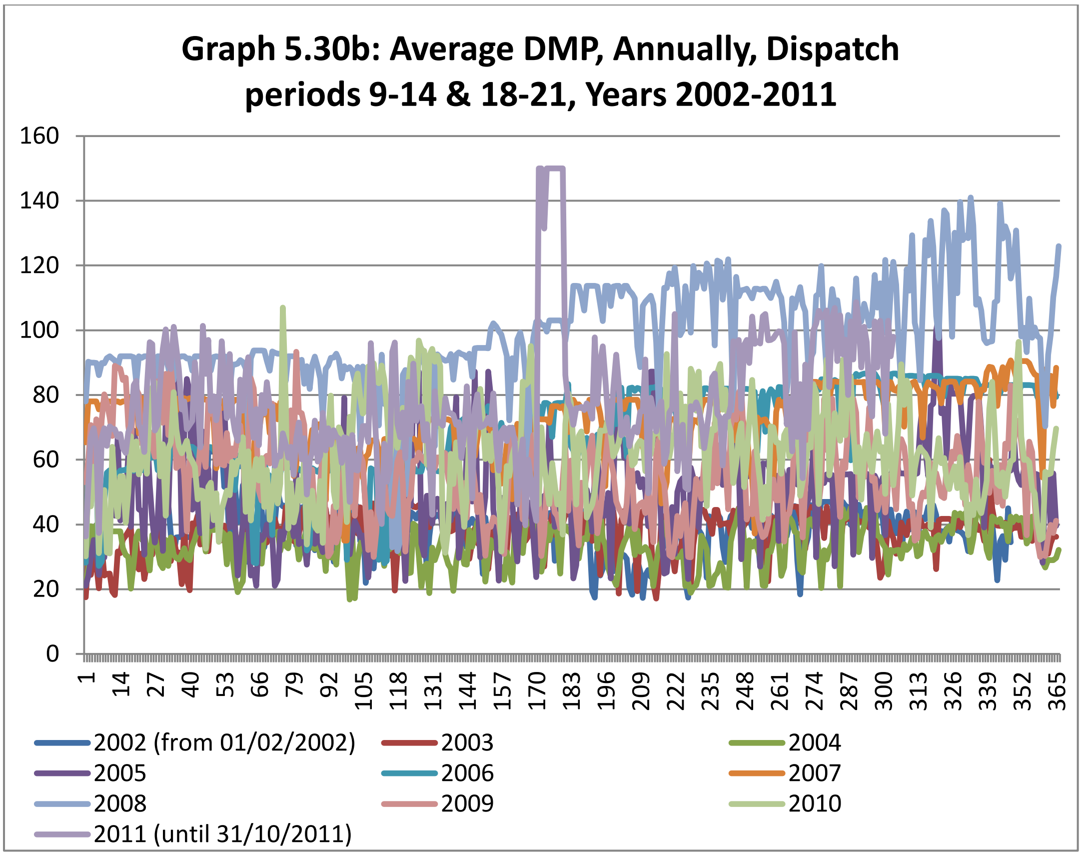

Graph 5.29a: Day-time Average DMP, Dispatch periods 7-22
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562

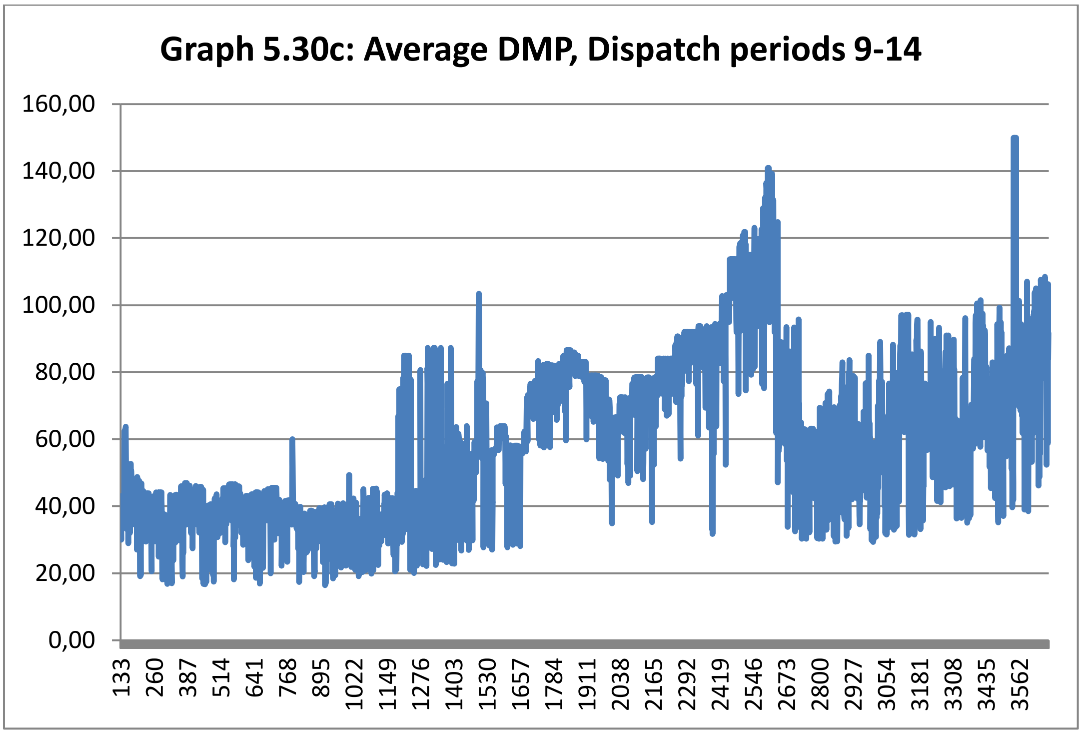


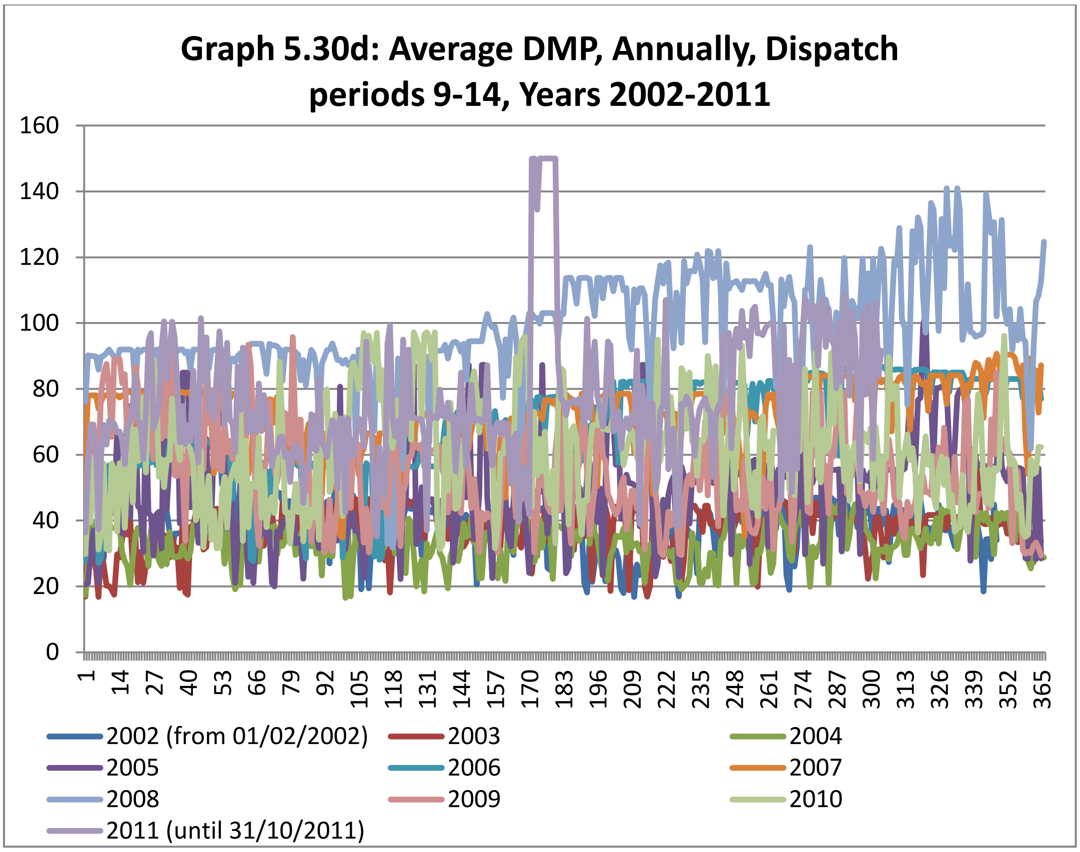
Graph 5.29b: Day-time Average DMP, Annually, Dispatch periods 7-22, Years 2002-2011
160
140
120
100
80
60
40
20
0
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

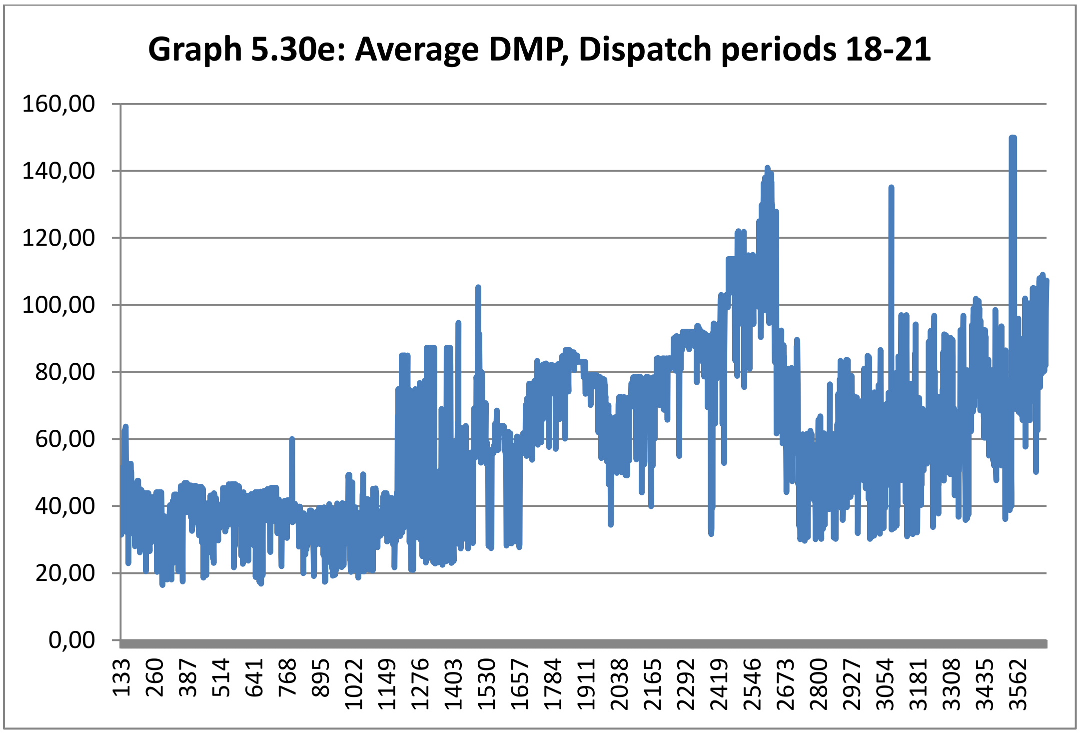


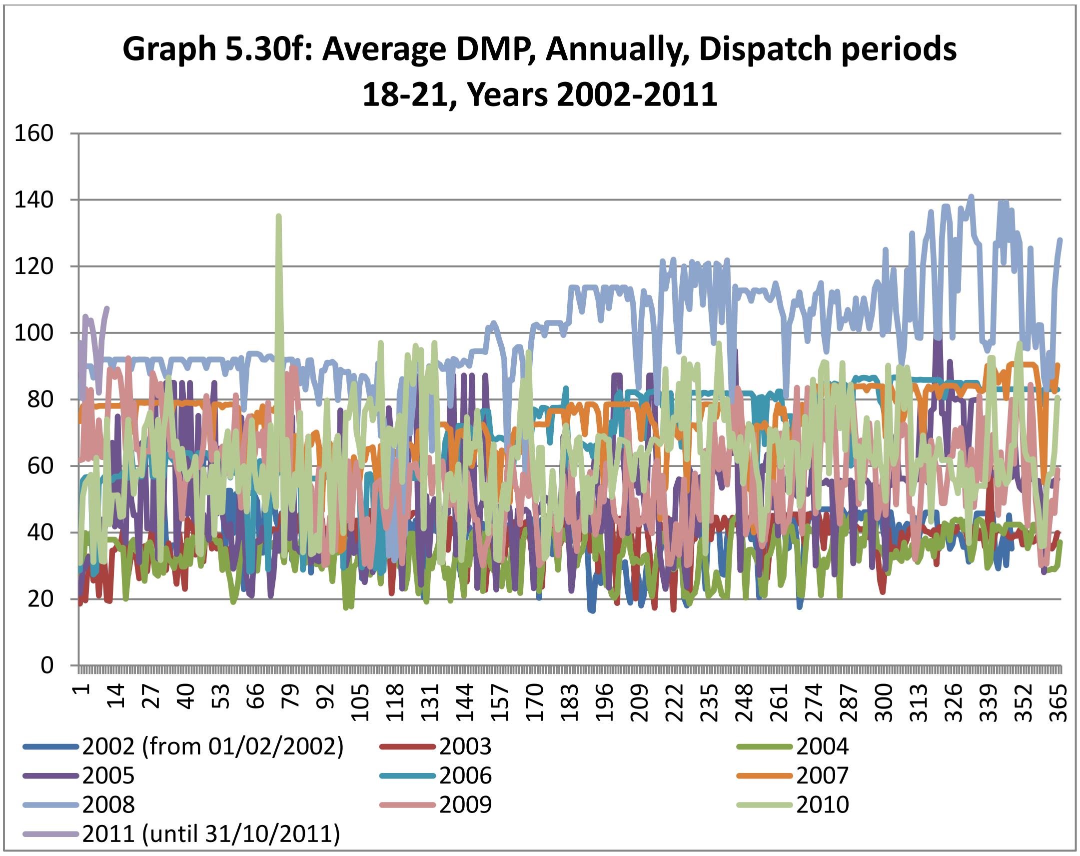
Graph 5.30a: Average DMP, Dispatch periods 9-14 & 18-21
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562

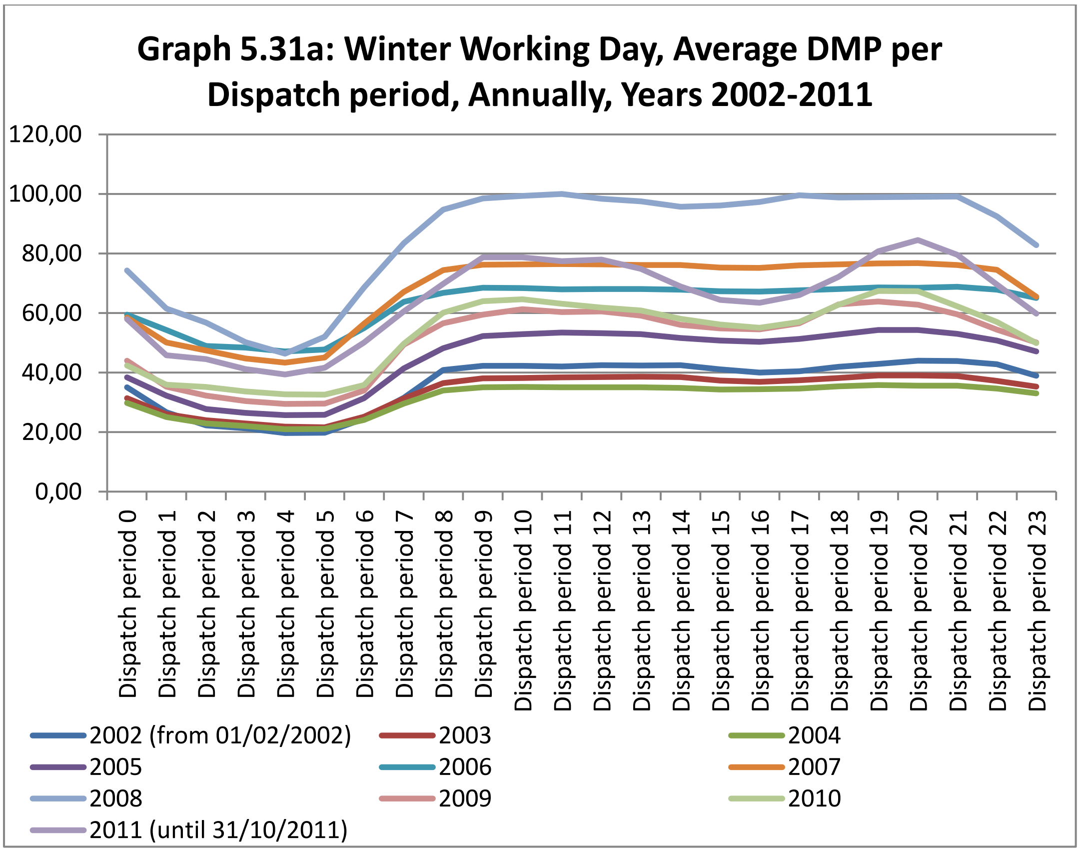

Graph 5.30b: Average DMP, Annually, Dispatch periods 9-14 & 18-21, Years 2002-2011
160
140
120
100
80
60
40
20
0
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

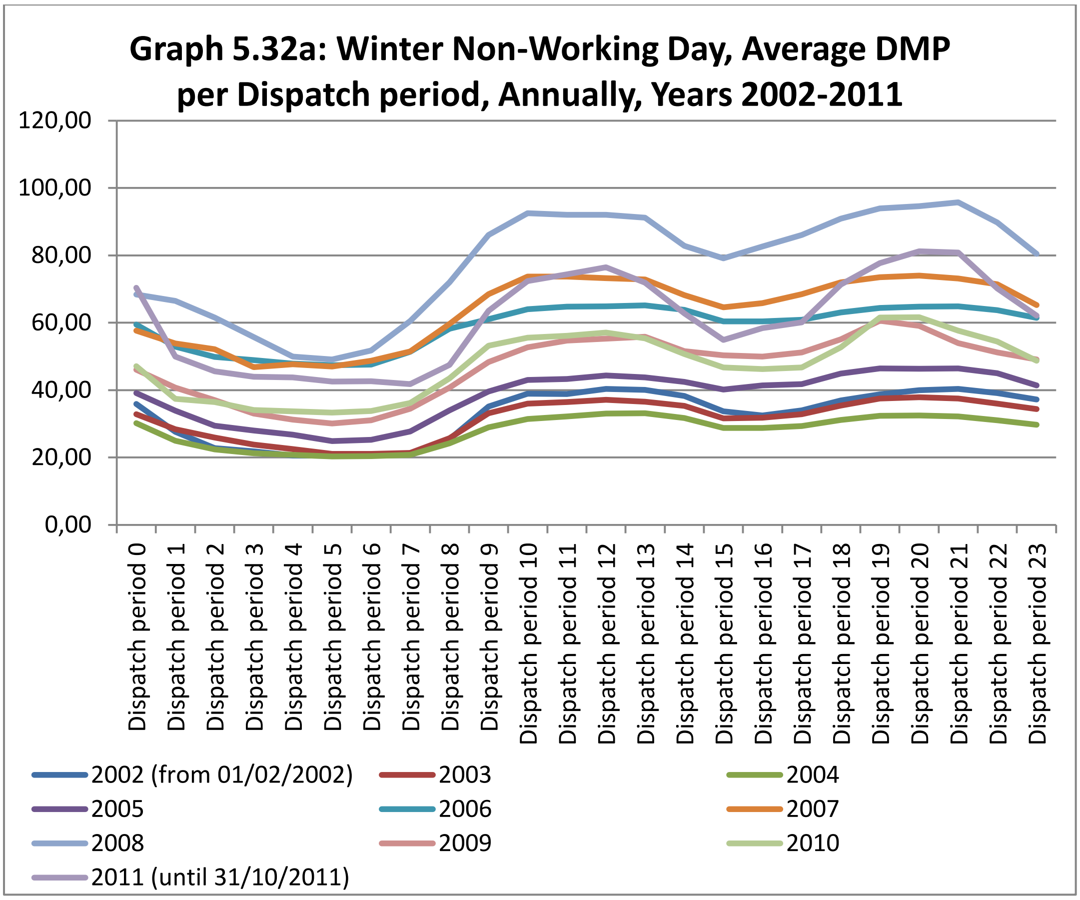

Graph 5.30c: Average DMP, Dispatch periods 9-14
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562

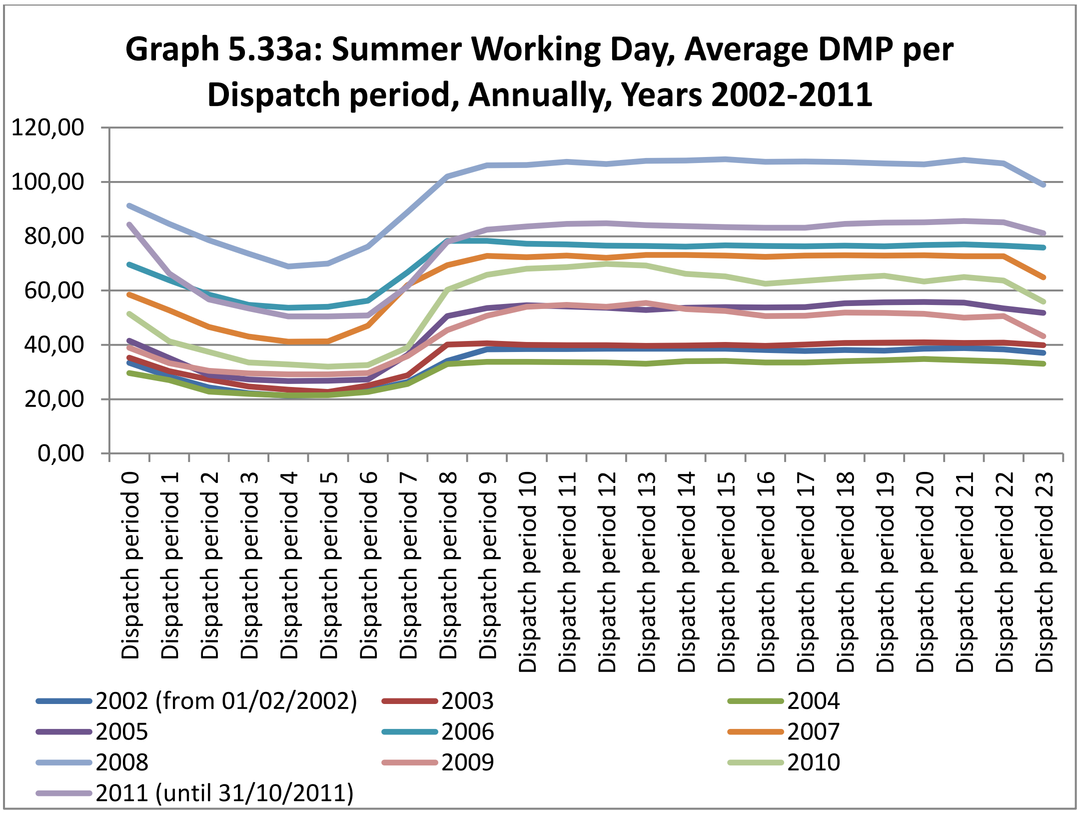

Graph 5.30d: Average DMP, Annually, Dispatch periods 9-14, Years 2002-2011
160
140
120
100
80
60
40
20
0
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

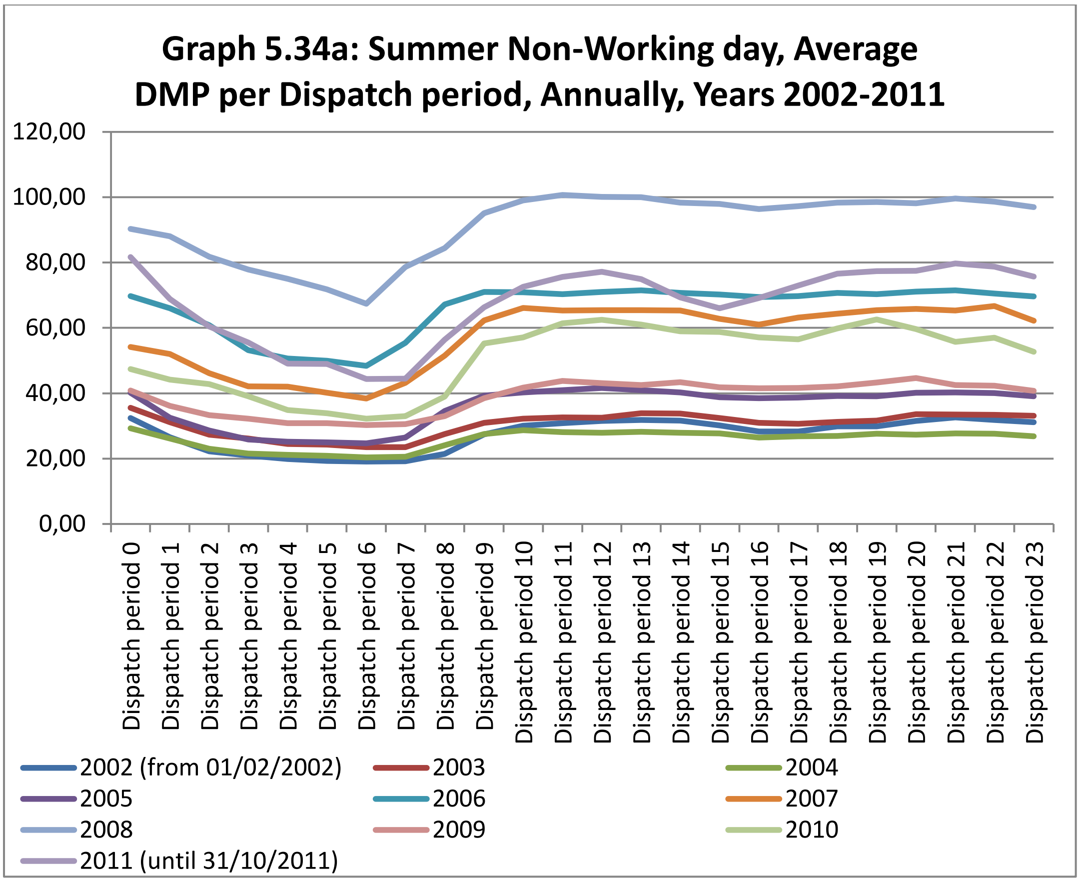

Graph 5.30e: Average DMP, Dispatch periods 18-21
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562


Graph 5.30f: Average DMP, Annually, Dispatch periods 18-21, Years 2002-2011
160
140
120
100
80
60
40
20
0
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.31a: Winter Working Day, Average DMP per Dispatch period, Annually, Years 2002-2011
120,00
100,00
80,00
60,00
40,00
20,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.32a: Winter Non-Working Day, Average DMP per Dispatch period, Annually, Years 2002-2011
120,00
100,00
80,00
60,00
40,00
20,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

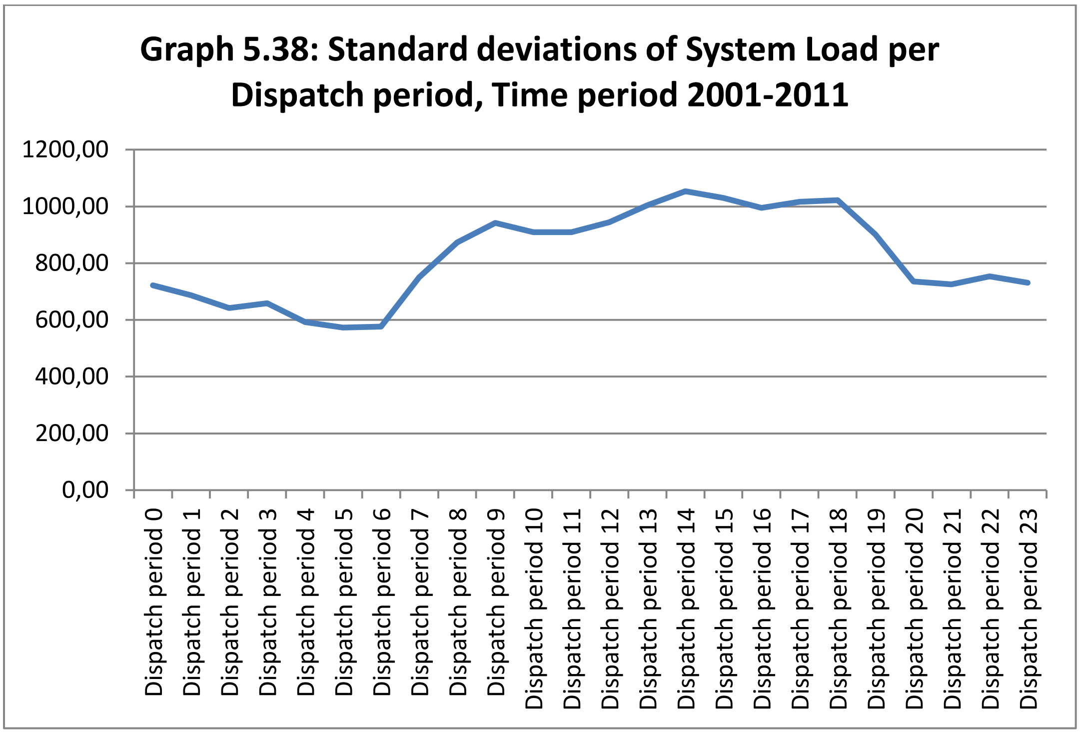

Graph 5.33a: Summer Working Day, Average DMP per Dispatch period, Annually, Years 2002-2011
120,00
100,00
80,00
60,00
40,00
20,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

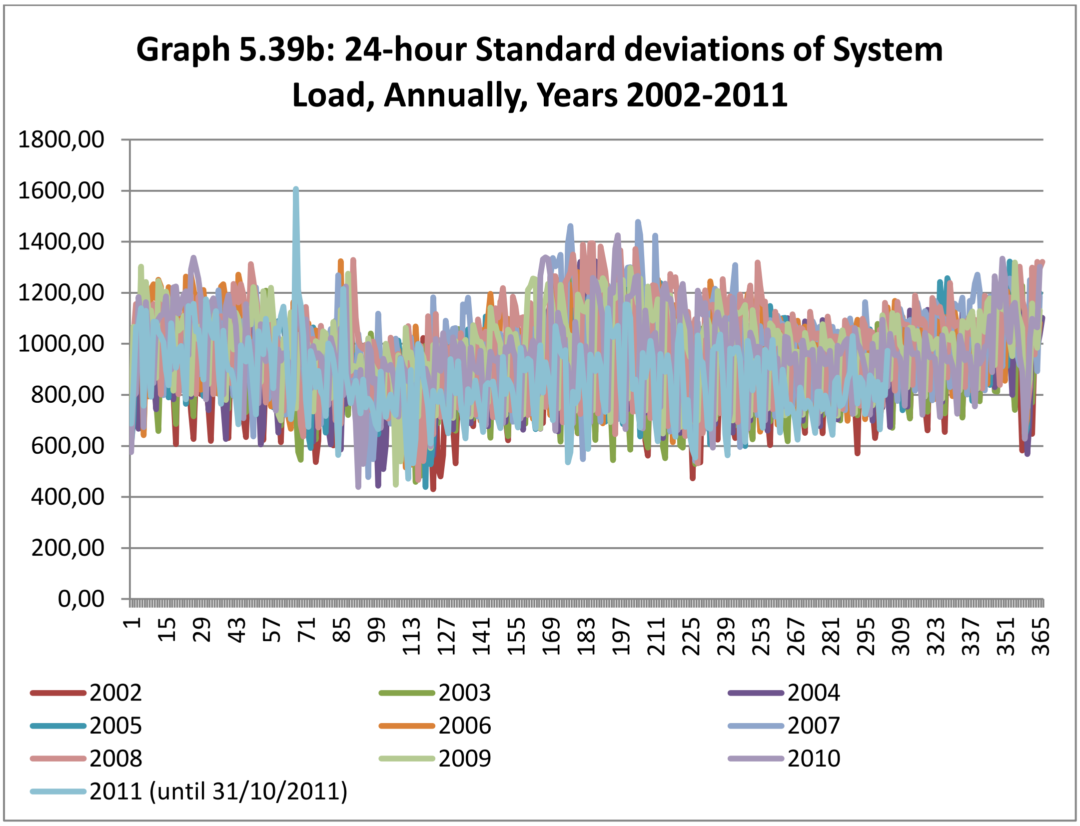


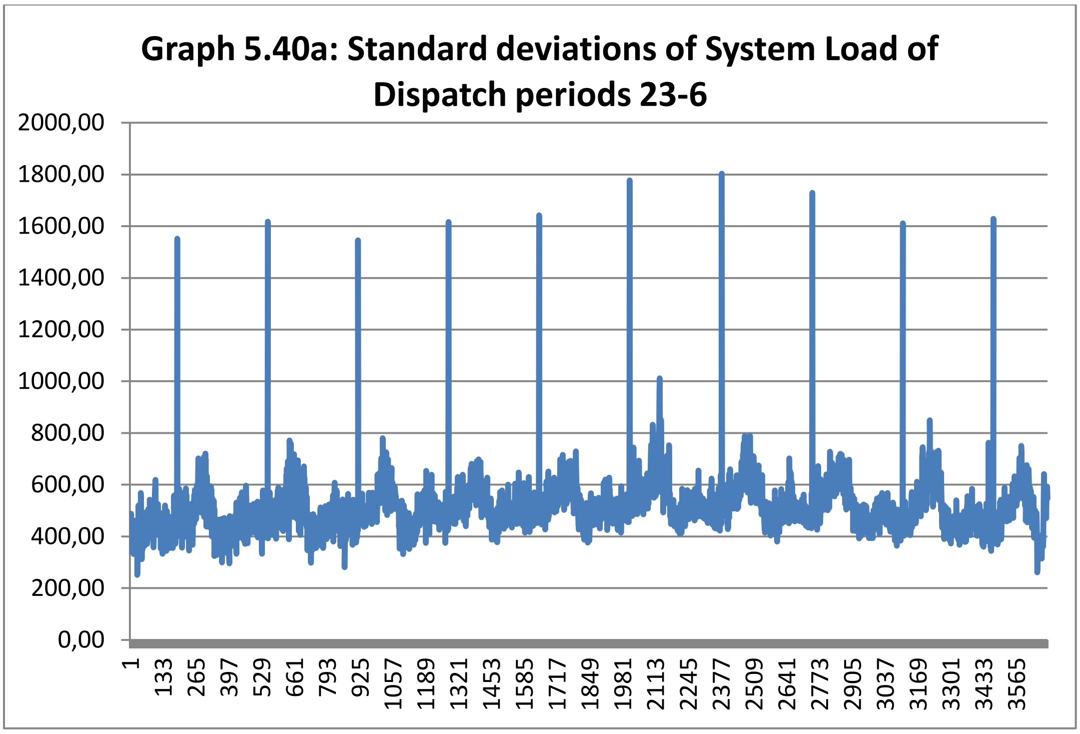
Graph 5.34a: Summer Non-Working day, Average DMP per Dispatch period, Annually, Years 2002-2011
120,00
100,00
80,00
60,00
40,00
20,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

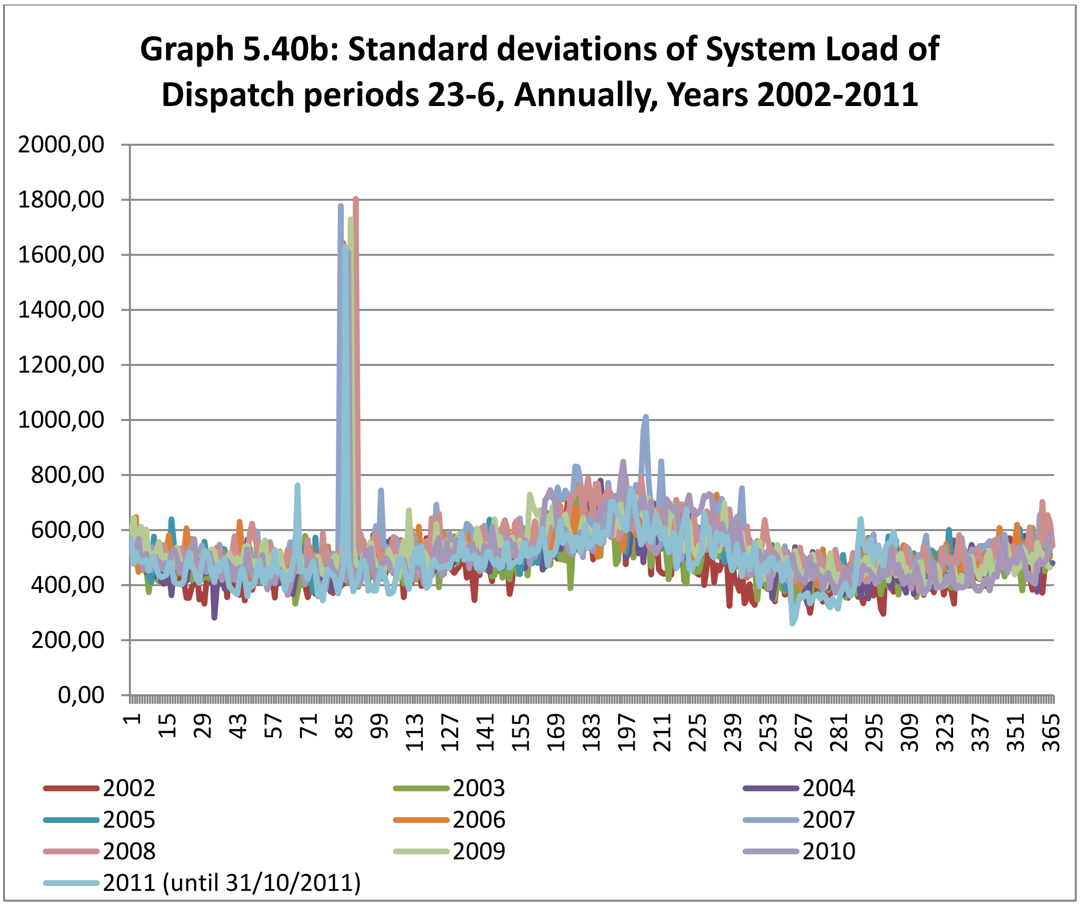
Part 4

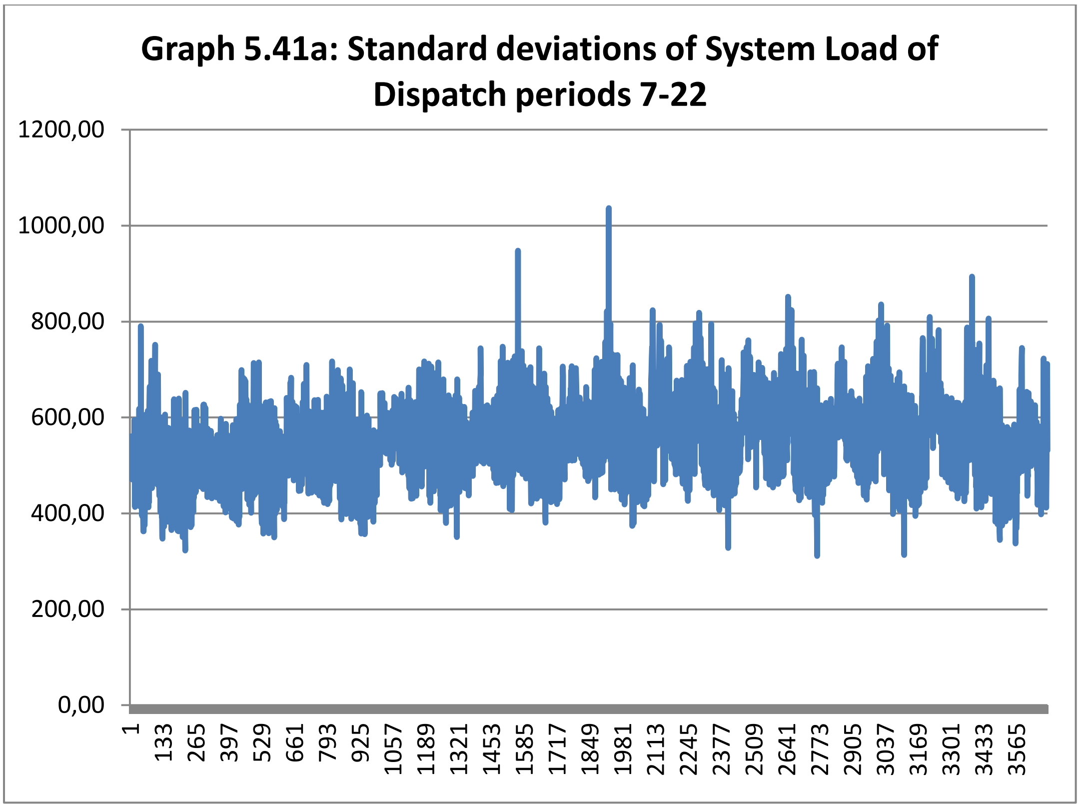
Graphs of Standard deviations of System Load are presented in this part.

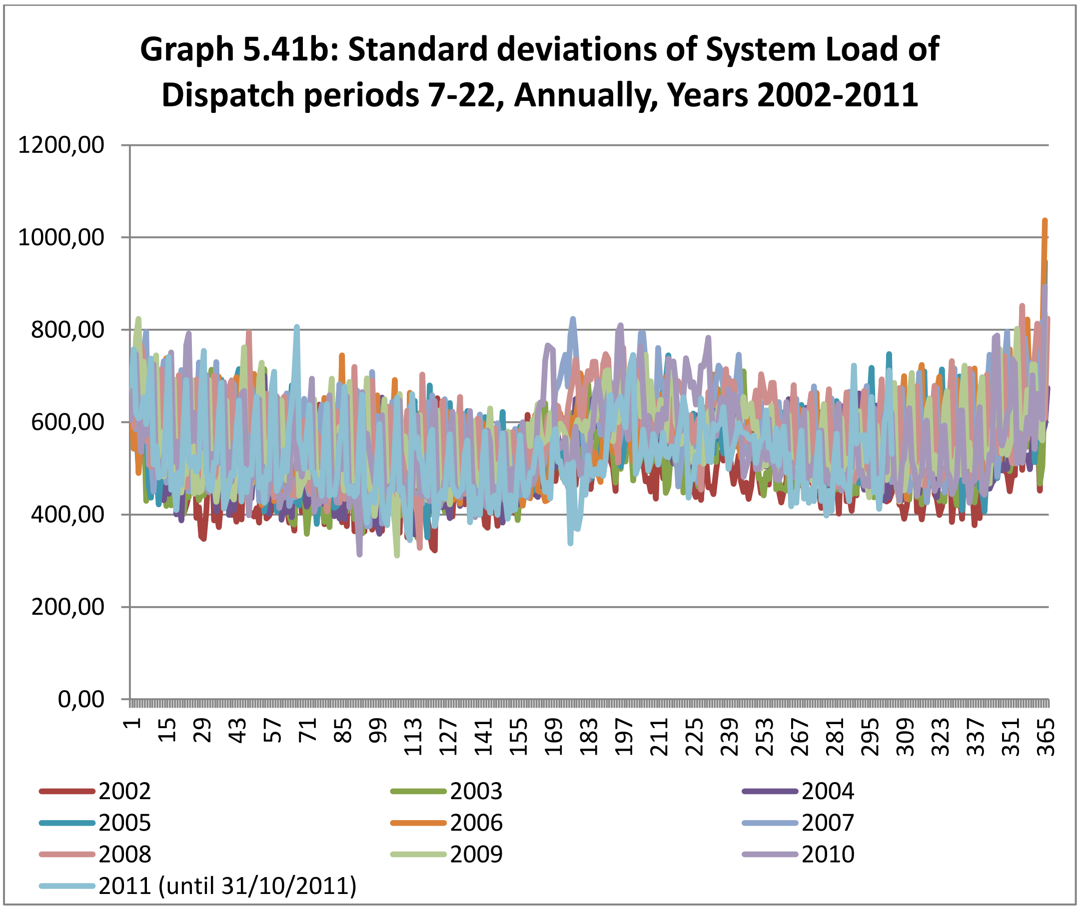




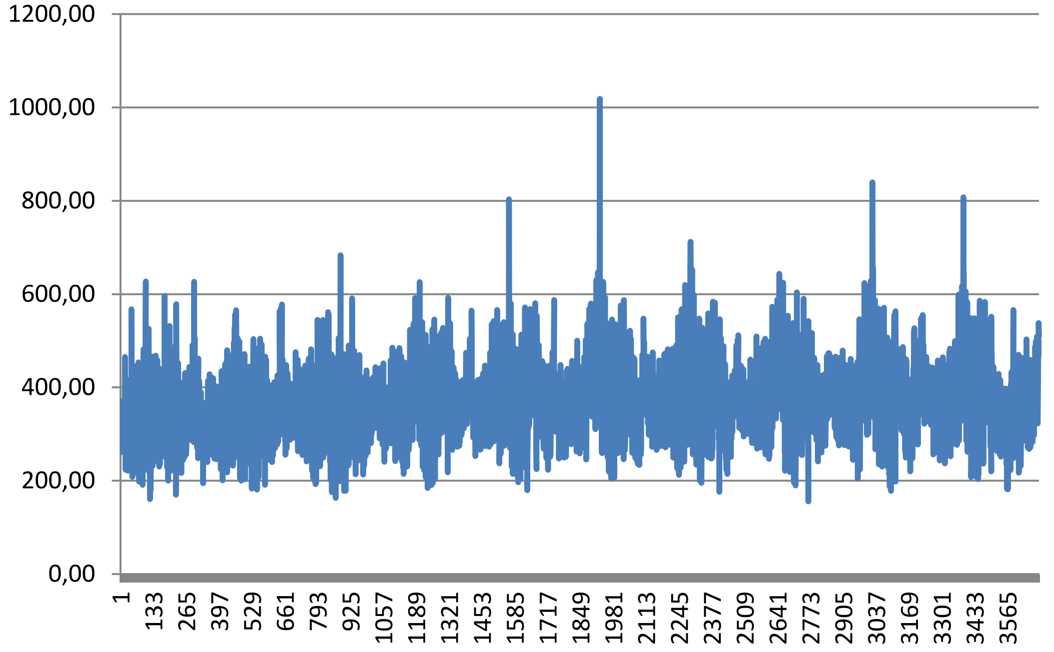

Graph 5.40a: Standard deviations of System Load of Dispatch periods 23-6
2000,00
1800,00
1600,00
1400,00
1200,00
1000,00
800,00
600,00
400,00
200,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.40b: Standard deviations of System Load of Dispatch periods 23-6, Annually, Years 2002-2011
2000,00
1800,00
1600,00
1400,00
1200,00
1000,00
800,00
600,00
400,00
200,00
0,00
1
15
29
43
57
71
85
99
113
127
141
155
169
183
197
211
225
239
253
267
281
295
309
323
337
351
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

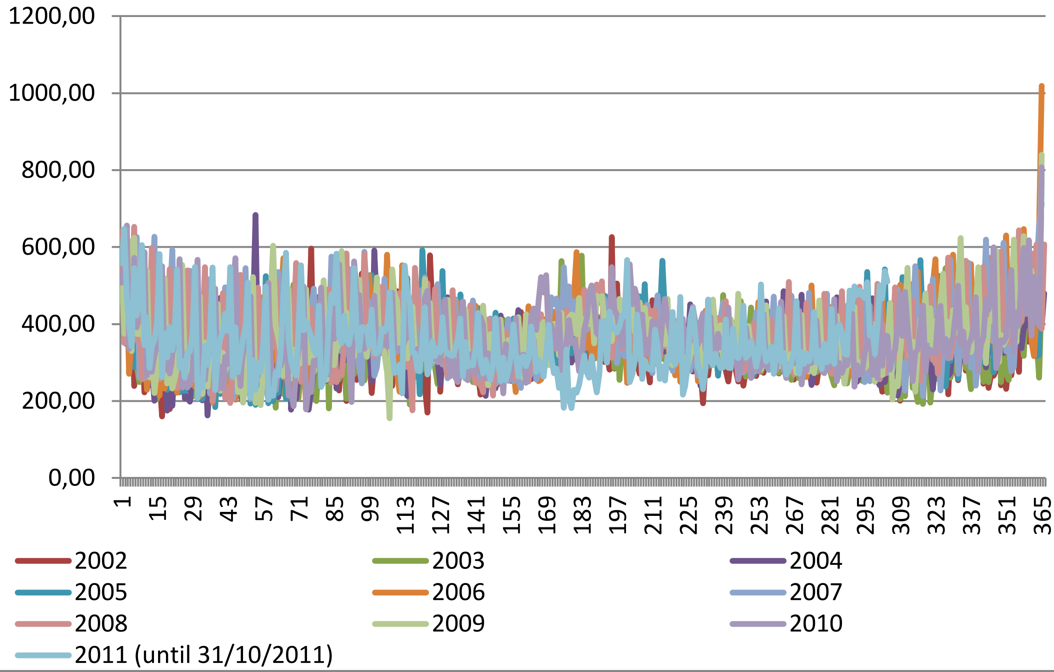

Graph 5.41a: Standard deviations of System Load of Dispatch periods 7-22
1200,00
1000,00
800,00
600,00
400,00
200,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

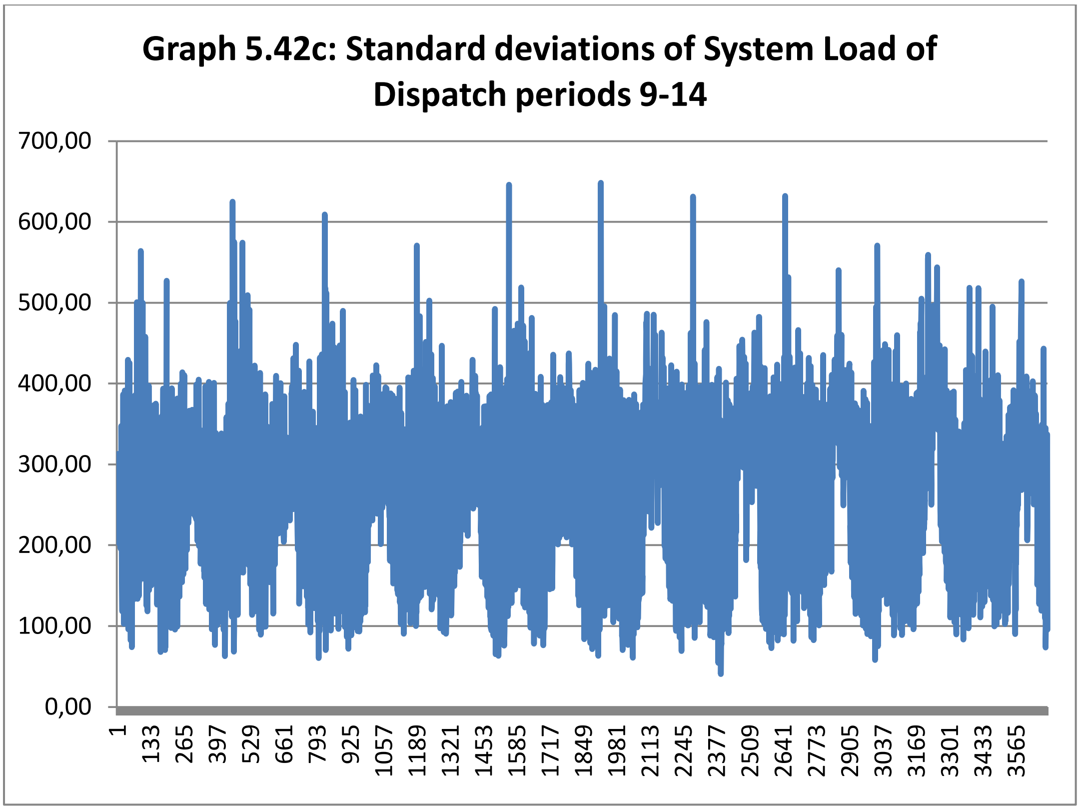

Graph 5.41b: Standard deviations of System Load of Dispatch periods 7-22, Annually, Years 2002-2011
1200,00
1000,00
800,00
600,00
400,00
200,00
0,00
1
15
29
43
57
71
85
99
113
127
141
155
169
183
197
211
225
239
253
267
281
295
309
323
337
351
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

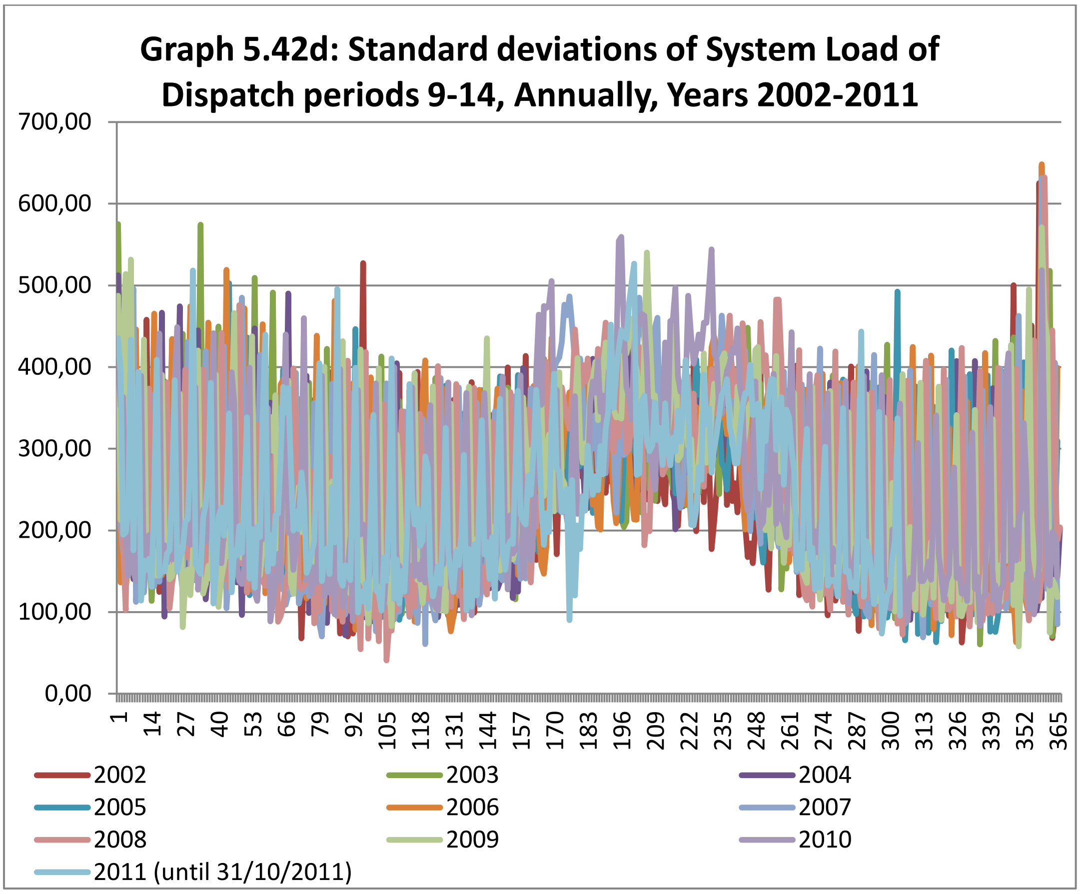
Graph 5.42a: Standard deviations of System Load of Dispatch periods 9-14 & 18-21

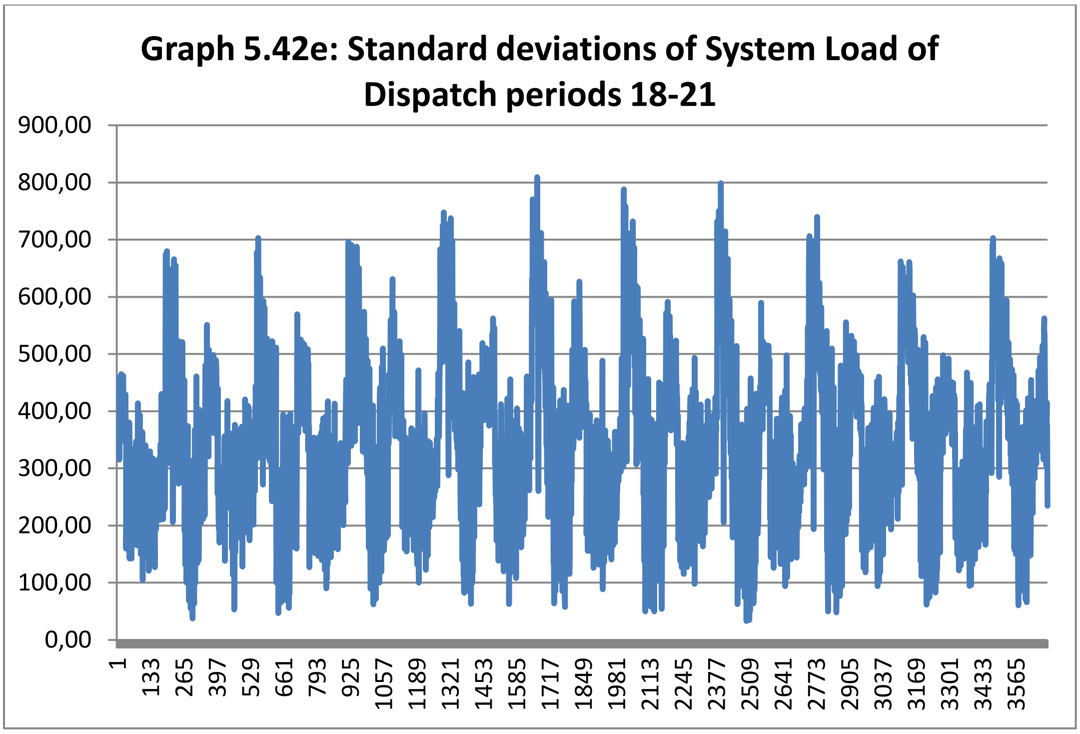


Graph 5.42b: Standard deviations of System Load of Dispatch periods 9-14 & 18-21, Annually, Years 2002-2011

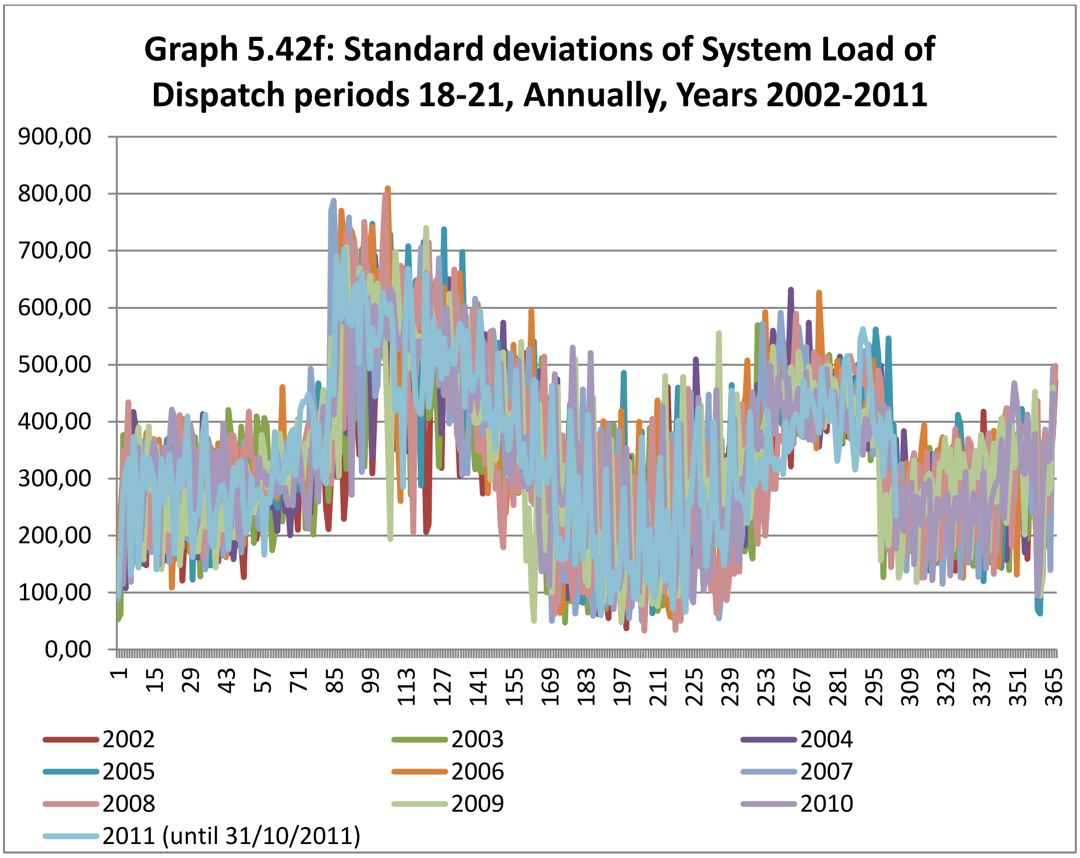



Graph 5.42c: Standard deviations of System Load of Dispatch periods 9-14
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

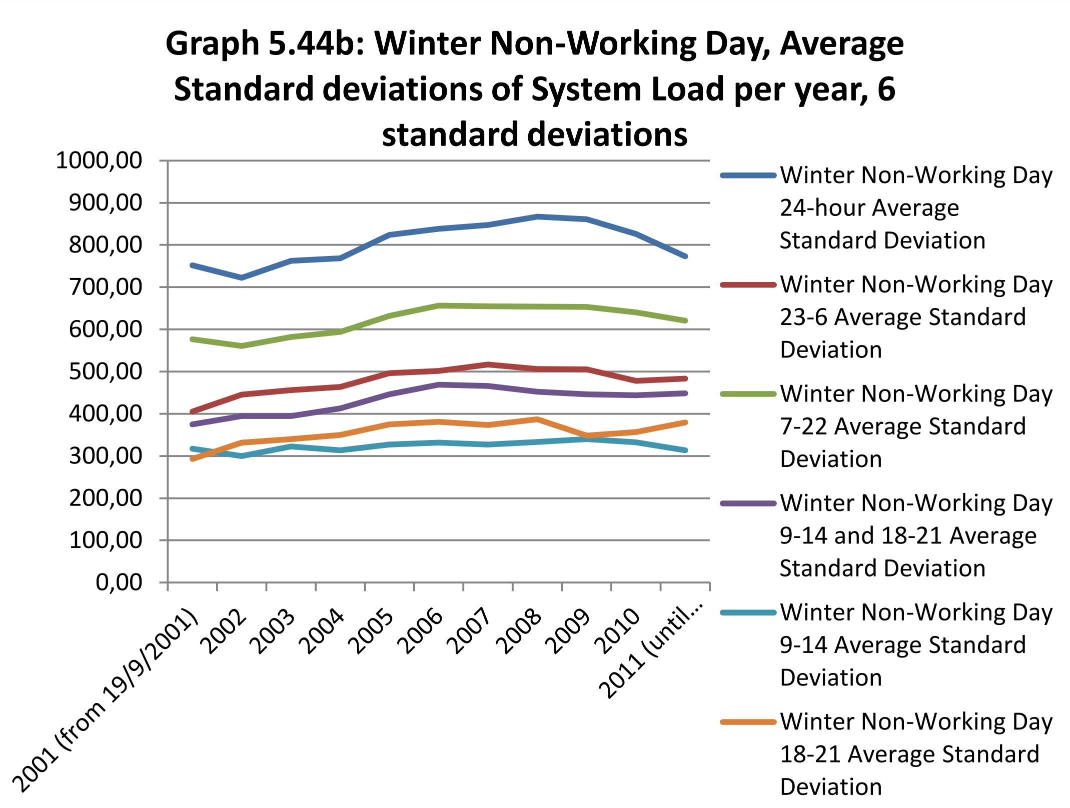

Graph 5.42d: Standard deviations of System Load of Dispatch periods 9-14, Annually, Years 2002-2011
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

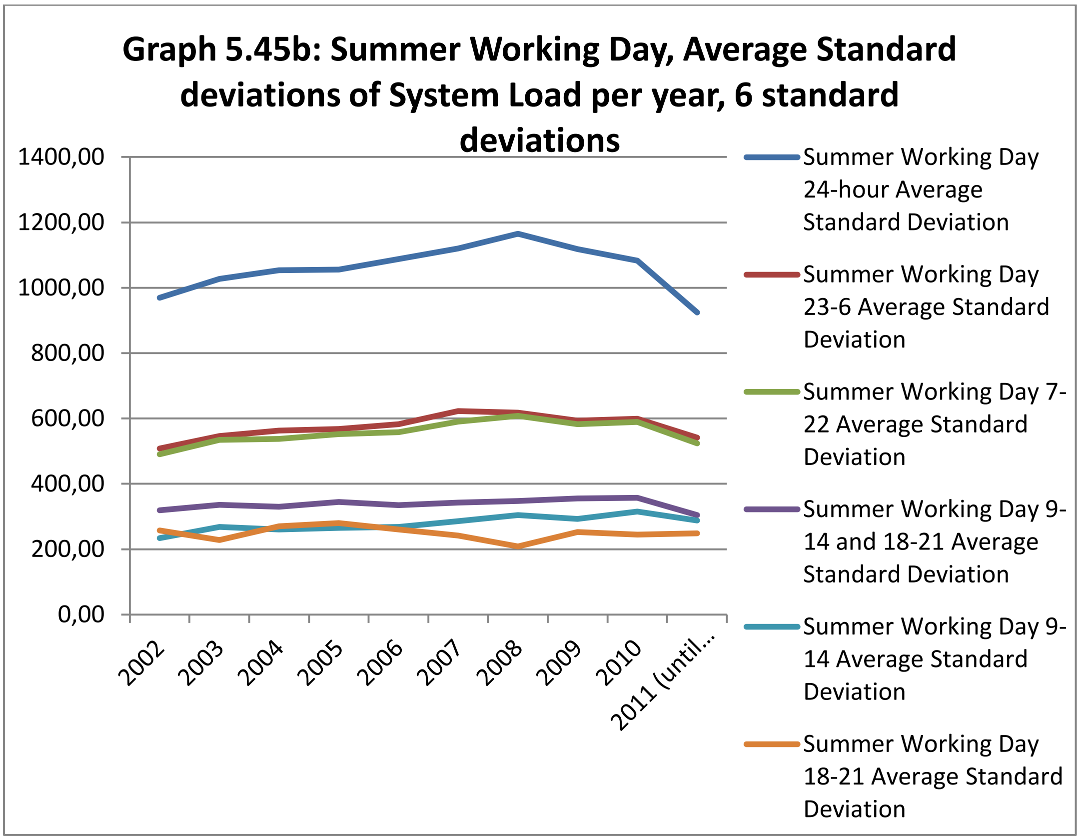


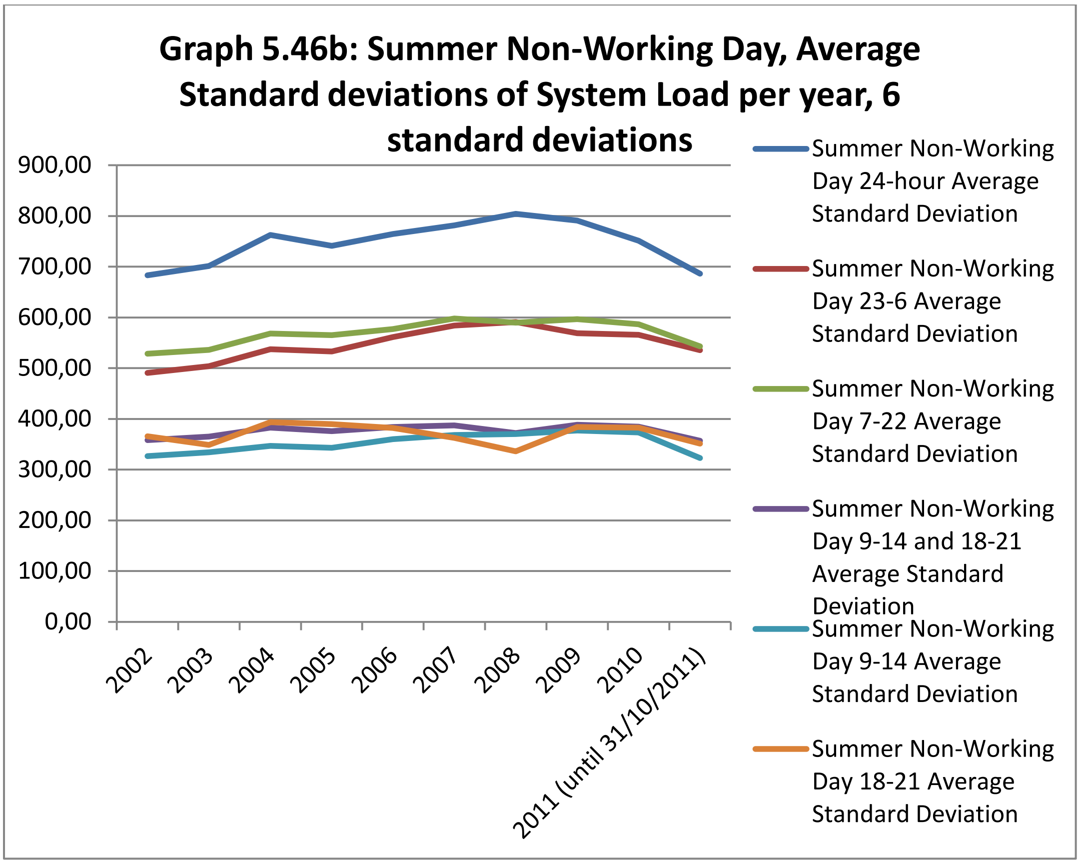
Graph 5.42e: Standard deviations of System Load of Dispatch periods 18-21
900,00
800,00
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

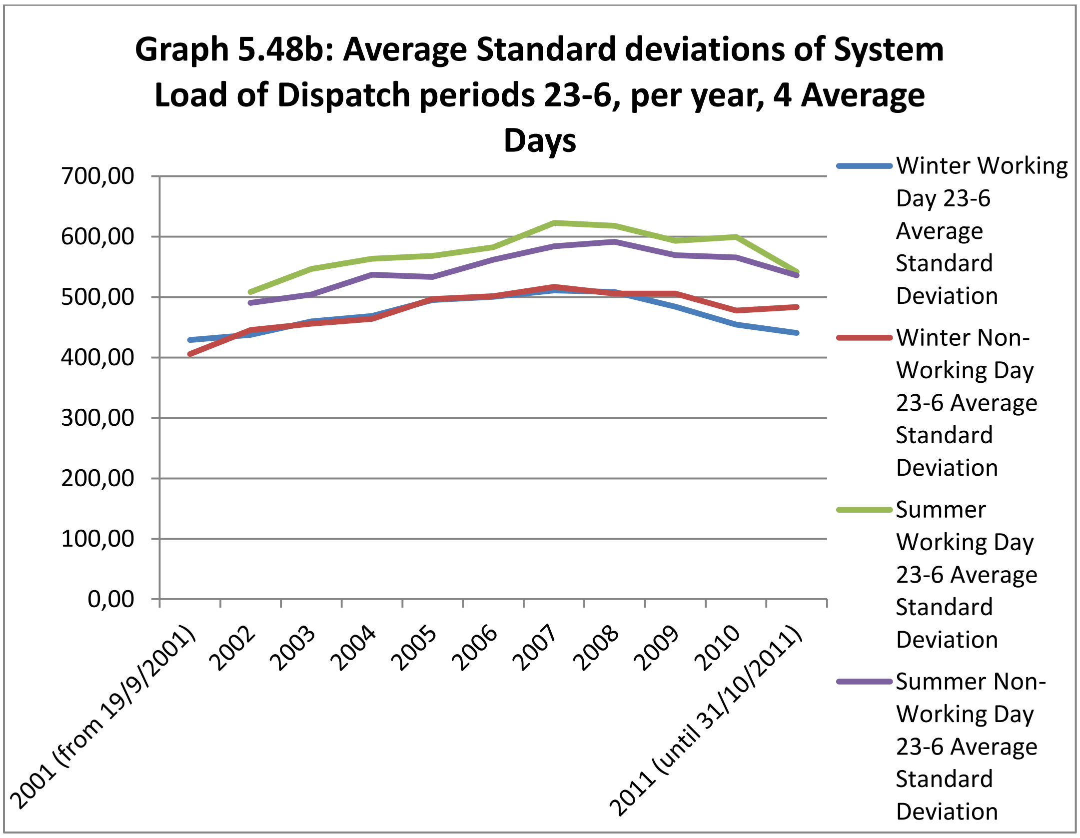


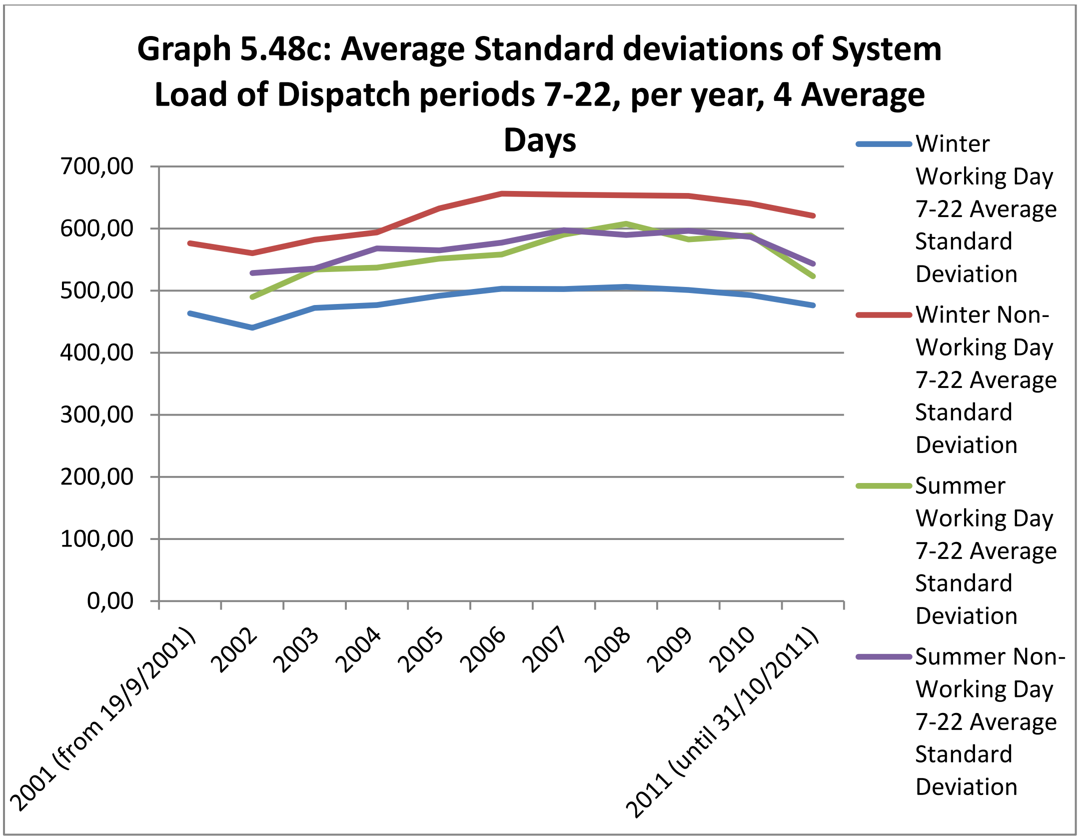
Graph 5.42f: Standard deviations of System Load of Dispatch periods 18-21, Annually, Years 2002-2011
900,00
800,00
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
1
15
29
43
57
71
85
99
113
127
141
155
169
183
197
211
225
239
253
267
281
295
309
323
337
351
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

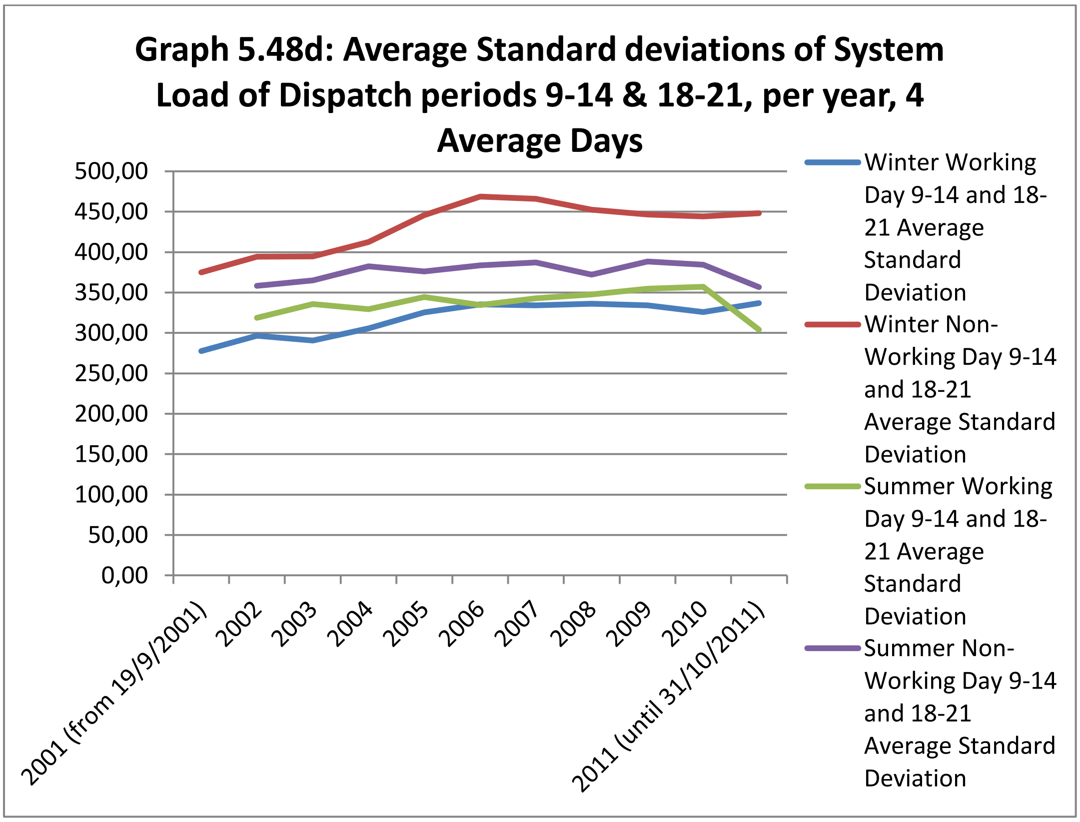

Graph 5.44b: Winter Non-Working Day, Average Standard deviations of System Load per year, 6 standard deviations
1000,00
900,00
800,00
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until...
Winter Non-Working Day 24-hour Average Standard Deviation
Winter Non-Working Day 23-6 Average Standard Deviation
Winter Non-Working Day 7-22 Average Standard Deviation
Winter Non-Working Day 9-14 and 18-21 Average Standard Deviation
Winter Non-Working Day 9-14 Average Standard Deviation
Winter Non-Working Day 18-21 Average Standard Deviation

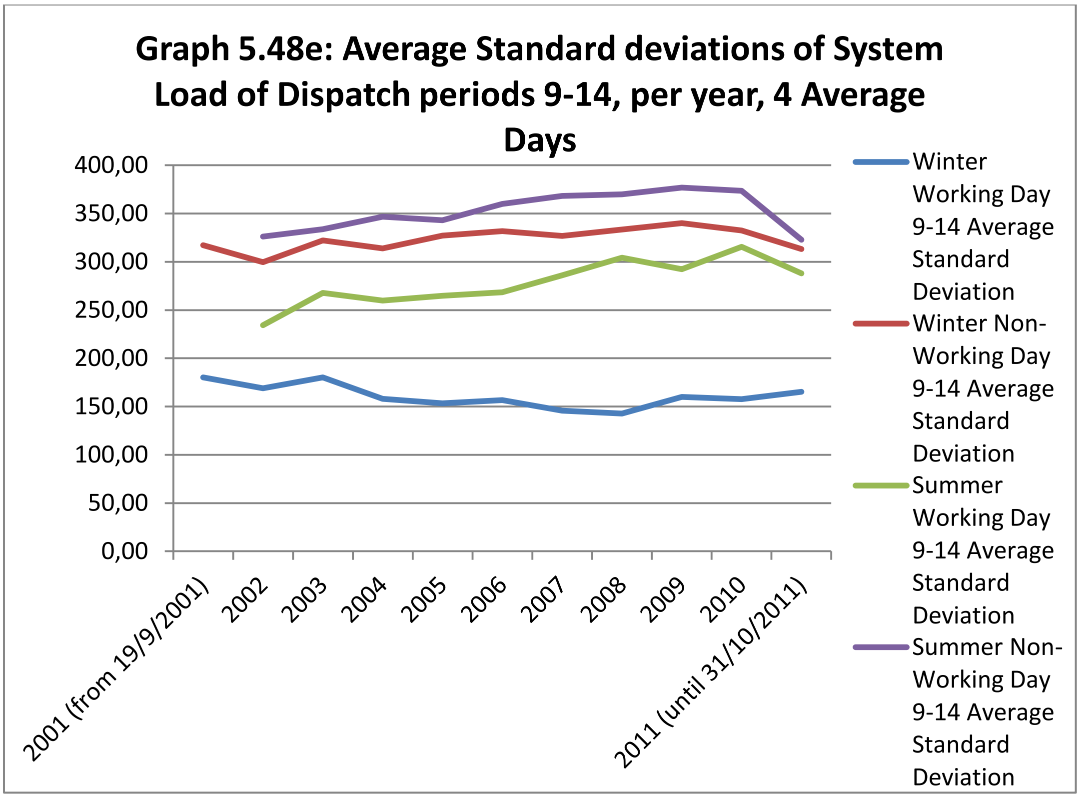

Graph 5.45b: Summer Working Day, Average Standard deviations of System Load per year, 6 standard deviations
1400,00
1200,00
1000,00
800,00
600,00
400,00
200,00
0,00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until...
Summer Working Day 24-hour Average Standard Deviation
Summer Working Day 23-6 Average Standard Deviation
Summer Working Day 7-22 Average Standard Deviation
Summer Working Day 9-14 and 18-21 Average Standard Deviation
Summer Working Day 9-14 Average Standard Deviation
Summer Working Day 18-21 Average Standard Deviation

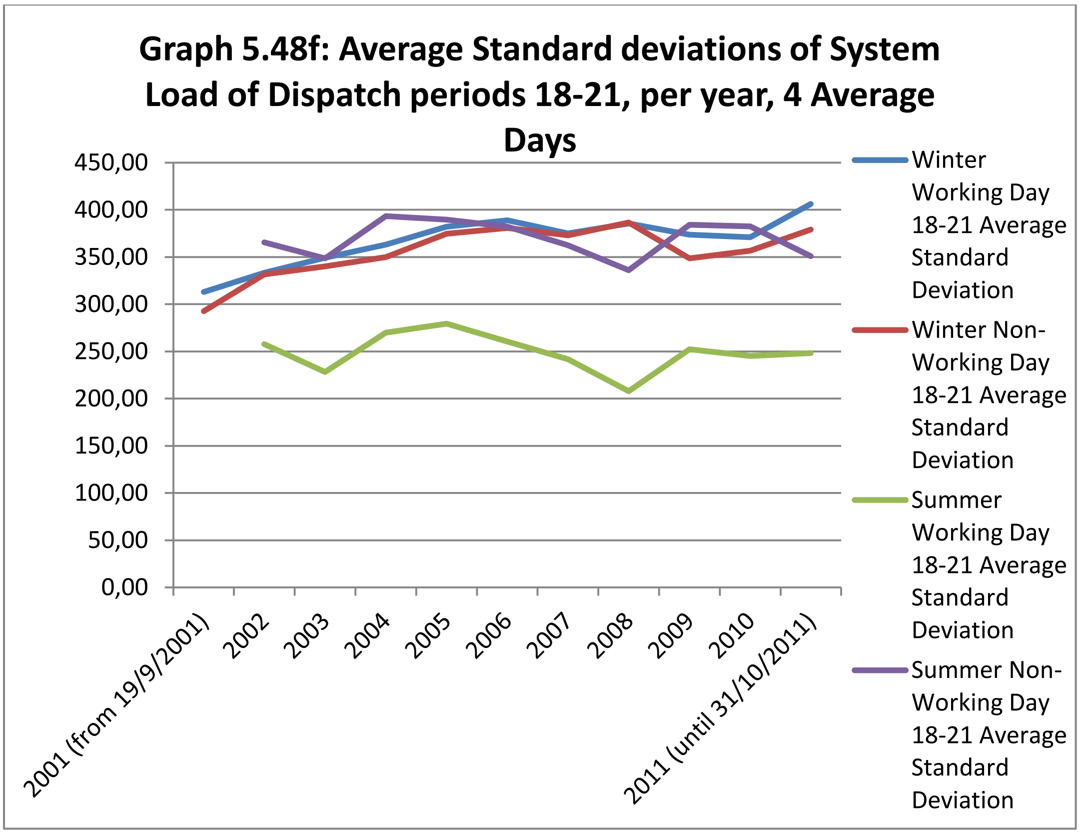

Graph 5.46b: Summer Non-Working Day, Average Standard deviations of System Load per year, 6 standard deviations
900,00
800,00
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Summer Non-Working Day 24-hour Average Standard Deviation
Summer Non-Working Day 23-6 Average Standard Deviation
Summer Non-Working Day 7-22 Average Standard Deviation
Summer Non-Working Day 9-14 and 18-21 Average Standard Deviation
Summer Non-Working Day 9-14 Average Standard Deviation
Summer Non-Working Day 18-21 Average Standard Deviation


Graph 5.48b: Average Standard deviations of System Load of Dispatch periods 23-6, per year, 4 Average Days
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 23-6 Average Standard Deviation
Winter Non-Working Day 23-6 Average Standard Deviation
Summer Working Day 23-6 Average Standard Deviation
Summer Non-Working Day 23-6 Average Standard Deviation


Graph 5.48c: Average Standard deviations of System Load of Dispatch periods 7-22, per year, 4 Average Days
700,00
600,00
500,00
400,00
300,00
200,00
100,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 7-22 Average Standard Deviation
Winter Non-Working Day 7-22 Average Standard Deviation
Summer Working Day 7-22 Average Standard Deviation
Summer Non-Working Day 7-22 Average Standard Deviation

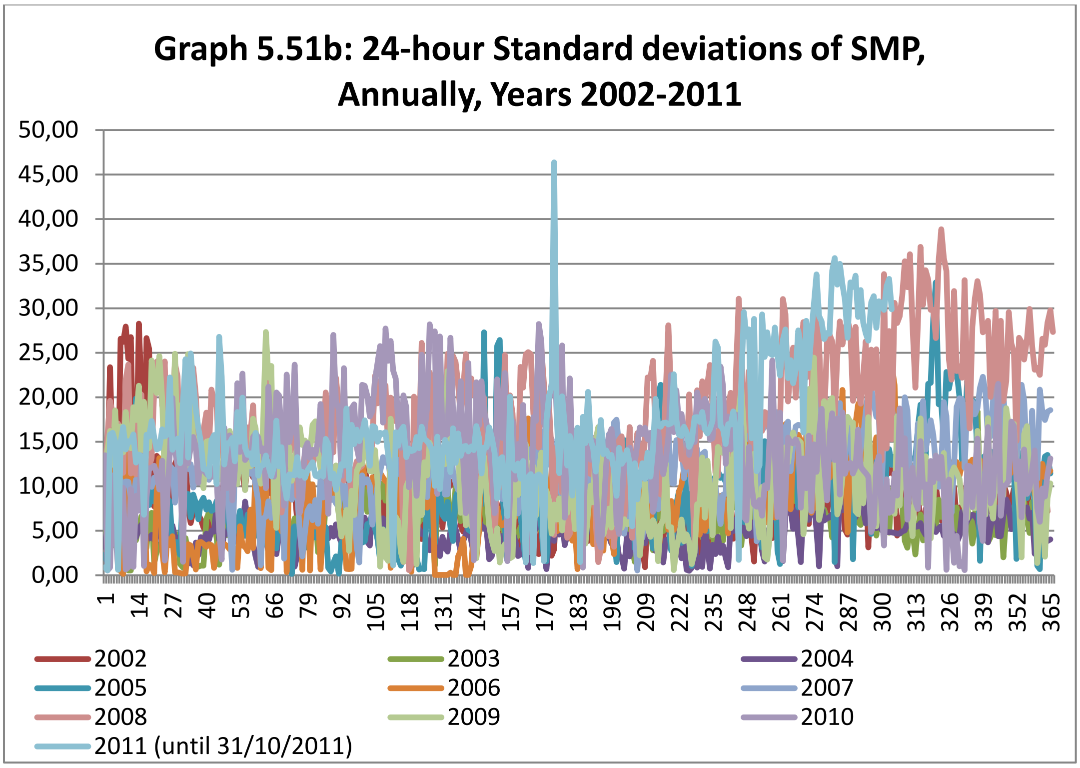

Graph 5.48d: Average Standard deviations of System Load of Dispatch periods 9-14 & 18-21, per year, 4 Average Days
500,00
450,00
400,00
350,00
300,00
250,00
200,00
150,00
100,00
50,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 and 18-21 Average Standard Deviation
Winter Non-Working Day 9-14 and 18-21 Average Standard Deviation
Summer Working Day 9-14 and 18-21 Average Standard Deviation
Summer Non-Working Day 9-14 and 18-21 Average Standard Deviation

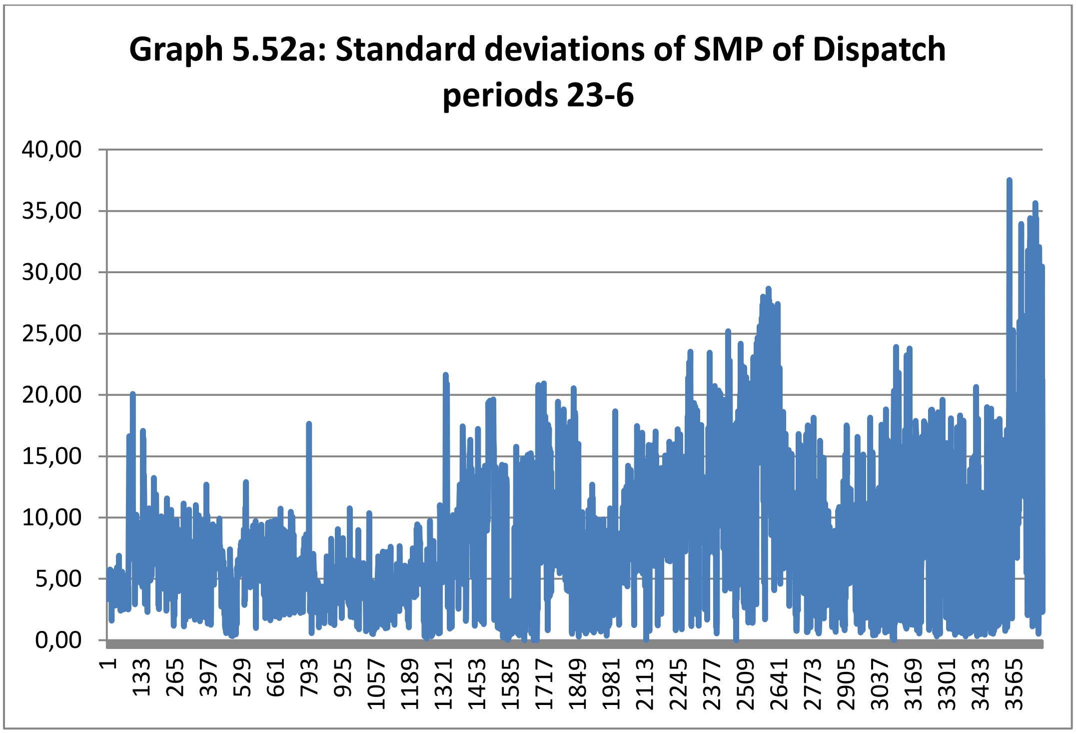

Graph 5.48e: Average Standard deviations of System Load of Dispatch periods 9-14, per year, 4 Average Days
400,00
350,00
300,00
250,00
200,00
150,00
100,00
50,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 Average Standard Deviation
Winter Non-Working Day 9-14 Average Standard Deviation
Summer Working Day 9-14 Average Standard Deviation
Summer Non-Working Day 9-14 Average Standard Deviation

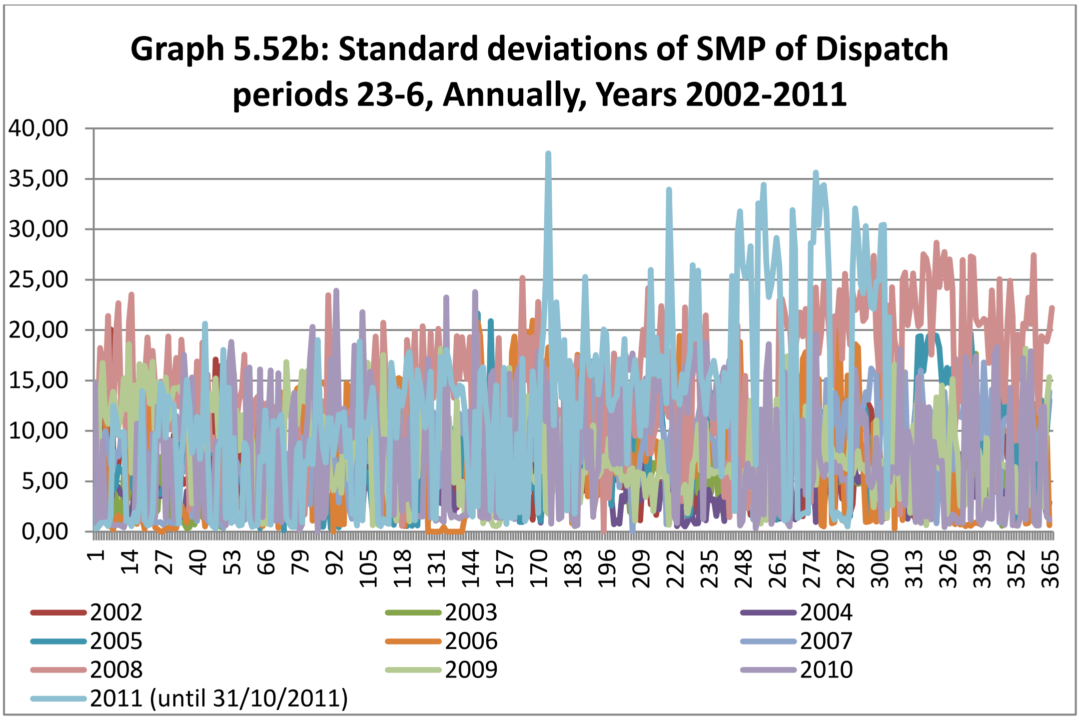

Graph 5.48f: Average Standard deviations of System Load of Dispatch periods 18-21, per year, 4 Average Days
450,00
400,00
350,00
300,00
250,00
200,00
150,00
100,00
50,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 18-21 Average Standard Deviation
Winter Non-Working Day 18-21 Average Standard Deviation
Summer Working Day 18-21 Average Standard Deviation
Summer Non-Working Day 18-21 Average Standard Deviation

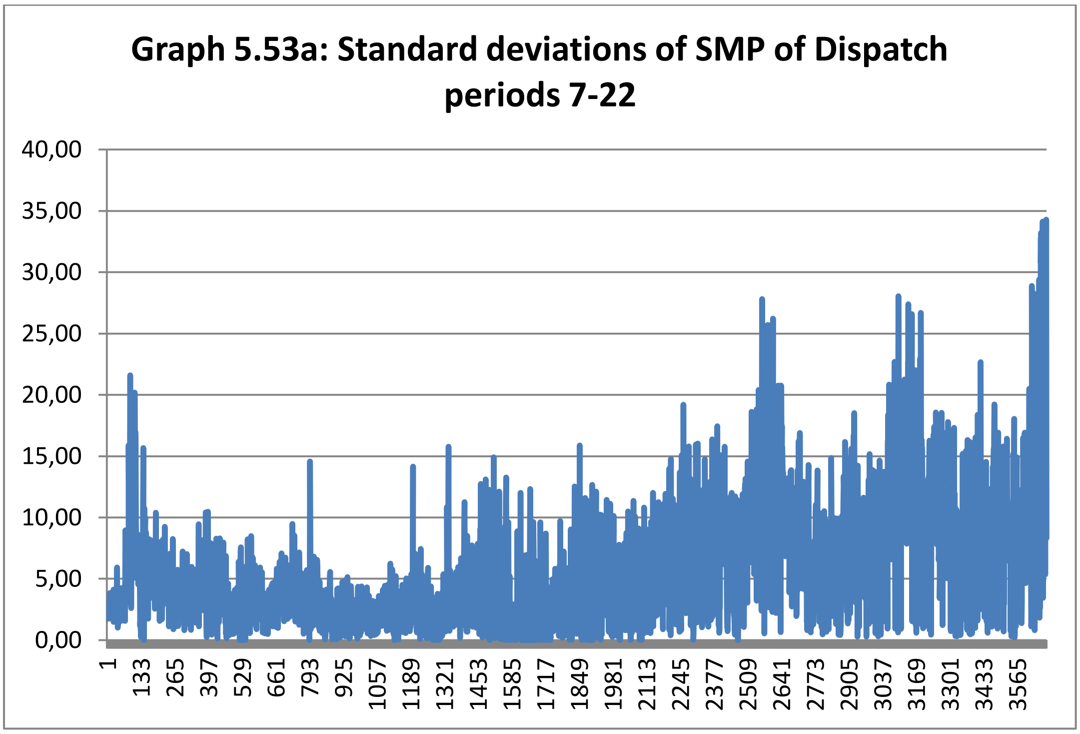
Part 5

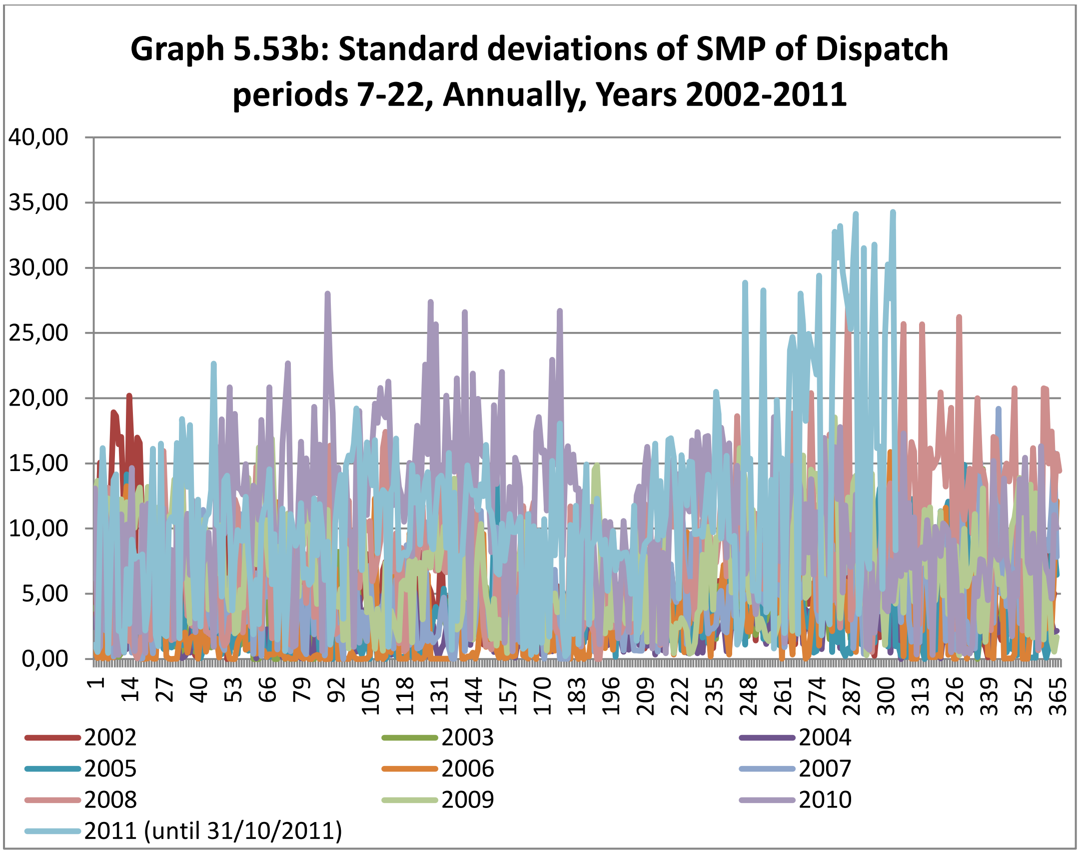
Graphs of Standard deviations of SMP are presented in this part.

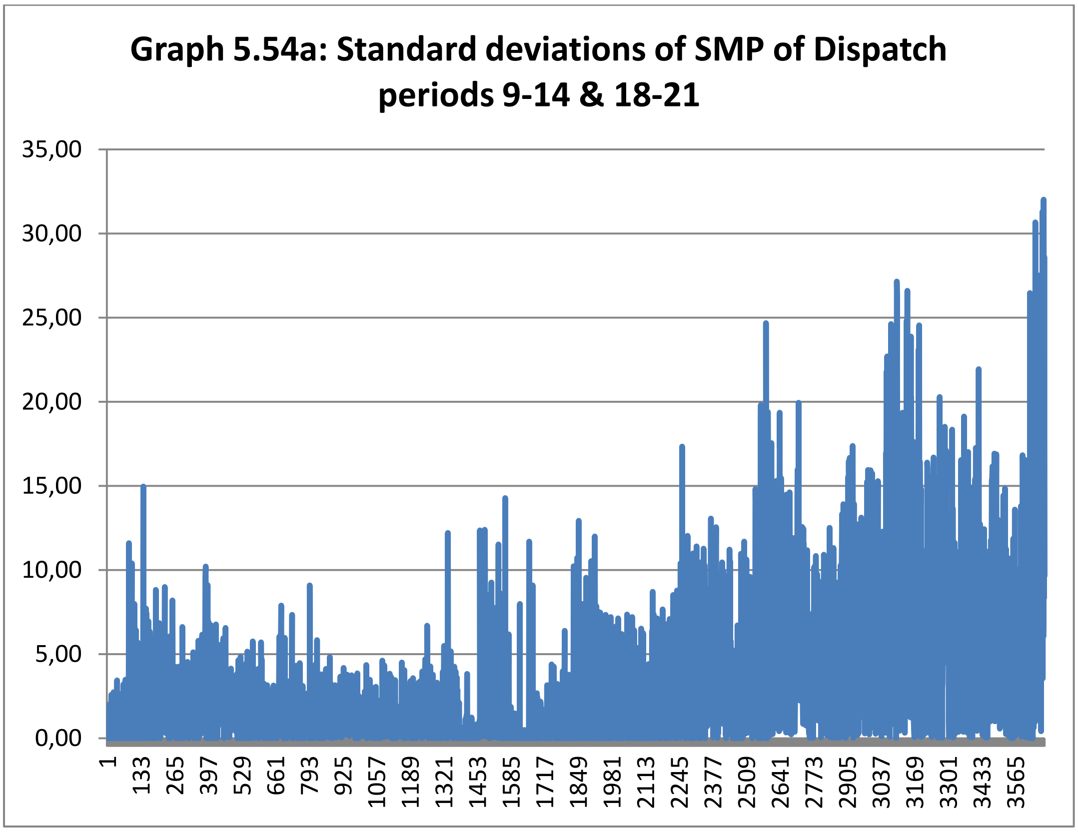




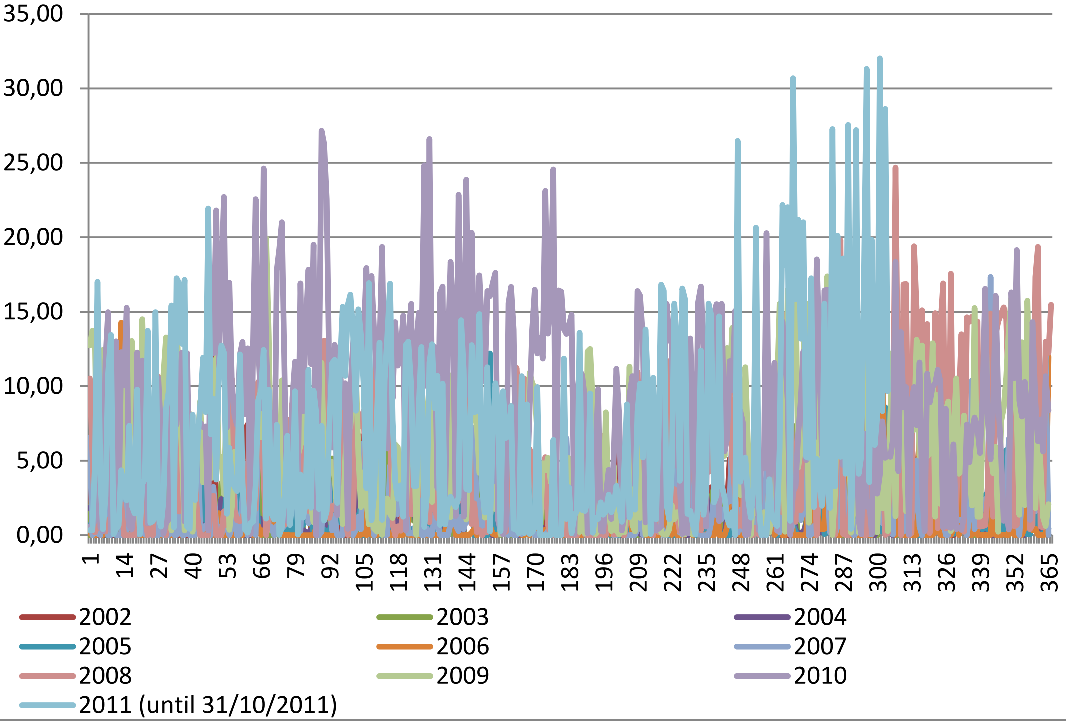

Graph 5.52b: Standard deviations of SMP of Dispatch periods 23-6, Annually, Years 2002-2011
40,00
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.53a: Standard deviations of SMP of Dispatch periods 7-22
40,00
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

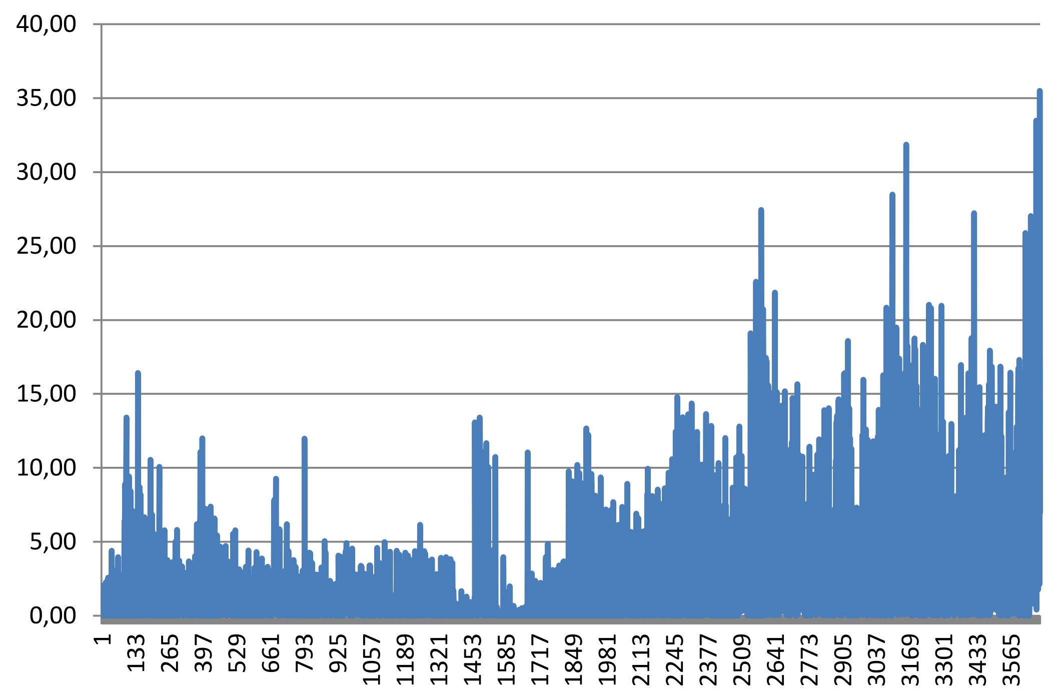

Graph 5.53b: Standard deviations of SMP of Dispatch periods 7-22, Annually, Years 2002-2011
40,00
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

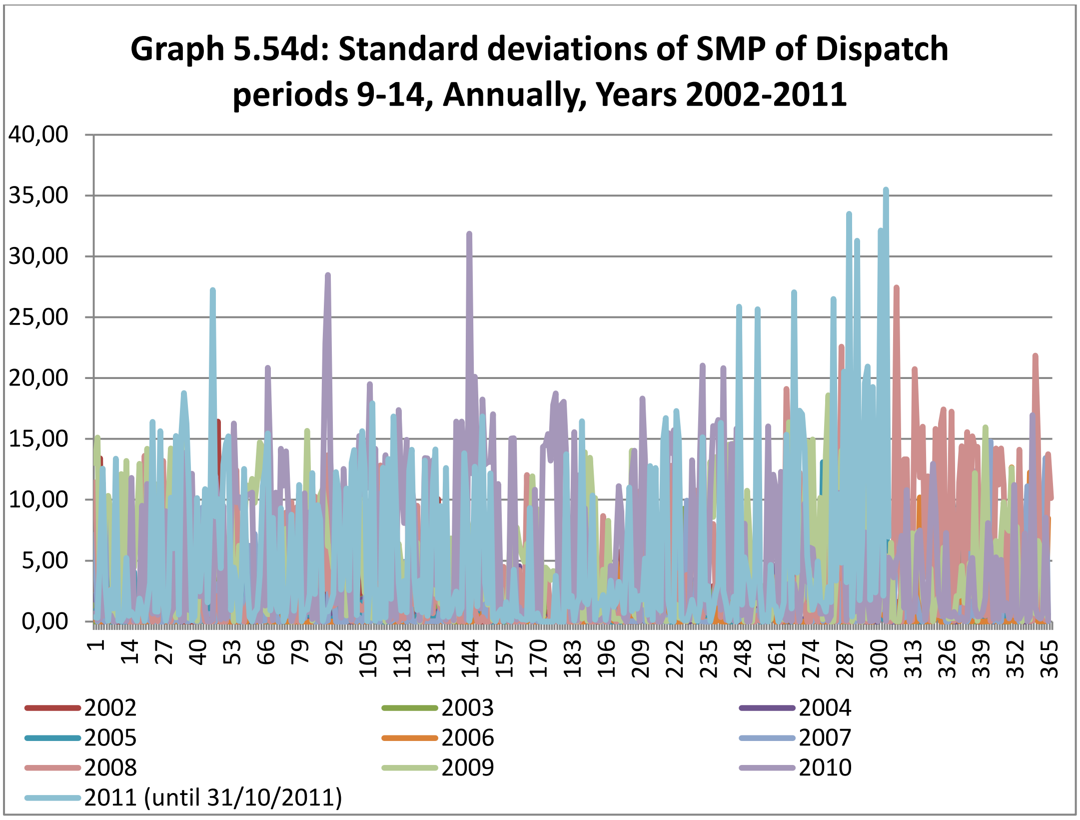

Graph 5.54a: Standard deviations of SMP of Dispatch periods 9-14 & 18-21
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565

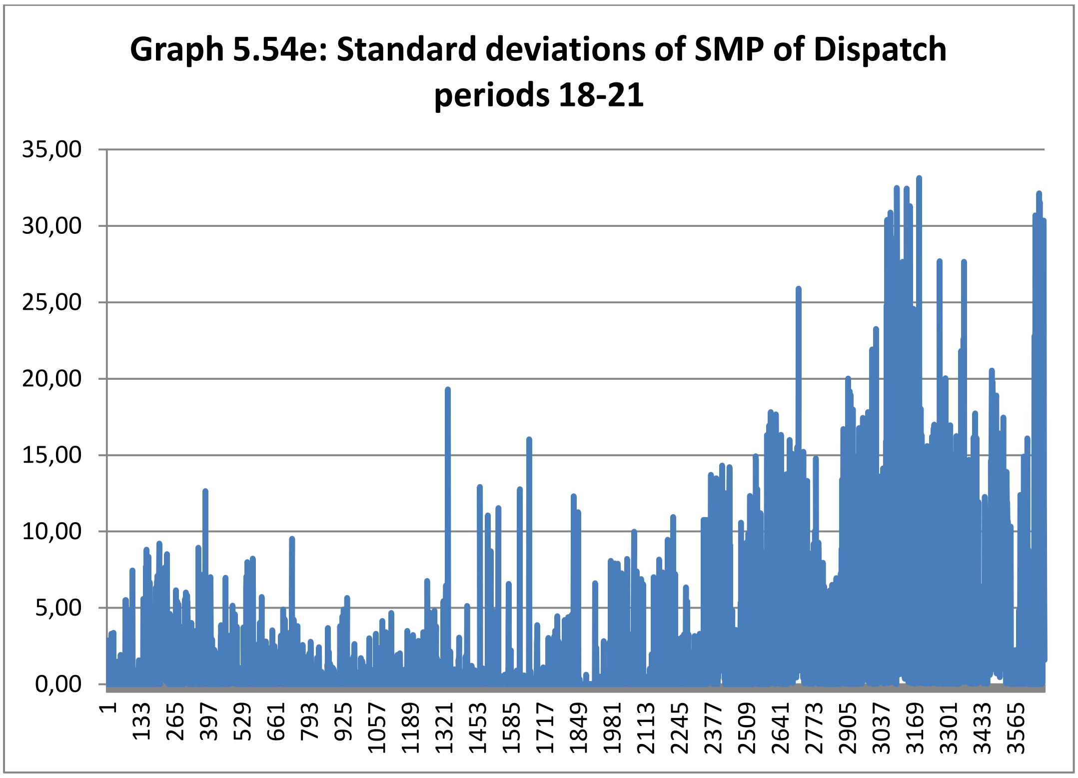
Graph 5.54b: Standard deviations of SMP of Dispatch periods 9-14 & 18-21, Annually, Years 2002-2011

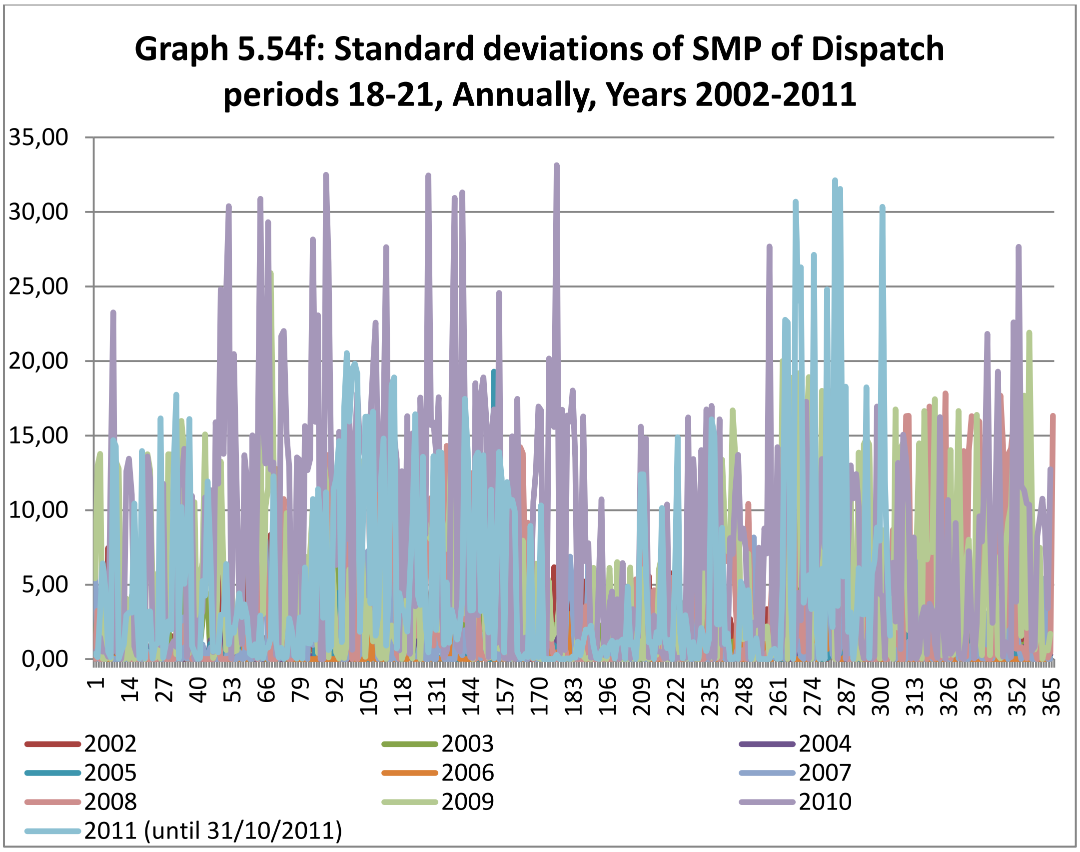


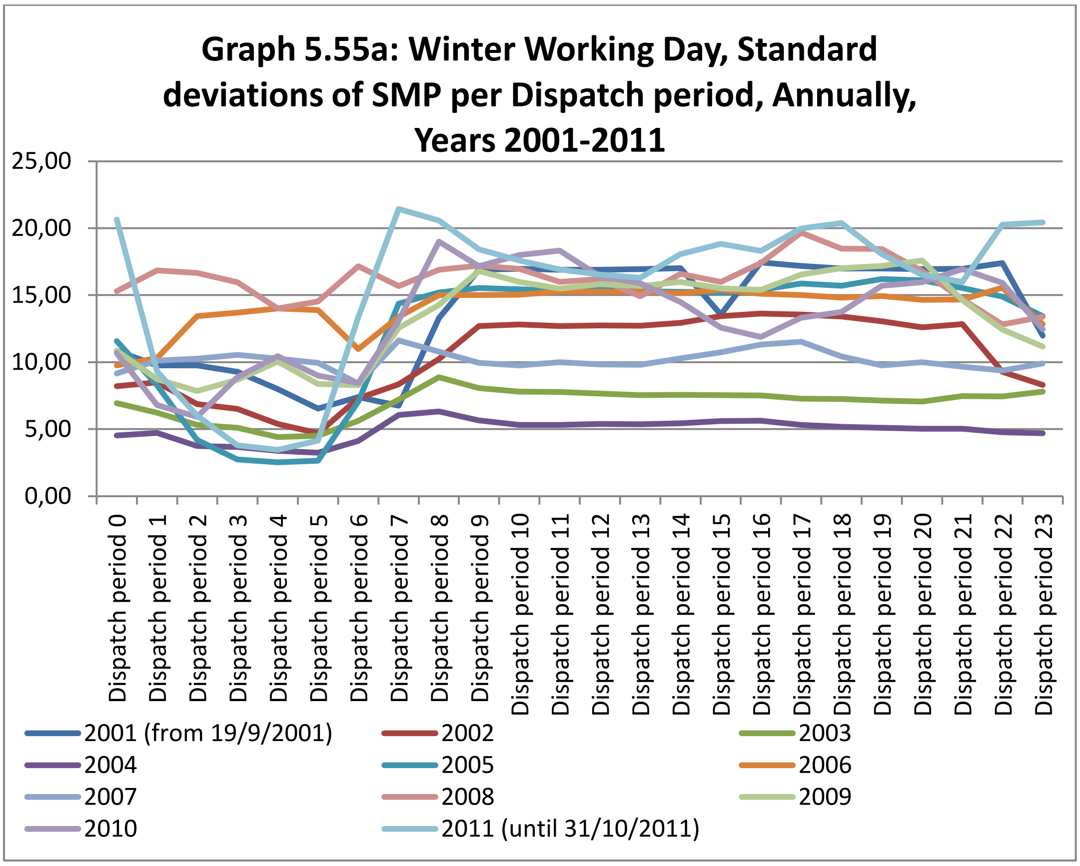
Graph 5.54c: Standard deviations of SMP of Dispatch periods 9-14

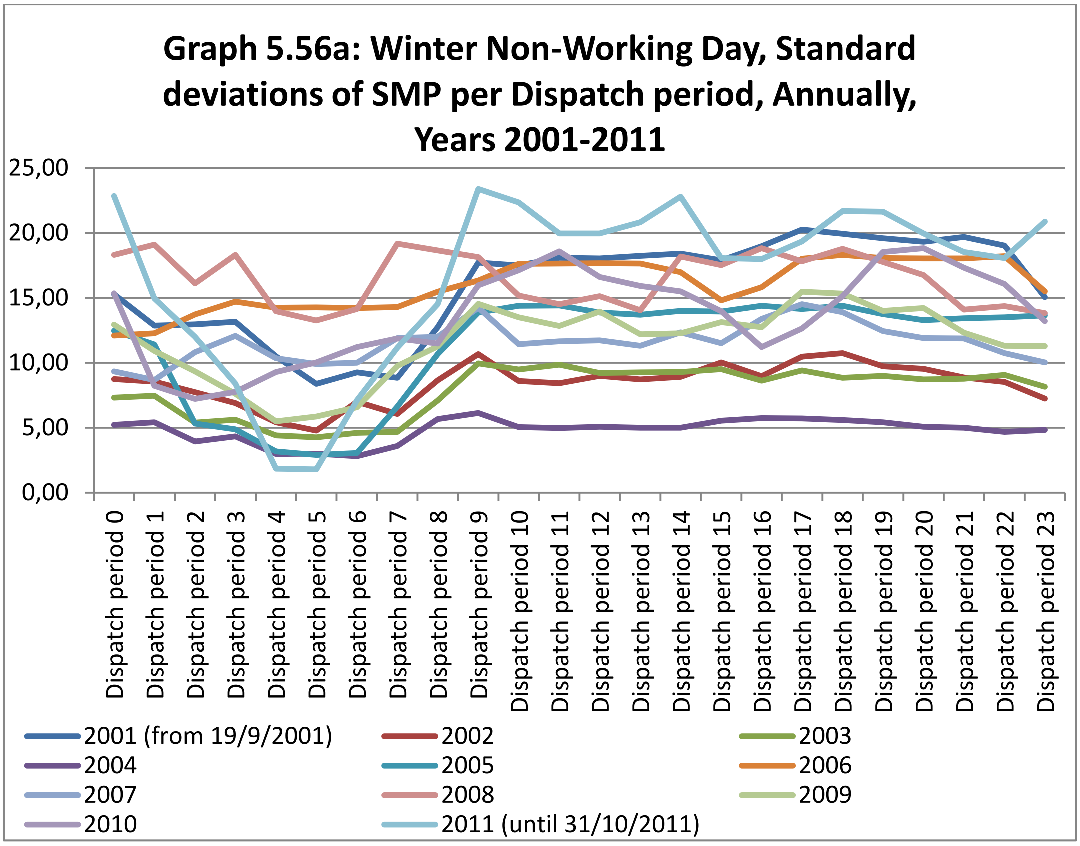



Graph 5.54d: Standard deviations of SMP of Dispatch periods 9-14, Annually, Years 2002-2011
40,00
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

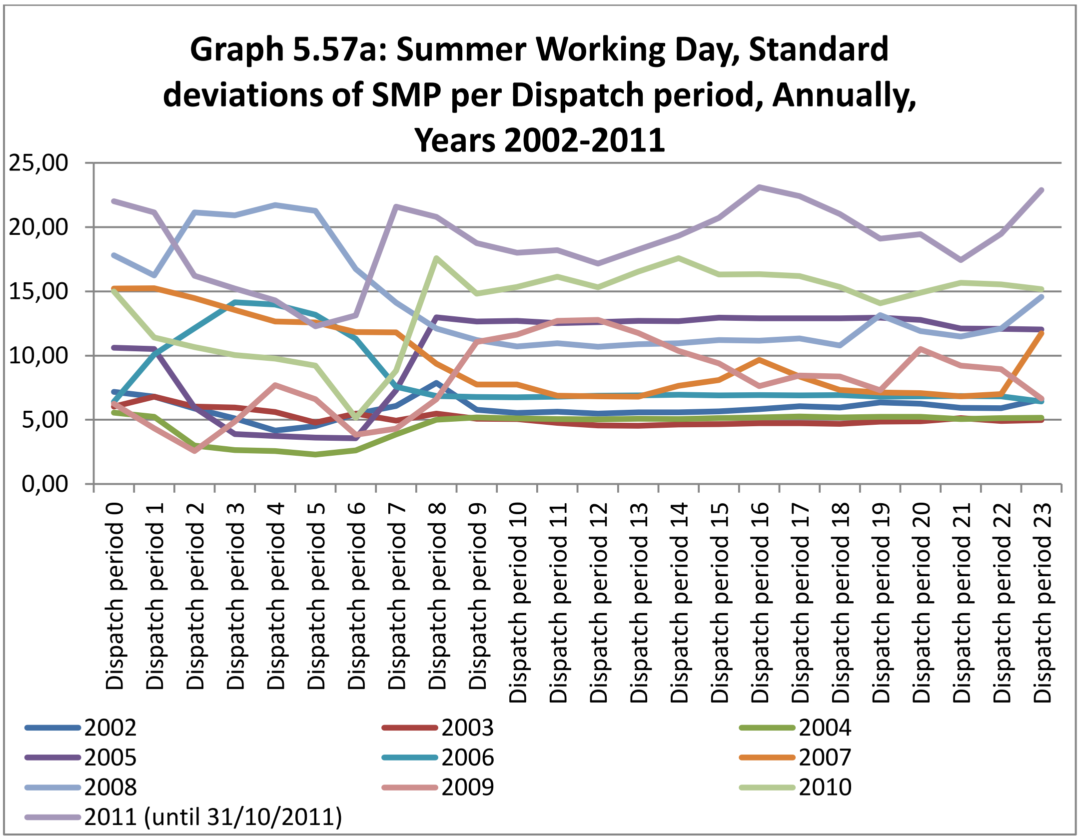

Graph 5.54e: Standard deviations of SMP of Dispatch periods 18-21
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
1
133
265
397
529
661
793
925
1057
1189
1321
1453
1585
1717
1849
1981
2113
2245
2377
2509
2641
2773
2905
3037
3169
3301
3433
3565


Graph 5.54f: Standard deviations of SMP of Dispatch periods 18-21, Annually, Years 2002-2011
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

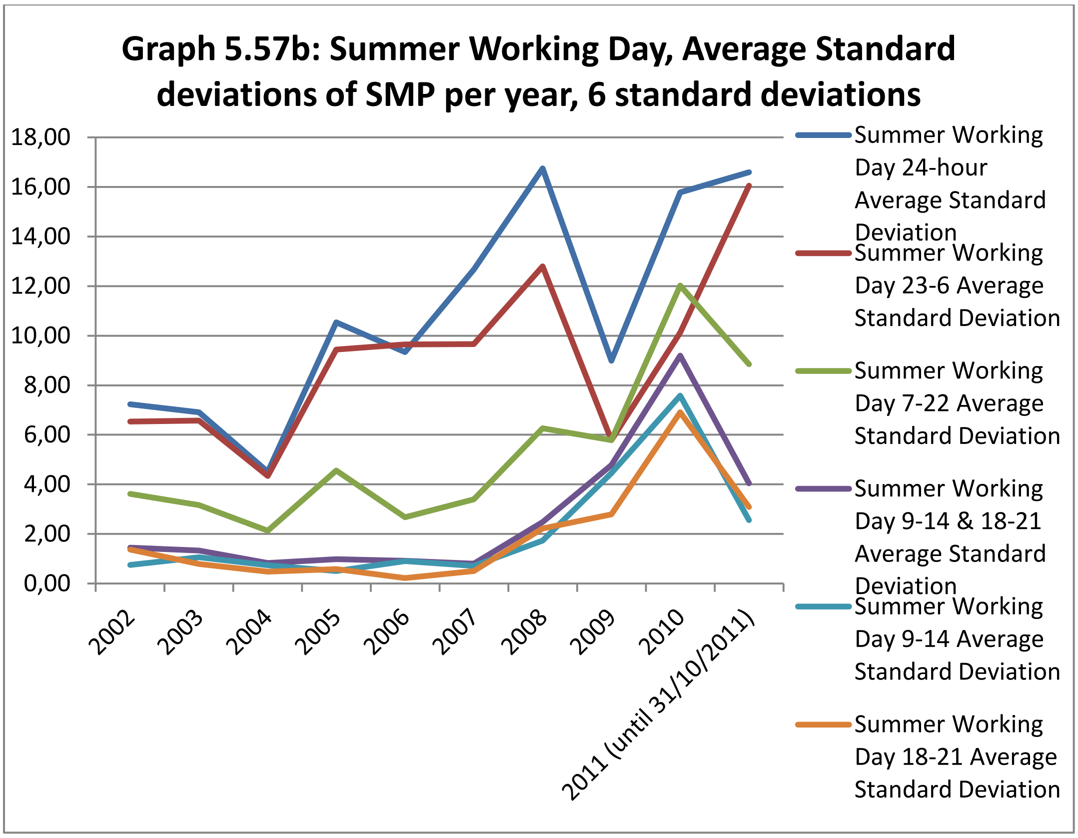

Graph 5.55a: Winter Working Day, Standard deviations of SMP per Dispatch period, Annually, Years 2001-2011
25,00
20,00
15,00
10,00
5,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

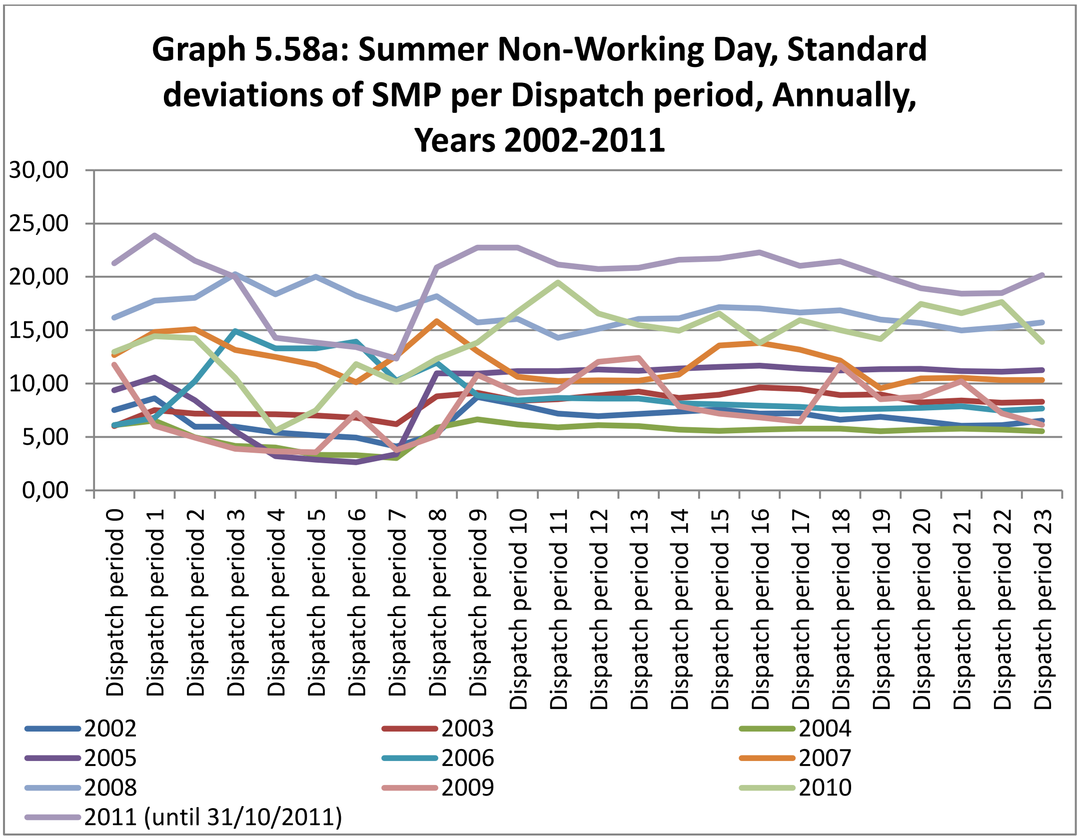


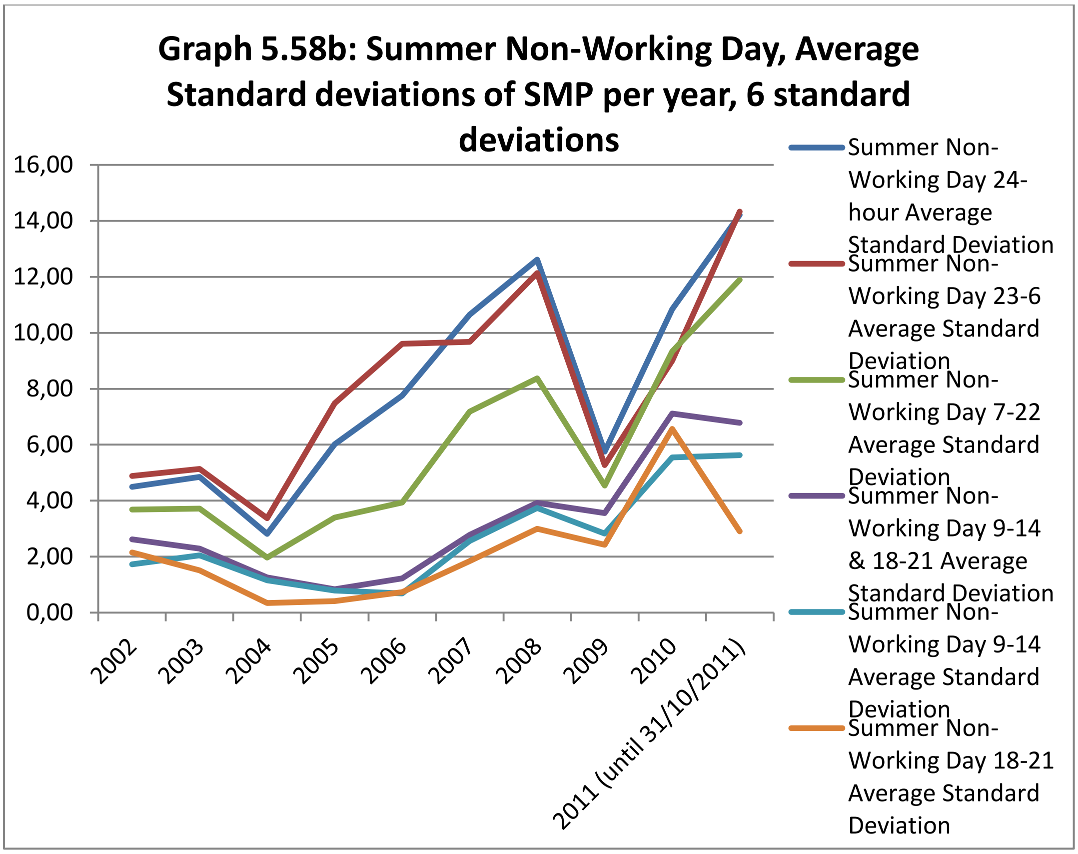
Graph 5.56a: Winter Non-Working Day, Standard deviations of SMP per Dispatch period, Annually, Years 2001-2011
25,00
20,00
15,00
10,00
5,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)



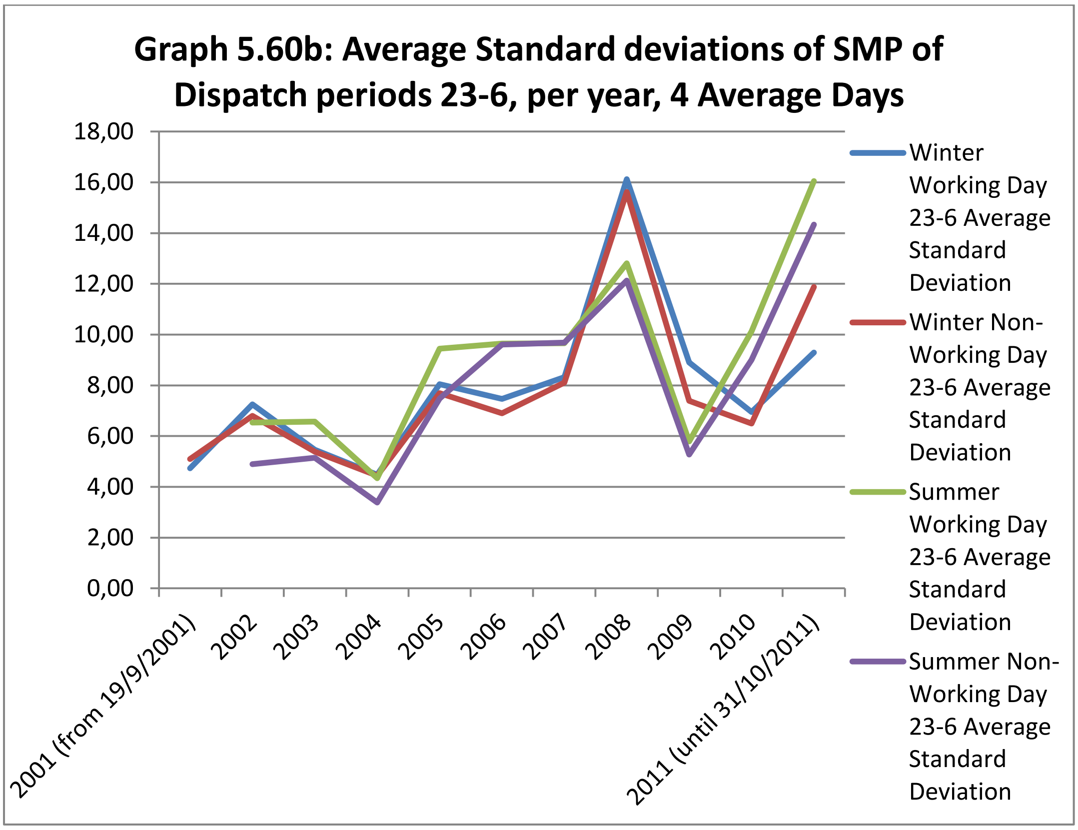
Graph 5.57a: Summer Working Day, Standard deviations of SMP per Dispatch period, Annually, Years 2002-2011
25,00
20,00
15,00
10,00
5,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.57b: Summer Working Day, Average Standard deviations of SMP per year, 6 standard deviations
18,00
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Summer Working Day 24-hour Average Standard Deviation
Summer Working Day 23-6 Average Standard Deviation
Summer Working Day 7-22 Average Standard Deviation
Summer Working Day 9-14 & 18-21 Average Standard Deviation
Summer Working Day 9-14 Average Standard Deviation
Summer Working Day 18-21 Average Standard Deviation

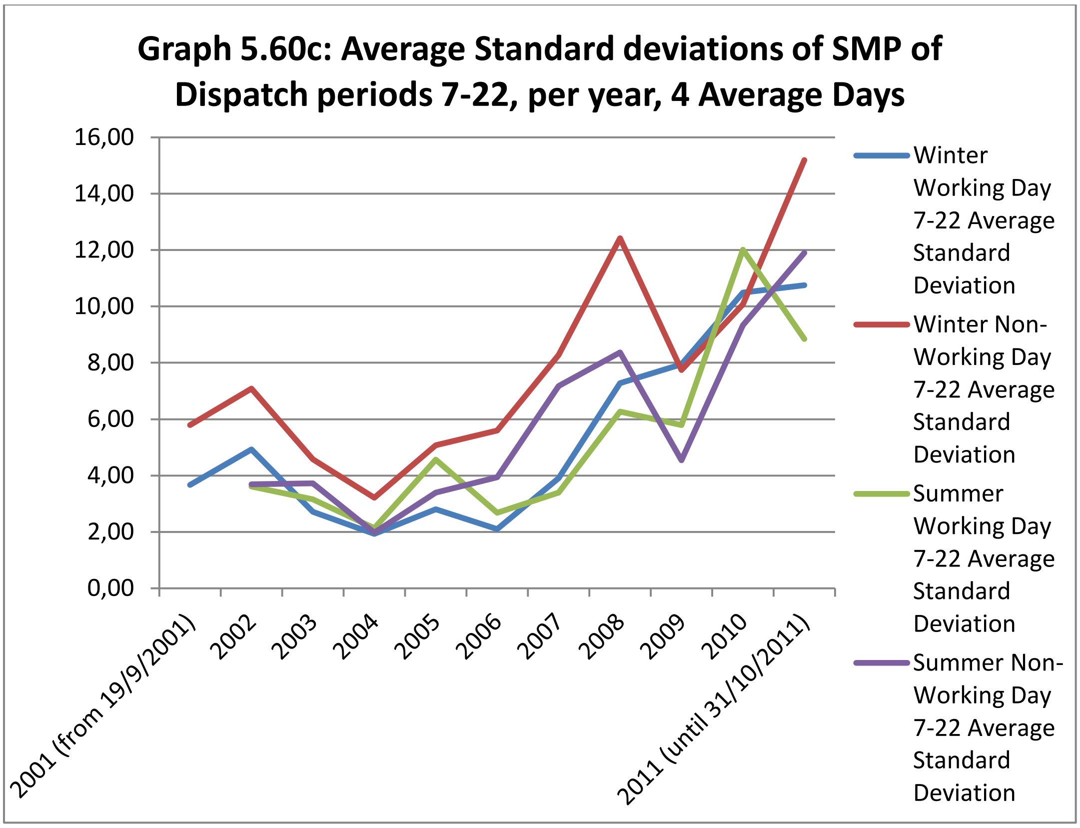

Graph 5.58a: Summer Non-Working Day, Standard deviations of SMP per Dispatch period, Annually, Years 2002-2011
30,00
25,00
20,00
15,00
10,00
5,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

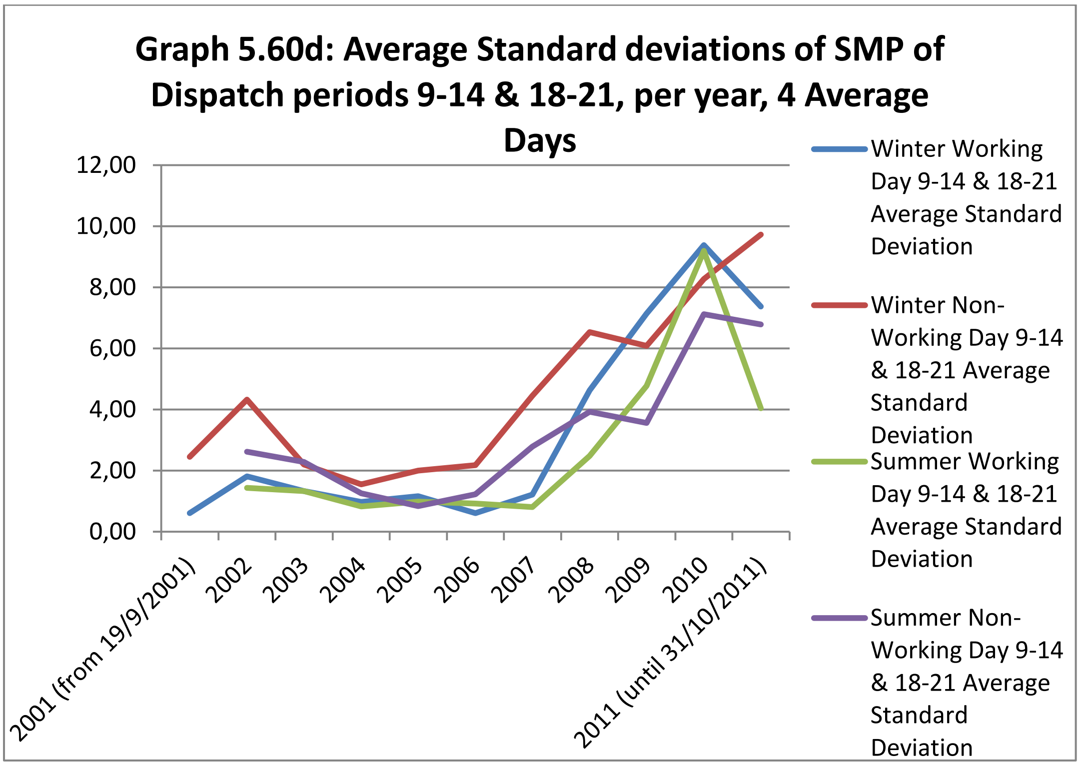


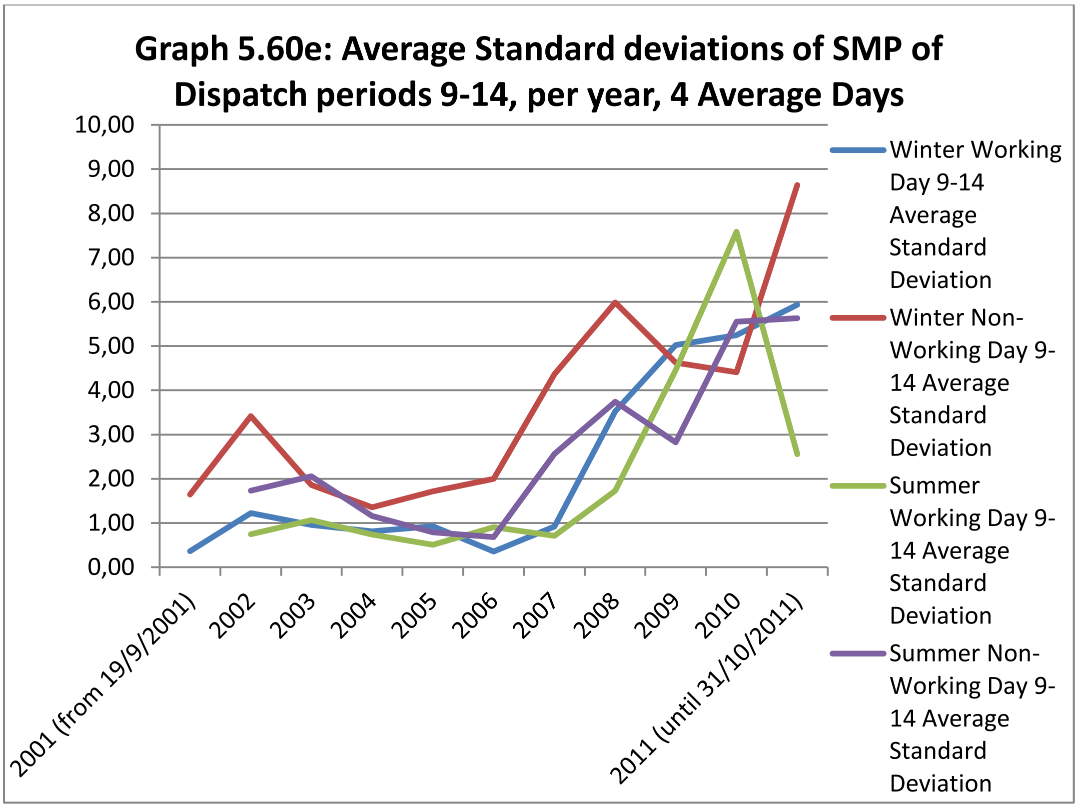
Graph 5.58b: Summer Non-Working Day, Average Standard deviations of SMP per year, 6 standard deviations
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Summer Non-Working Day 24-hour Average Standard Deviation
Summer Non-Working Day 23-6 Average Standard Deviation
Summer Non-Working Day 7-22 Average Standard Deviation
Summer Non-Working Day 9-14 & 18-21 Average Standard Deviation
Summer Non-Working Day 9-14 Average Standard Deviation
Summer Non-Working Day 18-21 Average Standard Deviation

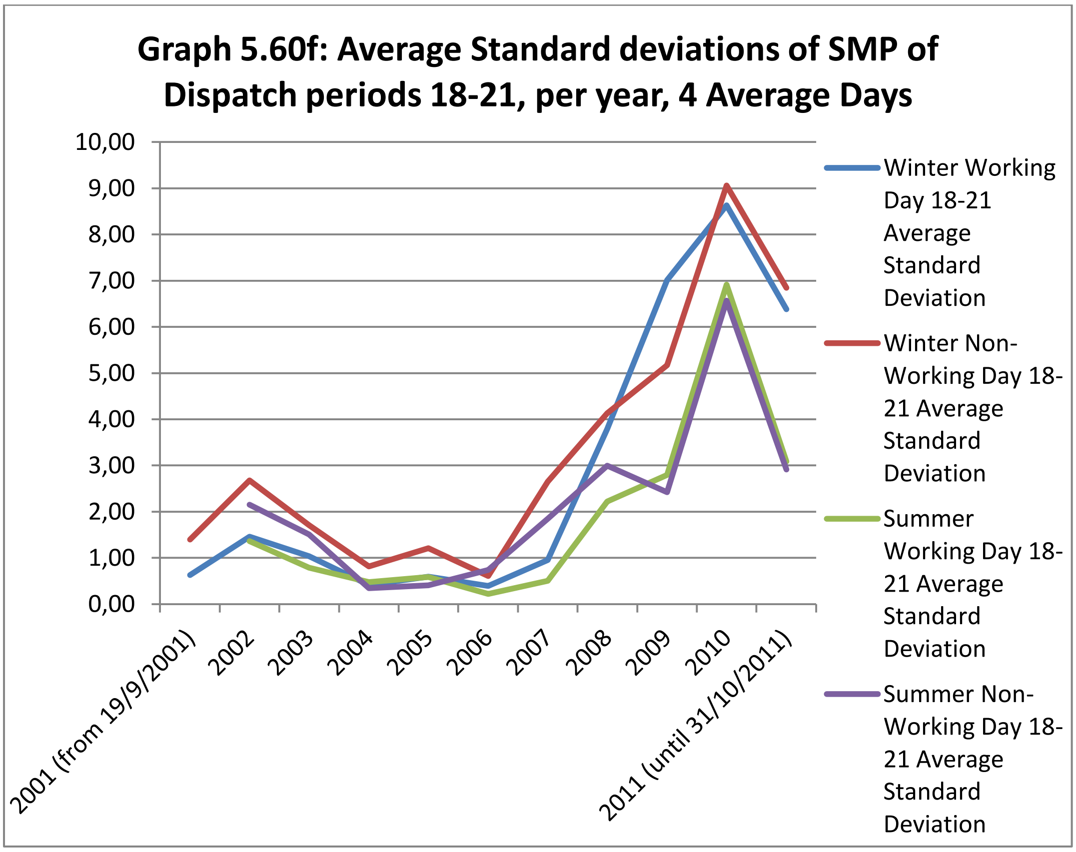


Graph 5.60b: Average Standard deviations of SMP of Dispatch periods 23-6, per year, 4 Average Days
18,00
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 23-6 Average Standard Deviation
Winter Non-Working Day 23-6 Average Standard Deviation
Summer Working Day 23-6 Average Standard Deviation
Summer Non-Working Day 23-6 Average Standard Deviation


Graph 5.60c: Average Standard deviations of SMP of Dispatch periods 7-22, per year, 4 Average Days
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 7-22 Average Standard Deviation
Winter Non-Working Day 7-22 Average Standard Deviation
Summer Working Day 7-22 Average Standard Deviation
Summer Non-Working Day 7-22 Average Standard Deviation

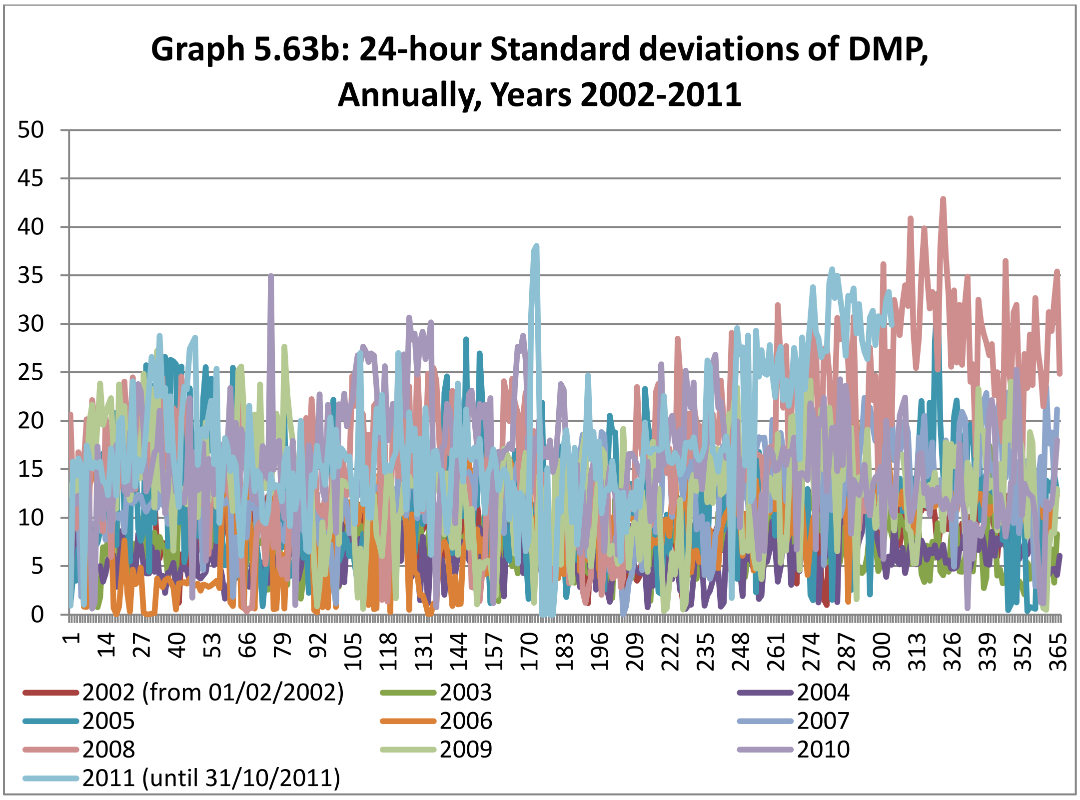

Graph 5.60d: Average Standard deviations of SMP of Dispatch periods 9-14 & 18-21, per year, 4 Average Days
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 & 18-21 Average Standard Deviation
Winter Non-Working Day 9-14 & 18-21 Average Standard Deviation
Summer Working Day 9-14 & 18-21 Average Standard Deviation
Summer Non-Working Day 9-14 & 18-21 Average Standard Deviation

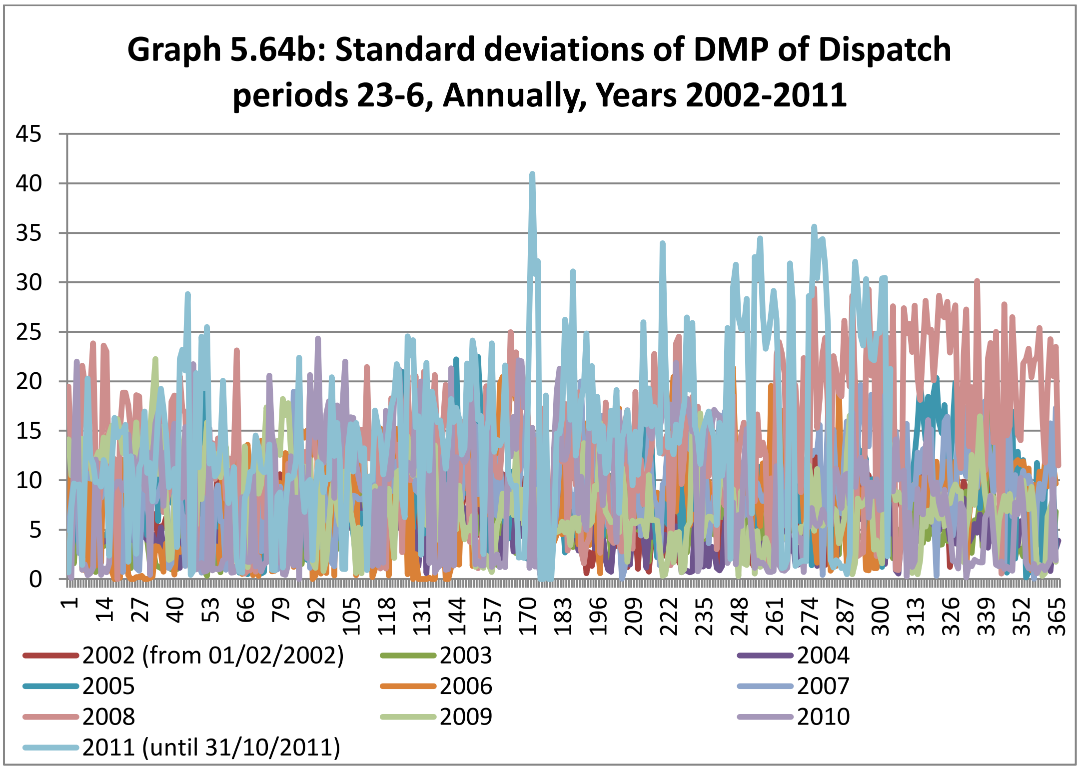

Graph 5.60e: Average Standard deviations of SMP of Dispatch periods 9-14, per year, 4 Average Days
10,00
9,00
8,00
7,00
6,00
5,00
4,00
3,00
2,00
1,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 Average Standard Deviation
Winter Non-Working Day 9-14 Average Standard Deviation
Summer Working Day 9-14 Average Standard Deviation
Summer Non-Working Day 9-14 Average Standard Deviation

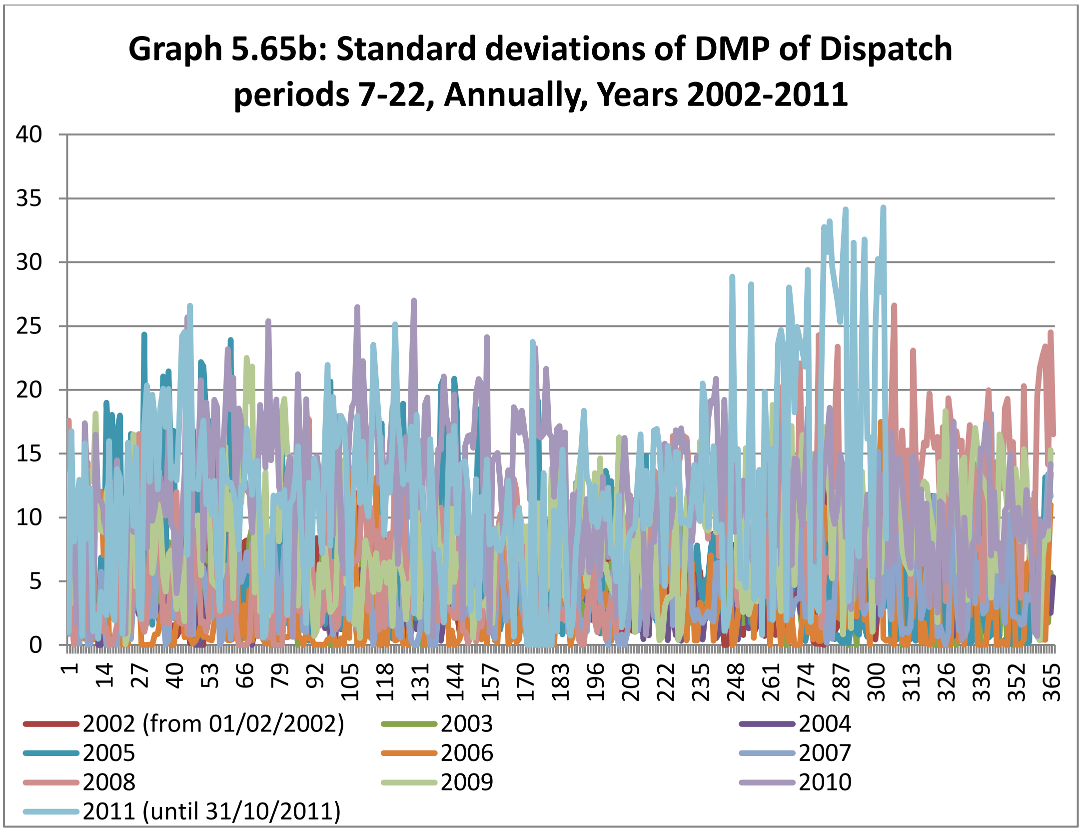

Graph 5.60f: Average Standard deviations of SMP of Dispatch periods 18-21, per year, 4 Average Days
10,00
9,00
8,00
7,00
6,00
5,00
4,00
3,00
2,00
1,00
0,00
2001 (from 19/9/2001)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 18-21 Average Standard Deviation
Winter Non-Working Day 18-21 Average Standard Deviation
Summer Working Day 18-21 Average Standard Deviation
Summer Non-Working Day 18-21 Average Standard Deviation

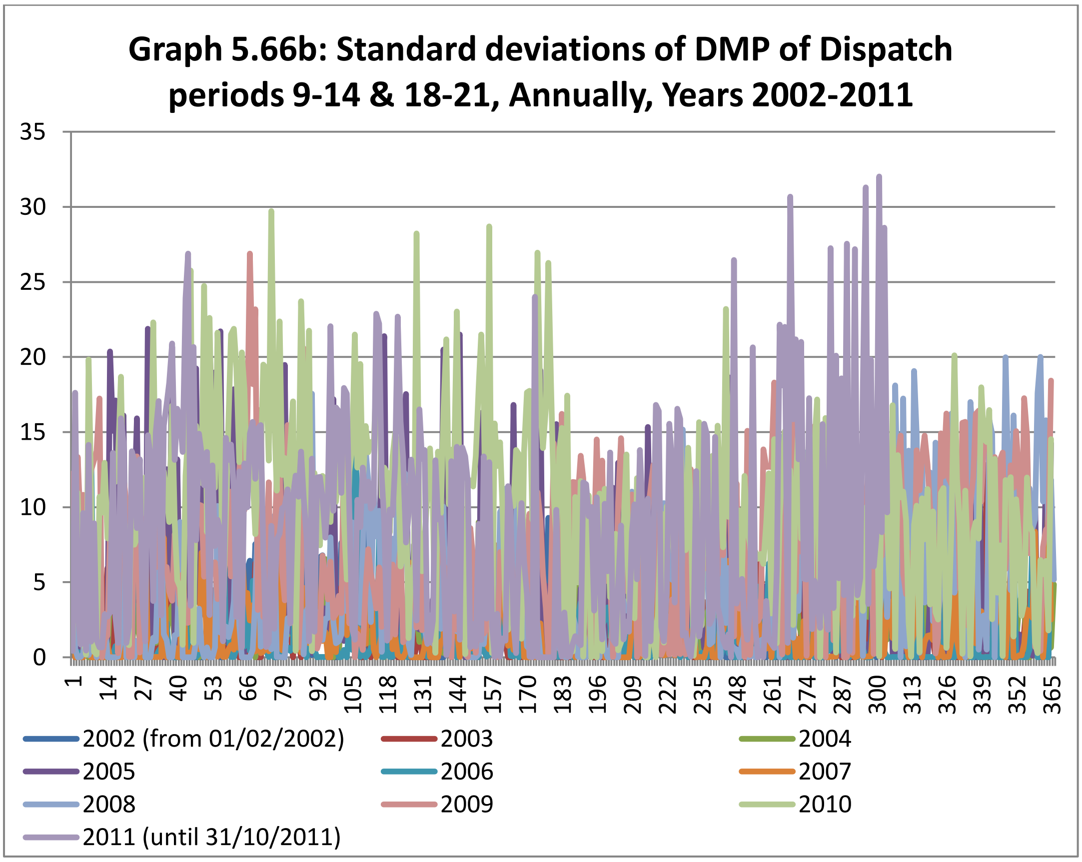
Part 6

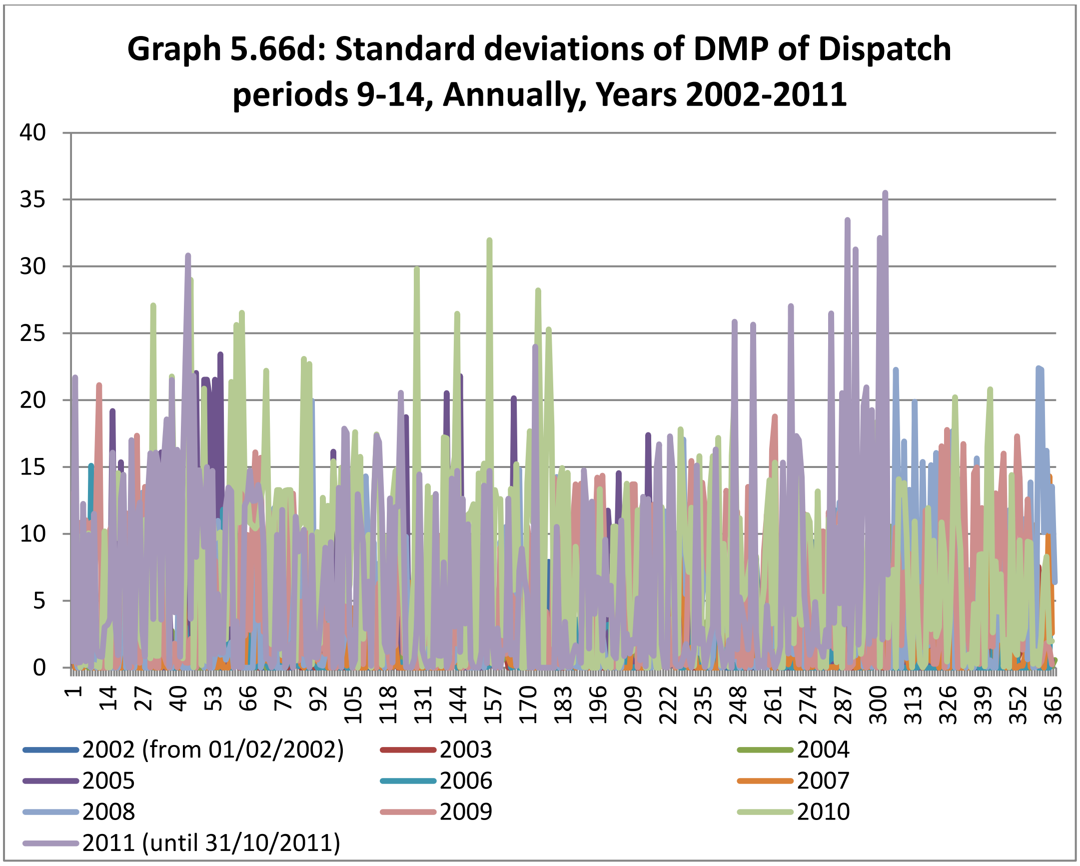
Graphs of Standard deviations of DMP are presented in this part.

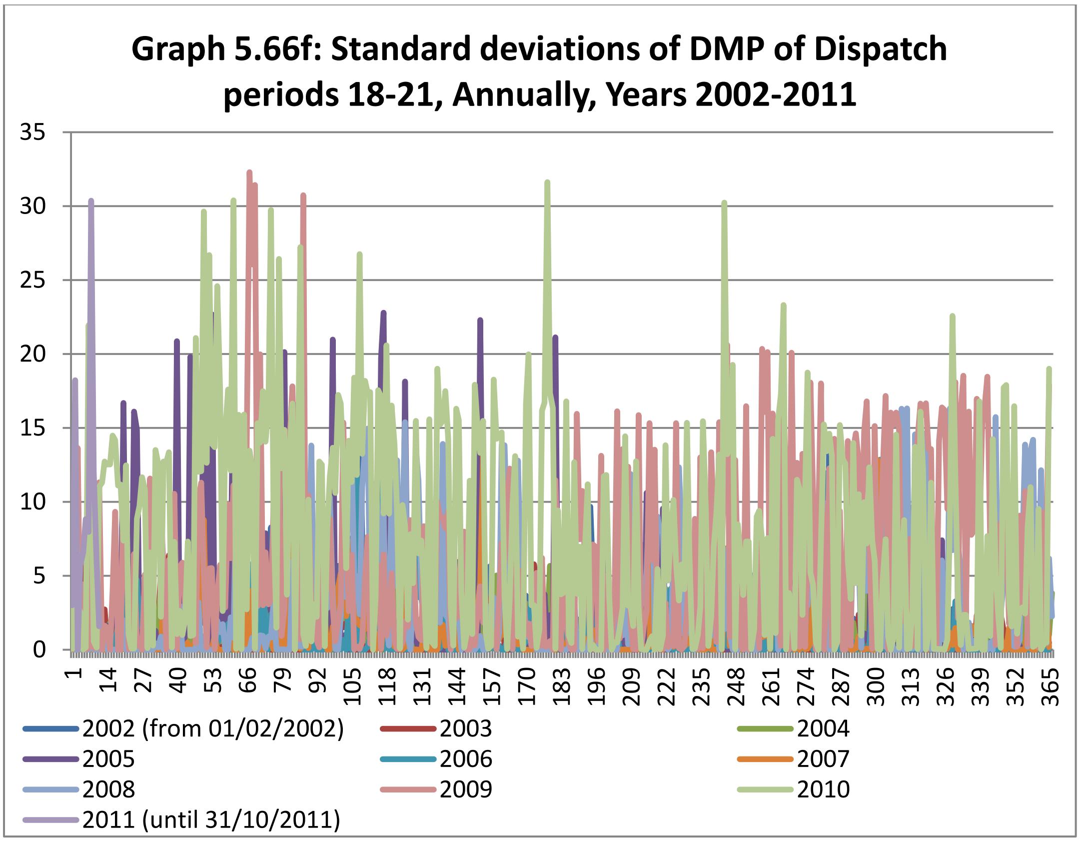


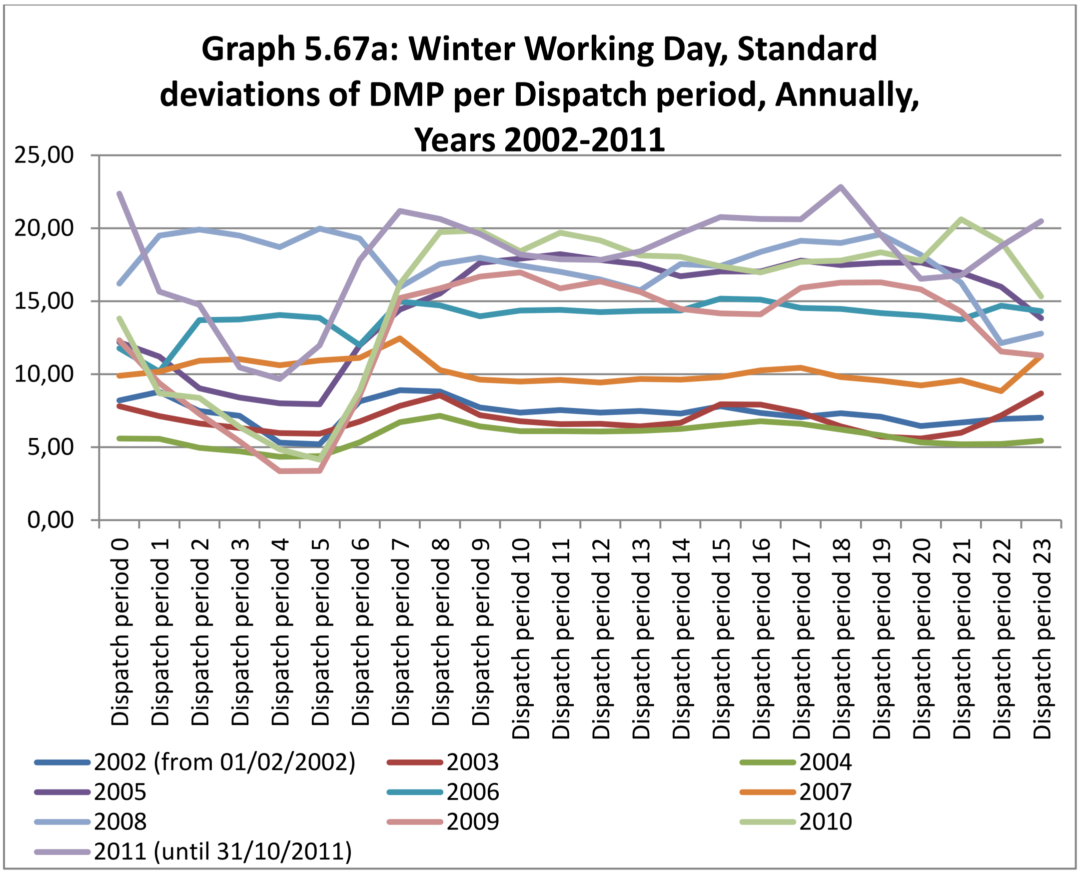


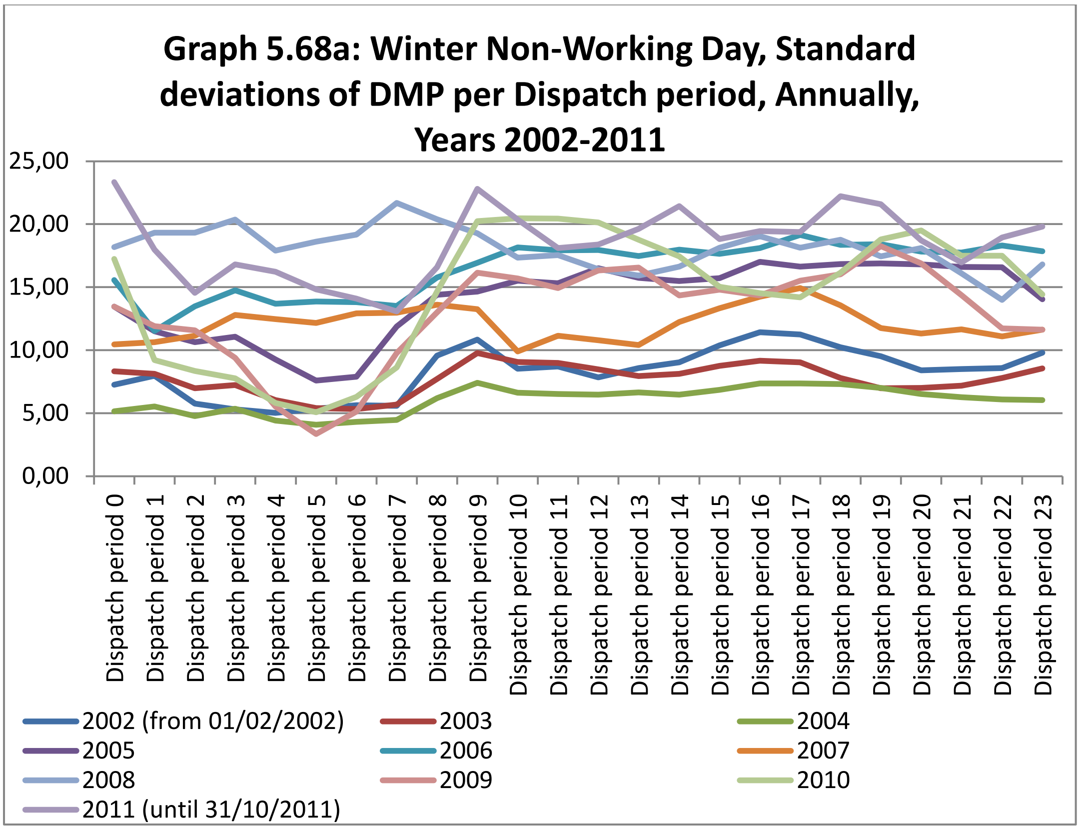

Graph 5.65b: Standard deviations of DMP of Dispatch periods 7-22, Annually, Years 2002-2011
40
35
30
25
20
15
10
5
0
1 14 27 40 53 66 79 92 105 118 131 144 157 170 183 196 209 222 235 248 261 274 287 300 313 326 339 352 365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

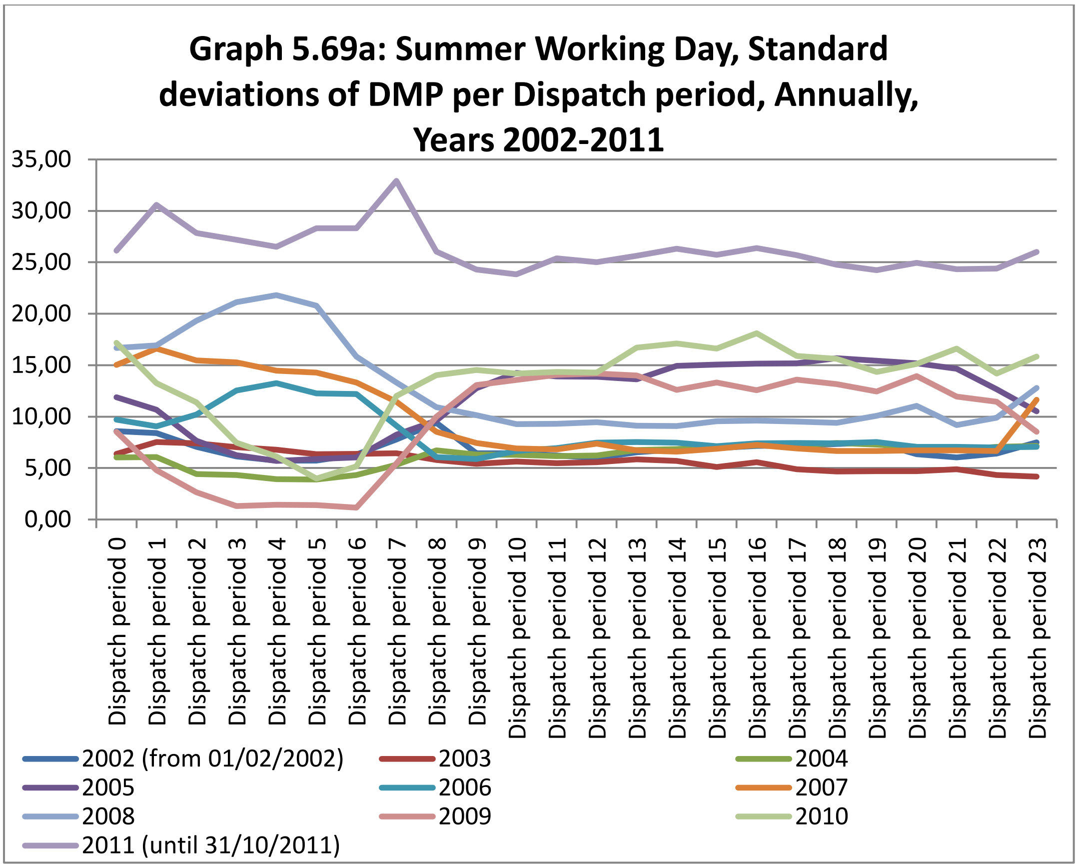

Graph 5.66b: Standard deviations of DMP of Dispatch periods 9-14 & 18-21, Annually, Years 2002-2011
35
30
25
20
15
10
5
0
1 14 27 40 53 66 79 92 105 118 131 144 157 170 183 196 209 222 235 248 261 274 287 300 313 326 339 352 365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

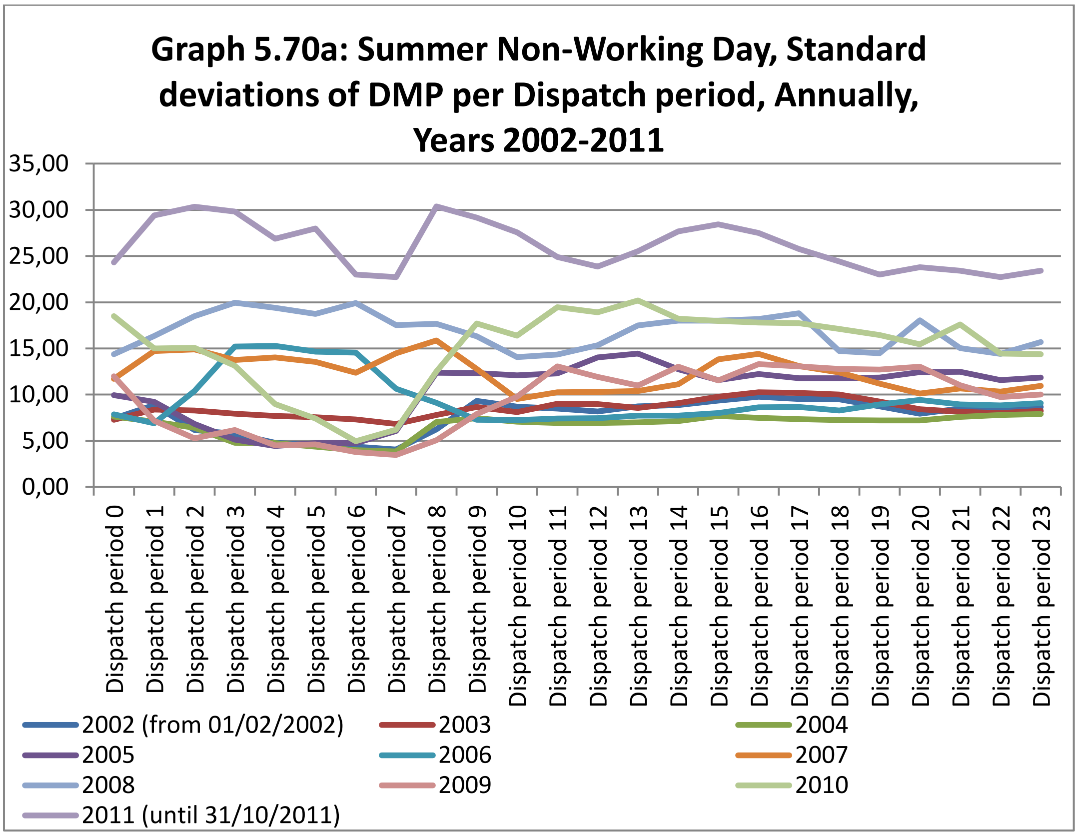

Graph 5.66d: Standard deviations of DMP of Dispatch periods 9-14, Annually, Years 2002-2011
40
35
30
25
20
15
10
5
0
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.66f: Standard deviations of DMP of Dispatch periods 18-21, Annually, Years 2002-2011
35
30
25
20
15
10
5
0
1
14
27
40
53
66
79
92
105
118
131
144
157
170
183
196
209
222
235
248
261
274
287
300
313
326
339
352
365
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)


Graph 5.67a: Winter Working Day, Standard deviations of DMP per Dispatch period, Annually, Years 2002-2011
25,00
20,00
15,00
10,00
5,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

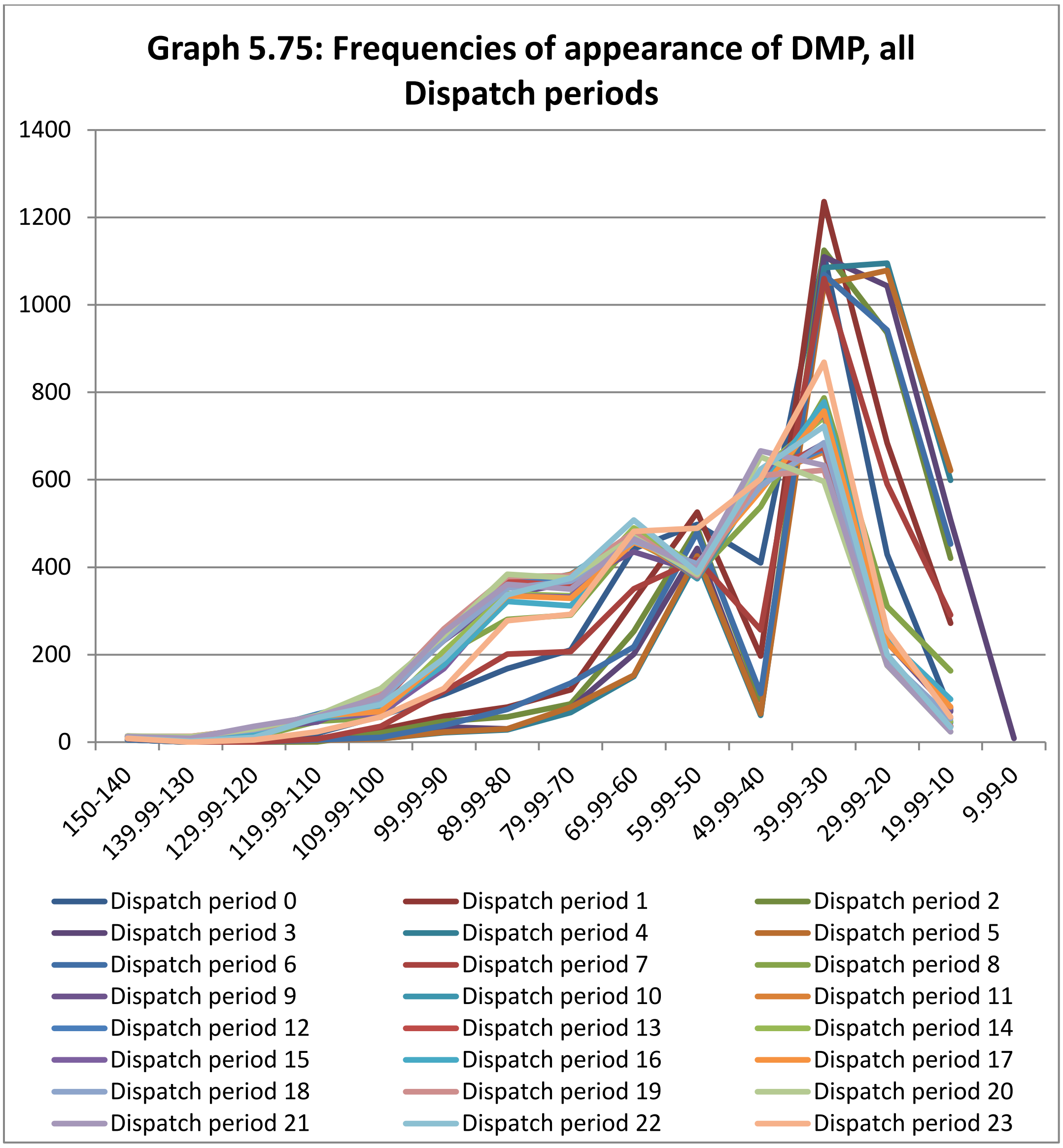

Graph 5.68a: Winter Non-Working Day, Standard deviations of DMP per Dispatch period, Annually, Years 2002-2011
25,00
20,00
15,00
10,00
5,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

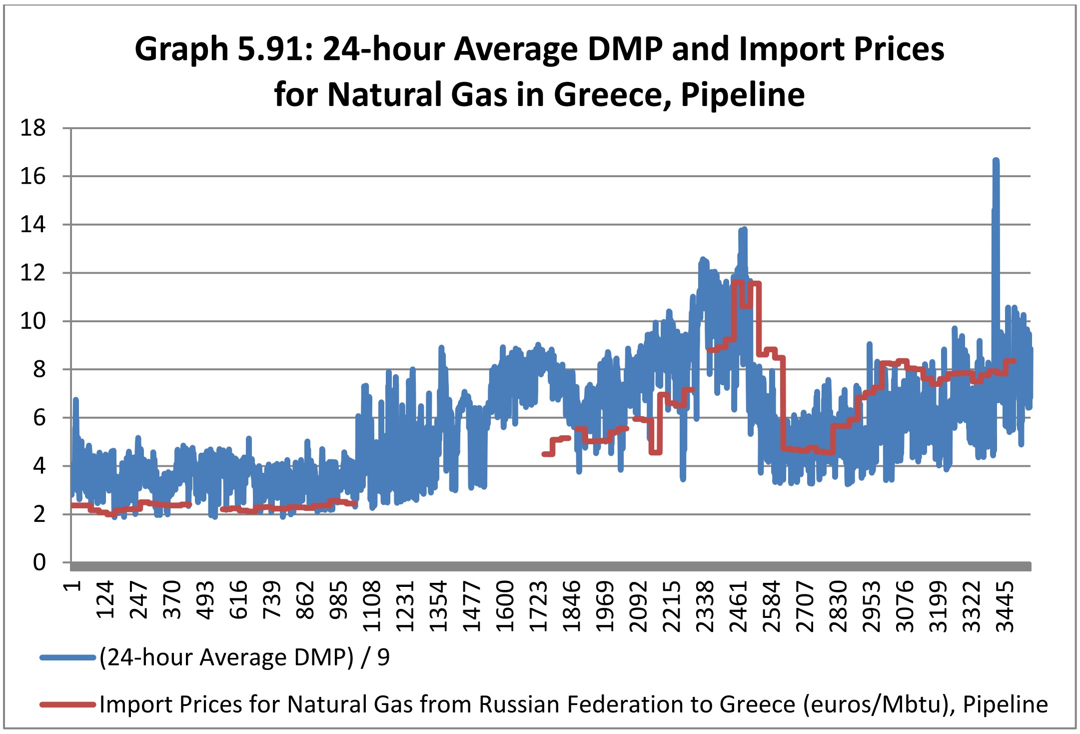

Graph 5.69a: Summer Working Day, Standard deviations of DMP per Dispatch period, Annually, Years 2002-2011
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

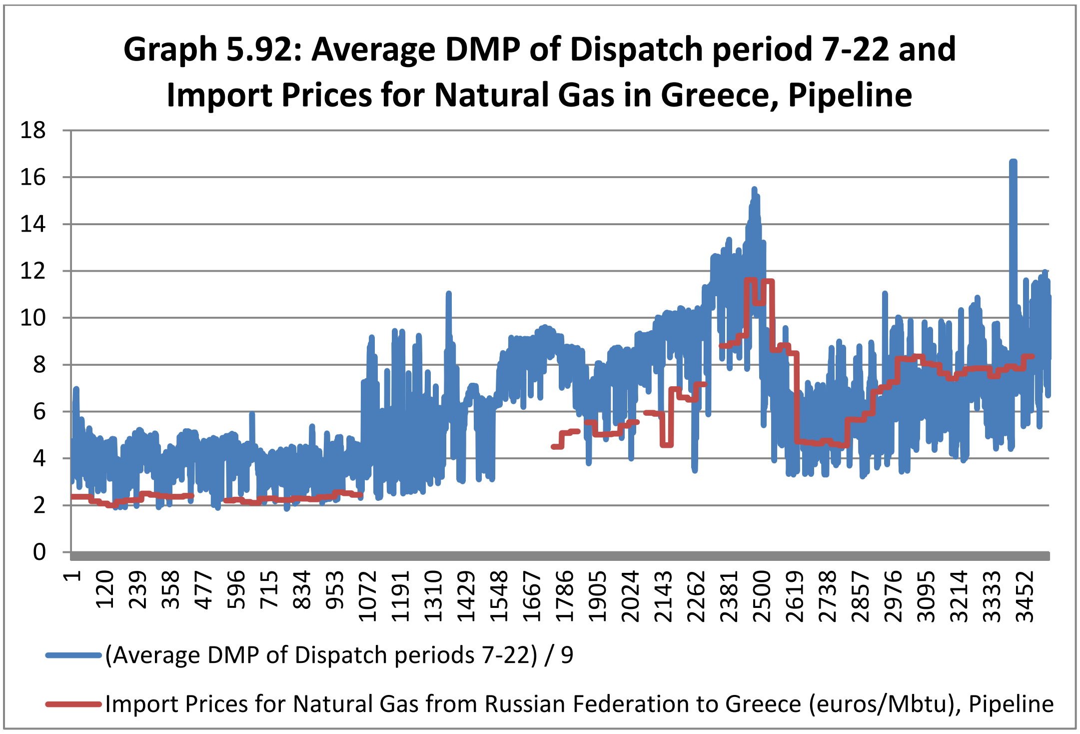

Graph 5.70a: Summer Non-Working Day, Standard deviations of DMP per Dispatch period, Annually, Years 2002-2011
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)

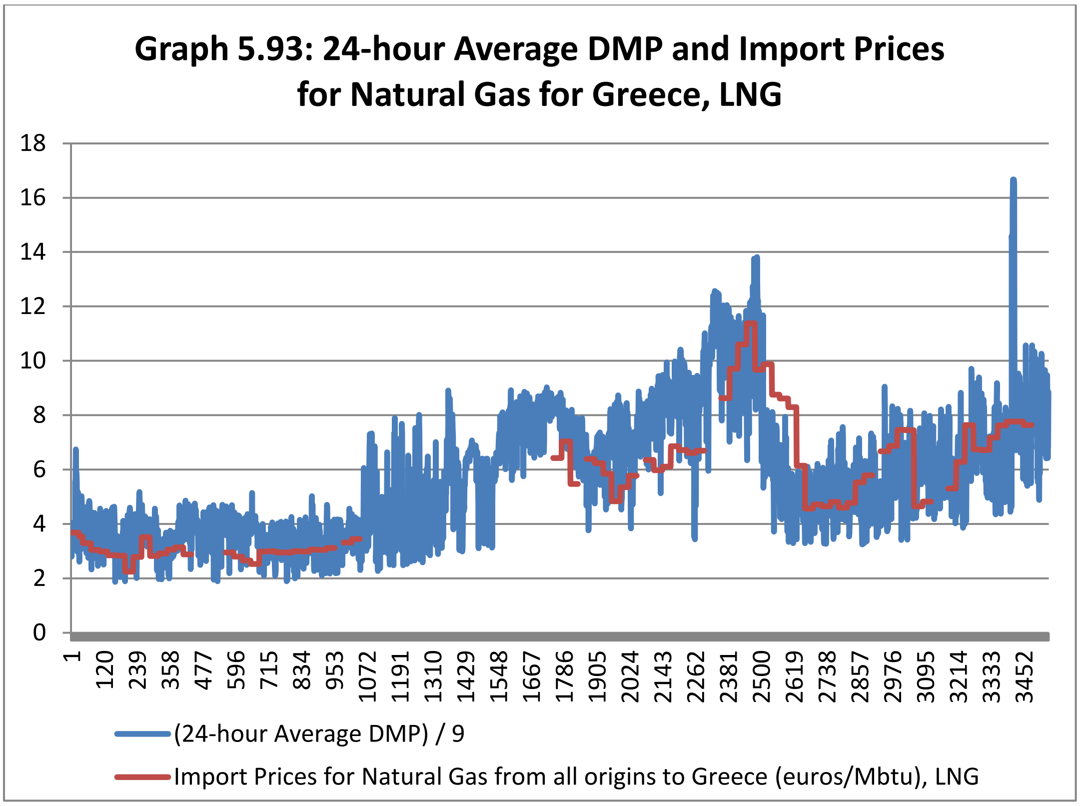
Part 7

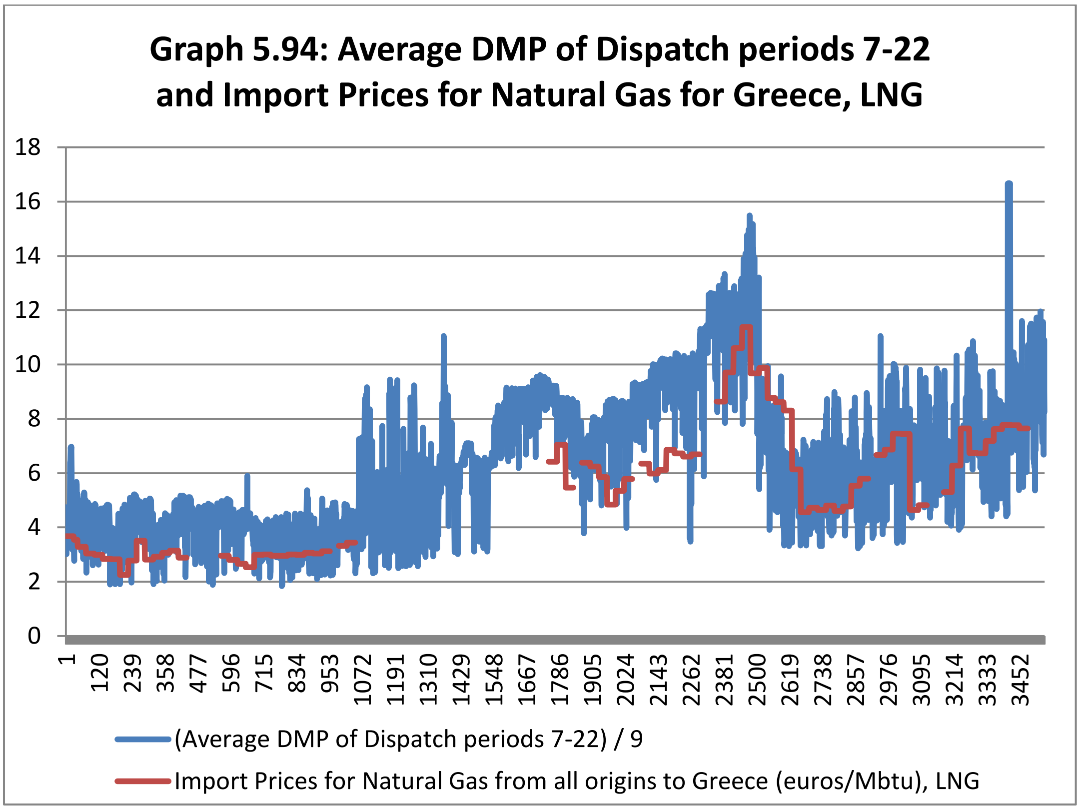
Graphs referring to DMP data are presented in this part.

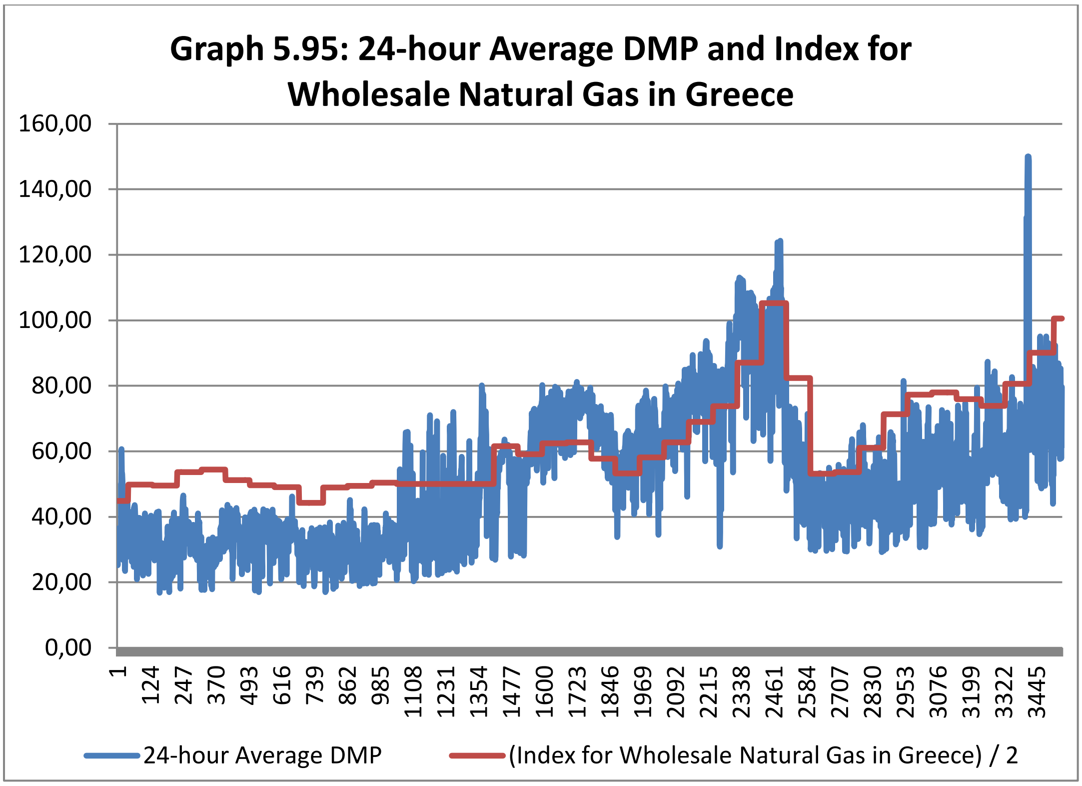


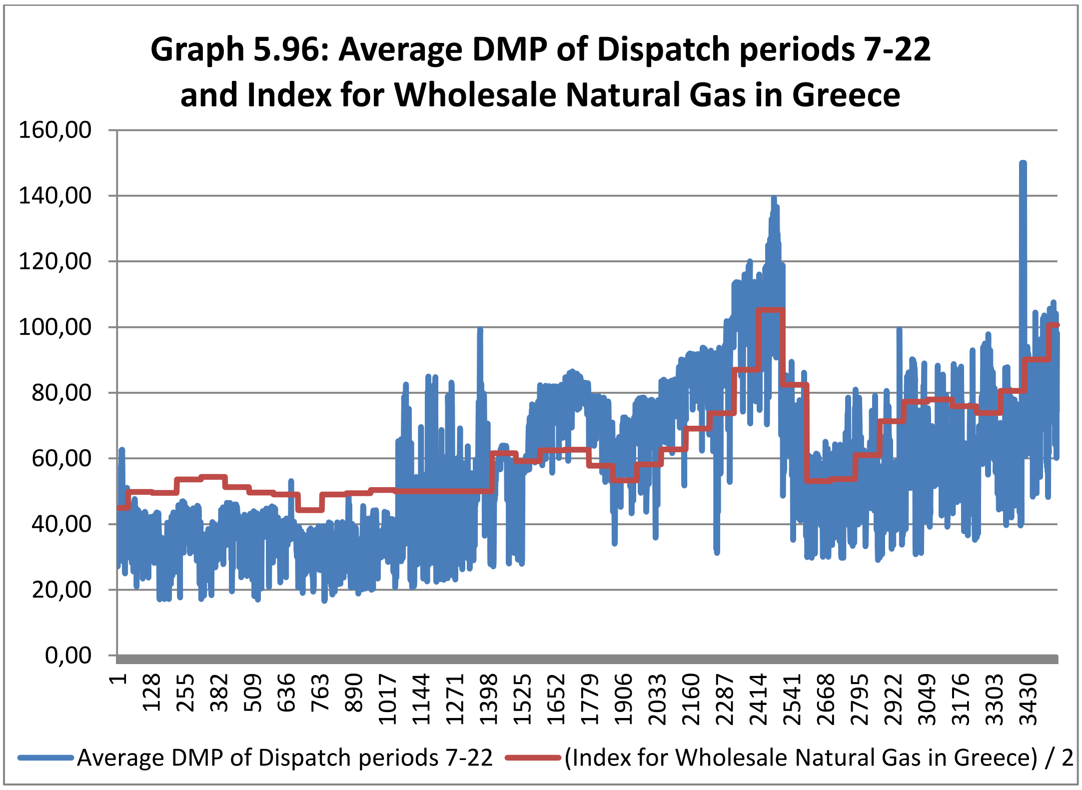

Graph 5.91: 24-hour Average DMP and Import Prices for Natural Gas in Greece, Pipeline
18
16
14
12
10
8
6
4
2
0
1
124
247
370
493
616
739
862
985
1108
1231
1354
1477
1600
1723
1846
1969
2092
2215
2338
2461
2584
2707
2830
2953
3076
3199
3322
3445
(24-hour Average DMP) / 9
Import Prices for Natural Gas from Russian Federation to Greece (euros/Mbtu), Pipeline

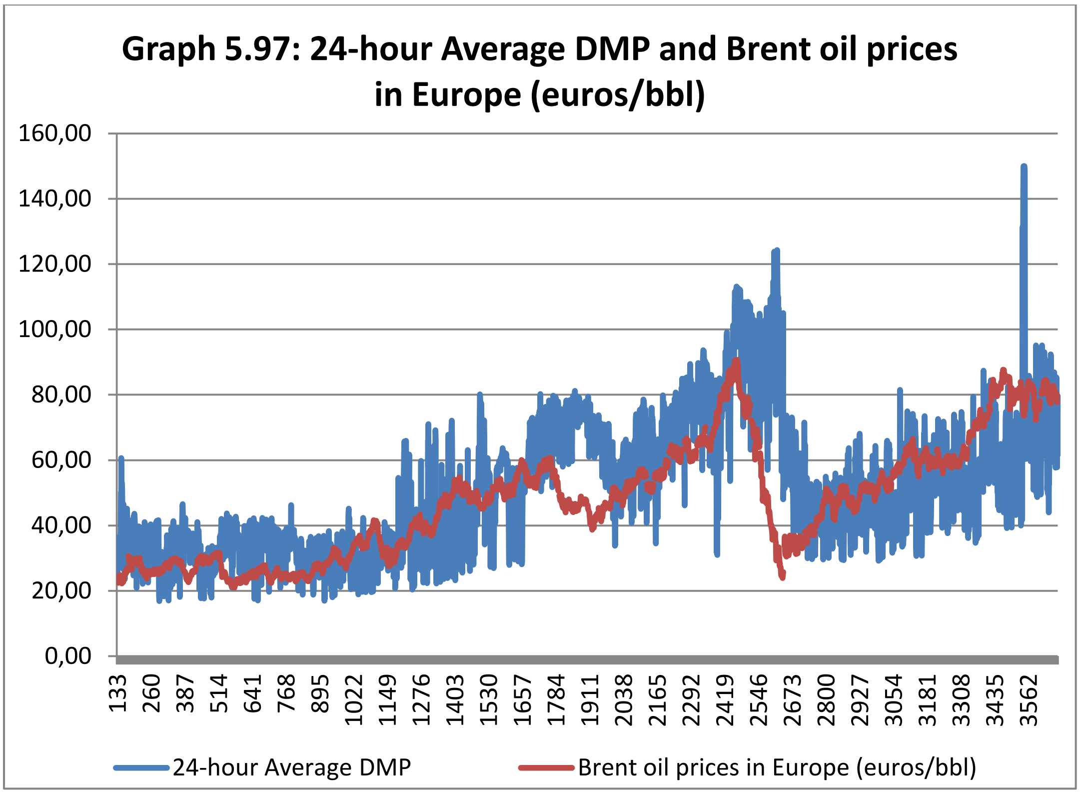

Graph 5.92: Average DMP of Dispatch period 7-22 and Import Prices for Natural Gas in Greece, Pipeline
18
16
14
12
10
8
6
4
2
0
1
120
239
358
477
596
715
834
953
1072
1191
1310
1429
1548
1667
1786
1905
2024
2143
2262
2381
2500
2619
2738
2857
2976
3095
3214
3333
3452
(Average DMP of Dispatch periods 7-22) / 9
Import Prices for Natural Gas from Russian Federation to Greece (euros/Mbtu), Pipeline

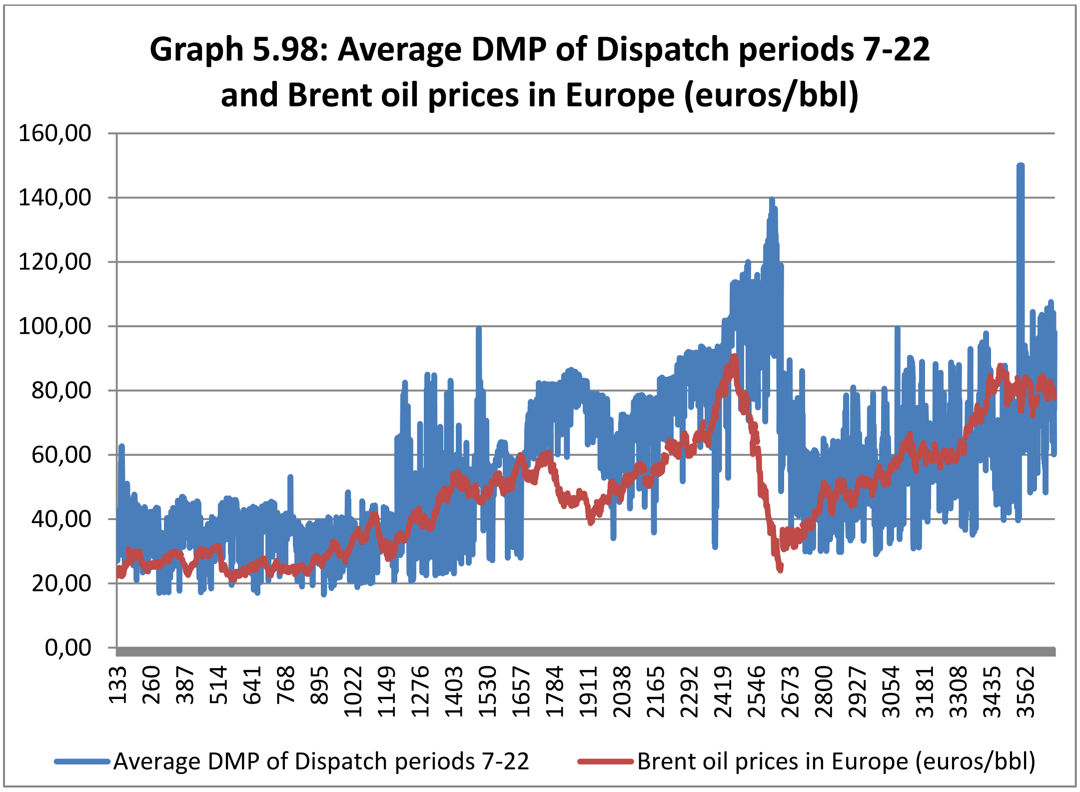

Graph 5.93: 24-hour Average DMP and Import Prices for Natural Gas for Greece, LNG
18
16
14
12
10
8
6
4
2
0
1
120
239
358
477
596
715
834
953
1072
1191
1310
1429
1548
1667
1786
1905
2024
2143
2262
2381
2500
2619
2738
2857
2976
3095
3214
3333
3452
(24-hour Average DMP) / 9
Import Prices for Natural Gas from all origins to Greece (euros/Mbtu), LNG

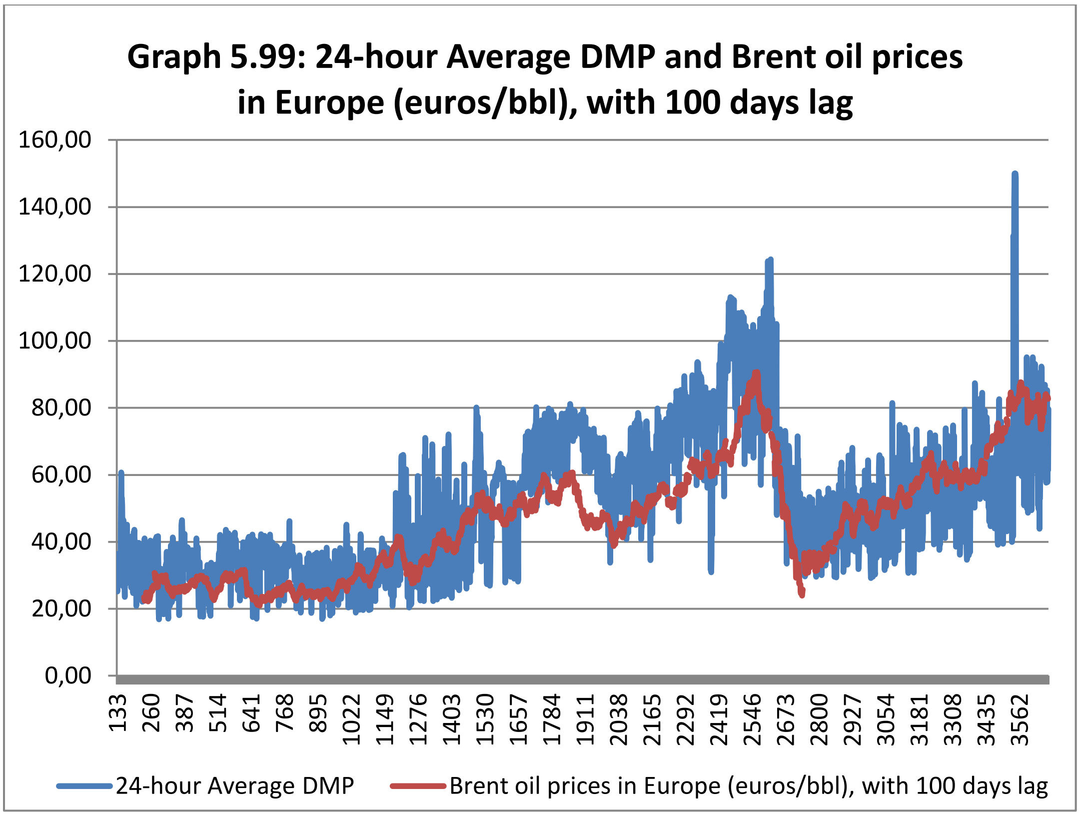

Graph 5.94: Average DMP of Dispatch periods 7-22 and Import Prices for Natural Gas for Greece, LNG
18
16
14
12
10
8
6
4
2
0
1
120
239
358
477
596
715
834
953
1072
1191
1310
1429
1548
1667
1786
1905
2024
2143
2262
2381
2500
2619
2738
2857
2976
3095
3214
3333
3452
(Average DMP of Dispatch periods 7-22) / 9
Import Prices for Natural Gas from all origins to Greece (euros/Mbtu), LNG

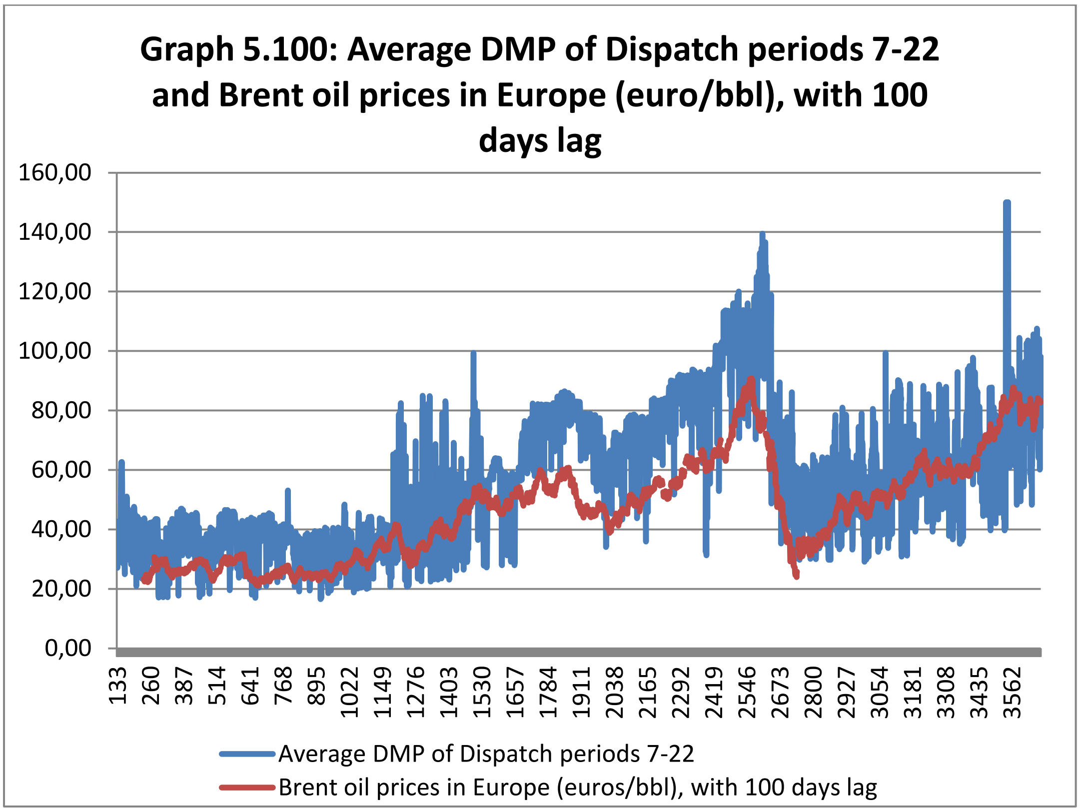

Graph 5.95: 24-hour Average DMP and Index for Wholesale Natural Gas in Greece
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
124
247
370
493
616
739
862
985
1108
1231
1354
1477
1600
1723
1846
1969
2092
2215
2338
2461
2584
2707
2830
2953
3076
3199
3322
3445
24-hour Average DMP
(Index for Wholesale Natural Gas in Greece) / 2

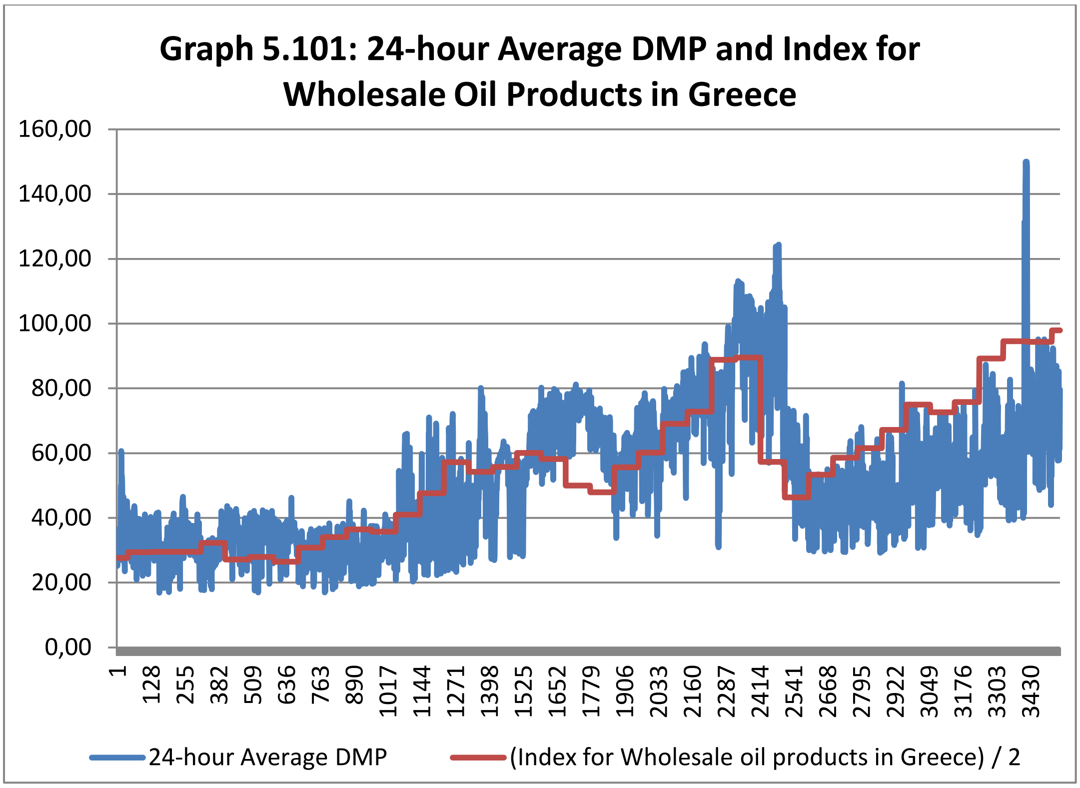

Graph 5.96: Average DMP of Dispatch periods 7-22 and Index for Wholesale Natural Gas in Greece
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
128
255
382
509
636
763
890
1017
1144
1271
1398
1525
1652
1779
1906
2033
2160
2287
2414
2541
2668
2795
2922
3049
3176
3303
3430
Average DMP of Dispatch periods 7-22
(Index for Wholesale Natural Gas in Greece) / 2

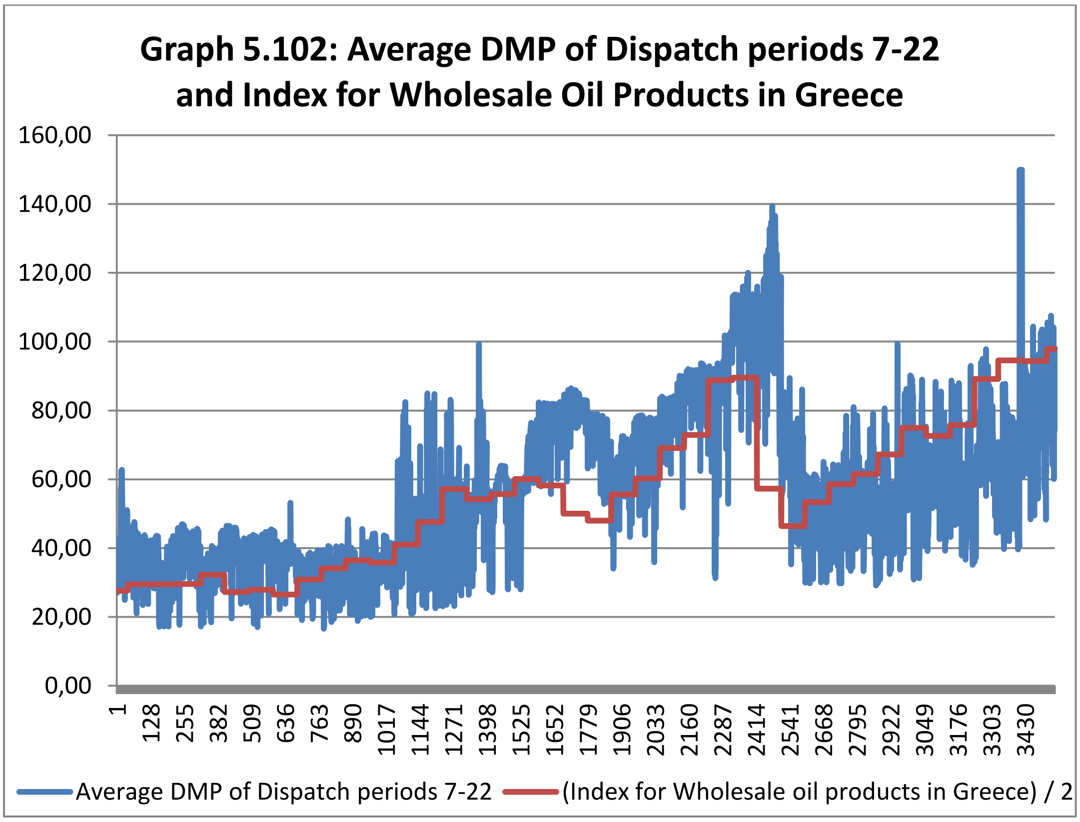

Graph 5.97: 24-hour Average DMP and Brent oil prices in Europe (euros/bbl)
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562
24-hour Average DMP
Brent oil prices in Europe (euros/bbl)


Graph 5.98: Average DMP of Dispatch periods 7-22 and Brent oil prices in Europe (euros/bbl)
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133
260
387
514
641
768
895
1022
1149
1276
1403
1530
1657
1784
1911
2038
2165
2292
2419
2546
2673
2800
2927
3054
3181
3308
3435
3562
Average DMP of Dispatch periods 7-22
Brent oil prices in Europe (euros/bbl)

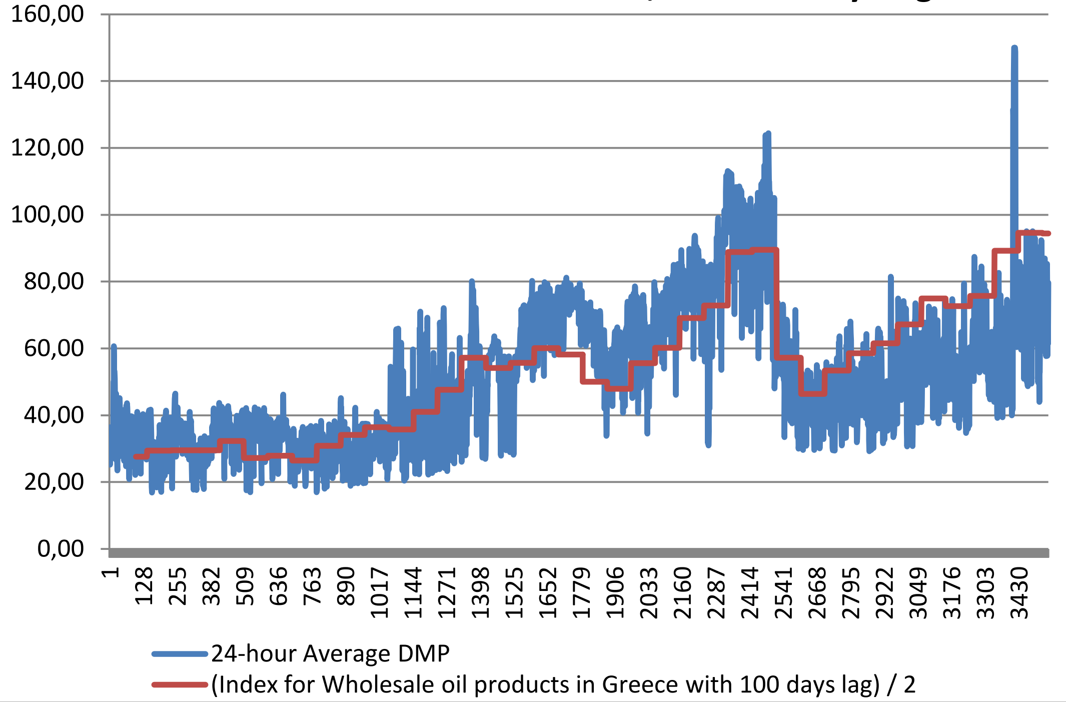

Graph 5.99: 24-hour Average DMP and Brent oil prices in Europe (euros/bbl), with 100 days lag
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133 260 387 514 641 768 895 1022 1149 1276 1403 1530 1657 1784 1911 2038 2165 2292 2419 2546 2673 2800 2927 3054 3181 3308 3435 3562
24-hour Average DMP
Brent oil prices in Europe (euros/bbl), with 100 days lag


Graph 5.100: Average DMP of Dispatch periods 7-22 and Brent oil prices in Europe (euro/bbl), with 100 days lag
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
133 260 387 514 641 768 895 1022 1149 1276 1403 1530 1657 1784 1911 2038 2165 2292 2419 2546 2673 2800 2927 3054 3181 3308 3435 3562
Average DMP of Dispatch periods 7-22
Brent oil prices in Europe (euros/bbl), with 100 days lag

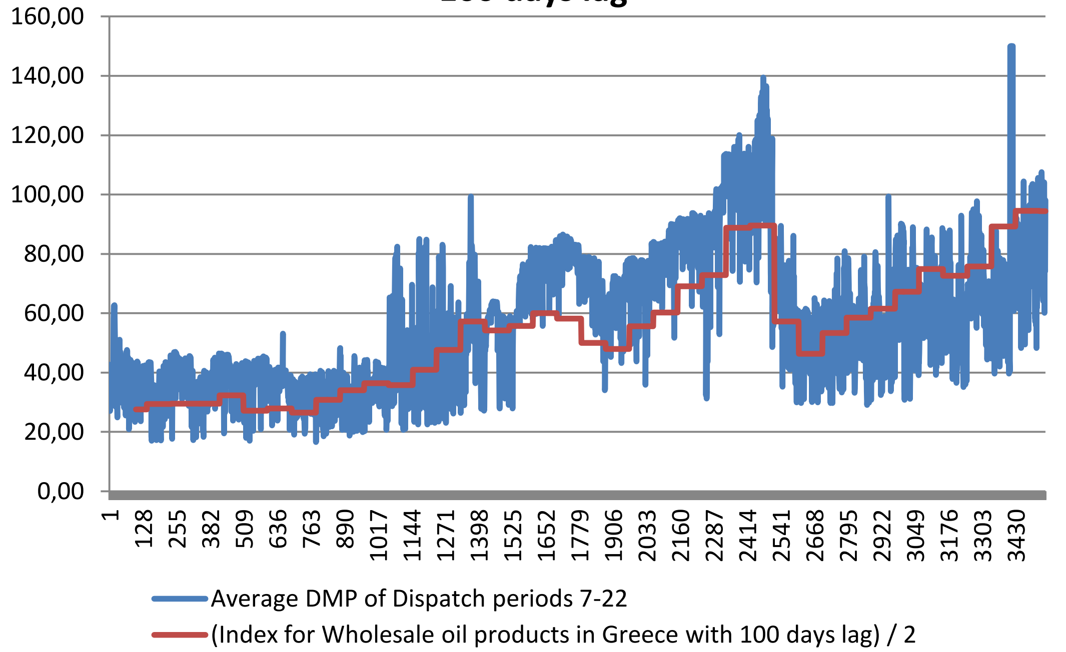

Graph 5.101: 24-hour Average DMP and Index for Wholesale Oil Products in Greece
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
128
255
382
509
636
763
890
1017
1144
1271
1398
1525
1652
1779
1906
2033
2160
2287
2414
2541
2668
2795
2922
3049
3176
3303
3430
24-hour Average DMP
(Index for Wholesale oil products in Greece) / 2


Graph 5.102: Average DMP of Dispatch periods 7-22 and Index for Wholesale Oil Products in Greece
160,00
140,00
120,00
100,00
80,00
60,00
40,00
20,00
0,00
1
128
255
382
509
636
763
890
1017
1144
1271
1398
1525
1652
1779
1906
2033
2160
2287
2414
2541
2668
2795
2922
3049
3176
3303
3430
Average DMP of Dispatch periods 7-22
(Index for Wholesale oil products in Greece) / 2

Graph 5.103: 24-hour Average DMP and Index for Wholesale Oil Products in Greece, with 100 days lag



Graph 5.104: Average DMP of Dispatch periods 7-22 and Index for Wholesale Oil Products in Greece, with 100 days lag



Appendix C

Part 1

Algebraic Analysis

1.1 The setting

In the algebraic analysis, we consider two markets, market 1 and market 2, indicated by our use of subscripts/superscripts as appropriate.

For the cost-minimising supplier that supplies both markets, we have:

$$TC = F\max(Q_1, Q_2) + (V_1 + P_{E1}^W)Q_1 + (V_2 + P_{E2}^W)Q_2 \qquad (1)$$

Where F = Average fixed cost per unit of capacity

V_i = Average variable cost for market *i* (excluding the cost of wholesale electricity)

P_{Ei}^W = Average wholesale price for electricity for market *i*

Q_i = Quantity for market *i*

We consider a situation where there are no capital constraints, meaning there is no issue with the strategic interactions of decisions related with capacity building.

We set: $\overline{F} \geq F\max(Q_1, Q_2)$ (2)

We take into account fixed costs in the formula (1), but these are not going to be taken into account when we will determine profit-maximizing quantities and prices. In this section, we are considering the situation where all fixed costs are sunk, so we get to use the total variable cost:

$$TVC = (V_1 + P_{E1}^W)Q_1 + (V_2 + P_{E2}^W)Q_2 \qquad (3)$$

The price for electricity in the wholesale market is the same for both markets, meaning that the average wholesale electricity cost functions used are the same for both markets 1 and 2:

$$P_{Ei}^{W} = a_0 + a_1 Q_i \qquad (4)$$

where parameters $a_0, a_1 \rangle 0$

Assuming that demand curves are potentially different in both their slope and position, the demand function for electricity in the retail markets is of the form:

$$P_i = b_0^i - b_1^i Q_i \qquad (5)$$

where P_i is the retail price for electricity for market *i*,

and where parameters $b_0^i, b_1^i \rangle 0$

1.2 Serving both markets

For the supplier that supplies both markets, its total revenues will be:

$$TR_i = \sum_{i=1}^{n} P_i Q_i = P_1 Q_1 + P_2 Q_2 \qquad (6)$$

Profits are equal to:

$$\pi_{1,2} = TR - TVC = P_1 Q_1 + P_2 Q_2 - \left[\left(V_1 + P_{E1}^{W}\right)Q_1 + \left(V_2 + P_{E2}^{W}\right)Q_2\right] \qquad (7)$$

Note that we calculate profits with TVC and not with TC, using formula (3) instead of (1).

By substituting equations (4) and (5) into (7) and we have:

$$\pi_{1,2} = (b_0^1 - b_1^1 Q_1)Q_1 + (b_0^2 - b_1^2 Q_2)Q_2 - \left[(V_1 + a_0 + a_1 Q_1)Q_1 + (V_2 + a_0 + a_1 Q_2)Q_2\right]$$

$$\pi_{1,2} = (b_0^1 Q_1 - b_1^1 (Q_1)^2) + (b_0^2 Q_2 - b_1^2 (Q_2)^2) - \left[\left(V_1 Q_1 + a_0 Q_1 + a_1 (Q_1)^2\right) + \left(V_2 Q_2 + a_0 Q_2 + a_1 (Q_2)^2\right)\right]$$

We will refer to the above profit calculating formula for both markets as (8)

1.3 Serving one market

For a supplier supplying only one market the total cost including fixed costs is:

$$TC = F(Q_i) + \left(V_i + P_{Ei}^W\right)Q_i \qquad (9)$$

For a supplier supplying only one market the total variable cost is:

$$TVC = \left(V_i + P_{Ei}^W\right)Q_i \qquad (10)$$

The total revenue of that supplier is

$$TR = P_i Q_i \qquad (11)$$

We are trying to find where the profits are maximized for one market, without using fixed costs, and using (10) and (11), we get:

$$\pi_i = TR - TVC = P_i Q_i - \left[\left(V_i + P_{E1}^W\right)Q_i\right] \qquad (12)$$

Substituting (4) and (5) in (12), that becomes:

$$\pi_i = (b_0^i - b_1^i Q_i)Q_i - \left[(V_i + a_0 + a_1 Q_i)Q_i\right] = b_0^i Q_i - b_1^i (Q_i)^2 - [(V_i Q_i + a_0 Q_i + a_1 (Q_i)^2]$$

(13)

so in order to derive first order conditions, we set $\frac{\partial \pi_i}{\partial Q_i} = 0$ for (13) and we get:

$$\frac{\partial \pi_i}{\partial Q_i} = b_0^i - 2b_1^i Q_i - [V_i + a_0 + 2a_1 Q_i] = 0 \qquad (14)$$

So, we have:

$$b_0^i - V_i - a_0 = 2b_1^i Q_i + 2a_1 Q_i \qquad (15)$$

The quantity[1] for which we have maximum profits is:

$$Q_i^* = \frac{b_0^i - V_i - a_0}{2b_1^i + 2a_1} \qquad (16)$$

These are maximum profits because by taking the second order conditions for (13), and given that $a_1, b_1^i \rangle 0$:

$$\frac{\partial^2 \pi_i}{\partial Q_i^{\ 2}} = -2b_1^i - 2a_1 \langle 0 \qquad (17)$$

1.4 Observations

So these quantities are profit maximizing for the case where there is no price cap in the market. Also these refer to the case the where fixed cost is sunk (there is no fixed cost to consider) and there is no capacity constraint. These are the quantities that a profit maximising monopolist would choose to supply.

---

[1] The profit maximizing quantity Q_i^* that is calculated here is introduced in the diagrams as quantity Q_1.

It is worth noting that Q_i^* in (16) has been calculated using the profit equation (13) that refers to the supplier that participates in one market only. Nevertheless, the profit maximising quantity in each market does not change if the supplier elects to supply both markets. That is so because of the assumption that these two markets do not coexist in the same time. If output in one market affected the other, such as would be the case if the markets coexisted in the same time, we would need to consider the issue of available capacity, meaning that (2) would have to become:

$$\overline{F} \geq F \max(Q_1^t + Q_2^t) \forall t \qquad (18)$$

In (18), t represents time periods.

If multiple markets *n* coexist in the same time, then the cost of wholesale electricity is affected by the amount of electricity supplied in all of them. That means that in this case, (4) becomes:

$$P_{Ei}^W = a_0 + a_1 \sum_{i=1}^{n} Q_i \qquad (19)$$

In (19), we get the cost of wholesale electricity when supplying all of the *n* markets. However, for markets that do not coexist in the same time, the cost of wholesale electricity is calculated by (4).

When profit maximizing, fixed costs are not included in the formula that determines the profit maximizing quantity despite the fact that these costs factor in the determination of output. Even if we used formula (9) instead of (10) when calculating (12), fixed costs would not have changed the profit maximizing quantity, since when applying first order conditions, these would have been removed.

Since Q_i^* is positive (because it is a quantity), given that $a_1, b_1^i \rangle 0$, we conclude that $b_0^i - V_i - a_0 \rangle 0$ which can also be written as $b_0^i \rangle V_i + a_0$. That means that in order for profit maximization to be possible, the intercept of the demand curve on the price axis should be above the level of the intercept of the MVC curve. That would make sense anyway, since if that was not true, there would be no market for the supplier to make any profits whatsoever, since there would be no output for which it would be that $P \rangle AVC$. So the profit maximising quantity for the supplier would be at zero output. The MVC curve that we mentioned is calculated below.

According to (10), we have $TVC = (V_i + P_{Ei}^W)Q_i$

By substituting (4) in it we get $TVC = (V_i + a_0 + a_1 Q_i)Q_i = V_i Q_i + a_0 Q_i + a_1 (Q_i)^2$ (20)

The MVC is calculated by differentiating TVC

$$MVC = \frac{\partial TVC}{\partial Q_i} = V_i + a_0 + 2a_1 Q_i \qquad (21)$$

For $Q_i = 0$ that we get at the point where MVC intercepts the price axis, we have $MVC = V_i + a_0$

1.5 Profit maximization

The profit maximising prices are calculated using the inverted demand function of (5):

$$P_i = b_0^i - b_1^i Q_i \qquad (22)$$

So, we substitute (16) to this expression and we obtain the profit maximizing prices for market *i*:

$$P_i^* = b_0^i - b_1^i [\frac{b_0^i - V_i - a_0}{2b_1^i + 2a_1}] \qquad (23)$$

Maximum profits are calculated by substituting the profit maximising quantities in the profits equations (8) and (13) that we calculated earlier.

$$\pi_{1,2} = (b_0^1 Q_1 - b_1^1 (Q_1)^2) + (b_0^2 Q_2 - b_1^2 (Q_2)^2) - \left[\left(V_1 Q_1 + a_0 Q_1 + a_1 (Q_1)^2\right) + \left(V_2 Q_2 + a_0 Q_2 + a_1 (Q_2)^2\right)\right]$$
(8)

$$\pi_i = b_0^i Q_i - b_1^i (Q_i)^2 - [(V_i Q_i + a_0 Q_i + a_1 (Q_i)^2] \qquad (13)$$

As we can see, we can obtain (13) through (8) by considering participation only in one market by setting the quantity of the other market equal to zero.

The maximum profits that can be made are show below.

When the firm operates in both markets:

$$\pi_{1,2}^* = (b_0^1 Q_1^* - b_1^1 (Q_1^*)^2) + (b_0^2 Q_2^* - b_1^2 (Q_2^*)^2) - \left[\left(V_1 Q_1^* + a_0 Q_1^* + a_1 (Q_1^*)^2\right) + \left(V_2 Q_2^* + a_0 Q_2^* + a_1 (Q_2^*)^2\right)\right]$$
(24)

where Q_1^* and Q_2^* are the quantities calculated by (16).

When being in only one market:

$$\pi_i^* = (b_0^i Q_i^* - b_1^i (Q_i^*)^2) - \left[\left(V_i Q_i^* + a_0 Q_i^* + a_1 (Q_i^*)^2\right)\right] \qquad (25)$$

$$\pi_i^* = [b_0^i - V_i - a_0 - (a_1 + b_1^i) Q_i^*] Q_i^* \qquad (26)$$

where Q_i^* is the quantity calculated by (16).

Using the general form of (16), we get:

$$\pi_i^* = [b_0^i - V_i - a_0 - (a_1 + b_1^i)\frac{b_0^i - V_i - a_0}{2(a_1 + b_1^i)}][\frac{b_0^i - V_i - a_0}{2(a_1 + b_1^i)}]$$

$$\pi_i^* = [\frac{b_0^i - V_i - a_0}{2}][\frac{b_0^i - V_i - a_0}{2(a_1 + b_1^i)}]$$

$$\pi_i^* = \frac{(b_0^i - V_i - a_0)^2}{4(a_1 + b_1^i)} \tag{27}$$

By substituting the profit maximizing quantities given by (16) into (8) and (13), we determined maximum profits both for the case of supplying one market and for the case of supplying both. These maximum profits refer to the case where the supplier can enter the market and supply the whole quantity that he chooses to without having to build additional capacity. Should such a requirement exist, the profit maximizing outputs will remain unaffected as we discussed earlier, however the actual profits are going to be decreased by the expenditures for capacity building.

Part 2

Comparative Statics

Using the result for the profit maximizing quantity, and taking into consideration that the value of the quantity has a positive sign, we get the profit maximising output:

$$Q_i^* = \frac{b_0^i - V_i - a_0}{2b_1^i + 2a_1} \rangle 0 \qquad (16)$$

Also, given that $a_1, b_1^i \rangle 0$, we conclude that $2b_1^i + 2a_1 \rangle 0$, so that using equation (16), we get that $b_0^i - V_i - a_0 \rangle 0$.

At this point, we can explore the comparative statics of the profit maximizing quantities that we calculated above. In that way, we will be able to determine how changes in other variables affect the profit maximizing quantity. We will be looking at the comparative statics analysis in one market. For illustration purposes, we can use Diagram 3.1 as reference.

In our comparative statics analysis, we will partially differentiate formulas (16) with respect to all its determinants, one at a time.

2.1 First factor

In the partial differentiation of (16) with respect to b_0^i, we have:

$$\frac{\partial Q_i^*}{\partial b_0^i} = \frac{1}{2b_1^i + 2a_1} \rangle 0 \qquad (28)$$

This implies that when b_0^i increases, the profit maximizing quantity increases. That can be interpreted as a statement that when we have larger markets with larger demand, the profit maximizing output is larger.

Diagrammatically, in Diagram 3.1, when b_0^i increases, then the point of interception of the demand curve on the price axis moves upwards and we have a rightward shift of the demand curve. Along with that, the marginal revenue (MR) curve also moves to the right. So, the point where we have MC=MR also moves to the right and the profit maximizing quantity Q_i^* increases.

2.2 Second factor

In the partial differentiation of (16) with respect to V_i, we have:

$$\frac{\partial Q_i^*}{\partial V_i} = -\frac{1}{2b_1^i + 2a_1} \langle 0 \qquad (29)$$

This implies that when V_i increases, the profit maximizing quantity decreases. That can be interpreted as a statement that when a part of the average variable cost increases (V_i does not include the cost of wholesale electricity), the profit maximizing output decreases. Also, when the marginal variable cost increases (V_i determines MVC according to (21)), profit maximizing output decreases.

Diagrammatically, in Diagram 3.1, when V_i increases the MVC curve also moves upwards. As a result, the point where we have MVC=MR moves to the left and the profit maximizing quantity Q_i^* decreases.

2.3 Third factor

In the partial differentiation of (16) with respect to a_0, we have:

$$\frac{\partial Q_i^*}{\partial a_0} = -\frac{1}{2b_1^i + 2a_1} \langle 0 \qquad (30)$$

This implies that when a_0 increases, the profit maximizing quantity decreases. That can be interpreted as a statement that when a part of the average variable cost increases (we are saying so because an increase in a_0 means that there is an increase in the average cost of wholesale electricity), the profit maximizing output decreases. Also, when the marginal variable cost increases (a_0 determines MVC according to (21)), profit maximizing output decreases.

Diagrammatically, in Diagram 3.1, when a_0 increases we have higher cost of wholesale electricity and as a result the MVC curve moves upwards. This implies that the point where we have MVC=MR moves to the left and the profit maximizing quantity Q_i^* decreases.

2.4 Fourth factor

In the partial differentiation of (16) with respect to b_1^i, we have:

$$\frac{\partial Q_i^*}{\partial b_1^i} = -\frac{2(b_0^i - V_i - a_0)}{(2b_1^i + 2a_1)^2} \langle 0 \qquad (31)$$

This implies that when b_1^i increases, the profit maximizing quantity decreases. That can be interpreted as a statement that when we have smaller markets with smaller demand, the profit maximizing output is smaller.

Diagrammatically, in Diagram 3.1, when b_1^i increases the demand curve gets steeper and pivots around the point where it intersects the price axis. The same happens for the MR curve and as a result, we have a new MR curve which is to the left of the initial one. So, the point where we have MVC=MR also moves to the left and the profit maximizing quantity Q_i^* decreases.

2.5 Fifth factor

In the partial differentiation of (16) with respect to a_1, we have:

$$\frac{\partial Q_i^*}{\partial a_1} = -\frac{2(b_0^i - V_i - a_0)}{(2b_1^i + 2a_1)^2} \langle 0 \qquad (32)$$

This implies that when a_1 increases, the profit maximizing quantity decreases. That can be interpreted as a statement that when a part of the average variable cost increases (we are saying so because an increase in a_1 means that there is an increase in the average cost of wholesale electricity), the profit maximizing output decreases. Also, when the marginal variable cost increases (a_1 determines MVC according to (21)), profit maximizing output decreases

When a_1 increases, we have higher average cost of wholesale electricity and the slope of the supply curve for wholesale electricity (it is not show separately in Diagram 3.1) pivots anticlockwise around its point where quantity supplied is zero, thereby affecting the slopes of the AVC and the MVC curves in a similar way (a_1 determines MVC according to (21)). So, the point where we have MVC=MR moves to the left and the profit maximizing quantity Q_i^* decreases.

Part 3

Introduction of the price cap algebraically

3.1 Setting the price caps

If we introduce a price cap PC, a restriction is added. That is:

$$P_i \leq PC_i \ , \qquad (33)$$

That would not affect the demand for quantities exceeding Q_0, where Q_0 is the quantity corresponding to the point where the price cap and the demand curve intersect (the point where the demand curve "kinks" after the introduction of the price cap). By substituting to the initial demand function (5), we have:

$$P_i = b_0^i - b_1^i Q_i \leq PC_i$$

and $Q_i \geq \dfrac{b_0^i - PC_i}{b_1^i}$ (34)

What we get from (34), is that the introduction of the price cap established a minimum quantity for the market when demand is fully met. This quantity is quantity Q_0 and is set after the form: $Q_0 = \dfrac{b_0^i - PC_i}{b_1^i}$ (35)

After the price cap has been imposed, the market will only demand quantities equal or larger than Q_0. For the price cap to have an effect on the market, it should be that with prices set at the price cap level, the quantity for which the supplier maximizes profits in the unconstrained case, Q_i^*, should be lower than Q_0. That is, $Q_i^* \langle Q_0$. If $Q_i^* \rangle Q_0$, then the price cap leaves the market unaffected.

In terms of prices, for the price cap to have an impact on the market, we require that the price that the supplier would want to charge in order to maximize profits, should be larger than the price cap, that is $P_i^* \rangle PC_i$.

From equation (23), we get that the profit maximizing price is $P_i^* = b_0^i - b_1^i [\frac{b_0^i - V_i - a_0}{2b_1^i + 2a_1}]$

.

Combining (33) and (23), we get that for the price cap to have an impact on the market, we should have $PC_i \langle b_0^i - b_1^i [\frac{b_0^i - V_i - a_0}{2b_1^i + 2a_1}]$ (36)

3.2 Price cap and profit maximization

By substituting the profit maximizing quantity of the unconstrained case (16) into the quantity restriction under the price cap when the market demand is met (34), we get to see the ranges that the price cap should take in order to allow to the supplier to make the maximum profits of the unconstrained case:

$$\frac{b_0^i - V_i - a_0}{2b_1^i + 2a_1} \geq \frac{b_0^i - PC_i}{b_1^i} \qquad (37)$$

and by solving for PC_i

$$PC_i \geq -\left[\frac{b_0^i - V_i - a_0}{2b_1^i + 2a_1}\right] b_1^i + b_0^i \qquad (38)$$

So, if the price cap is set to a level that satisfies the above condition, the monopolist can make maximum profits in market *i* equal to those of the unconstrained case (see also Diagram 3.3a). That is consistent with the conclusion from examining diagram 3.7 that the monopolist can be restricted from making profits equal to these of the unconstrained case, because of the existence of the price cap, when that is set within certain ranges.

3.3 Supplier supplying for the maximum allowed price

As we have seen in Diagrams 3.3a, 3.3b and 3.3c, the price cap can either not affect the price and the outcome in the market (Diagram 3.3a), or it might do so (Diagrams 3.3b and 3.3c). In the case of the diagram 3.3b, the supplier sets prices equal to PC_i and quantity equal to Q_0, meeting the market demand.

In the case of diagram 3.3c, the price in market is set by the supplier to be equal to $P_0 = PC_i$ (equal to the price cap), and the quantity is set at Q_i^{PC} which leads to the maximum profits that this constrained case allows to be made. Maximum profits for price equal to PC_i can be calculated as below (these correspond to the point where MVC cuts PC_i and do not take fixed cost into account). We are using (12) and (4) and we substitute PC_i as the price.

$$\pi_i^{PC} = TR - TVC = PC_i Q_i^{PC} - (V_i + P_{Ei}^W) Q_i^{PC} \qquad (39)$$

$$\pi_i^{PC} = PC_i Q_i^{PC} - V_i Q_i^{PC} - P_{Ei}^W Q_i^{PC}$$

$$\pi_i^{PC} = PC_i Q_i^{PC} - V_i Q_i^{PC} - (a_0 + a_1 Q_i^{PC}) Q_i^{PC}$$

$$\pi_i^{PC} = PC_i Q_i^{PC} - V_i Q_i^{PC} - a_0 Q_i^{PC} - a_1 (Q_i^{PC})^2 \qquad (40)$$

In order to determine maximum profits, we set first order conditions:

$$\frac{\partial \pi_i^{PC}}{\partial Q_i^{PC}} = 0$$

We calculate $\frac{\partial \pi_i^{PC}}{\partial Q_i^{PC}} = PC_i - V_i - a_0 - 2a_1 Q_i^{PC}$ (41)

And by setting equal to 0, we get:

$$\frac{\partial \pi_i^{PC}}{\partial Q_i^{PC}} = PC_i - V_i - a_0 - 2a_1 Q_i^{PC} = 0 \qquad (42)$$

So the profit maximizing quantity in the presence of the price cap is

$$Q_i^{PC} = \frac{PC_i - V_i - a_0}{2a_1} \qquad (43)$$

We know that this is a profit maximizing quantity because, given that $a_1 \rangle 0$, we get from our second order conditions:

$$\frac{\partial^2 \pi_i^{PC}}{\partial (Q_i^{PC})^2} = -2a_1 \langle 0 \qquad (44)$$

In Diagram 3.3c, the monopolist will not want to meet the market demand, since by doing so he would not be getting the maximum profits of the constrained market. This case occurs when at level of output Q_0, we have $MVC \rangle PC_i$. What the supplier wants to do is produce the output that corresponds to the point where $MVC = P_0 = PC_i$.

Also, we notice (see Diagrams 3.3a and 3.3b) that when at the level of output Q_0 we have $PC_i = P_0 \rangle MVC$, the monopolist will want to supply the whole market demand, since that leads to the maximum profits of the constrained case.

3.4 Price caps and quantities supplied

We consider two cases:

$Q_i^{PC} \langle Q_0$ or $Q_i^{PC} \geq Q_0$

Q_0 is the quantity that the market demands when the market price is set at P_0 (which is the price cap on the diagrams where we have only one price cap). Q_i^{PC} is the profit maximising quantity of the constrained case and therefore it is the quantity that the supplier wishes to supply, given the existence of the price cap.

3.4.1 First case

For the first case, we get $Q_i^{PC} \langle Q_0$ (45)

This is a case such as the one illustrated in diagram 3.3c, where the supplier does not want to meet the market demand.

Substituting (43) in (45), we get:

$$\frac{PC_i - V_i - a_0}{2a_1} \langle Q_0 \qquad (46)$$

We replace $P_i = PC_i$ in (5) and we solve for Q_i.

$$PC_i = b_0^i - b_1^i Q_i$$

$$Q_i = \frac{b_0^i - PC_i}{b_1^i} \qquad (47)$$

Since the price is set by the price cap, the market demand will be asking for quantity $Q_i = Q_0$ So, (47) becomes:

$$Q_0 = \frac{b_0^i - PC_i}{b_1^i} \qquad (48)$$

Substituting in (46), we get:

$$\frac{PC_i - V_i - a_0}{2a_1} \langle \frac{b_0^i - PC_i}{b_1^i} \qquad (49)$$

Solving for PC_i we get:

$$PC_i \langle \frac{b_1^i (V_1 + a_0) + 2a_1 b_0^i}{2a_1 + b_1^i} \qquad (50)$$

That is the condition that derives the level of the price cap in order for the supplier not to want to meet the market demand. The above borderline price is price P_2 in the diagrams.

3.4.2 Second case

Similarly, the condition for which the supplier will want to meet the market demand would be $Q_i^{PC} \geq Q_0$ (51)

and that would in exactly the similar manner lead to the condition:

$$PC_i \geq \frac{b_1^i (V_1 + a_0) + 2a_1 b_0^i}{2a_1 + b_1^i} \qquad (52)$$

This is a case such as those illustrated in diagrams 3.3a and 3.3b, where the supplier wants to meet the market demand and that exactly is what the condition for the price cap shows us.

3.4.3 Price cap ranges

If we have $P_0 \geq P_1$ as is the case in diagram 3.3a, then the firm sets its price at P_1 which is the price that leads to maximum profits in the unconstrained case and meets the market demand at that price.

If $P_1 \geq P_0 \geq P_2$, P_2 being the price where MVC and demand curves intersect, as is the case in diagram 3.3b, then the supplier wants to meet the demand and the output is constrained by the demand curve. The profits made are the maximum profits of the constrained case.

For cases where $P_0 \langle P_2$, as is the case in diagram 3.3c, the supplier does not want to meet demand.

3.5 Calculating quantities in the presence of the price cap

In diagram 3.3b, the retail price is set by the supplier to be equal to PC_i, and the supplier maximizes profits by supplying the quantity that corresponds to market demand. The supplier makes the maximum profits of the unconstrained case for quantity $Q_0 = Q_i^{PC}$ calculated below.

Since $P_i = PC_i$, and $Q_i = Q_i^{PC}$, (5) becomes

$$PC_i = b_0^i - b_1^i Q_i^{PC} \qquad (53)$$

and we also know from equation (16) that we have maximum profits for $Q_i^* = \dfrac{b_0^i - V_i - a_0}{2b_1^i + 2a_1}$

We substitute $b_0^i = PC_i + b_1^i Q_i^{PC}$ that we get from (53), into (16) and we get this relationship providing us with Q_i^{PC}, the profit maximizing quantity in the constrained case (that is, in the presence of the price cap).

$$Q_i^{PC} = \frac{PC_i + b_1^i Q_i^{PC} - V_i - a_0}{2b_1^i + 2a_1} \qquad (54)$$

Solving for Q_i^{PC}, we get:

$$Q_i^{PC} = \frac{PC_i - V_i - a_0}{2b_1^i + 2a_1 - b_1^i} \qquad (55)$$

$$Q_i^{PC} = \frac{PC_i - V_i - a_0}{b_1^i + 2a_1}$$

This Q_i^{PC} is exactly the same as the one calculated earlier as $Q_i^{PC} = \frac{PC_i - V_i - a_0}{2a_1}$ in (43).

Part 4

Presenting the obligation to meet the market demand algebraically

4.1 Ranges of price caps

If we introduce an obligation to meet the market demand in the presence of the price cap. The quantity Q_i^{PC} that we will refer to is the profit maximizing quantity of the constrained case. That means that Q_i^{PC} is the quantity that the supplier would wish to supply for price equal to price cap P_0. The quantity Q_0 is the level of output that the market demands when price is set at P_0.

For $Q_i^{PC} \leq Q_0$, the quantity that the supplier is forced to supply becomes Q_0 and the price is $P_i = PC_i = P_0$, such as is the case shown in Diagrams 3.3b and 3.3c.

For $Q_i^{PC} \rangle Q_0$, the quantity that the supplier wishes to supply is larger than the one that he is obliged to supply. Therefore, the quantity supplied remains unaffected by the introduction of the obligation to meet the market. The quantity that the market is supplied with is actually Q_i^* and the supplier receives the maximum profits of the unconstrained case. The price in the market is $P_i = P_1 = b_0^i - b_1^i Q_i^*$. That is the case where the price cap is set too high to affect the market, such as is the case in Diagram 3.3a.

Discussing that matter from the viewpoint of price, we can say that if the price cap is set higher than P_i^* (P_1 in the diagrams), so that we have $PC_i \rangle P_i^*$, then the price cap will not be affecting the market and the supplier will be supplying its profit maximizing quantity. The price will be $PC_i = P_i^* = b_0^i - b_1^i Q_i^*$.

If the price cap is set in the range $P_0 \langle PC_i \langle P_i^*$ then the supplier wants to meet the market demand and sets price at $PC_i = P_0$. Quantity supplied is Q_0 and is determined by the demand curve and will be $Q_0 = \dfrac{b_0^i - P_0}{b_1^i}$. It is also that $Q_0 = Q_i^{PC}$

since that quantity supplied also is the profit maximizing quantity of the constrained case.

If the price cap is set lower than P_2, then the supplier will be selling Q_0 because he will be forced by the obligation to meet the market demand. Knowing Q_0 will allow us to determine profits π_i using form (12).

4.2 Prices on Diagram 3.1

Moving back to Diagram 3.1 we have five significant price levels that we can identify algebraically.

- Price $P_S = b_0^i - b_1^i Q_S = b_0^i$, given that $Q_S = 0$.
- Price $P_1 = b_0^i - b_1^i Q_1$ and given that Q_1 on the diagrams is Q_i^* and P_1 on the diagrams is P_i^* which is given by equation (23), we get:

$$P_i^* = P_1 = b_0^i - b_1^i \frac{b_0^i - V_i - a_0}{2b_1^i + 2a_1}$$

- Price $P_2 = b_0 - b_1 Q_2$ and given that Q_2 on the diagrams is the output where Demand intersects MVC, we get it at the point where:

$$MVC = D$$

The formula for MVC is (21) calculated earlier:

$$MVC = \frac{\partial TVC}{\partial Q_i} = V_i + a_0 + 2a_1 Q_i$$

So, in order to get the point where MVC intersects D, we set $MVC = P_2$ and it becomes:

$$V_1 + a_0 + 2a_1 Q_2 = b_0^i - b_1^i Q_2$$

$$Q_2 = \frac{b_0^i - a_0 - V_1}{2a_1 + b_1^i} \quad (56)$$

$$P_2 = b_0^i - b_1^i [\frac{b_0^i - a_0 - V_1}{2a_1 + b_1^i}] \quad (57)$$

- In order to determine price P_A , where the supplier makes zero profits, we need to get the point where AVC intersects D. In that way, we will determine the point on AVC that corresponds to price level P_A.

We have $P_A = AVC = P_{Ei}^W + V_i = a_0 + a_1 Q_A + V_i$ (58)

We solve (58) for Q_A and we get $Q_A = \frac{P_A - a_0 - V_i}{a_1}$ (59)

From the demand curve function (5) we get $P_A = b_0^i - b_1^i Q_A$ meaning that $Q_A = \frac{b_0^i - P_A}{b_1^i}$.

Substituting in (59), we get $\frac{b_0^i - P_A}{b_1^i} = \frac{P_A - a_0 - V_i}{a_1}$ (60)

Solving for P_A, we get:

$$P_A = \frac{a_0 b_1^i + a_1 b_0^i + V_i b_1^i}{a_1 + b_1^i} \quad (61)$$

Knowing the rest of the parameters, we can calculate P_A and using (59) we can also calculate Q_A.

- Price P_3 is set at the point where MVC intersects the price axis, so we can get it through (21) by setting $Q_3 = 0$.

$$P_3 = MVC = \frac{\partial TVC}{\partial Q_i} = V_i + a_0 + 2a_1 Q_3 = V_i + a_0 \quad (62)$$

Appendix D

Part 1

Deviations Marginal Price (DMP) data

1.1 Introduction

The Deviations Marginal Price (DMP) of the Greek wholesale electricity pool is the ex-post determined price for the quantities of electricity that are sold in the wholesale pool, and without having been included in the Dispatch Scheme of each specific day. This is the price that the generators will be paid for any quantity they sell which is additional to what they have been scheduled to generate, and the price that they will pay for any quantity of electricity that they fail to generate, despite being scheduled to. DMP is determined by IPTO [IPTO, 2012a].

We assume that the DMP is affected by the same factors that determine SMP. As mentioned above, we anticipate that some of the most important of them would be: cost of fuels; cost of emission licences; available generation capacity at each fuel generation technology; price and quantity of imported electricity; mandatory use of hydroelectric plants; projected electricity demand; cost of capacity payments; amount of generators and market power. In addition, DMP is expected to be affected by unpredictable events that do not allow to the Dispatch Scheme to be executed.

1.2 Presentation of the DMP data

The Deviation Marginal Price (DMP) data that we have available refer to the time period 01/02/2002-31/10/2011. For that time period we have 24 DMPs for every day, one for each of the 24 dispatch periods of each day. The numbers given to describe each period correspond to the time at the start of each of the one-hour periods. That means that period 0 is between midnight and 1am, period 1 is between 1am and 2am, etc. We have created 24 graphs that describe these data that we have. We have one graph for each of the 24 dispatch periods and in these graphs we plot the 3,543 DMPs (one for each day) for each of the dispatch periods. The period that we examine has 3,560 days, meaning that we are missing data from 17 days. The dates of these missing days are: 15/03/2002-31/03/2002. The DMPs per dispatch period are presented in Graphs 5.400-5.423 which are to be found in Appendix B, Part 3.

In these graphs we can see that in the timelines of DMPs, there are not any obvious seasonality patterns. However, by examining these graphs, we can see that there is a pattern similar to the pattern that we have seen in the SMP data. That was expected since the DMP is the ex-post SMP price of the Greek wholesale market therefore it is expected to be around the area of the SMP of the system for any given period that we examine. However, that does not mean that there is nothing to observe in comparing the DMP graphs one-by-one and the SMP graphs with the DMP graphs as well. DMPs for the different dispatch periods increase and decrease at the same dates, forming loosely similar graphs, however this pattern that they present does not incorporate any seasonality. And these DMP graphs appear to be quite similar to the SMP graphs. Time also seems to be a factor here as the dispatch periods that we previously identified as having a higher demand (dispatch periods 7-22) have higher DMPs.

Using the “Data Analysis” tools of the Microsoft Excel software, we have ranked the DMP data for each dispatch period, in a descending order. Using the ranked data, we counted the frequency of having the DMP set between certain ranges for each dispatch period and we created histograms to present these frequencies. These histograms are showing how many times we observed DMPs within the specific range that each column of the histogram refers to. The ranges have been taken to be 10 euro/MWh wide. The results are presented in Graphs 5.424-5.447 and can be found in Appendix B, Part 3.

We have also graphed all these frequencies together in Graph 5.75, to be found and discussed later in Chapter 5.

1.3 DMP Graphs-Actual Data

Graphs 5.400-5.423 show us what the DMP has been for all the days of the time period that we are discussing. Each of the graphs refers to one specific dispatch period. In these graphs, the data start from day 133, instead of day 1, in an effort to coordinate them with the system load and SMP data that start from earlier dates. Graphs 5.400-5.423 are to be found in Appendix B, Part 3.

Observing these graphs, we cannot identify any periodical pattern in the DMP. However, we observe that all the diagrams that we have follow a certain non-periodical pattern. As we move from the one dispatch period to another, the shape of the timeline remains roughly similar and it adjusts upwards or downwards depending on the hour of the day. This pattern is visible in all the graphs and regardless of the fact that the system loads are different for different dispatch periods, the seasonality pattern remains. In Graphs 5.400-5.406 we can see that the line of the DMP is quite "clear", indicating that there is relatively small volatility in the DMPs. That can be due to the fact that these dispatch periods are late night dispatch periods.

The important issue is to identify what the changing levels of volatility throughout the day mean to the electricity system and what they mean to the participants in the wholesale market, both to the generators and to the suppliers. These prices should always be considered together with the SMP as these define the profitability of the market participants. The existence of the DMP and its level is connected with the accuracy of the projections about the system load that have been used to determine the SMP in the Day-ahead market, the system load at these specific dispatch periods, the availability of generating plants, the technical specifications of the system and the bids that are submitted in the electricity pool for each dispatch period. These bids incorporate, as we have mentioned earlier, a variety of elements, such as the cost of fuel, the depreciation of the units, the avoidable and non-avoidable cost of operation and the bidding strategy that the generators are using.

The annual seasonality pattern that was evident in the system load data does not appear in the DMP data, in the same way that it was not present in the SMP data. That means that although system load apparently plays a role, this role is not significantly large to make its effect visible as it is always combined with the operation costs of the electricity generation plants. However, we can assume that whichever factors are determining the pattern of the SMP are also affecting the pattern of the DMP, since they appear to be similar.

By looking at the line that is formed across all the graphs we can see that there are 2 “peak zones”. These are from May 2006 to May 2009 and from May 2009 until the end of October 2011, where our data end. The start of May 2006 is in observation 1,666 and start of May 2009 is in observation 2,762. In some of our graphs these can be very easily identified (Graphs 5.400, 5.409-5.423) whereas in others this is not so clear (Graphs 5.401-5.408).

It is very interesting that certain peaks of the DMPs are to be found on all graphs. Peaks like these could also be seen in the extended period 13/1/2005-02/12/2005 (observations 1,193-1,516). We also have the peak of the period 20/06/2011-29/06/2011 (observations 3,542-3,551) where DMP reaches as high as 150 euros/MWh. That specific time period is more extensively discussed elsewhere. However it is important to note that this increase was due to a PPC strike and to the non-availability of a number of electricity generating plants. This result therefore indicates how large the impact of a strike in the incumbent firm can be for the whole market, as well as how strong is the Union of PPC workers.

These peaks are mentioned because they can be very easily identified in most graphs and because these seem to be caused by different mechanisms than the intra-day activities of the electricity market. This means that there were some factors that played a role during these specific dates that increased DMP across all dispatch periods. When discussing what these factors could potentially be, it is important to note the level of the SMP during each of these days.

There are other peaks that we can identify, but these are not evident consistently in all graphs, thus suggesting that these are created by the effect of intra-day activities.

We also observe that DMP is relatively stable from the beginning of our data until the start of January 2005 (observation 1,181) and it experiences large volatility until the beginning of December 2005 (observation 1,515). From May 2006 (observation 1,666) and onwards we experience an increase in the DMP which peaks in the last six months of 2008 (observations 2,458-2,641) and then it starts decreasing from that point on until the end of February 2009 (observation 2,700) where it reaches a trough. From that point and until the end of our data (31/10/2011) we get an increasing trend in DMP.

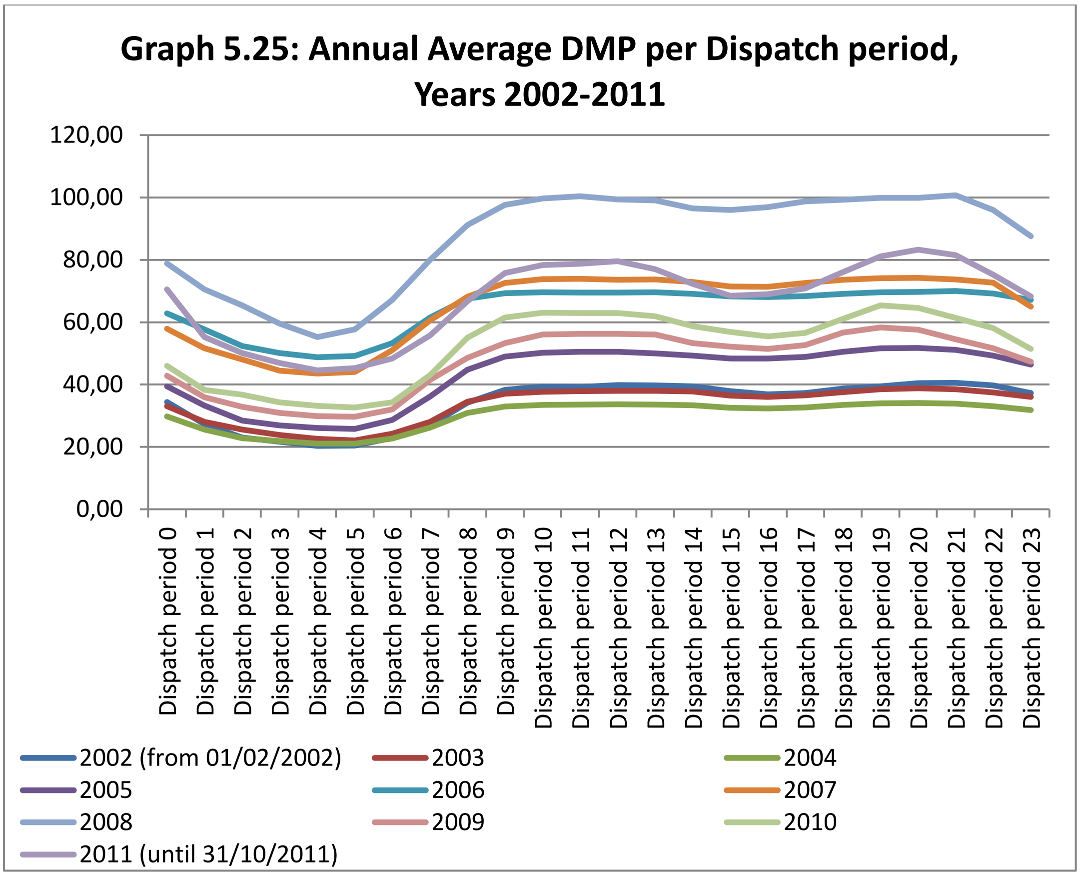
A suggestion that can be made at this point is that the wholesale electricity prices are following fossil fuel prices. That could be the case because the wholesale price is set by the highest bid that is accepted in each dispatch period. That price can sometimes be the result of strategic bidding behaviour. However, regardless of the existence or not of market power in the wholesale electricity market, the submitted bids in it are always dependent on the variable cost of electricity generation, which they are expected to cover. Specifically in the Greek electricity market there are minimum bids that the generators cannot bid lower than, and these are equal to the minimum variable cost for thermal units and equal to the variable cost for hydroelectric units [OOEM, 2012e, p. 70]. The bidders are anyhow expected to set their bids in such a way that these would cover the short-run avoidable cost of electricity generation, which is a cost that covers at least the cost of fuel. As a result we would expect the cost of fuel to be strongly influencing SMPs and DMPs.

1.4 DMP Graphs-Calculated averages

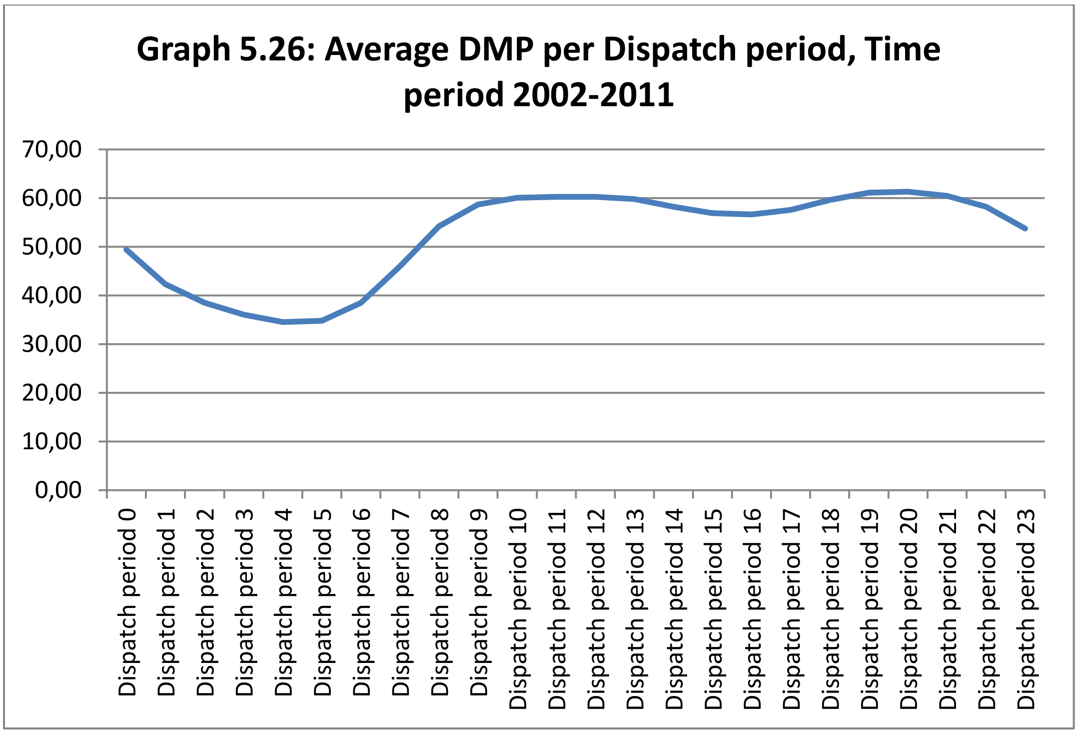
In Graph 5.25 we can see the DMP per dispatch period for every one of the years that we are looking at. We observe that there seems to be an intra-day pattern that is somewhat consistent throughout the years. As we discussed previously when referring to system load data and SMP data, there is an intra-day seasonality pattern for system load and SMP in the Greek electricity market. This pattern seems to be present in DMP as well.

However, this pattern does seem to evolve from year to year. By comparing the different lines in Graph 5.25 we realize that it is not only the level of the DMP that varies (some years having significantly higher DMP than others), but also the pattern over the dispatch periods. These pattern changes mainly refer to the dispatch periods 13-20. In the discussion of system load, these periods have been previously identified as being periods during the day where there is a small decrease in system load. However, in certain years there is a decrease of the SMP and DMP during that time period and in other years there isn't. Examining dispatch periods 13-20, there is no decrease in the SMP for years 2002-2007. From 2008, we can identify a pattern where the SMP decreases during the periods 13-20 and that decrease becomes larger as we go through the years up until 2011. This can be perceived as being the effect of increased competition in the wholesale pool, forcing the price to adjust to the intra-day system load pattern. That occurs because within any given day, the other factors that determine pool prices are relatively stable, thereby allowing for the effect of system load to become evident.

The second thing that we observe in Graph 5.25 is that the DMP levels are changing as the years pass. All of the averages that we see separately in 5.25 are averaged together to create Graph 5.26.



Graph 5.25: Annual Average DMP per Dispatch period, Years 2002-2011
120,00
100,00
80,00
60,00
40,00
20,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
Dispatch period 17
Dispatch period 18
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)



Graph 5.26: Average DMP per Dispatch period, Time period 2002-2011
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
Dispatch period 0
Dispatch period 1
Dispatch period 2
Dispatch period 3
Dispatch period 4
Dispatch period 5
Dispatch period 6
Dispatch period 7
Dispatch period 8
Dispatch period 9
Dispatch period 10
Dispatch period 11
Dispatch period 12
Dispatch period 13
Dispatch period 14
Dispatch period 15
Dispatch period 16
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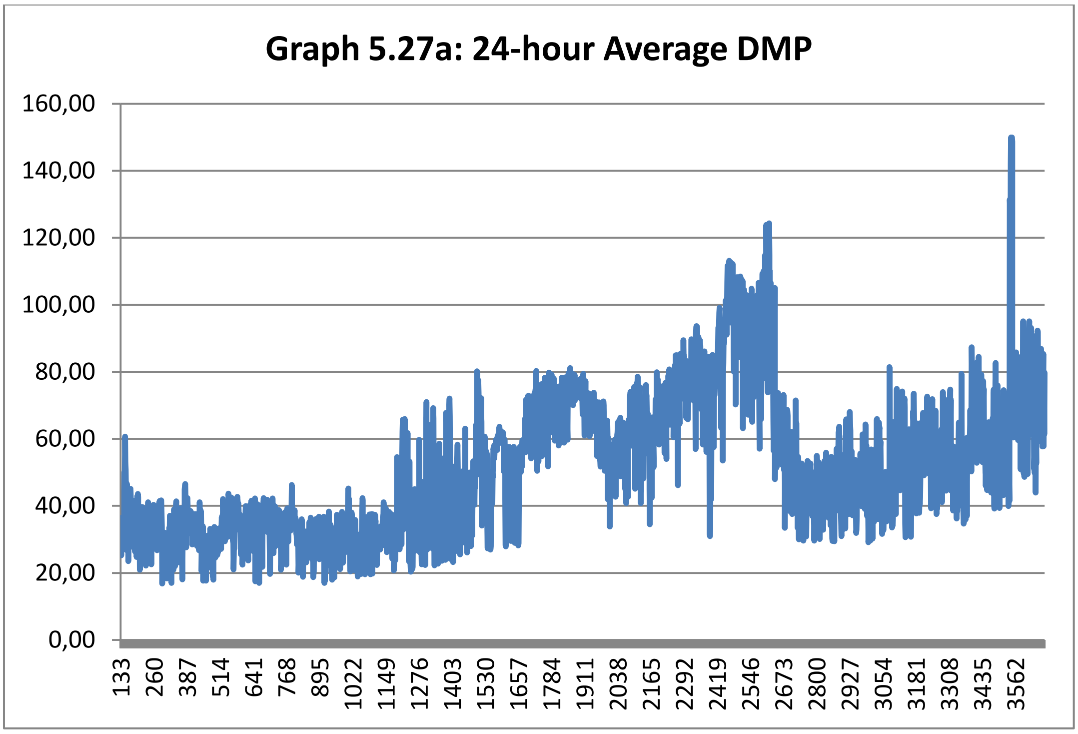
Dispatch period 19
Dispatch period 20
Dispatch period 21
Dispatch period 22
Dispatch period 23



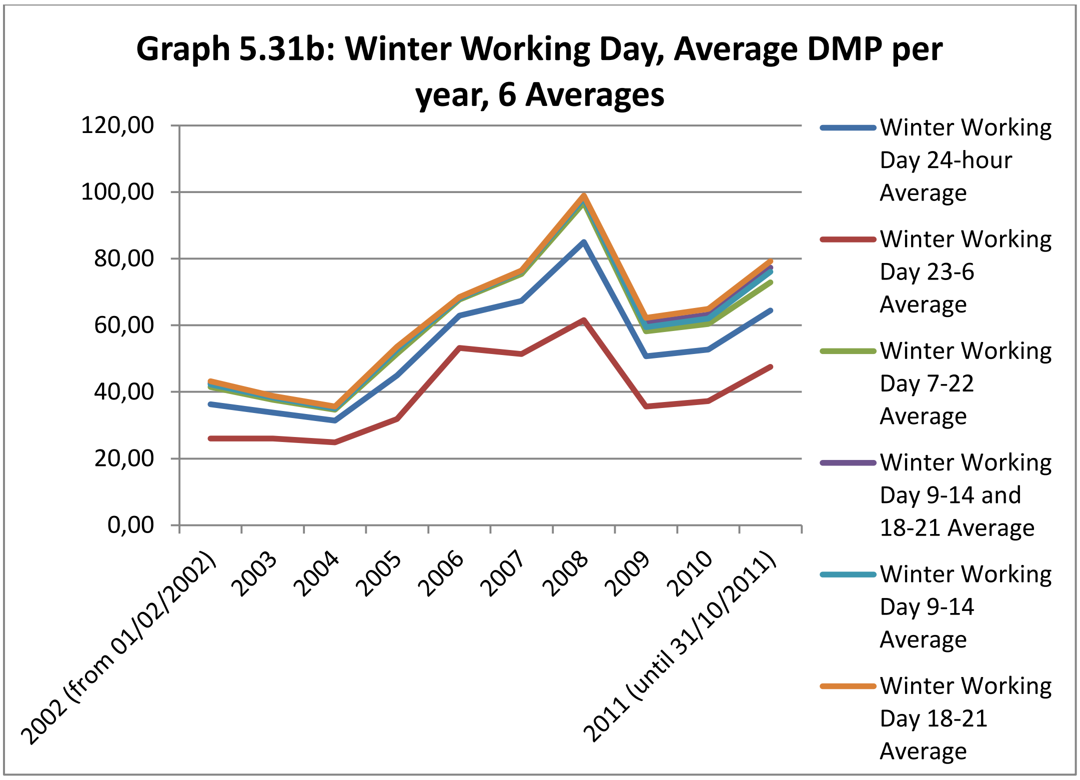
Graph 5.27a has been created by averaging all of the Graphs 5.400-5.423. In that case, the effect of the factors that determine the DMP during peak demand periods is not very strong, however we can still observe that the "DMP pattern" that is incorporated in the data sets that have been used to create this graph. Similarly as was the case with the graphs of the actual data, we experience the same peaks and the same troughs. We can also see how for that specific period there is an increasing trend from May 2007 (observation 2,031) to end of December 2008 (observation 2,641) and a decreasing trend from that point until the end of May 2009 (observation 2,792). We can also see the peak of the summer 2011 (observations 3,543-3,551) and the increased DMPs of the period of September and October 2011 (observations 3,615-3,675).

The "DMP pattern" that we identified in Graph 5.27a can also be seen in Graph 5.28a for the night-time period, in Graph 5.29a for the day-time period and in Graphs 5.30a, 5.30c and 5.30e for the "peak load" periods that we have identified earlier. Graphs 5.28a, 5.29a, 5.30a, 5.30c and 5.30e are to be found in Appendix B, Part 3.

Graph 5.27b incorporates all of these DMP 24-hour averages presented in a year-by-year fashion. That diagram is hard to be used to extract results from since it is very congested with lines. The same happen for Graphs 5.28b (night-time average), 5.29b (day-time average), 5.30b (average for "peak load" period 9-14&18-21), 5.30d (average for "peak-load" period 9-14) and 5.30f (average for "peak-load" period 18-21). All of these graphs are to be found in Appendix B, part 3.

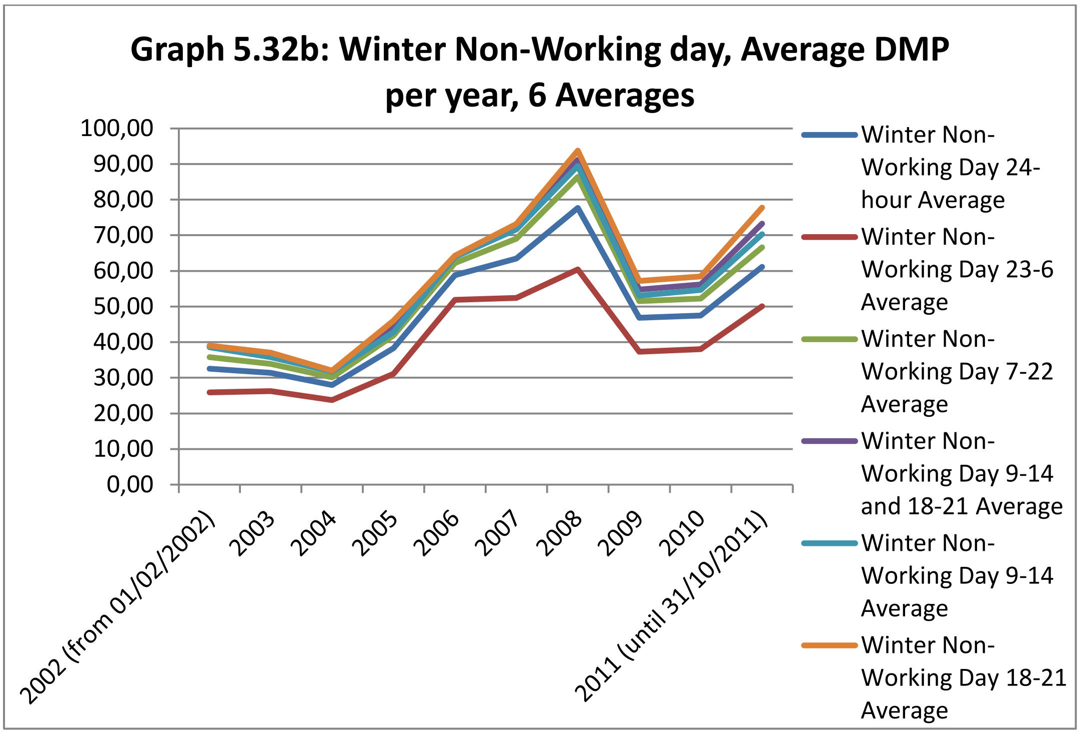
An important observation is that in Graphs 5.27a, 5.28a, 5.29a, 5.30a, 5.30c and 5.30e there are two large periods that we can identify. The one is the early period which is from the start of our data until the area around observation 1,181. Until that point, there are only small variations in the wholesale prices. This reflects the fact that for the period until January 2005 the incumbent is the sole player in the market and there is actually no true competition. In summer 2004, we have the introduction of the first independently owned natural gas fired unit ([Iliadou, 2009], [DEPA, 2012]) and that seems to have affected the market DMP. Also we can see that the price level in the first period of our data is never achieved later. We can assume that this is in part due to the level of fossil fuel prices and to inflation but also to the fact that from that point onward, the market structure changes and its operation is conducted on an entirely different basis.

In Graphs 5.31a, 5.32a, 5.33a and 5.34a we present the annual average DMP per dispatch period for each of the Average Days, creating an "DMP profile" per year and per Average Day. These four graphs indicate that DMP tends to be lower during the night-time hours (dispatch periods 0-6 and 23) as opposed to day-time hours (dispatch periods 7-22). These graphs are to be found in Appendix B, Part 3.



Graph 5.31b presents 6 different averages for the Average Winter Working Day, reporting one DMP for each of the averages for each year. In these averages we can see how, for all 6 of the averages, the DMP decreases from 2002 to 2004, then increases from 2004 to 2008 (except for the night-time average that decreases in 2006), decreases from 2008 to 2009 and increases again in 2010 and 2011. So we show that there is a specific effect that each year has on DMP which is visible in all of the averages, signaling the fact that the year under discussion is always relevant to the level of DMP in the wholesale electricity pool. We can also see that we get lower average night-time (23-6) DMPs, then the averages for the 24-hour period, then even higher for the dispatch periods during the day (7-22) and the highest are those of the three “high demand” periods (9-14, 18-21 and then both of them together). The day-time averages and the “high demand” ones seem to be almost identical. Some small differences are noted in the period 2009-2011. During that period, from the three “high demand” averages, the highest one is the winter afternoon (18-21) average. In the winter, as we discussed in the system load

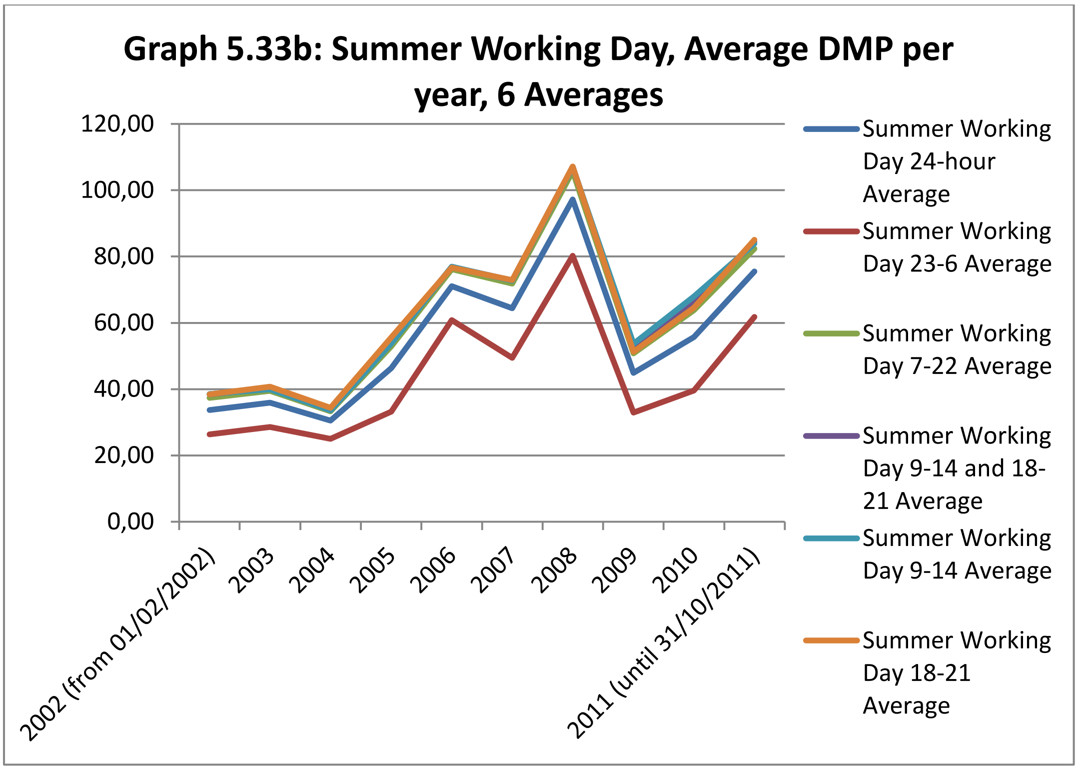
section, electricity demand is higher in the afternoon than it is in the morning and that has an effect on the determination of the SMP and the DMP. The morning average (9-14) is the lowest from the three "high demand" averages and the aggregated one, which includes both lies between the two, as expected.



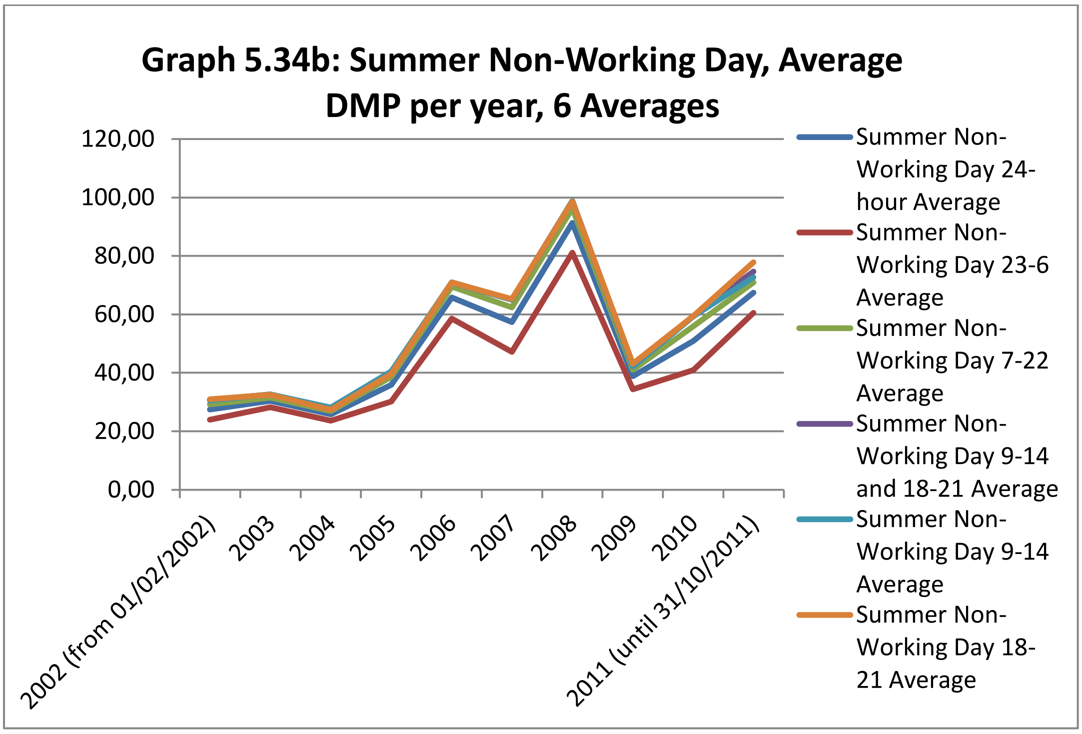
In Graph 5.32b, we present the same 6 averages as for Graph 5.31b, but for the Average Winter Non-Working Day producing one DMP for each of the averages for each year. These averages show that there is a specific effect that each year has on DMP, as all are increasing and decreasing in the same direction as we move through the years. That signals the fact that the year under discussion is always relevant to the DMP level in the wholesale electricity pool. We can also observe lower average DMPs for night-time averages (23-6), then the averages get higher for the 24-hour period, then even higher for the averages of the dispatch periods during the day (7-22) and the highest averages are those of the three "high demand" periods (9-14, 18-21 and then both of them together). The "high demand" averages get values that are almost identical. Of the three “high demand” averages, the highest one is the winter afternoon (18-21) average. In the winter, as we discussed in the system load section, electricity demand is higher in the afternoon peak-load period (18-21) than it is in the morning one (9-14) and that has an effect on the determination of the DMP. The morning average (9-14) is the lowest from the three “high demand averages” and, as expected, the aggregated one both lies in between of them.

By comparing 5.31b and 5.32b we can see that each of the average DMPs increases or decreases together each year for both Winter Working and Winter Non-Working Days. This shows that the period of the year (summer or winter) is relevant in the determination of the DMP and that this effect applies to both working and non-working days.

Comparing 5.31b with 5.32b, the DMPs that these diagrams are referring to are set at different levels for the 24-hour, day-time (7-22) and “high demand” (9-14, 18-21 and both of them together) averages. The DMP values are higher during the working days as opposed to non-working days. The DMP averages during the night (23-6) are at similar levels for both working and non-working days. This suggests that the factors that are creating differences in the DMP values between working and non-working days are related to activities that are carried out during the day, and since these activities only occur in the working days, we can assume that these are business-related activities.



In Graph 5.33b, we present the same 6 averages as we did in Graphs 5.31b and 5.32b. However this is for the Average Summer Working Day. These averages show that there is a specific effect that each year has on DMP, as all values are increasing and decreasing in the same time as we move through the years. That signals the fact that the year under discussion is always relevant for the DMP level in the wholesale electricity pool. We can also see that we get lower average DMPs for night-time averages (23-6), then the averages get higher when we calculate them for the 24-hour period, then even higher for the averages of the dispatch periods during the day (7-22) which are exactly at the same levels as those of the three “high demand” periods (9-14, 18-21 and then both of them together). The three “high demand” averages only differentiate in years 2009-2011. During that period, the highest “high demand” average is for the summer morning (9-14) and the lowest one is for the afternoon (18-21) with the day-time average (7-22) being even lower than that. In the summer, as we discussed in the system load section, electricity demand is higher in the morning than it is in the afternoon and that has an effect on the determination of the SMP and the DMP.



In Graph 5.34b, we present the same 6 averages as we did in Graphs 5.31b, 5.32b and 5.33b, however this time for the Average Summer Non-Working Day. The averages that we get show us that there is a specific effect that each year has on DMP, as all of them are increasing and decreasing in the same time as we move through the years: the year under discussion is always relevant in determining the DMP in the wholesale electricity pool is. By examining 5.34b and the position of its averages, we can see that we get lower average DMPs for night-time averages (23-6), then the averages get higher when we calculate them for the 24-hour period, then even higher for the averages of the dispatch periods during the day (7-22) and the highest averages (by a very small difference to the 7-22 average) are those of the three “high demand” periods (9-14, 18-21 and then both of them aggregated). Of the three “high demand” averages, there seems to be little (if at all) differentiation in the average DMPs. The only differentiation is evident in 2011, where the highest one is the summer afternoon (18-21) average.

An important observation that we can make in Graph 5.34b is that the average DMPs of the "high demand" periods are almost identical in all years and only vary in 2011. As we previously discussed in Graph 5.10b, the average system loads of the "high demand" periods for the Average Summer Non-Working Day are also almost identical for all years and vary in 2011.

By comparing Graph 5.33b with Graph 5.34b we can see that the each of the average DMPs increases or decreases together each year for both Average Summer Working Days and Average Summer Non-Working Days. This shows that the period of the year (summer or winter) is relevant in the determination of the DMP, irrespective of the day of the week (working or non-working).

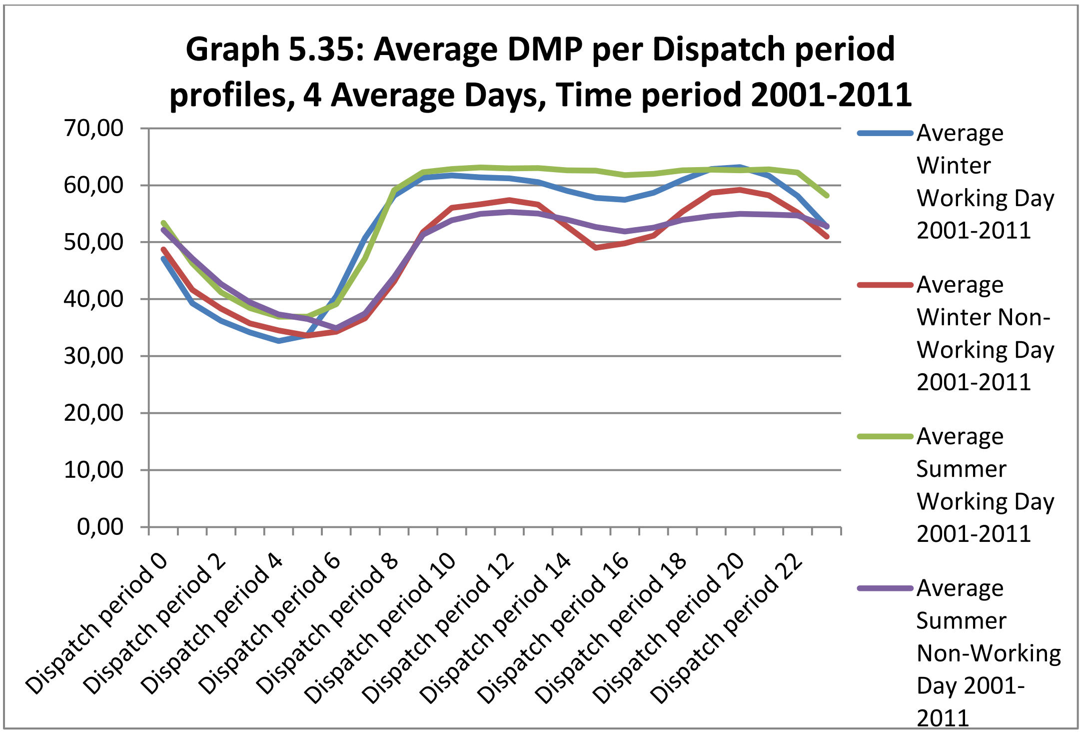
Comparing Graph 5.33b with Graph 5.34b, the average DMPs of each year are set at different levels in working days and in non-working days. That happens for the 24-hour, day-time (7-22) and "high demand" (9-14, 18-21 and both of them aggregated) averages. Average DMPs are higher during the working days as opposed to the average DMPs of the non-working days. The DMP averages during the night (23-6) are at similar levels for both working and non-working days, thus suggesting that the factors that create the differences are related to activities carried out during the day. The fact that these activities do not seem to affect the DMP in non-working days suggests that these are business-related activities.

Also, by looking at 5.31b, 5.32b, 5.33b and 5.34b we can make the observation that in all of the graphs, figures for the dispatch periods 7-22 are very close together. The only values that present some differences are the night-time ones (dispatch periods 0-6 and 23), which are lower than the rest. That is so because, as we have seen in Graph 5.25, the DMP levels in most years are not differentiating in the intra-day dispatch periods 7-22, and DMP decreases only during the night. As a result, choosing varying groups of these dispatch periods does not alter the resulting average.

Also, by looking at the SMP diagrams and comparing them with the DMP ones, we can evidence the relationship between these two prices. By comparing:

- Graph 5.19b with 5.31b (SMP and DMP averages for Winter Working Days)
- Graph 5.20b with 5.32b (SMP and DMP averages for Winter Non-Working Days)
- Graph 5.21b with 5.33b (SMP and DMP averages for Summer Working Days)
- Graph 5.22b with 5.34b (SMP and DMP averages for Summer Non-Working Days)

We can see that these sets of graphs provide us with SMP and DMP averages that are increasing and decreasing in the same time for any given Average Day. That means that there is a strong relationship between SMP and DMP and that the same factors affect both of them in similar ways for any given day of the electricity market operation.



The averages included in Graphs 5.31a, 5.32a, 5.33a and 5.34a (found in Appendix B, Part 3) have been averaged to create an average DMP per dispatch period for each of the four Average Days for the whole time period 2002-2011. These were put together in Graph 5.35. By examining Graph 5.35 we can see that there is an intra-day DMP pattern that roughly applies to all of the 4 Average Days. In all four Average Days, the DMP is lower during the time period that corresponds to dispatch periods 23-6. Therefore it is justifiable to expect that there will be tariffs capturing this market characteristic and offering lower retail prices for electricity during the night.

It is important to note that by comparing the levels of the DMPs that we get from Graph 5.35 for the different average days, we get similar results to those that we get from Graphs 5.11 (for system load) and 5.23 (for SMP). It therefore appears that the intra-day system load plays an active role in the determination of the intra-day DMP, in the same way that it does for SMP (as we mentioned when discussing Graph 5.23). However that is only true when we are referring to the effect of the system load during the different hours of a given day, since for that given day, other significant factors are expected to be constant and therefore not affecting the intra-day DMP (and SMP). So, we conclude by comparing Graphs 5.35, 5.23 and 5.11 that with all other factors kept constant, DMP and SMP are affected by the system load.

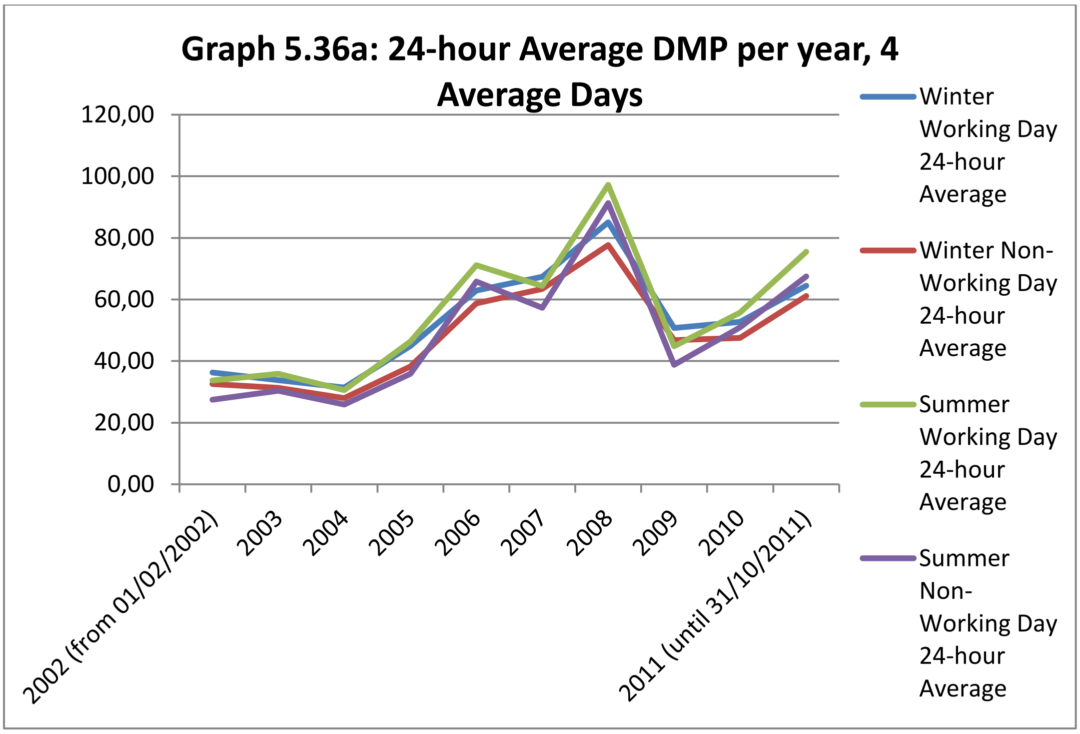
So, we see that prices (SMP and DMP) and quantities (system load) are moving together during the day. It is important to note that system load, SMP and DMP are interrelated because of the way that the market operates. System load represents the demand for electricity and that demand is met through electricity bought in the pool. Electricity generators are bidding in the wholesale market in order to be included in the dispatch scheme and the combination of their bids and of the system load requirements determines the electricity prices. Therefore, a relationship between system load, SMP and DMP is established through the market operation mechanisms.

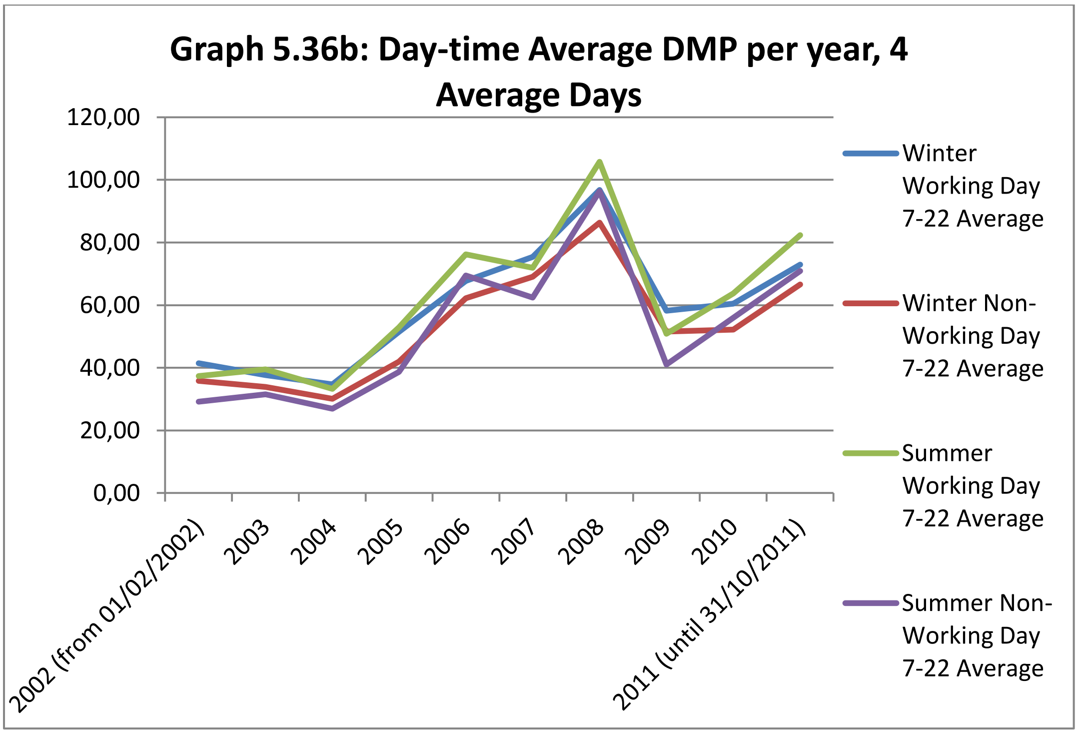
The averages that we previously discussed in Graphs 5.31b, 5.32b, 5.33b and 5.34b have been rearranged into Graphs 5.36a, 5.36b, 5.36c, 5.36d, 5.36e and 5.36f, where they have been grouped not by the Average Day but by the Average DMP that is calculated. In these 6 graphs, we look more analytically at what has been observed in Graph 5.35, by taking each of the averages separately. So we do not examine the effect of the hour of the day, since that is constant in each graph, we rather address the differences in annual average DMP by varying the time of the year (winter or summer) and the day in the week (working or non-working).

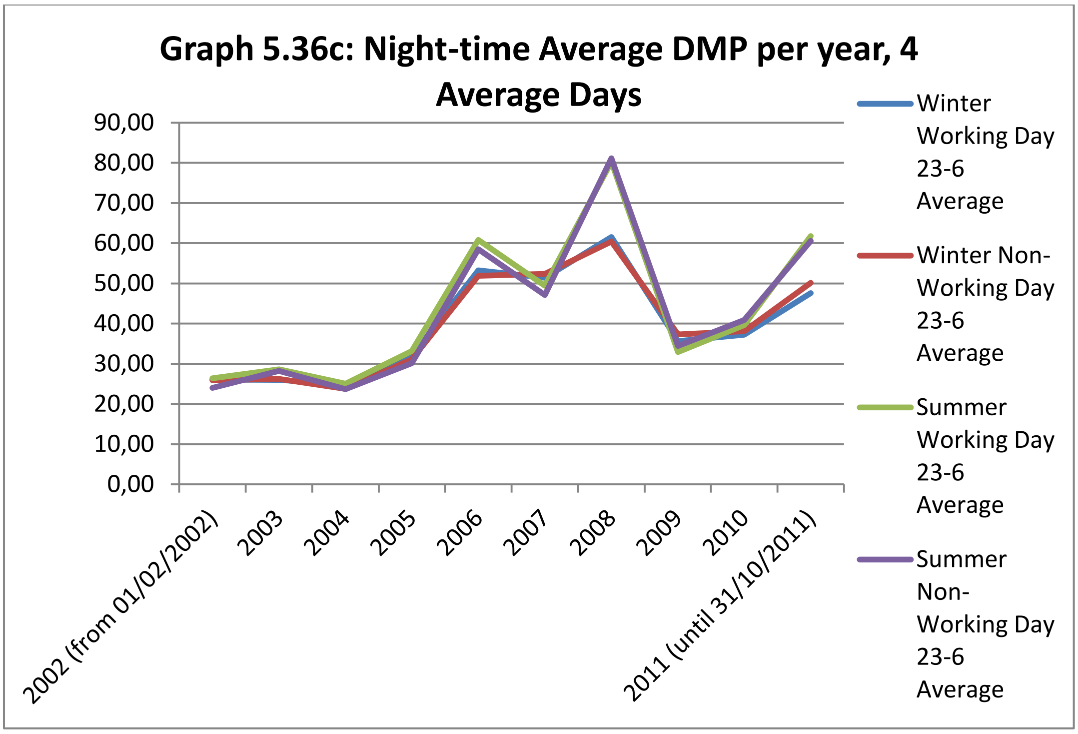
Some observations on Graphs 5.36a-5.36f:

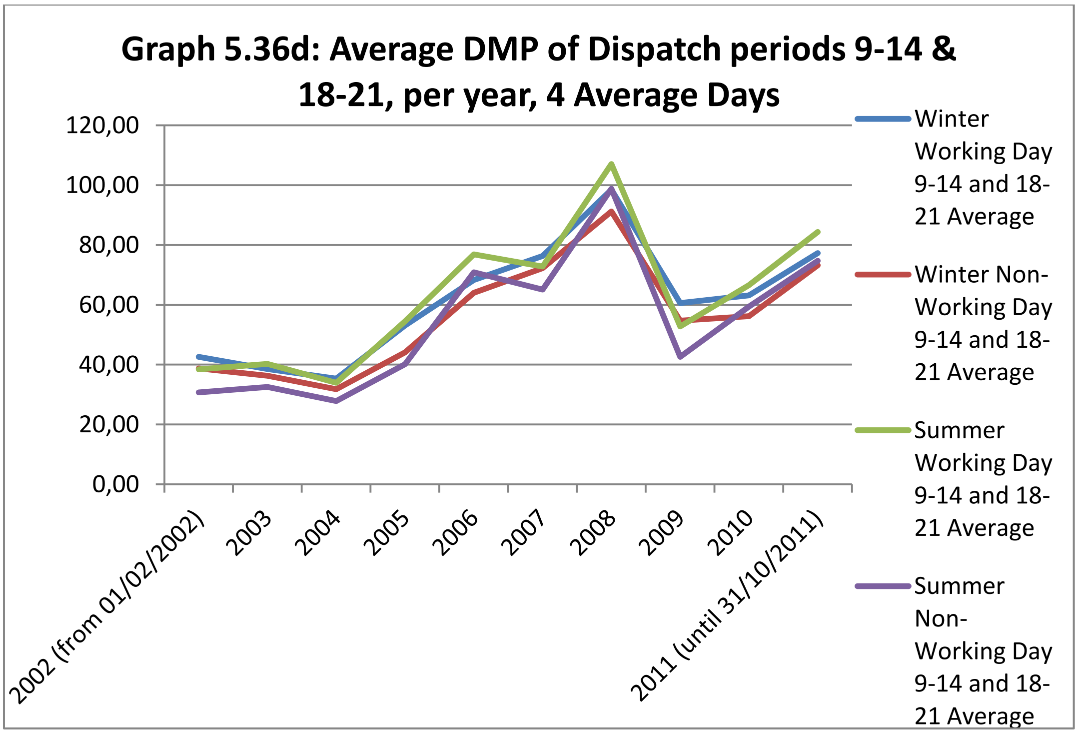
- Apart from the values for the night-time dispatch periods (23-6), the average DMPs of all day-time averages are at similar levels for any given year, regardless of which of the four Average Days we are looking at. That suggests that there are some factors related to each year that determine the average DMP during the dispatch periods 7-22 in both summer and winter and in both working and-non working days. Such a factor could be the international fossil fuel prices.
- The time of the year (summer or winter) is also very significant as we can see that we have two patterns for our averages in all graphs, one for the two Winter Average Days and one for the two Summer Average Days.
- Whether the day of the week is working or non-working has a specific effect on average DMP. Comparing working and non-working days for all averages, except the night-time ones, reveals that the working day average DMPs are always higher.
- The night-time average DMPs are set at lower levels that the averages of DMPs of the day-time period (dispatch periods 7-22) in all years and for all Average Days. This could be related to the tariff setting structure that allows for lower electricity prices during the night-time period.
- Also, the night-time average DMPs show no differences between working days and non-working days. That was expected as the differentiation

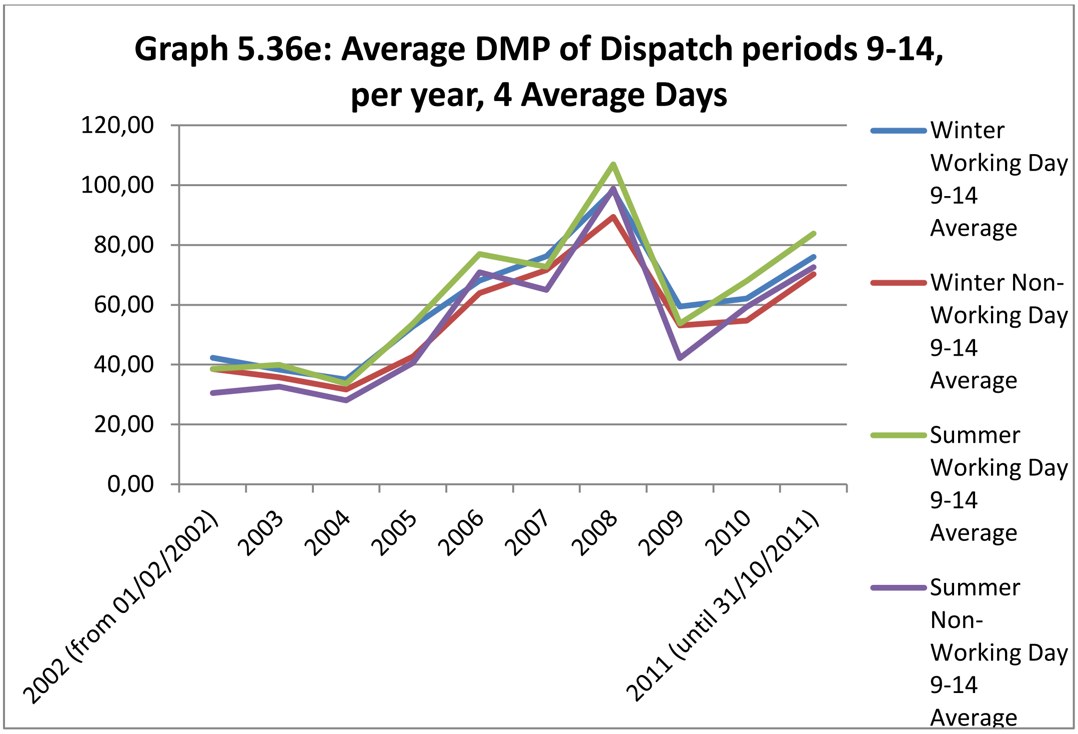
between working and non-working days is made in recognition of the fact that business activities play an important role in electricity demand.

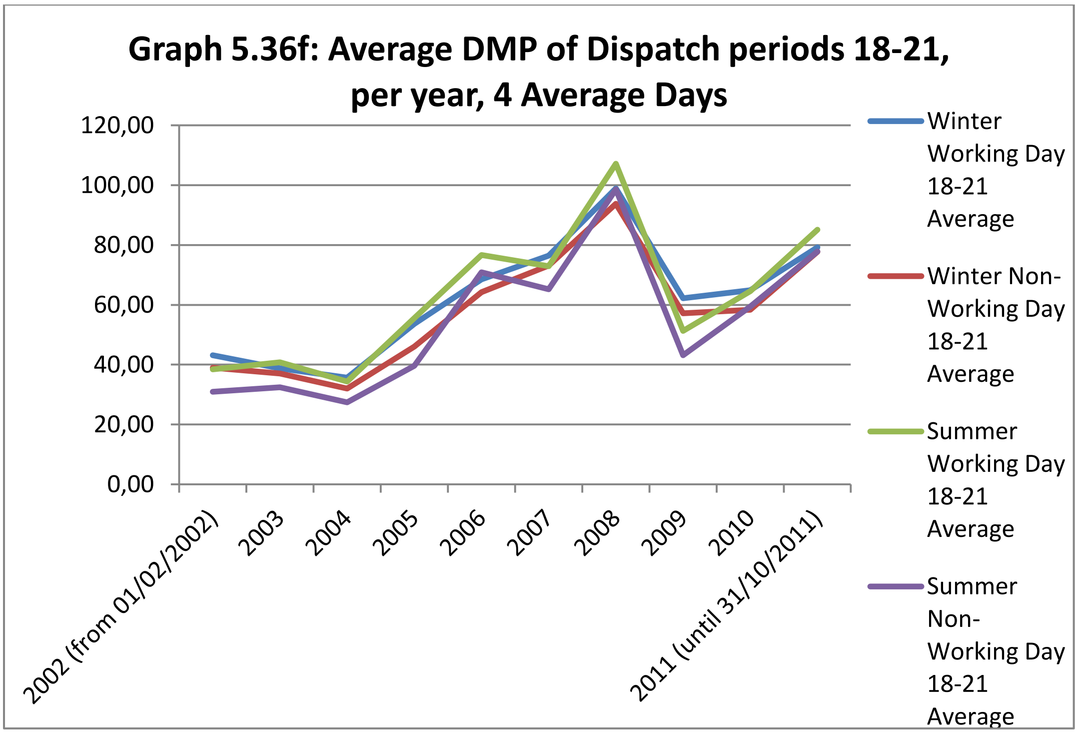





Graph 5.36c: Night-time Average DMP per year, 4 Average Days
90,00
80,00
70,00
60,00
50,00
40,00
30,00
20,00
10,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 23-6 Average
Winter Non-Working Day 23-6 Average
Summer Working Day 23-6 Average
Summer Non-Working Day 23-6 Average


Graph 5.36d: Average DMP of Dispatch periods 9-14 & 18-21, per year, 4 Average Days
120,00
100,00
80,00
60,00
40,00
20,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 and 18-21 Average
Winter Non-Working Day 9-14 and 18-21 Average
Summer Working Day 9-14 and 18-21 Average
Summer Non-Working Day 9-14 and 18-21 Average


Graph 5.36e: Average DMP of Dispatch periods 9-14, per year, 4 Average Days
120,00
100,00
80,00
60,00
40,00
20,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 Average
Winter Non-Working Day 9-14 Average
Summer Working Day 9-14 Average
Summer Non-Working Day 9-14 Average


Graph 5.36f: Average DMP of Dispatch periods 18-21, per year, 4 Average Days
120,00
100,00
80,00
60,00
40,00
20,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 18-21 Average
Winter Non-Working Day 18-21 Average
Summer Working Day 18-21 Average
Summer Non-Working Day 18-21 Average

An important observation also has to do with the changes that we observe in the rankings across Graphs 5.36a-5.36f. As we mentioned, except for the night-time ones, the average DMPs are very close. There is no Average Day that consistently has the highest or the lowest DMP. That could be due to the effect of external factors. It should be noted that although the averages are calculated for each year and graphed together, two of the averages refer to the period of the summer and two of them refer to the period of the winter. Therefore, they do not refer to exactly the same period, and any external factors affecting DMP during the winter of one specific year are not guaranteed to be present during the summer of that same year.

Part 2

DMP-Standard deviations

2.1 Introduction

The Deviation Marginal Price (DMP) data that we have available are for the time period 01/02/2002-31/10/2011. For that time period we have 24 DMP values for every day and these correspond to the 24 dispatch periods of each day (one for each hour of the day).

The standard deviation measures the volatility of prices paid for deviations for the dispatch scheme in the Greek electricity wholesale market. The importance of examining the standard deviations of DMPs lies in describing the volatility levels and considering the implications that these have on profitability for electricity generators and suppliers.

2.2 A note on the DMP Data

Before looking at the standard deviations of the DMP, we should note that the analysis of the average values for SMP and DMP registered similarities. We therefore expect that some of these similarities would also occur in the standard deviations.

2.3 DMP Graphs-Standard deviations

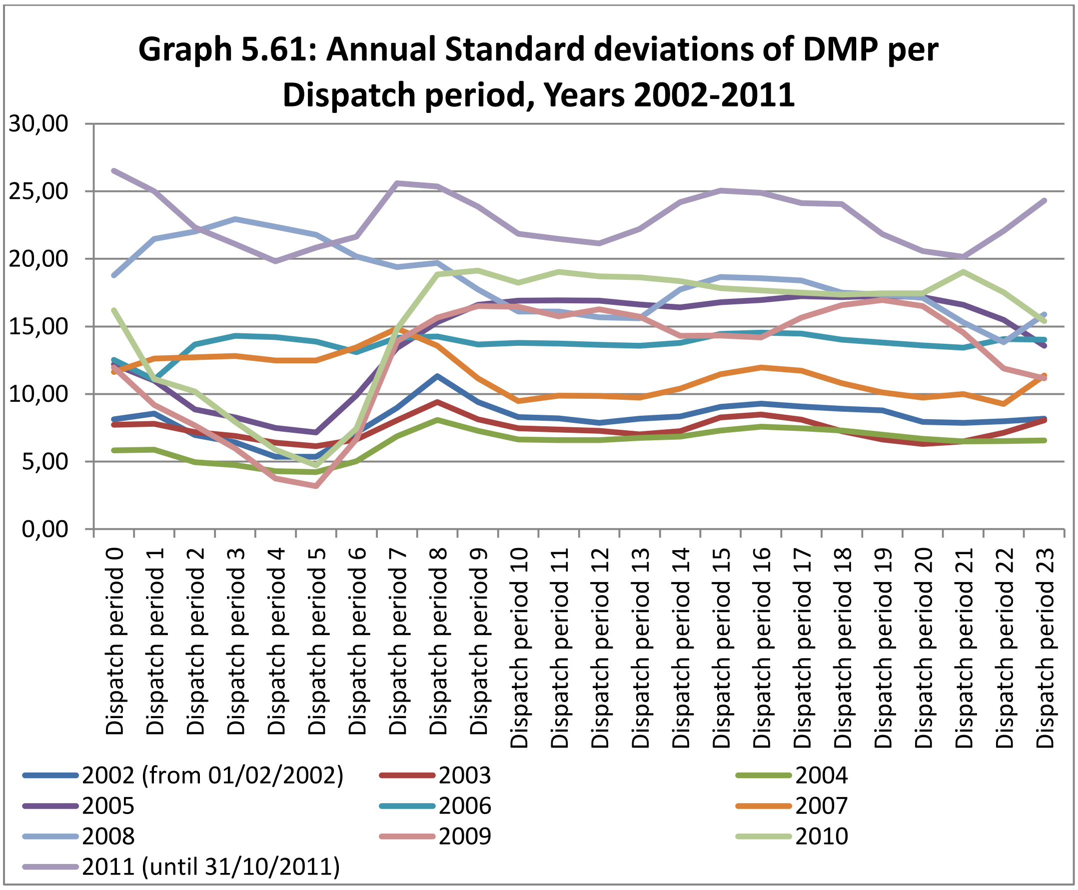
Graph 5.61 shows the annual standard deviations for DMP for every dispatch period for the years 2002-2011. The two main observations are similar to those for Graph 5.49:

- In some years, the DMPs of the night-time periods have lower standard deviations than the DMPs of the day-time periods.

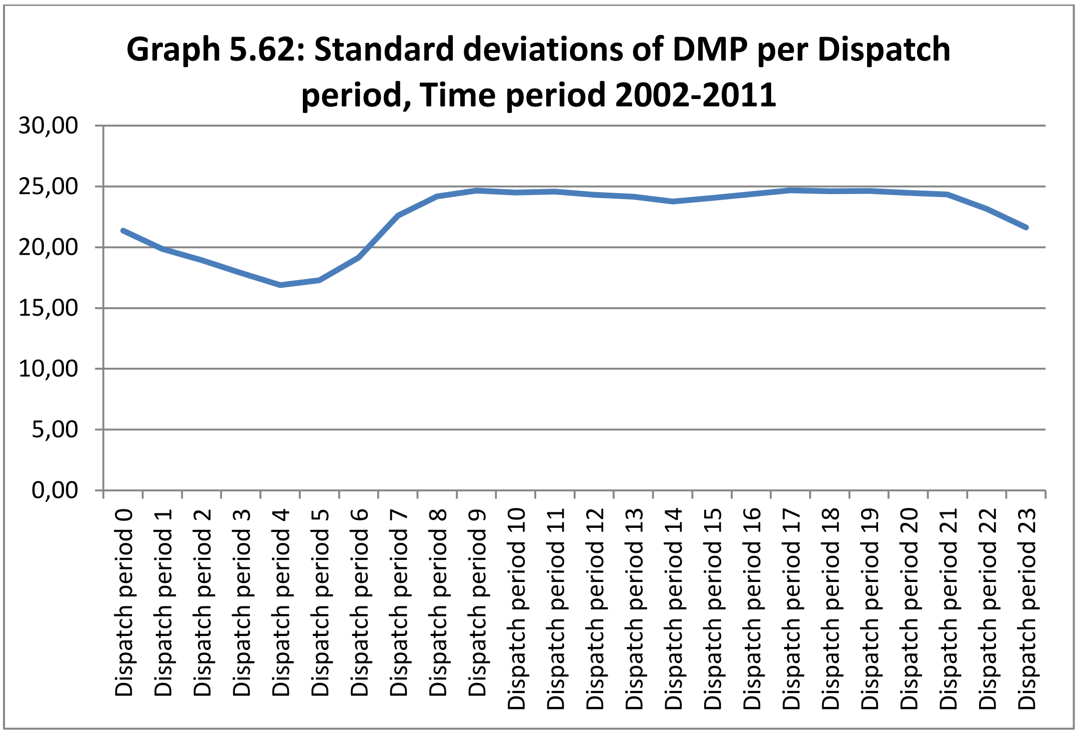
- As we move from the earlier to later years, the DMP standard deviations tend to increase.

DMPs are paid by the electricity suppliers for any electricity bought in addition to the amount scheduled. Therefore these two observations lead us to say that the volatility of the DMP means for the electricity suppliers that:

- There is less uncertainty concerning the wholesale price of electricity at night and therefore, accounting for these lower levels of price volatility, the retail suppliers can set night-time tariffs closer to the average wholesale cost of electricity.
- The increased overall levels of standard deviation of DMP in the latest years imply that there is much larger uncertainty for market participants, in terms of their profitability.

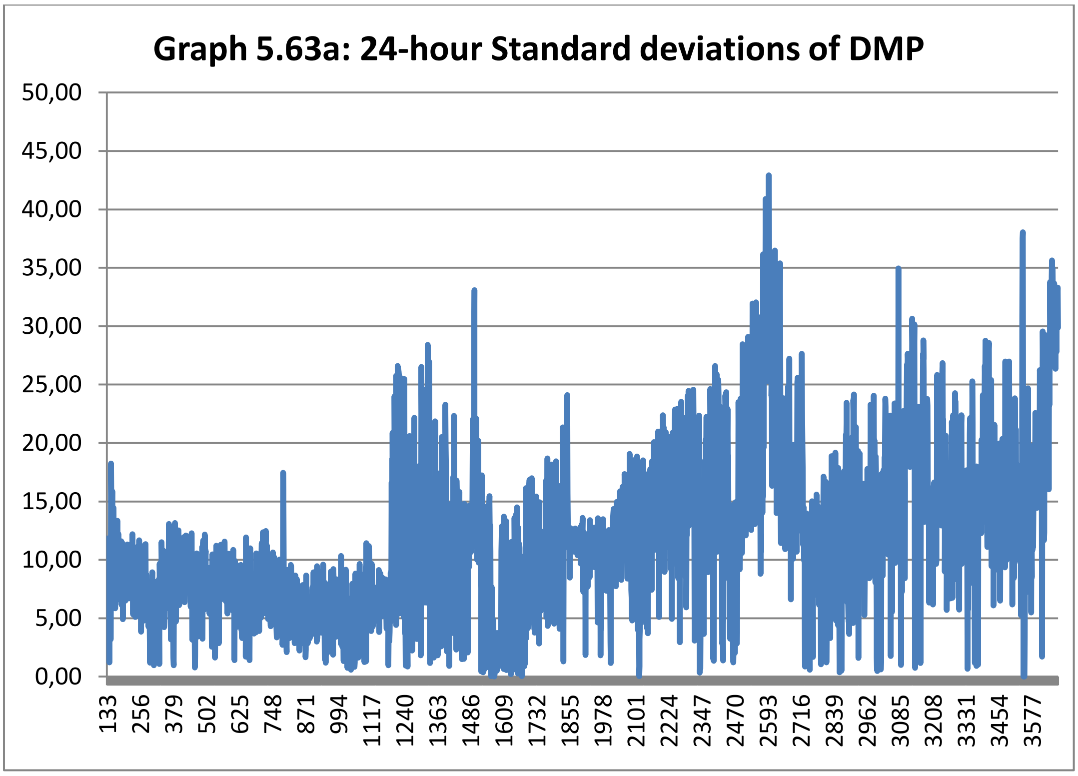


The standard deviations for the DMPs for every dispatch period of all the time period that we examine are presented in Graph 5.62. In this Graph we can much clearer identify that standard deviations of DMPs of the night-time periods are lower than those of the day-time periods.

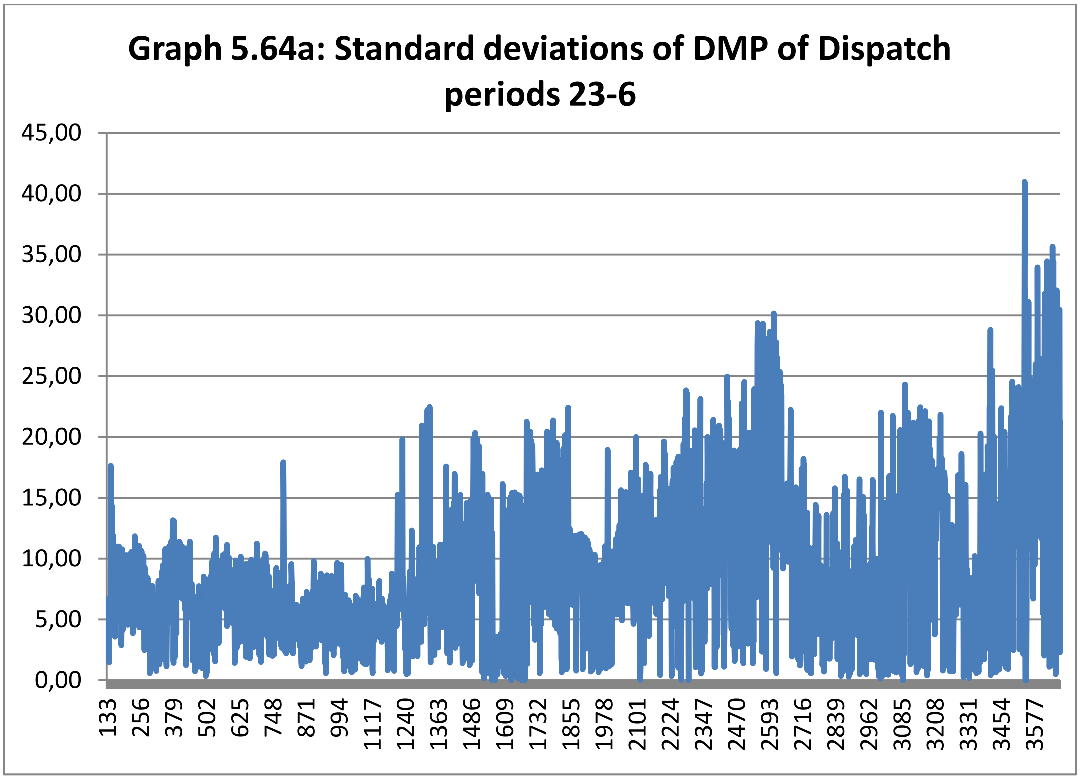


Graph 5.63a presents the 24-hour standard deviation of the DMP of each day of the whole time period that we examine. We can see that the standard deviation is in somewhat low levels for the initial time period that we examine and that sharply increases from mid-January 2005 (observation 1,193 at 13/01/2005). After that point, the 24-hour standard deviations of DMP are quite volatile. In a similar manner as we did for Graph 5.51a, we can assume that this volatility is the result of competition in the wholesale electricity market. In Graph 5.63a we can also see the “spike” that was created in DMPs at the end of June 2011 as a result of the PPC strike, as well as the increasing trend in the standard deviation of DMPs during the

months September and October 2011, as a result of the taxation that was imposed on natural gas.



Graphs 5.64a, 5.65a, 5.66a, 5.66c and 5.66e follow roughly similar patterns as 5.63a. Graphs 5.65a, 5.66a, 5.66c and 5.66e that specifically refer to the dispatch periods 7-22, in different combinations, seem to present even greater similarities. In that pattern, standard deviations of DMP remain at low and stable levels, most of the time below or around 15 euros/MWh and get above 20 euros/MWh only in roughly 4 time periods. Exactly as was the case when discussing SMP, the price uncertainty in the wholesale market is affecting the levels of business risk undertaken by the electricity firms that participate in the market during these dispatch periods.


Graph 5.64a: Standard deviations of DMP of Dispatch periods 23-6
45,00
40,00
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
133
256
379
502
625
748
871
994
1117
1240
1363
1486
1609
1732
1855
1978
2101
2224
2347
2470
2593
2716
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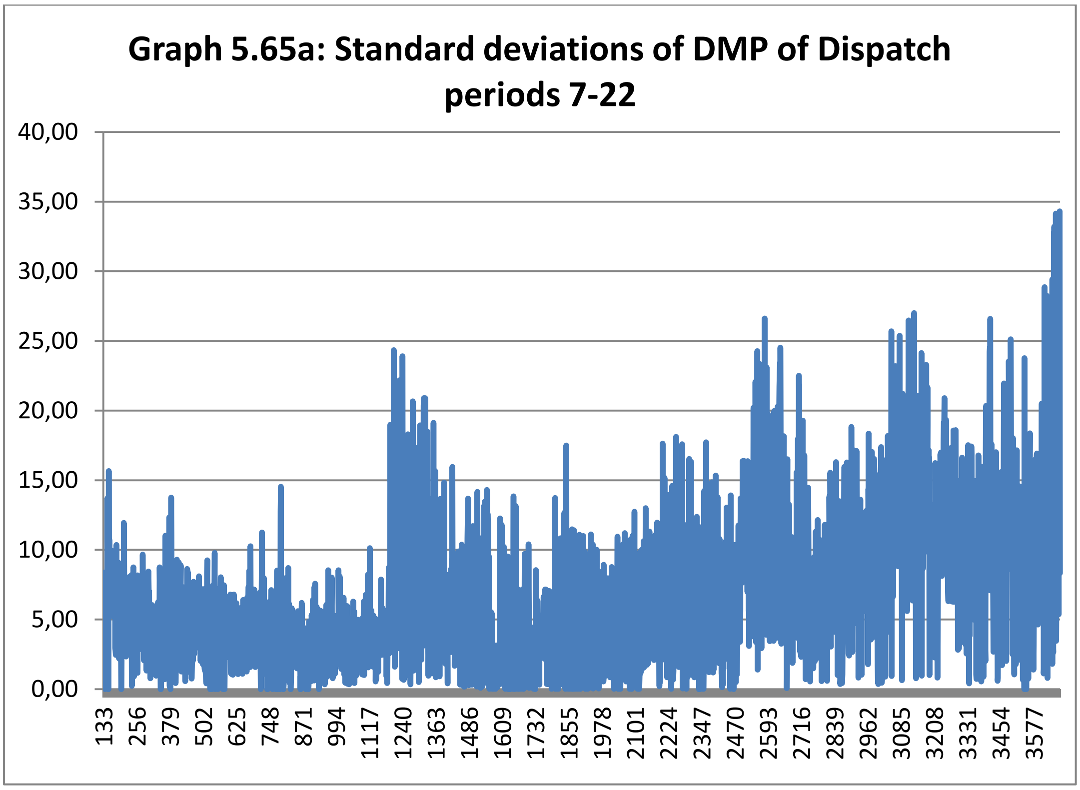
3085
3208
3331
3454
3577


Graph 5.65a: Standard deviations of DMP of Dispatch periods 7-22
40,00
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
133
256
379
502
625
748
871
994
1117
1240
1363
1486
1609
1732
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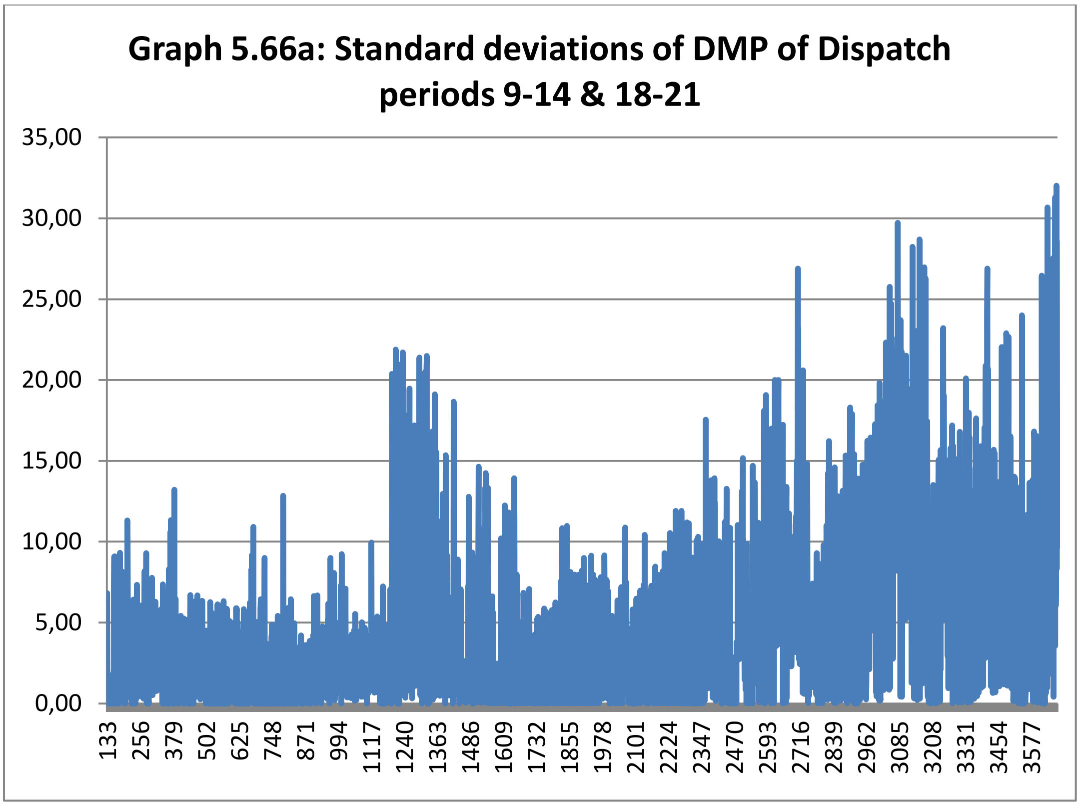
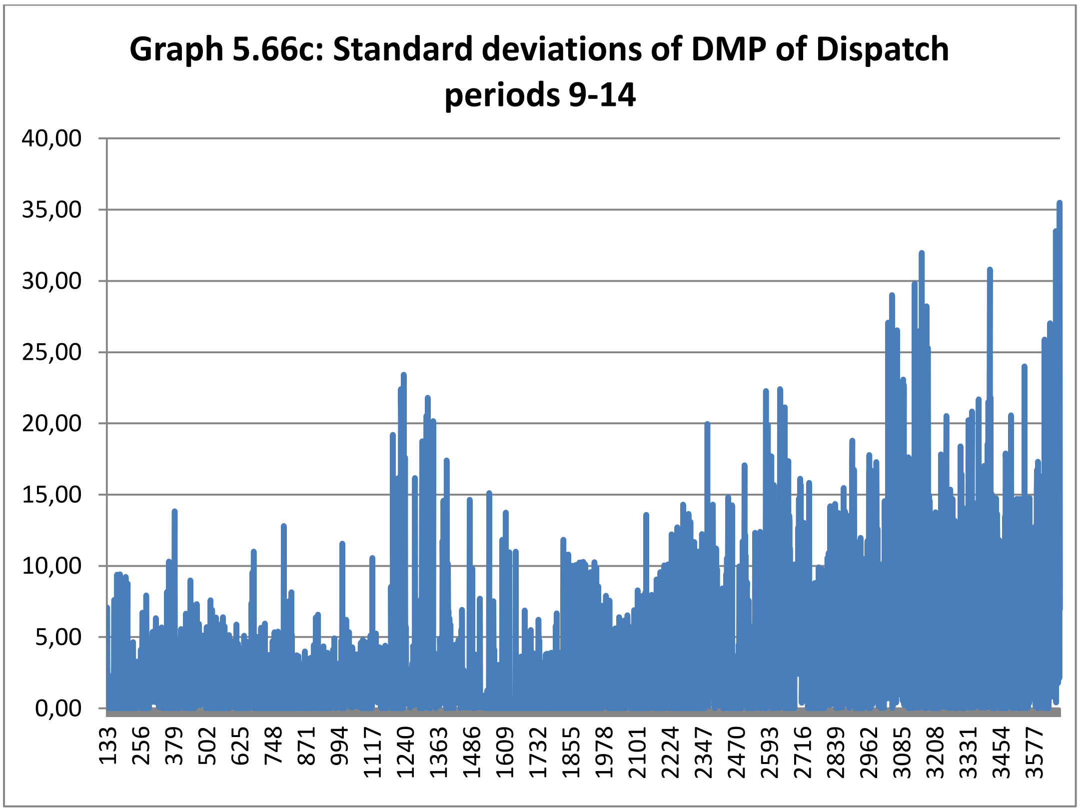
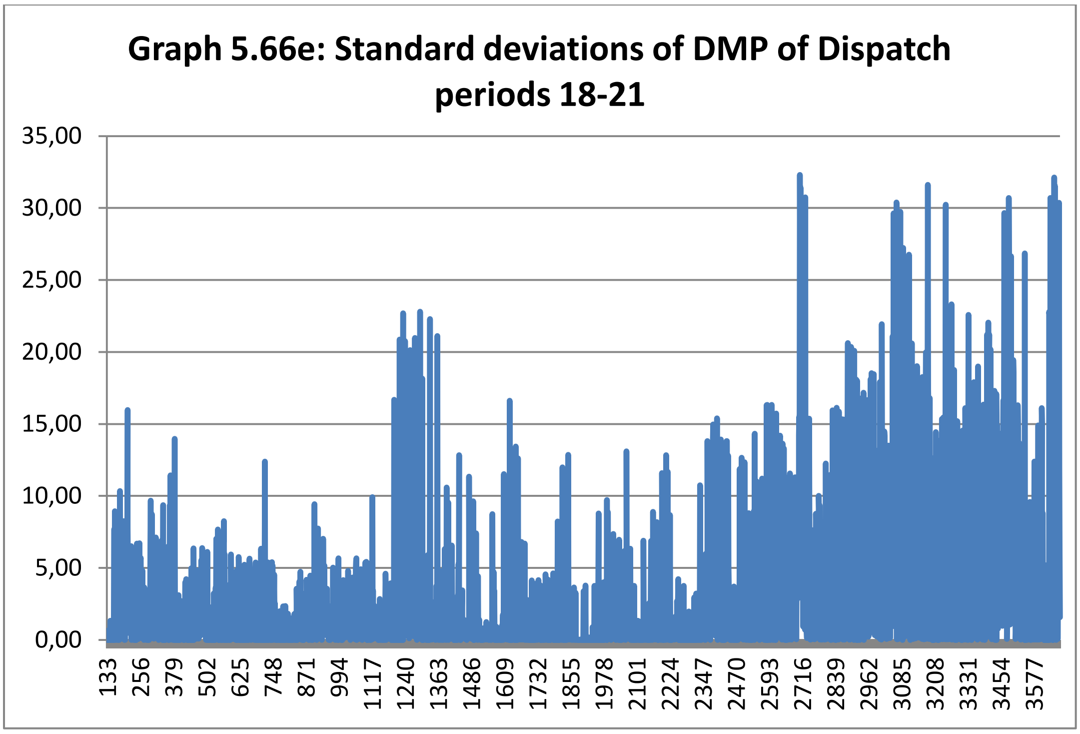
3208
3331
3454
3577


Graph 5.66a: Standard deviations of DMP of Dispatch periods 9-14 & 18-21
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
133
256
379
502
625
748
871
994
1117
1240
1363
1486
1609
1732
1855
1978
2101
2224
2347
2470
2593
2716
2839
2962
3085
3208
3331
3454
3577


Graph 5.66c: Standard deviations of DMP of Dispatch periods 9-14
40,00
35,00
30,00
25,00
20,00
15,00
10,00
5,00
0,00
133
256
379
502
625
748
871
994
1117
1240
1363
1486
1609
1732
1855
1978
2101
2224
2347
2470
2593
2716
2839
2962
3085
3208
3331
3454
3577



An important observation is that in Graphs 5.63a, 5.64a, 5.65a, 5.66a, 5.66c and 5.66e there are 2 distinct periods. The first is the early period which is from the start of our data until mid-January 2005 (observation 1,193 at 13/01/2005). Until that point, the standard deviations are at low levels. This has to do with the fact that the period until January 2005 is a period where PPC is the sole player in the market and there is actually no true competition. After that point we seem to get a market where there is some level of competition, since after that point, independently owned natural gas-fired generators enter the electricity generation market ([Iliadou, 2009], [DEPA, 2012]).

Graphs 5.63b, 5.64b, 5.65b, 5.66b, 5.66d and 5.66f present the annual standard deviations of the DMP in a year by year basis with that standard deviation calculated for 6 different time periods in each day. It is difficult to extract any conclusions from these graphs. However we can say that the highest levels of standard deviation of the DMP appear to be reached only during the later years, especially during 2008-2011. These graphs are to be found in Appendix B, Part 6.

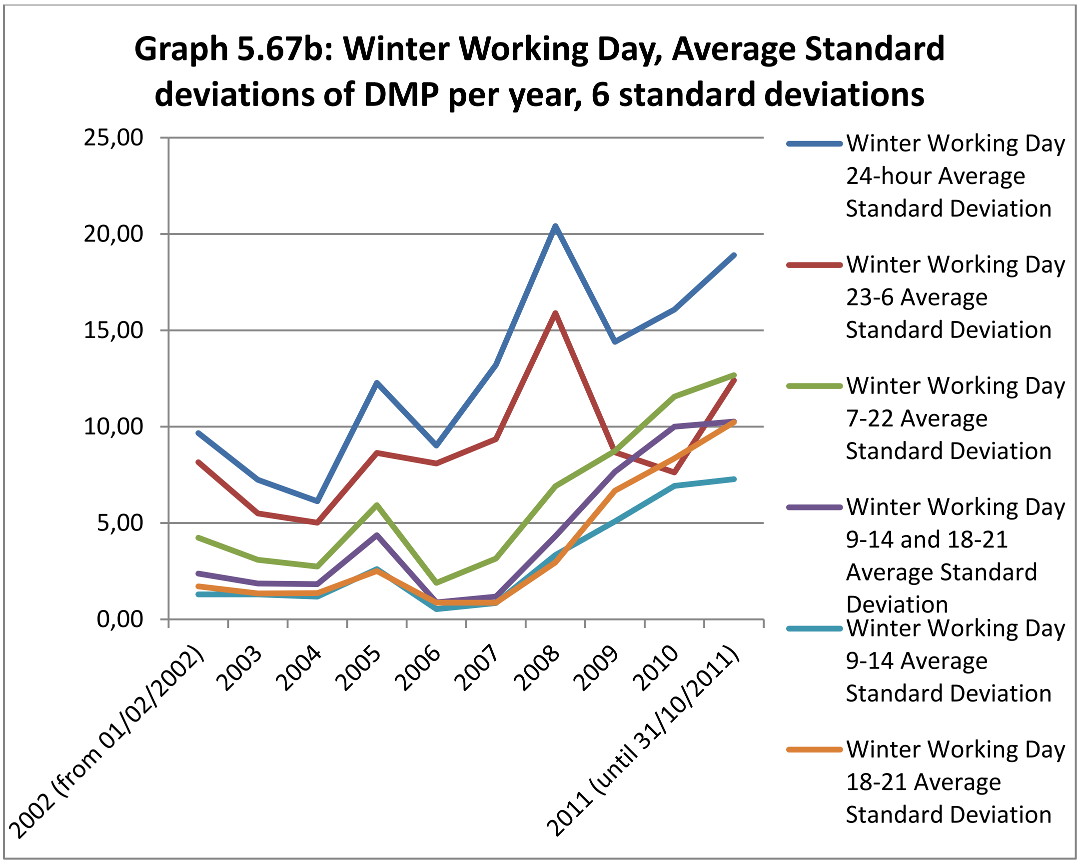
Graphs 5.67a, 5.68a, 5.69a and 5.70a present the annual standard deviations of the DMP per dispatch period in a year by year basis for the 4 Average Days. These graphs identify two key themes. Firstly, on a number of occasions, the standard deviations of the DMPs tend to be lower during the night-time dispatch periods. Secondly, there generally seems to be an increase in the level of the standard deviations of the DMPs as we go through the years. These graphs are to be found in Appendix B, Part 6.

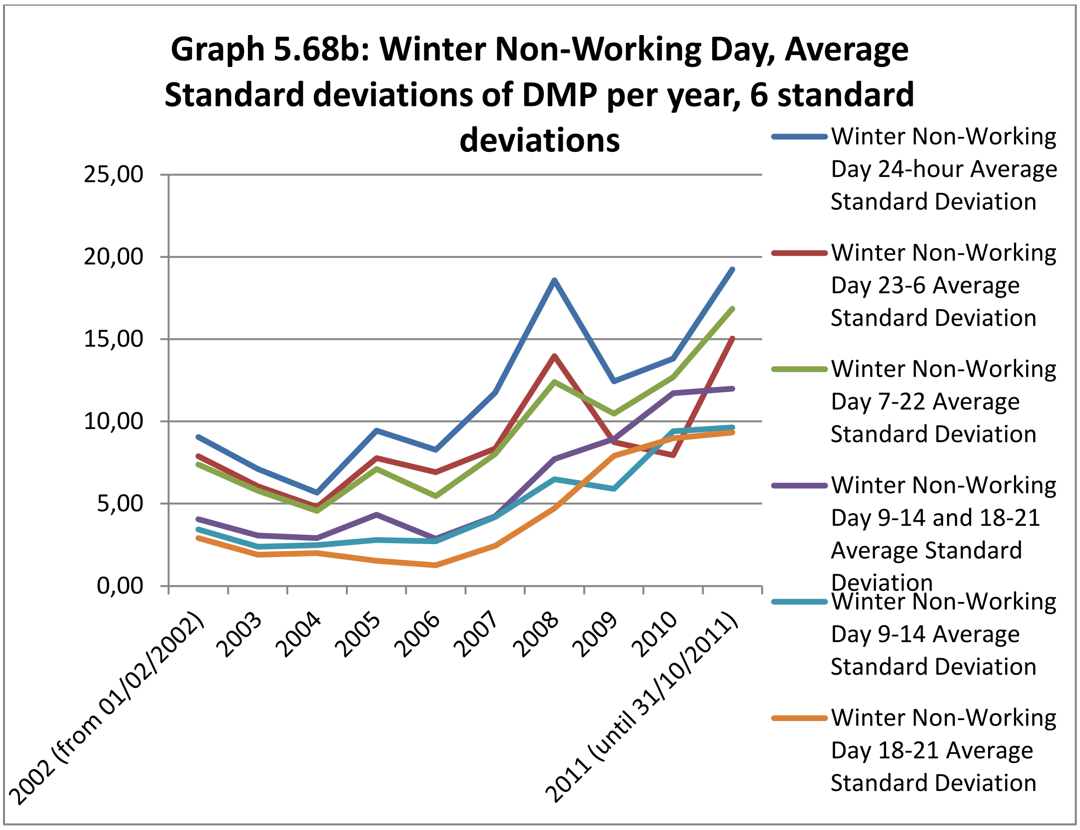
In Graphs 5.67b and 5.68b, we present the averages of the standard deviations of the DMP of 6 combinations of dispatch periods. These are calculated and presented separately for the Average Winter Working Day in Graph 5.67b and for the Average Winter Non-Working Day in Graph 5.68b. There are two observations to be made from examining these graphs. First, the standard deviations of the DMP are at low levels until 2004 and volatility increases only after that period. That is anticipated as being the effect of introduction of competition in the generation part of the market that gradually occurred since the summer of 2004 ([Iliadou, 2009], [DEPA, 2012]). As the market becomes competitive, the market price starts reflecting the volatility of the cost of fuel. The second observation has to do with the patterns of evolution from year to year of the standard deviations of the DMP. These two patterns are similar for the two Average Winter Days, regardless of them being Working or Non-Working.

The same results apply:

- In Graphs 5.19b and 5.20b with the average SMP of the Average Winter Days.
- In Graphs 5.31b and 5.32d with the average DMP of the Average Winter Days.
- In Graphs 5.55b and 5.56b with the average standard deviations of SMP of the Average Winter Days.

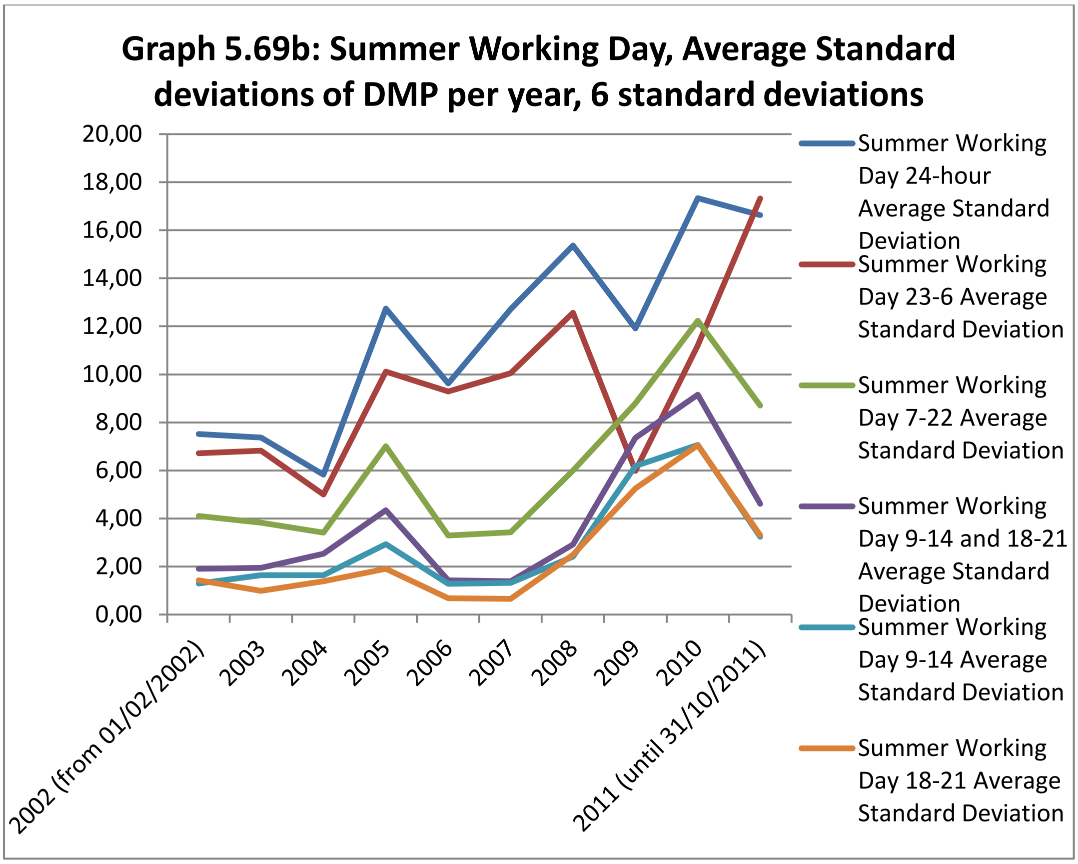
That suggests that the year under discussion is relevant to the SMP and DMP level as well as to the SMP and DMP volatility levels.

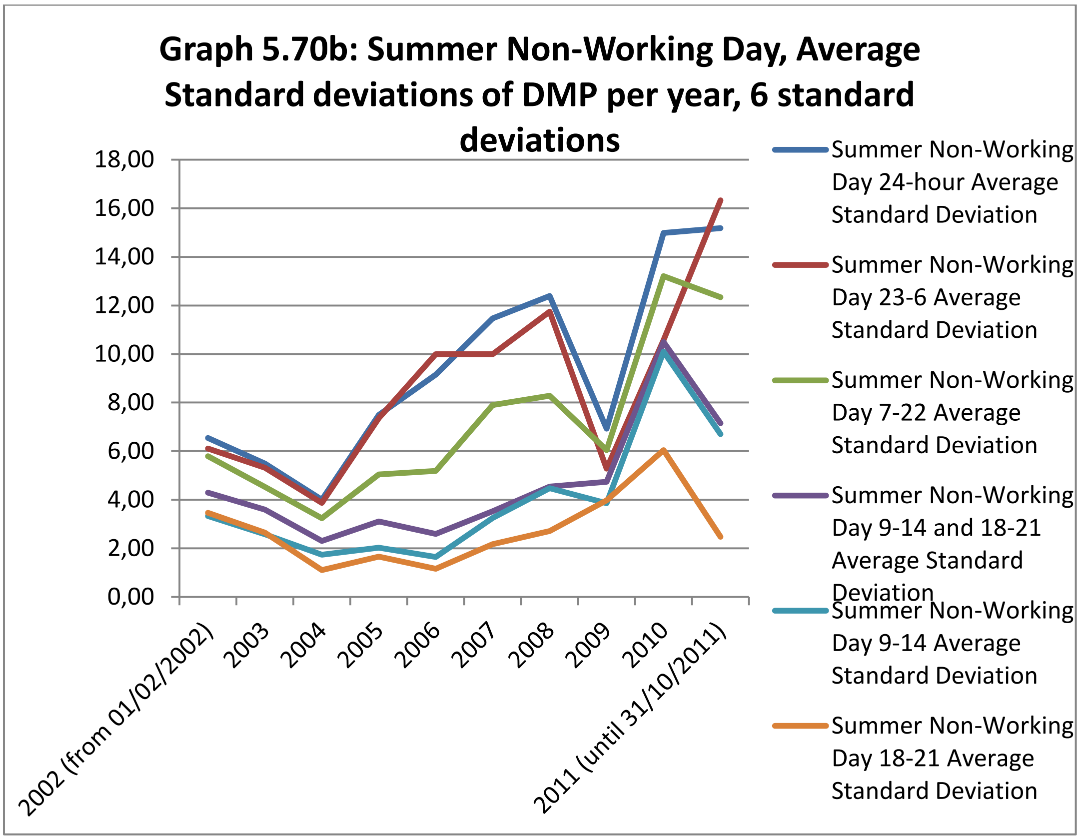

Graph 5.67b: Winter Working Day, Average Standard deviations of DMP per year, 6 standard deviations
25,00
20,00
15,00
10,00
5,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 24-hour Average Standard Deviation
Winter Working Day 23-6 Average Standard Deviation
Winter Working Day 7-22 Average Standard Deviation
Winter Working Day 9-14 and 18-21 Average Standard Deviation
Winter Working Day 9-14 Average Standard Deviation
Winter Working Day 18-21 Average Standard Deviation


Graph 5.68b: Winter Non-Working Day, Average Standard deviations of DMP per year, 6 standard deviations
25,00
20,00
15,00
10,00
5,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Non-Working Day 24-hour Average Standard Deviation
Winter Non-Working Day 23-6 Average Standard Deviation
Winter Non-Working Day 7-22 Average Standard Deviation
Winter Non-Working Day 9-14 and 18-21 Average Standard Deviation
Winter Non-Working Day 9-14 Average Standard Deviation
Winter Non-Working Day 18-21 Average Standard Deviation

In Graphs 5.69b and 5.70b, we present the averages of the standard deviations of the DMP of 6 combinations of dispatch periods. These are calculated and presented separately for the Average Summer Working Day in Graph 5.69b and for the Average Summer Non-Working Day in Graph 5.70b. There are two observations that we make by examining these graphs.

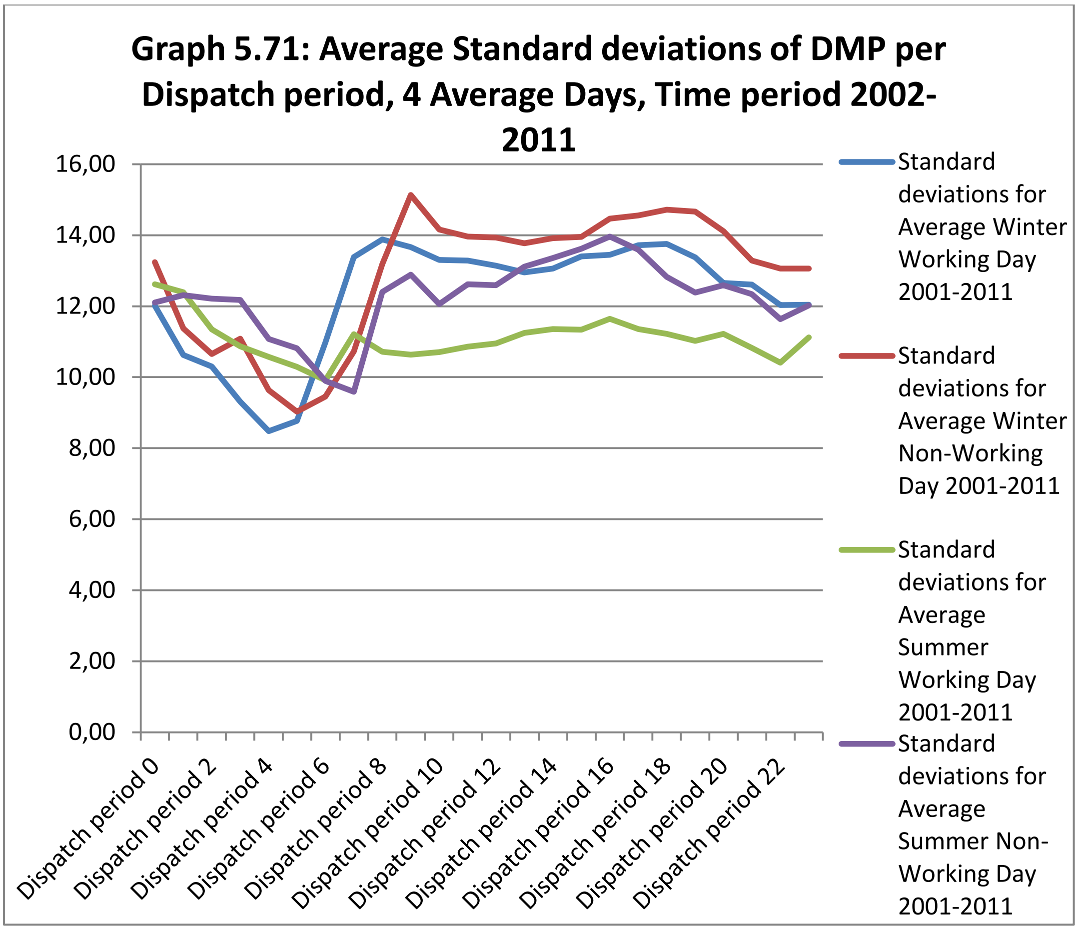
- Firstly, the average standard deviations of the DMP are kept at low levels until 2004 and volatility increases after that period. That is anticipated as being the effect of introduction of competition in the generation part of the market that gradually occurred since the summer of 2004 ([Iliadou, 2009], [DEPA, 2012]). As the market becomes competitive, the market price starts reflecting the volatility of the cost of fuel. However that does not translate into increased standard deviations of DMP for all periods of the day, as the standard deviations of the DMP for the “high demand” periods of the day are at low levels until 2008.
- Secondly, there does not seem to be a consistent pattern that the two Average Summer Days are following. Also, although there are some patterns in the evolution of different average standard deviations of DMP within the two Average Summer Days, these are not followed by all the average standard deviations that we present. Nevertheless, the existence of these patterns for the average standard deviations of specific time periods suggests that the year under discussion is relevant to the DMP volatility.


Graph 5.69b: Summer Working Day, Average Standard deviations of DMP per year, 6 standard deviations
20,00
18,00
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Summer Working Day 24-hour Average Standard Deviation
Summer Working Day 23-6 Average Standard Deviation
Summer Working Day 7-22 Average Standard Deviation
Summer Working Day 9-14 and 18-21 Average Standard Deviation
Summer Working Day 9-14 Average Standard Deviation
Summer Working Day 18-21 Average Standard Deviation


Graph 5.70b: Summer Non-Working Day, Average Standard deviations of DMP per year, 6 standard deviations
18,00
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Summer Non-Working Day 24-hour Average Standard Deviation
Summer Non-Working Day 23-6 Average Standard Deviation
Summer Non-Working Day 7-22 Average Standard Deviation
Summer Non-Working Day 9-14 and 18-21 Average Standard Deviation
Summer Non-Working Day 9-14 Average Standard Deviation
Summer Non-Working Day 18-21 Average Standard Deviation

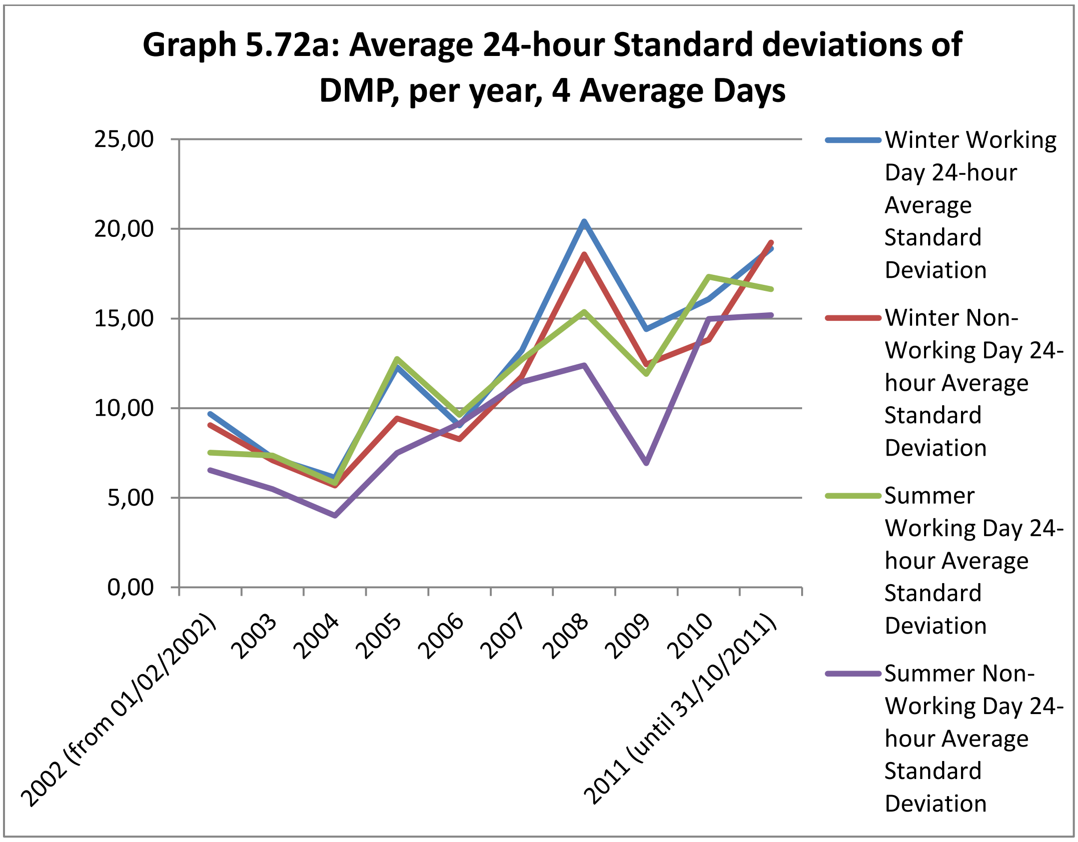
The annual standard deviations that we presented in Graphs 5.67a, 5.68a, 5.69a and 5.70a (to be found in Appendix B, Part 6) have been averaged to calculate the average standard deviation of the DMP per dispatch period for each of the 4 Average Days for the time period 2001-2011. These are presented in Graph 5.71. Graph 5.71 is very similar to Graph 5.59 in both average standard deviation levels and in the patterns that are present. So, in Graph 5.71, we have:

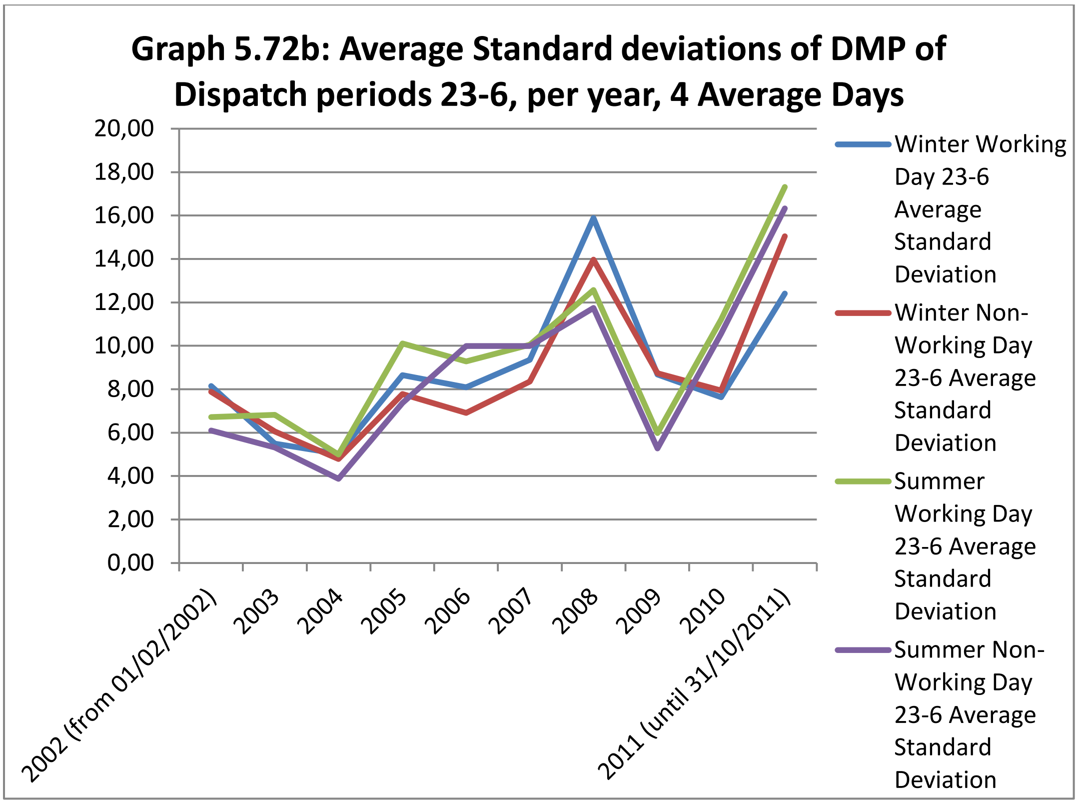
- For the two Average Winter Days, the night-time dispatch periods have lower average standard deviation of DMP than the day-time ones.
- For all the Average Days, the day-time dispatch period present average standard deviations of DMP which are almost constant within each Average Day.
- The two Average Winter Days present for the most part of the day-time hours, higher levels of average standard deviations of DMPs that the two Average Summer Days.
- The Average Summer Working Day presents average standard deviation of the DMP which is at roughly constant levels across all dispatch periods.

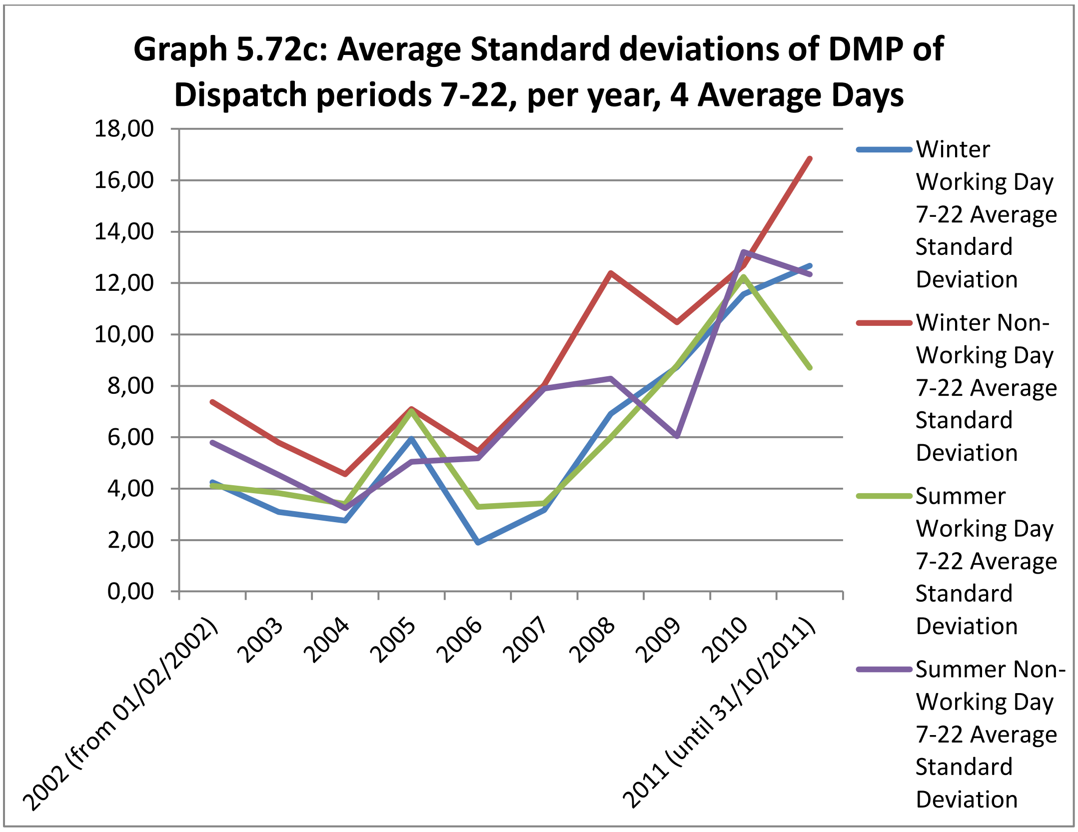


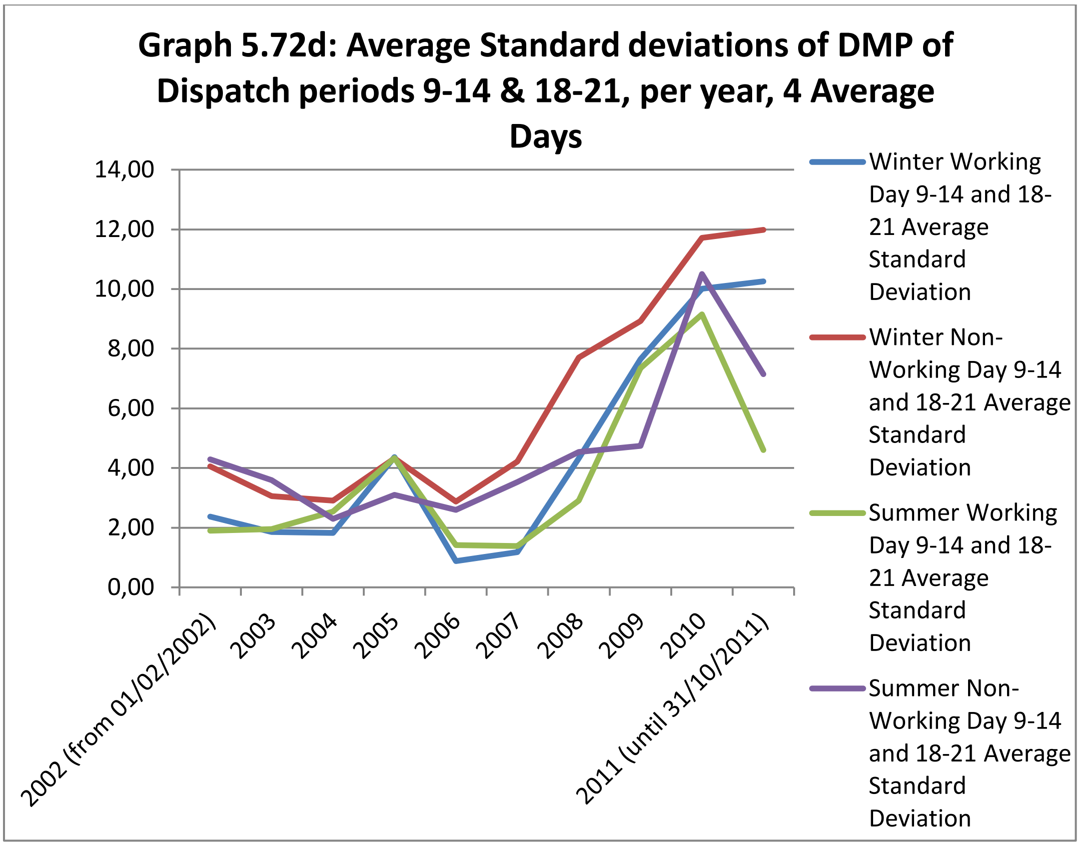
The average standard deviations that we presented in Graphs 5.67b, 5.68b, 5.69b and 5.70b have been rearranged into new graphs and have been now grouped not by the Average Day but by the average standard deviation that is calculated. The result is presented in Graphs 5.72a, 5.72b, 5.72c, 5.72d, 5.72e and 5.72f. In these 6 graphs the average standard deviations of DMP remain at steady levels in the early years that we examine and start increasing and varying from 2007 onwards. In some graphs there seem to be some patterns that are followed by either one or more of the lines that are presented. These graphs differ from the corresponding SMP and System Load graphs. The corresponding graphs for System Load identify flat average standard deviations for System Load, suggesting low volatility from year to year and the corresponding graphs for SMP present different patterns in the values presented. Therefore the volatility of SMP and DMP should be attributed to factors other than volatility in the System Load.

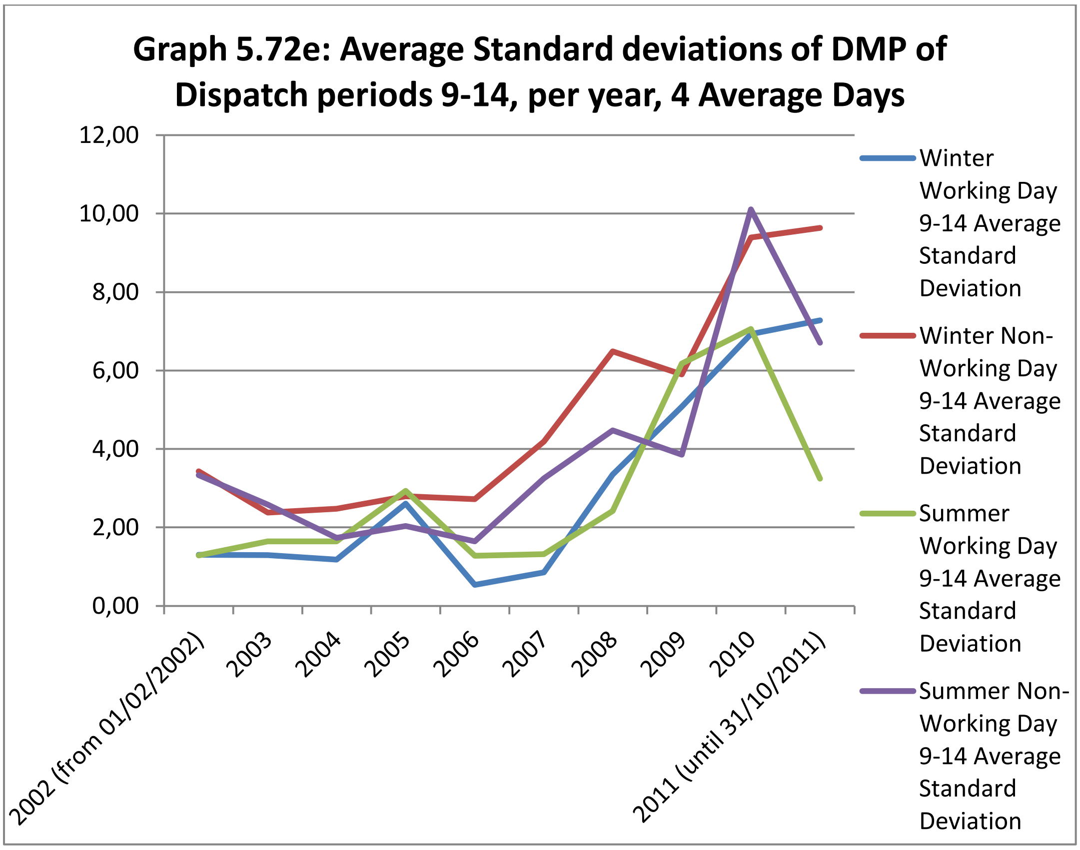
But even though these specific graphs are somewhat ambiguous, the main conclusion is that through examining SMP and DMP and their graphs both for averages and for standard deviations, we show that these are interrelated and the factors that are determining the one are also determining the other.

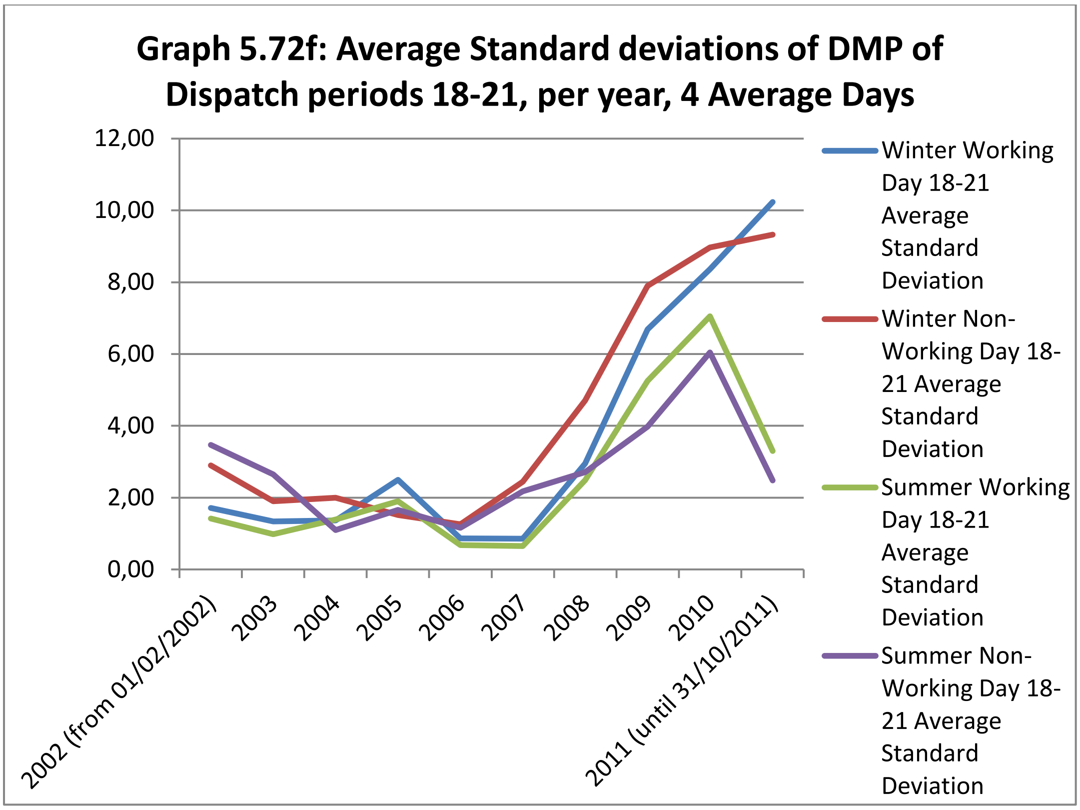



Graph 5.72b: Average Standard deviations of DMP of Dispatch periods 23-6, per year, 4 Average Days
20,00
18,00
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 23-6 Average Standard Deviation
Winter Non-Working Day 23-6 Average Standard Deviation
Summer Working Day 23-6 Average Standard Deviation
Summer Non-Working Day 23-6 Average Standard Deviation


Graph 5.72c: Average Standard deviations of DMP of Dispatch periods 7-22, per year, 4 Average Days
18,00
16,00
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 7-22 Average Standard Deviation
Winter Non-Working Day 7-22 Average Standard Deviation
Summer Working Day 7-22 Average Standard Deviation
Summer Non-Working Day 7-22 Average Standard Deviation


Graph 5.72d: Average Standard deviations of DMP of Dispatch periods 9-14 & 18-21, per year, 4 Average Days
14,00
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 and 18-21 Average Standard Deviation
Winter Non-Working Day 9-14 and 18-21 Average Standard Deviation
Summer Working Day 9-14 and 18-21 Average Standard Deviation
Summer Non-Working Day 9-14 and 18-21 Average Standard Deviation


Graph 5.72e: Average Standard deviations of DMP of Dispatch periods 9-14, per year, 4 Average Days
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 9-14 Average Standard Deviation
Winter Non-Working Day 9-14 Average Standard Deviation
Summer Working Day 9-14 Average Standard Deviation
Summer Non-Working Day 9-14 Average Standard Deviation


Graph 5.72f: Average Standard deviations of DMP of Dispatch periods 18-21, per year, 4 Average Days
12,00
10,00
8,00
6,00
4,00
2,00
0,00
2002 (from 01/02/2002)
2003
2004
2005
2006
2007
2008
2009
2010
2011 (until 31/10/2011)
Winter Working Day 18-21 Average Standard Deviation
Winter Non-Working Day 18-21 Average Standard Deviation
Summer Working Day 18-21 Average Standard Deviation
Summer Non-Working Day 18-21 Average Standard Deviation