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Thao Pham

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École doctorale de Dauphine

Thèse

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Thao PHAM

Market power in power markets in Europe

The cases in French and German wholesale electricity markets

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”I have seen flowers come in stony places
And kind things done by men with ugly faces
And the gold cup won by the worst horse at the races,
So I trust too.”
John Masefield (1878 - 1967)

”Genius is one percent inspiration, ninety-nine percent perspiration”
Thomas Edison (1847 - 1931)

To my parents,
and my grandfathers Lien PHAM and Kiem NGUYEN

Preface

Four years and a half ago I started this PhD thesis with a very good will to put all my enthusiasm and my intelligence on it. I realize now that I needed to and have put much more than that. It turned out to be a so challenging road filled with long days spent in the lab, with hope and joy for good results, with sadness and tiredness of each failed attempt, with "nuits blanches", coffee, laughs and tears. Fortunately, I was not alone on this trip, but accompanied by an extended team of experts, crazy band of PhD, PhD-to-be and non-PhD friends, lovely family, who are always willing to coach, help, and motivate me.

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Thao PHAM
Paris, March 2015.

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Introduction

Electricity systems around the world prior to liberalization were *vertically integrated monopoly under regulation*, either state-owned (most of the cases) or under regulated private ownership (the U.S's for example). That is, all physical functions were incorporated into a limited number of companies - the utilities[1]. Customers received a bill that had all these functions "bundled" into a single regulated tariff. There was no market for electricity trading because the vertically integrated companies had monopolies in their own geographical areas and prices were set or regulated by the central government. This mechanism was maintained for a long time after World War II and until the end of the twentieth century, we had rarely thought that it could be done in any other way.

The reasons for the monopoly are redundant but perhaps the most persuasive argument was that electricity generation had characteristics of economies of scale. As the infrastructure was exploited in larger and larger scale, the average costs went down. Efficiencies continued with the increase of plant size. And the large investments in power plants were greatly economic when we integrated their development with the expansion of the transportation networks. These characteristics made it efficient to have one entity (utility) build the plants and develop network of wires [2]. The ideas of organizing the indus-

[1] A public utility is an organization that maintains the infrastructure for a public service. Public utilities are subject to forms of public control and regulation ranging from local community-based groups to state-wide government monopolies. The term utilities can also refer to the set of services provided by these organizations consumed by the public: electricity, natural gas, water.

[2] These general arguments were not restricted to electricity. The similar stories can be found, with different details, in different network industries like telecommunication, airlines, rail, natural gas, oil industries at that time. The typical organization was large monopolies, with government ownership or regulation. See more details in Joskow [1996]; Shy [2001] or Economides [2004].

try in that way were probably valid at that time. However, the scene started to change by the late 1970s. During these times, a large number of power plants (especially nuclear) were built throughout Europe at tremendous cost overruns, which had resulted in dramatic increase of prices [3]. Electric utilities probably insisted that the post-war economic boom in Western countries would continue to increase the demand for electricity even when prices increased. At the end of the 1980s, many utilities involved long term debts and annual losses, with seemingly endless delays in infrastructure investment (Hogan [2000]). In retrospect, one of the biggest flaws bound to the old system was a *lack of incentive*. When a firm thought that it was "using" someone else's money, it would have less incentive to minimize costs or to promote innovation. The long era of monopolies under government protection had resulted in slow-moving arrogant companies which were accustomed to the "quiet life", as famously demonstrated by Hicks [1935], creating the "X-inefficiency", as Leibenstein [1966] observed [4]. Regulation could hardly fix the problem because suppliers always know the market better than the regulators. Indeed, the interest of monopolistic firms is to take advantage of their asymmetrical information relationship with the regulators to increase their revenue (Tirole and Laffont [1993]). The ideas of re-organizing the industry in the way of greater reliance on market forces began to be discussed.

In the late 1970s, a technological advance, known as gas turbine technology, was made and contributed to reshape the electric power industry. This new technology had nearly double energy efficiency with lower investment costs and smaller in size as compared to the old methods of burning gas or oil to produce electricity. The economies of scale, saying that bigger and bigger power plants produce lower and lower costs and that only the government is able to carry out that huge needed investment were no longer valid. With these technological developments (along with significant improvements in transmission systems), any plausible supplier can deliver power at the minimum cost to cus-

[3] This trend was initially triggered by the 1970s energy crisis in which the economies of the major industrial countries in Western Europe were heavily affected and faced substantial petroleum shortages as well as elevated prices. (oil shocks in 1973 and 1979).

[4] The concept of X-inefficiency was introduced by Harvey Leibenstein (1966). It is the difference between efficient behavior of firms implied by economic theory and their observed behaviors in practice. It occurs when technical-efficiency is not being achieved due to a lack of competitive pressure.

tomer in any particular market. The early initiatives to introduce competition in the electricity industry in the U.S were first marked by the Public Utility Regulatory Policy Act (1978), which played an important role in stimulating the entry of independent power producers into the electric power sector during the 1980s and helped to set the stage for more dramatic reforms of the late 1990s (Joskow [2000]). In Europe, changes began a bit later during the end of 1980s. The arguments to support monopolies had been questioned after the World War II and the new ideology, extolled by the former British Prime Minister Thatcher, which supported market driving forces, was introduced at the right time.

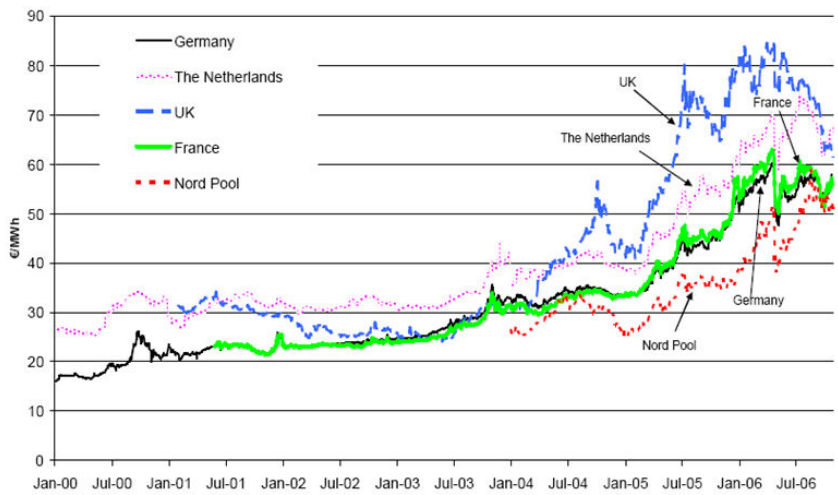
Since the late 1980s, the advance and success of market–based system and deregulation in many industries like airlines, natural gas and telecommunication shed light on the electric power industry, one of the last great twentieth century monopolies. The new idea was to rely on markets forces to drive innovation forward and costs down as well as to narrow the control of government to the areas where markets typically fail. In Europe, the process started in the United Kingdom with the British Electricity Act of 1989 then gradually spread across neighborhoods like Scotland, Northern Ireland and the Scandinavian countries before expanding to the rest of Europe.

Reforming the electricity industry was much harder than it appeared at the first glance. One cannot simply break up the monopoly, cease to regulate and wait for the market forces to rush in making competition work. The shift to reliance on market prices, given concentrated structures and particular characteristics of electricity industry, raises a possibility that some firms could influence the market prices by exercising their market powers. If market power is exercised to a certain extent, the resulting harm may be worse than when no competition had been introduced. That had been the case of California electricity crisis 2000-2001, when transitional market rules severely limited participation of its utilities in forward markets and enhanced the market power of new generating entities (Friedman [2009]). Prices in California's wholesale electricity market increased by 500% between 1999 and 2000 (Joskow [2001]). Many customers have been required to curtail electricity consumption in response to supply shortage. The situation went as far as having one of the state's largest energy companies collapsed, widespread rolling blackouts and

economic fall-out.

"Market power" is indeed not a new concept. It is defined in classic economics as the ability to alter profitably prices away from competitive levels (Fellner [1949]; Baumol [1986]; Case and Fair [1988]; Stiglitz [1993]; Krugman and Wells [2009]). Theoretical and empirical studies of *"market power in power markets"*; however, have only been developed recently. The issue of market power in the newly liberalized electricity markets raised concerns in both sides of the Atlantic, as regard to the way of defining, detecting, and monitoring it. In 2005, for instance, the European Commissions DG Competition launched a Sector Inquiry into the European electricity and gas markets. The final report published January 2007 revealed serious distortions of competition in the sector (Competition [2007]). It highlighted a concern that market concentration remained very high, *which gives scope for exercising market power* and that large energy consumers still do not believe that prices on the spot wholesale markets are the result of fair competition. Indeed, the evolution of electricity prices on wholesale markets in Europe since the early days of the liberalization has raised concerns among consumers and regulators.

Figure 1: Wholesale electricity price year-ahead base load in EUR/MWh 2000-2007



Source: European Commission, Energy Sector Inquiry (2007)

Clearly, since the summer of 2003 electricity wholesale prices started to rise on most markets and diverged strongly between countries (figure 1). What

made those prices increase was; however, not clear. A rise in the electricity prices could be resulted from a number of exogenous reasons such as the increase in fuels costs; the implication of CO2 pricing (since 2005), or constraints on interconnection, etc. It could also be explained by an endogenous reason: the possibly strategic behaviors of firms as they exercise their market power. This endogenous factor, however, could not be observed. As wholesale prices directly impact supply prices offered to final customers (especially to industrial users) in a number of Member States, their increase provoked wide-spread concerns about the overall functioning of the electricity markets.

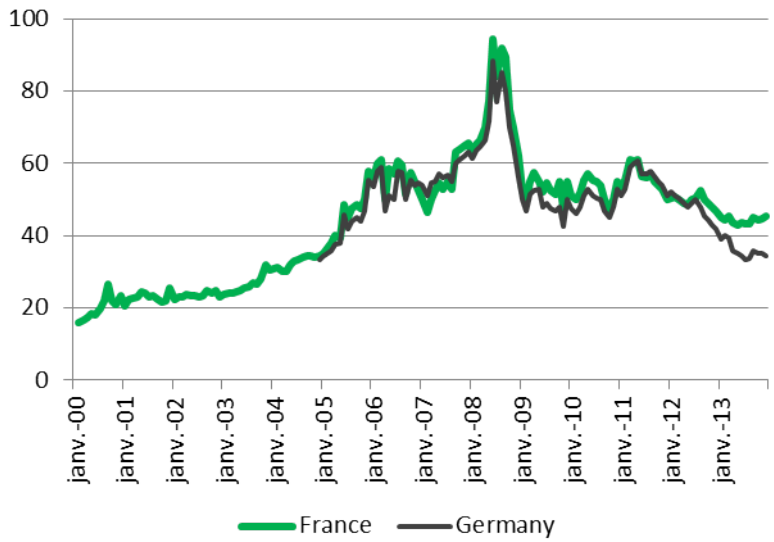
In this thesis, we carry out an insight research around market power questions in deregulated wholesale electricity markets in Europe. Studying market power has never been an easy task and doing so in electricity markets is even more challenging. Certain problems, some of which arrive from peculiar characteristics of electricity (such as lack of demand response, non-storability of electricity), some of which arrive from political and social concerns (creating some sort of entry barriers), make exercising market power in power markets particularly likely and detecting it extremely challenging. In this thesis, we attempt to shed some light on the puzzle by an in-depth research on the problem of market power in term of defining and measuring it. We carry out empirical studies in two of the biggest liberalized electricity markets in Europe: France and Germany.

French and German electricity markets are the third and second largest in Europe after the British one in terms of installed capacity and consumption. Together, they count for one third of the entire European electricity consumption. Although the two power systems are quite different: one centralized, rather monopolistic and nuclear-based, the other more and more renewables-based decentralized, convergence has been observed in recent years regarding expansion of renewable energy, energy efficiency or reduction of nuclear energy (under the energy transition policy in both countries: *transition énergétique* in France and *Energiewende* in Germany[5]).

[5]The national debate of energy transition (transition énergétique) was launched in November 2012 by the new French government and The Energy Concept (Energiewende) was adopted by German federal government in September 2010. This policy trend refers to a shift to sustainable economies by means of renewable energy, energy efficiency and sustainable development.

Germany's and France's electricity systems been dynamically evolving since the early years of liberalization. Yet, the questions of designing tools for a fully competitive market are still being debated. This is also one of the major issues being discussed in the energy transition in both countries. In fact, electricity market in France is highly concentrated with Electricité de France (EDF), the biggest producer of electric power in Europe, dominating the domestic market. In Germany, four dominant firms - E.ON, RWE, EnBW and Vattenfall Europe - still control over 77% of the market at the end of 2011 according to the Federal Cartel Offices monitoring data in 2013 (FNA and FCO [2013]). These market structures continue to evolve in response to many recent changes in the European energy market.

Figure 2: Wholesale electricity price year-ahead base load 2000-2013 in France and Germany (monthly average)



Source: CRE

Figure 2 depicts monthly average year-ahead prices in the wholesale markets in France and Germany. The prices in these two markets, being strongly convergent, were almost tripled within only several years since the end of 2013. The year-ahead prices for baseload[6] soared from around 30€/MWh to over 80 €/MWh between 2004 and 2008, growing even faster than oil price. Though

[6]Baseload refers to the minimum amount of electric power delivered or required over a given period of time at a steady rate.

highly increased prices do not necessarily imply market power abuse, this increase has raised much concerns (and discontent) among consumers about the competitiveness in those markets. While competition was supposed to lower the market prices, this has not been what we observed since the market opening in France and Germany. All those observations motivate us to carry out empirical analysis of market power in these two markets.

Market power detection techniques have been dynamically evolved over the last 15-20 years, varying enormously from theoretical to empirical models and from market structure to market outcome approaches. Indeed, up to the late 1980s, empirical studies of market power in liberalized generation electricity markets were scarce since it had rarely been contemplated outside the United States. Most studies attempted to assess the potential for exercising market power by measuring the extent of market concentration in regional submarkets (Schmalensee and Golub [1984]). Studies of market power in Europe were developed a bit latter but were not out of this line. Since then, the analysis of market power based on structural approach has not only been limited on traditional concentration method but extended to more electricity-adapted method like residual supply indexes, which take also the demand side into account (Sheffrin [2002]). A more sophisticated and popular approach to detect market power involves simulation models based on market outcomes data. Named in different ways and implemented in different modelling strategies, the decisive clue of this approach concerns the estimation of system marginal cost. This can be done by econometric modelling, known as New Empirical Industrial Organisation (NEIO), for example Hjalmarsson [2000] and Mirza and Bergland [2012]; or by various simulation models as conducted in Green and Newbery [1992], Borenstein, Bushnell and Wolak [2000] (supply function equilibrium), Borenstein, Bushnell and Wolak [1999&2002] (Nash-Cournot equilibrium), Bushnell and Saravia [2002] Lang and Schwarz [2006], Weigt and Von Hirschhausen [2008] (optimization models). Each of those methods has strengths and weaknesses. Using structural indexes is simple, straightforward and requires little data but it provides only suspected location of market power, not the actual level of market power. Though this could be useful for an ex-ante analysis about the "potential" of market power in many mergers and acquisition cases, for most of economists this is not suf-

ficient. Market simulations models, on the other hand, are more sophisticated and firmly grounded in price theory. The outcomes of such models could give valuable information about the actual level of market power abuse. However, this method requires precise estimation of marginal costs. A lot of assumptions bound to the models might negate the certitude of conclusions.

Over the last two decades, a number of works have been implemented to diagnose market power in electricity markets using both approaches, with some authors finding market power in certain markets and some others disputing it. Although many advances have been made, we are still far from being able to define an appropriate method to detect market power taking into account all possible aspects and well-functioning market designs to overcome the problem of market power. In this thesis, we will shed lights on these issues, by examining various methods developed by economists for detecting market power in literature and implementing empirical analyses in France's and Germany's electricity wholesale markets. We are using the method of market simulation and modeling because this has been considered better able to capture relevant factors and dynamic considerations that are not present in traditional tools such as structural indicators (Twomey, Green, Neuhoff and Newbery [2006]). Two different modelling strategies are employed: econometric model (New Empirical Industrial Organisation approach) and optimization model.

The thesis is composed of five chapters and a prologue:

We provide in the Prologue some background details that tie into the main chapters. Definitions of key concepts described in the Prologue are important to give clarity throughout the thesis. They involve several terms defined in relation to the thesis, including some essential aspects of electricity industry and key terminologies commonly used in the economics of electricity markets as well as industrial organization.

Chapter I discusses the evolution of wholesale competition in the European electricity industry as well as associated regulatory reforms, and some fundamental economic aspects of electric sector. This chapter implies a qualitative analysis. It begins with a discussion of the industry structure and regulatory framework that characterized the electric power industry world-

wide during most of the twentieth century and reviews the initial efforts to reform the industry (regulation, deregulation and market opening processes) in European electricity markets during the 1980s and early 1990s. From this starting point, we analyze fundamental economic aspects of electricity market. It encompasses the questions of supply and demand; costs and prices; equilibrium and optimization. We also provide the standard prescription for the reform of electric power sector, which has been derived from both theory and from years of practical experience in the field. Understanding these factors is essential, no matter which country and no matter what its initial conditions are.

In chapter II, an insight literature review of market power issues in electricity markets is carried out. We provide some clarifications on "market power" definition and the application of this definition in wholesale electricity markets. While standard definition of market power can be perfectly applied in electricity markets, the methods for detecting market power in the electric power sector could not be the same as ones applied in any other markets. Many distinguished idiosyncrasies of the industry as well as the existence of entry barriers make exercising market power in power markets particularly likely and detecting it extremely challenging. The methods to estimate market power in power markets that have been employed in the literature during the last three decades are discussed in detail. An initial assessment of the strengths and weaknesses of various approaches to estimate market power and some analyses regarding future challenges and trends are also provided.

In chapter III, we present the method of New Empirical Industrial Organisation (NEIO) commonly used to estimate the market power in various industries during the late 1980s and developed recently in electricity markets. We describe the logic of this method on both theoretical and empirical basis, and provide a framework an analyst can use to develop the models to evaluate market power in electricity industry. The nature of the data on wholesale electricity market is described to justify the choice of models that we are implementing. We provide a detailed description of the data including various demand shifters and price drivers in the French electricity wholesale market. The French data during 2009-2012 is used largely thanks to its availability and also because empirical works on French power markets on the issues of market

power during this period have been rarely employed in literature.

In chapter IV[7], the NEIO model is conducted to investigate the presence of market power abuse in the French wholesale electricity market during 2009-2012. Both multivariate and panel data models are taken into account. The issue of market power in the French power market is of particular interest in the context of its expansion in the next few years after the end of regulated tariffs for all firms under European pressures and national decisions. The performance of wholesale power market has been thus one of the issues being discussed in the energy transition in France (*transition énergétique*), given the highly concentrated market structure and the significant increase in market prices during recent years despite the advantage of inexpensive nuclear power electricity generation in France. The model-based results are subject to be discussed.

The empirical analysis of market performance in the German wholesale electricity market in 2011 is carried out in chapter V. Following the method of linear programming as commonly used in literature of electricity market modelling, we simulate a competitive benchmark for German wholesale market in which all demand is cleared via a single market process. Marginal costs and market clearing prices under the hypothesis of perfect competition are estimated via an optimization program in which costs are minimized, subject to several technical constraints and energy balance. This competitive benchmark is then compared with actual spot prices. On the basis of the difference between modeled marginal costs and observed market prices, we estimate the price-cost markups, or the Lerner Indexes across hours. The robustness of the results is verified via several sensitivity analyses.

The question addressed by this thesis is of intense practical significance because it is raised in the right place and at the right time. The European generation electricity market is enormous - accounted for nearly 30 % of worlds total generation in 2010 (IAE[2013]) and has evolved without cease. Indeed, the energy landscape in recent years is dramatically agitated with unpredictable events: the revolution of non-conventional gas in the U.S, the catastrophe of Fukushima in March 2011 whose impacts on the energy choices in the world

[7]Chapter III and chapter IV of this thesis were summarized in a research paper, published in the *Energy Studies Reviews, 2015, 21* (2) (Meritet and Pham [2015]).

are still immeasurable, the political turbulence in the Arabs countries in 2011 followed by the increase of fuel prices, the sudden sharp decline of oil prices since June 2014, and the strong volatility of the European CO2 prices, etc. These unexpected events remapped the European energy balances, which in turn have significant impacts on the electricity market. Many European countries release new rules for the energy transition towards a less carbon-intensive production mix, while promoting further competitiveness in energy markets particularly electricity production sector. These phenomena altogether contribute to making more volatile power prices. Wholesale electricity prices are thus more risked to be distorted. This raises concerns about the efficiency of market reform process. Indeed, the consequences of market power abuse refer not only to the wealth transfers between customers and operators but also to the impacts on the secure and efficiency of the whole electricity system. The experiences from California's electricity crisis 2000-2001 show that market power abuse could result very harmful consequences on the functioning of the industry as a whole. This provides a necessity of defining relevant efficient methods to detect the problem of market power. Furthermore, the issue addressed by this thesis ties with the ongoing reorganization of European electricity market and the increasing liquidity on the wholesale markets in Europe. This being the case, developing relevant market power detection tools for electricity spot markets is a key issue for both academics and regulators. We concentrate in this thesis only in European power markets, though examples in different markets in the United States are sometimes given. The thesis deals with the problematics covered in the Economics of Industrial Organization, using econometric regressions and electricity simulation models as main methodologies.

Prologue

We provide in this Prologue some background details that tie into the main chapters. Definitions of key concepts described in the Prologue are important to give clarity throughout the thesis. The following terms are defined in relation to the thesis, including several essential aspects of electricity industry and key terms commonly used in the economics of electricity markets.

The Essential Aspects of Electricity Industry

Electricity systems around the world have similar functional organization. This involves four main activities (1) the production or generation of electricity, (2) the transport of electricity on high voltage levels (transmission), (3) its transportation on low voltage levels (distribution); and (4) merchant functions such as retailing to final customers and wholesale power procurement.

Generation (Production)

Electricity has been described as "secondary" commodity in energy industry. It takes multiple raw fuels and turns them all into one product: electric energy. The process of transformation of different forms of energy into electric energy is called electricity generation. This is done either chemically through the combustion of fossil fuel such as coal, oil or gas, or physically through the use of nuclear fission, or kinetic energy from wind or water in motion. Each plant uses only one fuel, but one company may use a variety of fuels in different plants in their portfolio.

Generation accounts for about 35% to 50% of the final cost of delivered electricity[8]. Different types of generating plants are characterized by different cost structures (shares of fixed and variable cost). Hydro-electric and nuclear plants have high fixed costs (for example nuclear and hydropower have the overnight costs at about $4619/kW and $2134/kW respectively) and low variable costs (essentially low for nuclear and almost zero for hydropower). These plants, called "*baseload*", function with a constant output over 24 hours of each day throughout the year except in the case of scheduled maintenance. On the other hand coal, oil, and gas plants have lower fixed costs, which vary from $300 to $2000/kW according to the data of International Energy Agency's report (OECD-IEA [2010]) [9], but very high variable costs due to the high fuels' prices. This special characteristic is of great importance as considering the questions of pricing in electricity market (See more in section 1.2).

Transmission system

Once generated, electricity is transported in high-voltage over a network of copper or aluminum wires called the transmission system. Transmission accounts for about 5% to 15% of the final cost of electricity depending on countries or regions (Hunt [2002]). The transmission system is fragile: each line has a maximum capacity it can safely take. When this maximum has been reached, the network becomes congested. Beyond that, it becomes overloaded and can cause widespread blackouts. Electricity flows must be managed on a continuous, real-time basis with no traffic jams, no busy signals. In particularly electricity flows along the lines of least electrical resistance, according to the laws of physics, not along contractual path.

Transmission System Operator

Transmission System Operators (TSOs) are responsible for the bulk transmission of electric power on transmission networks. TSOs provide grid access to the electricity market players (i.e. generating companies, traders,

[8]The cost of the various functions of the electricity industry varies widely in different countries/regions, the percentages are given as a general indication only.

[9]Again, the cost of the various technologies varies from place to place

suppliers, distributors and directly connected customers) according to non-discriminatory and transparent rules. In many countries, TSOs are in charge of the development of the grid infrastructure too.

System operations could be eithor system operator with responsibility only to balance demand and supply in the real time consistent with the stability and reliability of the network; or a transmission company that owns and manages the network's transmission facilities as well.

Distribution system

Electricity is delivered from transmission network to local distribution systems (low voltage levels), and then to customers by distribution wires. Together with transmission, distribution systems are functioned to transport electricity but they are organized separately. The former works with generation (through the system operator) whereas the later works with the customer. Once electricity reaches the distribution wires, it could no longer be controlled: electricity just flows over the wires to the customers, and meters record how much has flowed. The distribution function accounts for about 30% to 50% of the final prices paid by the consumers depending on countries/regions.

Merchant function

Wholesale procurement

The term "wholesale" refers to electric trading among producers, distributors and big customers (figure 3). Electricity is traded in wholesale level via organized marketplace like power exchanges and power pool or Over-the-Counter (OTC) contracts.

Power exchange is a centralized market in which securities, commodities, derivatives and other financial instruments are traded. Power exchange does not provide side payment: at any given time and location, all generators selling power receive the same price.

A ***power pool*** is a centralized market whose functions are as same as those of power exchanges. However, power pool uses "side payments" which depend on the suppliers' bids: it pays different prices to different suppliers at

the same time and location. These payments are only made when the pool price is too low for an accepted supplier to recover its costs.

OTC contracts involve only two counterparties, the buyer and the seller, trading via a network of brokers, rather than matchmaking service. OTC contracts can be seen as financial instruments and OTC market is not standardized or organized. Though OTC represent a big fraction of total market volume, it is not main concern of this thesis. Furthermore, the prices in the OTC market (bilateral contracts), like prices in forward markets, are devired from prices in spot markets. If spot prices are competitive and efficient, these tend to be convergent.

Trading for energy delivered by any minutes begins years in advance and continues until real time by a sequence of overlap of forward and spot markets. Spot markets for energy in wholesale level are composed of *day-ahead, intra-day adjustment* and *real time balancing markets.*

Day-ahead market is considered either as spot market or forward market with the greatest physical implications (because it is run just one day prior to physical transactions). The day before the delivery day, supply and demand bids are submitted; winning bids are selected and prices are determined based on "uniform price" or "pay-as-bid" rules. The former refers to a rule which the successful sellers of power in should all receive the uniform, market-clearing price and the latter implies several bid pricesthat is, the prices at which each offered its energy blocks (Kahn, Cramton, Porter and Tabors [2001]).

Real time balancing market (or real-time market) consists of trades that are not under contract; i.e., the transactions of real time market are derived from deviations from quantities specified in forward contracts (including day-ahead commitments). This market is managed by the TSOs in order to guarantee the availability of power reserves to ensure global supply-demand balance in real time.

Trading in the wholesale level could also involve in capacity markets (which is not covered in this thesis). In fact, there is a difference between energy and capacity markets. A power plant, for example, generates electricity and are paid for that electricity in the **energy markets**, which is our main concern. **Capacity markets**, on the other hand, are designed to ensure the

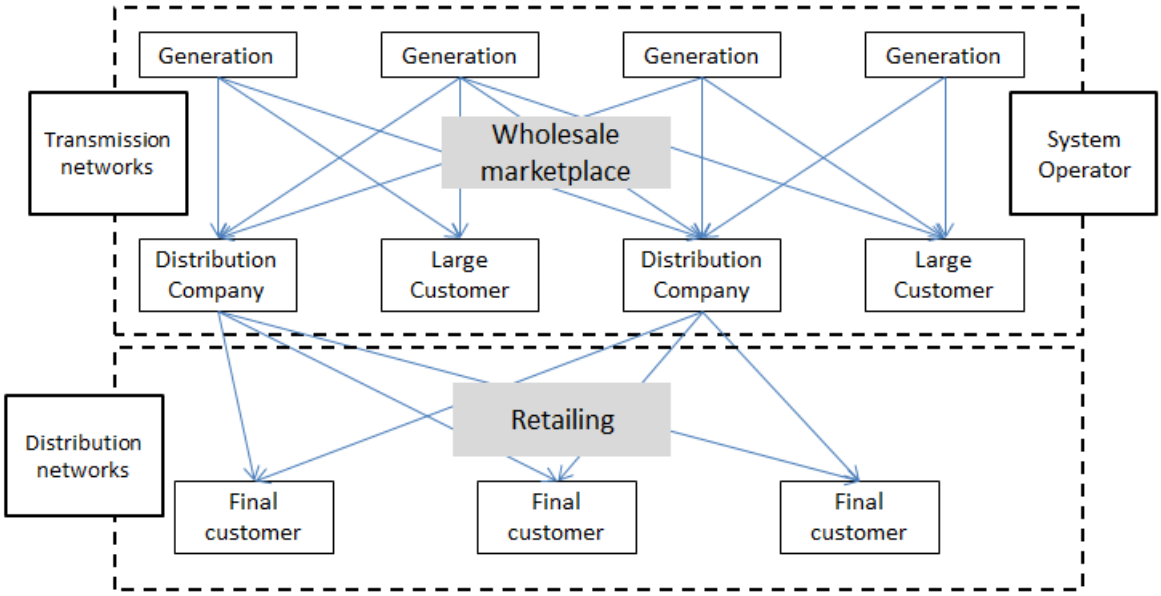
reliability of the electricity system. The basic idea is that power plants receive compensation for capacity, or the power that they will provide at some point in the future.

Retailing

Retailing is sales to the end – users and involves commercial functions such as procuring, pricing and selling electricity, metering, billing the usage and collecting payment. Trading in retail markets is not employed in this thesis because this sector had been generally regulated in most countries in Europe since the early days of market reform. However, the retail function could be competitive as far as procuring, pricing, and selling electricity. In most countries today, every customer may choose his or her own electricity supplier and opt for market prices or regulated tariff.

To summarize, generation, system operations, transmission, and distribution are physical functions while Retailing and wholesaling are merchant functions. The relation between thoses functions are illustrated in figure 3

Figure 3: An example of electricity value chain and organisation of markets



Source: Hunt [2002]

This is model which has a fully competitive generating and retailing sector. The arrows imply energy sales' flows

Market coupling

A generator who wants to sell its power has to implement two steps: trading power, and trading the transmission rights (not necessarily in this order). There are two general approaches to allocating scarce transmission capacity. Transmission rights can be allocated via explicit auctions among generators (*explicit auction*). Alternatively, the system operator sells transmission rights along with any trade it arranges. In such a market, a (competitive) generator only needs to bid its marginal cost without consideration of market conditions for transmission rights (*implicit auction*).

Market coupling is a method for integrating electricity markets in different areas. With market coupling, the daily cross-border transmission capacity between the various areas is not explicitly auctioned among the market parties, but is implicitly made available via energy transactions on the power exchanges on either side of the border (hence the term implicit auction). It means that the buyers and sellers on a power exchange benefit automatically from cross-border exchanges without the need to explicitly acquire the corresponding transmission capacity (See more in Meeus, Vandezande, Cole and Belmans [2009], Hobbs, Rijkers and Boots [2005]).

Key concepts in the economics of electricity markets

Economies of scale

In microeconomics, economies of scale are the cost advantages that enterprises obtain thanks to their size, with cost per unit of output (average cost) generally decreasing with increasing scale as fixed costs are spread out over more units of output. Operational efficiency is also greater with increasing scale, leading to lower variable cost as well. There are various explanations for the presence of economies of scale, such as the existence of substantial fixed costs; opportunities for specialization in the deployment of resources and a strong market position of factor inputs (Baumol and Bradford [1970]). Economies of scale are often the reason of the existence of natural monopoly. An industry

is a natural monopoly if the production of a particular good or service (or all combinations of outputs in the multiple output case) by a single firm minimizes cost

Transaction costs

Transaction costs are the costs associated with making contracts (between firms) to replace command-and-control relationships (within a firm). Contractual relationship in this context may mean any agreement about the terms on which the transactions take place between separate firms (Coase [1937] and Williamson [1979]).

Franchised monopoly

Franchised monopoly is a legal monopoly status given by the government to a company. In most nations, franchised monopolies can be found in essential sectors such as transportation, water supply and power. In many countries, primarily developing nations, natural resources such as oil and gas, and metals and minerals are also controlled by government-sanctioned monopolies.

Network Externalities

An externality is an effect that is external to the market, that is, somebody profits or is hurt, but nobody pays/is paid for it (positive and negative externalities). Most externalities are negative, that is, the effect is harmful to the third party which is not part of the market. Network Externalities might be either positive or negative. There is a positive network externality when the value that existing network users get from the network increases as another user joins the network. The new user therefore has an effect that is "external" to him. On the other hand, there is also a negative externality arose from networks when congestion binds. For example, a "blackout" might occur when the transmission lines become overloaded. Since an externality is an economic effect not covered by the market, it normally results in "market failures", that is, the market does not achieve optimum welfare (Literature on network externalities can be found in Economides [1996]).

Market/regulation terms related to Liberalization of Electricity Industries

Liberalization: the opening up of markets to competition. Prices and investment decisions are thus determined by market forces. Economic liberalization is often associated with *privatization*, but these two concempts are distinct. For example, the European Union has liberalized gas and electricity markets, instituting a competitive system, but some leading European energy companies such as France's EDF and Sweden's Vattenfall remain partially or completely in government ownership.

Material privatization: the change of ownership from public to private (ownership).

Formal/functional privatization: outsourcing of some of the functions to the private sector.

Deregulation: replacing regulated tariff systems by market-based prices, the change/creation of (legal) rules leading to the opening of markets i.e., leading economic actors to compete among themselves. (The issue of deregulation are discussed in detail in section 1.2)

Unbundling: the breaking up of vertically integrated infrastructures into seperate segments (competitive and non-competitive). Specifically, competitive segments (generation, marketing and retail supply) must be separated from regulated segments (transportation and system operation). Unbundling involves thus both ownership and legal unbundling.

Ownership unbundling is advocated by the European Commission and the European Parliament. This option is intended to split generation from transmission (Art. 9-12 of directive 2009/72/EC). The Art. 13 – 16 of directive 2009/72/EC gives the member states also the opportunity to let the transmission networks remain under the ownership of energy groups, but transferring operation and control of their day-to-day business to an independent system operator. It is also a form of ownership unbundling, but with a trustee. This would remove the conflicts of interest between transmission and generation by preventing discrimination that might arise where there is common ownership between network users and network operators.

Legal unbundling (referring also as acounting unbundling) means that transmission and distribution are to be done by a separate "network" company, independent transmission operator. This model envisages energy companies retaining ownership of their transmission networks, but the transmission subsidiaries would be legally independent joint stock companies operating under their own brand name, under a strictly autonomous management and under stringent regulatory control. However, investment decisions would be made jointly by the parent company and the regulatory authority (Art. 17-23 of directive 2009/72/EC).

Chapter 1

European electricity reforms and the economics of electricity markets

Abstract: Reforming electricity industry is harder than most people think. It is, in Joskow's expression "easy to do badly and difficult to do well" (Joskow, 2002). The government's interferences should not be phased out completely once at a time like the deregulation of many other industries. One cannot simply stop to regulate the industry and break up the monopoly then "laissez-faire", expecting a competitive market to rush in and do its magic. The success of electricity reform depends upon understanding the complexities of electricity markets and designing solutions to account for those complexities. In this chapter, we describe fundamental regulatory as well as economic aspects of electric sector. We provide also the standard prescriptions for the reform of electric power sector, which have been derived from both theory and from years of practical experience in the field. Understanding these factors is essential, no matter which country and no matter what its initial conditions are.

Introduction

The organization of electricity industries in Europe has experienced a long history from competition to regulation at the end of World War II 1945, then a switch back from regulation to deregulation/competition in late 1980s. Up to now, most of European countries have opened up their markets to competition.

It is a fair question, and often asked: If competition is good for consumers, why politicians did not proceed it right from the beginning and had to wait for until late 1980s for those changes? The merits of competition as well as the problems involved monopoly were abundantly demonstrated in economic theory, for example, Hicks (1935) and Leibenstein (1966). Indeed, before the end of World War II in Europe, there was competition. Electrical industries at that time were in hands of a large number of private companies. Those companies provided production, distribution and other services under a variety of agreements with local authorities and regional administrations. In France for instance, by the outbreak of World War II, electricity was provided by about 200 companies engaged in production, another 100 in transport, and about 1150 involved in distribution. With overlapping transportation lines and lack of centralized planning, the system was irrational and inefficient, going as far as having two companies provided electricity to the same place (Gant [2001]). Competition for customers was brutal and costs were high and wasteful.

In consequence, following the end of World War II, most European governments decided to nationalize their electricity industries by merging hundreds of electricity companies and incorporating generation, transmission and distribution companies to be vested in a single merged utility in each nation. This structure is known as "vertical integration monopoly". Furthermore, in a post-war Europe, the first objective of electricity sector in almost every country was to build enough generation facilities to speed up industrialization after war. In order to achieve this goal as quickly as possible, countries increase their control on the electricity industry. In France (1946), the UK (1947), and Italy (1946) for example, the governments decided to consolidate the electrical industry into a single nationalized utility where state had direct control on pricing and investment choices (Chick [2007]). Other countries like Germany and Spain, though not having state monopolies, their electricity industry

still corresponds to an integrated model under regulation (Grand and Veyrenc [2011]). This mechanism was maintained for a long time since the World War II and until the end of twentieth century (1986), we had rarely thought that it could be done in any other way.

The idea of organizing the industry in this way was valid in the context of post-war industrialization. There were, in fact, sound economic and political reasons to support the nearly-half-century history of the industry as integrated monopoly. But when technology and economic ideology evolved with time in a new European context, the scenes started to change. In the late 1980s throughout 1990s, many of monopolies were broken up, markets for electricity trading were created and competition was introduced. In restropect, what were the prerequisites and turning points to make competition feasible in that time although it didn't work well before? What were the ideas behind this new organization of the industry? How to make competition work in the newly opened markets? What to deregulate and what not to deregulate, etc.? This chapter gives fully-detailed analysis for those questions.

The chapter is structured as follows. Section 1.1 discusses industry structure and regulatory framework that characterized the electric power industry worldwide during most of the twentieth century. Section 1.2 reviews the initial efforts to reform the industry (regulation, deregulation and market opening processes) in European electricity markets during the 1980s and early 1990s. Section 1.3 analyzes fundamental economic aspects of electricity market: supply and demand; costs and prices; equilibrium and optimization. Understanding this is essential for any further studies in power system economics.

1.1 Review of vertically integrated monopoly under regulation model

In a context of post-war, most European countries decided to nationalize their electricity industries by merging hundreds of electricity companies and incorporating generation, transmission and distribution companies to be vested in a single nationalized utility. The customers received a bill that had all functions "bundled" into a single tariff, set by central governments. This had been

the case in France, the UK and Italy with the consolidation of Electricité de France (EDF) in 1946, the Central Electricity Generating Board (CEGB) in 1947, and Ente Nazionale per l'energia Elettrica (Enel) in 1946 respectively.

The model of vertical integration monopoly under regulation was maintained for nearly half of century in Europe. There were, in fact, sound economic and political reasons supporting this model.

1.1.1 Reasons for monopoly and regulation post-war in Europe

(i) ***The natural monopoly aspects of generation.***

Electricity generation industry had a characteristic of "economies of scale". A conventional wisdom supposed that there was no way to produce power cheaply on a small scale. Investment in a power plant required enormous capital. Bigger and bigger plants produced lower and lower prices. The long run average total cost declined substantially with the increase of scale, or, efficiencies continued with the increase of power plant sizes. Larger companies were more profitable and drived out smaller ones[1]. For the same reason, established companies had a cost advantage over any potential entrant. So economies of scale can both give rise to and sustain monopoly. This was what the economists called "natural monopoly" (Baumol [1977], Joskow [2007]). In regard to estimates of economies of scale in the power sector, there has been a substantial amount of empirical works. The pioneering works on the subject were done by Nerlove [1961] and Christensen and Greene [1976]. Translog cost functions were estimated using cross-section data for US firms producing electric power in 1955, both authors unanimously agreed upon that economies of scale existed in electricity generation. For more recent works on the subject, see for example, Hisnanick and Kymn [1999] and Knittel [2002].

[1]Firm cost functions that have this attribute are said to be subadditive at output level. Baumol and Bradford [1970] introduced formally the notion of subadditive costs as a characteristic of natural monopoly.

(ii) ***The natural monopoly aspects of transmission and distribution***

Firstly, there were also serious economies of scale in constructing and managing transportation system, which make competition in those functions uneconomic. This was empirically proved, for instance, in retail electricity distribution during 1970–1990 (Kumbhakar and Hjalmarsson [1998]), during 1988-1991 (Filippini [1998]). The empirical evidence suggests that franchised monopolies, rather than competition, were more efficient in the electric power distribution industry. It does not make any economic sense to build multiple sets of competing transportation systems because of the tremendous cost, not to mention to environmental or esthetic sense. Only one set of transmission or distribution wires could economically serve any area.

Secondly and most importantly, the physical aspect of electricity makes it impossible to follow a simple "contract path" through the network. Indeed, electricity takes the path of least resistance, according to the laws of physics (known as Kirchhoff's laws). This creates complex interactions that give rise to significant "network externalities". The subject of network externalities had been substantially exploited the economic and legal literature, for instance, Rohlfs [1974], Katz and Shapiro [1985], Economides [1996], and more recently in electricity transmission industry like Hogan [1992], Hogan [2003], Littlechild [2003], Joskow and Tirole [2005]. The fundamental idea is that transmission is characterized by strong interdependencies between decisions (operating, investment or demand decisions) made in one part of the network and the potential impact of these decisions on transfer capability or stability in others. Given these complex interactions, it is difficult to determine which party created costs or conferred net benefits on other network users. This feature makes it very difficult to introduce market mechanisms to provide incentives to develop and operate the transmission network. "Regulation" could do it better than "market forces".

Another reason for monopoly and regulation in transmission and distribution systems is that electricity is an indispensable good which should be accessible to everyone. If the investment of the transportation lines were put in hand of private competitive companies (driven by market forces), these companies would only invest in big cities where the demand for electricity is high

and ignore the remote regions.

For those reasons, the transmission and distribution functions are natural monopolies and should be regulated. The arguments are still valid even when electricity industries have been reformed in most countries.

(ii) ***Vertically integrated models***

The two factors described above explain the monopolies in each function of electricity value chain, but they do not explain why these monopolies should be integrated into the same company. Indeed, the perhaps most convincing argument for vertical integration models was to save the transaction costs. Transaction Cost Economics was identified with Coase [1937] and Williamson [1979] and developed in power markets by Joskow and Schmalensse (1983). In fact, in order for electricity to be transmitted from the generator to the consumer, electricity supply and electricity demand must remain in precise balance at every instant over a wide area. That challenging task requires an every – minute coordination between the generation and transmission. If those functions belonged to separate companies, the transaction costs could be too high. And the best way to do that at the minimized costs at that time was to have them in the same company where one manager manages both activities. Another economic rationale of the integrated monopoly is double marginalization, the concept introduced by Spengler [1950]. Consider two successive markets, namely electricity generation and transmission: if both are monopolized, each monopolists will exploit its monopoly profit, creating a double marginalization problem. As a result, the welfare loss will be considerable. Now, if these monopolists are vertically integrated, the double marginalization problem might be partly solved (The discussion on double marginalization effect on the organisation of electricity systems can be found in Pollitt [2008].

In conclusion, there were natural monopolies in generation, transmission and distribution functions of electric power, these functions should be integrated into one monopolized company. When the governments own the monopoly, the governments set the prices, which was the case in most countries. When private companies owned the monopoly, there had to be some form of regulation so that they could not exercise their monopoly power. This

refers to administrative regulation of prices, entry, and other aspects of firm behavior. Regulatory instruments should be put in place to determine the prices so that the firms can not abuse their monopoly power to increase the prices and that they could recover all their fixed costs. It was also government's regulation to decide the new investment in the industry. (See more in Kahn [1971b] and Joskow [2007]). This model, vertical integration monopoly under regulation was maintained for nearly half of century since 1946 until late 1970s in the US and late 1980s in Europe.

1.1.2 The problems of regulation - Motivations for deregulation and competition in Europe

The ideas behind the old way of organizing the industry that we discussed above were probably valid at that time and should obviously be taken for granted. By the late 1970s, however, the scene started to change. The long era of protection and government regulation had resulted in slow-moving companies that were hostile to innovation and cost minimization. Many electric utilities involved long term debts and annual losses, with endless delays in infrastructure investment (Hogan [2006]). The criticism towards regulated monopoles and integrated models had emerged. At the same time, technological advances made in electricity industry (development of gas turbine technology, improvements in transmission systems) abolished the conventional wisdom about natural monopoly in generation sector. The merits of competition as well as the questioning of monopoly and regulation had spread out.

Since the late 1980s, the advance and success of market–based system and deregulation in many industries like airlines, natural gas and telecommunication shed light on the electric power industry, one of the last great twentieth century monopolies. *"Deregulation, reform, liberalization, restructure"* are the terms usually used to describe this process. To summarize, there have been three mains reasons to reform the industry: *(i) Regulation faces an unsolved dilemma, (ii) Conditions for deregulation had been confirmed and (iii) competition brings more benefits than losses.*

(i) *The problems of regulation - regulator's dilemma*

Public utility regulation had been criticized in literature throughout substainable works since 1960s because of its ineffectiveness as shown in Stigler and Friedland [1962] or because of the undesirable indirect effects it produced, among them the Averch - Johnson effect. These reflections had been pursued in the 1970s by Kahn [1970,1971a] and Baumol [1977]. In deed, regulatory theory distinguished two traditional types of regulation: cost – of – service regulation and price cap regulation.

Cost of service regulation (or rate-of-return regulation) assures that suppliers will recover all of their costs. This is based on classical economic assumption that long run economic profits equal zero under perfect competition. Cost of service regulation allows companies to earn a reasonable rate of return on their assets and to recover all their expenses, thus helping hold price down to long – run marginal costs. However, this kind of regulation does not provide incentives to minimize those costs. Indeed, the expenditures on construction of new power plants (new capital investments) and transmission lines were included in the form of electricity tariffs as the necessary expenses of the company. The prices of electricity that the customers were due to pay must recover all those expenses. If the investments were not efficient or regulatory bodies were mistaken, for example, in the forecasts of electricity demand, neither regulators nor monopoly companies would have to pay the bill; but the customers. In a nutshell, if the monopoly companies make an innovation or investment that saves a dollar of production costs, the regulator takes it away and gives it to the customer. And if the investments failed, it's always the customers who guarantee the costs. The monopoly companies, in both cases, do not have incentives to minimize their costs: they do not take the risks. In deed, they know that higher costs would be reimbursed in the form of higher prices, then inefficient modes of production may lead to higher profits. Averch and Johnson [1962], and Wellisz [1963], among others, have pointed out that these considerations could induce public utility companies to develop an excessively capital intensive technology or/and to maintain a large amount of standby capacity, in excess of peak requirement (Kahn [1971b]). Shepherd and Gies [1966] described the rates in gas and electricity which followed this

principle as "the most glaring instance" of inefficient pricing.

Price – cap regulation, developed by Littlechild and Britain [1983], is at the other extreme. It sets a cap on the supplier's price according to some formula that takes (attempt to) into account of overall costs, inflation rate, etc. Now every dollar saved is kept by the supplier and if their investments were wasteful, the customers would not pay more to cover the costs [2]. Price-cap regulation could avoid the problem of cost minimization induced by rate of return regulation. The major challenge, however, lies on the price cap formula. How to determine the long term price cap that takes into account all factors of costs or risks? If the cap is too low, it does not allow the suppliers to cover their costs. If it is set too high, the suppliers will not have incentives to hold the prices down to their marginal costs; they will be just interested in keeping the prices well under the price cap no mater how much a MWh does really cost. Both errors cause the regulator to alter the cap in a direction that yields revenues more in line with the firm's incurred costs, making price-cap regulation resemble cost-of-service regulation (Wolak [1998]).

The literature of economics of regulation is too vast and too complex to discuss here and it is beyond the scope of this thesis[3]. As concerned in our discussions, regulation had failed to provide full cost minimizing incentives while holding prices down to marginal costs. Indeed, one could possibly invent other clever ways for regulators to achieve those two objectives at once or to harmonize regulatory spectra, to adjust the price cap more or less frequently, etc., but all will risk to fail (Stoft [2002b]). As shown by Tirole and Laffont [1993], this failure was due to the asymmetrical information relationship between monopolistic firms and the regulators: firms always know the market better than the regulators. That is the root of regulatory trade-off problem.

[2]Price cap regulation is sometimes called "CPI- X", (in the United Kingdom "RPI-X") after the basic formula employed to set price caps. For example "RPI-X+K" where RPI is rate of inflation measured by UK Retail Prices Index, K is based on capital investment requirements, and X is expected efficiency savings. Now any savings above the predicted rate X can be passed on to shareholders, at least until the price caps are next reviewed. The system is therefore intended to provide incentives for efficiency savings.

[3]A thorough literature of economics of regulation can be found, for example, Joskow [2007], Kahn [1971b])

(ii) ***The benefits of competition***

The merits of competition, rooted back to Adam Smith in The Wealth of Nations (1776), had been strongly supported in literature. Adam Smith suggests intuitively that a perfectly competitive market would produce an outcome that is in some way ideal (for example, all firms are price takers, prices are equal to marginal cost and firms' long term profits are equal to zero, the social welfare is maximized). Many challenges can cause a market to fall far short of this ideal, but even a market that is only "workable competitive" can provide a powerful force for efficiency and innovation. Leibenstein, in his famous article "Allocative Efficiency vs. X-Efficiency" in 1966, describes many sources of efficiencies other than allocative efficiency, stem from competition, which he called "X-efficiencies". He shows that a major element of "X-efficiency" is motivation and assignes increases in X-efficiency to increases in motivational efficiency. There have been substainable empirical works in economics that provided confirmations of X-efficiency, for instance, Scherer and Ross [1990] or Borenstein and Farrell [2000]. Though Leibenstein's observations had been casted doubt by some scholars, for example, George Stigler through his article "The Xistence of X-efficiency" in 1976 (Stigler [1976]), nobody has refused the efficiency which can arise from competition in every eligible markets. In electricity, the benefits of competition as well as the discussions of designing a competitive market in generation sectors have been redundantly developed in literature throughout last decades of the XXth century: Joskow, Bohi and Gollop [1989], Joskow [2003], Joskow and Tirole [2007], Joskow [2006], Hogan [2006], Green and Newbery [1992], Newbery [1997], Percebois [1999] and Percebois [2004], Glachant [2009], to name just a few. The ideas behind the introduction of competition in wholesale electricity markets are summarised as follow.

The first major benefit of the transformation from regulated monopoly to competitive wholesale market has been risk transfer. The risks might refer to, for example, uncertainty of demand, management decisions about maintenance and investments; credit risks, regulation failure risks, etc... Under regulated monopoly, customers take most of the risks while under competition, these risks are initially with the suppliers. For instance, under regulation, if the monopoly company made a wrong choice in investment activities or regulators

were mistaken, the customers would pay for those failures. Under competition, if these happened, the suppliers would have to suffer from the consequences, they could not force the customers to pay more for the recovery of their wasteful expenditures. Under regulation, if demand turns out to be less than anticipated, the customers will have to pay more to cover the cost of excess capacity whereas under competition, excess capacity causes prices to fall. This shift of risks, in turn, provide better incentives for controlling capital and operating costs of new and existing generating capacity.

Secondly, competition could solve the regulators' dilemma. Regulation could not guarantee the incentives for the suppliers to hold down prices to marginal costs and to minimize cost at the same time. Competition can do both at once. Under competition, the suppliers take most of the risks, and also take most of rewards, it will be the suppliers who benefit from any dollar they could save from one unit of investment. This provides strong incentives for suppliers to make many kind of cost saving innovations like wiser investment choices, more efficient repairs, innovation in power supply technologies etc. Under competition, generating companies are supposed to compete on price which results in fierce competition in which each generator has incentive to hold price down to marginal costs. At the end, final customers could benefit from lower prices for a better inovative services.

Another benefit of competition come from the demand side. The high prices of the wholesale market will be passed on to customers and will make them to curb their demand when the prices is highest and generation is most costly. This will not only help reduce the total cost of providing power but also provide a long run benefits to society (in term of energy savings).

Though reforming electricity industry is a technical, institutional and political challenge (details in Chapter 2) and making competition work in electricity is in practice much harder than all what has been written in theory, when we consider the problems of regulation and how competition will improve them as well as long run profits that liberalization can provide to society, that is no longer a question.

(iii) *Traditional arguments for monopoly and regulation turned out irrelevant – Conditions for deregulation had been confirmed.*

Market competition is good for consumers, but competition can only be introduced to markets that are not characterized by "natural monopoly". Indeed, one of the most reasonable defenses of the old monopoly system in electric generation industries is "economies of scale". If a monopolist can produce power cheaper than many competitive companies, then deregulation makes little senses. Since the late of 1970s, the questioning of economies of scale as reason for natural monopoly had been emerged in literature such as Baumol [1977] *"... scale economies are neither necessary nor sufficient for monopoly to be the least costly form of productive organization"* (Baumol (1977), pp.809). Empirically, Christensen and Greene [1976], using cross-section data for US firms producing electric power in 1955 and 1970, found that a small number of extremely large firms were not required for efficient production and that policies designed to promote competition in electric power generation could not be faulted in terms of scarifying economies of scales.

The recourse to economies of scale as motivation for natural monopoly had been truly questioned in the late of 1980s, where new technological advances were made in electric power generation and largely contributed to reshape the industry. The technological advance, known as combined cycle gas turbines (CCGT), has technical efficiencies close to 60 % against 18% to 36% of nuclear or coal technologies according to the IEA. Its construction duration is shorter (less than 2 years) with low investment costs and smaller in size than the old models. For large scale power generation, the optimal size of a CCGT plant is 250 to 400 (MW) against a nuclear plant optimum of 900 to 1,000 MW or coal plant optimum of 500 to 600 MW. These technical developments (along with the development of natural gas transportation networks) have made the CCGT a dominant choice for new investment and entry into the industry will be open to any plausible supplier. The economies of scale, saying that bigger and bigger plants produced lower and lower prices and that only government is able to carry out that big needed generation investment are no longer true.

The advanced technology of CCGT was only a necessary but not sufficient condition for the opening of electricity generation market. Cheap CCGT

technology did not alone end the natural monopoly in electricity. Because if it really did, then most of Asian developing countries having always their electric power industries monopoly regulated till now would be considered irrational. They might be irrational to some other extents, but they have rational reasons to keep their industries vertically regulated. Iimi [2003], using data on the electricity industry of Vietnam, proved that deregulation and unbundling do not necessarily entail the social welfare maximization and that developing countries cannot always expect the same positive results of the deregulation and privatization as developed countries. Another example is Norway, where there are abundant falling water plants, was one of the pioneers in electricity liberalization process.

It has been proved that the great evolution of markets and significant improvements in transmission system have helped remove the natural monopoly of the wholesale power market in most European countries. Markets are larger through many year and vast transmission grids have been developed which makes any new supplier be able to deliver power at the minimum cost to the customer in any particular market. However in small developing countries with low demand and/or inadequate transmission networks, the economies of scale might well indicate continued monopoly.

The conditions for deregulation and liberalization had been confirmed and the new economic view, which supported market driving forces, was introduced at the right time then rapidly expanded.

1.2 Review of electricity reforms in Europe

The electricity reforms generally involves: (1) restructuring: unbundling different functions of electricity supply chain and breaking up the monopoly mechanism; (2) halting government's regulation to support competition in generation and retail supply; and (3) designing market mechanisms. Note that the implement of the reform did not necessarily follow in that order. It depends on initial conditions of industry's organization and policy in each country. The arguments of electricity reform process given below are standard prescriptions and applicable for most of the cases.

1.2.1 Restructuring

Restructuring is about changing existing vertically integrated monopoly structures. This involves mostly unbundling the vertical integration structure and breaking up the monopoly. The aims are to prevent discriminatory behavior and to consolidate transmission over a wide region. The experience with electricity reforms worldwide have showed that the key of a successful reform program must be supported by a good restructuring programs which include both vertical and horizontal restructuring.

(i) Vertical restructuring (unbundling)

Unbundling involves a vertical separation of different segments of electricity supply chain. Specifically, competitive segments (generation, marketing and retail supply) must be separated from regulated segments (transportation and system operation). Baumol [1977] shows that competition in the electric industry generally involves only the production (generation) of electricity and in the commercial functions of wholesaling and retailing. The transportation functions (transmission and distribution) should not be competitive because of its natural monopoly characteristics. But competition in generation sector would have lesser sense if transportation system was in hand of one generating company because this would create a discrimination against access of all other competitive suppliers. This is known as the problem of "vertical market power", about which we discuss in chapter 2. Unbundling involves thus both ownership and legal unbundling (See more in Prologue). Most economists agreed that unbundling is a key part of energy market reform in the most successful reform jurisdictions. Empirical works on this issue can be found, for example, in Pollitt [2008], Alesina, Ardagna, Nicoletti and Schiantarelli [2005], Steiner [2000], Hattori and Tsutsui [2004], Van Koten and Ortmann [2008].

(ii) Horizontal restructuring

Horizontal restructuring involves generation segment. Competition could only make sense when there are many small competitors enough and none of them could have influence against market prices. Old structure with model of integrated utilities did not support this requirement. Horizontal restructuring

involves thus creating an adequate number of competing generators so that none of these companies are able to exercise its "horizontal market power", i.e., to beneficially drive the price up (discussed in chapter 2). Apart from these changes, restructuring encompasses also the horizontal integration of transmission and network operations to internalize network externalities or the creation of new wholesale market institutions for electricity trading.

Restructuring the industry sounded fairly simple but the practical implementation might be extremely difficult and time-consuming. Indeed, it is very hard to get a consensus to divide physical and financial assets between new companies. Besides, unbundling the different functions could loose the economic coherence that had been functioning well in the traditional monopoly structure: transaction costs might be high. And breaking up the existing giant generating company to many equally small ones is extremely hard in practice, not to mention that in many countries the regulatory framework for Mergers and Acquisitions is not paid adequate attention or lack of proactive control. Facing all these challenges, the governments must offer in the right place, at the right time enough "carrots and brandished sticks" to encourage and promote voluntary restructuring progresses.

1.2.2 Deregulation

While regulation is about controlling prices of monopoly suppliers as well as investment activities and restricting entry to the markets, deregulation is about removing some of those controls. The idea is simple: if we want to shift from regulated monopoly to market-based mechanism, it is the market with its "invisible hand" that will guide the prices or investment decisions, not the government with its regulatory instruments. By doing so, prices were no longer regulated but determined by market forces.

"Deregulation" must be done with necessary supervisions and market should be well designed to make competition work. One can not simply declare to deregulate the industry, providing open access to the transmission system then wait for competitive markets produced by itself. In the best case, nothing might happen, but in worsen case, crisis occurs as it did in California in 2000, when transitional market rules severely limited participation of its

utilities in forward markets and enhanced the market power of new generating entities (Friedman [2009]), going as far as having one of the state's largest energy companies collapsed, widespread rolling blackouts and economic fall-out. Therefore, deregulation does not mean "no regulation at all" but implies "less and better regulation".

1.2.3 Market designs

Deregulation means that market forces need to replace control-and-command regulation but "markets" in electricity need to be made and designed, they do not just happen. Market design refers to a set of rules or organizational patterns that facilitate the operation of a market [4]. Prior to deregulation, the questions of which and when to commit and de-commit a system's generating unit or which prices should be set for such commitment were solved by collecting data on all the generators and applying the techniques of mathematical programming (details are given in section 1.3). As this control-and-command regulation was removed, market should be designed to induce generators to voluntarily and accurately provide this same data. Bad market designs might cause serious market failures because suppliers would rapidly take advantage of design flaws to manipulate the prices. A good market design would produce market prices that reflect the true minimized-costs and give right signals for investment activities.

Because competition in the electric industry involves only the production segment and commercial functions of wholesaling and retailing; market designs have been concerning more about those functions. The principles of market designes include: (i) Designing markets for energy trading at wholesale level; (ii) Designing markets for transmission rights and (iii) Designing markets for capacity.

[4] Market designs should not be confused with "regulation" though it concerns "rules" or "principles". It is simply the way of organizing a market so that it can be operated smoothly because market does not design itself.

(i) Designing markets for energy trading at wholesale level

Designing markets for energy trading at wholesale level is of great importance because retail markets can not produce competitive outcomes if the wholesale markets are not competitive. Trading for energy delivered by any minutes begins years in advance and continues until real time by a sequence of overlap of forward and spot markets. Spot markets for energy in wholesale level are composed of *day-ahead, intra-day adjustment* and *real time balancing markets* (See more in Prologue).

Most of the important rules in electricity market involve auction rules which determine directly pricing rules. The process of determining the clearing prices will be discussed further in section 1.3. The importance is not really which rules are preferable to the others but which rules are preferable given market structure (competitive vs monopolistic). In a competitive structure, i.e., the bidders are small relative to the size of the market, demand is relatively elastic, design of auctions can easily produce competitive prices but in a monopolistic structure, the best results we can hope for are auction rules that bring market prices as nearest as possible to the competitive levels, i.e., reducing the exercise of market power. In electricity markets, competitive prices sometimes reach disconcertingly high levels due to a shortage of supply during peak demand period or due to network congestion, etc. This might inspire many designers to redesign the pricing rules to hold them below the competitive level. If market forces did not succeed to subvert this failure, it would cause inefficient prices, thus inadequate and distorted investment. Fortunately, markets are composed of clever and rational players who can always find the most profitable way to respond to changes in rules. So *"the most fundamental mistake a market designer can make is to treat a market as if it were a machine that does not change behavior when the rules change."* (Stoft [2002b],p.96).

Real time balancing market (or real-time market) mainly refers to adjustments of supply to keep it balance to demand. The quantity sold in the real time market is the difference between total real time production and quantity specified in forward contracts (day-ahead). The real-time quantity is quite small but the real time price is decisively important. It covers (and controls)

all the power flows in real time even though most of these flows are forward trades. This might be confused at the first glance but not contradictory. The real time price must balance total actual supply and demand. Suppose at time t of day d, more power is needed than what was planed on d-1, the system operator looks for a generators who will be willing to supply this extra amount of power at real time price, say EUR 40/MWh. There is a generator with a day-ahead contract and a marginal cost of EUR45/MWh. Consequently, this generator will not produce but rather buying power in real time to fulfil its commitment because producing will cost him more than buying. The market is consequently imbalance. In contrast, if the real time price is EUR46/MWh, the generator will earn more if it produces rather than buying. For example, if this generator produces and sells 10MW for 4h a part from what it has sold in the day-ahead contract, it will be paid an extra amount of 10MW x 4h x EUR46/MWh= 1480 EUR. It is profitable for the generator and by doing so, it will help balance the market. Therefore, market designers should pay much attention about price formation during "scarcity conditions": when load is in excess of maximum capacity supplied, and network congestion makes it impossible to import electricity from outside. Prices should be high enough (spikes) to balance the market. If it cannot be balanced because of shortage of supply, load must be shed.

(ii) Designing markets for transmission rights

An optimal design of wholesale market needs to integrate allocation of transmission with energy markets. Indeed, competing generators must rely on the transmission network to schedule and dispatch their plants for sales of electricity. The process of trading transmission rights is following: A generator who wants to sell its power has to implement two steps: trading power, and trading the transmission rights (not necessarily in this order). There are two general approaches to allocating scarce transmission capacity. In a de-centralized market, the generator has to examine market conditions to offer a relevant price in one market or the other. For example, if power is traded first, the generator must guess the cost of transmission right to set an offer for the power and vice versa, if transmission right is traded first, then the generator must guess the

power prices in order to make its offer for transmission right. Transmission rights are allocated via explicit auctions in this case. In a centralized market, however, the system operator, sells transmission rights along with any trade it arranges. In such a market, a (competitive) generator only needs to bid its marginal cost without consideration of market conditions for transmission rights (implicit auction used in market coupling mechanism).

The introduction of transmission rights raised some market power concerns as demonstrated by Bushnell [1999] and Joskow and Tirole [2000]. Indeed, if transmission rights are traded in an explicit auction, their owners can use them or sell them; or can keep them but not use them. Under perfect competition, buying transmission rights but not using them would be economically irrational. On the other hand, a firm with market power could purchase transmission rights but not use or resell these rights because this effectively reduces the amount of power that would be sold by other generators. This allows the firm to increase the profit on its production.(Discussions about market designs for transmission rights and concerning issues are found more in Oren [1997], Hogani [2012], Gilbert, Neuhoff and Newbery [2004]).

(iii) Designing markets for capacity

Experiences from two decades of reforming the industry showed that there were some imperfections in energy markets: some of which arrived from peculiar characteristics of electricity, some of which arrived from government's efforts to control market powers or system operators' efforts to deal with reliability constraints. "Energy only" market for energy and ancillary services provides inadequate revenue to attract enough investment to be consistent with reliability rules (problem of "missing money" [5]). The question of whether we need a secondary markets under the form of different capacity remuneration mechanisms like capacity market, capacity payment or strategic reserve have been discussed rigorously in the US and also in the EU in recent years. Capacity remuneration mechanisms are designed to ensure the reliability of the electricity system. The basic idea is that power plants receive compensation for capacity, or the power that they will provide at some point in the future.

[5]The concept of "missing money" in electricity markets is discussed in section 1.3

The issues of capacity mechanisms are too complex to be discussed here and beyond the scope of this thesis. The literatures and empirical researches on this issue can be found in Cramton, Ockenfels and Stoft [2013], Spees, Newell and Pfeifenberger [2013].

To summarise, reforming electricity industry is challenging. Details were different in different countries. In countries like the United States, where private companies were operated as regulated monopolies, the electricity reform started with breaking up the monopolies and deregulating, then relying on market forces to bring innovation and drive costs down. In most nations in Europe, where the governments owned many of the companies, the reform involved first of all privatization. The common feature of this new big ideology was to leave to markets what they can do and to save the best of the old regime for what market cannot do.

1.2.4 Europe: Where are we with the reform?

European electricity reform was pursued by three EU legislative packages (1996, 2003, 2009) whose aims are (1) Introducing competition in electricity generation and supply/retail in every Member State; (2) Introducing regulated network monopolies (transmission and distribution) and (3) Gradually removing obstacles to trade electricity between Member States. Initially it refers mainly national reforms, but more recently coordination between Member States have been increasingly paid much attention.

In most other continental European countries, market liberalization was triggered by the European Commission directive, 1996(EC), "Directive for a common electricity market". At the start of liberalization, each country has its own pre-existing conditions as regards to ownership of electricity assets, market structure, the legal traditions in each country as well as the reasons behind the liberalization or the objectives it was expected to achieve. Therefore market reforms did not follow any single model. Various alternatives were tried out. In England, for example, the reforms started with restructuring and privatization of the industry amongst several generating companies competing in a newly-created wholesale market. Consumers were then granted the right to choose their supplier. Distribution and transmission remained regu-

lated. While the transport activity stayed in the hands of a single company, distribution was split up into several ones (Newbery [2002]). Germany, in the meanwhile, started with a 100% market opening without any restructuring of the industry, in the expectation that market forces would slowly erode the market share of "incumbents". At time of liberalisation, there were neither independent system operator nor transmission regulators in Germany. The questions of grid access and transmission pricing were left to be negotiated among different electricity companies and the German heavy industries. (

At the date of approval of the 1st Directive in 1996, it seemed that many Member States were forced from Bruxelles rather than voluntarily accept the challenge of a transformation of their industries. Very soon, great divergences between countries have impeded liberalization progress, triggering a long process of review and re-negotiation (Glachant [2009]). This ended with the approval of the 2nd Directive in 2003 which aimed to complete liberalization at both wholesale and retail level. Up to 2005, most countries had mechanisms for introducing wholesale competition by creating organised markets, either compulsory or voluntary. They consist of at least a day-ahead; a balancing market and independent market operators. Most countries pursued the model that provides both legal and owner separation of the transport activity from other electricity business sectors (See more details in Haas, Glachant, Keseric and Perez [2006]).

The period 1998-2005 proved a lot advantages of reforming the industry. Even in France, where liberalization has been relatively slow, non-EDF suppliers serve about 15 percent of the eligible market at the beginning of 2006 (Glachant and Finon [2005]). There were much positive evidence that market liberalization was translated into lower prices for consumers. The picture, however, varied according to the category of consumer - industrial, commercial, retail, ect. In the United Kingdom, average electricity prices for industrial consumers had fallen by 30 per cent by the end of 2003, compared with 1990. This number was 13% and 9% in Germany and France respectively according to data from Eurostat.

Upto now, the liberalization of the electricity market has not been an option but an imperative in Europe. Although a lot of issues remain unsolved or being debated, it seemed that the electricity market has been moving in

the right direction. Positive results have been achieved in raising the level of service quality, increased efficiency of the sector and allowing consumers to choose the electricity supplier. The discussions about the achievements and evolution of electricity reform in some countries in Europe can also be found in Jamasb and Pollitt [2005], Meritet [2007], Hansen, Percebois, Boiteux and Tirole [2010]. Today, the majority of the wholesale markets are now completely opened, and prices in those market are no longer determined by the goverment but drived by market forces. In the next section, we analyse the process of price-formation in those newly opened electricity wholesale markets.

1.3 Price-formation process in electricity wholesale markets

Competition in wholesale markets mean equilibrium prices must be determined by "market forces" and adjusted by "invisible hands". However, the formation of equilibrium price in the electricity markets is slightly different from other markets due to the various cost structures and the nonstorability of electricity in large scale. Some of processes in the old model of control-and-command regulation are still efficient in newly deregulated markets to set the price while some others are not. This sometimes creates confusions about the application of conventional marginal pricing method to electricity markets. This section shed lights on these issues.

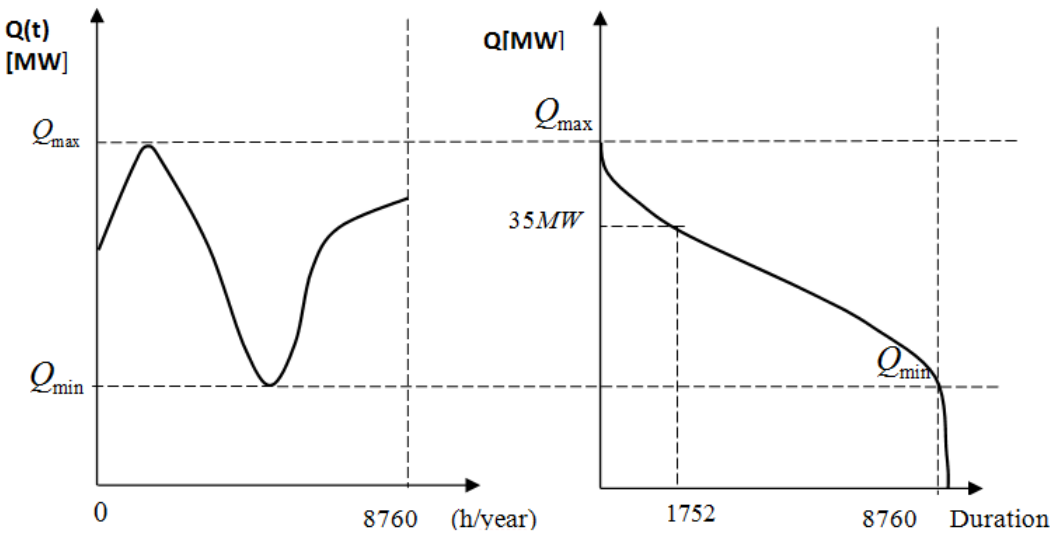
1.3.1 Demand and supply for electricity - Economically optimal production mix

In this subsection, we describe the process of how electricity plants are dispatched to meet the demand under condition of minimized cost. This is based on the combination of (i) load duration curve which represents demand for power; (ii) cost structures of different plants which represent suply side; and (iii) equilibrium for optimal dispatch.

(a) Demand for power - Load duration curve

Together with natural gas or water, electricity is a commodity to be demanded at any moment and, particularly, varies all the time – daily, seasonally and yearly. The electricity demand by different time cycles depends largely on the meteorological fluctuations, which means for example to be higher due to heater utilization in the winter or air conditioners in the summer. The exogenous variables allowing to explain the consumption level are: temperature, nebulosity (for lighting), length of the days, type of consumer, etc. These distinguished characteristics make the load curve fluctuated and continuous over time. Figure 1.1a represents the load curve, Q(t) [MW], the power which is successively called by the network during one year cycle (8760 hours). The amplitude between Q_{max} and Q_{min} depends essentially on the type of consumption. For example, $(Q_{max} - Q_{min})$ is supposed to be bigger for a system where the demand of the residential consumer is predominant, but smaller for a network with the industrial clients whose demand is necessarily continuous to function their processes (Hansen et al. [2010]).

Figure 1.1: Load Duration Curve



Source: Hansen et Percebois (2012)

Generally the demand curve for power is described by a load–duration curve that measures the number of hours per year during which the total load

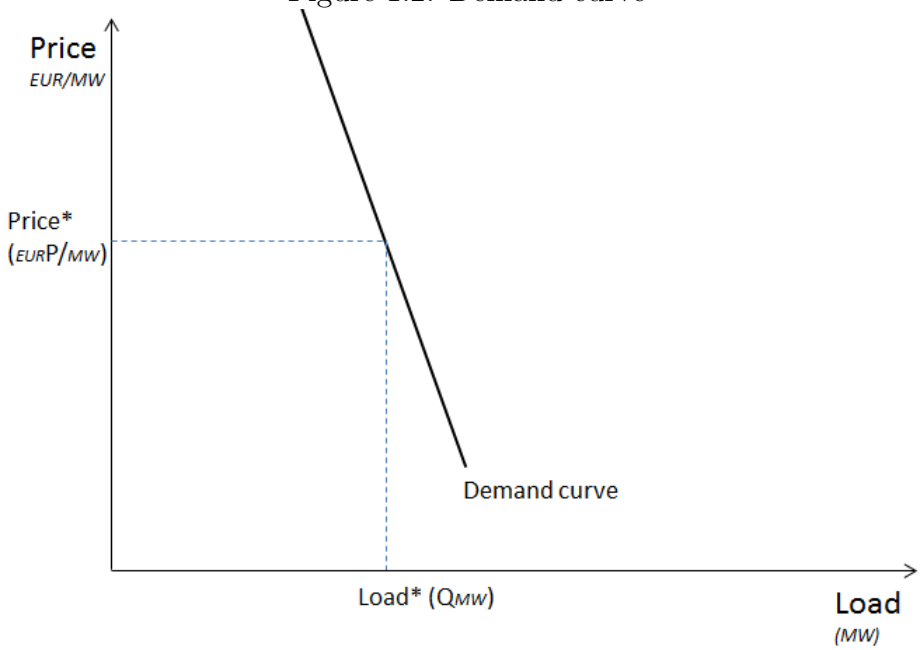
is at or above any given level of demand (a cumulative frequency distribution by load). The load duration curve is created by representing figure 1.1.a in the monotonically descending order (instead of chronological order). A load duration curve can be constructed for a given region by measuring the total load at hourly intervals for every 8760 hours in a year (100% of the time), sorting them by descending order and graphing them starting with the highest load [6].

It is important to note that the load duration curve was conventional demand curve used in regulated electric market without the price factor. The introduction of a market adds the dimension of price i.e., representing demand by a demand curve that expresses demand solely as function of price (Figure 1.3.1). However, the load duration curves are still relevant in unregulated market in order to check "equilibrium" and "optimal production mix".

A load duration curve has typically two principle segments: the base load which exists all the time and peak period where demand is at highest level typically for less than 20% of the time in a year (Bhattacharyya [2011]). As electricity cannot be stored in significant quantities at low cost, the demand has to be met by modulating the supply to match the demand. Therefore, for smooth system operation, a diversified production mix is required. Peak demand must be satisfied by production from generators with low fixed costs even the variable costs are high such as coal or gas fired combustion turbines. These generators, called peakers, are used as little as 20% of the time. In contrast, base load generators, with very high fixed costs and inexpensive variable costs, run most of the time and are stopped only rarely: it will be inefficient to run expensive plants (e.g. nuclear) to use solely during a very small period of time. The crucial question is how much and what type of plant have to be disposed to meet the demand at each hours in the load duration curve; or, what is "optimal production mix"? The word "*optimal*" is used in the sense that the mix of technology should satisfy the condition of minimizing cost, that is, at each hour or each period of time, dispatched plant should be

[6] The horizontal axe of the load duration curve can be expressed as a pure number, a ratio, or percentage because the duration is measured in hours per year, both hours and years are measures of time, so duration is dimensionless. For example, using the load duration curve in figure 1.1.b, we can say that 1752 hours (or 1752/8760 = 20% of the time), the load is 35 GW or greater. In other word, the probability of load being 35 GW or greater in a randomly selected hour is 20 %.

Figure 1.2: Demand curve



The market demand curve show how much of electricity consumers want to purchase at any given price. It is steep because demand for electricity in short term is inelastic with the variation of price

the cheapest.

(b) Supply for power - Production costs and Screening curve

To find which plant is cheaper among various technologies, one should understand the cost structures of each generator. A generator has an "overnight cost" which is typically given in EUR/kW. This is the investment cost if no interest was incurred during construction, as if the project was completed "overnight." In economic terms, this is the present value cost of the plant that would have to be paid as a lump sum up front to completely pay for its construction (Stoft, 2002). For example, the overnight cost of a coal plant might be at 2133€/kW net [7], so a 750MW coal plant would cost 1599 million euros. On the other hand, a 480MW CCGT plant with an overnight cost of 1068€/kW would cost closer to 512 million euros. Is CCGT three times cheaper than the coal plant? In fact, when ones consider variables costs, it is not sure that CCGT is more inexpensive choice. For example, the total

[7]Source: IAE (2010), median case, see more in table 1.1

variable cost per unit of energy output of coal is 22.46€/MWh while the total variable cost for a CGGT comes to 65.6 €/MWh (median cases) [8]. Now which plant is cheaper? More information is needed.

Now let us construct the generation costs of each plant cost by taking into account of three factors: fixed cost, variable costs, and load duration.

The annual generation cost is given by [9]:

$$TC = (K + F) + VC.U \tag{1.1}$$

where

TC: Annual generation cost, measuring in [€/MW- year]

K: Operation and maintenance (exploitation costs), measuring in [€/MWy]

F: Fixed cost, measuring in [€/MW - year] [10]

VC: Variable cost, measuring in [€/MWh]

U: Load duration (utilization/capacity factor), measuring in a pure number (percentage)

Plotting annual generation cost as a function of load duration, we have a screening curve, shown in figure 1.3, in which the vertical intercept represents the plant's fixed cost and the slope gives the variable cost per MWh generate.

Suppose there are two plants in the system: one of which is, saying B, base load plant with higher fixed costs but lighter in variable costs (nuclear plant, for instance), the other, P-peaker presents the inverse characteristics (coal fired or CCGT for example): $(K + F)_B > (K + F)_P$ and $VC_B < VC_P$. The screening curves of these two plants are illustrated in figure 1.4

We can now easily see which plant is cheaper by deducing immediately from figure 1.4. At U, the two technologies are equal of costs, so for the

[8]The variable costs computed here include the variable cost of Operation and Maintenance and exclude the CO2 cost .

[9]For simplicity, the formula is given in the most general way: total cost = fixed costs + variable costs. In reality, each part of the total cost should take account of a lot of other factors.

[10]Fixed costs of a power plant is not overnight cost. A plant with an overnight cost of 1000 €/kW does not cost 1000 €/kW - year. The correct fixed-cost is the overnight cost amortized over the life of the plant (a discount rate is involved). The formula is, $K = I\frac{i(1+i)^n}{(1+i)-1}$, measuring in kW – year , with we refers to overnight cost €/kW, n is amortized years and i implies discount rate.

Figure 1.3: Example of a screening curve

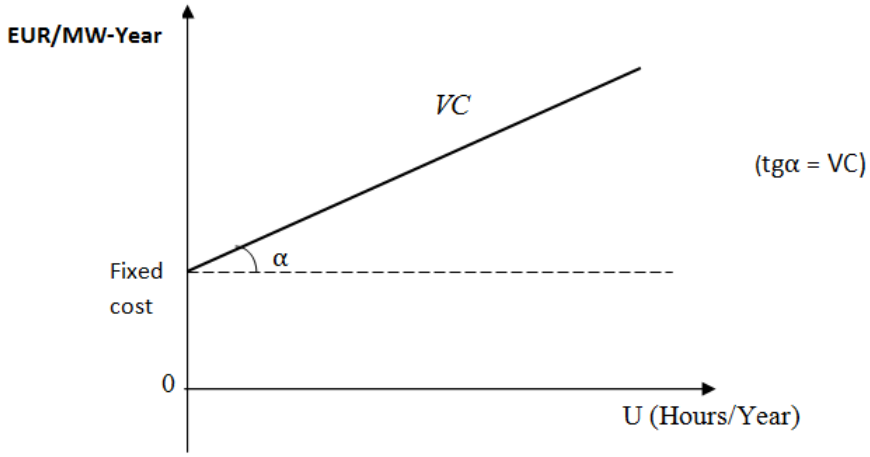
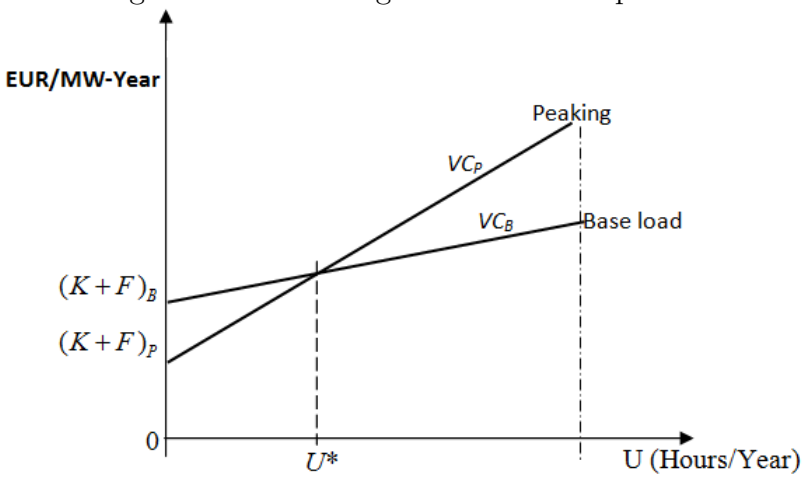


Figure 1.4: Screening curve with two plants

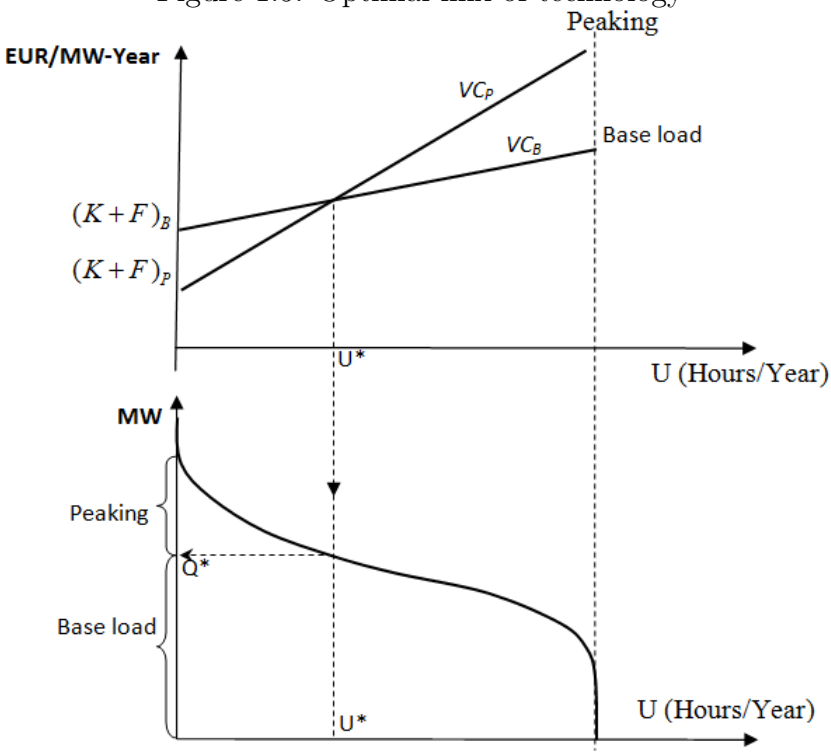


utilization $U < U*$, peaking plant will be cheaper (the total cost curve of peaking plant is under that of base load plant) and inversely the base load plant is cheaper for more intensive use $U > U*$.

(c) Optimal mix of technology - long run equilibrium

Once we have almost all necessary tools to find the optimal production mix of an electricity system by having answered the two core questions: which plant should be in use in certain period of time and how much capacity of each plant should be mobilized. The screening curve help to answer the former and the load duration curve could answer the latter.

Figure 1.5: Optimal mix of technology



Source: Stoft [2002a] and Hansen et al. [2010]

As we analyzed earlier, the intersection between two screening curves for each technology determines the utilization equilibrium $U*$ that separates the regions in which the different technologies are optimal. For example, the utilization equilibrium taken from the figure 1.5 is approximately 30%, or about 2600 hours, so all the load with the duration greater than 2600 hours would be served by base load plant, while load of lesser duration should be served by the peaker. The arrow in the figure shows how we can read from the load duration curve the needed capacity of base load plant, $Q*$. The optimal capacity of peaking plant is found by subtracting Q* from the maximum load D, total necessary capacity [11].

The utilization equilibrium between the two technologies is U* which is given by solving equation:

[11] In reality, taking account of reserved capacity R (in %), the maximum load D will not equal to Q_{max} but $Q_T = (1+R)Q_{max}$

$$(K+F)_B + VC_B.U* = (K+F)_P + VC_P.U*$$
$$\leftrightarrow U* = \frac{(K+F)_B - (K+F)_P}{VC_P - VC_B}$$

So the optimal mix of technology implies the recourse of:

- Q* MW of power of base load plant, serving from 8760 to U hours per year
- (D - Q*) MW of peaking plant, serving from U* to 0 hour per year

For a mix of n plants with the order of descending fixed costs and increasing variable costs from 1 to n plants:

$(K, F, VC)_n | (K+F)_n < (K+F)_{n-1} < \ldots (K+F)_1$ and $VC_n > VC_{n-1} > \ldots VC_1$

all the load with the duration from 8760 to $U_{1,2}$ will be served by Q_1 MW of plant (1) where $U_{1,2}$ refers to the load equilibrium at which the two technologies of plants (1) and (2) are equilibria in costs and so on :

- from $U_{1,2}$ to $U_{2,3}$: $(Q_2 - Q_1)$ MW of plant (2) should be called;
- from $U_{2,3}$ to $U_{3,4}$: $(Q_3 - Q_2)$ MW of plant (3) should be called
- ...
- from $U_{n-1,n}$ to 0: $(D - Q_{n-1})$ MW of plant (n) should be called

The optimal mix during 8760 hours will be the recourse of: $(Q_1)_1 + (Q_2 - Q_1)_2 + (Q_3 - Q_2)_3 + \ldots (D - Q_{n-1})_n$ [MW] where $(Q_1)_1$ implies Q_1MW of plant (1) and so forth.

Together with load duration curves, screening curves of the available technologies provides an insight into the system optimisation strategies. It captures the major trade-offs between capital costs, operating costs and the utilisation levels of different technologies in the power sector. This technique of dispatching is relevant in the old model of control-and-command regulation and still used in unregulated markets to confirm a market equilibrium (but

not to find one). In a market, its role in analysis is more subtle because the shape of the load-duration curve is affected by price, so this technique canot be taken as given until the equilibrium is known. Classic competitive equilibrium [12] is found based on marginal cost function (which determines supply curve in competitive market) and demand curve (load duration curve in combination with price elastic).

1.3.2 Marginal cost pricing in power market

Marginal cost is one of the most fundamental and important factor in economics generally as well as economics of electricity markets particularly. Generally, a market is said to be competitive and an optimal could be obtained when all goods or services are sold at marginal cost. Marginal cost helps thus find if a market is competitive or suffers from potential market power problems. Unfortunately, the theory of marginal cost pricing is not always clear in case of electricity.

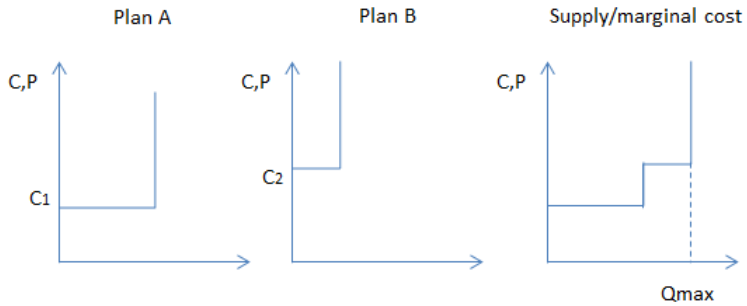
(a) Marginal cost curve in electricity - Merit order

Classical economic theory defines marginal cost as the change in total cost that arises when the quantity produced changes by one unit. That is, it is the extra cost of producing one more (or less) unit of output. The "or less" was used cautiously by Samuelson [1973] with the assumption that the cost of producing one more unit of output would be exactly equal to the saving from producing one less unit. It is true for the marginal cost curves which are continuous. Applying exactly this definition to electricity is, however, little troublesome.

The capacity of most electricity plants is very rigid: load cannot exceed the limit value. Technical constraints do not allow the supplier to produce electricity as much as they want at any time, but rather until all the plants reach the maximum capacity saying Q_{max}. This is called inelasticity of supply as illustrated in figure 1.6

[12] We are referring to classic Walrasian competitive equilibra to distinguish it from efficient competitive Nash/Bertrand equilibria.

Figure 1.6: Supply/marginal cost curves in electricity

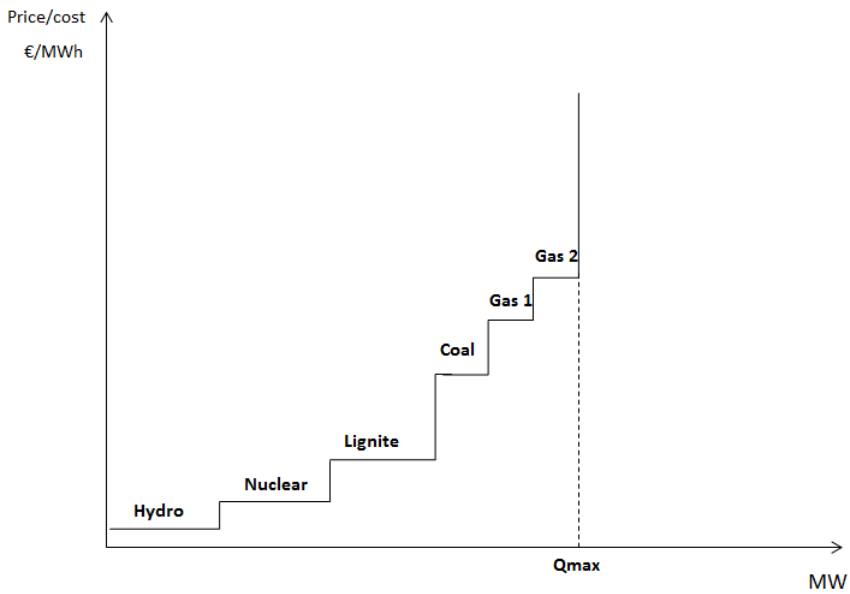


−The supply cost curve of an individual plant define its marginal costs curve. Adding horizontally all individual marginal cost curves (with different technologies) yields market supply/marginal cost curve.

−If the number of plants/technologies is big enough, the market supply curve is supposedly smooth until max capacity point Q_{max}

The marginal cost curve in electricity is often referred to the "*merit order curve*". The merit order is a way of ranking available sources of energy based on ascending order of their short-run marginal costs of production together with amount of energy that will be generated (figure 1.7)

Figure 1.7: An example of Merit order curve



Due to inelasticity of supply, the market marginal cost curve might take an infinite upward leap when it reaches full output Q_{max}. At this maximum

capacity, marginal cost could probably jump from say P_0 to infinity with only an infinitesimal change in output. Consequently, at this point the cost of producing one more unit could not be equal to the cost of producing one less: reading from figure 1.Xa gives clearly $+\infty$ for the former and P_0 for the latter:

$$\lim_{Q \to Q_{max}-} S(Q) = P_0$$
$$\lim_{Q \to Q_{max}+} S(Q) = +\infty$$

This causes a lot of ambiguities in defining marginal cost and competitive price in electricity, adding to the confusions that competitive prices in electricity market are sometimes undefinable or prices should rise above marginal cost during certain hours without presence of market power.

Figure 1.8: Marginal cost pricing

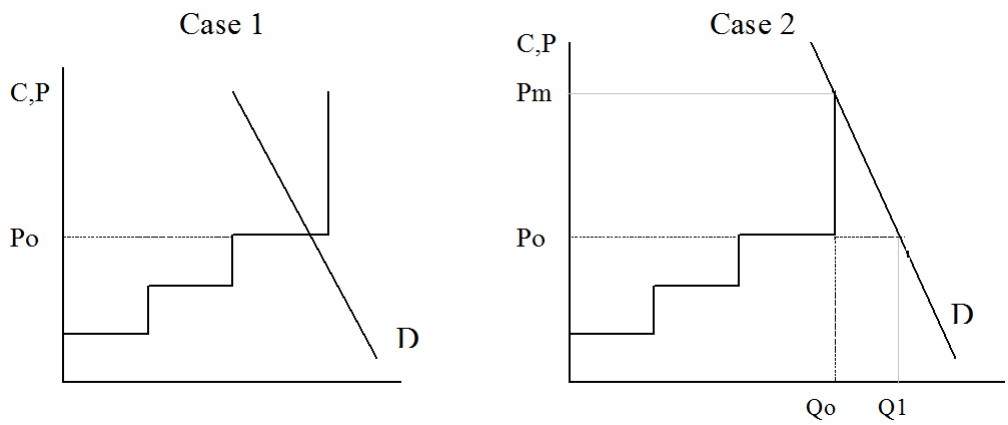
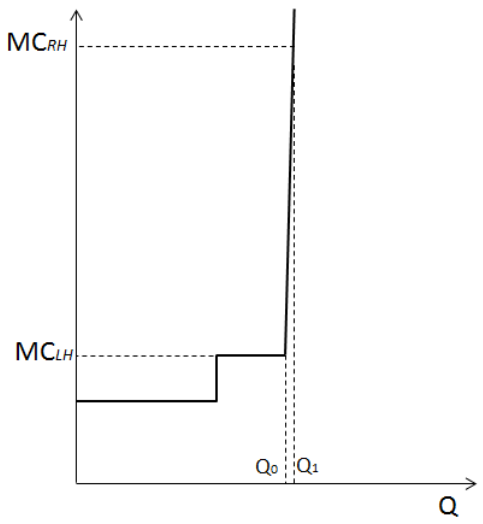


Figure 1.8 shows that in the first case, market is cleared at price P_0 which also equals to production marginal cost of the last unit called to the system(without capacity constraint). In the case 2; however, the market clearing price seems to be not "clear". Some people who miss the point might say that at Q_0, according to marginal cost pricing principle, competitive price must equal to P_0, or even that equilibrium price is undefinable. Neither of them is true.

It is important to note that short run marginal cost curve determines only the competitive supply curve, not the competitive price. Competitive price is

determined by both supply and demand curve. In the figure 1.8.b, we easily see that when the price is P_0, which equal to the variable cost of the last unit producing electricity, there will be an excess of demand $(Q_1 - Q_0)$. Certain consumers agree to pay more than P_0 for one extra MWh. In this example, the competitive price continue to rise until it reaches P_m, level at which the last customer is willing to buy. At this price, demand will be shed to Q_0 and supply too. In this case, system marginal cost might be ambiguous $(+\infty)$ but competitive price is not. The demand side (supposedly non-absolutely vertical) restricts the price that firms could bid up to. With any price inferior to this level, demand will rise and the price will too. Any price superior to this level indicates market power.

Figure 1.9: Two-sides marginal cost



So far we have learned that competitive price is equilibrium price of supply and demand. But whether this price is equal to marginal cost seems not very clear yet. We know that with such kind of supply curve, the price will sometimes be superior to production marginal cost, P_0 in figure 1.9, known as "left hand side marginal cost", but we don't know for sure how far competitive price should go above it. Stoft (2000) proved that competitive price will not go up to infinite but somewhere in between left hand side marginal cost and a value, high but finite, called "right hand side marginal cost". The domain within these two values is called "marginal cost range". To see it, let's replace vertical segment of marginal cost curve by a nonvertical but extremely steep

segment (Figure 1.9): the change from Q_0 and Q_1 is so minimal that the last segment of marginal cost curve become extremely steep.

Now this supply curve has its slope of MC_{LH} at Q_0, say 35 €/MWh at 500 MW and then slopes upward linear reaching a value which is probably 1000 times higher than the initial value with a tiny change in output, say around €35 000/MWh at 500.0001 MW. Assuming marginal cost curve in that way is much more straightforward, harmless in measurement, and not unrealistic in practice. In fact, the situation at Q_{max} is similar at points where one type of technology is used up and new type of plant is called in the system so that the marginal cost curve jump from one to another level. The marginal cost curve might be discontinuous at each of those points of capacity maxima $Q_{1,...}Q_{max}$ but marginal cost is always within a range from $C_{1,}C_{2...}$ and when the load reaches Q_0, the marginal cost in this case could jump up from C_n (around 35EUR/MWh) to an extremely high price, about 35000 €. This is always within the marginal cost curve (the cost of producing one more unit, even infinitesimal). Competitive price never exceeds market marginal cost (or market marginal cost range); otherwise, market power is being abused. This result is proved to *be true in any market including electricity.* Understanding this is crucial for further analysis.

(b) Short-run marginal cost vs long-run marginal cost

The marginal cost we have discussed up to now is marginal cost in short term, not in long term. Someone who misses the point might sometimes states that selling at marginal cost should be interpreted as "selling at long-term marginal cost"; and that marginal cost in long run is generally higher than that in short-run, so if one equates price to short-run marginal cost, this price is not efficient and too low to enable generators to recover their fixed costs. None of these two statements is true.

Proposition 1: ***Provided there is an optimal investment policy, short-run pricing is efficient and also long-term pricing: there is no contradiction.***

Long-term marginal cost does not refer, as is often supposed, to marginal cost in a very long period of time. In stead, it refers to "*the completion of*

particular market adjustment processes" (Stoft [2002b], p.56), i.e, it takes into account fixed cost. When one considers "short run price", the adjustments in the capital stock are being ignored; only adjustments in the output of existing plants are being taken into account. In the meanwhile, the concept of "long-run" means that adjustments in capital stock are being considered.

Marginal cost is by definition equal to the slope of the total cost curve CT for a given output q. Boiteux [1960] used the term "*differential cost*" to describe short-term marginal cost. It is defined as the slope at the abscissa point q taken on the short term curve of a given plant:

$$\gamma = \frac{\partial TC}{\partial q}$$

On the long term curve TC_0, the long term marginal cost, or to use Boiteux's word, *development cost* of a given plant of capacity q_0, is defined as:

$$\delta = \frac{\partial TC_0}{\partial q_0}$$

which satisfies:

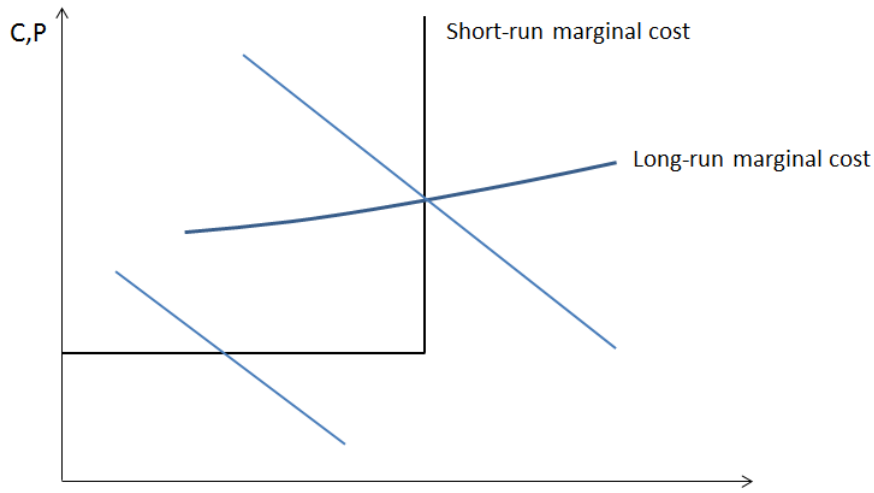
$$\begin{array}{lll} \gamma < \delta & if & q < q_0 \\ \gamma > \delta & if & q > q_0 \\ \gamma = \delta & if & q = q_0 \end{array}$$

Figure 1.10 illustrates the short term and long term equilibrium with two types of demand curve: one for the day(peak) and one for the night (based).

At equilibrium, without barriers to entry nor taxes or subventions, the price at peak demand is equal to both short run marginal cost and long run marginal cost. This is a message of market indicating that the capacity is optimal. So at the optimum, the three curves of demand, differential cost and development cost all intersect at the same point.

Hansen and Percebois [2012] showed that the complete cost of electricity production (EUR/MWh) of a new installed unity (or long run marginal cost of an electricity unity) is, by definition, the sum of variable and fixed costs:

Figure 1.10: Short-run vs long run Marginal cost



$$C_m^{LT} = \frac{p_f}{\eta} + (\frac{P_{CO2}}{\eta}.EC02) + OMV + \frac{OMF}{D} + (\frac{i(1+i)^y}{(1+i)^y - 1})\frac{I}{D} \tag{1.2}$$

with:

- p_f the utilized combustible costs (or fuel costs), measured in EUR/MWh
- η thermal plant efficiency (%)
- P_{CO2} price of the ton of C02 emitted (EUR/t)
- $EC02$ emission factor of fuel considered (t/MWh)
- OMV variable cost of operation and maintenance (EUR/MWh)
- OMF fixed cost of operation and maintenance (EUR/MW)
- i interest rate
- y life time of the plant
- I overnight cost EUR/kW
- D Utilisation (duration) of the plant by year (h/year)

Table 1.1 gives the calculation results of long run marginal cost based on indicative technical data for different power generation technologies - median case (OECD-IEA [2010]) [13]. To conclude, we have showed that provided there is an optimal investment policy, short-run pricing is efficient and also long-term pricing: there is no contradiction.

[13]Projected Costs of Generating Electricity 2010 Edition published by OECD-IEA presents the main results of the estimation of the costs of generating electricity from a wide range of technologies iusing various country data. The data we report in the table is the median case.

Table 1.1: Long run marginal cost – median case (IEA 2010)

	Unit	nuclear	offshore	Solar	Onshore	Coal (without CCS)	CCGT
Capacity	MW	1400	400	100	100	750	480
lead time	year	7	4	3	3	4	2
overnight cost (unit capital cost)	$ /kW	4101	5974	4691	2437	2133	1068
Efficiency	%	0.33	-	0.15	0.35	0.411	0.57
Expected lifetime (years)	year	60		25	25	40	30
Fixed cost of O&M	$ /kW	88.75	53.33	64	28.07	29.67	14.39
Variable cost of O&M	$ /MWh	2.04	46	0	21.92	4.25	4.48
CO2 Emission	kg/Gji	0	0	0	0	13	22
Fuel cost	$ /MWh	9.33	0	0	0	18.21	61.12
CO2 Price	$ /tonne	25	25	25	25	25	25
Load factor							
Hours of function	h	7446	3766.8	1138.8	2277.6	7446	7446
Discount rate		0.08	0.08	0.08	0.08	0.08	0.08
CO2 cost	$ /MWh	0	0	0	0	23.96	10.54
total variable cost per MWh	$ /MWh	30.31	46.00	0.00	21.92	72.52	122.25
total fixed cost per MWh	$ /MWh	55.98	141.03	385.74	97.92	26.90	13.41
marginal cost long term	$ /MWh	86.29	187.03	385.74	119.84	99.42	135.66
total capital cost	$ M	5741.40	2389.60	469.10	243.70	1599.75	512.64

Source: OECD-IEA [2010] Projected Costs of Generating Electricity

Table 1.2: Example of cost structures

Technology	Fixed cost/MWh	Variable cost/MWh
Baseload	K_1	c_1
Peaker	K_2	c_2

Proposition 2: ***Competitive prices (short run marginal cost prices) do enable generators to cover their fixed costs without overcharging customers.***

There is often a misunderstandings stated that marginal cost pricing will not enable generators to cover their costs, known as problem of "missing money", then in order to ensure adequate investments, competitive prices must go far away from marginal cost. This statement is not true. It does, in fact, exist the problem of missing money in electricity market, but that is not due to marginal cost pricing. Competitive prices (marginal cost prices) do enable generators to cover their fixed costs without overcharging customers.

We illustrate as following: In a market with two kind of technologies: peaker and base-load generators with costs as shown as:

As we admitted above, we can not satisfy "demand" all of the time, some level of load shedding is needed. Therefore it should be accepted the existence of price spikes which can be illustrated as a kind of "technology" with zero fixed cost but very high variable cost. Screening curves are described in figure 1.11

As reading from figure 1.11, the optimal level of installed capacity during T hours will be recourse of:

- x_1 MW of baseload generators, functioning from h_1 to T h
- x_{21} MW of baseload generators, functioning from h_2 to h_1
- Load shedding[14] from 0 to h_2

We summarize as in table 1.3 :

[14]Load shedding is process of disconnecting the electric current on certain lines when the demand becomes greater than the supply

Figure 1.11: Load sheding

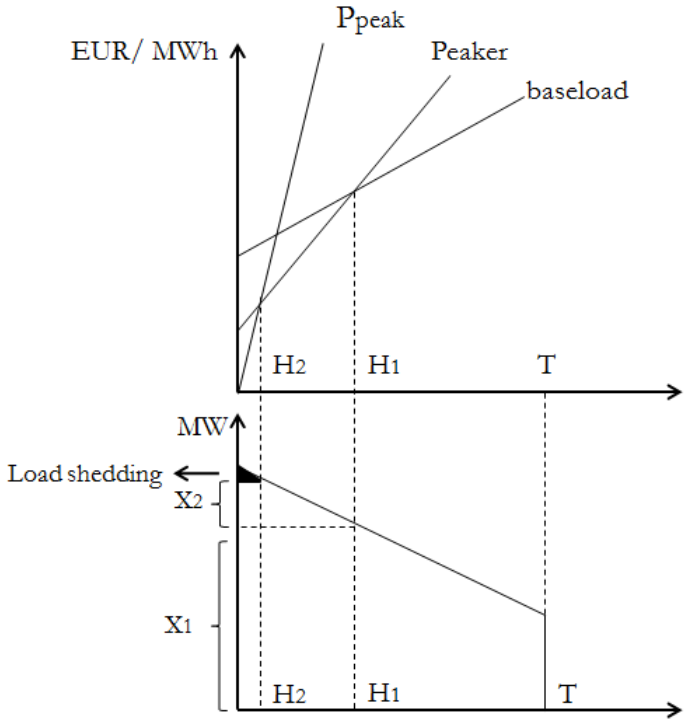


Table 1.3: Resulting profits

	$T - h_1$	$h_1 - h_2$	h_2
Capacity (MW)	x_1	x_2	x_3
Price/MWh	c_1	c_2	Price spikes P_{Peak}
Short run profit of baseload	$c_1 - c_1 = 0$	$c_2 - c_1$	$P_{peak} - c_1$
Short run profit of peaker	0	$c_2 - c_2 = 0$	$P_{peak} - c_2$

1 MW of baseload will have profit of:

$$\Pi_1 = (c_2 - c_1)(h_1 - h_2) + (P_{peak} - c_1)h_2 - K_1 \tag{1.3}$$

Substituting $h_1 = \frac{K_1 - K_2}{c_2 - c_1}$ and $h_2 = \frac{K_2}{P_{peak} - c_2}$ and manipulating equation (1.3) yields $\Pi_1 = 0$. Calculating similarly with Π_2 will lead to same result. Competitive prices will recover the fixed costs of each kind of technology and no more.

However, sometimes the residual load has to be served by some sorts of peaker with low fixed costs and very high variable costs, functioning during very little hours; and when this occurs, there will be the problem of "missing

money" - generators could not cover their fixed costs (long - run profit is negative) [15]. But this is due to possibly technical or institutional reasons that make the market enable to respond as quick as possible (function of load shedding couldn't work). This is not the problem of marginal cost pricing. Competitive prices (short run marginal cost prices) do enable generators to cover their fixed costs without overcharging customers.

(c) Equilibrium without market clearing price

So far we have assumed that market can always find an equilibrium (Q, P) and this is where supply and demand intersect. This equilibrium is competitive and efficient if and only if at price P, (1): demand equals supply and (2) suppliers could not increase profits by selling a quantity different from Q as well as consumers could not increase their satisfaction (utility) by buying a quantity different from Q. In this case, we say that there is a price that "clears the market" and this price is competitive and efficient. However, if production cost function is nonconvex, there may be no market clearing price and economic theory fails to guarantee efficiency. This situation might occur in electricity market.

"*Non-convex operating cost*" in electricity might be caused by (1) minimum technique [16] and (2) startup costs and no-load costs [17] (Hansen and Percebois, [2012]). This has property that the cost of producing two units is less than twice the cost of producing one (See more in box 1.1). For example, 200 MW for two hours would cost 35 €/MWh while 100 MW for the same hours would cost 50€/MWh because of start up cost. Twice as much is cheaper per unit, so the production cost is nonconvex. If the demand needed for two hours is exactly 100MW, there will be no price at which supply equals demand. More precisely, there is no price at which a supplier could profitably sell 100 MW but could not increase its profit by selling more. So at demand

[15] One can recalculate long run profit of each technology in similar way as above.

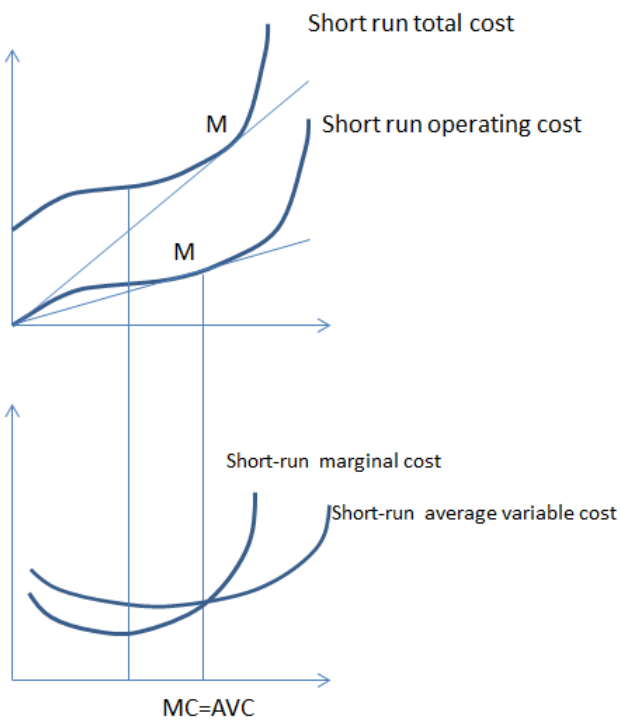
[16] A power generation plant is characterized by a maximum developable power (in MW), but also a minimum power, below which it can not function for technical reasons.

[17] Startup costs are incurred because of starting up a generator. They are usually found in the range between EUR 20 and EUR 40/MW. Startup costs are costly particularly for midload plants and costless for peakers. There are also no-load cost which is the cost of running a generator while producing no output.

level of 100 MW, a generator with startup cost refuses to run at a market price of 35€/MWh because this does not allow it to recover its startup cost. This is known as "unit-commitment" problem, meaning that some generators might refuse to start their plants in real time, then optimal dispatch cannot be archived.

Box 1.1 The non-convexity of operating cost function

Up to present, we have always assumed that the short-run marginal cost and average variable cost functions eventually rise because short-run operating cost function is convex. The figures below illustrates how a non-convex operating cost function could affect the shape of marginal cost curve as well as suppliers decisions of producing.



The upper graphic illustrates short run total cost and operating cost curves which are non-convex in the interval $[0; Q_M]$. The direct impact is shown in the lower graphic, where short-run average variable cost is decreasing when output is within the range $[0; Q_M]$. At Q_M, the average variable cost is minimum and equal the short run marginal cost. Suppose that demand is at somewhere between 0 and Q_M, where the short run operating cost is con-

vex and short run average operating cost is decresing, the producers refuse to produce because they know that the more they produce, the less cost they will pay. If the demand is rigid (like the case of electricity), there will be no price at which supply equals demand. More precisely, there is no price at which a supplier could not increase its profit by producing more (average operating cost is falling), (Stoft [2002b]).

It is often argued that a power pool design can somehow fix the problem because it offers a "side payments" for the plants that loses money from startup costs. With this arrangement, a power pool might induce the optimal dispatch. However, this causes, in long term, distorted investment in generation because this will encourage too much investment in the types of generation that receive the greatest side payments per MW of capacity.

To sum up, screening curves, together with load duration curves, had been used in old regulated system to find the optimal equilibriums. This technique is still relevant in unregulated markets to confirm a market equilibrium, but not to find one. In a market, their role in analysis is more subtle because the shape of the load-duration curve is affected by price, so this technique canot be taken as given until the equilibrium is known. Classic competitive equilibrium (in the sense of Walrasian) is found based on marginal cost function (which determines supply curve in competitive market) and demand curve (load duration curve in combination with price elastic). Marginal cost pricing in electricity is not always clear defined in case of electricity because it takes an infinite upward leap when it reaches full output. This form of marginal cost curve could lead to many misunderstandings about the existence of competitive equilibrium in electricity markets. Someone who misses the point might state that market could not be cleared when the system reaches its maximum and load is beyond this level; or that market price in this case must be above marginal cost. In this section, we prove that marginal cost pricing does give a market clearing price if load curve is combined with price elasticity. These prices are sometimes higher than the variable cost of the last unit produced electricity but are always within marginal cost range. Finally, marginal cost pricing does enable generators to cover their fixed costs without overcharging customers.

Conclusion

The last century has witnessed an amazing and broad revolution in the organization of electric power markets in Europe and all over the world. The rapid spread of those changes cannot fully explained by the development of technology alone. The story of "making markets in power" concerned society and economic ideas (Hogan, [2000]). Each country has its own pre-existing conditions, and each of them has its own way of doing that.

In this chapter, we describe industry structures and regulatory framework that characterized the electric power industry worldwide during most of the twentieth century and review the initial efforts to reform the industry (regulation, deregulation and market opening processes) in European electricity markets during the late 1980s and early 1990s. The organization of electricity industries in Europe after the World War II 1945 was vertically integrated monopoly under regulation because of many reasons. The perhaps most persuaded argument was that both electricity generation and transmission had characteristics of economies of scales. However, since the lates of 1980s and the beginning of 1990s, the advances in technology, the development of market size and trasmission capacity, the new economic idea of re-organisation all together motivated the industry toward the deregulation and liberalization process. This implied restructuring the industry vertically and horizontally, opening generation sector to competition and implementing a set of designing tools to make competition works in an efficient way.

Generally, liberalization in most countries started at the wholesale level and moved slowly to retail market. Some countries implemented restructuring initiatives before launching competitive wholesale and retail markets while some others did it after, etc. However, it has been experience that poor market structure poses the greatest threat to the functioning of power markets and even good market designs cannot fix a bad market structure. Best results of electricity reform come out with good market structure and it is much more difficult to restructure the industry after market opening has been launched and market participants have made investment decisions based on the rules of the game that are already made (Glachant [2009]). In almost all countries where electricity reforms have been put in place, the wholesale markets were

completely/partly opened to competition. This is also the big common feature of the reforms in both the USA and the EU. Prices and investment decisions, as such, have been no longer regulated in those markets but determined by "market forces". We have also analysed in this chapter how the market forces can be served in price-formation process in the newly-opened wholesale electricity markets. Though being different from other markets due to the distinct cost structures and nonstorability of electricity, most of economic theories about marginal pricing are still "valid" as applied to electricity industry.

Electricity reform has been in place around the USA as well as the EU for more than two decades and in reality there are many trade offs and only a few clear-cut answers. One thing is clear that the design of this newly-opened electricity market model is not yet definitive, and that some important problems are still unresolved. One of which concerns "market power", which we discuss in the following chapter.

Chapter 2

Market power issues in newly-opened wholesale electricity markets

Abstract: While reforming the industry may bring many benefits for the customers and the development of the industry as a whole, it is not a panacea. One of the most alarming issues arised from the shift to reliance on market prices instead of regulated tariffs for electric generation has been market power. "*Market power*" is not a new concept but theoretical and empirical studies of "*market power in electricity markets*" have only been developed recently. It raises concerns in both sides of the Atlantic, as regard to the way of defining, detecting, and monitoring it. In this chapter, we show that while most of economic theories such as market power definition, marginal pricing are still "valid" as applied to electricity, the methods of detecting market power in the new competitive electricity market could not be the same as ones applied in any other markets.

Introduction

Liberalisation in electricity markets aims to provide full-powered incentives for firms to hold price down to marginal cost, to minimize their costs, and to promote innovation. Thus end-users can profit from lower prices for energy and a better quality of service. It sounds very simple, but it is not such a simple task for member states to make it work properly. The assumption that markets will naturally produce a competitive result is not always justified. The shift to reliance on market prices, given concentrated structures and particular characteristics of electricity industry, raises a possibility that some firms could influence the market prices by exercising their market powers. If this happens to a certain extent, the resulting harm may be worse than when no competition had been introduced, going as far as widespread rolling blackouts and economic fall-out (Friedman [2009]).

"*Market power*" is not a new concept but theory and empirical studies of "*market power in electricity markets*" have been developed only recently. It has drawn much attention from both side of the Atlantic since the early days of deregulation and liberalization in power generation markets. Literatures on market power sometimes distinguish two types of market power, horizontal and vertical. Horizontal market power involves a firm which profitably drives up prices through its control of a single activity, such as electricity generation, where it possesses a significant share of the total capacity available to the market. Vertical market power is exercised when a firm involved in two related activities along the value chain, such as electricity generation and transmission, uses its dominance in one area to raise prices and increase profits for the overall enterprise. Because we examine solely electricity at the wholesale level, we focus only on horizontal market power, i.e. market power of generating companies. Furthermore, concerns related to vertical market power in the electricity sector are already commonly understood. The mechanisms for addressing them, such as requirements for independent operation of the transmission system and non-discriminatory access to it are widely accepted (Glachant [2009]).

Up to 1990s, empirical studies of measuring market power in liberalized generation electricity markets were scarce since it had rarely been contem-

plated outside the United States. Most studies had attempted to assess the potential for exercising market power by measuring the extent of market concentration in regional submarkets. Studies of market power in Europe were developed a bit latter but were not out of this line. However, over the last 15-20 years, market power detection techniques have been dynamically evolved, varying enormously from theoretical to empirical models, from market structure to market outcome approaches; from direct to indirect estimations, etc. Up to present, a number of works have been implemented to diagnose market power in electricity markets with some authors finding market power in certain markets and some others disputing it. Though advances have been made, we are still far from being able to define an appropriate method to detect market power and well functioning market designs to overcome this problem.

In this chapter, we carry out an insight literature review around market power issues in deregulated wholesale electricity markets. The chapter is organized as follow.

Section 2.1 presents some of the key concepts of market power, including the various definitions of market power and strategies of exercising market power Section 2.2 describes several limitations of theorical models as one attempts to examine market power in electricity markets. We show that many distinguished idiosyncrasies of the industry as well as the existence of entry barriers make exercising market power in power markets particularly likely and detecting it extremely challenging. Section 2.3 provides an thorough review of existing methods/aproaches of diagnosing market power in power markets both in Europe and in the US. We show that each of those methods has strengths and weeknesses. Although there is no definitive method for diagnosing market power, the more recent tools have been considered better able to capture relevant factors and dynamic considerations that are not present in traditional tools such as structural indicators.

2.1 Market power in power markets

In this section, we review some essential aspects concerning market power: how to define it in electricity markets and how a firm in a power market could exercise its market power.

2.1.1 Defining market power

Market power is defined in almost economic textbooks as "*the ability to profitably alter prices from competitive levels*" (Krugman and Wells [2009]; Mankiw [2008]; Mas-Colell, Whinston, Green et al. [1995])). This definition, with slight variations, has been used for a long time particularly in competition law, known in the United States as antitrust law. The antitrust regulators define market power is "the ability of a supplier to profitably raise prices above competitive levels and maintain those prices for a significant time period." (the U.S.Department of Justice (1997), hereafter referred to as DOJ) [1]. These definitions might seem harsh at the first look but they are precise and terse as a good technical definition should be. Each word/phrase is well-termed and carries much weights:

> Market power is defined as the **ability** ...

Because market power is defined simply as the "*ability*", it is not automatically unlawful as long as a firm possesses a market power but do not exercise it. Therefore, the regulators sometimes distinguish between "having" and "exercising" market power. Empirical studies of market power cover both. Because exercising market power is profitable (according to both economic and DOJ), once a firm has market power, the only rational reaction is to exercise it (Stoft, [2002]). The distinction between those two notions only makes sense as taking into account long-run considerations or as one is trying to categorize market power studies in ex-ante (having) or ex-post (exercising) approaches.

[1] We are referring the definition given by the U.S.Department of Justice (DOJ. 1997) which is most close to the well-termed standard economic one. One might find a number of definitions of market power given by legislation papers (e.g U.S FERC. 2002 or TFEU.2009) but most of them focus more on the methods of exercising market power and ignore important elements precised in the standard one, thus more complex and less general.

. . . **profitably** . . .

Both economic and regulatory definitions require that exercising market power must be *profitable*. Because without profitability requirement, a plant shut down for any reason might be considered as an exercise of market power. Without profitability requirement, a supplier with market power owning nuclear plants might choose to close down one of them even when exercising it would be hugely unprofitable. And without profitability requirement, a firm would be supposed to reduce its output as much as possible to raise the market prices despite the fact that it is profitable only if it withholds no more than its small gas turbine. So the effect of exercising market power must be profitable. Though this is not universally accepted it is a helpful standard to orient regulators toward the "real" suspect generator.

. . . **alter prices away** (economics definition) or **maintain prices above** (DOJ)

The regulatory definition rules out cases that a firm is likely to abuse its market power by setting the prices lower than that of competitive level to get rid of the new entrance or its competitors (known as predatory pricing). In predatory pricing, the predator, already a dominant firm, deliberately lower its price for a sufficient period of time to drive its competitors out of market and to deter others from entering. This implies that the predator as well as its victims has incurred losses and that these losses are significant. For the predation to be rational, there must be some expectation that these present losses, like any investment, will be made up by future gains. This, in turn, implies that the firm, as a monopolist, tends to raise the price following the predatory episode, and that profits gained from increased price of this later period should be sufficiently high to warrant incurring present losses. But as shown in various studies such as McGee [1980] and Easterbrook [1981], *the threat of predation is not credible* largely because the dominant firm would lose more by predating than by coexisting with a rival[2]. Furthermore, as pointed out by Hansen and

[2] McGee [1980] argues that predation is more costly to the predator than the victim given the predator's larger market share. As the market share increases, so too do the costs for the predator. Secondly, future profits must be discounted to present value terms and this reflects the uncertainty that a predator will have to cope with. Finnaly, even if the predator succeed in driving out its competitors, new entry is possible in the post-predation period (the existence of the victim demonstrates that entry is possible).

Percebois [2012], an incumbent has incentive to let certain place for the new entrants so that it could benefit from a higher price (in short term) and get less trouble with the competition authorities . Finally, as pointed out earlier, even when the incumbent might succeed to discourage entrance by his *predatory strategy*, it is supposed to raise the prices in post-predation period. For those reason, an abuse of market power implicitly refers to an increase of market prices, or, *the studies about market power often concern more about the nature of increase in price.*

...above competitive levels ...

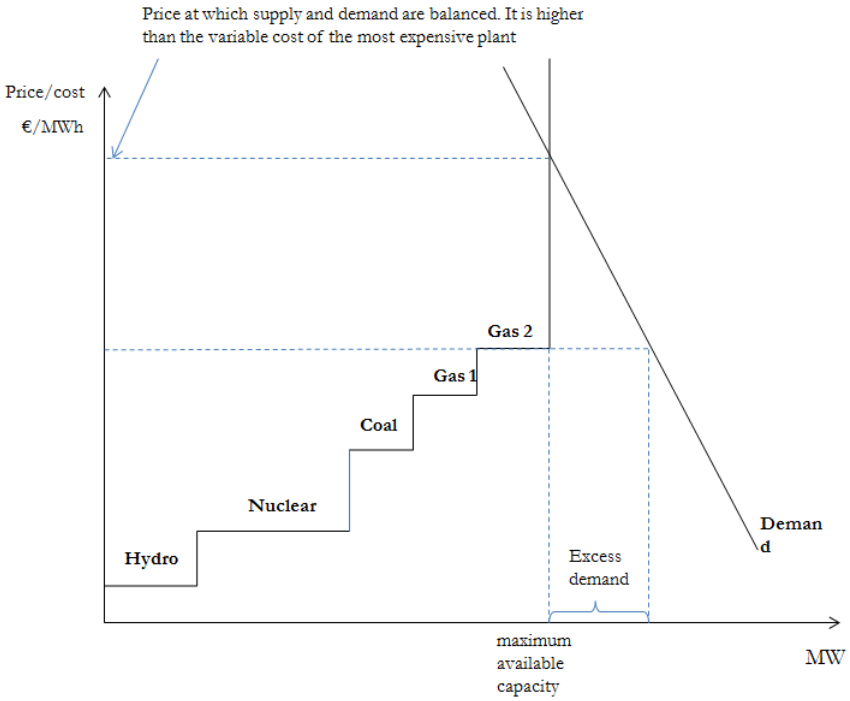
This is the most important requirement of market power definition, which also induces a lot of ambiguity and misidentification. In fact, not all higher prices are due to market power. A rise in the electricity prices could be resulted from a number of factors such as very high level of demand pushing the price up, increases in fuels costs; environmental related costs/taxes, or transmission constraints on interconnection, etc. A firm is said to have market power *if and only if*, one way or another, it can drive up the prices above competitive level.

In a truly competitive market, all sellers (and buyers) are "price-takers", i.e, their own production and purchase decisions do not affect the market price; market power is thus not a issue. The most profitable strategy for a price-taking producer in this case is to "bid" the output of each generating plant into the market at its variable cost of operation. If the market price is equal to or greater than the bid for a particular plant, that plant runs. And any surplus of the market price over variable cost (short run profits) will contribute toward fixed costs; long run profit equal zero (described in section 1.2.2). If the market price is below the bid level for a particular plant, the owner has no regrets about having bid at variable cost, because running that plant would make a loss.

However, prices will at times rise above the variable cost of production of the most expensive plant serving a market even if no producer exercises market power. This occurs when demand exceeds maximum available supply at the bid price of the most expensive plant, and transmission constraints make it impossible to bring in more power from other regions. Buyers who are willing to pay prices that exceed the highest competitive bid will offer to do so, and

prices will rise until they become high enough to balance supply and demand (figure 2.1). The increases of prices above the short-run variable costs reflect the value to consumers of consuming additional electricity in times of limited supply. These price increases allow peaking plants that operate only a few hours a year to recover their fixed costs [3].

Figure 2.1: Scarcity pricing



In neither of these two cases, market power is being exercised because prices, even sometimes very high, are still at the marginal cost range. Market power is said to be exercised only when a firm one way or another, can drive up the prices above system marginal cost range (or competitive level). This result is proved to *be true in any market including electricity* (c.f Section 1.3). Understanding this is crucial for further analysis because if it holds, existing economics tools are still able to applied to electricity markets. Indeed,

[3]We emphasized that in competitive market and without market failures, these high prices will only help all the plants recover their fixed costs, but no more. If they are higher than it should be to recover all fixed costs, it will be a signal to investors that new capacity may be an attractive investment opportunity. And in contrast, if they are not sufficient to recover all costs, this is not the problem of competition, nor marginal cost pricing, it is the signal of Adam Smith's "invisible hands" that there is an excess of capacity and that no more investment will be needed.

marginal cost pricing and competitive equilibrium are not always clear in the case of electricity. Even some authors with extremely good knowledge of the industry sometimes make it confused: *"... During the periods of peak load, the demand exceeds the maximum capacity, prices will rise above marginal cost, even if market power is absent..."* (Hunt [2002]) or *"... thus in the absence of market power by any seller in the market, price may still exceed the marginal production costs of all facilities producing output in the market at that time..."* (Borenstein [2000]).

2.1.2 Exercising market power in power markets

Market power in power markets is frequently characterized by withholding of capacity that could be produced at the market price (physical withholding); or it could be exercised by asking a higher price than marginal cost (financial withholding) Stoft [2002b]. These two different ways lead to the same result : a higher market price, higher profits, and withheld output. Because of the wide spectrum of productions costs in electricity, a firm with a diversified portfolio could easily exercise its market power by withdrawing the capacity of its most expensive plant without loss of profit. As doing so, the market prices would increase and the firm could gain higher revenues from other base load plants with low marginal costs.. A numerical example might clear up the points [4].

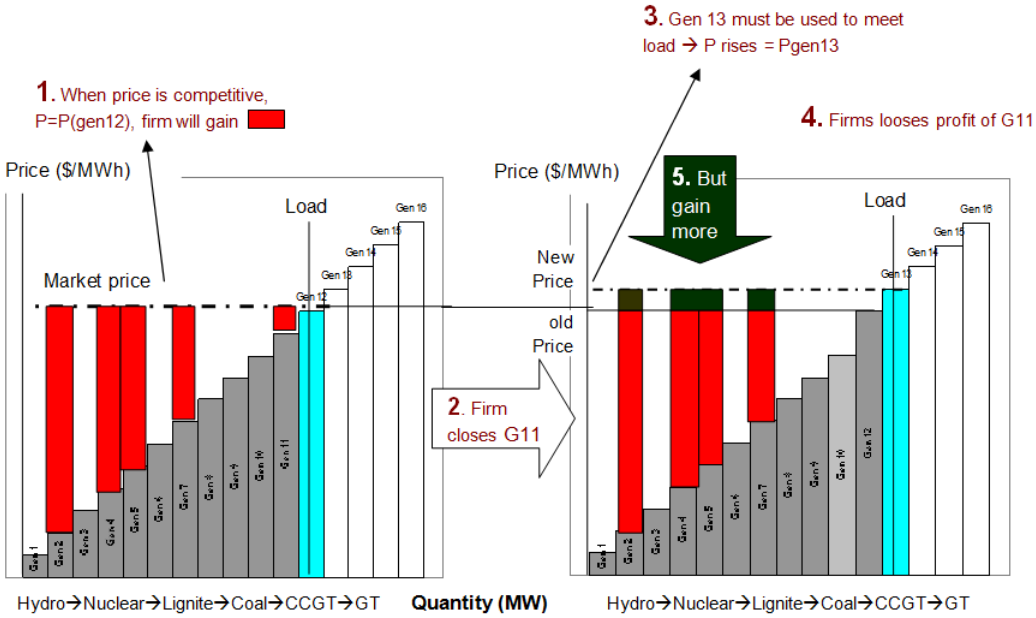
(i) Physical withholding

Suppose there are 16 symmetric generating units saying Gen 1 through Gen 16. For simplicity, assume each one has capacity of 100MW (generating units' capacity in practice varies upon the basis of different fuels and most electric systems are much larger and have more generating units). All generating units are listed in merit order from least expensive to most expensive variable cost. At time t, load is shown at a fixed level, somewhere from 1100 MW to 1200 MW. Assume now that a single firm A owns Gens 2, 4, 5, 7 and 11. How market power can be exercised in electricity spot market is illustrated as follow[5].

[4]This example is inspired by Hunt [2002]

[5]Market power can be exerted in electricity forward market in an analogous way

Figure 2.2: Exercise market power by physical withholding



1. If there were a perfectly competitive market, the price would be competitive and equal the production marginal cost of the most expensive plant producing electricity, i.e, Gen 12 in this case (Figure 2.2.left). The red area in the figure shows short-run profit of firm A [6] which is found by simplicity subtract total variable cost from total revenue. This short run profit allows company to recover its fixed costs.

2. When firm A exercises its market power by withholding its capacity by for instance shutting down completely one of its plants. Profitability requirement of market power definition results Gen 11 (the highest cost and lowest profitable plant) to be withhold.

3. Now Gen 12 through Gen 16 must move to the left on the supply curve, Gen 13 has to run to offset the 100 MW withdrawn from Gen 11. Gen 13 now becomes the marginal plant. Price rises and is now equal to that of Gen 13.

4. Firm A no longer makes any profit from Gen 11 that it withdrawn

5. But it gains more because profits from Gens 2, 4, 5 and 7 have increased

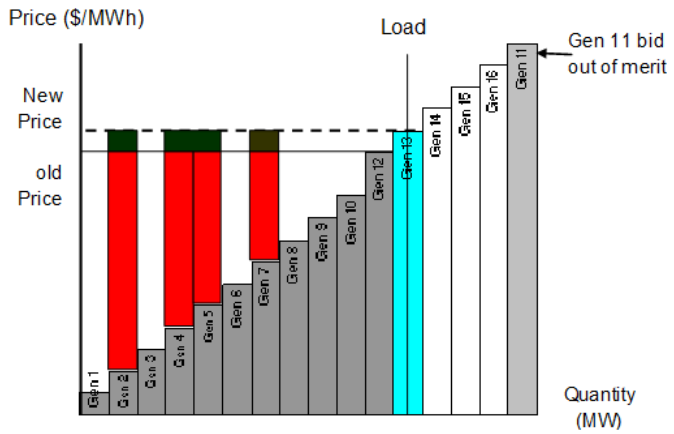
[6] Long run profit in a competitive market is however equal to zero.

thanks to the increased price (the green area in the figure 2.2.b). The increased profits from those four plants outweighs the lost profit from Gen 11. The company is better off.

(ii) Financial withholding

Another way to exercise market power which leads to the same result is to simply bid a higher price than marginal cost (financial withholding). In stead of physically withholding capacity of generator unit 11, firm A may simply bid a higher price for this unit. In this case, Gen 11 will be out of merit, Gen 12 through Gen16 must move to the left on the supply curve, things would happen exactly as when the firm withdraws it physically (Figure 2.3)

Figure 2.3: Exercise market power by financial withholding



Several interesting observations could be drawn from this numerical illustration:

- *Market-power detector should not focus only on the marginal generators*: Usually, a clearing price is set by a single generator, called "marginal generator" in both day-ahead and real time market. Therefore, many attempts to measure market power focus on the marginal generators with the argument that only price-setting generator can exercise market power. In this example, the bid that raises the price might not set the price: Gen 13 sets the price but it is Gen 11 that raises the price and generator who possesses Gen 11 is the one who exercises market power. The marginal generator, Gen 13, has bid its true marginal cost. If regulators only examined it for market power, none would be found.

- *Concentration and market power*: The ability to exercise market power is one way correlated , but imperfectly, with market concentration level (or supplier's market share)[7]. The above illustrative example shows that if firm A has a large portfolio and big market share, it will have strong incentive to exercise its market power because losses from shutting down one generating unit will be offset by increased profit from high prices. This strategy makes more sense if the firm still has some outputs left in the market that it can sell at a higher price to outweigh the losses. However, the relationship between concentration and market power in electricity market is not always that clear. A supplier with relatively small market share could sometimes have market power. It happens when capacity is tight, demand exceeds the maximum capacity and transmission constraints make it impossible to import power, even a supplier with 1% of total output can have incentive to exercise market power. Suppose a firm possesses a small market share, say, gen 16 in the example, when load reaches max capacity, it can profitably raise the price with little fear of being kicked out of the market (if demand is unable to respond to changes in price). This generator is considered "pivotal".

- *Who gains and who loses ?* : The exploitation of market power brings profit, not just for the exerciser, but for all suppliers. The supplier that exercises its market power gets no special advantage from being the one to do so because higer prices are enjoyed by every suppliers [8]. The customers, at the end, are worst off for paying a higher price than it should be if the market was competitive, creating some sorts of wealth transfer from customers to suppliers.

An argument frequently made is that in electricity, scarcity and opportunity cost can cause very high prices, exercise of market power whose impact on prices is much less important can be tolerated. The first observation is true; the second is false. It is true that in electricity market, charging 550

[7]More details on the relationship between concentration and market power are given in section 2.3

[8]In this example, we inplicitly assume that the auction rule on the wholesale market is based on "price uniform" - every supplier recieves the same market price (to distingushed with "pay-as-bid" model where each suppliers gets what they bid)

€/MWh instead of 50 €/MWh is not uncommon. This is 1000% higher than average variable cost. Then if a generator exercises its market power and raises the price only 5% above marginal cost, why it is worth worrying about? The answer is that there seems to be no regulatory standard about what amount of market power can be tolerated or acceptable[9] but it is always worthy supervising the market to detect any abuse of market power. The exercise of market power in electricity might cause serious problems and inefficiencies for the overall functioning of the system. How much those inefficiencies cost is hard to measure numerically. As estimated by Twomey et al. [2006]: in a 300 TWh/year market, the wholesale market might have a value of 10 billion euros/year, the inefficiency of only 1% of this can amount to 10 million euros/year. For example, changing the merit order to switch in a marginal plant of 500 MW running 5000 hours/year which costs only 2€/MWh more, amounts to an extra cost of 5 million euros/year [10]. Such inefficiencies might induce regulators to impose further controls which, in turn, risk further inefficiencies. While consequences of market power abuse might be very harmful, detecting it is extremely challenging due to many factors in electricity industry.

2.2 The limitations of theoretical models

So far we have showed that the ways of defining as well as exercising market power as applied to electricity are not too far from conventional economic theories. However, certain problems, some of which arrive from peculiar characteristics of electricity (such as lack of demand response), some of which arrive from political and social concerns (creating some sort of entry barriers), make exercising market power in power markets particularly likely and detecting it extremely challenging.

[9] A common suggestion should be that levels of withholding which are smaller than the normal fluctuation in weather, load, generation retirement, and outages could be tolerated. The market will remove them soon enough, and they are not more problematic than several other problems that must be accepted.

[10] This is found by: 500MW*5000h/year*2 €/MWh = €5.000.000/year

2.2.1 Lack of demand responsiveness to price

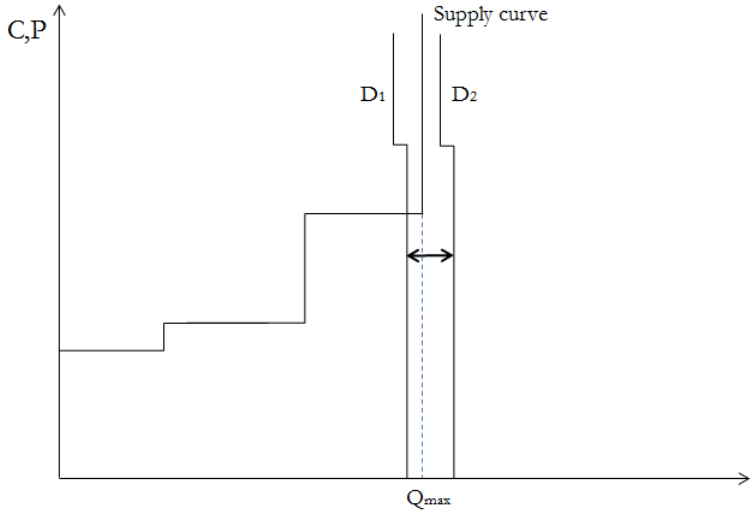
Together with water, electricity is an indispensable good that is consumed by essentially all customers at any moment. In electricity markets, consumers buy electricity whenever they turn on an electricity equipment. Within this millisecond, they have never needed/do not have mean to check the price first in order to respond to it. Spot electricity market works very poorly when supplies are tight (problem of "scarcity"), and is exacerbated when there is a combination of scarcity and extremely inelastic demand. A firm with market power in this case can bid up the price as high as they could unless there are customers who can say "play your game without me" (Hunt [2002]). This is a flaw that makes market power a major issue in so many power markets which are even well structured (Joskow [2001]).

The situation is more severe with the presence of several technical attributes. First, electricity cannot be stored economically on a large scale [11]. It cannot be bought in periods of low demand and stored at home for periods of high demand. This implies that when capacity is tight, demand exceeds the maximum capacity and there is no storage, even a supplier with 1% of total output can have incentive to exercise market power (pivot actors). Secondly, electricity is transmitted over a network and follows laws of physics known as Kirchoffs' laws (it takes the path of least resistance): transmission system is quite fragile, any unexpected events like changes in customers' use, sudden loss of output at a generating plant can destabilize the whole network and make it congested. When transmission constraints bind at a given point of the network, no electricity can be imported/exported in/to the local area where there is congestion: the local suppliers become the only to sell electricity - they have market power.

In the extreme case, the supply and demand curve may fail to intersect and market might be unable to determine a clearing price because demand responds so minimally to price.

[11] Hydroelectric plants might sometimes be thought of as a form of storage, since they store water that can be saved for peak uses; but this is not really storage of power, the water must pass through a turbine-generator to create electricity, so in many ways it is the same as having a coal pile and considering it "stored electricity" except that the hydro responds much faster.

Figure 2.4: Lack of equilibrium



Source: Own illustration

Figure 2.4 illustrates this situation where there is no market equilibrium due to lack of demand response to price. This situation occurs for only certain combinations of supply and demand curves: (1) inelastic demand, (2) inelastic supply. When it does occur, the market fails and the system operator, as default supplier, should set the market price. This price is the value that customers are willing to pay for not being cut off. Setting the price of energy in the spot market to this price whenever market cannot determine a price is VOLL pricing - the value of lost load. However, there is almost no market information of how high this value should be because most customers do not respond directly to real-time prices. This is to say VOLL pricing is regulatory. The VOLL is disconcertingly high, perhaps above €10.000/MWh while the cost of the last unit of power produced is generally at only €500/MWh. This produces strong incentives for the exercise of market power (details in box 2.1).

Box 2.1 VOLL pricing vs market power

To illustrate how market power is susceptible with the presence of VOLL pricing, let consider the following example (This example is inpired from Stoft [2002b]): A supplier possesses 2000 MW of generation dispatched with an average variable cost of €50/MWh. The marginal cost of the last unit of power produced (which is also market price) is €100/MWh. Load in time t

is 18.300 MW and total available supply is 20,000 MW. Now suppose that there are three possible of VOLL prices: €500/MWh, €5.000/MWh and €20.000/MWh. If the supplier withholds 1800 MW, it can push the price to one of these VOLL levels. The short run profits in different scenario are described as:

Scenario	Price scenario (€/MWh)	Short run profit (€/MWh)	Capacity (MW)	short run profit (€/h)
absence of capacity withholding/Full capacity	100	50	2000	100.000
Capacity withholding (1800 MW)	500	450	200	90.000
Capacity withholding (1800 MW)	1000	950	200	190.000
Capacity withholding (1800 MW)	5000	4950	200	990.000

If the supplier produces at its full capacity, the market price would be €100/MWh, and it earns a short run profit of €50/MWh or €100.000/h on its 2000MW. If the supplier considers to exercise its market power, i.e, withhold its 1800 MW to push the price up to VOLL levelsAt e500/MWh, the supplier would earn e 450/MWh on its 200 MW for a total of €90.000/h - less than what it earns at full output.

However, at €1.000/MWh or €5.000/MWh it would earn €190.000 and €990.000/h respectively, which is almost 2 or 10 times more than what it earns at full output. So with a VOLL price at 500 the supplier chooses not to exercise its market power. With a 5000 VOLL price it makes enormous profits by exercising market power. VOLL pricing provides ideal conditions for the exercise of market power.

The lack of demand response in short term is one of the fundamental flaw in electricity markets that renders exercising market power in electricity market particularly likely than other markets; and, as we see shortly, diagnosing

market power extremely challenging.

2.2.2 Barriers to entry

Together with the lack of demand responsiveness to price, the existence of barriers to entry is another factor that renders the exercises of market power likely.

In a competitive market, if one charges a higher price, buyers will respond ; and/or other companies will discover the profitable market, enter the market, conquer the market shares and prices would return to equilibrium. In electricity market, not only demand response does not work properly, but new entrants to this industry are also implausible due to the existence of barriers to entry.

(i) Barriers to entry in theories of competition in Industrial Organisation

From a theoretical perspective, the model of perfect competition requires free entry into and exit from a market; that is, firms can start up or shut down operation instantaneously and costlessly. A market with free entry and exit has less risk for the problem of market power because if a firms attempts to raise the prices more than covered fixed costs, investors will recognize this and penetrate the market; supply will outstrip demand and prices will fall to the level at which firms' long-run profit is equal to zero. With the existence of entry barriers, exercising market power would be more feasible because incumbent firms face no threat of new firms entering the market challenging them.

Competition scholars have had long debates to conclude a definition for barriers to entry, to cite a few:

"A barrier to entry is a cost of producing (at some or every rate of output) that must be borne by firms seeking to enter an industry but is not borne by firms already in the industry" (Stigler [1983] p. 67)

"A barrier to entry is a factor that makes entry unprofitable while permitting established firms to set prices above marginal cost, and to persistently earn monopoly return." (Ferguson [1974] p. 10)

"A barrier to entry is anything that prevents entry when entry is socially beneficial." (Fisher [1997] p. 23)

The long list of entry barriers definitions has been apparently continuing. Each definition highlights useful aspects of the relevant barriers to entry. However, as pointed out in Group [2012], no single definition is likely to cover all circumstances. Ferguson's definition, for example, ignores the factors such as superior management skills or higher product quality that may enable incumbents to enjoy higher profits but do not harm efficiency. Stigler's definition succeeded in identifying cost based reasons why incumbent firms earn economic rents (above normal returns on investment)but it could be too narrow in the sense that there are certain barriers required for both entrants and incumbents such as the "license case" (Demsetz [1982])[12].

A short version of the long story about barriers to entry is that there have been various ways of identifying entry barriers to a certain industry but no single definition can be considered best for all purposes. They might be either too broad or too narrow, they might be relevant in short run but not irrelevant in long run; some barriers have engagement value (or threat credibility) and some others don't.

A barrier to entry, interpreted in the most general way and in the context of this thesis, is any set of conditions that encourage the ability of incumbent suppliers, acting individually or in collusion, to set market prices above the competitive level. These conditions differ from theory and vary by industry. They may arise from structural factors such as sunk costs and scale economies (Bain [1956], Stigler [1983], Karakaya [2002]); absolute cost advantages (Spence [1977], Lieberman [1987]); control over strategic resources (Shepherd and Shepherd [1997]) or from strategic barriers that are created by the incumbents themselves to deter entry (Demsetz [1982], Milgrom and Roberts [1982], Shepherd and Shepherd [1997]), etc.[13]. After all, the final

[12]Demsetz [1982] gave an example where taxis are required to obtain licences by the Governement. If the number of licences is fewer than the number of taxis that would operate in a competitive market, then the licensing requirement should be considered as a barrier to entry. In this case the barrier to entry as licences are required for both entrants and incumbents.

[13]The debate over the concept of barriers to entry, though interesting, is not the focus of this thesis.

aim of any studies about entry is to identify whether there are features of the market that favour the suppliers' profit at the expense of customers, to what extent and how to do with this.

In recent years, several competition scholars have concluded that the debate about entry barriers should be considered irrelevant to competition policy. They argue that abstract, theoretical pondering on the definition of barriers to entry is unlikely to be very helpful in investigations and policy decisions. What matters in actual cases is not whether an impediment satisfies this or that definition of an entry barrier, but rather the more practical questions of whether, when, and to what extent entry is likely to occur given the facts in each case. (Competition and Barriers to Entry (Policy Brief) - OECD, 2007)

(ii) Potential barriers to entry in the electricity markets

Barriers to entry do exist in electricity markets, some of which come from technical factors and some of which are associated with regulatory uncertainties.

First, entry into electricity generation is particularly risky for investors because of many inherent factors of the industry such as high economies of scale, large capital requirements, and long lead times. As showned in the table 2.2.2, nuclear and coal-fired are of substantial scale to achieve minimum unit cost. Long construction lead times are also a risk associated with entry into this industry. Table 2.2.2 also shows that all technologies require a minimum of two years for plant construction. Technologies with larger scales of operation involve longer time: with three years for gas plants, four years for coal-fired, and fully seven years for nuclear facilities. Indeed, the protracted investment has high risks because market circumstances might change several years ahead when the planned facility is finally constructed. Significant sunk cost which may have already been incurred on initial stages can be lost if the project is blocked for any reason at a later stage. These technical factors make entry to electricity generation more risky than into many other industries.

Entry into the industry for renewable technologies has been even more challenging despite many renewable support policies put in place in many countries recently because of its inherent unpredictability and intermittence. These

Table 2.1: Various technologies

Technology	Online year*	Size MW	Lead time (years)	Overnight cost** in (2010 $/kW)
Integrated Coal-Gasification Comb Cycle (IGCC)	2015	1200	4	3.01
IGCC with carbon sequestration	2017	520	4	4.852
Conventional Gas/Oil Combine Cycle	2014	540	3	931
Advanced Gas/Oil Combine Cycle (CC)	2014	400	3	929
Advanced CC with carbon sequestration	2017	340	3	1.834
Convential Combine Turbine	2013	85	2	927
Advanced Combine Turbine	2013	210	2	634
Advanced Nuclear	2017	2236	6	4.619
Biomass	2015	50	4	3.519
Conventional Hydropower	2015	500	4	2.134
Wind	2011	100	3	2.278
Wind Offshore	2015	400	4	4.345
Solar Thermal	2014	100	3	4.384
Photovoltaic	2013	150	2	4.528

Source: US. IEA - AEO 2012

* Online year represents the first year that a new unit could be completed, given an order date of 2011. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occurring in anticipation of the expiration of the Production Tax Credit

** Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2011

attributes of renewable technologies, addition to high capital costs (2.2.2), create a discouragement for suppliers to invest in this type of energy. As shown by Twomey and Neuhoff [2010], wind generators receive a volume weighted average price that is lower than the average market price. This is because during the periods when high demand of electricity coincides with low output from inter mittent generation, the system has to resort to high cost fuel fired plants. Prices during these periods would be high because such plants have high marginal costs, and/or scarcity would push the prices even higher. Intermittent generators, however, would not benefit from these high prices since they occur when their output is low. In contrast, during periods of high wind output, the conventional generators will be required to back down and low cost wind turbine generators will capture a part of demand that should be served by conventional generators. Prices during these periods will be low. As result, wind generators receive a volume weighted average price that is lower than the average market price. In an electricity system where intermittent generation comprises a small share of total output, the high variability of renewable will have little impact on the average prices paid to renewable and conventional generators. However, if the share of intermittent generation is significant, the average prices paid to renewable generators are lower than those of conventional generators. This creates a significant barrier to entry for this kind of technology (For more discussions about entry barriers for renewable energy, see for example, Painuly [2001], Foxon, Gross, Chase, Howes, Arnall and Anderson [2005], Owen [2006]).

Another important risk for entry into the electricity generation market is associated with regulatory uncertainties. Facing a lot of recent upheavals in the world of energy (among those, the chaos in the Arab countries following with the increase of commodities' prices, the nuclear catastrophe of Fukushima, the increasingly alarmed global warming, the collapse of carbon price), all governments have been attempting to set more regulatory tools or policies to alleviate the tension. This, in turn, renders the market conditions more risky and uncertain for the potential entrants. For instance, one of the most popular policy trend in most countries over the last decade has been the intrusion of environmental-related policies such as promoting the development of renewable power generation. However, Public opinion is also considered a barrier to the

new entrants. This is exhibited in electricity market via the opposition to the construction of the new sites, popularised by the NIMBY concept (Not In My Back Yard) or more extreme, BANANA (Build Absolutely Nothing Anywhere Near Anybody).

The european electric power sector has experienced an exceptional policy trend that fundamentally reshaped the industry over the last decade: the intrusion of environmental-related policies.

Investment for power generation are generally driven by the net present value (NPV) of the production cost per MWh - the discounted costs to build a new plant. The uncertainties and risks described above could make investors demand higher market prices prior to entry – pushing prices above the efficient long run marginal cost (CEG, [2012]). The presence of risks as barriers to entry protects the incumbents from the competition of the new entrants, creating ideal conditions for them to exercise their market powers.

In conclusion, together with demand-side flaws, the existence of barriers to entry makes exercising market power particularly feasible in power markets. Indeed, a merely high price spike could occur in any moment of the day due to the inelasticity of both demand and supply. It is extremely hard to distinguish whether an "abnormally" high price is due to "normal" factors or because of market power abuse. Firms will take this into account as making their decisions, without challenge of being eliminated from the market.

2.3 Diagnosing market power in power markets - Retrospect and prospect

We have described in previous sections why market power is peculiarly potential to be exercised by a firm in electricity markets. This section shows that detecting market power in this industry is also a big challenge. We provide in this section a review of methods/approaches that have been employed in literature to diagnose market power in electricity markets in both Europe and the U.S over the two last decades.

We divide the detecting methods into two big categories: Structural approaches, which are based on market structure analyses and Market simulation

approaches, which are based on market outcomes, as listed in table 2.2[14]:

Table 2.2: Several methods to detect market power in literature

2.3.1 Structural approaches	a) Structural indexes vs Market power	(i) Concentration ratio (CR_n) & Herfindahl-Hirschman Index (HHI) (ii) Pivotal Supplier Indicator (PSI) & Residual Supply Index (RSI)
	b) Models on the relations between structure and performance	(i) Econometrics regressions (ii) Residual demand analysis
2.3.2 Market simulation approaches	a) Direct Estimation of marginal cost	(i) Cournot - Nash equilibrium model (ii) Supply Function Equilibrium model (ii) Optimization algorithms approach
	b) Indirect Estimation of marginal cost	Econometric simulation models (NEIO)

In the following, we analyse in detail the methodology, the strengths and weaknesses of each method.

2.3.1 Structural approaches

a) Structural indexes vs Market power

(i) Concentration ratio (CR_n) and Herfindahl-Hirschman Index (HHI)

The first attempt of empirical studies in market power has developed since 1930s, initiated by Havard scholar, Mason's [1939,1949] Structure Conduct Performance approach (SCP)[15]. It holds that an industry's performance depends on the conducts (behaviors) of sellers and buyers, which depend on the structure of the market. The structure is often summarized by the number of firms (concentration ratio) or some other measure of the distribution of firms, such as the relative market shares of the largest firms (Herfindahl-Hirschman Index - HHI), which are given by:

[14]The literature on market power detecting tools is enormous, and the list given in this thesis is inevitably incomplete despite its length. However, we attempt to cover the most remarkable methods that have been applied in electricity markets.

[15]Mason [1939] and Mason [1949] initially conducted case studies of individual industries whereas Bain [1951];Bain [1956] and others introduced comparisons across industries.

$CR_n = \sum_{i=1}^{n} S_i$ and $HHI = \sum_{i=1}^{n} S_i^2$ with S_i: market shares of n firm with $i = 1, \ldots n$

A market where concentration ratios CR1; CR3; CR5 exceed 33,3%; 50% and 66,7% respectively or HHI exceed 1000 points is presumed concentrated.

Up to the 1990s, empirical studies of market power in liberalized generation electricity markets are scarce since it has rarely been contemplated outside the United States. Several studies in the early stages of electricity market research used those standard concentration measures to find a magnitude that raises market power concerns. For example, Schmalensee and Golub [1984] calculated the HHI for over 170 regional generation markets in the US and found that the HHI exceeded 1800 in general. Cardell, Hitt and Hogan [1997], using 1994's year data, calculated the HHI values for 112 regions in the United States and suggested that electricity markets were still highly concentrated. More recently in Europe, in 2005, the European Commission's DG Competition launched a sector inquiry into the European electricity and gas markets. The final report of the inquiry was published on 10 January 2007. The main finding concerning the report was that market concentration remained critically high in a number of geographical and product markets. In fact, the EU sector inquiry examined market concentration level and found values of HHI in almost all countries exceeded 1800 points (highly concentrated).

Table 2.3: Concentration ratio and HHI across European electricity markets

Country	CR(n)	HHI
Belgium	90.7 %	8307
Germany	54.1 %	1914
Spain	71.4 %	2790
France	92.6 %	8592
The Netherlands	57.7 %	2332
Great Britain	32.6 %	1068

Source: European Comission, DG COM (2007)

*Except for Belgium and France where n=1, all other countries in the table have n=2 the CR(n) calculation.

The original idea of concentration approach is obviously valuable. It contains information about the suspected location of market power, which

could be used to guide policy in those areas. However, this method performed very poorly in electricity market because it does not take into account the demand side.

More importantly, any attempt to measure structural indicators must begin with a clear definition of the relevant product and geographic market. This is unfortunately problematic in electricity industry (Borenstein, Bushnell and Knittel [1999], Meritet [2003]). Relevant market definition is changeable each hour because the conditions of supply and demand can change quickly. For the consumers, one kWh at 8 o'clock in the morning and one kWh an hour later are hardly substitutable and their demand can vary greatly from one moment to another, depending, for instant, on weather condition. So every half-hour could be defined as a relevant market; that is, a possibility of 17 520 markets relevant each year, as in the case of power exchanges.

The geographic market is even more fragile to define because network's congestion. As soon as the line which connects an area of consumption depending on the outside is full, the native producer is protected from competition to meet any incremental demand. The geographic market in this case, is limited at the local area. Similarly, when the interconnection between the two countries reached its capacity limit, the geographic market is limited to national borders and no further exchange is possible. So transmission constraints can create separate geographic markets (which is likely to exist even at points that are not distant from each other); then each of which can have 17 520 separate product markets per year. Detecting potentials of market power in each of these markets is apparently a daunting exercise.

(ii) Pivotal Supplier and Residual Supply indicators (PSI & RSI)

PSI and **RSI** are other structural indicators designed particularly for electricity market by California ISO in 2002 (Sheffrin [2002]). Unlike traditional concentration indexes, PSI and RSI take into account factors of demand.

- The PSI is a binary variable which can take two values: 1 if the supplier is necessary to meet the demand (pivot) and 0 otherwise.

$$PSI_j = \begin{cases} 0 & \text{if } (\sum_{i=1}^{N} AIC_i - AC_j - \sum_{i=1}^{N} hourly - generation_i) \geq 0; \\ 1 & \text{if } (\sum_{i=1}^{N} AIC_i - AC_j - \sum_{i=1}^{N} hourly - generation_i) < 0. \end{cases}$$

i=1,2 ... N firms

where AIC_i is firm's available installed capacity (sum of AIC of all firm yields total supply); AC_j is available capacity of suspected firm j (it is adjusted to capacity firm has committed in system reserve requirements the net position of the company in the long-term contract market); $\sum hourly - generation_i$ refers to total demand.

- The RSI calculates the indispensability of a specific company relative to the load in a given hour. It permits to assess the degree to which the market is relying on this company's capacity to meet the load. It is given by:

$$RSI_j = \frac{\sum_{i=1}^{N} AIC_i - AC_j}{\sum_{i=1}^{N} hourly - generation_i} \tag{2.1}$$

When RSI is greater 100 %, i.e., suppliers other than the suspected firm have enough capacity to meet the demand of the market, the firm has less influence on market clearing price. On the other hand, if RSI less than 100 % over demand, this firm becomes the only source to fill the shortage and thus, is indispensable in the market. It has complete control of the market-clearing price and can set the price as high as the price cap allows.

The PSI and RSI can be calculated for every firm in every hour. A supplier is considered indispensable if its PSI is 1 during more than 20% of hours, or RSI is less than 110% for more than 5% of the hours in a year (about 438 hours).

Sheffrin [2002] calculated the RSI indexes for California during three years 2000, 2001 and 2002. She found that RSI was less than 1.1 for over

2000 hours in a year. In 2007, London Economics (DG Comp) [16] examined the performance of 6 electricity markets in Europe, the results showed that in Belgium and France, two extremely concentrated markets, one of suppliers had been pivotal during 100% of hours. Germany, the Netherlands and Spain, three modest concentrated markets, had 2 pivotal suppliers according to PSI, and 20% - 50% of the hours where these suppliers were indispensable according to RSI. There were only the UK with none pivot.

Table 2.4: RSI for largest companies in some European electricity markets (2003-2005)

Country	Company	% hours RSI<110%
Belgium	Largest company	100.00%
Germany	Largest company Second largest Co	77.10% 47.70%
Spain	Largest company Second largest Co	49.20% 41.10%
France	Largest company	100.00%
The Netherlands	Largest company	44.60%

Source: European Comission, DG COM (2007)

PSI and RSI are electricity-specific indicators which give richer measures of market structure in electricity markets than standard concentration measures. However, the application of these indicators in measuring market power encounters some inevitable shortcomings. Like traditional indexes CR_n and HHI, they always require a clear definition of relevant product and geographic market, which is problematic in electricity industry. The PSI and RSI, like all other structural indicators, only give the idea of potentials of market power. Though they contain valuable information about the suspected location of market power, they are recommended for ex-ante analyze, for instant, in order to examine a merger case or to test some different scenarios of electricity reform (e.g, dividing the historical monopoly into many parts, introduction of

[16] The study carried out by London Economics was unique thanks to its huge data collection that was "is unprecedented in the electricity-economics field globally". They include hourly observation, simulation, and relating to price outcomes of output and marginal cost, and market structure for almost every generation unit in every hour. It involved the collection of about 500 million data points and manipulation and analysis of close to 1 billion data points, and resulting in an approximate total of 75GB of data inputs and outputs.

new regulations, ect.) (Lévêque [2005]).

b) Models on the relations between structure and performance

(i) Econometric models on the relationship of structure to performance

The "structural" or SCP approaches do not limit at merely measuring the level market structure. A typical SCP conducts a regression of a market performance measure such as profit or price-cost margin [17] on a structural variable such as CR, HHI, PSI, RSI and other variables. A thorough analysis of SCP literature can be found in Schmalensee [1989]. By doing so, these studies assume that how much market power is exercised - is known, and focus on the question of what causes this market power. The original idea of these studies is valuable and there is a sound theory that justifies their empirical researches (Box 2.2).

Box 2.2 Relations between structure and performance in Industrial Organisation

For simplicity, suppose that there is n firms in a market produce a homogeneous product. Industry output: $Q = \sum_{i=1}^{n} q_i$. Given full information and no other distortions, a single market price, p, is determined by the inverse market demand curve, p(Q).

The single-period profit of firm i is:

$$\pi_i = p(Q)q_i - C_i(q_i)$$

where $C_i(q_i)$ is the total cost of firm i.

[17] The measures of price-cost margin will be discussed in detail later on, as we describe "market simulation approaches". Typically, with P_t being the observed price in some hour t, and MC_t the computed system marginal cost in the hour, the exercise of market power is then concluded on the basis of $P_t - MC_t$ (price–cost markup), or more formally, the Lerner index: $L = (P_t - MC_t)/P_t$. Lerner index is equal to 0 in pure competition (only found in economic textbook), and larger if more market power is exerted.

Suppose that firms engage in one-period game and each firm sets up a strategy that determines its actions. In the simple Nash - Cournot oligopoly model; i.e, each oligopolist assumes that his rivals will not change their outputs as it changes its own output, firm i maximizes profit for which the first-order condition is:

$$\frac{d\pi_i}{dq_i} = 0 = p - C_i - p(\frac{q_i}{Q})(-\frac{Qdp}{pdQ})$$

The Lerner index for firm i - denoted by L_i is then given by:

$$L_i = \frac{p - C_i}{p} = \frac{s_i}{\varepsilon}$$

where s_i is the market share of the firm q_i/Q and ε is the elasticity of market demand, as a positive number $\frac{P}{Q}\frac{dQ}{dP}$. The weighted average price-cost margin for the industry is:

$$L = \sum_i s_i \frac{p - C_i}{p} = \sum_i \frac{s_i^2}{\varepsilon} = \frac{HHI}{\varepsilon}$$

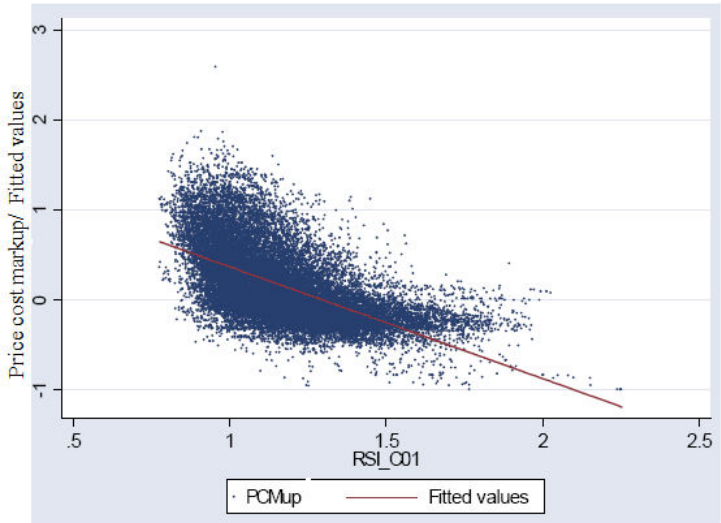
If the firm's RSI is $r_i = (\sum_{ji} q_j)/Q$(at the prevailing price, p) and substitute $q_i = Q - \sum_{ji} q_j$ in the first- order condition equation, we derive the Lerner index for firm i

$$L_i = \frac{p - C_i}{p} = \frac{1 - r_i}{\varepsilon}$$

Thus, at least for these Cournot models, we obtain a clear relationship between Lerner index, a measure of market performance, and the structure of the market as captured by the share of each firm, the HHI, or the Residual Supply Indicator RSI . Combination of low demand elasticity with small number of competing firms or low RSI would normally suggest a very high Lerner index (or price-cost markup).

London Economics (DG Comp 2007) implemented an empirical analyse of impact of the RSI for different electricity companies on the price-cost mark-up for period of 2003 - 2005.

Figure 2.5: Impact of RSI on price-cost margins: example in Spain



Source: European Comission, DG COM (2007)

The results showed that the RSI significantly explains market outcomes for almost all companies considered in all markets. In Spain during the period 2003-2005 for example, a significant relationship between the level of residual supply and price-cost markup was found: Price-cost markup was at high level as RSI was less than 1.1, both indicates the existence of market power (figure 2.5).

However, there has been very little support for the relationship of market structure to market performance in literature. Many of empirical findings showed only a weak relationship or no relationship between these two factors: Hart and Morgan [1977], Geroski [1981], Kwoka Jr and Ravenscraft [1986], Domowitz, Hubbard and Petersen [1986], Weiher, Sickles and Perloff [2002], to name just a few. Using different measures of performance such as rate of return, Price–Average Cost Margins, Price-Marignal cost margins, and applying in various industries, the authors found commonly a weak evidence of a link between concentration and various proxies for market performance. Are the theories concerning the link between performance and structure wrong or are these studies flawed?

In fact, when it comes to empirical studies, many SCP studies are seriously fawed because many of them suffer from substantial measurement or related statistical problems that are very difficult to correct. Some of problems in measurement of structural indexes were discussed earlier. Three serious additional flaws are analyzed here.

- First, a test of hypothesis that more concentrated market structure "causes" higher profit is only meaningful if structure affects profits but not vice versa. That is, this theory should be tested using exogenous measures of structure – the structure must be determined before profitability and that profitability does not affect structure. Unfortunately this is not the case in most industry, profitability affects the degree of concentration by affecting entry. Using endogenous measure leads to biased estimation. Most SCP studies have ignored the problem of obtaining exogenous measures of market structure. Indeed, correcting the endogeneity is very difficult due to the unlikelihood of instrumenting the structural variable with the equivalent exogenous one.

- A second serious problem is that market performance measures are frequently biased because of improper calculation. Most of SCP studies use price-cost margins as performance variable but they use average cost rather than marginal cost. If marginal cost can be directly measured or accurately calculated, then one can obtain a good measure of the Lerner index and the relationship between the price-cost margin and structure is somewhat meaningful. Unfortunately, one can rarely obtain reliable marginal cost measures. This is a serious flawed that not only SCP studies but almost all studies involving market power measures have suffered. We return on this shortly. Another common problem concerning market outcome measures is that most SCP studies use short-run performance (short run profit, short run marginal cost, etc.) while standard economic theories hold that it is long-run profits, not short-run, will vary with market structure. Thus, a SCP study based on short-run performance measures is not a proper estimation.

- Third, many studies inappropriately estimate linear relationship between

"performance" and "concentration". In fact, increases in concentration have large effects on performance up to a critical level, then those effects become less important. Therefore, the relationship between these two factors will resemble an S-shaped curve: first concave and then convex rather than a straight line. This curve can be approximated reasonably by a straight line only if concentration levels lie in some restricted range; if they vary from very low to very high levels, an estimate based on a presumed linear relationship might lead to improper results. Many imperfections of the method hold back its applications and make researches using the SCP approach continue at a reduced rate (Perloff, Karp and Golan [2007]).

(ii) Residual Demand Analysis

Categorized in "structural approach" but residual demand analysis is a more sophisticated measure, introduced by Wolak [2000]. The method involves the estimation of residual demand curve faced by a company. It is derived by subtracting from the total demand curve all the offer curves bid into the market by other participants. The original idea is similar to residual supply indicator except that it takes the demand elasticity into account. The slope of residual demand at production level is firm's market power for that demand realization. If a firm is pivotal, the slope of residual demand curve is infinite and firm can name any price for pivotal quantity of demand. The regulatory intervention is needed to set price in these circumstances. Distribution of slopes of residual demand curves for given hour quantifies market power. This was usually constructed ex-post because in real time residual demand curve was unknown at time the generator submits bids. An interesting feature of the ex-ante analysis based on this principle concerns supply function equilibrium that we discuss shortly. One of the advantages of electricity markets is that bid data for constructing residual demand curves actually exists but the burden on calculation might be too high because it is calculated on an hourly basis.

Wolak [2000, 2002] have demonstrated that unilateral market power that firm j possesses in hour h is defined as $L_{hj} = (P_h - MC_{hj})/P_h = -1/_{hj}$ where P_h is the market price in hour h, MC_{hj} is the marginal cost of the highest cost MWh produced by firm j in hour h, and ε_{hj} is elasticity of the residual

demand curve facing firm j during hour h evaluated at P_h. The results of residual demand analysis are usually expressed in this manner. Wolak [2002] measured the value of L_{hj} for five largest electricity suppliers in California during the four-month period from June to September of 1998, 1999, and 2000. He found that there was an enormous increase in the amount of market power exercised in the California market beginning in June of 2000 due to a substantial increase in the amount of unilateral market power *possessed* by each of the five large suppliers in California. A recent published paper using the same method for California's power market in 1998- 2000 can be found in Hobbs and Prete [2015].

One limitation of this analysis is that it's always required a clear definition of relevant market. It has, so far, not taken into account transmission constraints in constructing the residual demand curves. Such constraints would decrease the residual demand elasticity and thus increasing the potential to exercise market power. Ignoring this factor might lead to underestimate the level of market power.

To summarize the discussion so far on structural approach: A typical SCP study has two main stages: (1) obtaining measures of industry structure (CRn, HHI, PSI, RSI); (2) calculating measures of performance (most of the case involving price-cost markup) - through direct measurement rather than through estimation; and (3) regressing the performance measure on the various structure measures to show the relationship between the two factors or to explain the difference in market performance across industries. It has been shown in most studies that there is weak evidence of a link between concentration and market performance. It is important; however, to notice that many of the negative findings in these studies may be due to serious flaws in estimations (Perloff et al. [2007]). First, many of these studies suffer from problems related to measurement of structure indexes and/or price-cost markup that are difficult to correct. Second, and more importantly, most of these studies are frequently biased as regard to econometric estimations. Residual demand analysis, introduced by Wolak [2000], is a more sophisticated measure. Categorized in "structural approach" but unlike most studies in this category, residual demand analysis focus on the question of "how much market power is exercised"

by measuring the distribution of slopes of residual demand curves facing firms for given hours. It is therefore sometimes categorized as the non-structural market simulation approaches.

2.3.2 Market simulation approaches

Perhaps the most common means of measuring market power have been involving market simulation approaches. While SCP studies focus on the question of *"what causes market power"* with assumption that the level of this market power is known, market simulation models take market power as an unknown factor and attempt to measure it. Named in different ways and implemented in different methods from simplest to the most complicated, the decisive clue of this approach concerns the estimation of marginal cost and the determination of oligopoly equilibria in different wholesale electricity markets.

(a) Direct estimation of marginal cost

In all papers we discuss below, either they concern supply equilibrium, Cournot-Nash equilibrium or optimization approach, marginal cost is considered as known factor. It is derived from engineering data of fuel costs - the main cost component for nuclear and fossil fuel plants - and of heat rate-the efficiency with which fuel is converted into energy. Multiplying the heat rate with fuel prices allows reliable estimation of the fuel cost component. The common formula is given by:

$$Fuel - cost(\$/kWh) = Rate_{combustion}(Btu/kWh) \times P_{combustile}(\$/Btu) \quad (2.2)$$

The system price and quantity equilibrium is then found by various oligopoly models or optimization models:

(i) supply function equilibrium as done in Green and Newbery [1992] in British electricity market

(ii) simple Cournot - Bertrand - Nash equilibrium as done by a series of papers of Borenstein, Bushnell and Wolak [1999 & 2002] in Californian

electricity market;

(ii) model of optimization/dispatching as done by Bushnell and Saravia [2002], Green [2004], Lang and Schwarz [2006], Weigt and Von Hirschhausen [2008], Müsgens [2006], London Economics -DG.Com (2007).

(i) Supply function equilibrium, Green and Newbery [1992]

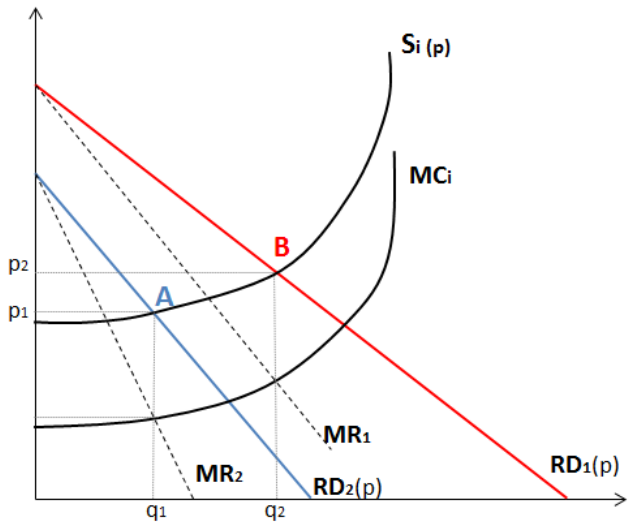
"Supply function equilibrium" model was first introduced by Klemperer and Meyer [1989] and popularized by Green and Newbery [1992] for electricity industry. A Supply Function Equilibrium (SFE) is a set of supply function $S_i(p)$ (offered to supply by firm i: i = 1,2,...n, when the price is p for which each firm maximizes its profit given the supply function (both prices and quantities) of all other firms (Nash equilibrium in supply function, not only in quantity or price).

The method based on this approach is, somewhat, extension of the method used by Wolak [2000] to estimate the residual demand curve facing by a firm that we discussed above. Each firm calculates its residual demand curve given bids submitted by competitors and aggregate demand, and given its marginal cost curve, firm can formulate its expected profit-maximizing bid curve (price and quantity pair), and they bid their supply function on that basis (Figure 2.6).

The difference in Klemperer and Meyer [1989] and Green and Newbery [1992] was that the analyse in Green and Newbery [1992] is done ex-ante, so at the time firms submit their bids, they do not know exactly the residual demand curve it faces. And the equilibrium will be a set of multi supply functions, bounded between Bertrand and Cournot solutions between which there may be a continuum of possible SFE outcome. Klemperer and Meyer (1989) showed that the more uncertainty a company faces, the range of possible equilibrium supply curves narrows away.

Using this method, Green and Newbery [1992] examined market power in the British electric power pools in the early days of the British Electricity Act 1989. The marginal cost function was estimated by informations on fuel costs and thermal efficiencies of each power station (Equation (2.2)). The simplified cost function was chosen under two form: linear and quadratic. Demand elasticity was chosen in three values (0.1, 0.25 and 0.5). The authors

Figure 2.6: Computing expected profit maximizing bid curve $S_i(p)$



Source: European Comission, DG COM (2007)

(i) If residual demand curve $DR_1(p)$ occurs, the firm will produce at q_2 where $MR_1 = MC$, the first profit maximizing price and quantity pair $B(q_2, p_2)$

(ii) Similarly, if residual demand curve $DR_2(p)$ occurs, the first profit maximizing price and quantity pair $B(q_1, p_1)$

(iii) The profit-maximizing biding curve will be any function passing points such as A and B,the curve $S_i(p)$ is one possible outcome.

found that in the base case with elasticity of demand equal 0.25, generators in a duopoly case will choose supply function whose price nearly double the marginal cost pricing case, creating a deadweight loss of 340 million per year. They solved the model for an restructured industry which was made up of five identical firms and concluded that the Nash equilibrium in supply schedules would produce better results (17 % price markup against 50 % under the existing structure).

Supply Function Equilibrium models seem attractive because it is firmly grounded in price theory but it poses many practical and conceptual problems. It's complex, because it requires an estimation of optimal bids for each relevant market and a computational search for bids that are best response to all other bids. Although it is possible to test the behavior of one firm given the bids of other firms, there will be multiplicity of such equilibrium (Newbery [2009]). Furthermore, Willems, Rumiantseva and Weigt [2009], by calibrating Cournot

and supply function models with identical demand and costs to the German electricity market, found that both model explained the same fraction of observed price variations, suggesting that for short run analysis, Cournot-Nash models are as suitable as supply function models.

(ii) Cournot-Nash models - Borenstein, Bushnell and Wolak (1999 - 2002)

Cournot-Nash equilibrium models was marked with the series of Borenstein, Bushnell and Wolak's work (1999 - 2002). Borenstein and Bushnell [1999] modeled California electricity industry as a Cournot triopoly with competitive fringes. They calculated residual demand facing Cournot producer by subtracting must-run generation and the fringe's supply from the total demand. They assumed that hydro units are dispatched so as to minimize cost (i.e. they cannot be used to exercise market power); hydro units are thus also excluded from the cost curve and an equivalent portion of demand is removed. Elasticity of demand was assumed to be constant and takes three different values (0.1; 0.4; 1.0). The marginal cost was calculated using the fuel costs data and heat rate as well as variable operating and maintenance (O& M) costs of each generating unit. Using marginal cost functions of the Cournots competitors and the estimated demand, they calculated the Cournot equilibrium at several demand levels. As a benchmark equilibrium, they also calculated the price that would result if all firms acted as competitive price takers and then derived the difference between two equilibrium results.

In the earliest paper, Borenstein and Bushnell [1999] concluded that the potential for market power was greater when demand was high and the fringe's capacity was exhausted. In lower demand period, Cournot producers had less incentive to withhold production because the fringe had excess capacity. Using the same method of calculation of marginal cost, Borenstein et al. [2000] found wholesale electricity prices in California to be 16% above the competitive level in the summer of 1998 and 1999. In a subsequent study, Borenstein, Bushnell and Wolak [2002] extended the analysis to include the summer of 2000 and showed that electricity expenditures in the state's wholesale market rose from \$2,04 billions to \$9 billion just in one year from 1999 to summer 2000 and 59% of this increase was due to increased market power.

By the approach taken through these papers, the authors come to qualitatively similar conclusions: market power existed in California electricity markets during summer 1999 and 2000 and was significant. Interestingly, in the early papers (1999 and 2000), it was still questionable whether market power was really a problem in California, because it only seemed to exist in a certain number of hours. However, after two years, rapid increases in demand and lack of hydro capacity from neighboring regions, nuclear outages, and flawed market designs all happened at once and combined to form a collapse for the state's largest energy companies as well as California's new deregulated markets.

(iii) Optimization algorithms approach

This approach comprised an optimal system dispatch (subject to network constraints and dynamic constraints on plants) to find the quantity offered by each producer in order to satisfy the demand while minimizing the total cost of production. Marginal costs were calculated from engineering data of fuel costs and heat rate as described above. Then hourly generation and generation cost values for each station in the model are reported (merit order) and the system marginal cost equals the fuel cost of the highest per MWh unit producing in each hour, albeit with some exceptions (when capacity constraint binds). Based on the difference between system hourly marginal costs and observed hourly prices, one can conclude about the level of market power (Smeers [2005]).

An example of this approach was done by London Economics (2007). The study was thorough in the sense that data collection was "*on a scale that has been unprecedented in the electricity-economics field globally*". Hourly observations for every generation unit in every hour (8,760 hours/year) for six countries France, Belgium, Spain, the Netherlands, Germany, UK in three years (2003, 2004 and 2005) were used to calculate the price cost margins for each hour. Large margins had been found in all examined markets (51% in Germany, 35% in Spain, 14 % in Netherlands and 31% in the UK on average 2003 - 2005 with exclusion of carbon cost) [18]. Other works with the same

[18]The results for Belgium and France were not reported because they came with a strong caveat particularly due to large propotion of nuclear power in technology mix, making it

approach were done by Bushnell and Saravia [2002], Green [2004], Lang and Schwarz [2006], Weigt and Von Hirschhausen [2008], and Müsgens [2006]. We apply this method to investigate the competition in German wholesale market in Chapter V.

In summary, though being firmly-grounded in oligopoly theory, the models described above are intractable in empirical estimation because they require a proper calculation of marginal cost. The common approximation of assimilating the variable costs of fuels and plant performance seems unsatisfactory in many cases, particularly for nuclear power generation and hydropower whose variable costs are close to zero but opportunity costs might be very high. When one uses the actual purchase cost of fuel to calculate the marginal cost of a generating plant, he does not take into account the fact that generators will in fact dispatch their plants based on the opportunity cost of using that fuel, which may be higher or lower than the purchase cost. There are other variable costs which are difficult to estimate as the cost of equipment degradation or risk of failure when one approaches the maximum capacity of the plant. Then at the end, even if a study finds a large price-cost margin, it is still difficult to convince whether this is due to abuse of market power or estimation errors. Neo industrial economists have used an alternative method to estimate the marginal cost: Indirect cost estimation or New Empirical Industrial Organisation (NEIO) models.

(b) Indirect estimation of marginal cost

As precised above, if we observe price and marginal cost, we can directly determine whether a firm in an industry is exercising market power. Unfortunately, we do not have explicit information on marginal cost. We usually observe only price and factors that are associated with cost and demand . One approach to overcoming the problem of not knowing marginal cost was introduced in the late 80s, known as New Empirical Industrial Organisation (NEIO). We quote the summary of this approach exactly from the "Handbook of Industrial Organization" to not loose its senses:

hard to compute marginal cost (as nuclear is generally a very low marginal cost technology, with high capital costs and unclear amortisation of fixed costs). In Belgium, the difficulty was that the data of hourly marginal or exchange price did not exist over the sample period.

"...Firms' price-cost margins are not taken to be observable; economic marginal cost (MC) cannot be directly or straightforwardly observed. The analyst infers MC from firm behavior, uses differences between closely related markets to trace the effects of changes in MC, or comes to a quantification of market power without measuring cost at all. Firm and industry conduct are viewed as unknown parameters to be estimated. The behavioral equations by which firms set price and quantity will be estimated, and parameters of those equations can be directly linked to analytical notions of firm and industry conduct. As a result, the nature of the inference of market power is made clear, since the set of alternative hypotheses which are considered is explicit. The alternative hypothesis of no strategic interaction, typically a perfectly competitive hypothesis, is clearly articulated and is one of the alternatives among which the data can choose." Bresnahan [1989], p. 1012.

There are two sub-directions of this methodology.

One approach is to estimate the firm's behavior - or the average behavior of all firms within an industry - and marginal cost, using a structural model. The method involves of estimating a simultaneous-equation model which composes of demand equation and supply relation. There were three sets of unknown parameters: costs, demand, and firm conduct. The observable variables that are endogenous to the industry equilibrium include industry price and system turnover. The observable variables that are exogenous include varibales that shift cost and demand functions. Oligopoly theory is used to specify the equations of the model to be estimated. The firm conduct parameter is introduced in the supply relation equation and is inferred in many ways depending on the choice of oligopoly theory. For example the specifications of "firm conduct parameter" can be derived from different solutions concepts (Bertrand, collusion, Stackelberg leader/follower models, etc.), each of which leads to a different version of supply relation equation, thus different specification of conduct parameters.

An alternative approach is to use a reduced form to determine the competitiveness of the market by testing how prices varies with shifts in costs (or factors that shift cost), see for example Baker and Bresnahan [1988]. If, empirically, the variables shifting all other firms' costs, rather than the firm's own

quantity, explain prices, the researchers conclude that the firm has no market power. The key advantages of this method is that it requires fewer data and assumptions than do the structural models. However, the method is typically only to test whether or not market is competitive but not provides a direct estimate of market power.

The approach has been applied widely in various single industries like textile (Appelbaum [1982]), gasoline, aluminum (Suslow [1986]); or railroads (Porter [1983]); to name just a few. It has been little applied in electricity until recently in several papers studying Nordic electricity market (to our knowledge, anyway): Hjalmarsson [2000], Bask, Lundgren and Rudholm [2011], Mirza and Bergland [2012]. We describe this approach in detail in Chapter 3.

Conclusion

In this chapter, we carried out an insight research around market power questions in deregulated wholesale electricity markets in Europe: how to define market power in power markets, how to exercise it and how to detect it. While standard definition of market power can be perfectly applied in electricity markets, the methods to detecting market power in the new competitive electricity market could not be the same as ones applied in any other markets. Many distinguished idiosyncrasies of the industry as well as the existence of entry barriers make exercising market power in power markets particularly likely and detecting it extremely challenging.

Detecting market power has never been an easy task and doing so in electricity is even more challenging. Over the last 15-20 years, market power detection techniques have been dynamically evolved, varying enormously from theoretical to empirical models, from market structure to market outcome approaches; from direct to indirect estimations, etc. Many advances have been made. Table 2.7 below summarizes the existing methods/approaches as well as the relative strengths and weakness of each detection techniques that we have analyzed.

Structural approach has not been just limited on traditional indexes such as market share/ HHI but extended to newly invented indicators like PSI and

RSI. With appropriate and adequate data, the results could be convincing. In very simple models, RSI has been proposed as a suitable index to measure potential market power in electricity markets, notably in California and more recently in the EU Sector Inquiry (Newberry, [2009]). It contains obviously valuable information about the suspected location of market power, which could be used to guide policy in those areas. However, it measures just "potential" not the actual exercised market power. For most of economists, this is not sufficient.

The perhaps most popular approach concerns market simulation models. Though being named in different ways and implemented in different methodologies, the decisive clue of this approach concerns the estimation of system competitive price equilibrium (or system marginal cost). Marginal cost, or Lerner index, described by Borenstein et al. [1999] is "fundamental measure of the exercise of market power". The direct method calculates marginal production cost based on accounting data and compares the estimate to observed market prices. Indirect methods start out from the observed prices and quantities and estimate market power parameters without using cost data.

The main conclusion of this chapter is that a case study, whether done by structural approaches or market simulation models; direct or indirect estimate of marginal cost, always help shed some lights in the puzzle. It would be superficial to say one method is more outstanding than another, they are just of different interests, or, some methods which are applicable in one particular market structure with particular data but some others are not. Market power detection tools has expanded over the last two decades. Although there is no definitive method for each of the main categories of market power detection previously outlined in table 2.7, the more recent tools have been considered better able to capture relevant factors and dynamic considerations that are not present in traditional tools such as structural indicators or the Lerner index (Twomey et al. [2006]).

Figure 2.7: Summary of Market Power Detection Approaches

	Category	Strengths	Weaknesses	Literature reviews	Popularity
Structural approaches					
Market share and HHI	Ex-ante Firm - level	Easy to understand - Only require sales or capacity data	- Challenges in determining appropriate markets - Ignores demand side - Little empirical justification	- Schmalensee and Golub [1984] - Cardell, Hitt and Hogan [1997] - Economic Londons [2007]	Standard tool for many decades Increasingly recognized and criticized as limited method.
Pivotal Supplier Indicator & Residual Supply Index	Ex-ante Ex-post Firm-level	- Easy to understand - Taking into account demand side conditions	- Challenges in determining appropriate markets - Ignore potential of gaming behaviors.	-Sheffrin [2002] - Economic Londons [2007] -Newbery [2009]	Recent tool (2000) but increasingly being applied
Models on relations between Structure and Performance	Ex-ante Ex-post Firm-level Industry level	Containing information about the suspected location of market power	- Biased in calculating structural and performance data. - Biased in econometric estimations which are difficult to correct - Biased as applying in electricity due to unclear relations between concentration and market power in the industry	- Economic Londons [2007]	Standard tool for many decades but little applied in electricity markets
Residual demand Analysis	Ex- post Firm-level	- Theoretical justification - Taking into account elasticities of residual demand curve	- Requires bid data - We are still stucked with relevant market definition to formulate residual demand	Wolak [2000, 2003]	Recent tool but so far limited empirical work.
Market simulation approaches					
Models involved in direct Estimation of marginal cost					
Supply function equilibrium model	Ex-ante Industry level	- Firmly-grounded in price theory - Integrates many market power factors - Does not require market definitions.	- Very difficult to compute costs or appropriate competitive benchmark level. - Complexity & intractable in empirical estimation due to wide range of possible equilibra - A lot of assumptions negates certitude of conclusions	- Green and Newbery [1992] - Willems et .al [2005]	-Introduced in early 1990s and still controversial given many estimation issues - increasingly being applied
Cournot - Nash models	Ex-ante Ex- post Industry level			- Borenstein, Bushnell and Wolak [1999 – 2002]	
Optimization models	Ex – post Industry level			- London Economics [2007] - Lang and Schwarz [2006] - Weigt and Von Hirschhausen [2008]	
Models involved in Indirect Estimation of marginal cost					
New Empirical Industrial Organisation	Ex – post Firm level Industry level	Reveal level of market power without cost or profit data.	So far limited application on electricity markets	- Hjalmarsson [2000] - Bergland et Mirza [2012]	Introduced in early 1990s but only recently applied in electricity and increasingly being applied

Source: Author, Newbery et. al. (2005)

Chapter 3

New Empirical Industrial Organisation: Theoretical and Empirical Models

Abstract: In this chapter, we present the method of New Empirical Industrial Organisation (NEIO) commonly used to estimate the market power in various industries during the late 1980s and developed recently in electricity markets. We describe the logic of this method on both theoretical and empirical basis, and provide a framework an analyst can use to develop the models to evaluate market power in electricity industry. The nature of the data on wholesale electricity market is described to justify the choice of models that we are implementing. We provide a detailed description of the data including various demand shifters and price drivers in the French electricity wholesale market during 2009-2012.

Introduction

As discussed in the previous chapter, if ones observe price and marginal cost, we can directly determine whether a firm in an industry is exercising its market power. Unfortunately, we usually observe only price and factors that are associated with demand and with cost but not explicit information on marginal cost. Calibrating a proxy for marginal cost is possible by various simulation models (cf: section 2.3) but many assumptions bound to the estimation of marginal cost negate the certitude of conclusions.

One approach to overcome the problem of not knowing marginal cost is to use the New Empirical Industrial Organisation (NEIO) method, which was introduced in the late 1980s and developed recently in electricity markets. A typical NEIO paper is foremost an econometric model of an industry based largely on time series data (Bresnahan [1989]). In those models, economic marginal cost cannot be *directly* or *straightforwardly* observable. The structural models involve of estimating three sets of unknown parameters: costs, demand, and firm conduct. Oligopoly theory is used to specify equations of the model to be estimated. The firm conduct parameter is introduced in the supply relation equation and is inferred in many ways depending on the choice of oligopoly theory. For example the specifications of "firm conduct parameter" can be derived from different solutions concepts (Bertrand, collusion, Stackelberg leader/follower models, etc.), each of which leads to a different version of supply relation equation, thus different specification of conduct parameters. An alternative approach is to use a reduced form or nonparametric approach to determine whether firms have market power by seeing how price varies with shifts in costs (or factors that shift costs).

The NEIO approach has been applied widely in various single industries with static model like (textile Appelbaum [1982]), gasoline, aluminum (Suslow [1986]), railroads (Porter [1983]); or with dynamic model as in Steen and Salvanes [1999], to name just a few. The method is recently employed in electricity industry, but mostly in Nordic power market to our knowledge: Hjalmarsson [2000], Steen [2003] Bask et al. [2011], Mirza and Bergland [2012]. In this chapter, we explain the logic of the NEIO method on both theoretical and empirical basis. We provide a framework an analyst can use to develop

the models to evaluate market power in electricity industry. The chapter is organized as follow.

Section 3.1 goes through the structural model approach for estimating market power in an oligopolistic market based on industry-level data. It provides also the extension of the classic model in the dynamic framework. In section 3.2, we present the nature of the data on French electricity wholesale market to justify the choice of models that we are implementing. We use French dataset largely thanks to its availability and also because empirical works in French power markets on this issue have been little employed in literature. Section 3.3 provides a detailed description of the dataset used in the empirical models including demand shifters and price drivers.

3.1 Structural model

In this section, we describe the general model used in NEIO literature and its recent extension in dynamic framework. We analyse how the conduct parameter (λ in the following), which measures the level of market power is interpreted and identified in the structural model. Finally, we provide some extensions of this static model to a dynamic one.

3.1.1 The model

In an oligopolistic market of a few supply firms producing a homogeneous product with q_i is supply of the ith firm, Q is the total supply equal to the total demand ($D = Q = \sum_{i=1}^{n} q_i$), the price elasticity of demand is retrieved from the aggregate demand function:

$$Q = D(P, X, \alpha) + \varepsilon \tag{3.1}$$

with X is a vector of exogenous variables affecting demand, the dependent variables of the model are market price P and system turnover Q, α is a vector of parameters of demand function to be estimated and ε is error term.

System marginal cost function takes the form:

$$P = MC(Q, W, \beta) + \upsilon \tag{3.2}$$

where W is a vector of exogenous variables on the supply side, β is vector of parameters of supply function and υ is error term of supply function, $MC(.)$ is marginal cost function. When firms are price takers, i.e. market is competitive, price equal marginal costs, equation (3.2) holds, the system marginal cost curve is as same as market supply curve.

Bresnahan [1982], and Lau [1982] suggest that we use a *conduct* parameter, λ, to nest various market structure [1]. For example, when firms are not price takers, it is perceived marginal revenue, not price, will be equal to marginal cost. The industry supply relation will no longer be determined by (3.2) but takes the form:

$$P = MC(Q, W, \beta) - \lambda.h(P, X, \alpha) + \eta \tag{3.3}$$

where $P + h(.)$ is marginal revenue and $P + \lambda h(.)$ is marginal revenue as perceived by the firm with $h(P, X, \alpha) = Q/\frac{\partial Q(.)}{\partial P}$. The demand-side parameters and exogenous variable are in $h(.)$ because they affect marginal revenue. λ is now a new parameter indexing the degree of market power. In perfect competition, $\lambda = 0$ and price equal to marginal cost, equation (3.2) holds. $\lambda = 1$ gives perfect cartel, and intermediate λ's correspond to various oligopoly solution concepts. For example, with n identical firms in a Cournot (or Nash-in-quantities) equilibrium, λ equals $1/n$.

Interpretation of λ

There exists at least two interpretations of λ in the literature. In the first approach, the game that firms are playing is not precised, thus λ is intepreted as a measure of the gap between price and marginal cost: From (3.3), price-cost margin can be derived as: $P - MC = -\lambda.Q/\frac{\partial Q(.)}{\partial P}$. The Lerner's measure is given by:

$$L \equiv \frac{P - MC}{P} = -\lambda \frac{Q}{P} \frac{\partial Q(.)}{\partial P} = -\frac{\lambda}{\varepsilon} \tag{3.4}$$

where ε is the market elasticity of demand. Because λ lies in the closed set [0,1], it follows that $L \in [0, 1/\varepsilon]$ with $\varepsilon < 0$. Thus, λ can be interpreted as an index of market power.

[1] An alternative is to use non-nested hypotheses tests: see Gasmi and Vuong [n.d.] and Gasmi, Laffont and Vuong [1992].

An alternative interpretation used by many econometricians is that λ is essentially an aggregate conjectural variation associated with firms' behavior.

The term "conjectures" in oligopoly models is dated back to the seminal works of Bertrand [1838] and Cournot [1838]. In the Cournot model, each firm simultaneously maximizes profit by choosing quantities assuming that their rivals' quantities are fixed. That is, each oligopolist conjectures that his rivals will go on producing a definite quantity irrespective of the quantity he produces. In the Bertrand model, each firm simultaneously maximizes profit by setting prices assuming that their rivals' prices are fixed. That is, each oligopolist conjectures that his rivals will keep their prices (not output) unchanged irrespective of the price he sets. Whether firms have "Cournot conjectures" or "Bertrand conjectures", firms act as if their rivals' choices are constant (i.e., no adjustment or variation) when they make their own choice [2]. In the extended models of Cournot/Bertrand, the rivals' choices conjectured by a firm are no longer constant but varied with the firm's own choice. This is what Fellner [1964] called "conjectural variation".

Stated in term of quantities, firm i choose its output level q_i by solving the problem:

$$max_{q_i} P(q_i, f(q_i)).q_i - C(q_i) \tag{3.5}$$

with $f(q_i)$ is the conjectured dependence of q_j on q_i. The first-order necessary maximizing condition is then:

$$[P(q_i) + P(q_j).f'(q_i)].q_i + P(q_i, f(q_i)) - C(q_i) = 0 \tag{3.6}$$

The maximizing solution showed in equation (3.6) is different with the traditional approach in the appearance of $f'(q_i)$ - the conjectural variation of

[2]Cournot and Bertrand oligopoly models make identical assumptions about cost and demand but apparently different assumptions about firm behavior. This difference leads to a large divergence in the predicted industry outputs (both quantities and prices). Clearly both models cannot be correct and no solution between Cournot and Bertrand can be based on mathematical correctness, it's economic criteria and idiosyncrasies of each industry that must guide the decision.

firm i which is defined as:

$$r_{ij} = f(q_i) = CV_i \tag{3.7}$$

The way to read equation (3.7) is: firm i believes that the output of their rivals q_j depends on its own output q_i in some fashion $f(q_i)$; thus, any changes in its own output is believed to induce $f'(q_i)$ change of rival's output. A quantity profile for which (3.6) holds simultaneously for all firms is conjectural variation equilibrium (i.e., $r_{ij} = r_{ji}$).

Denoting θ as aggregate conjectural variation, the first-order condition in equation (3.6) becomes:

$$P = MC - (1 + \theta)Q.P' \tag{3.8}$$

Because we know from the optimality - equation (3.3) that $P = MC - \lambda Q.P'$, it follows that $\lambda = 1 + \theta$.

- If $\theta_i = -1$, firms are Bertrand players since in this case, any output reduction of firm i will be offset by an output expansion of its rival ($dq_j/dq_i = -1$), then the total industry quantity (and therefore price) is conjectured to be a constant, the only profitable strategy of firm i in this case is marginal cost pricing. The supply relation in (3.8) would become $P = MC$.

- If, however, $\theta_i = 0$, we come back to Cournot solution where firm i conjectures that its rivals will hold their output levels constant no matter how much it changes the quantity.

- If $\theta_i = 1$, firm i acts like a colluder. In this case, it conjectures that any change in its own quantity will be matched by all other firms so that market shares remain constant. It is unable to conquer the market share then firms will simply have incentives to seek to maximize the overall profit pie that is jointly split between rivals.

Table (3.1) shows how λ, θ and Lerner index are related for those three structures:

Table 3.1: λ and Market structure measures

Market structure	λ	θ	L
Competition (Bertrand-Nash)	0	-1	0
Cournot-Nash	1/N	0	$1/n\varepsilon$
Cartel	1	N-1	$1/\varepsilon$

The implication of conjectural variations is appealing because it is based on sound economic theory. However, the idea of conjectural variation has been criticized ever since they were introduced. One of the most distinguished criticisms, which had been the core subject of any debates ever around the recourse of CV models in estimating market power during the late 1980s, traces the roots to Feller's famous remark: firms in CV models *"prove to be "right" for the wrong reasons"* (Fellner [1964]). That is, each firm's conjectures on how its rivals would seek to respond to any changes in its own behavior generally do not correspond to the rivals' best response functions. Put another way, the conjectural variations are not equivalent to the optimal response of the other firms at the equilibrium defined by that conjecture: they are "inconsistent" or "irrational". This important criticism appears to severely limit the usefulness of CV models as a tool to model competitive outcomes. Furthermore, as argued by many game theorists, the problem with the interpretation of λ as a conjectural variations equilibrium is that we can only justify only a few values of λ such as Bertrand, Cournot and collusion equilibria. We do not have a good economic theory to explain why λ could be a continuous index (See Bresnahan [1989]; Reiss and Wolak [2007] for a very deep discussion of how to identify λ). For those reasons, in the followings we are only interpreting λ as a measure of the gap between price and marginal cost and not precising the game that firms might be playing.

Box 3.1. Consistent conjectural variation

For any given conjectures $r_{ij} = f(q_i)$, we could define an oligopoly equilibrium point $q*$ in the non-negative orthant of the $q_i - q_j$ plane which satisfies:

$$q*_i = g_i(q*_j) \quad and \quad q*_j = g_j(q*_i) \tag{3.9}$$

where $g_i(i = 1 \ldots n)$ is found by solving simultaneously profit maximiza-

tion problems. Now the conjectural variation CV_i is consistent if:

$$f(q_i) = g_i(q*_j) \text{ for some } \varepsilon > 0 \text{ and all } q*_i \in [q*_i - \varepsilon, q*_i + \varepsilon]$$

What this equation assures is that firm i will correctly foresee the optimal reaction to changes in q_j at least within some local neighborhood of the equilibrium (local consistency conditions). This assumes implicitly that the rival's reaction function conjectured by a firm is exactly what is actually happening, that is, $f(q_i)$ is precisely predicted, as we can replace q_j by $f(q_i)$ in the first - order condition, and thus at equilibrium, $f(q_i)$ will be identical to the optimal choice, $g_i(q*_j)$.

Clearly, with this strict assumption, we may easily get involved in circular reasoning. If producer i knows that his rival j is reacting along the function $g_j(q*_i)$, saying F_2, then he would not be reacting along $F_1[g_i(q*_j)]$ like j is assuming. Instead, he would try to select the point along F_2 which is optimal from his own (producer i) point of view. Similarly, firm j could do the same thing. Such behavior might never result in consistent equilibrium because their assumptions about each other's reaction are turning out incorrect: firm j conjectures that firm i is reacting along F_1 and firm i conjectures that firm j is reacting along F_2 while they are actually not! Consequently, they cannot be "right for the right reason" as quoted by (Lindh [1992], p. 75) : "*Rational agents trying to outguess each other will anyway only rarely find themselves in a locally consistent conjectures equilibrium*".

Fellner [1964], again in his arguments about the correctness of original assumptions, introduces the notion of "quasi-correct". The firms are quasi-correct or quasi-rational in the sense that i produces the quantity which appears to justify j's present output, and at the same time, j's present output appears to justify that of i. These outputs are "justified" on the basis of entirely arbitrary notions of what one would do if the other changed his output. The equilibrium is consistent as long as none of them realizes that their notions are incorrect. Of course, any testing is likely and would show that the rival does not behave in the fashion assumed. Firms would therefore adjust simultaneously their conjectures about one another. This might lead to another equilibrium, but this new equilibrium, if any, will happen in the

next move (t+n), and always rational at least in their beliefs. To put it simply, in an one-shot game; i.e, no testing will take place, the conjectural variations equilibrium, if exists, is quasi-rational: "*firms are right for not quite so wrong reasons*" (Lindh [1992]).

This conclusion is only a way to emphasize that "rationality" or "consistency" would be much less paradoxical if we are allowed to weaken that notion to the extent that firms are right in their beliefs, and could be right for not so wrong reason. Because consistency must allow mistakes to be made and firms come to learn it in some ways in order that they ever deviate from an established equilibrium. In the static model (one-shot game), the firm come to learn how competitors react to change; we might think of it like a result of a dynamic process in the past, i.e. " *a real time adaptive process where firms alternatively make choices in each period based on the decisions of the former period and learn by adapting their output until ex ante profits equal ex post profits*" (Lindh [1992], p. 77). Indeed, if we are allowed to weaken the concept of consistency in this way, then conjectural variation could be a good interpretation of conduct parameter λ as a measure of market power.

Identification of λ

The general empirical problem in estimating (3.3) is how to identify λ because when the model is proceeded with the data, we will barely know whether we are tracing supply curve $P = MC$ or supply relation $MR = MC$. To see this more clearly, let us put (3.1) and (3.3) respectively in the simplest static linear relations:

Demand function:

$$Q = \alpha_0 + \alpha_p P + \alpha_x X + \varepsilon \tag{3.1$'$}$$

and supply relation:

$$P = \beta_0 + \beta_q Q + \beta_w W + \lambda \frac{Q}{\alpha_p} + \eta \tag{3.3 $'$}$$

(3.1′) is identified no matter which form the supply relation takes because it has only one included endogenous variable P and one excluded exogenous variable W. Similarly, (3.3 ′) is also identified. However, the degree of market power, λ, is not. To see this, rewrite (3.3 ′) as:

$$P = \beta_0 + \beta_w W + \psi Q + \eta \qquad with \qquad \psi = \beta_q - \frac{\lambda}{\alpha_p} \tag{3.3 ″}$$

Clearly (3.3 ″) is identified: Only one included endogenous variable Q and one excluded exogenous variable X. But we do not know whether we are tracing out $P = MC$ or $MR = MC$. The parameter ψ we can estimate depends on both β_q and λ; thus, we cannot determine both of these from the knowledge of ψ even though we can treat α_p as known.

Bresnahan [1982] and Lau [1982] solved this by introducing a new variable, say vector Z, entering the model to both shift the demand curve and rotate it around the industry equilibrium point (changing in slope of demand curve). The demand function (3.1) can be written as $Q = \alpha_P P + \alpha_Z Z + \alpha_{PZ} PZ + \varepsilon$, the supply relation (3.3) is now given as:

$$P = \beta_Q Q + \beta_W W - \lambda \frac{Q}{\alpha_P + \alpha_{PZ} Z} + \eta \tag{3.3 ‴}$$

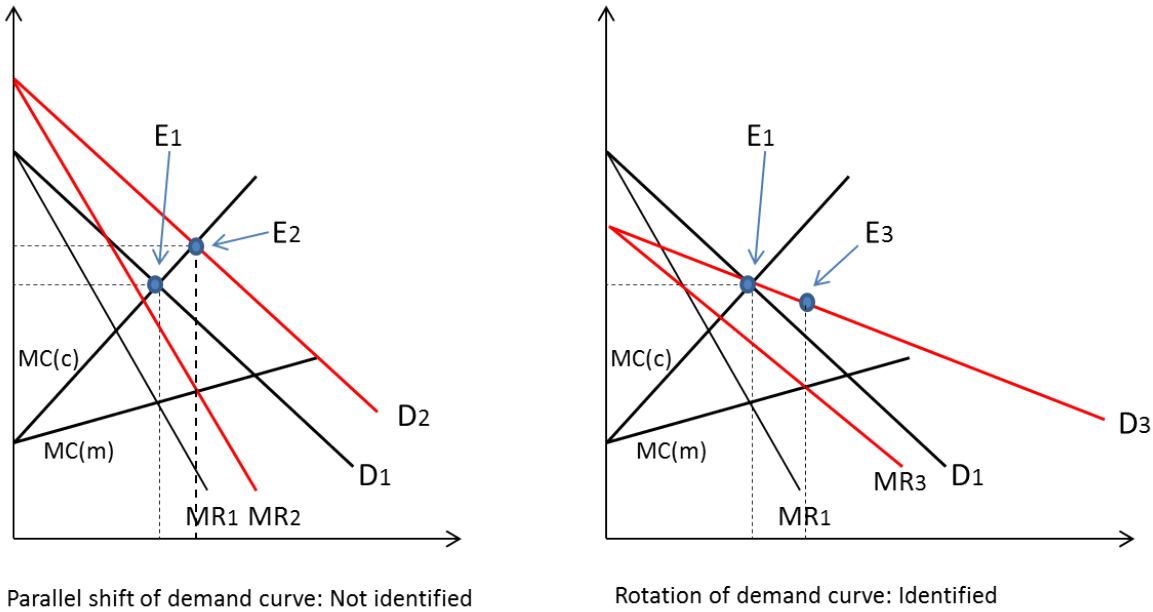
By treating α_P and α_{PZ} as known (from estimating the demand equation), λ is now identified. To see this, denote $Q* = -\frac{Q}{\alpha_P + \alpha_{PZ} Z}$, λ is identified as the coefficient of $Q*$ based on the estimation of (3.3 ‴).

The inclusion of the rotation variable PZ in the demand function is crucial for the identification of market power degree. Figure 3.1 may clarify the issues.

In both figures, the initial demand curve D_1, so MR_1 is linear with MR_1 twice as steep as D_1 ; the initial equilibrium is shown by a solid dot E_1. This equilibrium is consistent with a perfectly competitive industry with $P = MC^c$ or with market power $MR_1 = MC^m$ (the marginal revenue curve MR_1 intersects the relatively low, flat marginal cost MC^m at the same quantity as at the intersection of D and MC^c).

In the figure 3.1.a, we assume that a shock occurs: Z increases. Because the demand function does not have an interactive term PZ so that $\alpha_{pz} = 0$,

Figure 3.1: Identification solution



Source: Bresnahan (1982)

this shock will cause a parallel shift in the demand curve from D_1 to D_2. New equilibrium E_2 is defined, which is always consistent with both competitive and monopoly outcomes. In this example, we can not differentiate those two possible market structures unless we know marginal costs.

In contrast, in the figure 3.1.b, we assume that $\alpha_{pz} \neq 0$, the demand function has an interactive term PZ so that when Z increases, the demand curve D_1 rotates to D_3. Now the resulting equilibrium is either E_1, which correspond to competitive industry, or E_3, which correspond to monopoly structure. Thus, in this example, a shock allows us to differentiate two market structures.

The economic intuition behind this is quite straightforward. The rotation of demand curve around equilibrium will have no effect under perfect competition: supply and demand curve meet at the same equilibrium point before and after rotation. However, under either oligopoly or monopoly, firms with market power seeing that elasticity of demand is changing will adjust both their conjectures about other rivals' behaviour and their perceived marginal revenue. Equilibrium price and quantity will respond. Thus, the market power

parameter λ is identified.

3.1.2 Dynamic framework

One common feature in most papers using NEIO model is that they use time series data but they do not take into account the dynamic property of time series econometrics. Steen and Salvanes [1999] were perhaps the first to propose a dynamic reformulation of the NEIO model in an error correcting framework ECM and Hjalmarsson [2000] use the same dynamic concept but in an autoregressive distributed lag ADL model. These dynamic models allow for short-run deviations from long-run equilibrium in the data. Though not explicitly modelling feedback mechanisms (reaction function), the dynamic formulation allows firms to correct the errors of past decisions by solving a succession of static profit maximizing problems.

ECM framework is useful to treat the inference problem of using non-stationary data, for example Steen and Salvanes [1999] and Bask et al. [2011]. However, in those papers, the authors deal with average weekly data, which displays a potential of non-stationarity while we are using the high frequent hourly data of both demand and costs. This kind of data, as shown in section 3.2, performs a strong stationarity due to its high seasonality of both price and load. Furthermore, although manipulation of data by averaging introduces smoothness into the data by dampening the fluctuations in the hourly data and eases the calculation of parameters, this removes the possible short run dynamic across hours. For those reasons, we are conducting the ADL models instead of ECM framework.

The demand function (3.1′) and supply relation (3.3 ‴) can be written in ADL framework as follows:

$$Q_t = \alpha_0 + \sum_{i=1}^{k} \gamma_i Q_{t-i} + \sum_{i=0}^{k} \alpha_{P,i} P_{t-i} + \sum_{i=0}^{k} \alpha_{Z,i} Z_{t-i} + \sum_{i=0}^{k} \alpha_{PZ,i} PZ_{t-i} + \varepsilon_t \quad (3.10)$$

$$P_t = \beta_0 + \sum_{i=1}^{k} \phi_i P_{t-i} + \sum_{i=0}^{k} \beta_{Q,i} Q_{t-i} + \sum_{i=0}^{k} \beta_{W,i} W_{t-i} + \sum_{i=0}^{k} \lambda_i Q^*_{t-i} + \eta_t \quad (3.11)$$

where the long-run parameters in demand equation are given as:

$$\theta_j = \frac{\sum_{i=0}^{k} \alpha j, i}{1 - \sum_{i=1}^{k} \gamma_i} \qquad j = P, Y, Z, PZ \tag{3.12}$$

$1 - \sum_{i=1}^{k} \gamma_i$ is denoted as the adjustment speed and measures how fast firms can correct the errors of past decisions.

$h(.)$ in (3.3) can be written as:

$$Q_t^* = \frac{Q_t}{(\theta_P + \theta_{PZ} Z_t)} \tag{3.13}$$

and the long-run parameters are given as:

$$\Lambda = \frac{\sum_{i=0}^{k} \lambda}{1 - \sum_{i=1}^{k} \phi_i} \qquad \xi_Q^* = \frac{\sum_{i=0}^{k} \beta_{Q,i}}{1 - \sum_{i=1}^{k} \phi_i} \qquad \xi_W^* = \frac{\sum_{i=0}^{k} \beta_{W,i}}{1 - \sum_{i=1}^{k} \phi_i} \tag{3.14}$$

$1 - \sum_{i=1}^{k} \phi_i$ denotes as the adjustment speed.

The ADL formulation provides both a short-run measure of market power: λ and a long-run measure, Λ. The supply relation in (3.11) incorporates adjustment costs and allows short-run deviations from the requirement that marginal cost should equal perceived marginal revenue (Steen [2003]).

3.2 The nature of data and specification for different model considerations

As discussed in section 2.2, electricity industry exhibits a distinguished feature which makes modelling it different from other markets: it cannot be stored economically on a large scale. The non-storability of electricity requires that demand and supply must be always in equilibrium. Any imbalance in the market could create a cascade of failure in the network. One implication is that when demand varies across the hours during the day, supply needs to follow exactly the same rhythm, and so would prices. Electricity is the unique market where there exist 24 different prices for 24 hours per day. Any attempt to model electricity price should take this into account.

There have been four broad modeling strategies of electricity spot prices in the existing literature[3]:

1. Modeling of the daily/weekly average price: Koopman, Ooms and Carnero [2007], Schlueter [2010], Schlueter [2010], Bask et al. [2011], Ketterer [2014].

2. Treatment of the hourly prices as a single time series: Nogales, Contreras and Conejo [2002], Conejo, Contreras, Espinola and Plazas [2005], Liu and Shi [2013], Steen [2003].

3. Separate treatment of the hourly prices: Crespo Cuaresma, Hlouskova, Kossmeier and Obersteiner [2004], Weron and Misiorek [2008], Karakatsani and Bunn [2008], Bordignon, Bunn, Lisi and Nan [2012], Bessec, Fouquau and Meritet [2014],.

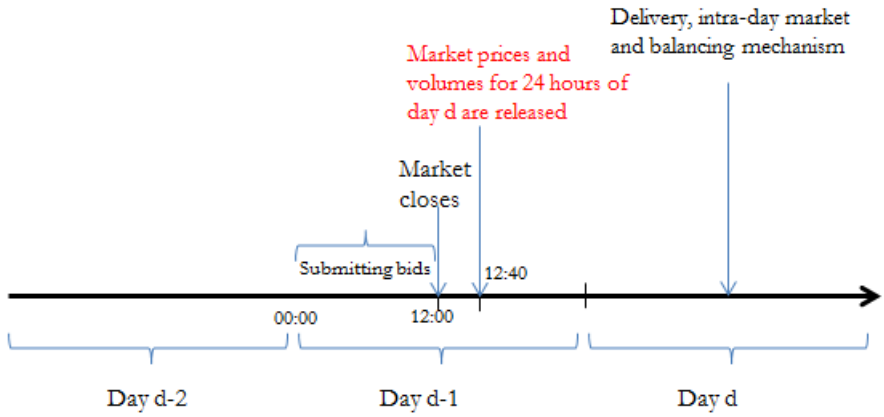
4. Treatment of the data as a panel framework: 24 hours are considered as cross-sectional individuals which are observed over time (daily base): Huisman, Huurman and Mahieu [2007], Meritet and Pham [2015].

Averaging hourly observations to obtain one daily/weekly price and quantity is the least complicated way to treat the dataset and this also introduces smoothness into the data by dampening the fluctuations in the hourly data. However, manipulation the data in this way might remove the possible short run dynamic across hours. In fact, demand elasticities are different during the day and firms with market power will adjust their perceived marginal revenue. Equilibrium price and quantity will respond correspondingly. For this reason we are not considering this method.

The treatment of the hourly prices as a single pooled time series, though being used in several recent papers, is not being considered in this thesis either. In fact, we are modelling the day-ahead market, where equilibrium outputs (price and quantity) are determined one day before the delivery through an auction mechanism. In the morning of each day, buyers and sellers submit their bids (price and quantity combination) for each hour of the forthcoming

[3]Except for Steen [2003] and Bask et al. [2011], those papers do not necessarily concern market power modelling but they give useful implications on price modelling methodologies.

Figure 3.2: Time framework of market information release



day. The market is closed at 12:00 noon in European Power exchange (Epex Spot). The Epex Spot then aggregates demand and supply curves. The results of equilibrium price and volume for each hour of the forthcoming day are published by Epex Spot from 12:40 pm for **simultaneous** 24 hours (See figure 3.2). Thus, the information of price and quantity for 24 hours is released **at the same time**. This is why considering the hourly prices as a continuous single pooled time series is not an appropriate methodology.

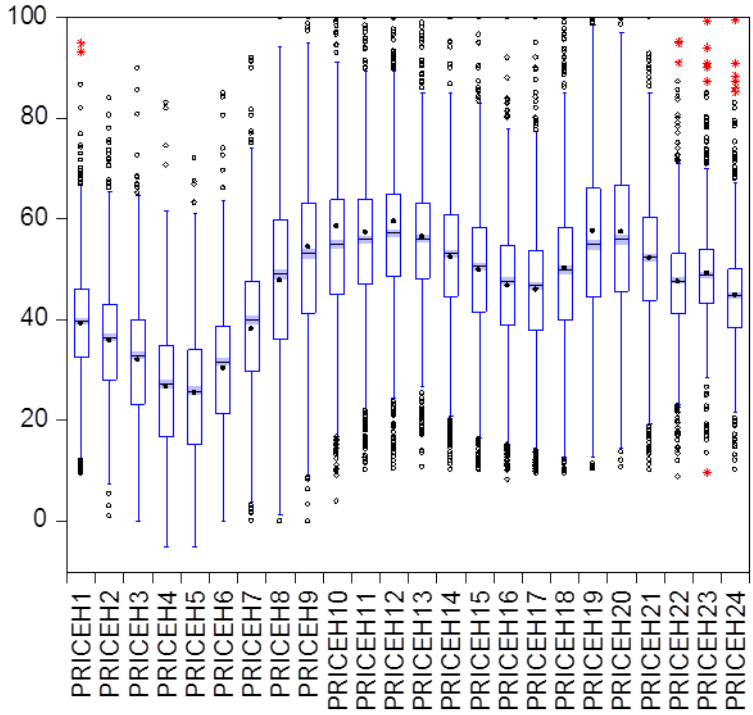
For those reasons, we are considering only two last modelling strategies on the above list: **treatment of the data as multivariate hourly series** and **treatment of the data as a panel framework**.

3.2.1 Specification for multivariate time series model

Electricity prices display a distinct pattern depending on the hour of the day. The strong variation is mainly result of the evolution of demand during the day. According to RTE (the French transmission grid operator), the intra-day profile of electricity consumption in France is categorized by four phases: the night trough, the morning peak, the afternoon trough and the evening peak. This corresponds to different need of electricity across hours of the day: the demand for transportation, the demand for lightening and heating, the demand for industrial production, ect. This motivates us to implement an hourly segmentation of the data.

Figure 3.3 shows the box plot of French spot prices between 2009 and

Figure 3.3: Boxplot of spot price (2009-2013)



Source: Author, based on data from EPEX SPOT

2013 at each trading hour [4]. In line with the load profile, peaks in price level occur from around 9am to 1pm and 7pm to 8pm, while prices are lower during the night from 0am to 8am and 2pm to 6pm. Thus, to allow a variation of the regression parameters for every hour, we are first modelling separately each hour of the day.

If $j_t^{(h)}$ denotes the given variable j in time h of day t, $h = 1...24$ and $t = 1...T$, the demand function (3.10) and supply relation (3.11) are given by:

$$Q_t^{(h)} = \alpha_0^{(h)} + \sum_{i=1}^{k} \gamma_i^{(h)} Q_{t-i}^{(h)} + \sum_{i=0}^{k} \alpha_{P,i}^{(h)} P_{t-i}^{(h)} + \sum_{i=0}^{k} \alpha_{Z,i}^{(h)} Z_{t-i}^{(h)} + \sum_{i=0}^{k} \alpha_{PZ,i}^{(h)} PZ_{t-i}^{(h)} + \varepsilon_t^{(h)} \tag{3.15}$$

[4]We are keeping only values ranging from -10 to 100 for the readability of the graph

$$P_t^{(h)} = \beta_0^{(h)} + \sum_{i=1}^{k} \phi_i^{(h)} P_{t-i}^{(h)} + \sum_{i=0}^{k} \beta_{Q,i}^{(h)} Q_{t-i}^{(h)} + \sum_{i=0}^{k} \beta_{W,i}^{(h)} W_{t-i}^{(h)} + \sum_{i=0}^{k} \lambda_i^{(h)} Q_{t-i}^{(h)*} + \eta_t^{(h)} \tag{3.16}$$

Modelling a multivariate model is appealing because this allows capturing precise coefficients for separate hours. However, there might be too many parameters to estimate as we increase the number of exogenous variables and instruments. In the following, we consider also the model in panel data framework.

3.2.2 Specification for panel model

An assumption under which the issue of having too many parameters can be solved is **contemporaneous correlation** between the error terms. This assumption says that the error terms in different equations (hours), at the same point of time, are correlated. The economic intuition behind this is that these errors contain the influence on demand and supply that have been omitted from the model, such as changes in market regulation, the general state of the economy, etc. Since the individual hourly prices share common dynamic in many respects, it is likely that the effects of the omitted factors on hour, say h8, will be similar to their effect on hour h9. If so, then the error terms $\varepsilon_t^{(h8)}$ and $\varepsilon_t^{(h9)}$ as well as $\eta_t^{(h8)}$ and $\eta_t^{(h9)}$ in the equations (3.15) and (3.16) will be capturing similar effects and will be correlated. This motivates us to implement also a panel model.

A simplification of equations (3.15) and (3.16) that allows a common dynamic across all hours and is:

$$\gamma_i^{(h)} = \gamma_i \qquad \alpha_{j,i}^{(h)} = \alpha_{j,i} \qquad j = P, Z, PZ \tag{3.17}$$

and

$$\phi_i^{(h)} = \phi_i \qquad \beta_{j,i}^{(h)} = \beta_{j,i} \qquad j = Q, W, Q* \tag{3.18}$$

Given this assumption, it follows that all behavioral differences between hours and over time are captured by the error terms (one-way or two-way error component model). The resulting econometric model for one-way error

component panel framework is:

Demand equation:

$$Q_{ht} = \alpha_0 + \sum_{i=1}^{k} \gamma_i Q_{h,t-i} + \sum_{i=0}^{k} \alpha_{P,i} P_{h,t-i} + \sum_{i=0}^{k} \alpha_{Z,i} Z_{h,t-i} + \sum_{i=0}^{k} \alpha_{PZ,i} PZ_{h,t-i} + \varepsilon_{ht} \tag{3.19}$$

with

$$\varepsilon_{ht} = \mu_h + \upsilon_{ht} \tag{3.20}$$

where μ_h denotes *unobservable* hour specific effect and υ_{ht} denotes the remainder disturbance in the one-way error component panel model.

Supply relation:

$$P_{ht} = \beta_0 + \sum_{i=1}^{k} \phi_i P_{h,t-i} + \sum_{i=0}^{k} \beta_{Q,i} Q_{h,t-i} + \sum_{i=0}^{k} \beta_{W,i} W_{h,t-i} + \sum_{i=0}^{k} \lambda_i Q^*_{h,t-i} + \eta_{ht} \tag{3.21}$$

with

$$\eta_{ht} = \nu_h + \tau_{ht} \tag{3.22}$$

where ν_h denotes *unobservable* hour specific effect and τ_{ht} denotes the remainder disturbance in the one-way error component panel model. Note that μ_h and ν_h are time-invariant which accounts for any individual (hour) specific effect that is not included in the regression (we could think of it as unobserved consumption behaviour in different hours). The remainder disturbance υ_{ht} and τ_{ht} vary with hour and time and can be thought of as the usual disturbance in the regression.

The model in (3.19) and (3.21) is conceptually simpler than multivariate model in the sense that less parameters are to be estimated. Thus, it helps ease some calculation burden imposed by using multivariate model. However, more specifications should be defined to make sure that the assumptions in (3.17) and (3.18) hold. The instrumental variable method applied to dynamic panel framework should be conducted with carefulness.

3.3 The data

In this section, we present a detailed description of the dataset used in the empirical models. We work with data on French electricity market largely because of its availability and also because empirical works on French power markets have been little employed in literature. We first present the two main endogenous variable: electricity spot price and turnover then several demand shifters as well as price drivers. The data concerns the period from 01/01/2009 to 31/12/2012.

3.3.1 The electricity spot price and turnover

We use hourly data of electricity spot prices (in €/MWh) and volume traded (in MW) from 01/01/2009 to 31/12/2012 in French wholesale electricity market which is released at 12:40 a day ahead the physical delivery by the Epex Spot[5].

The volume of electricity traded at market prices in France presents only around 17% of the total market. However, the electricity spot prices are considered as main reference on other markets (OTC, future, forward). Figure 3.4 shows the trends in electricity spot prices and volumes exchanged in France from 28 April 2005 to 27 February 2013[6].

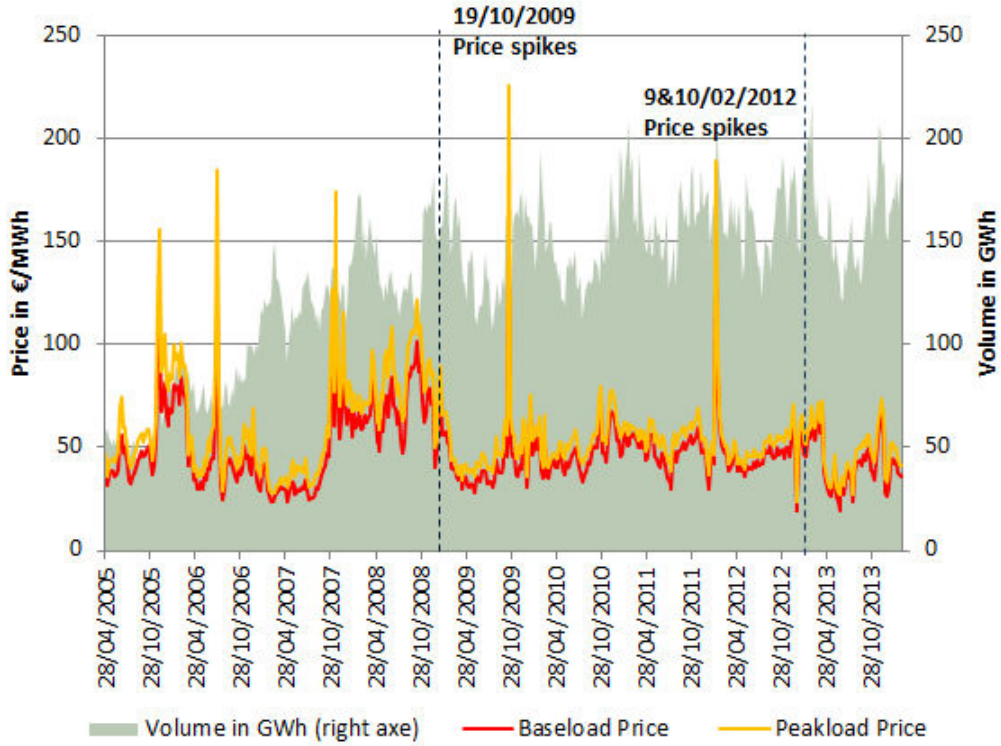
The quantity of electricity traded in the day ahead market has experienced an increase in volume, tripling from 50 GWh in 2005 (weekly average) to around 150 GWh in 2009. During the examined period (2009-2012), the electricity exchanged volume has been quite stationary.

The average baseload electricity price stood at around 48.5€/MWh and the peakload at around 57.6€/MWh in the whole period 2005-2013. The period has been marked by high prices in the last few months of 2005 and in 2008. This can be explained by the integration of CO2 price in 2005 and the global economics crisis in 2008, followed by the soar of oil price.

[5]The European Power Exchange (EPEX SPOT SE) is an exchange for power spot trading in Germany, France, Austria and Switzerland.

[6]We only use the data from 2009 to 2012 for modelling because of the inavailability of some key variables such as temperature. Futhermore, this period has been also experienced enormous evolution in the energy world

Figure 3.4: Average weekly prices and volumes on electricity spot market in France (2005-2013)



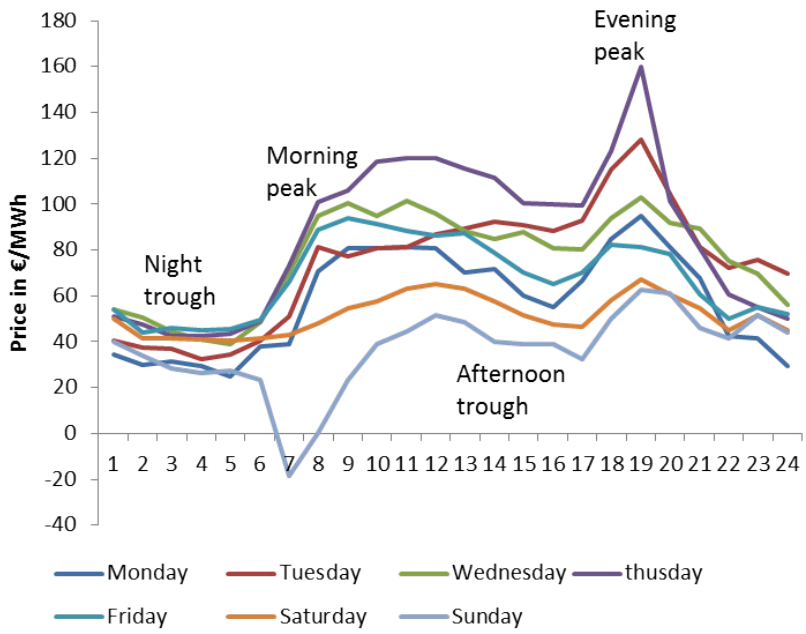
Source: Author, based on data from EPEX Spot

The day ahead electricity prices have been heavily weighted upwards by the price spikes occurring on 19/10/2009 and in February 2012. Prices reached at 3000 €/MWh from 9am to 12am on 19 October 2009 and around 1000-2000 €/MWh at the same hours on 10 February 2012. These high spikes were justified by the French regulatory commission (CRE) through the deliberations on 20 November 2009 and 10 May 2012 respectively (CRE [2009] and CRE [2012]). We discuss this in more detail in chapter 4. In our econometrics analysis, we remove these observations.

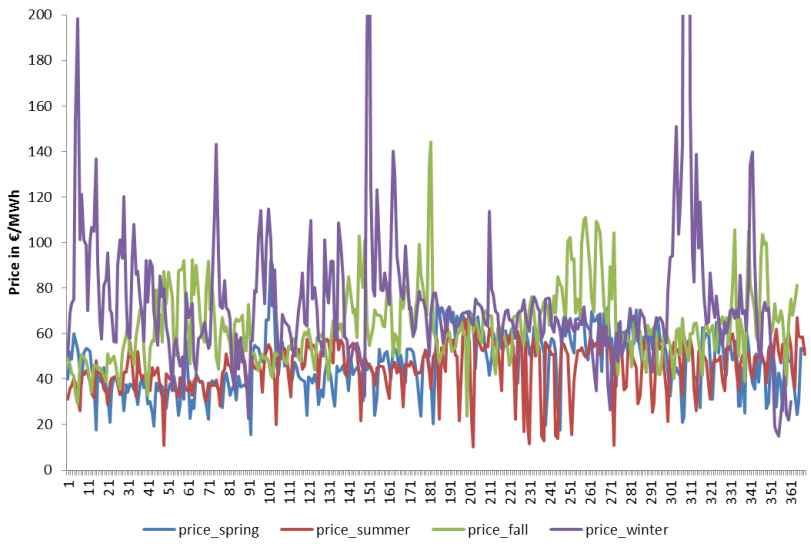
Electricity prices exhibits a strong seasonality in the intra-day, daily, weekly and monthly dynamics due to the strong seasonality of demand for electricity. Figures 3.5 shows the variation of electricity spot prices on the hourly, daily and seasonal basis.

As can be seen in figure 3.5a and 3.5b, prices are lower in the weekend and particularly on public holidays due to weak economic activity. They are

Figure 3.5: Seasonality of french wholesale electricity price



(a) per hour and day (12-18 Jan 2009)



(b) per season

Source: Author, based on data from EPEX Spot

higher on average in winter than other seasons of the year due to the high need of electricity for heating in the winter. To control the bank holidays effects, we include a dummy variable which takes value of 1 on weekend and on public holidays in France and 0 otherwise. To deseasonalize the price and turnover series, we include a set of dummy variable into both demand function and supply relation: for each season $\sum_{S=1}^{3} S_t$ where S stands for seasons of the year.

3.3.2 Demand shifters

We are considering several demand shifters as explanatory variables in the demand equation. Those variables are published at a daily or hourly frequency, which include the hourly temperature and the length of the day in France.

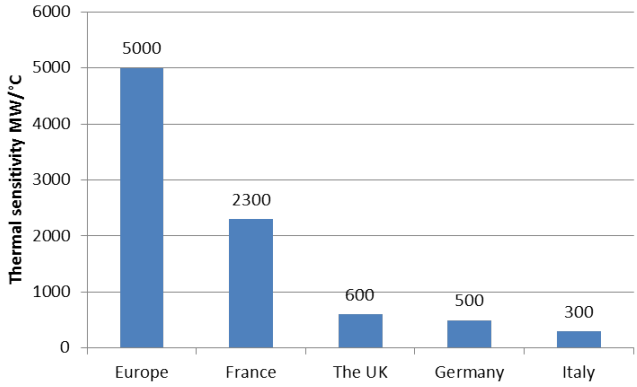
- The hourly temperature in France is the main variable to shift the demand and this is considered in literature a good instrument to identify the supply relation thanks to its pure exogeneity. We use the national temperature index constructed from a range of meteorological stations (32) distributed optimally in the French territory. This data is published by ERDF (French distribution system operator).

- The temperature sensitivity of electricity consumption, which has risen sharply over the last decade, is now estimated at 2300 MW /degree at 19h, time of peak consumption in the winter (RTE [2012]). This temperature sensitivity is much higher in France than in other European countries (Figure 3.6). It represents almost half of the total European thermo sensitivity. In France, this influence is particularly noticeable in the winter with the usage related to heating.

- Daylength is another variable to shift the demand. The influence of the length of day on the electricity usage is represented through the demand for lightening. This is calculated based on the time duration from sunrise to sunset in Paris [7].

[7] The data is available on www.timeanddate.com. We use the Paris's data on daylength as a representative because the population weight of Paris region is relatively high and the daylength does not vary very much between regions

Figure 3.6: Thermal sensitivity in Europe



Source: RTE [2012]

To be able to identify the degree of market power, we let spot price to interact with temperature ($P * Temp$) as done in Hjalmarsson [2000] and Bask et al [2011]. This interact term enters to the demand equation to both shift the demand curve and change the demand's slope by prices. It is considered endogenous and needs to be instrumented in the demand regressions.

3.3.3 Price drivers

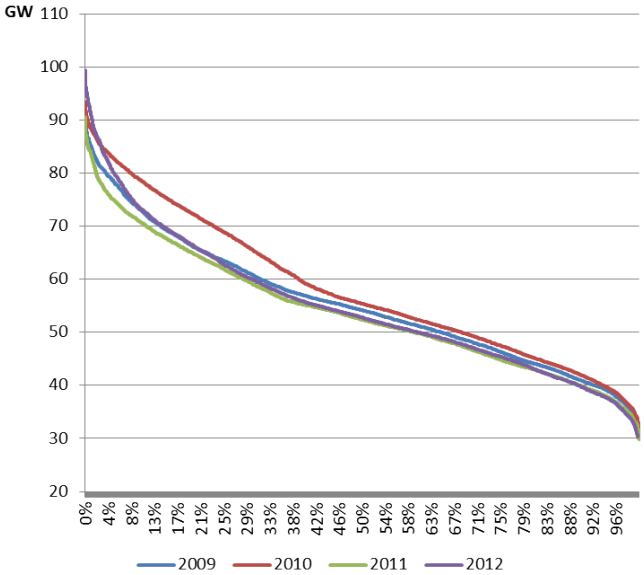
We are considering several price drivers as explanatory variables in the supply equation. We take into account the time release of spot prices in defining other explanatory variables: only information available up to noon before the market clearing is taken into account. Those variables include: load, gas price, coal price, carbon price, capacity margin and forecasted balance of exchanges with neighboring countries.

(i) Total load

We use the data of total load instead of turnover in the supply relation as quantity variable because total load is the main determinant of equilibrium prices. Indeed, total load gives information on which technology should be mobilized in the merit order, thus contributing to determine the marginal plant as well as marginal cost. We use the 24 hourly day-ahead forecasted load data for continental France released by RTE at 0:00 in day $t-1$.

The figure 3.7 shows the load duration in France from 2009 to 2012. The baseload demand has remained relatively stable over the four years while the

Figure 3.7: Load duration in France between 2009 and 2012



Source: Author, based on data from RTE

peak demand has slightly increased in 2012 after a severe winter in February. All the four curves are relatively steep meaning that the difference between the baseload and peakload demand is considerable.

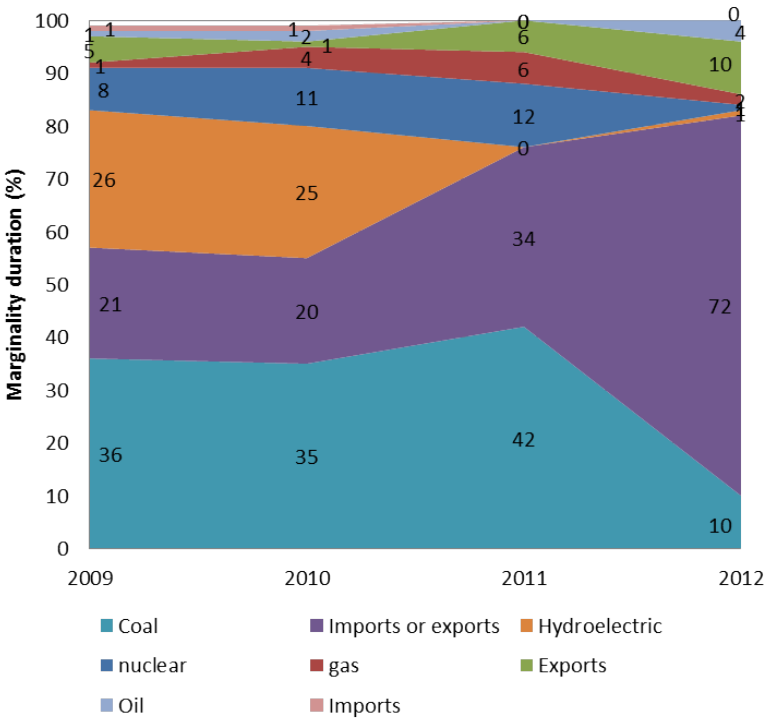
(iii) Gas prices

Although coal and gas plants present a very small part in the electricity mix in France (10 %), they might have effect on French electricity market prices following the logic of merit order that we discuss in section 3.2.1. Because French market is connected with neighboring countries' network, the marginal plants of interconnected zone are most of the time coal or gas plants, which constitute half of electricity production in Germany or Italy.

Figure 3.8 gives the annual marginality duration of different generation technologies in France from 2009 to 2012.

A technology is called marginal when its marginal production cost determines the market price (c.f. Section 1.3) . Figure 3.8 shows that coal–fired power plants had a major marginality during the examined period, though there has been a sharp decrease in the marginality of this type of technology in 2012. In fact, the emergence of unconventional hydrocarbons in North America has significantly reduced the demand for coal in the United States. This

Figure 3.8: Marginality duration of the various generation technologies (2009-2012)



Source: CRE

decline in demand considerably weakened global coal prices. In the same time, gas prices stay high in Europe because the imported natural gas is indexed with increasingly high oil prices under the long term contracts. This leads to the shutdown of many gas plants and the substitution by coal-fired power plants in Europe. Thus, although the marginality duration of coal in France has dropped in 2012, that of the borders has strongly increased, reaching at 72 % in 2012. This is because the share of relatively inexpensive coal–fired power plants in the neighboring countries is high especially in Germany (almost 50 %).

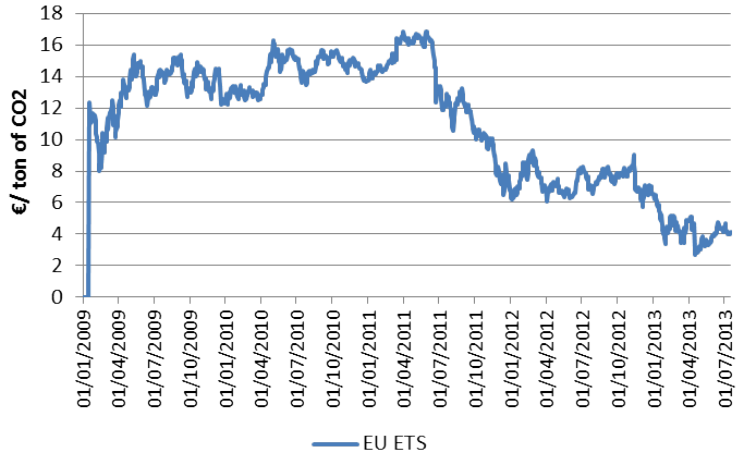
Due to the unavailability of the coal price on daily basis and the fact that weekly coal prices are rather stable during the examined period except in 2012, we are considering uniquely the gas price. We use European Gas Index – EGIX published by the European Energy Exchange AG (EEX). This index is based on all exchange trades concluded in the respectively current

front month contracts of the NCG and GASPOOL market areas [8] on the Derivatives Market. On the basis of these trading transactions EEX then calculates a volume-weighted average price across all transactions. To avoid endogeneity problem, we use lag-1 gas price.

(ii) Carbon price

The CO2 price represents an additional cost for electricity generated from fossil fuels. It may be either a direct cost, if CO2 allowances are purchased, or an opportunity cost, if allowances are received free of charge (De Perthuis and Jouvet [2011]). Thus, power producers add the carbon price to their marginal costs. This tends to increase the equilibrium prices in electricity markets as long as the marginality of carbon-emitting power plants like coal or gas fired remains majority. This correlation has been estimated empirically in several recent papers such as Sijm, Hers, Lise and Wetzelaer [2008] and Solier and Jouvet [2013]. We are therefore taking into account the carbon prices in the supply equation. We use the European Emission Allowances prices (€/ton of C02) which are released by EEX on daily basis. The evolution of carbon prices during 2009 - 2013 is illustrated in figure 3.9.

Figure 3.9: European Emission Allowances prices (2009-2013)



Source: EEX

To avoid endogeneity problem, we use lag-1 carbon price.

(iv) Cross–border net traded volumes

[8] The German spot markets

During the examined period, price levels were deemed to be explained by foreign supply and demand for almost 20 - 70 % (figure 3.8). For this reason, we take into account the exchange balance of French market with the neighboring countries in the interconnected zone. The forecasted balances of exchanges programs with Germany, Belgium, Italy, and Spain are used.

Exchanges between France and the neighboring countries are largely determined by the price difference and the interconnection capacity (NTC: Net Transfer Capacity). The information on cross–border net traded volumes is provided for each hour at the end of the afternoon for the following day by the RTE-France. Because it is released after the market clearing, we use lag–1 values. Figure 3.10 illustrates the forcasted trade balance in volume between France and various markets during 2009-2012.

Figure 3.10: Balance of cross-border exchanges 2009-2012

(a) With Germany (b) With Italy

(c) With Belgium (d) With Spain

Source: EPEX SPOT

The balance of contractual exchanges of electricity across France's borders remains positive, i.e. France remains a net exporter, with exports accounting for around 10 % of French demand according to RTE.

- The interconnection between France and Germany has a total capacity of 2800 MW for exports and 4950 MW for imports in 2012. Trading between France and Germany is conducted through market coupling mechanism in the Central Western Europe launched in 2010, integrating Benelux, France and Germany. As shown in figure 3.10a, the flows in the border Germany - France are quite volatile. In general the capacity transfer in the direction from Germany to France outweighed the other direction. The imports from Germany can reach very high levels, especially on days when wind production is high in Germany.

- The interconnection between France and Italy has a total capacity of 2495 MW in the direction France-Italy and 995 MW in the direction Italy-France in 2012. The very high prices due to high production costs in Italy explained the net exports from France to Italy between 2009 and 2012.

- The interconnection between France and Belgium has a total capacity of 3650 MW for exports and 1600MW for imports. Exports to the Benelux countries remain large majority although significant imports are sometimes scheduled.

- The interconnection between France and Spain has a total capacity of 1550 MW for exports and 1550 MW for imports in 2012. Between 2009 and 2012, France remains net exporter to Spain market although significant imports are recorded in 2012.

(v) Capacity margin

The capacity margin is also included in the supply equation. The RTE publishes the forecasts for capacity margin of the French electricity system for the morning and evening peakload times every day at 8 p.m. We use the margin of the morning peak available all over the year.

The capacity margin refers to the difference between the available generation capacity and forecast consumption. When the margin is large, i.e. there is a significant gap between generation capacity and consumption, only the least costly generation means are used, resulting in low system marginal

costs and spot prices. Conversely, if there are tensions on electricity system, the more expensive generation means are used, increasing daily auction prices (RTE, 2013).

Table 3.2 gives summary statistics for sample variables. The power prices, turnover, load, volumes of exchange and temperature have hourly frequency while daylength, the gas and carbon price, daylength and capacity margin are available at a daily frequency. The whole sample spans from January 01, 2009 to December 31, 2012, yielding 1461 daily observations for each trading hour.

The information of Skewness, Kurtosis as well as Jarque-Bera on price data shows that its distribution is far from normal. The Kurtosis is at very high level, indicating the presence of extreme values. Prices, for example, could reach 3000 €/MWh as happened on 19 October 2009 and around 1000-2000 €/MWh on 10 February 2012, while the average price is only at 46.13 €/MWh. The statistical information on each series of price also suggests that the normal distributions are rejected (Table 3.3): the skewnesses are highly positive and the kurtosises are far from 3, particularly from 8am to 12am where most extreme values of prices are observable (which coresponds to a very high demand for electricity). Several non-linear econometric models have been developed in literature to take into account this feature of price data, such as Generalized autoregressive conditional heteroscedastic (GARCH) model or switching models (Markow switching and threhold autoregressive). However, estimating these non-linear parameters in our modeling context is far from being tractable. We choose thus to remove those extreme observations in our regressions. We detect the outliers by non-parametric method, i.e. removing the values smaller than the lower outer fence or greater than the upper outer fence:

$$\text{lower inner fence} = Q1 - 3 * IQ \tag{3.23}$$

$$\text{upper inner fence} = Q3 + 3 * IQ \tag{3.24}$$

where $Q1$ and $Q3$ are lower quantile lower and upper quartiles (defined as the 25th and 75th percentiles) and IQ is interquartile range, defined as

$Q3 - Q1$. In the following we exclude any observations that beyond an outer fence on either side (extreme outliers).

Table 3.2: Descriptive statistics

	Unit	Mean	Median	Maximum	Minimum	Std. Dev.	Skewness	Kurtosis
Electricity Price	€/MWh	46.13638	46.252	716.033	-50.056	18.98393	4.235954	109.3078
Gas Price	€/MWh	19.65497	22.01	28.55	7.79	5.703643	-0.487586	1.784082
Carbon Price	€/t CO2	11.81185	12.95	16.84	0.02	3.411035	-0.67926	2.701959
Temperature	Celcius	12.52322	12.85	27.7	-5.15	6.405129	-0.253489	2.252443
Daylength	hours	12.06426	12.173	16.1052	8.1448	2.711247	-0.007733	1.580447
Load	MW	55.63161	53.7	99.4	29.9	12.72469	0.571252	2.714237
EX Germany	MW	-694.595	-857	2850	-5390	1702.846	0.193937	1.891437
EX Spain	MW	151.1926	0	1400	-2200	694.7847	0.210961	1.832861
EX Belgium	MW	377.991	300	5202	-1799	1113.764	0.310391	2.243382
EX Italy	MW	1872.296	2187	2962	-1083	737.7182	-0.785028	2.84714
Turnover	GW	6.394527	6.266	13.251	3.004	1.350896	0.562295	3.463442
Capacity Margin	MW	7065.713	6610.8	20580.9	625	2501.517	1.05195	4.748406

Sample period: January 1,2009 to December 31,2012. $N = 35065$ for price, turnover, load, volumes of exchange and temperature and $N = 1461$ for gas and carbon price, daylength, and capacity margin.

Table 3.3: Descriptive statistics of price series

	Mean	Median	Maximum	Minimum	Std. Dev.	Skewness	Kurtosis	Jarque-Bera	Probability
PRICEH1	39.24	39.85	108.88	9.49	11.27	0.18	5.11	278.72	0.00
PRICEH2	35.90	36.55	118.15	1.01	12.05	0.43	5.80	522.54	0.00
PRICEH3	31.92	32.94	106.96	0.01	12.35	0.32	4.21	114.36	0.00
PRICEH4	26.75	27.32	83.06	-5.07	12.09	0.26	3.06	16.67	0.00
PRICEH5	25.53	25.89	72.05	-5.06	11.74	0.22	2.61	20.54	0.00
PRICEH6	30.37	31.69	84.99	-0.01	12.48	0.05	3.17	2.35	0.31
PRICEH7	38.15	40.00	139.99	-0.01	15.40	0.13	4.83	207.63	0.00
PRICEH8	47.80	49.11	250.05	-50.06	20.91	1.52	17.11	12671.32	0.00
PRICEH9	54.42	53.19	3000.00	-0.09	82.89	31.66	1103.25	73936761.00	0.00
PRICEH10	58.52	55.10	3000.00	3.95	92.46	26.68	786.41	37534506.00	0.00
PRICEH11	57.36	55.95	1938.50	10.18	53.15	30.74	1078.75	70628024.00	0.00
PRICEH12	59.55	57.24	3000.00	10.46	82.34	32.23	1126.53	77095915.00	0.00
PRICEH13	56.46	56.18	716.03	10.75	24.19	17.10	431.25	11235481.00	0.00
PRICEH14	52.36	53.18	142.51	10.17	13.61	0.27	6.18	635.08	0.00
PRICEH15	49.84	50.67	138.45	10.09	14.26	0.33	5.77	492.32	0.00
PRICEH16	46.75	47.84	133.70	8.21	13.81	0.27	5.97	555.28	0.00
PRICEH17	45.95	46.85	126.61	9.50	14.23	0.23	5.16	298.10	0.00
PRICEH18	50.25	49.95	151.88	9.50	16.86	0.86	6.23	817.38	0.00
PRICEH19	57.65	55.00	500.00	10.33	25.23	5.87	82.95	397467.60	0.00
PRICEH20	57.42	55.96	540.60	10.72	22.05	8.22	165.45	1622960.00	0.00
PRICEH21	52.23	52.43	143.02	10.15	13.59	0.53	6.50	816.07	0.00
PRICEH22	47.54	47.81	101.19	8.82	10.52	0.12	5.07	264.17	0.00
PRICEH23	49.20	48.91	105.24	9.74	9.83	0.80	7.12	1190.57	0.00
PRICEH24	44.89	44.91	99.60	10.19	9.64	0.63	5.60	510.72	0.00

Conclusion

In this chapter, we presented the method of New Empirical Industrial Organisation (NEIO) to estimate the market power in a given industry. We analyse the logic of this method on both theoretical and empirical basis.

In principle, NEIO model has many advantages over the traditional structure-conduct-performance (SCP) approach according to Perloff et al. (2007). First, the model allows estimating marginal costs and market power level based on the information of prices and factors that are associated with demand and with cost rather than relying on an accounting proxy of marginal cost. Second, the estimating equation is based on formal economic maximizing models, so that the theory-related hypotheses can be tested directly. Nonetheless, such approach depends crucially on properly specifying the model and might be very sensitive to misspecifications.

A typical NEIO study is foremost an econometric model of an industry based largely on time series data. However, many properties of time series econometrics were usually ignored. Steen and Salvanes [1999] and Hjalmarson [2000] proposed a dynamic reformulation of the NEIO model in an error correcting framework ECM and autoregressive distributed lag ADL model. This dynamic framework allows both short run and long run estimates. Therefore, we are considering this in the econometric analysis and applying for France's electricity market.

The NEIO approach has been applied in various industries including electricity but many of them do not take into account the distinguished feature of the data in electricity market. Electricity is the unique market where there exist 24 different prices for 24 hours per day due to the combination of strong variability of demand for electricity and non-storability of electricity. Most papers manipulate the dataset to obtain daily/weekly average price or treat the hourly prices/quantities as a single pooled time series. We have shown that both these approaches are inefficient as applied to electricity market because the information of price and quantity for 24 hours is released by the EPEX SPOT at the same time. Instead, we consider two alternative modelling strategies: treatment of data as multivariate hourly series and treatment of the as a panel framework. In the next chapter, we conduct these two methods and

present the empirical results on the French electricity wholesale market.

Chapter 4

Empirical results on French electricity wholesale market 2009-2012

[1] **Abstract:** In this chapter, we carry out the NEIO model, using hourly data from French wholesale electricity market during period 2009-2012. We estimate a demand-supply system using the two-stage generalized method of moments (GMM) and use the identification method of Brenahan and Lau [1982] discussed in previous chapter to examine the presence of market power. Both multivariate and panel data models are taken into account. The issue of market power in the French power market is of particular interest in the context of its expansion in the next few years after the end of regulated tariffs for all firms under European pressures and national decisions. The performance of wholesale power market has been thus one of the issues being discussed in the energy transition in France (*transition énergétique*), given the highly concentrated market structure and the significant increase in market prices during recent years despite the advantage of inexpensive nuclear power electricity generation in France.

[1] Chapter III and chapter IV of this thesis were summarized in a research paper, published in the *Energy Studies Reviews, 2015, 21* (2) (Meritet and Pham [2015]).

Introduction

The French wholesale market is the third largest in Europe after the German and British ones in terms of installed capacity and consumption, and is about to change drastically. Following the European Commission decision, the regulated rates for electricity will discontinue from 1 January 2016 for residential and business consumers with a power subscription greater than 36kW on the retail market (NOME Law[2]). Therefore, the number of electricity contracts offered by suppliers with market prices will increase. That is why the French wholesale market should become more liquid with more participants in the near future. It is highly relevant to study the wholesale electricity prices in France at this stage.

In France, there have been some doubts provoked in the wholesale electricity market on the issue of market power. Indeed, Electricité de France (EDF), the biggest producer of electric power in Europe, still dominates the domestic market after the electricity reform (90% in 2000 and around 84% in 2010 of the total generation). Furthermore, despite the market opening in 2000, wholesale prices in France have drastically increased: the index of Powernext Baseload Forward Year Ahead almost tripled between 2004 and 2008, soaring from 30 to 87 €/MWh, growing even faster than oil price. The wholesale prices in France have been increasingly higher than those in Germany since the end of 2012 after a long period of strong price convergence between the two markets.

The empirical studies on the performance of the wholesale electricity market in France have been, however, little employed. The issue arose for any attempt to calibrate the marginal cost in French electricity market was the particularly flat-shaped merit curve due to the large part of nuclear power in the generation mix (over 85%) (Economics [2007]). As nuclear is generally a very low marginal cost technology but high capital costs, simulation models were most likely to under-estimate the marginal cost, thus making the calibration of price-cost margins less reliable.

In this chapter we employ a structural model developed in New Em-

[2]Law n 2010-1488 7 December 2010 on New Organisation of Electricity Market (La Nouvelle Organisation du marché de l'électricité

pirical Industrial Organisation (NEIO) described in chapter 3 to investigate the exercise of market power in the French wholesale electricity market during 2009-2012. The great advantage of using this method is to overcome the problem of not knowing accounting datum of economic marginal cost. We are considering two modelling strategies: the treatment of the data as multivariate hourly series and treatment of the data as a panel framework. The former allows capturing the variation of the market power parameter during the day and the latter allows common dynamic between hours.

The chapter is organized as follows. Sections 4.1 provides the detailed description of the market design in the French wholesale power market. Section 4.2 describes the modeling procedures for both multivariate and panel models. Section 4.3 presents the empirical results as well as the economic interpretation of the model-based results.

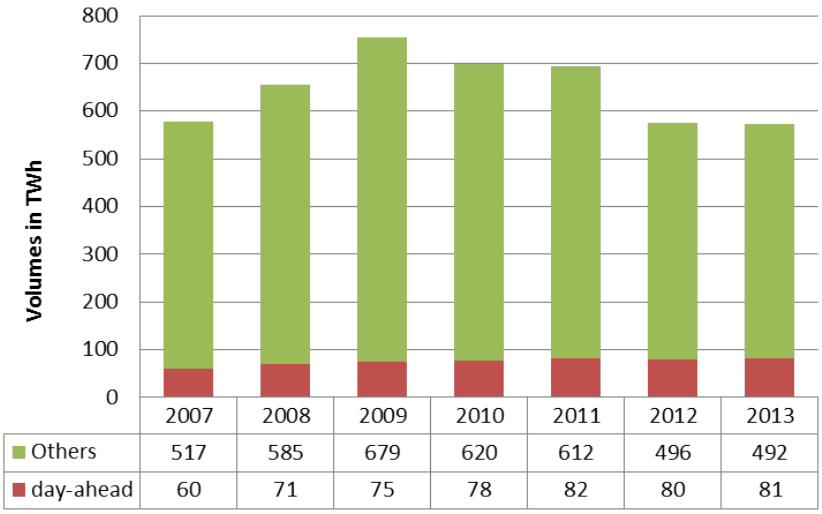
4.1 French market design on wholesale market

In this section, we describe some key factors of French electricity market as regards to market designs and policy on the wholesale power markets. Recent discussions on retail competition in France can be found in Creti, Pouyet and Sanin [2011], Lévêque and Saguan [2010] and Finon [2010].

The French wholesale market is the third largest in Europe after the German and British ones, and has been drastically evolved during recent years. Indeed, the total volume traded in day-ahead market increases from around 50GW per day in 2005 to around 200GW per day in 2013. This share is supposed to increase with the termination of regulated tariffs for small businesses on retail market planned in 2016 by the 2010 NOME Law.

Electricity generation in France is dominated by the incumbent Electricité de France (EDF), which holds around 80% of the total generation capacity. EDF offers access to its competitors around 6GW of its production capacity located in France via quarterly auctions (Virtual Power Plants or VPP) following the judgment "anti-competitive" of the European Commission in 2001 about the acquisition by EDF of 34.5% of the German utility EnBW. The biggest source of competition comes from the high interconnec-

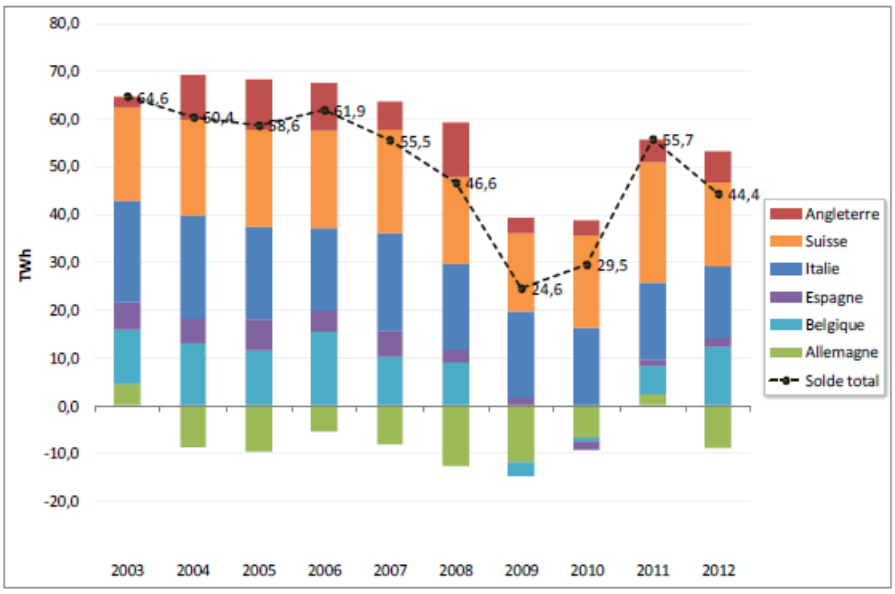
Figure 4.1: Volumes traded on the French wholesale electricity market



Source: Author, based on data from CRE [2013]

tion capacity with neighboring countries (12GW of exportation and 8GW of importation) that allows trading between France and other continental markets: Germany, Switzerland, Belgium, Netherlands and the UK (CRE [2013]).

Figure 4.2: Evolution of French exchange balances 2003-2012



Source: CRE

When domestic demand is low, France exports the excess nuclear capacity to higher price neighboring countries (Electricity prices in Italy are among

the highest). During hours when demand is high and available capacity is restrained, the imports occur from lower price countries especially from Germany thanks to its massive integration of inexpensive wind power generation during recent years. Furthermore, electricity trading between France, Germany and Belgium is particularly facilitated thanks to market coupling mechanism put in place in November 2010.

Electricity trading for energy can take place on organised markets (Epex Spot France for spot products, based in Paris, and EEX Power Derivatives France for future products, based in Leipzig) and brokerage venues (intermediated *over-the-counter*). Trading for energy delivered by any minutes begins years in advance and continues until real time by a sequence of overlap of forward and spot markets. Spot markets for energy in wholesale level are composed of day-ahead, intra-day adjustment and real time balancing markets. Day-ahead market is considered either as spot market or forward market with the greatest physical implications (because it is run just one day prior to physical transactions).

One particular characteristic of French wholesale power market is an overlap of different types of prices and tariffs, which are resulted from a number of regulatory instruments - the government's attempt to reconcile the economic, social, and political contradictions.

With the gradual market opening since 2000, a certain number of "eligible consumers" decided to quit the system of regulated tariff to participate in the system of competitive prices on the market which, at that time, was relatively low (see figure 4.3). This choice was, however, irreversible. Since 2005, the market price began to surge well above the regulated tariffs, almost tripled between 2004 and 2008, soaring from 30 to 87 €/MWh while the regulated tariffs remained almost unchanged, around 30 €/MWh, according to the data from EPEX and Eurostat. Indeed, the regulated tariffs are set largely based on the cost of production of nuclear and hydroelectric power, which represent about 90% of total production in France (data from Eurostat and the IEA). They were, therefore, little impacted by the increase of fossil fuels prices or the implication of CO2 prices since 2005. On the other hand, market prices reply to all these changes. In fact, market prices are set equal

to marginal cost of the last plant mobilized to fulfil the demand (marginal plant). If the French electricity system was isolated, i.e, no exchanges with neighboring systems, the nuclear plants would be the marginal plants for most of time and the market prices would be generally set based on marginal cost of nuclear power; the gap between regulated tariffs and market prices thus would be shortened (Champsaur [2009]). However, with market opening and interconnection between France's and neighboring countries' network, the marginal plants of production necessary to satisfy the demand of interconnected zone are thus most of the time coal or gas plant. The market prices align to the production cost of these plants, which, in turn, vary with the volatility of fossil fuel prices.

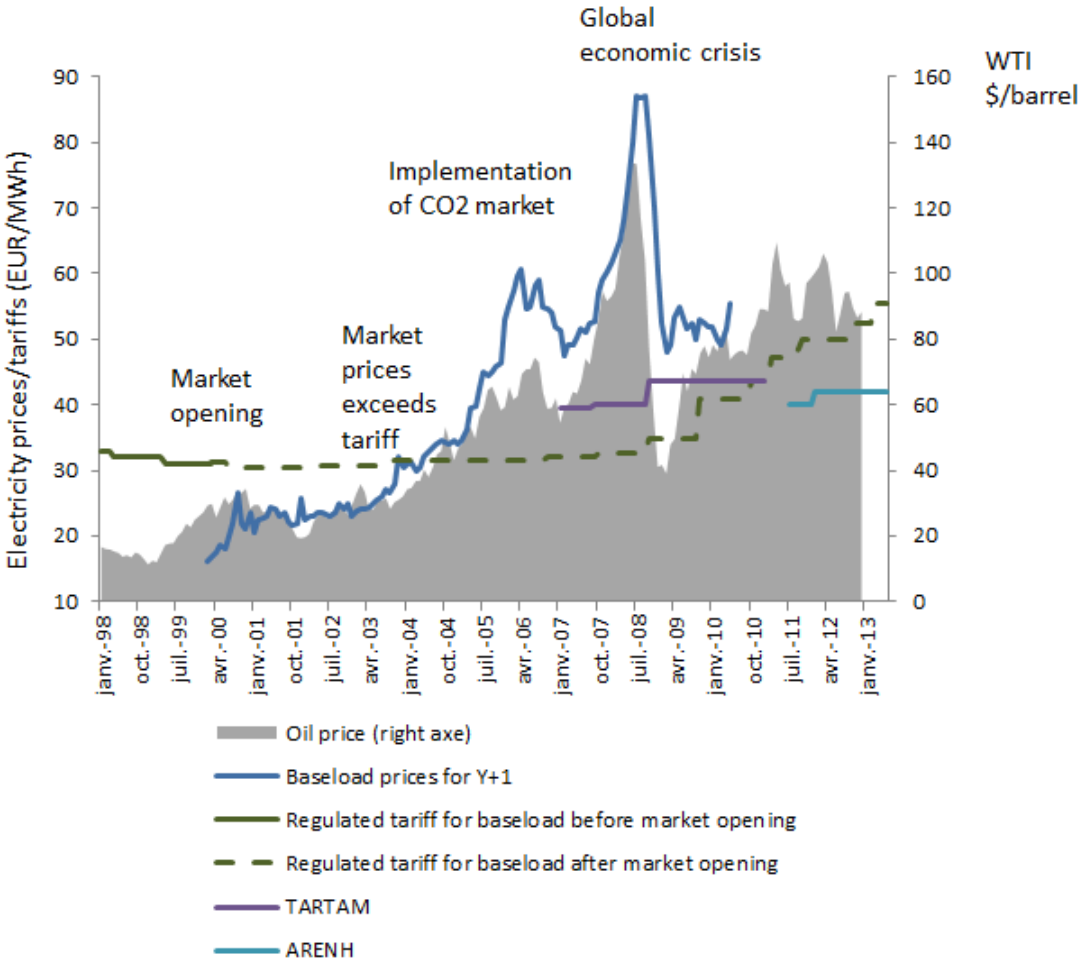
Figure 4.3 illustrates also the correlation of electricity market prices and crude oil prices - the leading price in energy sphere [3]. The surge of crude oil prices from 2004 [4] leading to increases in the two other fossil fuels' prices: coal and gas, and thus, have some impacts on electricity market prices. Therefore, although a coal or gas plant represents a very small part of total generation in France, the production cost of this plant will still become the reference price for the market because it is connected with other market like Germany or Italy where half of electricity production is from coal and gas. Figure 4.4 illustrates the diversity of electricity balances in Europe.

During peak load, electricity is imported from, for example, Germany and the prices would align to the gas plant which is relatively expensive. During the base load, electricity is exported to Germany. Even if the prices correspond to certain marginality of nuclear in France, the coal-fired plants which function

[3]The evolution of natural gas and coal prices is highly correlated with the oil prices largely because they are substitute in the power and heating markets; high price differences cannot remain for long. Indeed, natural gas is frequently purchased by long term contracts which contain a price clause setting an automatic link between gas price and the price of petroleum products (Geoffron and Chevalier [2012]).

[4]The surge of crude oil from 2004 was largely due to dramatical world economic growth especially in China. In 2004, China and the United States imported 3 and 13 million barrels per days respectively while oil production in Venezuela, Iraq and Negeria had not recovered. OPEC had lost its power to control the oil prices and the prices started to soar, peaking on July 2008 at $147/barrel (versus $22/barrel in 2004). The economic crisis hit the real global economy at the end of 2008 caused a sudden collapse in crude oil prices (from $147/barrel in mid 2008 to around $40/barrel at the end of the same year). In 2011, political echoes occurred in many Arab oil exporting countries, oil prices surged again exceeding $100/barrel (Data from U.S. Energy Information Administration (EIA))

Figure 4.3: Evolution of french electricity prices and tariffs (1998-2012)

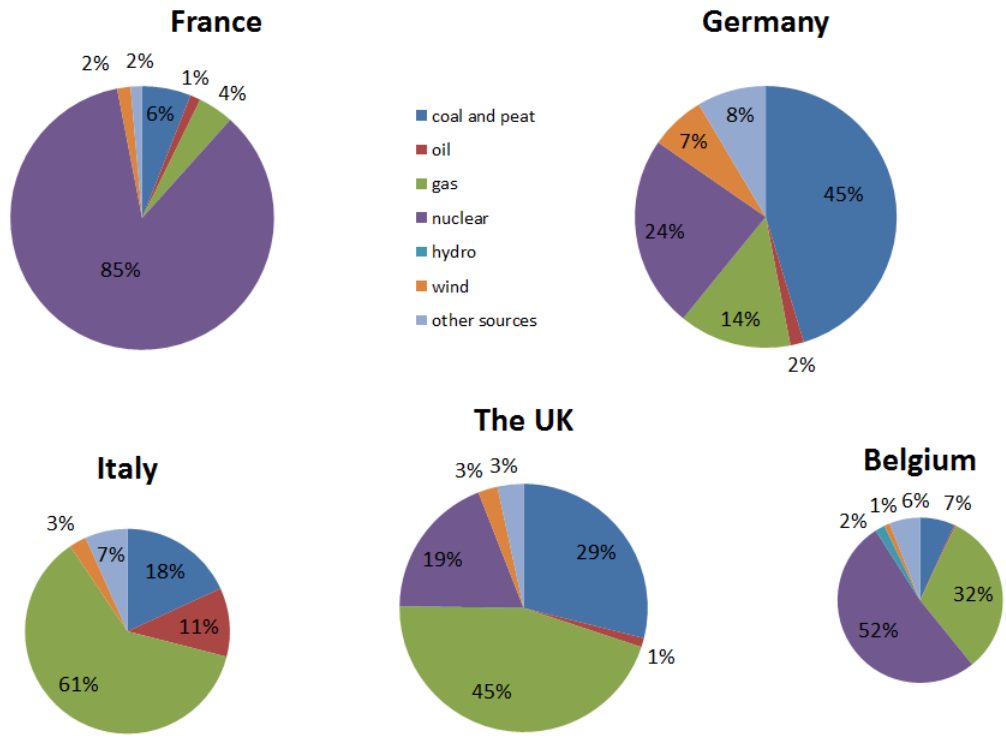


Source: Author, based on data from EPEX, CRE, Eurostat

almost all the time in Germany could influent market prices in France. The price convergence between France and Germany has been even more significant since the creation of market coupling contracts in the Central western European which covers Benelux, France and Germany in November 2010 according to the data from EPEX SPOT.

The great divergence between market price and regulated tariff had made the consumers having quitted the regulated system manifest their malcontent toward the liberalisation (generally competition would have induced lower price). This contradiction led French Government to authorize, by a law on energy in 2006, that the consumers having quitted the tariff can return to the

Figure 4.4: The diversity of European electricity balances (capacity) in 2012



Source: Author, based on data from IEA(2012)

protective tariff system - the so called TARTAM "Tarifs réglémentés transitoires d'ajustement au marché ", or, more prosaically "tariff of return". The TARTAM is calculated from the regulated tariff, increased by 10 %, 20 %, or 23% matching with a mechanism of compensation ex-post [5].

The juxtaposition of regulated tariff, TARTAM, and market prices, as well as the conditions of irreversibility between regulated and market offers caused even more contradictions. Two clients having the same consumption profile do not have access to the same tariff offers. Incoherence of pricing system made market prices now too far from being a signal for new investment. Indeed, new entrants now could hardly compete with the actual regulated tariffs, which reflect the amortized production cost of nuclear power of the

[5]The TARTAM is considered as a Government aid for big enterprises and set with a mechanism of compensation ex-post for suppliers who suffered from the loss of differences between wholesale market prices and the TARTAM (for energy only). This compensation is financed by a tax on the capacity of hydro and nuclear, most of which are contributed by the EDF. Put in other words, EDF compensated the alternatives suppliers up to 97 % (Champsaur, Percebois and Durieux [2011])

incumbent to which its competitors have a priori no access. A new contradiction was provoked: competition is generally expected to lower prices but to promote competition in French electricity market, we need to raise the prices.

It was in these conditions that a law on new organization of the electricity market (Nouvelle Organisation du Marché de l'Électricité - the NOME law) was enacted in December 2010. This law is to attempt to enhance the competition by abolishing gradually the regulated tariffs and the TARTAM. Furthermore, by this law, the incumbent EDF has obligation to sell part of its nuclear production to its competitors at a regulated price fixed by the regulator - ARENH (l'Accès régulé à l'électricité nucléaire historique) [6]. The ARENH price demanded by EDF's competitors was 35 €/MWh while that proposed by EDF was 42€. It was finally settled by the government at 40 €/MWh at start to be coherent with the TARTAM (from the 1st July 2011) then 42 €/MWh from the 1st January 2012 [7]

Although the co-existence of spot prices and regulated tariff system should not have a great impact on the merit order, it reduces the market's liquidity and could make the spot prices more sensitive to supply/demand variations.

[6]Regulated access to historical nuclear energy.

[7]The ARENH price is prosaically regulated price at the wholesale level. It is established, according to the Champsaur report in 2011, on the following assumptions: (1) the ARENH price must assure to cover all the costs of actual nuclear park during the period 2011 - 2025, and at the beginning, allow a good transition with the actual price system; (2) the ARENH price does not take into account the cost of replacing the expired nuclear reactors but it does take into account the cost of extension of life expectancy of the these reactors. Based on those assumptions, 2011 Champsaur report proposed an average ARENH price during this period to be around 39 €2011/MWh , composing of three elements: 25 €2011/MWh for operating expenses (to be covered every year), 8 €2011/MWh for future investments every year, 6 €2011/MWh for capital invested in the past still immobilized.
The ARENH price was finally settled by the Government at 40 €/MWh from the 1st July 2011 then 42 €/MWh from the 1st January 2012. These prices are higher than hypothetical levels proposed by the Champsaur report because they take into consideration the catastrophe of Fukushima in late 2011 (as such, a lot of costs was added to assure the security of nuclear power system).

4.2 Modeling procedures

We describe in this section the procedures for modeling market power in both multivariate time series models and panel data framework.

4.2.1 Multivariate time series models

Several unit root tests (Im-Pesaran-Shin, Augmented Dickey-Fuller, Phillips Perron) are applied to each variable, all series are found stationary at the usual significance levels except for gas price. The results are given in tables from 4.7 to 4.14 in the appendix for each series. In the following, we are considering gas price in difference.

The estimation procedures are as follows. We estimate respectively demand (4.1) and supply equation (4.2) for each hour. To encounter the problem of endogeneity in the demand-supply equation system, these models are estimated with two-stage generalized method of moments (GMM). We use heteroskedasticity and autocorrelation consistent (HAC) robust standard errors to make the estimates robust against any type of autocorrelation and heteroskedasticity. Using estimated parameters from the demand equations, the price response term $Q_t^{*(h)}$ is used as an endogenous regressor in the estimation of supply relation equation (3.16).

Demand functions

The two-stage generalized method of moments (GMM) was employed to estimate the demand functions (4.1) for separate 24 hours.

$$Q_t^{(h)} = \alpha_0^{(h)} + \sum_{i=1}^{k} \gamma_i^{(h)} Q_{t-i}^{(h)} + \sum_{i=0}^{k} \alpha_{P,i}^{(h)} P_{t-i}^{(h)} + \sum_{i=0}^{k} \alpha_{Z,i}^{(h)} Z_{t-i}^{(h)} + \sum_{i=0}^{k} \alpha_{PZ,i}^{(h)} PZ_{t-i}^{(h)} + \varepsilon_t^{(h)} \tag{4.1}$$

in which $j_t^{(h)}$ denotes the given variable j in time h of day t, $h = 1...24$ and $t = 1...T$.

In order to control for endogeneity in P and $P * Temp$ and to identify the demand functions, the vector of carbon prices, gas prices and exchange balances with neighboring markets as well as lag-1; lag-7 of price and forecasted

load are used as instruments. The results of the first stage are convincing with R^2 ranges from 0.8 to 0.9 and very high F-statistics.

In order to decide how many lags that are needed in the autoregressive distributed lag terms, we start with $k = 7$ then test our models down by excluding non-significant lags. The results suggest that only the lag-1 of the turnovers Q are kept. The long term elasticity of demand (θ_P and θ_{PZ}) is then calculated using equation (3.14).

The results of first stage regressions are presented briefly in table 4.18 in the Appendix (Postestimation tests)

Supply relations

Given that we have reasonable estimated demand functions, we generate values for $Q_t^{*(h)}$ using equation (3.13) and use these as regressors in the supply relationship (4.2). The parameter λ associated with this variable will reveal the existence of market power.

$$P_t^{(h)} = \beta_0^{(h)} + \sum_{i=1}^{k} \phi_i^{(h)} P_{t-i}^{(h)} + \sum_{i=0}^{k} \beta_{Q,i}^{(h)} Q_{t-i}^{(h)} + \sum_{i=0}^{k} \beta_{W,i}^{(h)} W_{t-i}^{(h)} + \sum_{i=0}^{k} \lambda_i^{(h)} Q_{t-i}^{(h)*} + \eta_t^{(h)} \tag{4.2}$$

The supply equations (3.16) are estimated using two-stage generalized method of moments (GMM) for each hour. The temperature, daylength, as well as lag-1; lag-7 of price and forecasted load are used as instruments to identify the supply functions. The results of first stage are also very convincing with the F-statistics far over 10, the level required to suggest sufficiently strong instruments.

In order to decide how many lags that are needed in the autoregressive distributed lag terms, we start with $k = 7$ then test our models down by excluding non-significant lags. The results suggest that 7 lags of price variable (form AR(1) to AR(7) are chosen.

The results of first stage regressions are reported briefly in table 4.21 the appendix.

4.2.2 Panel model

We apply several unit root tests for panel framework (Im-Pesaran-Shin, Augmented Dickey-Fuller, Phillips Perron) to power prices, turnover, load, volumes of exchange and temperature series. All series are found stationary at the usual significance levels. The results are given in tables from 4.7 to 4.14 in the appendix for each series.

We could rewrite equation (3.19) and (3.21) by substituting in for ε_{ht} and η_{ht} from (3.20) and (3.22) to obtain:

Demand function:

$$Q_{ht} = \alpha_0 + \alpha_1 X^d_{ht} + \mu_h + \upsilon_{ht} \tag{4.3}$$

where X^d_{ht} is vector of all independent variables in the demand equation and α_1 is vector of parameters associated with X^d.

and supply equation:

$$P_{ht} = \beta_0 + \beta_1 X^s_{ht} + \nu_h + \tau_{ht} \tag{4.4}$$

where X^s_{ht} is vector of all independent variables in the supply relation and β_1 is vector of parameters associated with X^s.

As specified in section 3.2.3, μ_h and ν_h encapsulate all of the variables that affect P_{ht} and Q_{ht} cross-sectionally but do not vary over time - for example, unobserved consumption behaviour in different hours. These effects can be either fixed or random. In the case that μ_h and ν_h are assumed random, $\mu_h \sim IID(0, \sigma_\mu), \upsilon_{ht} \sim IID(0, \sigma_\upsilon)$ and $\nu_h \sim IID(0, \sigma_\nu), \tau_{ht} \sim IID(0, \sigma_\tau)$; the μ_h , ν_h are independent of the υ_{ht} , τ_{ht} respectively. The fixed effects model seems to be a more appropriate specification for our dataset with individual dimension N (hours) is relatively small. Thus, a fixed effects model would not lead to a loss of degrees of freedom (Baltagi [2008]). We justify this choice by Hausman specification test (Hausman [1978]), which assume random effects (RE) estimator to be fully efficient under null hypothesis. The results of the Hausman test give the overall statistics, $\chi^2(7)$ for demand equation and $\chi^2(13)$ for supply relation, having $p - value = 0.000$. This leads to strong rejection of

the null hypothesis that RE provides consistent estimates. We are considering therefore the fixed effects model in both demand and supply function.

One basic problems introduced by the inclusion of a lagged dependent variable is the bias induced from the correlation between these lagged variables $y_{h,t-i}$ (lagged Q and lagged P) and μ_h and ν_h components. This is an issue raised uniquely in the dynamic panel data models. It is because y_{ht} is a function of μ_h or ν_h in equations (4.3) and (4.4), it immediately follows that $y_{h,t-1}$ is also a function of μ_h or ν_h (because these components are time-invariant). Therefore, $y_{h,t-1}$, right-hand regressors in (4.3) and (4.4), are correlated with the error terms, which renders the estimators biased and inconsistent even if the υ_{ht} and τ_{ht} are not serially correlated (Baltagi, 2008). There are broadly two methods to overcome this problem by wiping out the individual effects μ_h or ν_h.

Arellano and Bond [1991] proposed a transformation by first differencing to eliminate the individual effects and using the matrix of instruments $W = [W_1', \ldots, W_N']'$ where W_i is given by:

$$W_i = \begin{bmatrix} [y_{i1}] & & & 0 \\ & [y_{i1}, y_{i2}] & & \\ & & \cdots & \\ 0 & & & [y_{i1}, \ldots, y_{i,T-2}] \end{bmatrix}$$

The Arellano and Bond method is appealing because it uses the instrument set of lagged values of dependent variables, thus requiring no external instrumental variables. However, this method is uniquely appropriate to a micro panel dataset with $N \longrightarrow \infty$ and T very small. When $T \longrightarrow \infty$, the matrix of instruments would become quickly unmanageable. With $T = 1461$ as in our case, the number of instruments would be exploded, even if we break the whole datasat into several sub-sample.

The second choice to deal with the problem of introducing lagged dependent variable is to include the fixed effects (FE) estimator (Winthin transformation) in order to wipe out the individual effects μ_h and ν_h. Nickell [1981] shows that the dynamic panel models with fixed effects are biased of $(1/T)$. However, as $T \longrightarrow \infty$, the fixed effects estimator becomes consistent because

the bias will not be large (Baltagi, [2008]), which is in our case. Another argument which might be favor of using fixed effects estimator in this case is that we have external instruments instead of using only lagged values of dependent variables. In the following we are considering the fixed effects dynamic panel model. Given that $T = 1461$, the bias could be as small as $0.00069 = 1/1461$ of the true value of the coefficients.

The estimation procedures are as follows.

We estimate respectively demand (3.19) and supply equation (3.21) (or (4.3) and (4.4)). Because we still have the problem of endogeneity in both demand and supply functions, these models are estimated with two-stage generalized method of moments (GMM). We use Stock-Watson bias-corrected heteroskedastic-robust standard errors (SEs) to make the estimates robust against any problem of heteroskedasticity. The two-way cluster-robust SEs, proposed by Miller, Cameron and Gelbach [2009] and Thompson [2011], are used to assure that the estimators are consitent to arbitrary winthin-panel autocorrelation and contemporaneous cross-panel correlation. Using estimated parameters from the demand equations, the price response term Q^*_{ht} is used as an endogenous regressor in the estimation of supply relation equation (3.21).

Demand function

The two-stage generalized method of moments (GMM) was employed to estimate the demand function (3.19). To control for endogeneity in P_{ht} and $P_{ht} * Temp_{ht}$ in order to identify the demand function, the matrix of excluded variables including lagged (1) value of carbon prices, gas prices and exchange balances with neighboring markets as well as lag-1; lag-7 of power price and forecasted load are used as instruments. The results of the first stage are convincing with R^2 is at 0.82 and very high F-statistics (197.66).

Using the same method as with multivariate series model, in order to choose the number of lags for autoregressive distributed lag terms, we start with $k = 7$ then test our models down by excluding non-significant lags. The results suggest that only the lag-1 of the turnovers Q are kept. The long term elasticity of demand (θ_P and θ_{PZ}) is then calculated using equation (3.14).

Supply relation

Given that we have reasonable estimated demand functions, we generate values for Q^*_{ht} using equation (3.13) and use these as endogenous regressors in the supply relationship. The parameter λ associated with this variable will reveal the existence of market power.

We arbitrarily choose the quadratic form for the supply function with respect to "forecasted load". The excluded variables temperature, daylength are used as instruments to identify the supply functions. We include 7 autoregressive terms AR(1-7).

4.3 Empirical results

In this section, we present results of the regressions described in previous sections. We first provide the results for panel data model and then detailed results for each hour.

4.3.1 Panel data model

Demand estimation

The second stage GMM estimation results for the demand function with panel dataset are reported in table 4.1. The parameter estimates are highly significant and with expected signs.

Table 4.1: Panel data model - Demand Equation

Variables	coef	Robust Std.Err	z-stat	Prob.	[95% Conf.	Interval]
Price	-0.0210***	(0.00789)	-2.662	0.0077	-0.0365	-0.00554
Temperature	-0.130***	(0.0416)	-3.129	0.0017	-0.212	-0.0487
$P * Temp$	0.00196***	(0.000674)	2.910	0.0036	0.000640	0.00328
Turnover(-1)	0.522***	(0.0195)	26.84	0.0000	0.484	0.561
Daylength	0.00813	(0.0201)	0.404	0.6860	-0.0313	0.0476
Holidays	-0.249***	(0.0766)	-3.251	0.0011	-0.399	-0.0989
Summer	-0.147	(0.117)	-1.256	0.2090	-0.375	0.0822
Spring	-0.258***	(0.0859)	-3.003	0.0026	-0.426	-0.0896
Fall	-0.0929	(0.0738)	-1.258	0.2080	-0.238	0.0518

$***p < 0.01, **p < 0.05, *p < 0.1$. Robust standard errors in parentheses

The coefficient associated with price has negative sign as a standard demand equation should have. This is highly important result because it shows that our instruments have succeeded to identify the demand equation[8]. This is enhanced by underidentification and weak identification tests' results, which are given in table 4.19 in the appendix. The coefficient of price is at -0.0210 meaning that on average, taking into account other factors, an increase by 1€/MWh of price would lead to a decrease by $21MW$ of quantity demanded on wholesale electricity market. The elasticities of demand by price are equivalent to -0.15 in short-term and -0.31 in long-term [9].

The coefficient of temperature is negative as expected and is at -0.130 meaning that all other things being equal, a decrease by 1 degree of temperature would lead to an increase by 130 MW on average of quantity demanded for electricity traded on wholesale market, which is relatively high level in Europe. The daylength, on the other hand, is not resulted significantly, meaning that the length of the day does not have significant impact on the electricity consumption in France. The coefficients associated with seasons dummies have negative signs though statistically insignificant for summer and fall[10] as electricity demand is supposed to be higher on average in winter. The coefficient of holidays (including weekend) is negatively significant as expected. On average, prices are at 0.249 €/MWh lower on weekend and holidays than on weekdays.

The coefficient of interacted term $Price * Temperature$ is also significant and positive at 0.002. The implications of this specification are as follows: The effect of prices on quantity demanded now depends on temperature, and vice versa, the impact of a change in temperature on demand now depends on prices. Because the parameter associated with $P * Temp$ is positive, the

[8]Note that prices and quantity that we obtain are equilibrium points, i.e; when we conduct a simple OLS regression of quantity on price, we do not know whether we are tracing demand or supply equation. The results of such a regression are completely biased because price is strictly endogenous. We have tested this by conducting a simple OLS regression without instrumental variable method for equation (3.19) and the results show that price's coefficient is positively insignificant.

[9]The elasticity of demand by price is obtained by $\alpha_P \frac{\bar{P}}{\bar{Q}}$ in short term and $\theta_P \frac{\bar{P}}{\bar{Q}}$ in long term (equation (3.12)

[10]The insignificance of seasonal dummies (summer and fall) can be explained by the fact that Daylength, which represents the similar effects on electricity demand, is also included in the regression.

higher temperature the lower will be the fall attributable to a change in prices; i.e, when temperature increases, the negative effect of price on demand is less evident. Similarly, as prices increase, the value of the partial derivative of Q on $Temp$ increases, the negative impact of temperature on demand declines. The inclusion of interacted term is also of great importance to identify the supply relation as discussed in the previous section.

Based on results of the demand function, we are generating Q^*_{ht} using equation (3.13):

$$Q^*_{ht} = \frac{Q_{ht}}{-0.021 + 0.002 * Temp_{ht}} \tag{4.5}$$

We use (4.5) as an endogenous regressors in the supply relationship to reveal the existence of market power.

Supply estimation

The second stage GMM estimation results for the supply relations with panel dataset are reported in table 4.2. The parameter estimates are also generally significant and with expected signs except for gas and carbon price.

The coefficients associated with forecasted load variable are significantly positive for both *Load* and $Load^2$ terms. The autoregressive terms AR(1-7) are also generally significant and positive. The coefficient associated with capacity margin is negatively significant as expected: when the margin is large, less costly generation plants are mobilized resulting in low system marginal costs and spot prices. The coefficients estimated for forecasted balance of exchanges between French and the neighbouring markets are also statistically significant with positive sign for German and Belgian borders and negative for Spain and Italy borders. This is because electricity prices in French wholesale market seemed to be convergent with those of Germany and Belgium during the examined period, an increase in trade balance with these markets would lead to an increase in prices. On the other hand, in Spain or Italy, where electricity is mostly produced from expensive fossil fuels (coal and gas)[11], any increase in imports from those markets (decrease in exchange balance) would lead to an increase in prices in France.

[11] In Spain, wind generation accounts for 16% of total electricity balance.

Table 4.2: Panel data model - Supply Equation

Variable	coef	Robust Std.Err	z-stat	Prob.	[95% Conf.	Interval]
Q^*	1.33e-05*	-7.46E-06	1.787	0.0871	-2.10E-06	2.88E-05
Load	0.346***	-0.051	6.797	0.0000	0.241	0.452
$Load^2$	0.00130***	-0.000309	4.192	0.0003	0.000657	0.00194
Price (-1)	0.276***	-0.0287	9.623	0.0000	0.216	0.335
Price (-2)	0.0783***	-0.0155	5.066	0.0000	0.0463	0.11
Price (-3)	0.0603***	-0.00987	6.106	0.0000	0.0399	0.0807
Price (-4)	0.0533***	-0.0082	6.498	0.0000	0.0363	0.0703
Price (-5)	0.00692	-0.0106	0.652	0.5210	-0.015	0.0289
Price (-6)	0.0350***	-0.00999	3.5	0.0019	0.0143	0.0556
Price (-7)	0.115***	-0.0202	5.683	0.0000	0.0732	0.157
Gas price	0.142	-0.116	1.226	0.2330	-0.0974	0.381
Margin	-0.629***	-0.0569	-11.05	0.0000	-0.747	-0.511
Carbon	-0.0241	-0.0191	-1.259	0.2210	-0.0636	0.0155
EX Germany	0.180***	-0.0625	2.879	0.0085	0.0507	0.309
EX Italy	-1.887***	-0.302	-6.239	0.0000	-2.513	-1.261
EX Spain	-0.960***	-0.233	-4.123	0.0004	-1.442	-0.478
EX Belgium	0.278***	-0.0814	3.409	0.0024	0.109	0.446
Holidays	-6.935***	-1.546	-4.486	0.0002	-10.13	-3.737
Summer	7.007***	-0.358	19.57	0.0000	6.267	7.748
Spring	5.341***	-0.28	19.09	0.0000	4.763	5.92
Fall	7.715***	-0.379	20.37	0.0000	6.931	8.498

$***p < 0.01, **p < 0.05, *p < 0.1$. Robust standard errors in parentheses

The estimated coefficient of gas price is not statistically significant, which is not a big suprise. As shown in figure 3.8, the share of gas generation technology accounts for a very small part in the total annual marginality duration in France. The impact of marginality of gas plants on electricity prices in France is captured mostly through exchanges with neighbouring countries like the UK, Italy or Belgium where gas represents a large share in the technology mix. Furthermore, due to the high gas prices and relatively low coal price in Europe, many of gas plants have been shutdown, which partly explains the non-significance of gas price's coefficient.

The coefficient estimate for carbon price is also showed insignificant. Indeed, we are studying the period of 2009-2012, where carbon market is at the second phase and carbon price has significantly driven down to the absurdly low level, at around 2.5€/ton of CO2 at the end of period because of many economic and political reasons [12]. Thus the relationship between CO2 price and electricity price seems to be not evident during the examined period, as also found in Solier and Jouvet [2013].

Finally and most importantly, the coefficient associated to $Q*$ is significantly only at 10 %, and is very close to zero (1.33.e-05) suggesting that on average we find no market power in the electricity market in France. We are discussing this result in detail in section 4.3.3.

4.3.2 Multivariate time series models

Demand estimation

The second stage GMM estimation results for the demand equations for each hour is briefly reported in table 4.3 [13]. The parameter estimates are also highly significant and with expected signs for every hour.

[12] For those who are interested in the discussion about the collapse of carbon market in Europe, see for example De Perthuis et Jouvet (2012).

[13] We are reporting only the coefficients and statistics associated with price, temperature, the interact term, daylength and the autoregressive term

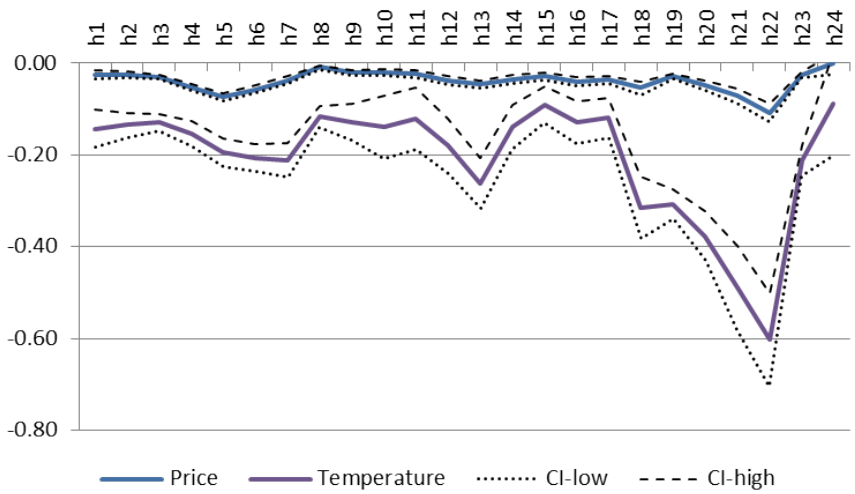
Table 4.3: Demand Estimates

	Price		Temperature		$P*Temp$		Daylength		Turnover(-1)	
h1	-0.0246***	(0.00481)	-0.143***	(0.0206)	0.00266***	(0.000438)	0.00884	(0.00965)	0.531***	(0.00452)
h2	-0.0251***	(0.00336)	-0.135***	(0.0139)	0.00271***	(0.000290)	0.0170*	(0.00920)	0.514***	(0.00567)
h3	-0.0296***	(0.00261)	-0.129***	(0.00975)	0.00320***	(0.000227)	0.0261***	(0.00700)	0.534***	(0.00532)
h4	-0.0529***	(0.00384)	-0.153***	(0.0138)	0.00526***	(0.000330)	0.0220**	(0.0103)	0.536***	(0.00704)
h5	-0.0736***	(0.00414)	-0.195***	(0.0153)	0.00708***	(0.000385)	0.0279**	(0.0111)	0.550***	(0.00643)
h6	-0.0574***	(0.00407)	-0.206***	(0.0147)	0.00584***	(0.000352)	0.0563***	(0.00939)	0.550***	(0.00857)
h7	-0.0371***	(0.00440)	-0.211***	(0.0185)	0.00476***	(0.000368)	0.0445***	(0.00945)	0.494***	(0.00711)
h8	-0.00912***	(0.00197)	-0.117***	(0.0122)	0.00185***	(0.000196)	-0.000641	(0.0104)	0.488***	(0.00838)
h9	-0.0207***	(0.00265)	-0.128***	(0.0201)	0.00202***	(0.000305)	-0.0312**	(0.0151)	0.426***	(0.0111)
h10	-0.0198***	(0.00309)	-0.139***	(0.0345)	0.00157***	(0.000514)	-0.0110	(0.0119)	0.000439***	(1.02e-05)
h11	-0.0227***	(0.00407)	-0.120***	(0.0338)	0.00114**	(0.000510)	0.00589	(0.0115)	0.455***	(0.00725)
h12	-0.0372***	(0.00492)	-0.180***	(0.0306)	0.00206***	(0.000466)	0.0221*	(0.0115)	0.458***	(0.00739)
h13	-0.0468***	(0.00443)	-0.262***	(0.0275)	0.00376***	(0.000404)	0.0104	(0.0136)	0.438***	(0.00581)
h14	-0.0359***	(0.00494)	-0.140***	(0.0244)	0.00198***	(0.000407)	-0.0108	(0.0114)	0.452***	(0.00849)
h15	-0.0280***	(0.00395)	-0.0900***	(0.0201)	0.00129***	(0.000347)	-0.0249**	(0.0105)	0.471***	(0.00850)
h16	-0.0404***	(0.00520)	-0.130***	(0.0235)	0.00221***	(0.000436)	-0.0702***	(0.0117)	0.492***	(0.00970)
h17	-0.0369***	(0.00444)	-0.119***	(0.0222)	0.00208***	(0.000394)	-0.105***	(0.0123)	0.522***	(0.00812)
h18	-0.0544***	(0.00749)	-0.314***	(0.0341)	0.00537***	(0.000505)	-0.0272	(0.0173)	0.489***	(0.0102)
h19	-0.0287***	(0.00311)	-0.308***	(0.0162)	0.00454***	(0.000213)	0.0750***	(0.0163)	0.415***	(0.00551)
h20	-0.0490***	(0.00506)	-0.377***	(0.0271)	0.00534***	(0.000359)	0.0936***	(0.0174)	0.412***	(0.00896)
h21	-0.0718***	(0.00784)	-0.489***	(0.0461)	0.00729***	(0.000690)	0.111***	(0.0194)	0.491***	(0.00888)
h22	-0.109***	(0.00966)	-0.603***	(0.0516)	0.0100***	(0.000823)	0.127***	(0.0249)	0.487***	(0.00838)
h23	-0.0252***	(0.00339)	-0.212***	(0.0168)	0.00338***	(0.000282)	-0.0345***	(0.0111)	0.481***	(0.00603)
h24	-0.00155	(0.0112)	-0.0892	(0.0567)	0.00142	(0.00109)	-0.0491**	(0.0232)	0.493***	(0.0256)

Standard errors (HAC Newey-West) are in parentheses
***/significant at a 1% level, **/significant at a 5% level, and */significant at a 10% level

The coefficients associated with price and temperature have negative sign and vary from one hour to another. As figure 4.5 shows, quantity of electricity demanded is more sensitive with temperature during the night peak from 6.pm to 10.pm. For example, with all other things being equal, at 10.pm a decrease by 1 degree of temperature would lead to an increase by 0.6 GW on average of quantity demanded for electricity traded on wholesale market. The impacts of price on wholesale demand stay at relatively low level.

Figure 4.5: Negative impacts of Price and Temperature on Quantity



Based on results of the demand functions, we are generating Q_t^{h*} for each hour using equation (3.13) and use this as an endogenous regressors in the supply relationship to identify the existence of market power.

Supply estimation

The second stage GMM estimation results for the supply relations for each hour is briefly reported in table 4.4 [14]. The parameter estimates are also generally significant and with expected signs except for gas and carbon price. This result corresponds with what we found for panel data-set.

Table 4.5 presents estimates for the market power parameters $\lambda^{(h)}$ across hous of the day. They are found either statistically insignificant or positively significant at the usual levels except for hours 5, 8, 9, 11, 12, 22 and 24,

[14] We are reporting only the coefficients and statistics associated with Load, Q^*, carbon and gas price, border exchanges and omitting the results on AR terms and seasonal dummies

Table 4.4a: Supply Estimates

	h1	h2	h3	h4	h5	h6	h7	h8
Q^*	-0.000365	0.000481	3.99e-08	0.00251	-0.00569**	-7.92e-06	0.00222	-0.00193**
	(0.000373)	(0.000465)	(2.98e-08)	(0.00205)	-0.00274	(9.19e-05)	(0.00189)	(0.000879)
Load	0.272***	0.365***	0.363***	0.378***	0.708***	0.270***	0.257***	0.399***
	(0.0562)	(0.0510)	(0.0362)	(0.0606)	(0.128)	(0.0377)	(0.0306)	(0.0738)
Carbon price	0.0420	-0.0144	-0.0322	-0.153***	0.143**	-0.0466	-0.160**	0.0438
	(0.0526)	(0.104)	(0.0935)	(0.0537)	(0.0700)	(0.0642)	(0.0769)	(0.136)
Gas price	-0.171	-0.394*	-0.892**	-1.710***	0.411	-0.558	1.488***	-0.954*
	(0.129)	(0.205)	(0.423)	(0.481)	(0.901)	(0.454)	(0.527)	(0.524)
Capacity margin	-0.421***	-0.479***	-0.725***	-0.546***	0.00528	-0.544***	-1.061***	-0.764***
	(0.0716)	(0.0844)	(0.104)	(0.0960)	(0.249)	(0.0940)	(0.137)	(0.139)
EX Germany	-0.358***	0.112	0.602***	0.749***	1.050**	0.221	0.276**	-0.00654
	(0.119)	(0.114)	(0.125)	(0.241)	(0.436)	(0.155)	(0.139)	(0.176)
EE Italy	-0.311	-0.00318	-0.0705	0.736	-0.427	-0.533*	-0.925***	-2.756***
	(0.257)	(0.311)	(0.233)	(0.673)	(0.601)	(0.313)	(0.317)	(0.412)
EX Spain	-0.940***	-0.626**	-0.182	-0.243	1.463**	-0.287	0.106	-1.523***
	(0.246)	(0.280)	(0.414)	(0.503)	(0.626)	(0.263)	(0.274)	(0.387)
EX Belgium	0.216	0.298	0.656	0.571	1.570***	0.411**	0.119	0.348
	(0.506)	(0.579)	(0.593)	(0.456)	(0.509)	(0.207)	(0.415)	(0.734)

	h9	h10	h11	h12	h13	h14	h15	h16
Q^*	-0.00683**	0.00525***	-0.00621***	-0.00344*	-0.0109	-0.000322	-0.000174	-0.00111
	(0.00320)	(0.00116)	(0.00227)	(0.00192)	(0.0108)	(0.000686)	(0.000146)	(0.000826)
Load	1.185***	1.327***	1.157***	1.009***	0.388***	0.246***	0.262***	0.319***
	(0.265)	(0.187)	(0.194)	(0.276)	(0.0698)	(0.0470)	(0.0297)	(0.0267)
Carbon price	2.257**	-0.672	-0.228	0.504	0.345	0.0365	0.0750	0.0297
	(0.905)	(0.415)	(0.379)	(0.396)	(0.228)	(0.0388)	(0.0540)	(0.0376)
Gas price	12.61***	6.445***	-4.414	2.913*	2.731**	0.800***	1.357***	1.524***
	(3.368)	(2.238)	(2.788)	(1.582)	(1.334)	(0.255)	(0.297)	(0.455)
Capacity margin	-2.677***	-2.097***	-2.001***	-1.872***	-0.104	-0.663***	-0.680***	-0.700***
	(0.428)	(0.297)	(0.547)	(0.515)	(1.667)	(0.0843)	(0.0666)	(0.137)
EX Germany	-5.078***	-1.073	1.287	-0.420	-3.883	0.00885	-0.119	0.0373
	(1.899)	(1.085)	(0.831)	(1.120)	(4.276)	(0.0963)	(0.120)	(0.121)
EE Italy	-12.47***	-10.73***	-15.50***	-8.822***	2.530	-1.605***	-1.395***	-1.799***
	(3.051)	(2.218)	(3.638)	(1.603)	(4.880)	(0.328)	(0.333)	(0.317)
EX Spain	-0.0641	-5.192	-2.925	0.652	1.053	-1.046***	-0.972**	-0.665***
	(2.366)	(3.505)	(4.264)	(4.791)	(3.191)	(0.255)	(0.394)	(0.235)
EX Belgium	8.897***	-1.324	-3.118*	-3.439***	-0.867	-0.0528	0.0832	0.173
	(2.690)	(0.874)	(1.751)	(0.740)	(0.906)	(0.318)	(0.269)	(0.300)

	h17	h18	h19	h20	h21	h22	h23	h24
Q^*	0.000949*	0.000741	-0.00270	0.00265	0.000209***	-3.96e-07**	0.00124**	-0.0190**
	(0.000516)	(0.00220)	(0.00326)	(0.00570)	(7.39e-05)	(1.94e-07)	(0.000540)	(0.00933)
Load	0.282***	0.371***	0.560***	0.475**	0.245***	0.239***	0.280***	0.593***
	(0.0384)	(0.0340)	(0.0759)	(0.233)	(0.0312)	(0.0242)	(0.0307)	(0.206)
Carbon price	0.0843***	0.0278	-0.0459	-0.167	0.0709	0.0179	-0.139**	-0.125
	(0.0321)	(0.0452)	(0.0964)	(0.150)	(0.0514)	(0.0574)	(0.0561)	(0.182)
Gas price	1.405***	1.018***	1.698**	0.922**	0.0689	1.043***	0.373	0.970
	(0.302)	(0.278)	(0.693)	(0.424)	(0.146)	(0.352)	(0.366)	(0.968)
Capacity margin	-0.599***	-0.613***	-0.943***	-0.776***	-0.667***	-0.395***	-0.238***	-0.244
	(0.0481)	(0.0527)	(0.0838)	(0.140)	(0.137)	(0.0791)	(0.0681)	(0.170)
EX Germany	-0.0667	0.104	0.362	0.486	-0.147	0.0527	0.0440	-0.158
	(0.0805)	(0.141)	(0.419)	(0.681)	(0.111)	(0.108)	(0.120)	(0.171)
EE Italy	-1.453***	-1.830***	-3.132***	-1.539***	-0.864***	-1.104***	-0.382	2.066
	(0.277)	(0.310)	(0.687)	(0.420)	(0.218)	(0.250)	(0.303)	(1.523)
EX Spain	-1.288**	-1.138***	-1.716***	-2.827***	-1.069**	-1.979***	-1.204***	1.392*
	(0.640)	(0.364)	(0.244)	(0.457)	(0.465)	(0.248)	(0.388)	(0.830)
EX Belgium	0.861***	0.649***	0.723	-0.513	1.077***	0.662**	-0.187	0.638
	(0.244)	(0.208)	(0.630)	(0.668)	(0.345)	(0.282)	(0.216)	(0.477)

Standard errors (HAC Newey-West) are in parentheses
***/significant at a 1% level, **/significant at a 5% level, and * significant at a 10% level

which are negatively significant. However, the estimates for those hours stay at relatively low level.

Table 4.5: Estimates for the market power parameters across hours

λ	Estimate	HAC(N-W)
λ^{h1}	-0.000365	(0.000373)
λ^{h2}	0.000481	(0.000465)
λ^{h3}	3.99e-08	(2.98e-08)
λ^{h4}	0.00251	(0.00205)
λ^{h5}	-0.00569**	(0.00274)
λ^{h6}	-7.92e-06	(9.19e-05)
λ^{h7}	0.00222	(0.00189)
λ^{h8}	-0.00193**	(0.000879)
λ^{h9}	-0.00683**	(0.00320)
λ^{h10}	0.00525***	(0.00116)
λ^{h11}	-0.00621***	(0.00227)
λ^{h12}	-0.00344*	(0.00192)
λ^{h13}	-0.0109	(0.0108)
λ^{h14}	-0.000322	(0.000686)
λ^{h15}	-0.000174	(0.000146)
λ^{h16}	-0.00111	(0.000826)
λ^{h17}	0.000949*	(0.000516)
λ^{h18}	0.000741	(0.00220)
λ^{h19}	-0.00270	(0.00326)
λ^{h20}	0.00265	(0.00570)
λ^{h21}	0.000209***	(7.39e-05)
λ^{h22}	-3.96e-07**	(1.94e-07)
λ^{h23}	0.00124**	(0.000540)
λ^{h24}	-0.0190**	(0.00933)

Standard errors (HAC Newey-West) are in parentheses
***/significant at a 1% level, **/significant at a 5% level, and * significant at a 10% level

Price cost margins can be estimated for the hours with negative coefficents[15], the results are given in table 4.6. The very low level of Lerner indexes suggest that no market power has been excercised over the sample period.

[15]Price-cost margin $P - MC = -\lambda.Q/\frac{\partial Q(.)}{\partial P}$. The Lerner's measure is:$L \equiv \frac{P-MC}{P} = -\lambda\frac{Q}{P}\frac{\partial Q(.)}{\partial P} = -\frac{\lambda}{\varepsilon}$ where ε is the market elasticity of demand.

Table 4.6: Lerner index across hours

	LI-h5	LI-h8	LI-h9	LI-h11	LI-h22
Short term	0.01963641	0.02803341	0.04188475	0.01715386	4.7438E-07
Long term	0.0446282	0.03467772	0.02644286	0.01000519	8.7443E-07

4.3.3 Discussion

Despites of some doubts arose about the performance of wholesale electricity market in France, the model-based result suggesting the non-existence of market power is not really surprising. In fact, there are several economic arguments to justify this finding.

There is indeed a correlation between a very high level of market concentration and the presence of market power exercise in the industrial organization theory. It would be even clearer in electricity market since the elasticities of demand by prices are normally at very low levels. However, applying this in French power market would not be appropriate. In fact, the total volume of electricity traded in wholesale market, though increasing since 2005, represents as small as 17% of the total electricity produced and sold in France. More importantly, the wholesale market is extremely regulated with the co-existence of market price and regulated tariff (ARENH price in wholesale market). The ARENH price was set by the French government at 42 €/MWh, which is relatively high. During the examined period, the frequency of spot prices observed in the wholesale market to be lower than 42 €/MWh is up to 40%. The alternative suppliers might sometimes prefer to buy electricity at the spot prices rather than regulated tariff. To make the long story short, as long as "market" comprises about only 17% of domestic delivery, the interconnexion with neighbouring markets is increasingly strong, and prices in the spot market stay strictly regulated, it is extremely hard for an incumbent to exercise its market power even if it possesses one.

Another observation is that Electricité de France (EDF), the incumbent in France and also the biggest producer of electric power in Europe, does not have incentives to exercise its market power because the possible gains from doing this would fall far behind the risks of being broken up the monopoly by the competition authorities. The high prices observed in French spot market

since 2005 could be possibly explained by a number of exogenous reasons but hardly by market power abuse. Indeed, the trend of increased electricity price has been common in many power markets in Europe in the last decade because of many dramatic changes: the implication of carbon price since 2005, the global economic crisis in 2008 pushing up the fuel costs to the highest level in the history, the catastrophe of Fukushima in Japan in 2011 adding burden to the costs of nuclear technology, the continuous political turbulence in Arabs countries followed by the increase of fuel prices, ect.

The doubts provoked on French spot prices due to the growingly divergence with German spot prices could be justified by the increasing share of renewable power generation in the German electricity portfolio. In fact, the next day of Fukushima nuclear accident, the German government decided to accelerate the phase-out of nuclear fleet by 2022, starting with the immediate closure of the eight oldest nuclear plants. Although fossil fuels fired energy has to put in place during the transitional period, renewable electricity generation is being considered as cornerstone of current and future energy supply. In Germany, a lot of support schemes for the development of renewable electricity generation have been put in place. Over the last ten years, the installed wind turbine capacity in Germany has increased with a factor of 5, from 6 GW in 2000 to 31.3 GW in 2012, and that of photovoltaic has raised from only 100 MW in 2000 up to 32.6 GW in 2012. The massive integration of renewable into electricity system creates a reduction effect (or merit-order effect) on German spot prices because this type of energy is bided zero in the merit order. This would be the reason why price divergence between France and Germany has been increasing despite a strong interconnected network.

It is important to note that our analyses have been done ex-post with historical data (2009-2012). During these years, there has been an excess capacity at European level with the exception of certain areas such as southern Germany, according to a report of Commissariat général à la stratégie et à la prospective[16] (CGSP [2014]). The total installed capacity during this period was at about 128 GW while the peak demand was observed at only 102.1 GW (Bayer [2015]). In the context of overcapacity, it seems to be unprofitable for

[16] A French institution that is responsible for defining the economic planning of the country

the dominant firm to unilateral withhold its capacity, thus exercising market power seems not a gainful strategy.

Another observation that must be taken into account in the discussion is the existence of extreme values of the spot prices in France. These values, which we exclude from our regressions, are specified in table 4.7:

Table 4.7: Extreme outliers of spot prices

Date	h9	h10	h11	h12	h13	h19	h20
19/10/2009	3000	3000	3000	3000	716.033		540.603
09/02/2012	966.898	1785.165	1938.504	999.973	456.699	500	

12 extreme price spikes occurred in two days 19th October 2009 and 9th February 2012 from 9am to 1pm and 7pm to 8pm where peak demand is usually recorded in France. As discussed in previous chapters, a merely high price spike observed in spot market could reveal nothing about the existence of market power abuse. This could happen at any moment of the day due to the inelasticity of both demand and supply. It is extremely hard to distinguish whether an "abnormally" high price is due to "normal" factors or because of market power abuse. When demand exceeds the maximum capacity and transmission constraints make it impossible to import power from neigbouring networks, prices can rise up until the last consumers are willing to pay. But because demand responds so minimally, prices can reach disconcerting high levels as illustrated in figure 1.9. Indeed, price spikes observed in those two days were investigated by the French Energy Regulatory Authority (CRE) through the deliberations on 20 November 2009 and 10 May 2012 respectively (CRE [2009] and CRE [2012]).

The spot market prices remained relatively low during the summer of 2009, at around 35.23 €/MWh, clearly down compared with the previous year at the same period due to the sharp fall in fuel prices since the end of 2008. However, as winter approached with the increase of electricity consumption for heating, prices on the French spot market fluctuated substantially. On Monday 19 October, spot prices reached 3000 €/MWh between 9am and 12am, which was actually the price cap as set within the framework of the EPEX Spot auctions. According to CRE's investigation, there were an enourmous excess of demand during these four hours. The volumes offered for sale were

not sufficient to cover the buying orders, the lack of quantity demanded was nearly 1000 MW on average after the process of trilateral coupling. Indeed, the excess of demand was due to a combination of two factors: an upward RTE's revision of consumption estimates for Monday 19th October (+3000 MW) and a downward revision of the capacity availability for this day (-4100 MW) mainly due to unplanned outages of nuclear plants and of the Grand-Maison hydroelectric plant, which was put back in service at the end of 18th October. There was no evidence of unilateral withholding of capacity according to the CRE's report. A request was made by the CRE to the Union Française de l'Électricité (UFE) about the reinforcement of the transparence on publications of unplanned outages for each plant.

Extreme price spikes occurred again on Thursday, 9 February 2012 where hourly spot prices approached 1000 €/MWh from 9am to 1pm and 500 €/MWh at 7pm. The report of CRE suggests that during these hours, there was no evidence of unilateral withholding: the availability of nuclear power was 58.5 GW on 9 February, compared to an average of 58.9 GW from 1 to 13 February, which corresponds to an availability rate of 93%. The publication of forecast availability data and unplanned outages complied with the transparency process implemented. However, the consumption levels broke the record during this period with the levels higher than 100 GW. On 8 February, the day before the price spike, consumption was at its highest, reaching 102.1 GW at the evening peak. It is important to note that these extremely high prices occurred within a specific climate context: from 1 to 13 February, France, and Europe in general, experienced a cold snap with temperatures much lower than seasonal averages. Though only France recorded such high prices on the electricity spot market, it is indeed the most sensitive to changes in temperature in Europe (See figure 3.6). In this context, demand would have been met by cross border exchanges. However, except Italy and Switzerland, all the interconnections within the framework of market coupling were saturated. To sum up, the tension between supply and demand, rather than market power abuse, explained the formation of high prices on those two days. These high prices, as discussed in section 1.3.2, are always within the marginal cost curve (the cost of producing one more unit, even infinitesimal). They reflect the tension between supply and demand, and create very high short-run profits (scarcity rent) for

all suppliers, allowing them to recover their fixed costs without exercising their market power (Stoft [2003]).

Conclusion

The ongoing reorganization of the French electricity market will lead to an increasing volume of trade on the wholesale market. This being the case, studying the performance of electricity spot markets is a key issue for both academics and regulators. In this chapter, we employ a structural model developed in New Empirical Industrial Organization (NEIO) to investigate the presence of market power abuse in the French wholesale electricity market during 2009-2012. We consider both multivariate data model and panel data framework. The model-based results suggest that on average, no market power has been exercised during the examined period. Although market power is found statistically significant in several peak-load hours, it stays at very low level. There are many economic justifications to support this conclusion. Indeed, as long as "market" comprises a very small part of domestic delivery (17%), the interconnexion with neighbouring markets is increasignly strong in the context of market coupling contracts, and prices in the spot market stay strictly regulated, it is very hard for an incumbent to exercise its market power even if it possesses one.

Indeed, the price of electricity in France is lower than the average level of Europe. However, this difference reflects less and less the advantage from the "nuclear choice" made in the past, but more and more a good will to protect consumers from the tensions of actual energy world (Geoffron and Chevalier [2012]). Although no market power is exercised, the price system in France with the overlap of different prices and regulated tariff seems now to become too far to be able to send the right signals to investors and consumers.

The results of this chapter also confirm that there is little evidence of correlation between market concentration and market power abuse. Among countries which liberalized their electricity markets in Europe, France follows a market structure which is the most concentrated with one dominant firm, EDF, controlling almost entire domestic market (with the exception of Belgium). The idea of "big one" producing bad performance is unjustifiable in the case of French wholesale market. In the next chapter, we carry out an analysis of market power in German wholesale market which is characterized by an oligopolistic structure.

Appendix

Unit Root Tests

Table 4.8: Unit root tests on price series
Im, Pesaran and Shin Unit root tests on individual price series

Series	t-Stat	Prob.	Lag
Price h1	-5.1857	0.0000	13
Price h2	-5.0947	0.0000	13
Price h3	-4.8934	0.0000	13
Price h4	-6.3565	0.0000	7
Price h5	-5.9016	0.0000	7
Price h6	-3.8446	0.0026	21
Price h7	-4.0038	0.0014	21
Price h8	-4.7149	0.0001	22
Price h9	-36.2140	0.0000	0
Price h10	-33.8350	0.0000	0
Price h11	-16.6310	0.0000	2
Price h12	-36.3950	0.0000	0
Price h13	-9.4036	0.0000	6
Price h14	-5.1363	0.0000	22
Price h15	-5.1081	0.0000	22
Price h16	-4.9799	0.0000	22
Price h17	-4.3806	0.0003	21
Price h18	-3.7407	0.0037	21
Price h19	-5.1507	0.0000	13
Price h20	-6.1523	0.0000	6
Price h21	-3.6991	0.0042	21
Price h22	-5.3429	0.0000	13
Price h23	-7.9039	0.0000	2
Price h24	-7.7361	0.0000	2

Panel unit root test: Summary			
Method	Statistic	Prob.	Cross- sections
Im-Pesaran-Shin	-14.4675	0.0000	24
ADF - Fisher	322.276	0.0000	24
PP - Fisher	5977.54	0.0000	24

Automatic lag length selection based on Akaike information criterion.

Table 4.9: Unit root tests on Load series

Im, Pesaran and Shin Unit root tests on individual price series

Series	t-Stat	Prob.	Lag
Load h1	-2.9243	0.0428	21
Load h2	-2.7287	0.0694	22
Load h3	-2.7713	0.0627	23
Load h4	-2.7893	0.06	23
Load h5	-2.7398	0.0676	22
Load h6	-2.7435	0.067	22
Load h7	-2.7893	0.06	21
Load h8	-2.7531	0.0655	22
Load h9	-2.7965	0.059	22
Load h10	-2.8638	0.0499	22
Load h11	-2.9421	0.0409	22
Load h12	-3.0255	0.0328	22
Load h13	-3.0455	0.0311	22
Load h14	-3.0464	0.031	22
Load h15	-3.0887	0.0276	22
Load h16	-3.1513	0.0232	22
Load h17	-3.1684	0.0221	22
Load h18	-3.0933	0.0273	22
Load h19	-3.0099	0.0342	22
Load h20	-2.8736	0.0487	22
Load h21	-2.7847	0.0607	22
Load h22	-2.8572	0.0508	21
Load h23	-3.0162	0.0337	21
Load h24	-3.0292	0.0325	21

Panel unit root test: Summary				
Method	Statistic	Prob.	Cross- sections	
Im-Pesaran-Shin	-4.02343	0.0000	24	33432
ADF - Fisher	74.66	0.0082	24	33432
PP - Fisher	1907.83	0.0000	24	34944

Automatic lag length selection based on Akaike information criterion.

Table 4.10: Unit root tests on Turnover series

Im, Pesaran and Shin Unit root tests on individual price series

Series	t-Stat	Prob.	Lag
Turnover h1	-6.1182	0.0000	8
Turnover h2	-6.2282	0.0000	6
Turnover h3	-6.3046	0.0000	6
Turnover h4	-6.9403	0.0000	6
Turnover h5	-6.9184	0.0000	6
Turnover h6	-6.7301	0.0000	6
Turnover h7	-6.1964	0.0000	11
Turnover h8	-3.9345	0.0019	21
Turnover h9	-4.3709	0.0003	20
Turnover h10	-4.3228	0.0004	21
Turnover h11	-4.4374	0.0003	21
Turnover h12	-4.7228	0.0001	22
Turnover h13	-4.5839	0.0001	22
Turnover h14	-4.4556	0.0002	21
Turnover h15	-4.4564	0.0002	21
Turnover h16	-3.907	0.0020	21
Turnover h17	-3.7145	0.0040	22
Turnover h18	-3.8672	0.0024	22
Turnover h19	-4.4366	0.0003	14
Turnover h20	-4.0147	0.0014	20
Turnover h21	-3.8904	0.0022	21
Turnover h22	-5.8634	0.0000	6
Turnover h23	-6.4986	0.0000	6
Turnover h24	-5.9117	0.0000	9

Panel unit root test: Summary			
Method	Statistic	Prob.	Cross- sections
Im-Pesaran-Shin	-20.9235	0.0000	24
ADF - Fisher	577.09	0.0000	24
PP - Fisher	6321.38	0.0000	24

Automatic lag length selection based on Akaike information criterion.

Table 4.11: Unit root tests on series of Exchanges with Germany

Im, Pesaran and Shin Unit root tests on individual price series

Series	t-Stat	Prob.	Lag
EX Germany h1	-3.1239	0.0251	20
EX Germany h2	-3.1578	0.0228	20
EX Germany h3	-3.23	0.0185	20
EX Germany h4	-3.4967	0.0082	20
EX Germany h5	-4.6463	0.0001	15
EX Germany h6	-3.602	0.0059	20
EX Germany h7	-3.302	0.015	20
EX Germany h8	-3.2009	0.0202	20
EX Germany h9	-3.4486	0.0096	20
EX Germany h10	-3.6813	0.0045	20
EX Germany h11	-3.8964	0.0021	20
EX Germany h12	-4.1072	0.001	20
EX Germany h13	-4.3273	0.0004	20
EX Germany h14	-4.3024	0.0005	20
EX Germany h15	-4.2215	0.0006	20
EX Germany h16	-4.0304	0.0013	20
EX Germany h17	-3.7713	0.0033	20
EX Germany h18	-3.7357	0.0037	20
EX Germany h19	-3.2811	0.016	20
EX Germany h20	-3.0759	0.0286	20
EX Germany h21	-3.0596	0.0299	19
EX Germany h22	-3.0116	0.0341	20
EX Germany h23	-3.347	0.0131	20
EX Germany h24	-3.3248	0.014	20

Panel unit root test: Summary			
Method	Statistic	Prob.	Cross- sections
Im-Pesaran-Shin	-10.7343	0.0000	24
ADF - Fisher	222.611	0.0000	24
PP - Fisher	5938.78	0.0000	24

Automatic lag length selection based on Akaike information criterion.

Table 4.12: Unit root tests on series of Exchanges with Italy

Im, Pesaran and Shin Unit root tests on individual price series

Series	t-Stat	Prob.	Lag
EX Italy h1	-5.5241	0	14
EX Italy h2	-5.6946	0	14
EX Italy h3	-5.7282	0	14
EX Italy h4	-5.3625	0	14
EX Italy h5	-4.9865	0	21
EX Italy h6	-5.1297	0	21
EX Italy h7	-5.5768	0	14
EX Italy h8	-5.4111	0	21
EX Italy h9	-6.0771	0	14
EX Italy h10	-5.4346	0	21
EX Italy h11	-5.386	0	21
EX Italy h12	-5.3946	0	21
EX Italy h13	-5.4186	0	21
EX Italy h14	-5.3697	0	21
EX Italy h15	-5.1593	0	21
EX Italy h16	-4.9634	0	21
EX Italy h17	-4.8829	0	21
EX Italy h18	-5.0231	0	21
EX Italy h19	-5.8994	0	14
EX Italy h20	-5.2655	0	21
EX Italy h21	-5.0292	0	21
EX Italy h22	-4.842	0	21
EX Italy h23	-5.315	0	21
EX Italy h24	-5.5912	0	15

Panel unit root test: Summary

Method	Statistic	Prob.	Cross- sections
Im-Pesaran-Shin	-21.5828	0.0000	24
ADF - Fisher	571.592	0.0000	24
PP - Fisher	5464.12	0.0000	24

Automatic lag length selection based on Akaike information criterion.

Table 4.13: Unit root tests on series of Exchanges with Belgium

Im, Pesaran and Shin Unit root tests on individual price series

Series	t-Stat	Prob.	Lag	Lag	Obs
EX Belgium h1	-3.5161	0.0118	21	23	1437
EX Belgium h2	-3.1975	0.0204	13	23	1445
EX Belgium h3	-3.1352	0.0243	18	23	1440
EX Belgium h4	-3.4819	0.0086	13	23	1445
EX Belgium h5	-3.1578	0.0228	20	23	1438
EX Belgium h6	-2.9626	0.0388	20	23	1438
EX Belgium h7	-3.2248	0.0188	20	23	1438
EX Belgium h8	-2.9614	0.0389	22	23	1436
EX Belgium h9	-3.429	0.0102	13	23	1445
EX Belgium h10	-3.3859	0.0116	13	23	1445
EX Belgium h11	-3.5545	0.0068	15	23	1443
EX Belgium h12	-3.5052	0.008	13	23	1445
EX Belgium h13	-2.5992	0.0933	20	23	1438
EX Belgium h14	-2.7325	0.0688	20	23	1438
EX Belgium h15	-3.5155	0.0077	13	23	1445
EX Belgium h16	-3.4425	0.0098	13	23	1445
EX Belgium h17	-3.3435	0.0132	13	23	1445
EX Belgium h18	-3.5231	0.0076	13	23	1445
EX Belgium h19	-2.6683	0.0799	21	23	1437
EX Belgium h20	-2.6536	0.0873	20	23	1438
EX Belgium h21	-2.5544	0.1029	20	23	1438
EX Belgium h22	-3.0608	0.0298	14	23	1444
EX Belgium h23	-2.9341	0.0418	14	23	1444
EX Belgium h24	-2.8743	0.0486	13	20	1430

Panel unit root test: Summary			
Method	Statistic	Prob.	Cross- sections
Im-Pesaran-Shin	-15.2292	0.0000	24
ADF - Fisher	339.749	0.0000	24
PP - Fisher	6292.09	0.0000	24

Automatic lag length selection based on Akaike information criterion.

Table 4.14: Unit root tests on series of Exchanges with Spain

Im, Pesaran and Shin Unit root tests on individual price series

Series	t-Stat	Prob.	Lag
EX Spain h1	-3.7333	0.0038	20
EX Spain h2	-3.9675	0.0016	23
EX Spain h3	-3.9015	0.0021	23
EX Spain h4	-3.9188	0.0020	23
EX Spain h5	-3.7868	0.0031	22
EX Spain h6	-3.9145	0.0020	23
EX Spain h7	-3.8509	0.0025	23
EX Spain h8	-4.4497	0.0002	23
EX Spain h9	-4.7291	0.0001	23
EX Spain h10	-5.1552	0.0000	23
EX Spain h11	-5.2215	0.0000	23
EX Spain h12	-5.2924	0.0000	22
EX Spain h13	-5.1908	0.0000	22
EX Spain h14	-4.9658	0.0000	23
EX Spain h15	-4.9583	0.0000	23
EX Spain h16	-4.923	0.0000	23
EX Spain h17	-5.1904	0.0000	23
EX Spain h18	-4.8979	0.0000	22
EX Spain h19	-4.8035	0.0001	22
EX Spain h20	-4.8191	0.0001	22
EX Spain h21	-4.6803	0.0001	23
EX Spain h22	-3.9466	0.0018	20
EX Spain h23	-3.5955	0.0060	21
EX Spain h24	-3.6176	0.0056	20

Panel unit root test: Summary			
Method	Statistic	Prob.**	Cross- sections
Im-Pesaran-Shin	-15.2515	0.0000	24
ADF - Fisher	344.371	0.0000	24
PP - Fisher	6313.3	0.0000	24

Automatic lag length selection based on Akaike information criterion.

Table 4.15: Unit root tests on temperature series
Im, Pesaran and Shin Unit root tests on individual price series

Series	t-Stat	Prob.	Lag
Temperature h1	-3.2425	0.0179	10
Temperature h2	-3.2594	0.0170	10
Temperature h3	-3.2217	0.0190	10
Temperature h4	-3.2671	0.0166	10
Temperature h5	-2.8037	0.0580	13
Temperature h6	-2.8124	0.0567	13
Temperature h7	-2.8074	0.0574	13
Temperature h8	-2.922	0.0431	12
Temperature h9	-2.9134	0.0440	12
Temperature h10	-3.2475	0.0176	10
Temperature h11	-3.1916	0.0207	10
Temperature h12	-3.1524	0.0231	10
Temperature h13	-3.1402	0.0240	10
Temperature h14	-3.1346	0.0243	10
Temperature h15	-3.1056	0.0264	10
Temperature h16	-3.2312	0.0185	9
Temperature h17	-3.1902	0.0208	9
Temperature h18	-3.1452	0.0236	9
Temperature h19	-3.1502	0.0233	9
Temperature h20	-3.1605	0.0226	9
Temperature h21	-3.1889	0.0209	9
Temperature h22	-3.2522	0.0174	9
Temperature h23	-3.1377	0.0241	10
Temperature h24	-3.1732	0.0218	10

Panel unit root test: Summary

Method	Statistic	Prob.	Cross- sections
Im-Pesaran-Shin	-3.53556	0.0002	24
ADF - Fisher	68.5389	0.0274	24
PP - Fisher	93.6101	0.0001	24

Automatic lag length selection based on Akaike information criterion.

Table 4.16: Unit root tests on gas, carbon price, daylength and margin

	ADF t-Statistic	Prob.	PP t-Statistic	Prob.
Carbon price	-3.310637	0.0146	-3.284036	0.0158
Gas Price	-1.064673	0.7315	-1.021487	0.7475
Daylength	-7.437354	0.0000	-4.194934	0.0000
Capacity margin	-3.178134	0.0215	-28.53151	0.0000

Automatic lag length selection based on Akaike information criterion.

Elasticity of demand

Table 4.17: Elasticity of demand in short term and long term

	Short term	Long term
h1	-0.16756565	-0.35728283
h2	-0.15440626	-0.31770835
h3	-0.15856023	-0.34025801
h4	-0.2240971	-0.48296789
h5	-0.28976784	-0.64392854
h6	-0.27922005	-0.62048901
h7	-0.2283249	-0.45123498
h8	-0.06884642	-0.13446566
h9	-0.16306652	-0.28408802
h10	-0.1713885	-0.17146378
h11	-0.20053799	-0.36795961
h12	-0.32935119	-0.60765902
h13	-0.40033841	-0.71234593
h14	-0.29018634	-0.52953712
h15	-0.21527357	-0.40694436
h16	-0.2865569	-0.56408838
h17	-0.24935928	-0.52167213
h18	-0.39148256	-0.76611068
h19	-0.24133342	-0.41253575
h20	-0.40804549	-0.69395491
h21	-0.58940396	-1.15796456
h22	-0.8347804	-1.62725225
h23	-0.20831308	-0.40137395
h24	-0.01167619	-0.02302997

Postestimation tests

Table 4.18: Summary of first stage regressions of demand functions for 24 hours

	Variable	R-sq.	Adj. R-sq	Robust F-stat	Prob.
h1	Price	0.6212	0.6150	2835.69	0.0000
	Price*Temp	0.8313	0.8285	2738.13	0.0000
h2	Price	0.6778	0.6728	4009.41	0.0000
	Price*Temp	0.8006	0.7975	3120.19	0.0000
h3	Price	0.7111	0.7066	5638.34	0.0000
	Price*Temp	0.7679	0.7642	1934.44	0.0000
h4	Price	0.7267	0.7224	6266.10	0.0000
	Price*Temp	0.7231	0.7188	1487.14	0.0000
h5	Price	0.7234	0.7191	10177.44	0.0000
	Price*Temp	0.7192	0.7148	1222.08	0.0000
h6	Price	0.7306	0.7264	8322.71	0.0000
	Price*Temp	0.7715	0.7679	2084.33	0.0000
h7	Price	0.7667	0.7630	4964.78	0.0000
	Price*Temp	0.8113	0.8084	2489.04	0.0000
h8	Price	0.7674	0.7638	8679.95	0.0000
	Price*Temp	0.8323	0.8297	3821.26	0.0000
h9	Price	0.6556	0.6503	2753.91	0.0000
	Price*Temp	0.8352	0.8327	3423.07	0.0000
h10	Price	0.5442	0.5371	1303.94	0.0000
	Price*Temp	0.8562	0.8540	3993.52	0.0000
h11	Price	0.5469	0.5399	1145.05	0.0000
	Price*Temp	0.8701	0.8681	4299.36	0.0000
h12	Price	0.5249	0.5175	1101.98	0.0000
	Price*Temp	0.8650	0.8629	4841.74	0.0000
h13	Price	0.5716	0.5649	2153.72	0.0000
	Price*Temp	0.8923	0.8906	7313.66	0.0000
h14	Price	0.7391	0.7350	4482.32	0.0000
	Price*Temp	0.9016	0.9001	10960.96	0.0000
h15	Price	0.7357	0.7316	5210.19	0.0000
	Price*Temp	0.8912	0.8895	10496.77	0.0000
h16	Price	0.7355	0.7314	4192.10	0.0000
	Price*Temp	0.8875	0.8858	8825.31	0.0000
h17	Price	0.7570	0.7532	5396.31	0.0000
	Price*Temp	0.8811	0.8793	5010.85	0.0000
h18	Price	0.7877	0.7844	7602.46	0.0000
	Price*Temp	0.8748	0.8728	5416.94	0.0000
h19	Price	0.7812	0.7778	5967.45	0.0000
	Price*Temp	0.8704	0.8684	4093.04	0.0000
h20	Price	0.7020	0.6974	2763.42	0.0000
	Price*Temp	0.8774	0.8755	4242.39	0.0000
h21	Price	0.7097	0.7052	5171.92	0.0000
	Price*Temp	0.9002	0.8986	3469.77	0.0000
h22	Price	0.6248	0.6190	4171.88	0.0000
	Price*Temp	0.9126	0.9113	6545.19	0.0000
h23	Price	0.6143	0.6083	3217.38	0.0000
	Price*Temp	0.9393	0.9384	9436.82	0.0000
h24	Price	0.6609	0.6557	99.43	0.0000
	Price*Temp	0.9284	0.9273	900.30	0.0000

Table 4.19: Summary results for first-stage regressions - Panel Demand Equation

			Underidentification		Weak Identification
Variable	F(8,23)	Prob.	AP Chi-sq	Prob.	AP F(7,23)
Price	167.51	0.0000	210.26	0.0000	28.77
P*Temp	73.59	0.0000	109.22	0.0000	14.95

Table 4.20: Summary results for first-stage regressions - Panel Supply Equation

			Underidentification		Weak Identification
Variable	F(2,23)	Prob.	AP Chi-sq	Prob.	AP F(2,23)
Q*	12.8	0.0000	26.73	0.0000	12.8

Table 4.21: Summary of first stage regressions of supply functions for 24 hours

Variable	R-sq.	Adj. R-sq	Robust F-stat	Prob.
h1	0.0127	0.0019	29.75	0.0000
h2	0.0174	0.0029	45.83	0.0000
h3	0.0278	0.0132	24.95	0.0000
h4	0.0139	0.0006	54.28	0.0000
h5	0.0137	0.0008	29.61	0.0000
h6	0.0205	0.0061	68.93	0.0000
h7	0.0239	0.0095	58.17	0.0000
h8	0.0187	0.0043	34.5	0.0000
h9	0.0099	0.0047	48.77	0.0000
h10	0.0438	0.0297	678.02	0.0000
h11	0.0069	0.0077	30.38	0.0000
h12	0.0099	0.0046	18.28	0.0000
h13	0.0047	0.0099	85.29	0.0000
h14	0.0166	0.0021	93.28	0.0000
h15	0.0157	0.0005	42.48	0.0000
h16	0.026	0.0117	66.22	0.0000
h17	0.0201	0.0057	69.14	0.0000
h18	0.016	0.0016	90.47	0.0000
h19	0.0197	0.0053	49.81	0.0000
h20	0.0179	0.0035	49.28	0.0000
h21	0.0262	0.0119	23.42	0.0000
h22	0.0084	0.0061	4.27	0.0000
h23	0.0157	0.0012	43.75	0.0000
h24	0.0169	0.0025	105.53	0.0000

Table 4.22: Overidentifying tests for GMM-demand and supply regressions

	Demand Regressions		Supply Regressions	
	Hansen's J chi2	Prob.	Hansen's J chi2	Prob.
h1	1.69139	0.9955	1.42966	0.2318
h2	1.84178	0.9855	1.42645	0.2323
h3	1.88251	0.9844	1.53483	0.2154
h4	1.8118	0.9862	1.58024	0.2087
h5	1.8635	0.9849	0.117857	0.7314
h6	1.90913	0.9837	0.315958	0.574
h7	1.92563	0.9832	0.49015	0.4839
h8	1.9112	0.9836	1.61111	0.2043
h9	1.87549	0.9846	1.29932	0.2543
h10	1.89971	0.9839	1.42991	0.2318
h11	1.88988	0.9842	1.54003	0.2146
h12	1.8917	0.9842	1.41558	0.2341
h13	1.90203	0.9839	0.644335	0.4221
h14	1.84198	0.9855	1.13625	0.2864
h15	1.86956	0.9848	1.39286	0.2379
h16	1.90936	0.9837	0.662752	0.4156
h17	1.93162	0.9830	0.063139	0.8016
h18	1.93015	0.9831	0.176069	0.6748
h19	1.85785	0.9851	1.61335	0.204
h20	1.88518	0.9843	1.6103	0.2044
h21	1.92442	0.9832	1.04987	0.3055
h22	1.88338	0.9844	1.04987	0.3055
h23	1.92022	0.9834	0.51538	0.4728
h24	12.4731	0.1313	0.599015	0.439

Chapter 5

Market Power in Germany's Wholesale Electricity Markets in 2011

Abstract: German power market has undergone many fundamental changes in 2011 following the Fukushima nuclear accident in March 2011. Prices on wholesale electricity market in the year of 2011 were at the highest level since mid 2009. The purpose of this chapter is to identify whether market power is responsible for this increase. Following the method of linear programming as commonly used in literature of electricity market modelling, we simulate a competitive benchmark for German wholesale market taking into account power plant characteristics, fuel and CO2-allowance prices and renewables power generation. On the basis of the difference between modeled marginal costs and observed market prices, we estimate the price-cost markups, or the Lerner Indexes across hours.

Introduction

German electricity market is one of the biggest in Europe (in terms of number of consumers and their consumption) and has evolved drastically since the early years of the European liberalization process. Germany has followed the model of vertically integrated oligopoly where four dominant firms controlled over 90% of market share by the beginning of 2001 and approximately 77% at the end of 2011 according to the Federal Cartel Offices monitoring data. This market structure continues to evolve in response to many recent changes in energy policy in Germany, known as The Energy Concept, adopted by the federal government in 2010 and followed by*Energiewende* in 2011. It sets out the German energy policy until 2050, with the progressive nuclear phase-out and expansion of renewable energy capacity. It is highly relevant to study the performance of wholesale electricity market in Germany in this context.

The empirical studies on market power in Germany's wholesale electricity market, unlike French market, have been much employed in literature. Indeed, from 2001 to 2008, wholesale electricity prices were more than triple in Germany, soaring from about 25 to 87 €/MWh. This had drawn much attention from both academics and regulators to investigate the exercise of market power in the German market during this period, for example, Bower, Bunn and Wattendrup [2001], Möst and Genoese [2009] using an agent-based simulation model or Lang and Schwarz [2006], Müsgens [2006], Weigt and Von Hirschhausen [2008] using a linear optimization programming. Though each paper takes different approaches and uses different modelling methods, they essentially come up with similar conclusions about the existence of market power abuse in 2006, when wholesale electricity prices experienced an exceptional increase in Europe especially in Germany. Since then, the German electricity market has undergone significant changes, yet the discussion about the appropriate market design and market regulation seems not come to an end.

Shortly after the global economic crisis hit the energy-fuels markets, German wholesale electricity prices dropped sharply but began to rise rapidly, on average from 37€/MWh in 2009 to 51€/MWh in 2011 (37%) before slightly decreasing again in 2012 (according to the data from EEX). At the same period,

oil prices started to surge, exceeding $100/barrel in 2011. Although a price increase does not necessarily imply an abuse of market power, the oligopolistic structure of Germany's generation market has brought forward some doubts about the malfunctioning of the market.

In this chapter, we investigate the level of competition in the German wholesale electricity market in 2011. Indeed, 2011 is the year when market spot prices in Germany experienced the highest level since 2009, and many changes in German energy policy were implemented following the Fukushima's nuclear accident in March 2011. We attempt to estimate costs and market clearing prices under the hypothesis of perfect competition and compare this competitive benchmark to observed market prices. The hourly marginal costs for power production are estimated on the basis of a linear programming model as done by Müsgens [2006] and Weigt and Von Hirschhausen [2008].

The chapter proceeds as follows.

Section 5.1 discusses the market design and recent evolution of electricity market in Germany. We provide also a literature review of relevant studies analysing market power in the German spot market. A general overview of linear programming model description as well as the data are given in Section 5.2. We conduct several robustness analyses and summarize our main findings as well as the economic interpretation of the model-based results in the Section 5.3. The last section concludes.

5.1 Literature review on market power in German electricity spot market

We describe in this section the fundamental factors and recent evolutions in German power system in the context of energy transition in this country. We then provide a literature review of quantitative studies on market power issue in Germany's wholesale electricity market.

5.1.1 Germany's wholesale electricity market

The German electricity market is the largest in Europe, with annual power consumption of around 600 TWh and an installed generation capacity of 171.7

GW (data in 2011 according to OECD/IEA [2013]). German electricity market was liberalised in 1998 following the 1996 EU Electricity Market Directive. The Energy Industry Act (*Energiewirtschaftsgesetz*) came into force, ending more than 100 years of local monopoly and opening the electricity market fully to competition with a minimum of institutional interference[1]. As a result of intense competition, wholesale electricity prices fell by as much as 60% (Atkins and Taylor [1999]). In response to the significant fall of prices and profits, all eight of the major vertically integrated electricity companies, and many other smaller ones, were involved in a merger and acquisition process (Bower et al. [2001]). The German electricity market was thus transformed from a fragmented highly competitive market structure at the beginning of 1999 to a vertically integrated oligopoly one where four dominant firms controlled over 90% of market share by the beginning of 2001. In 2011, four largest utilities - E.ON, RWE, EnBW and Vattenfall Europe supply approximately 77% of the market according to the Federal Cartel Offices monitoring data[2]. This market structure continues to evolve in response to many recent changes in the European energy market.

Over the last decade, the European electric power sector has experienced an exceptional policy trend that fundamentally reshaped the industry: the intrusion of environmental-related policies. Germany is perhaps the most distinguished example of this energy policy trend. The next day of the nuclear catastrophe in Fukushima in March 2011, the German government decided, with the support of quasi-totality of German population, to accelerate the phase-out of nuclear fleet by 2022 - a policy which has been discussed since the beginning of 2000. It starts with the immediate closure of the eight oldest nuclear plants, and to continue to expand renewable energy capacity *(Energiewende)* [3].

[1] At time of liberalisation, there were neither independent system operator nor transmission regulators in Germany. The questions of grid access and transmission pricing were left to be negotiated among different electricity companies and the German heavy industries (Atkins and Taylor [1999])

[2] The *Bundesnetzagentur* (German regulatory authority) and the *Bundeskartellamt* (Federal Cartel Office) were required under the Energy Act (EnWG) and the Competition Act (GWB) respectively to conduct a joint Monitoring Report on activities in the electricity and gas sectors in 2012.

[3] The Energy Concept *(Energiewende)* was adopted by the federal government in September 2010 to set out the Germany's energy policy until 2050. The role of nuclear power in

In 2011, wind, hydro and solar supplied together around 15% of electricity balance in Germany and this share should increase to 35% by 2020 and 80% by 2050. Hard coal and lignite are still comprised about 45% of the total production in 2011 (Figure 5.1). The shutdown of eight nuclear plants with a combined capacity of about 8.4 GW has reduced the electricity production from this type of energy from around 140556 GWh (22.5%) in 2010 to 107971 GWh (18%) in 2011. This closure has also reduced the market share of the big four generators. Nonetheless, they still account for about 73% of generating capacity according to the Monitoring Report 2013, Developments of the Electricity and Gas Markets in Germany, Federal Network Agency and Federal Cartel Office, 2013 (FNA and FCO [2013]). Given the large amount of available interconnection capacity between Austria and Germany, these two markets are considered to comprise one electricity market, diluting the market share of the big four by approximately 10%.

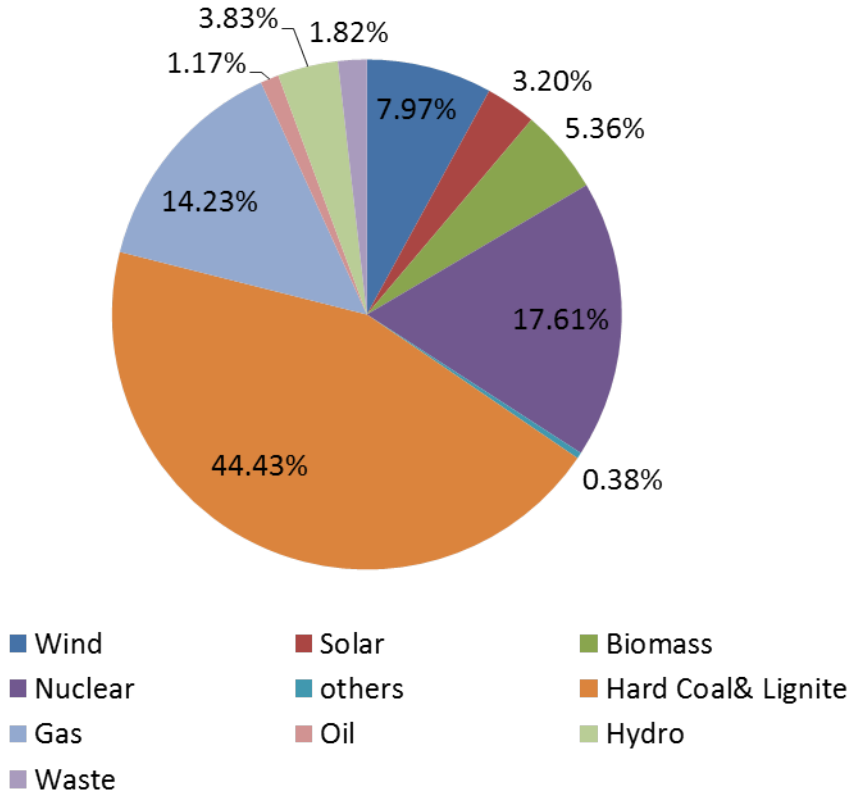
As regarding electricity wholesale prices, there was a significant increase in German spot market in 2011, compared with the previous years (2009 and 2010): from 37€/MWh in 2009 to 51€/MWh in 2011 (37%) on average before slightly decreasing in 2012 (figure 5.2).

It is difficult to conclude about the nature of increases in spot prices during this period without quantitative analysis. In fact, the *Energiewende* policy of replacing nuclear power with extra fossil fuel capacity and vastly expanding highly-subsidised renewables has two different impacts on wholesale power prices. In one hand, the extra fossil fuels generation was supposed to increase the wholesale spot prices due to its expensive fuel costs. In the other hand, the massive integration of renewable power generation (from wind, solar, biomass) should drive the electricity spot prices down because electricity produced from renewable is bidded at almost zero price on the market, following the Feed-in-tariff mechanism[4].

the *Energiewende* was reassessed following the Fukushima nuclear disaster in March 2011. The federal government decided, with the support of the majority of German population, to immediately shut down the eight oldest nuclear power plants and the remaining nine nuclear power plants on a phased basis by 2022 (See more in table 5.3). Although fossil fuels fired energy has to put in place during the transitional period, renewable electricity generation is being considered as cornerstone of current and future energy supply.

[4]The *Energiewende* has; however, increased the tariffs paid by the final consumers due to the heavily subsidised renewables integrated massively into the electricity system during recent years. It is important to note that German retail prices of electricity is at the highest

Figure 5.1: Electricity production in Germany - 2011

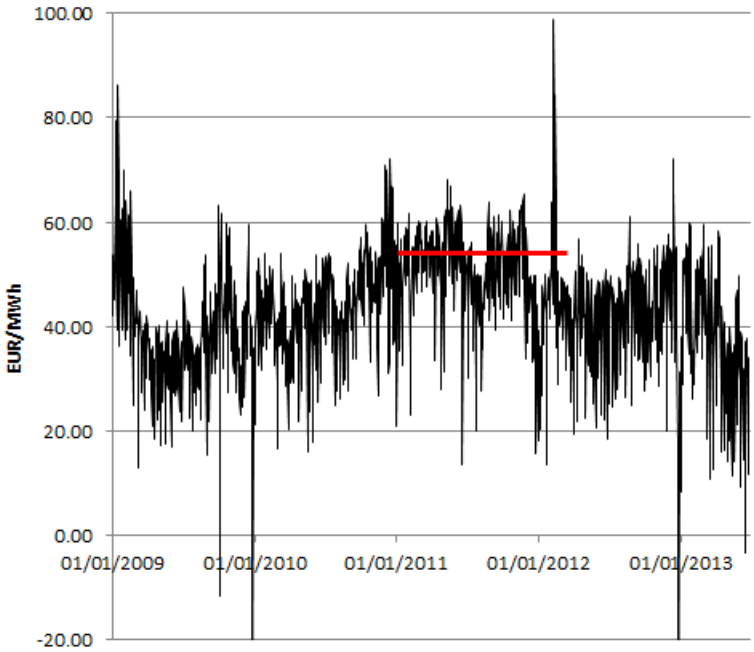


Source: IEA (2014)

Feed-in law is a mechanism which assures the obligation and priority of the integration of electricity output produced by renewables into the market no matter how conditions of conventional capacities are. In fact, the technical and commercial responsibility of this integration is supported by the system operator, who has been obliged to take the delivery of wind/solar electricity generation and put it immediately on the market. The German wind generators sell their output to the system operators at a guaranteed tariff. These tariffs vary with the installed capacity of the facilities and the type of renewable energy source. In principle, they drop annually by a pre-determined degression rate, so as to take account of cost decreases for installations and

level in Europe except those of Denmark - European champion for CO2 emissions and the development of wind power. The cost of subvention for renewable generators made retail prices even higher. This amount is expected to increase from 5.3 ct/kWh in 2013 (20% of total 2013 price) to around 6.2 ct/MWh in 2014 according to the data from Eurostat

Figure 5.2: Evolution of Germany's daily spot price 2009-2013



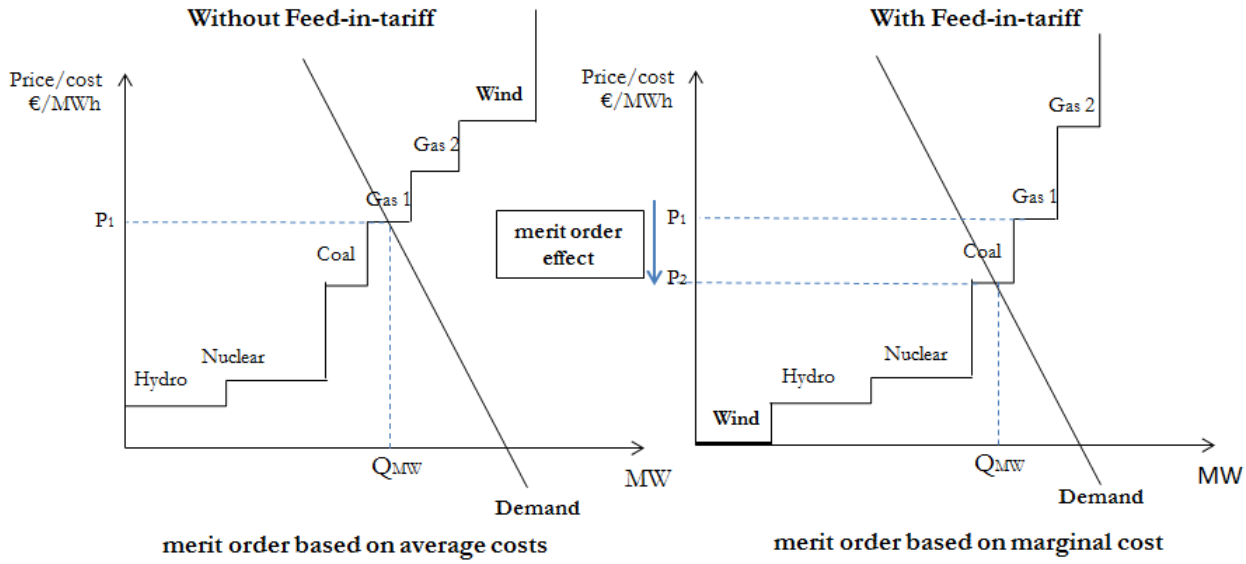
Source: EPEX Spot

to encourage technological advancements. The mechanism is financially neutral for renewable producers because they are paid at fixed tariffs which are independent from the conditions of supply and demand that determine the market price. If the market price is lower than the tariff, the loss suffered by the system operator is compensated by final consumers. Renewable generators will have no incentives to restrain their output, even if market conditions are particularly unfavorable.

While wind generators are paid at a fixed tariff and do not participate directly to spot market, wind output does have impact on the spot market prices. In fact, when wind generation is put in the merit order, it takes the value of "zero marginal cost", and since it will be the first to be dispatched, generation from other energy sources must move to the right of merit order curve. This analysis is applied analogously to other types of intermittent generation.

Figure 5.3 illustrates the difference between a logic of merit order based on average costs and a logic of merit order based on marginal cost. Electricity generated by wind energy, albeit zero fuel cost, has the highest average cost

Figure 5.3: Merit order with and without fed-in wind tariff



Source: Benhmad and Percebois [2013]

because the overnight cost (unit capital cost) is relatively high, particularly wind off-shore, and its load factor is relatively low: 26% and 43 % for onshore and offshore as compared to 85% for nuclear or other thermal plants (IAE, [2011]). However, in a logic of merit order based on marginal cost, wind generation will be the first to be dispatched since it takes the value of "zero marginal cost". As consequence, generation from other sources must move to the right of merit order curve, thus at a given demand, market price decreases. This is illustrated in figure 5.3.b where merit order effect is represented by the difference between P_1 and P_2. When renewable electricity generation comprises a large share of sources eligible to feed-in-tariffs mix, this merit order effect could be significant.

To sum up, the *Energiewende* policy could induce two different impacts on the wholesale market prices. In one hand, the substitution of nuclear power by extra fossil fuels capacity would increase the electricity spot prices. In the other hand, the vastly expanding highly-subsidised renewables would lower the spot prices, even to negative level[5]. The nature of high prices observed in 2011

[5]Negative prices are the consequence of two coincident events: a low demand and a very high level of wind which makes off-shore wind turbines in the Baltic run at full speed. When

is thus difficult to justify. As discussed in chapter 2, increases in prices do not necessarily imply an abuse of market power. It could be explained by many exogenous elements which impact the factor of costs other than market power abuse. However, the line between those two factors is sometimes ambiguous. Given the oligopolistic structure of Germany's generation market, the question of whether the market outcomes represent competitive behavior has been brought forward.

5.1.2 Literature on market power in Germany's wholesale market

The quantitative studies on market power in Germany's wholesale electricity market have been much employed in literature particularly in the period 2000-2008. After a few years since the European liberalization process, wholesale electricity prices have increased dramatically in Germany even though there was a sharp fall in prices at the beginning of the liberalisation. Within a couple of years, the disappearance of more than one-third of small generation companies by the M& A negotiations and the dominance of four big utilities brought about the same regulatory dificulty as many other countries that have liberalised their electricity markets: how to control the abuse of market power in a highly concentrated oligopoly structure. This had drawn much attention from both academics and regulators to investigate the exercise of market power in the German market during this period. Most of the studies used simulation market models to estimate the marginal costs. On the basis of the difference between the estimated costs and observed market clearing prices, the authors conclude about the competitiveness of the outcomes.

The earliest study investigating market power abuse in the German electricity market was Bower et al. [2001]. Using an agent-based simulation model

this situation occurs, the conventional thermal plants are required to back down so that demand and supply can be in balance. Some conventional generators, however, wish to continue to run because shutting down their plants would be too costly knowing that they have to restart them a few hours afterward (technically, it is not that simple). In this case, they prefer to pay an operator who could accept to take the electricity that they inject into the network rather than shut down their plants and suffer the start up costs. It would be the Swiss generators, who dispose a high capacity of pumped storage hydroelectricity and who would be paid for evacuating this excess electricity. This is the nature of *"negative prices"* issue (See more details in Benhmad and Percebois [2013])

with the dataset in 1998, the authors showed that the process of strategic consolidation with the creation of four dominant firms in the early years of liberalization suggested a substantial increase in market power in the wholesale electricity market and hence a significant rise in price-cost markups during this period. Using the same approach of agent-based simulation model, Möst and Genoese [2009] carried out the analysis for 2001, 2004, 2005 and 2006 in Germany. They concluded that the exercise of market power could not be verified .

Müsgens [2006] estimated the degree of market power in German wholesale electricity market for the period of June 2000 - June 2003. Using a linear optimization model, he simulated the competitive benchmark of market prices to reveal the level of market power. Müsgens concluded that until August 2001, the observed market prices were based on competitive marginal costs. From September 2001 onward; however, a divergence as large as 50% to 77% between the observed and modeled market prices was found. He regarded this as strong evidence of market power and that strategic company behavior and learning effects were the main drivers. Using the similar approach, Lang and Schwarz [2006] conducted an investigation of market power in German wholesale electricity market during the period from June 2000 to December 2005. The authors took into account the CO2 prices in estimating marginal costs. They found the similar results as Müsgens [2006] that no market power was exercised in 2000 and 2001 as observed prices were rather close to the modeled ones. From 2002 onward, there was a substantial deviation of market prices to the competitive benchmark, varying from 30% in 2003 and 15% in 2004 and 2005 particularly in peak hours. However, the authors concluded that apart from peak times in 2003, the increase of prices due to market power was considered to be small. The price rise in this period was rather traced back to the high fuel prices and the additional cost of CO2 allowances. Weigt and Von Hirschhausen [2008] followed Lang and Schwarz [2006] and extended the analysis to 2006. They found that market prices were above competitive levels for a significant period of time in 2006. Facing a significant rise of electricity prices in Europe, the European Commission launched an in-depth analysis Competition [2007] using various approaches (concentration indexes such as CR, HHI, PSI, RSI and linear optimization model). The final report con-

firmed that the German wholesale electricity market had undergone markups of 50% from 2003 to 2005.

Janssen and Wobben [2009] took a different approach. Instead of relying on an estimate of the entire generation cost, they investigate producers' behaviors in the context of electricity pricing with respect to several time-dependent marginal costs (TMCs). The authors derive the work-on rates, which provide information about the impact of TMC variations on electricity prices in different market structures: perfect competition, quasi-monopoly and monopoly. Comparing these model-based work-on rates with actual work-on rates, which are estimated by an adjusted first-differences regression model of German power prices on fuel costs and emission allowances, the authors find the evidence of the exercise of market power in the period 2006 to 2008.

More recently, Schill and Kemfert [2011] develop a game-theoretic computational Cournot model to analyze strategic electricity storage utilization in an imperfect market setting. They applied the model to the German electricity market using reference demands and prices of a particular week in October 2008. The authors conclude that introducing pumped storage smoothes market prices and increases consumer rent and overall welfare.

Though each author incorporates different assumptions in their models, most papers cited above apply the similar approach to estimate the level of market power. On the basis of the difference between modeled marginal costs and observed market prices, the authors calculate the mark-up costs and they essentially come up with similar conclusions. The general suggestion in all of those papers is that there has been evidence of market power abuse in the German electricity wholesale market during the period 2005-2008. However, it is important to note that estimating a cost-proxy is extremely challenging. As mentioned in section 2.3.2, the lack of full information in the empirical model could reduce the certitude of the conclusion. As Harvey and Hogan [2002] demonstrate, every model has some level of uncertainty and thus produces a range of possible outcomes. We are fully aware of this criticism as interpreting the mark-up results in this chapter.

5.2 Model and data

This section describes the approach of competitive benchmark analysis that commonly used in most papers and the data used. We follow the method of linear programming model in Müsgens [2006] and Weigt and Von Hirschhausen [2008] to simulate the German wholesale market in which all demand is cleared via a single market process. The EPEX German market clearing prices are used as reference to compare with the modeled ones. However, the electricity traded via EPEX platform comprises only about 30% of total consumption. As this is the only publicly accessible source, we assume that EPEX spot prices act as benchmark for OTC trading or forward market prices.

5.2.1 Model formulation

The power system consists of a set of nodes $N = n_1, \ldots, n_N$, at each of which there is the demand d_n and deterministic injection of three kinds of renewables: wind, solar and biomass - generation $g_n^{wind}; g_n^{solar}; g_n^{biomass}$. The power generation from these renewables sources are injected to the system independently from the market conditions and priced at zero following the feed-in tarif mechanism. The residual demand is then served by dispatchable plants $p = p_1, \ldots, p_p$ each of which being located at a certain node. Each conventional plant exhibits constant marginal generation costs c_p and a maximum capacity g_p^{max}. Exports to or imports from neighboring countries are taken into account implicitly by adjusting the demand data (see Section 5.2.2). The market clearing prices are determined at the same level across all nodes. Perfect competition is assumed to find a competitive benchmark.

As described in section 1.3, in a perfect competition situation, the hourly electricity spot prices reflect the short-run marginal cost of the most expensive technology amidst all the plants mobilized to satisfy the hourly demand. The system prices are thus determined by a traditional optimization program which minimizes the costs of meeting the hourly demand subject to the energy balance and the capacity constraint. To ease the non-linear calculation burdens, start-up/shut-down costs, ramp up and down rates are not taken into account (See more in Weigt and Von Hirschhausen [2008] about the startup constraint). In the following, variables are denoted by capital letters, param-

eters are denoted by lowercase letters.

$$\text{Min costs} = \sum_{t,p} (c_{t,p} G_{t,p}) \qquad \text{objective} \tag{5.1}$$

where $c_{t,p}$ are the marginal generation costs of plant p in hour t, and $G_{t,p}$ is the dispatched output of that plant in hour t. The output of a plant is restricted by the thermal capabilities of the generation process:

$$0 \leq G_{t,p} \leq g_p^{max} \qquad \text{capacity constraint} \tag{5.2}$$

with g_p^{min} and g_p^{max} as the minimum and maximum available power output. The maximum generation g_p^{max} is calculated based on the availability rate for each technology i and generation capacity of each plant p and the minimum generation g_p^{min} is calculated based on the minimum generation rates associated to each technology and the generation capacity of each plant :

$$g_p^{min} = Min - generation - rate_i * Gen - Capacity_p \qquad \text{Minimum Generation} \tag{5.3}$$

$$g_p^{max} = Availability_i * Gen - Capacity_p \qquad \text{Maximum Generation} \tag{5.4}$$

The marginal generation costs $c_{t,p}$ of plant p in hour t consist of the fuel costs based on plant efficiency η and fuel price p_f, operating costs, and opportunity costs for emissions based on plant-specific CO_2 emissions and the associated CO_2 price (on daily basis) at the EEX.

$$c_{t,p} = \frac{p_f^t}{\eta_p} + \frac{p_{CO2}^t}{\eta}.emissions_p + operation\,costs_p \qquad \text{marginal costs of generation} \tag{5.5}$$

As the model is ex-post analysis, demand d in hour t is known and has to satisfy the supply-demand balance:

$$d_t = \sum_{t,p} G_{t,p} + g_t^{wind} + g_t^{solar} + g_t^{biomass} \qquad \text{energy balance} \tag{5.6}$$

with $g_t^{wind}; g_t^{solar}; g_t^{biomass}$ are power generation from wind, solar and biomass respectively in hour t. Network constraints are not considered and thus losses are not taken into account.

The Lagrange multipliers or shadow prices associated to the supply-demand balance constraints indicate the marginal values and therefore the prices for the next incremental load $\lambda_t = \frac{\partial(Total\,costs_{t,p})}{\partial G_{t,p}}$.

The model is implemented in GAMS.

5.2.2 Data

The application of the described model covers the electricity system of Germany for the year 2011. In the following, we present the data sources as well as the assumptions on generation and load. Most of the data described below is taken from the data documentation of *Deutsches Institut fur Wirtschaftsforschung* done by Schröder, Kunz, Meiss, Mendelevitch and Von Hirschhausen [2013].

Generation

As described above, we explicitly distinguish between conventional thermal generation and renewable power generation. The former is indeed subject to be dispatched at specified marginal generation costs determined by (5.5) and the latter is neither dispatchable nor subject to any uncertainty, but enters the model as deterministic data.

Thermal generation is considered on block level, and capacities as well as locations of plants are based on BNetzA [2014]. We take into account the post-Fukushima impacts on nuclear power generation by adjusting generation capacity with the shutdown of 8 nuclear plants from mid-March 2011 (total capacity of around 8.5 GW). The generation capacity of 17 nuclear power plants is given in table 5.3 in the Appendix.

The information used to estimate the marginal generation costs about input fuel for nuclear, lignite, hard coal, gas, oil, hydro and technologies such as steam process, gas turbine, combined cycle gas turbine as well as

the data/assumptions on fuel prices, carbon content, is summarized in table 5.1.

Table 5.1: Information on different technologies and fuels

Technology	**Main Fuel**	**Efficiency %**	**Price €/MWh**	**Carbon Content t/MWh**	**Availability %**	**Min Generation %**
Nuclear	Uran	31%	3	0	90%	45.16%
Lignite	Lignite	37%	4	0.364	90%	40%
Coal	Hard Coal	42%	13.143	0.354	90%	38%
CCGT	Gas	54%	29.603	0.202	91%	33%
OCGT	Gas	34%	29.603	0.202	90%	20%
Gas Steam	Gas	39%	29.603	0.202	90%	38%
CCOT	Oil	50%	43.606	0.279	91%	33%
OCOT	Oil	34%	43.606	0.279	90%	20%
Oil Steam	Oil	39%	43.606	0.279	90%	38%
Reservoir	Hydro		0	0	50%	0%
PSP	Hydro		0	0	100%	0%
RoR	Hydro		0	0	50%	0%
Wind Onshore	Wind		0	0	100%	0%
Wind Offshore	Wind		0	0	100%	0%
Solar	Sun		0	0	100%	0%
Biomass	Biomass		0	0	90%	38%

Source: Statistik der Kohlenwirtschaft [2013], Schröder et al. [2013], Kunz and Zerrahn [2013] and EEX [2011]

The data for fuel prices of hard coal, gas and oil is based on Statistik der Kohlenwirtschaft [2013] summarized in Schröder et al. [2013], varying from 13.14 €/MWh for hard coal; 29.6 €/MWh for gas and 43.6 €/MWh for oil. The fuel prices for uranium and lignite are based on the assumptions done by Kunz and Zerrahn [2013], which are 3 and 4 €/MWh respectively. We take the average allowance price in 2011 at the European Energy Exchange (EEX) for simplicity, which yields 12.94€per ton of CO_2. The efficiency of the generation process is taken from Kunz and Zerrahn [2013], which is based on the process itself as well as the commissioning year of individual power plants. It ranges from 31% for nuclear power plant to 54% for a CCGT plant. An error term is imposed in the range of 0-0.01%. to avoid an underestimation of simulated prices, except for wind, solar and pumped-storage hydro power units, all plants are assumed to have the availability rate at 90% because a plant can be offline due to various exogenous reasons like weather conditions, maintenance, or outages.

The renewable sources (except hydro) in-dispatchable comprise wind, solar and biomass. The data of wind and solar generation in quarter-hour in 2011 is collected from different TSOs (Tennet TSO, 50 Hertz, Amprion, EnBW) and via EEX for validation. We take the average of four quarter-hours to get the hourly data. Concerning biomass facilities, we assume constant generation at available capacity as done in Kunz and Zerrahn [2013]. The total generation capacity is about 99.8 GW with over 500 power plants including renewable energy sources.

Load

The data on load is collected from ENTSO-E for 2011. The hourly demand level for Germany ranges between 80GW at peak (during winter months) and 45GW at off-peak times. It is important to note that the load data from ENTSO-E refers to the 24 hourly power consumed by the German network including the network losses but excluding the consumption for pumped storage. Furthermore, beside domestic load, part of the available generation capacity could be sold abroad and cannot be used to cover the German demand. For these reasons, the exports to neighboring countries and pumping must be taken into account. We adjust the load data from ENTSO-E with the data from the

four German TSOs by including exports and pumping. Table 5.2 depicts the final demand on a yearly basis.

Table 5.2: Load and renewable generation in 2011 (in TWh)

Load incl.exports and pumping	542.84
Total RES. Generation	94.70
of which Wind	44.25
of which Solar	18.53
of which Biomass	31.92

Source: EEX, ENTSO-E

5.3 Results and sensitivity analysis

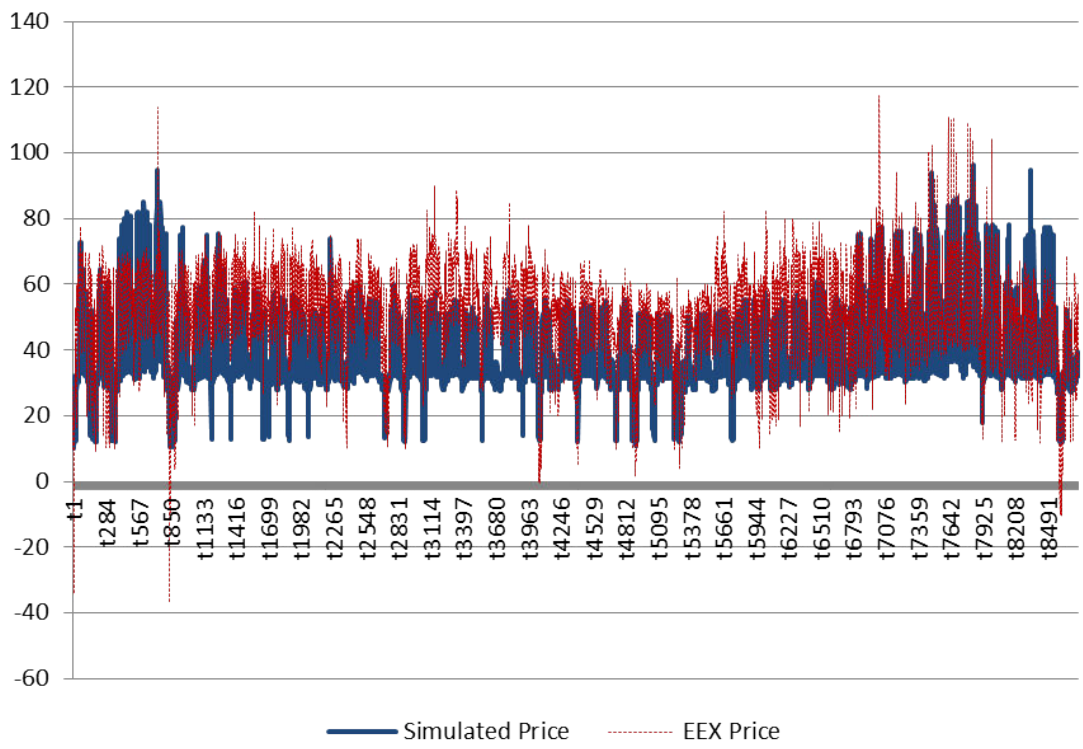
In this section, we compare the model-based market prices with observed priced at the EEX for all hours of 2011, obtaining mark-ups (or Lerner Indexes). The general results are then testified by several robustness tests. First, to avoid the overestimate of available capacity of power plants, we reduce the availability rate. Because electricity spot prices exhibit a very strong seasonality, we conduct separately fours model runs, one for each season with the adjusted seasonal availability factors for each plant type (the highest level of availability in winter months). Second, the modeled prices might be subject to be underestimated due to possibly low fuel prices, we are thus testify the model by increasing gas and oil prices.

5.3.1 Market power and price-cost markups

The simulated dispatched generation outputs of thermal plants, $G_{t,p}$ is illustrated in figures 5.8 (annual) and 5.9 (hourly) in the Appendix. As demonstrated in both figures, hard coal and lignite plants tend to have a major marginality during the examined period: particularly in the off-peak time, lignite plants took the marginality. The marginal production costs of these plants thus determine the market prices for the majority of time. The shutdown of 8 nuclear reactors since March 2011 (taken into account in the model from 01 April 2011) had a clear impact on the hourly generation output dispatched

as shown in figure 5.9. The accumulated generation output for 2011 is also presented by the merit order as illustrated in figure 5.10 in the Appendix.

Figure 5.4: Comparison of modeled price and EEX.

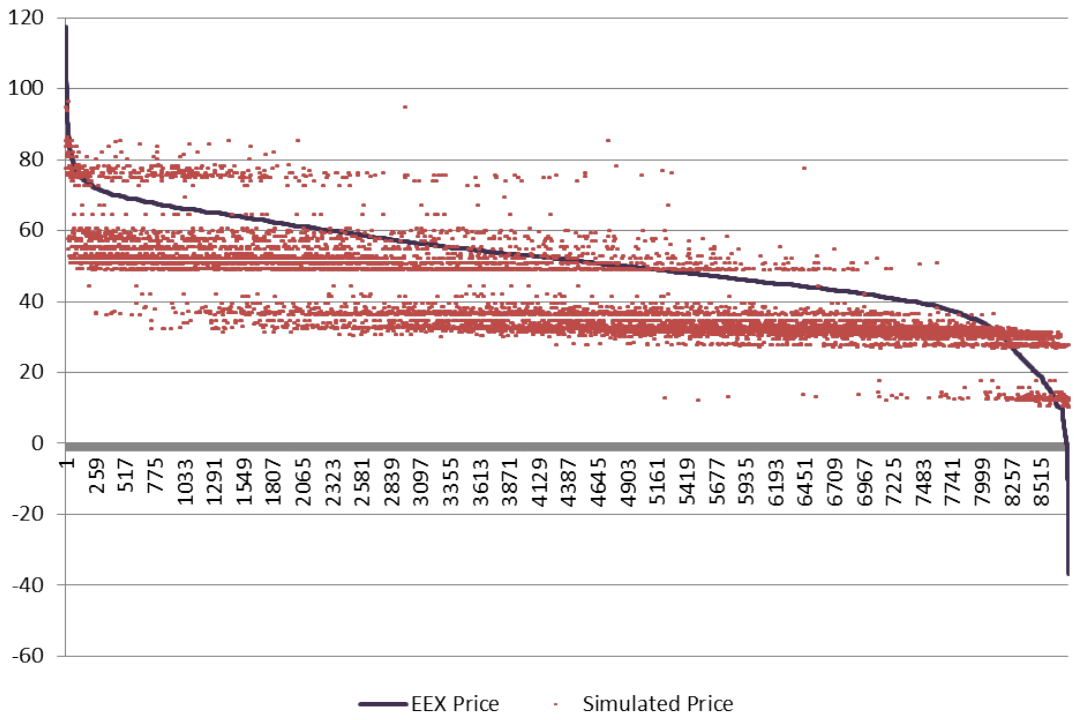


Source: Own calculations and EPEX Spot

The simulated prices for 8760 hours in 2011 are depicted in figure 5.4. It is important to note that the simulated marginal costs could be much higher than the observed EEX prices especially during off-peak times because the EEX prices could drop to the very low level, even zero or negative level whereas simulated prices always reach a positive level, representing coal and lignite-fired base load plants. Figures 5.10, 5.8 and 5.9 show that lignite and coal plants dominate the production balance of Germany in 2011. In general, prices below marginal costs are explained by startup conditions since the temporary shut-down of a base load plant can become more expensive than maintaining operations without revenues (Weigt and Von Hirschhausen [2008]). The operators thus prefer to bid a price lower than the marginal production costs of their base load plants than shutting them down. The start-up costs are also

the reason to explain why market prices could go down to negative level as described in section 5.1.1. Figure 5.4 shows the modeled prices and the EEX prices in the chronological order while figure 5.5 depicts the modeled prices and the observed prices ordered from highest to lowest EEX price.

Figure 5.5: Price duration curves: modeled and EEX.



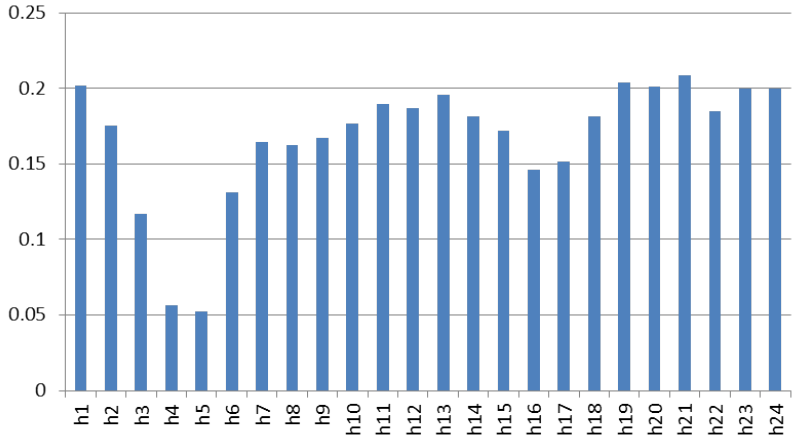
Source: Own calculations and EPEX Spot

The modeled prices are generally below the observed prices. In the off-peak time, both EEX and modeled prices vary between 15 and 40 €/MWh. The EEX prices; however, dropped toward zero or even negative (effect of subsidized intermittent renewables as described in section 5.1.1) while modeled prices tend towards a coal and lignite plants. In the mid-price segment the EEX prices range from 40 to 60 €/MWh while the modeled prices range between 30 and 60 €/MWh and generally below the EEX prices. The divergence is also found in the peak load period: the EEX prices increase from 65 to over 100 €/MWh while modeled prices remain between 60 and 80 €/MWh.

The Lerner indexes are then calculated based on the simulated competitive marginal costs and observed EPEX Spot. The average value is found at

17% for the year of 2011[6]. The hourly average values of Lerner indexes are depicted in figure 5.6.

Figure 5.6: Lerner indexes accross hours



Source: Own calculations

As shown in figure 5.6, the markup levels vary from 5 to 20% and are highest during the peak times: morning peak from 8am to 1pm and evening peak from 18h to 22h. During the nights, the Lerner indexes are shown at relatively low level especially from 2am to 5am. This corresponds to the fact that market power abuse is expected to occur when demand is high or close to the capacity limit.

5.3.2 Robustness tests

Before coming to the conclusion about the level of market power during the examined period 2011, it is essential to conduct several robustness tests. As precised above and in section 3.3.2, all simulation models [7] are subject to a certain extent of errors due to simplifications and assumptions restrictions. The results of these models should be interpreted with carefulness.

We are thus implementing two sensitivity tests in this section to verify the possibility of underestimating marginal production costs. First, we alter

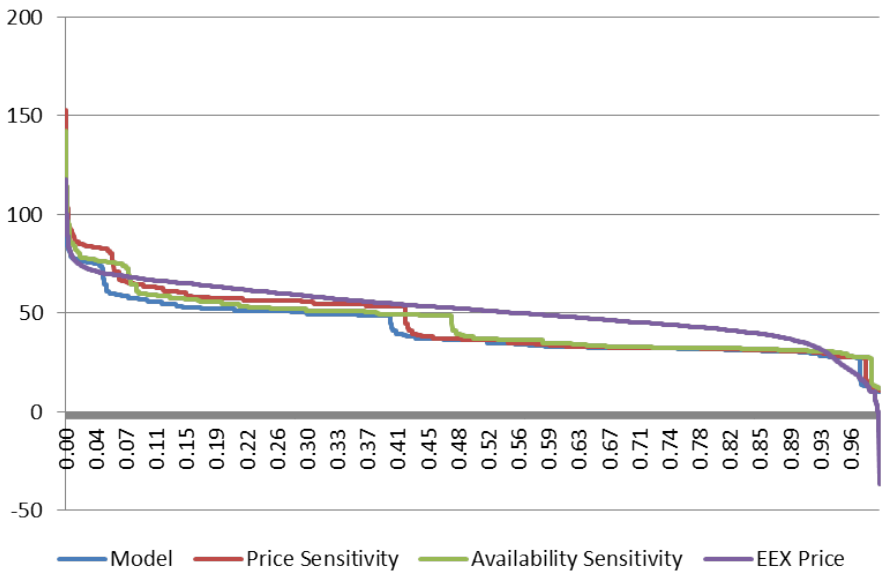
[6]Several extreme values of EPEX prices (both negative and positive) are removed to keep the standard deviation at normal levels.

[7]This type of models are categorized in "Direct estimation of marginal cost" approaches in section 3.3.2

the availability of power plants. Indeed, the reduction of availability rate of baseload plants would lead to an increase of prices because more peak-load plants would have to be mobilized to satisfy the demand. We model separately four seasons in the year while varying power plant availability for each season. On average, we reduce the availability by 3%, 4%, 5% and 6% in winter, spring, fall and summer months. Due to a lack of available information, we could not take into account other important factors that affect the availability rate of power plants as hourly weather conditions, hourly water level or plant outages, etc. Second, we vary the fuel price level by increasing prices for oil and gas by 10%. In fact, the uncertainty of fuel prices could lead to underestimate the marginal costs. Higher oil and gas prices should lead to an increase in peak prices when CCGT and oil or gas fired steam plants set the market price.

The results are shown in the figure 5.7 which demonstrates the price duration curves of three model sets: the basic case and the two sensitivity testing cases.

Figure 5.7: Price duration curves



Source: Own calculations and EPEX Spot

The impact of the increased fuel prices is obvious only during peak load times when oil or gas plants are needed. During this period, the marginal costs are slightly higher than those of base model (7.4% on average from

41.32€/MWh in the base model to 44.66€/MWh in the model with increased fuel prices). The impact of reduced plants' availability is quite similar. There is a no significant difference during off-peak and mid-load periods between the sensitivity testing case and the base model. This is because during off-peak times, the remaining capacity is still sufficient to keep a moderate price level even though the available capacity has been reduced. The impact is more obvious during peak times but the difference is rather small.

5.3.3 Discussion

Even though the robustness tests confirm the reliability of the results we obtained, it is important to underline that there might be always a significant margin between any simulated models and market reality. For example, the models we conducted are based on perfect knowledge, i.e, the bidders have always correct expectations about the market conditions. In reality, there might be asymmetric information; the bidders could have "wrong" expectations. Other two important weaknesses of any direct simulation of marginal costs are the lack of information on the real availability of power plants and the unlikelihood of estimating the opportunity costs. Indeed, the availability rate of a power plant can be varied hourly due to the conditions on temperatures, the water levels or plant outages that we are not likely to take into account in the model. Estimating opportunity costs are even more challenging. Hydropower plants have variable costs at zero (table 5.1) but opportunity costs might be high because of their dynamic flexibility. Indeed, hydroelectric plants are actually the only cheap way to "store" electricity thanks to its water storage system (pump storage facilitites)[8]. So the opportunity cost of producing any MWh of electricity by a hydroelectric plant during the off-peak times, for example, is the revenue that the firms could have gained if they stored water and used this to produce electricity during peak times. We did not explicitly take this into account in the model. We are fully aware of these limitations while interpreting the results.

In order to understand better the implication of the high observed mar-

[8]This is not really a form of storage of power, the water must pass through a turbine-generator to create electricity, so in many ways it is the same as having a coal pile except that the hydro responds much faster.

ket prices and potential markups, it is essential to emphasize that the year of 2011 marked an energy policy shift in Germany following the nuclear accident in Fukushima, which lead to the immediate shut-down of eight nuclear power plants. At the same time there was a strong expansion of volatile renewable power plant capacity, which has to be purchased and transmitted with priority by the grid operators, and is priced close to zero but remunerated with fixed feed-in tariffs pursuant Renewable Energy Sources Act (EEG). These two factors have led to a decrease in the capacities of the four leading operators RWE, E.ON, Vattenfall and EnBW. In 2012, the *Bundesnetzagentur* (German Energy Regulatory Authority) and the *Bundeskartellamt* (Federal Cartel Office) were required to conduct joint monitoring activities in the electricity and gas sectors since 2011. The mornitoring report highlighted that the volatile renewable energy sources *"pose risks to competition and the market"* because they are not organised on market economy concepts. Prices during this period were higher on average and much more volatile than previous years. This made market power more likely to be abused because firms would take this into account as maximizing their profits.

On one hand, the shutdown of eight nuclear power plants after March 2011 necessitated mid and peak plants like lignite or coal to substitute a part of the withdrawn nuclear capacity. However, this was not supposed to lead to significant increases of prices because expensive gas and oil were not much mobilized during this period. Furthermore, a great part of the shutdown nuclear had been made up by the nuclear capacity imported from neighboring countries like France. On the other hand, the massively expanding highly-subsidised renewables had led to significant decreases of wholesale prices. This impact, known as merit-order effect, has been quantified in a number of papers, for instance, Sensfuss, Ragwitz and Genoese [2008], Weigt [2009], Gelabert, Labandeira and Linares [2011], Würzburg, Labandeira and Linares [2013], Benhmad and Percebois [2013] Cludius, Hermann, Matthes and Graichen [2014], Ketterer [2014]. Yet, the observed EPEX spot prices have exhibited high levels in 2011 (figure 5.2). The doubt on the possibility of market power abuse could thus be justified.

Last but not least, the model carried out in this chapter does not explicitly take into account the role of constraints and congestions on the transmis-

sion grids. This refers to both internal congestions (Germany's South - North) and cross-border congestions. Indeed, when congestions bind at a given point of the network, no electricity can be imported/exported in/to the local area where there is congestion. As consequences, prices should increase. Ignoring this factor could possibly lead to under-estimation of actual marginal costs. However, integrating network to our model context is very complex because it requires the data information on each lines and nodes of the network.

If we allow a margin of up to 10% for estimation errors or for the ignorance of several factors as described above, the mark-ups level becomes less significant. On average, the markup of around 7% raises the question about whether missing data and model simplifications are solely responsible for this divergence.

Conclusion

Energy market in Germany has undergone fundamental changes in 2011. Following the Fukushima nuclear accident in March 2011, Germany decided to accelerate the phase-out of nuclear power by 2022 starting with the immediate closure of the eight oldest plants. This decision resulted in the adoption of a set of policy instruments commonly known as the *Energiewende*. Prices in wholesale market in this year have been observed to be at the highest level on average during period 2009-2013. Studying market power for German wholesale electricity market in 2011 is thus highly relevant for both academics and regulators.

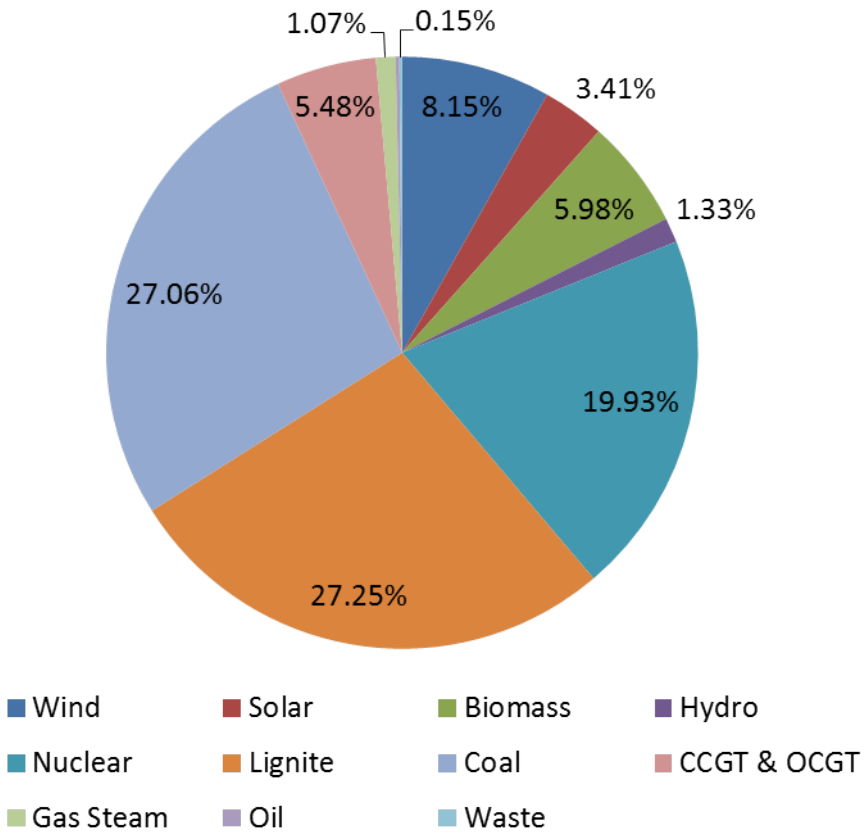
Following the method of linear programming as commonly used in literature, we simulate a competitive benchmark for German wholesale market in which all demand is cleared via a single market process. Marginal costs and market clearing prices under the hypothesis of perfect competition are estimated via an optimization program in which costs are minimized, subject to several technical constraints and energy balance. This competitive benchmark is then compared with EPEX spot prices. On the basis of the difference between modeled marginal costs and observed market prices, we estimate the price-cost markups, or the Lerner Indexes across hours.

The model-based results suggest that on average the EPEX prices are about 17% higher than the simulated competitive benchmark. The divergence is most observed during the peak time, up to 20% in the morning and evening peak hours when demand is high. Even if we allow for 10% of missing information or model simplification, the price-cost markups are still unignorable. We verify the robustness of the results by conducting two sensitivity tests: first, we increase the fuel prices for oil and gas by 10%, and second, we reduce the plant availability. In both sensitivity tests, the off-peak prices are almost unaffected and the peak prices are slightly higher. The results stay robust.

While we acknowledge the common limitations of this modelling approach, the large number of significant price differentials could indicate that the market has not yet sufficiently competitive to overcome market abuse particularly in peak times.

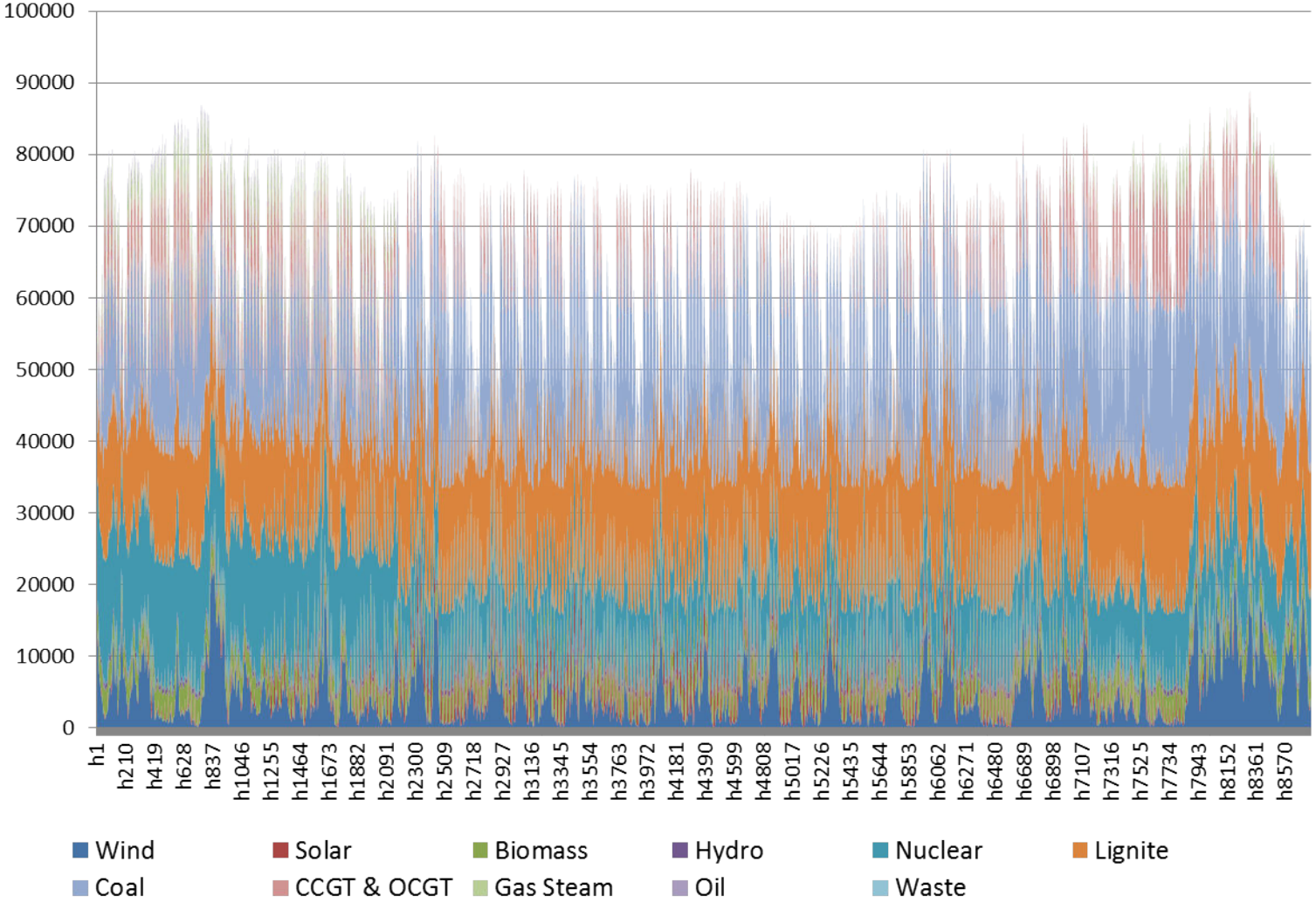
Appendix

Figure 5.8: Simulated annual elecitricty production for different plant types - 2011



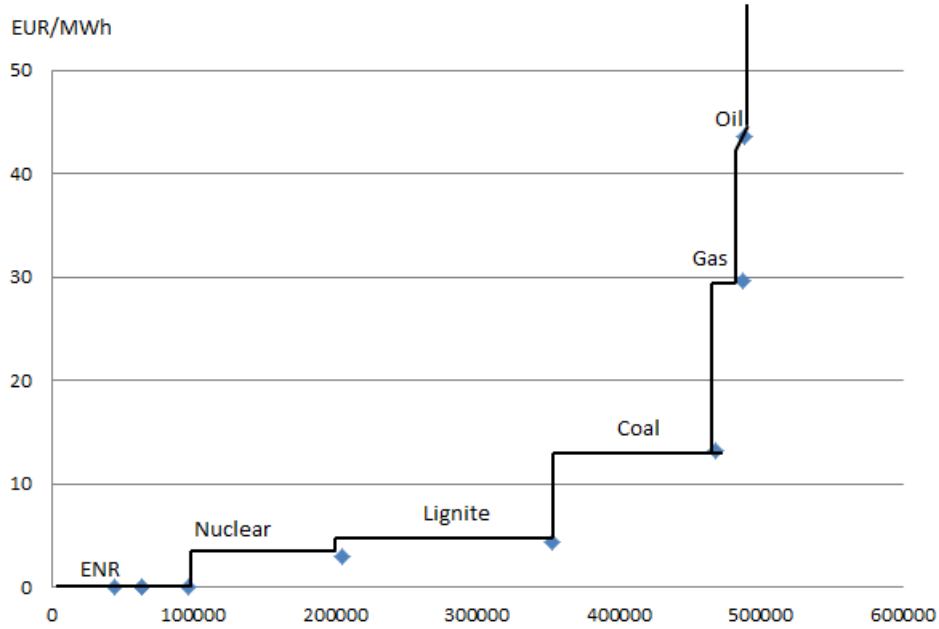
Source: Own calculations and EPEX Spot

Figure 5.9: Simulated hourly dispatched thermal output and renewables' capacity



Source: Own calculations and EPEX Spot

Figure 5.10: Simulated merit order - 2011



Source: Own calculations and EPEX Spot

The marginal generation costs in the vertical axe does not include the operating costs as well as the costs for CO_2 emissions. The generation outputs from renewables are supposed to have zero cost and to be automatically dispatched.

Table 5.3: Nuclear generation capacity

Plant	Type	MWe (net)	Commercial operation	Operator	Provisionally scheduled shut-down 2001	2010 agreed shut down	March 2011 shutdown & May 2011 closure plan
Biblis A	PWR	1167	fvr-75	RWE	2008	2016	shutdown
Neckarwestheim 1	PWR	785	dc-76	EnBW	2009	2017	shutdown
Brunsbttel	BWR	771	fvr-77	Vattenfall	2009	2018	shutdown
Biblis B	PWR	1240	janv-77	RWE	2011	2018	shutdown
Isar 1	BWR	878	mars-79	E.ON	2011	2019	shutdown
Unterweser	PWR	1345	sept-79	E.ON	2012	2020	shutdown
Phillipsburg 1	BWR	890	mars-80	EnBW	2012	2026	shutdown
Krmmel	BWR	1260	mars-84	Vattenfall	2016	2030	shutdown
Total shut down (8)		**8336**					
Grafenrheinfeld	PWR	1275	juin-82	E.ON	2014	2028	May 2015
Gundremmingen B	BWR	1284	avr-84	RWE	2016	2030	end 2017
Gundremmingen C	BWR	1288	janv-85	RWE	2016	2030	2021
Grohnde	PWR	1360	fvr-85	E.ON	2017	2031	2021
Phillipsburg 2	PWR	1392	avr-85	EnBW	2018	2032	2019
Brokdorf	PWR	1370	dc-86	E.ON	2019	2033	2021
Isar 2	PWR	1400	avr-88	E.ON	2020	2034	2022
Emsland	PWR	1329	juin-88	RWE	2021	2035	2022
Neckarwestheim 2	PWR	1305	avr-89	EnBW	2022	2036	2022
Total operating (9)		**12,003**					
Total (17)		20,339 MWe					

Source: World Nuclear Association 2014

The eight shut-down reactors are not yet defueled, nor decommissioned and written off by their owners.

Conclusion

The electricity reform has been put in place around Europe for more than two decades and in reality, there have been many trade-offs and only a few clear-cut answers. The design of these newly-opened markets is not yet definitive. Some important problems are still debatable, one of them concerns *"market power"*. This thesis addresses the issue of market power as regard to the way of defining and detecting it.

Studying market power in electricity market is not an easy task. We have showed through the first part of this thesis (Chapter 1 and 2) that while standard definition of market power can be perfectly applied in electricity markets, the methods for diagnosing market power in those markets could not be the same as ones applied in any other markets. Many factors, some of which come from peculiar idiosyncrasies of the industry (such as inelasticity of demand and supply), some of which arrive from political and social concerns (creating some sort of entry barriers), make exercising market power particularly likely and detecting it particularly difficult. Over the last 15–20 years, market power detecting methods have been dynamically developed, varying enormously from theoretical to empirical analyses, from the simplest market structural indexes to the most complicated simulation models, from ex-ante to ex-post approaches, etc. Although each of those methods has both strengths and weaknesses, the more recent tools concerning market modelling have been considered better able to capture relevant factors that are not present in traditional tools such as structural indicators. Two different approaches of market power modelling have been considered in this thesis: econometric modelling (indirect estimation of marginal cost) and linear optimization programming (direct estimation of marginal cost). We applied these two models for wholesale electricity markets in France (Chapter 3 and 4) and Germany (Chapter 5) respectively.

Market power has been doubted in French wholesale power market because of

its extremely concentrated structure: Électricité de France - the biggest producer of electric power in Europe - still monopolises the domestic market. Furthermore, prices in French wholesale market have increased without cease and fluctuated substantially since the market opening in 2000. However, empirical studies on the performance of wholesale power market in France have been little employed in literature. The perhaps first attempt to quantify market competition level using price-cost margins in France was carried out by the European Commission through the study conducted by an external consultant (London Economics) in 2007 (Economics [2007]). However, the results for France were reported "unreliable" as they came with a strong caveat. Indeed, the issue arose for any attempt to calibrate the marginal cost in French electricity market was the particularly flat-shaped merit curve due to the large part of nuclear power in the generation mix (over 85%). As nuclear technology has generally very low marginal cost but high capital costs, simulation models were most likely to underestimate the marginal cost, thus making the calibration of price-cost margins less reliable. One method to overcome the problem of not knowing marginal cost is to use the New Empirical Industrial Organisation (NEIO) model, which was analyzed in Chapter 3 on both theoretical and empirical basis. The great advantage of this method as applied for French power market is that it requires no accounting information of production costs. Marginal costs are not subject to be *directly simulated* but *indirectly estimated* through econometric estimates using historical data. A firm conduct parameter is introduced in the system of demand and supply equations to identify market power. We extended the NEIO model in a dynamic framework using hourly data in French wholesale market during 2009-2012. Both multivariate and panel data models are taken into account. The results for both models presented in chapter 4 suggest that though market power is found statistically significant in several peak-load hours, it stays at very low level. On average, no market power is exercised over the examined period. The main economic explanation for this conclusion would be the extremely regulated model of wholesale power market in France. Since "market" comprises only 17% of domestic delivery and prices in this market are strictly regulated, it is very hard for firms in France to exercise their market power especially in the context of strong interconnected network. Furthermore, the incumbent firm - EDF - seems not to have incentives to exercise its market power even though it possesses one because the potential gains from doing this would fall far behind the risks of being broken up the monopoly by

European competition authority. Furthermore, being extremely regulated, wholesale market activities and prices' behaviours in France are also being closely observed by French regulatory authority. Any abnormal high prices occurring in the spot market has been investigated and examnined by CRE. For all those reasons, there is, indeed, little room for market power exercise.

An alternative method to detect market power abuse that has been applied in this thesis is simulation model using linear optimization. Though poorly performing in modelling French electricity market due to its very flat-shaped marginal cost curve, it can be applied in German power market because its electricity production balance is more diversified. Linear optimization model has been much employed in literature on market power issue in German electricity market during the period 2001 - 2008. In Chapter 5 of this thesis, we have carried out the analysis of market power in German wholesale market using this method for data in 2011. Marginal costs and market clearing prices under the hypothesis of perfect competition are simulated via an optimization program in which costs are minimized, subject to several technical constraints and energy balance. On the basis of the difference between modeled marginal costs and observed market prices, we calculate the price-cost markups for the examined period. The model-based results suggest that the EPEX prices are about 17% higher than the simulated competitive benchmark on average, and around 20% in the morning and evening peak hours. The results are found robust under sensitivity analyses in which we increase the fuel prices and reduce the plant availability. Even though we acknowledge the common limitations of this modelling approach (missing information, model simplification as the ignorance of network bottleneck or ramping cost), the large number of significant price-cost divergences could suggest that the market has not yet sufficiently competitive to overcome market power abuse particularly in peak times.

An interesting observation throughout the empirical studies in French and German markets is that market power abuse seems much less obvious in France - a highly concentrated market with monopoly structure, than in Germany - a less concentrated market with oligopoly structure. Though comparison in this way does not have much sense because energy policies and market conditions are different in the two countries, these results illustrate a commonly accepted wisdom in electricity that the correlation between market concentration and market power abuse is not always justified. The idea of "big one" producing bad performance is not necessarily

true in the case of French wholesale market. Though divestiture of the dominant generator(s) has been the classical solution to the problem of market power, it is institutionally or politically difficult and costly to implement. And the case in France shows that a good performance is likely to come out even with a concentrated market structure. Instead of divesting the dominant firm, an alternative regulatory tool to mitigate market power is to require dominant generators to sell a certain amount of their capacity under long-term contracts at a pre-negotiated or regulated rate (Virtual Power Plant auctions in France and the Netherlands). In general, forward contracting encouragement is considered as an important method to reduce market power (Allaz and Vila [1993]). Furthermore, reducing or removing barriers to entry could be a useful means of encouraging new market participants to enhance competition in electricity market. These barriers may include generation site permits, non-discriminatory access to the transmission network, or uncertainties in regulatory policy (c.f Chapter 2). On the demand side, load management with various methods of increasing demand response is regarded as one of the most promising way of reducing market power because the lack of demand responsiveness to price is known to exacerbate market power dramatically. Last but not least, expansion of the transmission system is also a good method for reducing market power (by enlarging the market size)[9].

Most economists would argue that it is more costly to eliminate all market power than to allow some market power to exist and that a "workable competition" with an acceptable level of market power is preferable. For example, in electricity market, charging 550€/MWh instead of 50€/MWh is not rare. This is 1000% higher than the average variable cost and yet necessary for some base-load plants to cover their fixed costs. Then market power that raises the price sometimes a little above marginal cost could probably be tolerated. Unfortunately there is little empirical work that examines these trade-offs or quantify what an acceptable level of market power should be. In the case of German power market, if we allow 10% for estimation errors or any missing information on the results, the mark-up level seems less significant.

It is important to note that our analyses in both French and German markets

[9]We have provided several ideas of market power mitigation methods that might be implemented by a market monitoring depending on its purpose or market conditions in each countries but it is not the aim of this thesis to examine or evaluate the remedies for mitigating market power.

have been done ex-post with historical data (2009-2012 for France and 2011 for Germany). During these years, there has been an excess capacity at European level with the exception of certain areas such as southern Germany, according to a report of Commissariat général à la stratégie et à la prospective (CGSP [2014]). The situation of overcapacity in Europe stems largely from the effects of the economic crisis which has reduced electricity demand. While electricity demand increased by 50TWh per year in the EU-27 between 2000 and 2007 (about 1.8% per year); in 2012, the demand was still lower than 130 TWh (about 4%) compared to the 2008's peak. In the context of overcapacity, it seems to be unprofitable for firms to unilateral withhold their capacity, thus exercising market power seems not a gainful strategy. However, energy markets have been evolving dynamically since recent years. In the next 10 - 20 years, electricity balances in Europe are supposed to change drastically, particularly with the strong integration of renewables, the adjustment of nuclear and other fossil fuels shares in the energy mix, the evolution of demand, or the enlargement of market size due to the end of tariff for consumers, etc. Therefore, one potential extension to this thesis would be an ex-ante analysis of competition level under different scenarios in long term.

Finally, we fully acknowledge some limitations of this thesis. First, game theory models, which have been also commonly used in literature to detect market power, are not adequately employed. Second, only periods of 2008-2012 for France and 2011 for Germany have been analyzed due to limitation on data. Third, in the context of highly interconnected among European electricity networks particularly with market coupling mechanism, it would be more relevant to analyze market power at the European level. However, due to lack of data and because energy structures and policy are so divergent among European countries, we could not carry out empirical analyses at European level. Fourth, comparisons with pioneer countries of liberalization process like Nordic countries, the UK or the USA are still limited. Last but not least, in none of two empirical studies, network congestion has been explicitly taken into account. In fact, network congestion potentially provides opportunities for the exercise of market power. However, integrating network to our model context is very complex and worth another deeper research. The literature on market power issue is enormous, and the problems treated in this thesis are inevitably incomplete despite its length. However, throughout five chapters of this thesis, we hope to have shed lights on most key issues regarding *market power in power markets*.

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Abstract

The two last centuries have witnessed an exceptional revolution in the organization of electric power markets worldwide. The industry's organization has changed from vertically integrated monopolies under regulation to unbundled structures that favor market mechanisms; known as reform process in Europe. The shift to reliance on market prices, given concentrated structures and particular characteristics of electricity industry, raises a possibility that some firms could influence the market prices by exercising their market power. The issues of "*market power*" in a given industry have been abundantly employed in the literature of Industrial Organization since the late 1970s but theoretical and empirical studies of "*market power in electricity markets*" have only been developed recently. In this thesis, we attempt to carry out an insight research around market power questions in deregulated wholesale electricity markets in Europe, as regarding the way of defining and measuring it. We carry out empirical studies in two of the biggest liberalized electricity markets in Europe: France (2009-2012's data) and Germany (2011's data), using econometric regressions and electricity simulation models as main methodologies. The subject is particularly relevant in the context of energy transition in Europe (*transition énergétique* in France and *Energiewende* in Germany).

Key words: Market power, liberalization, wholesale electricity market, Europe, France, Germany.

Résumé

Les deux derniers siècles ont connu une révolution exceptionnelle dans l'organisation des marchés électriques dans le monde entier. Ainsi, traditionnellement organisé autour de monopoles verticalement intégrés et soumis à la régulation, le secteur électrique connait un processus de réforme et évolue vers une organisation décentralisée qui favorise les mécanismes du marché. Le passage des tarifs régulés à des prix du marché, compte tenu des structures concentrées et les caractéristiques particulières de l'industrie électrique, accroît la possibilité que certaines entreprises puissent manipuler les prix du marché en exerçant leur pouvoir de marché. Les questions de "*pouvoir de marché*" dans un secteur donné ont été abondamment étudiées dans la littérature de l'Économie Industrielle depuis la fin des années 1970, mais des études théoriques et empiriques de "*pouvoir de marché dans les marchés électriques*" n'ont été dveloppées que récemment. Dans cette thèse, nous essayons de mener une recherche approfondie autour des questions de pouvoir de marché sur les marchés de gros de l'électricité en Europe. Nous conduisons des études empiriques dans deux des plus grands marchés européens: la France (sur des données 2009-2012) et l'Allemagne (sur des données de 2011), en utilisant des méthodes économétriques et des modèles de simulation des marchés électriques. Le sujet semble pertinent dans la période de transition énergétique en Europe.

Mots clés: Pouvoir de marché, réorganisation, électricité, marchés de gros, Europe, France, Allemagne.