Contracts in the restructured electricity markets

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Contracts in the Restructured Electricity Markets

A Law and Economics Perspective

Laura Onofri

Contracts in the Restructured Electricity Markets: A Law and Economics Perspective

Laura Onofri

STELLIGEN

Behorende bij het proefschrift van L. Onofri

Contracts in the Restructured Electricity Markets: a Law and Economics Perspective

1. The "take-or-pay" contract is the electricity contract with the lowest risk degree for the generator-investor and the lowest efficiency pressure for the system (chapter 3).
2. The economic dispatch contract creates some competitive pressure and system efficiency but increases risks for the generator-investor (chapter 3).
3. The competitive pool contract is the electricity contract with the highest risk degree for the generator-investor and the highest efficiency pressure for the system (chapter 3).
4. Estimated coefficients for legal provisions are not statistically significant when the dependent variable is the minimum price. Economic variables (like fuel types, construction costs and so on) are more robust explanatory variables for minimum price (chapter 4).
5. As the investment in relationship-specific assets becomes more important, the longer becomes the electricity contractual duration. However, the parties will mitigate the long-term contracts inflexibility, based on *ex ante* bargained terms and conditions, with provisions that allow for contingent adaptation. Such empirical results provide support for the hypothesised relationships and are robust to different model specifications and alternative estimation techniques (chapter 5).
6. Standard competition policies might interfere in the trade-off among governance structures; they are inadequate and might be misinterpreted, when applied to particular organization forms like in the case of electricity long-term contracts (chapter 6).
7. Economics is the science of choices and can be applied to any field of life and experience.
8. Choices on cultural policy, typically by means of an efficiency verdict, appear to be in trouble when measuring costs and benefits in the far distant future, because such calculations involve not only a great deal of uncertainty (about people's preferences and available technologies) but also involve judgements about distribution of income across generations.
9. The possibility of introducing less strict employment-protection laws that increase both the participation in the labour force as well as the number of people who work will energise the role of redistribution of Rawls believer government if the rise in the participation in the labour force is less than the rise in the number of people who work.
10. If one accepts that the central banks should focus not only on consumer-price inflation, but also on financial asset prices, then the central banks may create a sort of moral hazard, encouraging investors to buy shares in the belief that it always step to prevent a collapse in the financial market (i.e. cut interest rates fast).

Contracts in the Restructured Electricity Markets:

A Law and Economics Perspective

Contracts in the Restructured Electricity Markets:

A Law and Economics Perspective

PROEFSCHRIFT

ter verkrijging van de graad van doctor
aan de Universiteit Maastricht
op gezag van de Rector Magnificus
Prof. mr.G.P.M.F. Mols

Volgens het besluit van het College van Decanen,
In het openbaar te verdedigen
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door

Laura Onofri

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When I started to be a research assistant at the Economics Department of the Law Faculty of the University of Urbino, my professor oriented my studies towards the restructuring process of the electricity markets.

I was not very eager to study electricity markets, until I read "*Markets for Power*", by Paul Joskow and Richard Schmalensee. The authors were applying Oliver Williamson's transaction costs framework to the electricity market deregulation process, and were concluding that restructuring would have substituted the vertical integrated organizational structure with a new market structure, mostly based on (long and short term) contracts between the different operators of the different production stages of the electricity markets. Nowadays, I can claim that they had a visionary perspective!

From that moment, I decided to pursue my research on contracts in deregulated electricity markets and from that moment my intellectual (and physical) trip started. Such trip has involved learning, studying, making contacts, meeting people, collaborating, exchanging ideas, presenting and publishing papers, getting obstacles, getting amazingly inspired by brilliant minds, facing moments of discouragement and moments of enthusiasm and many, many other work (and life) experiences.

The trip is now terminated and (part of it) is conveyed in this thesis.

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Maastricht, May 2006

Laura Onofri

Table of Contents

Introduction.....	1
1. Survey of the Economic Literature	9
1.1. Introduction.....	9
1.2. Empirical Contract theory	10
1.3. Survey of the Economic Literature on Electricity Contracts	13
2. Electricity Markets Restructuring	19
2.1. The Physical Characteristics of the Electricity Market.....	19
2.2. The Economic Characteristics of the Electricity Market.....	22
2.3. The Legal Restructuring of the Electricity Market: the EU Directives	25
3. Contracts, Investment Incentives and Efficiency In The Restructured Electricity Market.....	39
3.1. Introduction.....	39
3.2. Power Purchase Contracts in the Electricity Market	40
3.3. A Simple Contract Model	42
3.4. Economic Analysis of Power Purchase Contracts	44
3.5. Empirical Perspective: Discussing Some Experiences	55
3.6. Concluding Remarks.....	58
4. Price Formation And Legal Provisions In Electricity Contracts: An Empirical Study	65
4.1. Introduction.....	65
4.2. California Electricity Crisis	67
4.3. The Contracts' Institutional and Economic Framework	71
4.4. Long-Term Contracts and Market Organization.....	73
4.5. The Dataset	75
4.6. Hedonic Approach and OLS Estimation Results.....	78
4.7. SLS Estimation Results.....	83
4.8. SLS Estimation Results with Payment Schemes and Quantity Provisions as dependent variable.....	84
4.9. Concluding Remarks.....	88
5. Testing Williamson Theory On Transaction-Specific Governance Structures: Evidence From The Electricity Markets	91
5.1. Introduction.....	91
5.2. The Dataset and Descriptive Statistics.....	93
5.3. SLS Estimation Results.....	96
5.4. Maximum Likelihood Estimation Results	98
5.5. Concluding Remarks.....	100

6. Electricity Market Restructuring And Energy Contracts: A Critical Note on the EU Commission's NEA Decision.....	105
6.1. Introduction.....	105
6.2. Motivation and Literature Survey.....	106
6.3. Institutional and Empirical Background.....	107
6.4. The Nuclear Energy Agreement.....	109
6.5. The European Commission Decision.....	112
6.6. An Alternative Interpretation: A Simple Analytical Framework.....	115
6.7. Conclusive Remarks: Anticompetitive Effects or Misinterpretation?.....	122
7. Conclusions.....	127
Samenvatting.....	131
References.....	135
Curriculum Vitae.....	153

"If one is interested in seriously analyzing regulation and other institutional alternatives, it is necessary to open up the "black-box" of contracts" (Goldberg, 1970).

Introduction

During decades, the electricity industry around the world was organised predominantly as in the form of vertically integrated and mostly public monopolies. Recently, the liberalisation process aiming to introduce competition in the generating and supply segment of the industry has incurred dramatic changes. In Europe, the clear objective to create a competitive electricity market, formulated in Directive 96/92 and subsequently in Directive 2003/53, has led to an unexpected outcome. Where the Directives focus on the formation of a pan-European single electricity market, the restructuring process has given way to 15 more or less fragmented markets, each liberalised to a different degree and shaped following a wide range of different principles.

Boisseleau and Hakvoort (2005) argue that this outcome is partly due to the approach followed, which may be labelled as the '*Unstructured Restructuring Approach*'. In contrast to e.g. the U.S. liberalisation process, where the Federal Energy Regulatory Commission (FERC) has issued a proposal for standard market design and market power mitigation (the '*Notice of Proposed Rulemaking*', abbreviated as NOPR), in Europe, there is apparently a clear lack of what the European market design should look like. Additionally, the major issue of market power has been widely overlooked. In practice, the liberalisation process has focused extensively on the legal aspects describing the organisational network structuring but the European authorities forgot to pay due attention to the economic aspects of market design and the need for market monitoring. The authors indicate several critical areas where the European Union has failed to provide a proper and coherent market view. Positively, the paper will discuss why these issues are crucial for any electricity market. These relate to different aspects of market design, like market dynamics, congestion

management and long-term investment aspects, and to the Achilles-heel of liberalisation: the threat of market power.

Bergman *et al.* (1999) highlight the directive is silent on trading arrangements and market institutions that are necessary to support such restructuring for the creation of an integrated European market. Boisseleau and Hakvoort stress that the focus on institutional arrangements is not balanced by a view on the economic aspects: what a market in electricity should look like and how it is supposed to work. Indeed, creating an integrated market not only requires network access regulation and proper unbundling, it also needs designing market institutions and trading arrangements that are the heart of the market. One of the reasons why such arrangements are necessary for a market in electricity is that electricity is a network-related that cannot be stored in a commercially viable way. Therefore, the technical electricity system should be balanced minute by minute, which puts severe constraints on the flexibility and nature of electricity trade. Additionally, electricity is a product that cannot be transported over too long a distance as losses will increase. The institutions and trading arrangements should therefore describe the nature and conditions of electricity trading under these specific network and system related constraints. The creation of such arrangements is generally referred to as *market design*.

Ideally, the design of the market (including both structure and rules) should create a 'level playing field' for competing parties. However, international experiences (notably from California and the UK) have shown that once market mechanisms are introduced, market power, which is the ability to unilaterally manipulate prices, is a major concern in recently liberalised electricity markets. The introduction of competition in the electricity industry has produced the creation of multiple interdependent markets described as "*an extremely complicated non-co-operative game with a very high-dimensional strategy space*" (Wolak, 1999). Especially due to the high level of concentration of these markets its proper functioning must be ensured. For this purpose, it seems to be ineluctable to also install effective market monitoring. "*The creation of a really competitive electricity market requires not only 'liberalisation' but also needs to address both the issue of market design and*

market monitoring, which have been widely neglected (or even overlooked) in the European liberalisation process" (Boisseleau and Hakvoort, 2005).

The EU directive 96/92/EC represents the cornerstone of the European liberalisation process. However, it provides "*a framework in the loosest sense of the word: its objectives are laid down in general terminology and moreover, member states are given a substantial degree of choice in how they are about introducing more competition into their electricity markets. Indeed the margin is so substantial that it would seem possible for the determined anti-market countries to avoid introducing any meaningful degree of competition at all*" (Hancher, 1997).

"*While the new Directive 2003/54/EU aimed to correct the shortcomings of the initial Directive, it still holds most of the weaknesses of the first Directive, although the details differ.*" (Boisseleau and Hakvoort, 2005).

The criticism towards the EU Directives is the starting point of this thesis. In particular, we address the criticism about the lack of provisions on trading arrangements that are necessary to support such restructuring for the creation of an integrated European market. The study focuses on the analysis of electricity long-term trading arrangements in wholesale markets. Since the EU regulator was silent about such an important issue, the main research curiosity aimed at assessing and understanding how market agents reacted to the deregulatory dynamics; to assess the content of wholesale electricity contracts among generators; to scrutinize the agreements within the rigorous framework of economic theory, especially in order to derive a lesson for the policy-maker intervention (or non-intervention).

The thesis is organized as a set of four original essays, introduced by a general framework, aiming at providing the cognitive instruments to understand the manuscript, and concluded by some final remarks.

The first essays highlights and analyzes the tension between designing wholesale electricity agreements that reduce uncertainty for the private investors and running the power systems as more efficiently as possible in the restructured electricity market. The features of such agreements are

preliminary in resolving this tension and, therefore, in orienting the development of electricity markets restructuring towards a competitive direction. We define a theoretical contractual model, highlighting the tension between the two opposite directions: reducing uncertainty and risk in order to attract private investment and operating the power system efficiently. We apply the theoretical model for analysing the formal structure of a selected sample of power purchase agreements, really operating in the restructured electricity markets all over the world. We show how competitive contracting can increase efficiency pressures and, at the same time, increase investment risk. We then discuss some policy implications for the design of power purchase contracts in the restructured electricity market.

The second essays evaluate the effect of legal provisions on electricity contracts price formation. We consider 27 California long-term electricity contracts¹ for the trade of electricity between generators. We have created a dataset by using the contracts' main legal provisions, in order to perform an econometric exercise and target the main determinants that affect price in long-term electricity contracts. In general, the contracts contain information about the price at which energy is sold; (setting a minimum and a maximum price range); costs of energy production; quantity of energy produced; contract duration; dispatchability; type of fuel used to produce energy (natural gas or renewables, like wind, geothermal energy, landfill gas or biomass); type of electricity produced (whether base, peak or both); type of pricing mechanism (tolling, or fixed price); provisions about how to manage risk (fuel price risk; fuel supply risk; performance risk; demand risk; environmental risk and other type of risk). Given that the contacts set a minimum and a maximum price threshold we have performed separated econometric exercises. In general, these provisions affect the way the risk of the transactions is distributed between the parties and, therefore, render more (less) rewarding the transaction to that party that has to bear the highest (lowest) risk. This interpretation of the results confirms the economic theory on agents' incentives. The variables that affect the formation of the

¹ The small number of analysed contracts is due to the extreme difficulty to find such agreements and have the possibility to assess their content.

(minimum) price are less related to risk issues and to strict contractual provisions. This might suggest that the definition of an electricity contract minimum price mainly depends on other structural variables that we did not capture in our dataset and analysis, and that contractual provisions affect the definition of a maximum price, but are less preponderant in explaining how the minimum price is formed. The empirical results provide support for the hypothesised relationships and are robust to different model specifications and alternative estimation techniques.

The third essay represents one of the first attempts to test Williamson's theory (about the relationship between asset-specificity and market organizational forms) in the restructured electricity markets. In particular, following Joskow (1987), we attempt to empirically capture the positive relationship between physical assets specificity and the duration of long-term contracts stipulated between California electricity generators. In addition, following Masten and Crocker (1985), we try to capture the effect of legal provisions on contracts duration and interpret them as efficient instruments for providing flexibility in long-term relationships. As the investment in relationship-specific assets becomes more important, the longer becomes the contractual duration. However, the parties will mitigate the long-term contracts inflexibility, based on *ex ante* bargained terms and conditions, with provisions that allow for contingent adaptation. The empirical results provide support for the hypothesised relationships and are robust to different model specifications and alternative estimation techniques.

The fourth essay focuses on a case-study that highlights the relationship between long-term contracts and vertical integration in the restructuring of the electricity market in UK. In the early 90's, during the restructuring of the electricity market in UK, the three main Scottish electricity generators stipulated a long-term, "take-or-pay" contract, the Nuclear Energy Agreement, which contained provisions for the trade of wholesale electricity in Scotland.

The European Commission scrutinized such contract in order to derive the congruity of the agreement to European laws. Whilst the NEA was awarded an exemption under Article 85, paragraph 3 of the EU Treaty, the Commission recognized the inner anticompetitive content and

potential effects of the contract. The essay criticizes the Commission NEA decision and economic reasoning and provides an alternative reading and analytical approach, which lead to opposite results and conclusions (the NEA contract is not anticompetitive and it enhances efficiency in competitive electricity markets). Given that the restructuring process in the EU electricity market is still *in fieri*, we select the NEA contract as a benchmark-case, in order to provide an alternative reading and a case-study for eventual, future energy contracts administration and authority decisions.

PART I

Foundations

1. Survey of the Economic Literature

This section surveys the main literature contributions in the field of the economics of contracts, in particular empirical contract theory, and economics of electricity contracts.

1.1. Introduction

Masten (2000) defines a contract as a legally enforceable agreement. Although economists—and (occasionally) lawyers—have used the term more expansively to describe essentially any transaction, the term *contract* is reserved for “*formal, legal commitments to which each party gives express (though not necessarily written) approval and to which a particular body of law applies*”. What distinguishes a contract from a mere transaction is the opportunity contracts afford transactors to invoke the formal dispute resolution machinery and coercive power of the state to enforce promises. This definition is instrumental to highlighting the fundamental link between contract design, on the one hand, and contract enforcement, on the other: The choice of contract terms will depend in part on the legal rules and enforcement policies transactors expect courts to follow while, at the same time, the enforcement practices of efficiency-minded courts will depend on what courts perceive as the purpose and impediments to contracting. In short, the analysis of contract law and enforcement presupposes a theory of contracting behaviour, and vice versa.

Perspectives on contracting can be divided into three broad categories. The first consists of formal models associated with the principal-agent and asymmetric information literature, including theories of both complete and incomplete contracting; the second covers perspectives on contracting implicit in the law and economics literature on contract law and enforcement; while the third consists of what has come to be known as relational contracting theory, an approach often associated with transaction cost economics. Dimensions along which the theories differ include the functions of contracting, the impediments to contracting, and the role of courts and their implications for legal rules and contract enforcement. The theories differ in their ability to explain and predict actual

contracting behaviour. Last but not least, there exists a growing research field that attempts to capture empirical evidence in contractual choice. The latter represents the research method of the thesis.

Although theoretical tensions are likely to persist between those who value axiomatic rigor and those willing to invoke empirical regularities to develop testable predictions, the two approaches appear to be converging, namely, that further progress on understanding contracting requires a better appreciation of the interactions of contract design and contract enforcement and a recognition of the process functions of contracting (cf., Tirole, 1994).

1.2. Empirical Contract theory

One of the most firmly established regularities in the empirical literature on contracting is the association between relationship-specific investments (or reliance) and the use and duration of contractual agreements. A seminal example is Joskow's (1987) econometric analysis of the duration of nearly 300 coal contracts. Exploiting regional differences in the characteristics of coal and transportation alternatives and variations in contract quantity, Joskow's study showed the duration of coal contracts to be significantly correlated with measures of physical- and site-specificity and dedicated assets. A more recent study of engineering subcontracting practices in the United Kingdom by Lyons' (1994) suggests that specificity affects not only the duration of contracts but the decision to contract in the first place. The engineering firms and subcontractors in Lyons' sample were significantly more likely to adopt formal contracts, over more flexible but less secure informal agreements, where investments in relationship-specific physical and human capital left the subcontractor vulnerable to ex post opportunism.

Empirical research has also identified a correlation between long-term contracting and specificity in natural gas (Crocker and Masten, 1988); petroleum coke (Goldberg and Erickson, 1987); and ocean shipping contracts (Pirrong, 1993), among others.

Contracting appears less attractive as a way of governing production and exchange, however, where the alternative to contracting is integrated ownership and production. Empirical research on integration decisions reveals a consistent preference for integration over contracting as the specificity of investments increases (for overviews, see Joskow, 1988; Shelanski and Klein, 1995; Crocker and Masten, 1996). Contracting thus appears to be only an imperfect response to the hazards posed by relationship-specific investments. Empirical research suggests, moreover, that the costs and limitations of contracting grow with the complexity and uncertainty of the transaction. In Lyons' (1994) study of engineering transactions, for example, firms were less likely to use formal contracts for advanced technology projects than for relatively simple procurements. Meanwhile, Goldberg and Erickson (1987) and Crocker and Masten (1988) found that contract duration in petroleum coke and natural gas contracts decreased in periods of increased uncertainty, contrary to what would be expected if risk-sharing were the primary motive for contracting. Research on the determinants of make-or-buy decisions suggests that uncertainty and complexity diminish the attractiveness of contracting relative to integration as well (e.g., Masten, 1984).

Though clearly an important determinant, the protection of specific investments is not the sole motive for contracting. Unsupported assertions to the contrary notwithstanding, relationship-specific investments in franchising appear to be modest and unimportant as a motive for franchise contracting (see Lafontaine and Slade, 1997, 1998). Indeed, the viability of some contractual arrangements, such as franchising and equipment leasing, may depend on assets actually being redeployable at low cost (Klein, 1995; and Masten and Snyder, 1993). Case studies have also shown benefits of contracting to accrue to the desire to control free-riding on the provision of information or services (e.g., Rubin, 1978; Masten and Snyder, 1993) and to avoid unproductive search and sorting costs (Kenney and Klein 1983; Gallick, 1984).

The empirical literature offers broad support for the proposition that transactors choose contract terms to promote efficient adaptation and mitigate transaction costs. In studies of natural gas contracting, Masten and Crocker (1985) and Mulherin (1986) found that take-or-pay percentages in

natural gas contracts varied with the alternative value of gas reserves, supporting an incentive interpretation over the alternative view that take-or-pay provisions serve distributional or risk-sharing purposes (e.g., Hubbard and Weiner, 1986). Case studies describing the use of minimum purchase requirements for coal (Carney, 1978) petroleum coke (Goldberg and Erickson, 1987), and bauxite (Stuckey, 1983), among other products, corroborate this finding (see Masten, 1988, p. 91-92, for a discussion). In a related study, Crocker and Masten (1988) found that the prospect of inefficient adaptation associated with distortions in the size of take-or-pay provisions significantly reduced the willingness of parties to engage in long-term contracting.

Incentive considerations also appear to be influential in determining sharing arrangements. Lafontaine (1992), for example, found that royalty rates across franchises tend to vary with the relative importance of franchisor and franchisee effort. Observed correlations between uncertainty and royalty rates (and the use of franchised versus company outlets) are inconsistent with standard assumption of franchisee risk aversion, however. (Reviews of the empirical literature on franchise contracting can be found in Lafontaine and Slade, 1997, 1998).

Risk sharing as a motive for contracting has fared poorly in other settings as well. Allen and Leuck (1992), for instance, conclude that the incidence of crop-share versus fixed-rent contracts between farmer-tenants and landowners are unrelated to the riskiness of crops.

Whereas most of the empirical contracting literature focuses on standard price and quantity provisions, research on relational contracting has sought to account for the widespread use of contracts that leave important terms like price and quantity indeterminate. Examples of such provisions include price renegotiation and «market out» provisions in natural gas contracts (Crocker and Masten, 1991), «gross inequity» provisions in long-term coal contracts (Joskow, 1985), termination-at-will and best efforts clauses in franchise agreements (Hadfield, 1990), and substantial performance requirements in construction contracts (Goetz and Scott, 1981).

Large scale analyses of relational contract provisions have focused on methods of price adjustment. Crocker and Masten (1991), for instance, conclude from their study of price adjustment

in natural gas contracts that circumstances favouring the use of long-term, fixed-quantity agreements favor the adoption of relatively indefinite price adjustment provisions over formulaic adjustment mechanisms that, although less costly to implement, are more likely to induce efforts to evade performance obligations in extreme situations. As Goldberg and Erickson (1987) note, greater reliance on renegotiation provisions in fixed versus variable quantity contracts is difficult to reconcile with incentive alignment motives.

The available evidence thus generally supports the notion that transactors' choice of contract terms reflects a trade-off between the specification costs and rigidities associated with specifying detailed performance obligations in uncertain or complex transactions, on the one hand, and the greater flexibility but higher expected cost of establishing the terms of trade ex post in less definite relational contracts.

Theories that place confidence in the ability of parties to effect private orderings either through ex ante specification of contingent performance or through low-cost, ex post negotiation will favour a policy of passive judicial enforcement, whereas theories that emphasize the behavioural and cognitive impediments to ex ante alignment and ex post negotiation without similar regard for the cognitive limitations of judges will tend to favour more active enforcement and intervention by the courts. More subtle but important issues like the effects of contractual protections on the willingness of transactors to make relationship-specific investments are just beginning to receive scrutiny (e.g., Saussier, 1998).

1.3. Survey of the Economic Literature on Electricity Contracts

The seminal work by Joskow and Schmalensee (1983) applies transaction costs economics to discuss how electricity markets should be restructured. According to the authors, the characteristics of the new deregulated electricity market would lead to stipulate contracts having some of the following features.

1) The electricity transactions should be regulated by long-term contracts (ten to twenty years at least) and they should be negotiated before a plant is built.

2) Purchasers and sellers should oblige themselves to pay and to provide fixed minimum quantities of power each year under a contract. These commitments should be invariant for the entire year, so that the generation firms and the transmitter could rely on, at least, a period of certainty

3) Purchasers should agree to pay the promised quantities of power, via a payment system that could shift a substantial amount of the risks of cost increases to them. In order to provide incentives to the development of the market, the buyers should bear a substantial fraction of the risks of cost increases beyond the control of the supplier. Sellers should continue to bear some risks in order to provide incentives for cost minimisation. These provisions seem necessary in order to finance large plants investments in an unregulated scenario, where opportunistic behaviour is a serious problem.

Fundamental to the analysis of contracts in electricity wholesale markets are the longer run issue of entry and investment. A number of authors (Powell, 1993; Newbery, 1998; Wolak, 2000) have shown that long-term contracts can reduce wholesale electricity prices in the presence of market power. Powell, Green and Wolak focused on the static impact of contracts on companies' bidding strategies. They find that contracts tend to put a downward pressure on spot prices. Although, this provides disincentive for generators to offer such contracts, there is a countervailing force in that selling a large number of contracts commits a firm to be more aggressive in the spot market, and ensures that it is dispatched to its full capacity in more demand scenarios. They find asymmetric equilibria for variable demand scenarios where such a commitment is useful.

Powell early studies include contracts, and examine their impact on an imperfectly competitive electricity spot market, the U.K. pool. Powell explicitly models the effect of reconstructing by Regional Electricity Companies (RECs) after the maturation of the initial portfolio of contracts set

up after deregulation. He adds risk aversion on the part of RECs to the earlier models. Generators act as price setters in the contract market, but they compete in a Cournot equilibrium in the spot market. The RECs set quantities in the contract market. He shows that the degree of coordination has an impact of the hedge cover demanded by the RECs, and points to a 'free rider' problem which leads to a lower hedge cover chosen by the RECs.

Newbery (1998), in particular, extends the supply function model² of the England and Wales electricity spot market to include a contract market, and argues that, when combined with entry, this can have dramatic effects on competition and performance. He models competition in the electricity wholesale market as a two stage game in which firms first offer a fixed quantity of contracts at a specified price, and then consumers decide whether to accept the contracts on offer. The total amount of contracts is revealed, and producers submit supply functions to the spot market. In this framework, Newbery shows that the effect of contracts is to make the spot market more competitive because generators are willing to supply a given quantity for a lower price than in the absence of contracts. However, and precisely because of this pro-competitive effect, generators may choose not to contract if they assume that their contract positions have no effect on the level of contracts offered by the rivals. Increasing contracts cover moves the net supply function to the right; this lowers prices and reduces profits. Newbery argues that the generation market becomes contestable if entrants can sign long-term base load contracts. Using these contracts, potential entrants can lock in future prices and avoid the risk of retaliatory action by the incumbents. The incumbent generators then have an incentive to bid in such a way that the average spot market price is just below the price at which contract-backed entry of independent Power Producers was attractive (i.e. the average total cost of the entrants). This in turn induces the incumbents to sign contracts which mitigate their incentives to

² The supply function model is a model by Klemperer and Meyer (1989), who modelled an oligopoly facing uncertain demand. In such setting firms would prefer to set supply functions rather than compete in prices (Bertrand competition) or quantities (Cournot competition). The authors observed that under demand uncertainty, given any hypothesised behavior by other firms, the residual demand facing each firm is uncertain and hence each firm has a set of profit maximising points, one corresponding to each realization of its residual demand. If firms must decide on their strategies in advance of the realization of demand, then they are better off specifying an entire supply curve, rather than a single price or quantity.

raise prices in the pool, thus ensuring that contracts and pool prices converge: "...Contracts are thus doubly critical for competition. The contract cover reduces the incentive to exercise market power in the pool, while contracts make entry contestable. This gives the incumbent an incentive to keep pool prices down, which they can do by selling contracts. Indeed, the best strategy for entry-detering duopolists to coordinate on is to choose a level of contracts that maintains the average price just below the entry price...". Newbery also argues that one effect on incumbent generators following this entry-detering strategy is for incumbents to increase the spread between peak and off-peak prices, thus increasing price volatility in the pool. However, as entry occurs, the increase in the number of competitors "lowers spot price volatility, increases efficiency and raises consumer surplus". Newbery shows that, for a given aggregate capacity level, when the number of firms is above a critical level, firms will not be able to credibly commit through contracts to prices low enough to deter efficiency entry.

von der Fehr and Harbord focus on price competition in the spot market with capacity constraints and multiple demand scenarios. They extend their analysis of spot market competition to include a market of long-term contracts. The analysis identifies a number of important effects that the existence of (options) contracts may have on prices and market performance. In particular, they show that there are critical quantities of contracts that must be held by the generators for contracts to have any effect on electricity spot prices. In most cases when contracts are held in large enough quantities, the effect is to reduce spot prices to contract prices. Von der Fehr and Harbord also found that by selling a large quantity of forward contracts, a generator may be able to commit itself to a low-pricing, high output strategy in the pool, thus forcing its rivals to maintain high prices at the expense of their own output. Contracts, therefore, may have a commitment value, and hence be profitable only if sold for a low price.

With respect to the relationship between contracts and institutional setting, Saveedra (2001) analyzes post-contractual disputes in the newly privatized electricity sector in Chile and discusses the presumption that opportunistic behaviour and disputes arise due to inadequate market design,

ambiguous regulation, and institutional weaknesses. The author assesses the presumption that a large number of legal (public) disputes are inhibited by the non-existence of institutions able to verify and enforce contracts. An in-depth analysis of 6 cases of open conflict provides support to such presumptions and highlights the crucial role of an adequate (pre-privatization) market design. In addition, he concludes that the reduced number of open conflicts observed in Chile is probably due to institutional weaknesses, which induces the parties to use private conflict resolution mechanisms.

Finally, with respect to the long-term contracts issue, Green (2003) argues that long-term contracts for electricity can counter market power and reduce prices in short-term markets. If electricity retailers face competition, however, companies signing long-term contracts are exposed to the risk that a fall in short-term prices would allow rivals to buy on the spot market and undercut them and this could lead to less contracting and higher prices. The author combines a model of electricity retailing and a Cournot model of competition in the wholesale markets to estimate the size of this effect, and finds that it could raise wholesale prices by two or three percent.

Borenstein (2002) writes that long-term contracting is an important part of the solution to the fundamental problem of the electricity markets but it does not solve the mismatches between supply and demand. It just prevents large fluctuations in electric bills when those mismatches occur. It can, however, be used to pay for excess or standby capacity by assuring that the generating companies receive payments sufficient to cover their capital costs even if demand turns out to be low and some of the capacity does not get used. In fact, this is what the old regulatory system did. Utilities were assured of revenues to cover their costs and in return built sufficient capacity to make sure that all contingencies could be covered. Supply always exceeded demand by a significant amount and the costs that idle capacity was rolled into the price that customers paid for the power that they did use. Many players in California markets now advocate a return to this type of system in a quasi-deregulated electricity market. Utilities could sign long-term contracts for power and capacity that assured generators they could recover their costs even if the capacity were not actually used. A number of state and federal policymakers have argued that the state should always make sure that the

capacity exceeds demand by at least 15%. A policy of holding excess capacity would assure that spot prices were always very low (assuming that no generators held a large market share) and that many new "peaker" plants were built to assure excess capacity but virtually never used. This outcome would be unfortunate, since it does not make sense to hold such capacity if the customers' value of consuming the additional power when it is used is less than the full cost of making the power available. Real-time retail prices that reflect the cost imposed by additional consumption in each hour are the ideal mechanism for making that trade-off. Thus far, California and other states have attempted to make electricity markets work almost entirely on the supply side of the market. This approach has worked relatively well in some markets but the California crisis has demonstrated the variety of constraints that exist on the supply side. Deregulating only the supply side of the market seems to be the equivalent of making an electricity market operate with one arm tied behind its back. Combining long-term contracts with real-time pricing can provide the right economic incentives to reduce demand at peak times when the system is strained, while still assuring customers of relatively stable monthly bills.

2. Electricity Markets Restructuring

The section is an introduction that describes the physical characteristics of electricity; the economic characteristics of electricity markets and the EU deregulation legislation. The chapter introduces basic, fundamental concepts that are important for the understanding of the analytical part of the manuscript.

2.1. The Physical Characteristics of the Electricity Market

The existing matter is composed of atoms: massive positive nuclei surrounded by a cloud of enough negatively charged electrons to make the atoms as a whole electrically neutral. If an electron is moved away from its own atom, an electric force on neighbour electrons due to the resultant net positive charge is created. A neighbour electron jumps the gap, leaving its own home atom positively charged. This process continues and creates electricity. Electricity is, thus, a process of "charge displacement", it is energy created by the electrons in movement. Electricity is energy, if considered as a stock variable (and it is measured in watts); it is electric power, when it is taken into consideration as a flow variable (in this case it is measured in joules).

Electric power p can assume positive and negative values depending on the interval of time under consideration. A positive p indicates a transfer of energy from the source to the network, while a negative p corresponds to a transfer of energy from the network to the source.

Electric power can assume other interpretations. Electric power is said to be real (and it is indicated by P and measured by the watt), when we refer to the amount of electrical energy absorbed by the resistive elements of the circuit. Electric power is defined as reactive (indicated by Q and measured by volt-ampere-reactive, var), for indicating energy flowing from one part to the other, not real energy, but power useful in the transport of active power.

Electricity is usually supplied to a circuit element. This can cause three kinds of reactions. If the energy is consumed, then the circuit element is a pure resistor. If the energy is stored in a magnetic

field, the element is a pure inductor. If the energy is stored in an electric field, the element is a pure capacitor. In practice, a circuit involves any combination of resistors, inductors and capacitors, even if one may be predominant. When the current in a circuit changes, the magnetic flux linking the same circuit varies as well. The change in flux causes an electromotive force to be induced in the circuit; this force is proportional to the time rate of change of current, if the permeability is constant. The constant of proportionality L is the inductance of the system.

Electric power systems are high voltage circuits that are high voltage connections of several nodes. They consist of a number of individual nodes connected by high voltage transmission lines. A node is a point in a network common to two or more circuit elements. If three or more elements join at a node, that node is called principal node or junction. To each node in an electric power system can be assigned a different role: some nodes may represent low voltage distribution systems, others are generating plants, others are points where transmission lines are joined together.

Power flows are functions defined by four basic types of variables: real (P) and reactive (Q) power, voltage magnitude (V) and the phase angle θ . When P and Q are positive, they represent an injection when are negative, represent a withdrawal of power. Power flows move on the electric circuit or on the electric power system according to Kirchoff's laws, the physical rules directing the electrons on the grid. In fact, electrons move, by following the path of least resistance; therefore, individual generators within a power system cannot physically direct their output to any particular demand point. A generating plant can only affect the mechanical energy applied to the generator itself and the electrical energy applied to the generator field.

Power flows along transmission lines in a power system depend on the amount of power generated or demanded at each bus. However, the amount of power that a line can carry without developing a line overload and threatening the integrity of the whole system is limited. Therefore, Kirchoff's laws are essentials in indicating the relationships between power injections and withdrawals in the nodes and the power flowing over transmission links.

In order to the study the equations governing the power flows of the grid, we have to take into account the network flowing constraints, deriving from transmission losses and congestion. While being transmitted along the network, some power is "lost" along the grid. Bjorndal (2000, p.13) defines the real power loss of line gt as equating $P_{gt} + P_{tg}$. This power loss is a quadratic function, approximately proportional to the square of the power flowing over the line. In power systems, total losses constitute 2-5% of total generation, and are found by adding (positive) injections and (negative) withdrawals $\sum_{g=1}^n P_g$.

Also congestion can create a network flowing constraint, because, whenever a line is congested generation cannot increase at that node, even if other lines are uncongested. Suppose that from the generation node g , three lines (1, 2, 3) arise. Increasing injections at node g will increase outflow on lines 1, 2, and 3 in proportions depending on the loads of the entire network. If line 1 and 2 are uncongested and line 3 is congested, generation cannot increase in node g because it would increase flow over line 3, which is already at its limit. To relieve the congested line 3, generation has to occur in a different node.

The sum of the rises of potential around any closed circuit equals the sum of the drops of potential in that circuit. In other words, the algebraic sum of the potential differences around a closed circuit is zero. With more than one source, when the directions do not agree, the voltage of the source is taken as positive if it is in the direction of the assumed current. This Kirchoff's law implies that we can calculate the voltage across the line as a nodal voltage difference. Following Bjorndal (2000, p.9), the voltage drop of line gt equals $V_g - V_t$.

Another important law, governing the power flows in the network, is the *law of conservation of energy* according to which, total generation equals total consumption plus losses.

In order to have static electrical equilibrium, the sum of the power demanded at load buses must equal the sum of power supplied at generation buses minus the amount of power lost in transmission. The system operator (SO) has to solve a very complicated optimisation problem, in order to derive

the equilibrium of the power system. The generation and consumption of electricity must be balanced continuously to maintain the frequency, voltage and stability of an electric power network and to avoid sudden losses of power.

The sum of power (active and reactive) lost in transmission equals the sum of power supplied at generation buses minus the sum of power demanded at load buses. The amount of such line losses is a complicated function (in many cases a quadratic approximation) of the loads and generation at each bus. Beyond transmission losses, the SO has to consider several constraints, like voltage constraints, instabilities, unexpected contingencies, stability of the grid requirements, transmission congestion

2.2. The Economic Characteristics of the Electricity Market

A very complex structure features the electricity market, and this complexity affects the design of the restructuring project and the definition of its legal framework. The electricity industry, in fact, presents peculiar features, including: temporal and stochastic variability of demands and supply, non-storability of power, multiple technologies with varying sensitivities to capital and fuel costs, environmental and siting restrictions, dependence on secure and reliable transmission system.

The generation function generally includes planning, designing, constructing, procuring fuel³ for, and operating the facilities necessary to produce electricity for delivery to consumers. Producing electricity means to supply a very particular good: electricity cannot be stored, except at prohibitively high costs, and it must be moved on a closely co-ordinated, integrated system, displaying large economies of scale. Electricity, in fact, can't be stored, because supply and demand conditions change virtually instantaneously on an interconnected system, making it impossible, for

³ The most important energy inputs are of three kinds: fossil fuels (coal, oil, gas, orimulsion, a particular input produces from bitumen), nuclear fuels and renewables. All these sources involve high environmental costs: emissions of CO₂ and SO₂, generated by the burning of fossil fuel, have to be controlled and regulated in order to minimise the risk of acid rains and greenhouse effects; nuclear plants have had huge decommissioning costs. The choice of energy inputs depends on local availability of energy carriers, on environmental requirements, and on the economics. Renewable electricity sources like hydro, solar, wind and geothermal clearly site dependent. Access to gas pipelines and port facilities may limit the choice of fossil options, or at least require additional investment

decentralized markets, to manage physical transactions efficiently. At the same time, electricity demand, fluctuates by time of day and years, as the weather varies, and randomly. Supply is also subjected to predictable outages. However, equilibrium between supply and demand must be maintained continuously and throughout the system. This combination of circumstances poses considerable problems for the organization of supply. In addition to fuel costs, electricity generation is capital intensive and investment costs are sunk. Capital intensity is related to the type of energy sources. Nuclear power, for instance, implies the highest fixed costs and the longer lead times, but it presents proportionally low operating costs; gas constitutes the most expensive fuel source, but it has lower variable costs. In the short run, electricity supply is constrained by the capacity limits of power stations: supply security requires that total capacity exceeds expected demand with a margin to allow for uncertainty. There exist, in act, start-up costs whenever a station is switched on, and so it may be better to keep it running for a period when it is not producing rather than turning a station off and on again. In the longer run, theory and evidence both indicate increasing returns at low levels of production and approximately constant returns otherwise.

The transmission function generally includes planning, designing, constructing, and operating the facilities necessary to deliver bulk energy from generating stations and from neighbouring systems to terminals at which the voltage is transformed to lower levels for delivery of energy to customers. Electricity is very costly to transport. Transmission is capital intensive and costs are sunk: it constitutes a natural monopolistic activity because duplication of cables between two locations would generally be inefficient. Electricity is not transmitted *brevi manu*; there is not directly physical trade: at any time generators supply some power into the general system at one "node" and transmitters withdraw it.

Electricity flows cannot be directed along particular paths in the transmission system; they are allocated by nature, according to physical laws. The balance between supply and demand has to be maintained continually throughout the system, in order to avoid non-localized power outages, like

blackouts. These requirements imply a close “minute-by-minute” co-ordination between generation and transmission; and that is why the two stages have been traditionally vertically integrated.

A major element of transmission costs is constituted by the power losses. The rate of loss is an increasing (approximately quadratic) function of the net power flow, along transmission lines. It is, thus important to design the stream of energy path, in order to minimize the power losses; and this is possible, by exploiting those nodes in the network, where the power supply will reduce, rather than increase, losses.

Armstrong and al. (1994, page. 283-284) discuss a two node case example.

Figure 1: Electricity Transmission Lines

In this case, power flows go from north to south. Incremental supply at the northern node can add losses, while incremental supply at the southern node will reduce them. Losses are similarly affected by incremental demand, but with opposite sign. Efficiency issues require that location price differences take into account incremental losses: in this case, producers and consumers at the North Node should face lower prices than those at South Node. But, in the short run transmission capacity limits may constrain power flows, and negatively affect the overall capacity and efficiency of the system. In fact, if northern generators are more efficient than those in the south (despite the power losses), but if north-south transmission is limited by transmission constraints, part of the southern demand has to be served by the inefficient southern generators.

The distribution function provides for delivery of energy to the end-use customers. This stage includes planning, designing, installing, and operating the facilities necessary for delivery of energy at lower, as compared to transmission, voltage levels.

Distribution companies take power from points on the national transmission grid at high voltage levels and reduce voltages by transformers to levels appropriate for industrial and domestic use. Even this stage is characterized by capital intensity, sunk costs and natural monopoly costs conditions in any given area; therefore, duplication of wires would be inefficient. Distribution companies also provide supply functions. The supply function consists in purchasing electricity in bulk to the generators and selling it directly to large retail consumers.

While the generation stage is open to competition, transmission and distribution stages are natural monopolies, still requiring control and strict regulation. This, of course, implies that the implementation of full competition is not possible yet, and regulation in different market fragments is still requested.

2.3. The Legal Restructuring of the Electricity Market: the EU Directives

The EU directive 96/92/EC⁴ defined common rules for the generation, transmission and distribution of electricity. In June 2003, the European Commission published Directive 2003/54/EC⁵ concerning common rules for the internal market in electricity and Regulation No 1228/2003. The new Directive aims at opening up the electricity market more rapidly, reinforce the conditions which encourage real and fair competition and introduce a real single European-wide market. The new Directive replaces Directive 96/92/EC and establishes common rules for the generation, transmission, distribution and supply of electricity. The new Directive amends and recasts the earlier electricity Directive and includes provisions for the legal unbundling of the transmission and distribution

⁴ “Directive on Common Rules for the Internal Market in Electricity”, 96/92/EC OJ L27 of 30.01.1997. For recent amendments, see “Amended proposal for a Directive amending the Electricity and Gas Directives and Amended proposal for a Regulation on cross-border exchanges in electricity (COM(2002)304final of 07/06/2002)”

⁵ “Directive concerning Common Rules for the Internal Market in Electricity and repealing Directive 96/92/EC, 2003/54/EC of 26.06.2003”

system operators, consumer protection and the establishment of independent national regulatory authorities. The new Directive aims to reduce the risk of market dominance and predatory behaviour and to ensure non-discriminatory transmission and distribution tariffs and network access. Finally, the new Directive establishes provisions for the unbundling of transmission and distribution operators and prescribes labelling requirements for electricity suppliers regarding CO₂ emissions and radioactive waste from electricity production and the contribution of each energy source in a supplier's fuel mix.

This paragraph describes and discusses the main aspects of the two Directives. The 2003 Directive considers a gradual establishment of a single internal electricity market in distinction to 15 liberalised national electricity markets. For this, member States are obliged to open their national electricity supply market, which means that eligible customer must be able to choose their supplier. Moreover, the generation activity is totally free, allowing competitive electricity prices. Finally the operation of the transmission network has to be independent from generation and distribution at least in managerial terms in order to avoid discrimination.

The directive aims at full competition in the generation sector by removing the monopoly incumbent players had on the construction of new power plants. For this purpose, the 1996 Directive provided two alternatives to member states: an *authorisation* or a *tendering* procedure (articles 4–6). Under the first option, member states have to define public criteria and procedures, followed by an open and impartial procedure deciding which companies willing to build new power plants are allowed to do so. Under the second option, a specific authority designated by the Member State defines the needs for new investments and solicits tenders. The tenders are then accessed by an impartial procedure. The 2003 Directive prescribes Member States to apply the authorisation procedure and, only in case of insufficient capacity, the tender procedure may be used as a back up.

Concerning transmission, each member state must directly establish a transmission operator (articles 7–9). The role of the system operator is defined concerning its main tasks, i.e. generation dispatch and determination of the use of the interconnections. This part of the directive implies that

the system operator must dispatch power plant on a non-discriminatory basis between incumbents and new entrants. The goal of separation between generation and transport is to insure transparent and fair access to the network in order to avoid discrimination and cross-subsidisation between consumers (eligible and captive).

Electricity distribution must follow the same principles as electricity transmission concerning non-discrimination and independence from generation and supply (articles 10–12). Furthermore, it specifies that supply to final customers may be regulated as long as they are not eligible. An important distinction between distribution and transmission is that member states may impose requirements on distribution companies to meet specific public service obligation. Although this notion is not clearly defined it must relate to one of three categories: security of supply, price-quality of supply, or environmental protection.

Following the need for separation of activities, the directive also requests unbundling and transparency of accounts (articles 13–15). Hence, companies with generation, transmission and distribution activities must present separate balance sheets for each activity. The objective of this accounting unbundling is to avoid any cross-subsidisation between different types of activity. Under the new Directive, strict unbundling is required for transmission system operators. The new Directive also introduces a new type of unbundling by requiring integrated electricity companies to unbundle their accounts making a clear distinction for supply activities to eligible customers and non eligible customers.

The heart of the directive is the model of third party access (articles 16–18). The idea is that owners of a network are obliged to allow generators, traders and consumers to have access to their network in order to trade in accordance with the objectives of transparency and non-discrimination. The directive included three models for this: negotiated third party access (nTPA), regulated third party access (rTPA), and the now obsolete single buyer model. In the nTPA model, consumers and producers must be able to negotiate access to the network with the system operator. For this purpose, the system operator must publish an indication of the access price as a guide to potential new

players. In the rTPA model, the tariff for network access is regulated and not subject to negotiation. The tariff must be publicly available. The system operator may refuse access to the network for technical reasons but such refusal must be motivated by a legitimate reason. Finally, the single buyer model, in which a nominated entity acts as the sole purchaser of electricity, was included to appease France. Each member state was free to choose a different model. In the new Directive only rTPA must be adopted.

Finally, the directive specifies the extent of the market opening (article 19), which was defined as the percentage share of the electricity market that should be opened to competition. The directive defined thresholds for market opening, 40 GWh by 1999, 20 GWh by 2000 and GWh by 2003. These thresholds represent minimum requirement of market opening of 26% in 1999, 28% in 2000 and 33% in 2003. According to the new Directive, full opening of the electricity market for all consumers should be achieved in 2007.

The EU directive 96/92/EC represents the cornerstone of the European liberalisation process. However, it provides *"a framework in the loosest sense of the word: its objectives are laid down in general terminology and moreover, member states are given a substantial degree of choice in how they are about introducing more competition into their electricity markets. Indeed the margin is so substantial that it would seem possible for the determined anti-market countries to avoid introducing any meaningful degree of competition at all"* (Hancher, 1997).

"While the new Directive 2003/54/EU aimed to correct the shortcomings of the initial Directive, it still holds most of the weaknesses of the first Directive, although the details differ." (Boisseleau and Hakvoort, 2005).

The directive provides only guidelines while leaving actual implementation to the national governments. Such an approach leaves a large freedom to member states (which is condoned by appealing to the principle of subsidiarity). The directive focuses on administrative and legal unbundling and on the creation of a non-discriminatory and level playing field. With respect to liberalisation of end consumers it requires only 'soft' restructuring. However the directive is silent

on trading arrangements and market institutions that are necessary to support such restructuring for the creation of an integrated European market (Bergman et al, 1999). In Europe, paradoxically, the design of the 'European' market has been left to each national country. It is not surprising that this process has led to the creation of very different market designs. In order to illustrate the diversity of market design within Europe this section will describe the characteristics of the different European markets with respect to some key aspects of market design: short-term market mechanisms, congestion management and long-term aspects.

From the point of view of European market design, the energy commodity market (including short-term organised markets and the bilateral market) is separated from transmission. Short-term organised arrangements exist for both spot trade and balancing services. For the first one, numerous power exchanges have emerged providing organised marketplaces for day-ahead trading. For the second one, different arrangements are being applied as market-based ('balancing markets') and non-market-based ('balancing mechanisms') mechanisms to cope with system imbalances.

The institutional setting of these two types of markets is totally different, as power exchanges are private entities independent from the Transmission System Operator (TSO) while imbalance mechanisms are directly managed by the TSO.

With respect to national and international congestion the European markets combine different mechanisms. In general, at a national level congestion is not priced. The costs are socialised *ex post* (after physical delivery) among the users of the system. Hence at this level, congestion is managed by the national TSO according to national rules and not by market-mechanisms. At the international level, cross-border exchanges use a system of physical transmission rights (PTRs). This approach allows market participants to conduct their trades insulated from the details of system operation. Such a system allows *ex ante* (before physical delivery) pricing. The major difference between a physical transmission rights approach and a financial transmission rights approach as being applied in some areas in the U.S. is in the final settlement and its impact on the value of a transmission right (Green, 1998). In a PTR system, the price of transmission is set in advance by market participants,

while in a FTR system the prices are determined ex-post by the TSO. In practice, although the Association of European Transmission System Operators is working on harmonised international congestion management methods across Europe, the resemblance between the cross-border allocation mechanisms is superficial and many fundamental differences can be shown to exist.

At this moment, each country in Europe has its own energy programme responsibility system, with different procedures and different requirements. Absence of a minimum level of harmonisation appears to hamper international trade. Furthermore, for market design not only short-term market dynamics are important, but also long-term market development. Due to the fact that electricity storage is not yet commercially viable, the power system should develop in such a way that adequate supply remains available to meet demand. It is still an open question whether liberalised markets will provide sufficient investment signals to guarantee an adequate amount of generation in order to supply future load (Stoft, 2002). Additionally, since a tight margin between available supply and demand may increase market power, some level of overcapacity appears to be warranted. Nevertheless, the issue of investment in generation has not yet been addressed at a European policy level.

Following liberalisation, market participants have expressed the need for organised marketplaces which could facilitate short-term trading and reduce transaction cost for this type of trading. Since electricity is a homogeneous product, standardised contracts can be traded on organised marketplaces. Hence, market participants have promoted the creation of power exchanges. A power exchange is a competitive wholesale trading facility for electricity. The role of a power exchange is to facilitate the trade of short-term products by assisting market participants to balancing their purchase and sale portfolio more easily. In this respect, a power exchange forms a neutral marketplace where market participants trade day-ahead contracts at equal terms. Although many European countries already have a power exchange, it appears that most of them are shaped according to the national market model. In this way each power exchange solely provides a

marketplace for its own country and mechanisms to connect one power exchange with another in a neighbouring country are mainly absent. Such a feature does not facilitate international trading.

Similar to power exchanges, balancing arrangements have been designed at national levels. However, while power exchanges still have some common features, balancing arrangements widely diverge. In some member states, balancing electricity is priced according to market principles, where market participants bid into a monopsony 'pool' owned by the TSO (e.g. Denmark, Finland, Spain, and Netherlands). In other member states, the price of balancing is regulated (Italy, France, and Portugal). Second, the details differ, for instance with respect to the balancing periods varying from 15 to 60 minutes (EC, 2002). Hence, from the point of view of the balancing market, the national electricity markets work independently from each other. Moreover, regulated balancing mechanisms are shown to distort the price in the other markets because it construes price expectations on administratively defined penalties (Boucher & Smeers, 2001). In conclusion, both types of short-term arrangements have been designed separately at national levels regardless of the systems adopted in neighbouring countries.

At the moment, the national systems are much too diverse for the European electricity market to be considered 'harmonised'. Electricity networks have been built to optimise national supply and not European supply. In Europe, only about 8–10 % of national consumption originates from cross-border trading (EC, 2001). The existing price differences between national markets have encouraged international trade and thus increase the demand for interconnection capacity. European competition law does not prescribe any particular method for the system to charge transmission prices (Albers, 2001). Hence, in the event of cross-border disputes, the competition rules of the European Treaty apply. Moreover, the directive does not contain any specific rules for the allocation of interconnection capacity, which are essential for the development of an internal European electricity market. The directive only establishes general principles for open access of cross-border transmission capacity. Following these principles each member state was free to implement a system for national transmission pricing as well as access arrangements to cross-border capacity.

Paradoxically, this implies that in practice, the design of the internal European power market has been decided at the respective national levels. Due to this freedom granted by the directive it is not surprising to encounter a range of bilateral arrangements for allocation of cross-border capacity. Subsequently, the actual European electricity market is characterised by a patchwork of national and bilateral arrangements (Glachant and Finon, 2000). In practice, at the international level cross-border exchanges use a physical transmission rights (PTRs) system, also coined a system of 'explicit auctions'. This implies that interconnection capacities are defined in advance by the involved TSOs and that market participants should acquire capacity before contracting the energy. From a theoretical point of view such an approach is questionable since the separation of energy flows (resulting from trade) and transmission capacity (resulting from network capacity calculations) easily result in inefficient allocation of the available capacity because the real capacity available can only be determined once physical flows are known (Ruff, 2001). Moreover, even on the assumption that a transmission system operator can accurately estimate the actual network use, the methods applied to allocate cross-border capacity lack harmonisation and co-ordination. Although the member states have decided at the sixth Electricity Regulatory Forum in Florence 3 meeting that their allocation procedures should comply with an agreed set of rules on congestion management, in practice different methods are still being used. Apparently, not all European cross-border capacity is yet allocated according to a market-based mechanism. Additionally, many long term contracts signed before the reform initiated by the directive are still in place, allowing incumbent generators to control a large part of the interconnection capacity and limit the possibilities for new entrants to the national markets. In conclusion, that the directive lacks a design how to handle cross-border congestion has led to the creation of a non-harmonised patchwork of (mainly) non-market-based methods.

Market design relates to both short-term and long-term market functioning. As has been shown above, there has not been devoted much European policy attention to the question how the short-term market for electricity should be organised. Similarly, the question of long-term investment

signals for installing new generation has not been addressed either. This issue is not only important for securing energy supply for the next decades, but also for the functioning of short-term markets as a tight reserve margin may increase the potential to exert market power leaving ample possibilities for individual companies to influence the price. There is no scientific consensus whether liberalised electricity markets can be expected to produce adequate capacity levels continuously (De Vries & Hakvoort, 2003). While there are some cases (most notably California) in which a liberalised market appears to produce insufficient investment in generation capacity, practical experience with liberalised markets is rather limited, and the available cases are too much convoluted by factors such as flawed market design or regulatory restrictions, to provide convincing empirical evidence. As the social cost of capacity shortages is so high, at least the question whether additional investment incentives should be in place should have been discussed. At this moment, many European markets rely on energy only markets, which may expose the market to significant price risks on the long term. Another long-term issue concerns electricity network development. In order to facilitate European trade, the network should be able to transport at least the flows resulting from European trade. Although market-based congestion management systems are economically efficient 'patches' to cope with the current lack of interconnection capacity, many tie lines need to be reinforced. At least on this issue, the European Commission has expressed a view. In a recent document on Trans-European energy networks the European Commission has stated that *"it would appear to be a reasonable, initial target that all Member States should achieve a level of electricity interconnection equivalent to at least 10% of their installed generation capacity"* (EC, 2001). Notwithstanding it is unclear which assumptions and models underlie this number. Since it is a general number, it may be too low for some countries, or too high for others. Nevertheless, at least on this issue, the European Commission has expressed a clear view. The mentioned Trans-European energy network programme also provides incentives to study specific network reinforcements, although recent experience shows that most subsidies in this programme go to links at the outer areas of the European Union instead of network reinforcements at the heart of (continental) Europe where

trade will benefit most. A question related to network expansion is the increased dependence of some countries on European trade. Although this may enhance competition and lower the average price for electricity, there is also a strong relation with the topic of security of supply. In the absence of any harmonised regulation on mutual assistance in situations of prolonged supply shortages (except for system stability which is being agreed on in the existing UCTE regulations), those countries who are heavily dependent on imports do not have much certainty that the imported electricity will still be available in periods of supply shortages. Due to existing EU regulation it is possible for countries to cancel exports in case of severe system problems, thereby 'exporting' their supply shortage to neighbouring countries (Article 23 of the EU Directive). Depending on the national security of supply policies, this may still form a strong incentive for each country to have sufficient (national) backup generation capacity to compensate for lost imports, the cost of which will probably offset the efficiency gains by the European trade.

The ability to unilaterally manipulate prices, defined as market power, is a major concern in recently liberalised markets. Abuse of market power is easily possible given the high level of concentration of these markets and the nature of electricity markets (highly variable price-inelastic demand, significant short-run capacity, costly storage).

Two main categories of market power can be distinguished: vertical market power (the possibility to influence the network access price) and horizontal market power (the possibility to influence the commodity price). The liberalisation process has strongly diminished the source of vertical market power by providing open access and forcing unbundling of generation/supply and transmission/distribution. Thus, the creation of the independent transmission system operator, which has been achieved in most European countries, has reduced the possibility to exercise vertical market power. However, with the exception of the UK, the liberalisation process did not change market structures in terms of concentration and ownership.

The high level of market concentration is an important concern since it creates a high potential for the exercise of market power. This is for instance the case in France, Belgium and Italy where the

dominant players own more than 60% of the installed capacity in their national market. The objective of the liberalisation process to integrate the different national markets into a single pan-European market can be seen as a good way to dilute such national market power. However, the lack of sufficient interconnection capacity and the large differences in market design hamper the integration process and do not very effectively reduce market power on the national markets. Concentration measures are not sufficient to identify potential market power. Electricity markets are highly dynamic: the market can change dramatically in the course of just a few hours. For this reason, abuse of market power can take several forms in electricity markets. Market power can be exercised by withholding production on some units in order to increase market prices and profit more from production by other units (Hogan & Harvey, 2001) or by strategic bidding at excessively high prices compared to marginal costs (Wolfram, 1998). These types of abuse are possible due to inter-temporal variations of electricity demand and transmission constraints (Borenstein & Bushnell, 2000). Hence, even in apparently unconcentrated markets, market power can be exercised. International experiences and especially the California crisis have shown the scope and disastrous effects of such behaviour (Joskow & Kahn, 2002).

The threat of market power shows the necessity of effective penalising abuse of market power. For this accurate market monitoring is required since the electricity market is very complex and highly dynamic. Legally electricity is considered a 'good', similar to others market products, and is therefore subject to article 81 and 82 of the Treaty prohibiting anti-competitive behaviour. However, European competition law is designed for normal product and service markets but appears inadequate for the electricity market given the special property of electricity (Newbery, 2002). First, under European Union competition law, a market share above 40% is usually considered dominant. This threshold is ill suited for electricity because in many European countries some players exceed such market share. Moreover in a period of high demand and in the presence of transmission constraints, a player with a small market share in absolute terms can exercise significant market power by withholding a bit of its supply. In the EU restructuring process, the regulatory authorities

have failed to recognise such possible behaviour; neither had they addressed the question of how to mitigate market power.

PART II

Theoretical Framework

3. Contracts, Investment Incentives and Efficiency In The Restructured Electricity Market

3.1. Introduction

Private investment and entry in the electricity generation sector represent a crucial issue for the development and success of a competitive electricity market.

Suppose that a new investor decides to enter the electricity market. This market is characterized by high risks, uncertainty, sunk costs. The investor needs to be ensured against risks, at least in the initial phase of entry. The most proper way to achieve this purpose is represented by long-term contracts, which are required both to encourage entry by new potential investors and to safeguard their interests. Such contracts, in fact, attempt to minimize investor's risks, by creating reliance on long-term relationships. However, given that it is difficult to design juridical dispositions that cover uncertainties about future market conditions, contracts cannot be fully contingent and regulate all possible situations that business reality might feature. Therefore inefficiencies might arise in system operation.

There is an inevitably trade-off between designing contracts to reduce uncertainty for the private investor and running the power system as more efficiently as possible.

Suppose that at the time of signing a power purchase agreement, a generator owns the most efficient plant in the merit-order and should indeed run on base load as specified in the contract. But circumstances might change and after some years running the plant on base load, might no longer be optimal. When a contract does not allow for such a contingency, the operational efficiency of the system tends to decline. Contracts that provide for guaranteed sales to reduce private investors' risks also reduce the competitive pressure on them to operate efficiently.

In our opinion, this is particularly the case of power sales agreements in the restructured electricity market. Power sales contracts have to regulate transactions between electricity sellers and

purchasers, acting in a competitive setting. They have to provide incentives to private parties to enter the electricity market; deal with market uncertainty and risk; seek for operational efficiency.

How to design such contracts is a key point of this research. In particular, the chapter wants to highlight and analyze the tension between designing contracts that reduce uncertainty for the private investor and running the power system as efficiently as possible. In our opinion, the features of power sale agreements are preliminary in resolving this tension and therefore in orienting the development of electricity market restructuring towards a competitive direction.

The work is organized as follows: section 3.2 describes the main features of power purchase contracts operating in the liberalized electricity market. In section 3.3, a contract model is presented. In section 3.4, the theoretical model is used to formally analyze a selected sample of existing power purchase contracts. Section 3.5 discusses some illustrations. Conclusive remarks are finally provided in section 3.6.

3.2. Power Purchase Contracts in the Electricity Market

Electricity transactions are mainly regulated by power purchase agreements, lasting from one year to longer periods (15 years in the case of Nuclear Energy Agreement, or 28 years for the Pego contract).

Power purchase agreements have three main dimensions:

1. the selling prices for power and energy;
2. the amount of power and energy sold;
3. a set of incentives to improve performance and disincentives to ensure that performance does not fall below a basic standard.

Purchase agreements generally are based on a two part pricing structure with separate payments for capacity and energy. The price of capacity is usually related to the capacity declared available. It is likely to be set so that, at a given level of operation, the discounted revenue from capacity

payments will cover capital costs over the life of the project. Contracts tend to set a target level for availability over the year (say 80%), plus a bonus zone above this availability and a penalty zone below it. The price of energy is usually tied to an initial cost estimate and a series of cost indexation factors. An initial heat rate and initial fuel and operating and maintenance costs are assessed for the plant, together with the appropriate indexes.

There are substantial differences in the way the power purchase contracts deal with quantities ranging from "take-or-pay" or "economic dispatch" or "competitive pools" provisions⁶.

The stronger a power purchase agreement's guarantee of a market for the producer's output, the more attractive the investment becomes but the less pressure is created to generate that output efficiently and the less competitive pressure is applied to other generators.

Therefore, our problem focuses on the way to design a contractual structure that takes into account the two (sometimes conflicting) tasks of creating incentives for private generators to invest and improving sector efficiency.

⁶ See further for a more detailed explanation.

3.3. A Simple Contract Model

In this section, we present a simple contract model that formalizes the trade-off between two opposite directions: create investment incentives and operate the power system as more efficiently as possible.

The model general theoretical framework refers to the contract theory literature (in particular, Salanié, 1997). In order to sketch our model, we particularly refer to the incentive contracts literature (Laffont and Tirole, 1993).

The most familiar and basic purchase contract (in both public and private sector transactions) involves a fixed price provision: the offerer proposes a price that becomes the selling price if the offer is accepted. This is typically a fixed price arrangement, which does not capture the tension between investment incentives (depending on the risks coverage degree) and efficiency maintenance that we want to highlight.

The "incentive contract"⁷, developed by the Department of Defense in the USA in the sixties, represents a powerful instrument for our analysis. However, though the model mathematical "skeleton" is inspired to such literature, the economic content is quite different.

In our setting the contract is not a typical government procurement incentive contract.⁸ In our setting, an investor wants to enter the electricity market and invest in a new generating plant for electricity producing and purchasing. The decision about whether and how much to invest will depend on the perceptions of risk, risk sharing arrangements, aversion or willingness to take risks

⁷ In the economic incentive literature, we have contract of this type:

$$P = \alpha c + (1 - \alpha)p,$$

Where P represents the payment; c the costs and p the price agreed upon by the contract parties. When α equals 0, all the risk is borne by the supplier; when $\alpha = 1$, all the risk is borne by the buyer. Linear contracts with α strictly between 0 and 1 are called incentive contracts.

⁸ The literature about incentive contracts and public procurement is very broad. References concerning procurement practices include Fox (1974, 1988), Kovacic (1990), McAfee and Mcmillan (1987), Rogerson (1989). In Laffont and Tirole (1993) setting, for instance, the power of an incentive scheme (namely the fraction of the realised cost that is borne by the firm), is a central notion in policy debates. This notion underlies views about the relative merits of incentive contracts in procurement. The authors, in fact, point out the basic trade-off between rent extraction and incentives. Incentives are best provided if the firm bears a high fraction of its costs. But reimbursing the firm's cost limits its rent.

and business profitability perceived by the generator, who will charge the price taking also into account some range of expected returns.

The decision about whether and how much to invest is also influenced by the particular power purchase contract adopted by the investor-seller and its buyers, and by the different incentives that the agreement's provision are able to design.

The "action set" is the electricity wholesale market, where purchasers are typically represented by other generation firms, national Single Buyers, distribution companies, large industrial eligible customers.

We use the formal structure of incentive contracts, in order to modify the basic power purchase contract⁹ by adding parameters and constraint. The main idea is to define a reference theoretical power purchase contract, which can capture the trade off between incentives to produce electricity and efficiency of the all system. The theoretical model is then needed for evaluating the agreements existing in the electricity market business practice. The model describes a system for the delineation of the conditions for electricity trading in a competitive setting. The analysis is carried on from the point of view of one single generator¹⁰.

The parties could conclude a power purchase contract (C_{contract}), having the following linear, simple form:

$$(I) \quad C_{\text{contract}} = (\alpha q_K p_K + \beta q_K p_K) + [\alpha q_E p_E + \beta q_E (p_E - c_E)]$$

- q is the total contractually specified electricity quantity. We distinguish between capacity (q_K) and energy (q_E).
- p is the contractual price for the supply of the contracted amount of electricity. The price structure is formed by two parts: capacity (p_K) and energy (p_E), which is linked to an

⁹ In a power purchase contract, P (the payment) is given by:

$P = c + p$, where c is the seller's cost to produce the good and p the price agreed upon by the parties.

¹⁰ See paragraph 6, for a discussion about "generators trading".

initial cost estimate and a series of cost indexation factors. The capacity price is paid because the generator declared the plant availability, even if the plant is not ran.

- c is the estimated energy production costs.
- α is a contract parameter (where $0 \leq \alpha \leq 1$), defining the fixed fee element the investor is assured of.
- β is the incentive parameter (where $0 \leq \beta \leq 1$), indicating how to improve performance (for instance, bonus payments for capacity availability above the target or penalties to ensure that the generator remains efficient or incentives to bid low energy prices).

The contract parameters α and β define the structure and nature of the power purchase contract. The generation firm can decide a required return R , choosing among several sets of α and β values, satisfying both its requirements and the purchaser ones.

3.4. Economic Analysis of Power Purchase Contracts

The theoretical model defined in paragraph 3 allows us to highlight two opposite contractual "forces": risk insurance (therefore, creating incentives to invest) and efficiency requirement. In this section, we use the theoretical form as a benchmark for defining the structure of existing contracts and analyse them under at the light of risk degree and efficiency pressure. We survey a range of agreements types and analyse them by making the use of our contract model. By doing this, we want to highlight their risks and benefits for operational efficiency.

3.4.1 "Take-or-Pay" Contract

This agreement provides for the sale of a fixed, stipulated amount of power and energy for the life of the contract. The purchaser must pay for any contracted output that it does not take from the

generator. Therefore, the new entrant's investment is guaranteed by the contractual provision that ensures him secure returns.

For instance, in the NEA contract, a typical "take-or-pay" contract, it is stated that the purchasers (Scottish Power and Hydro-Electric) has to buy all the electricity that the generator (Scottish Nuclear) produces and delivers to the grid, even if the purchaser claims he does not want it.

The Italian *Decreto Legislativo* n 79/1999, implementing the Directive 96/92, provides for the use of "take-or-pay" contracts in the liberalized electricity market¹¹.

Proposition 1

The "take-or-pay" contract (TOPC) is the contract with the lowest risk degree for the generator-investor and the lowest efficiency pressure for the system.

Proof. In the "take-or pay-contract", the fixed fee parameter α equals 1 and the incentive parameter β equals 0 for both the energy and capacity parts of the contract. The "take-or-pay contract" will assume the following form:

$$(2) \quad TOPC = \alpha q_K p_K + \alpha q_E p_E$$

If we denote by R the generator's deterministic returns, we will obtain:

$$(3) \quad R = q_K p_K + q_E p_E$$

¹¹ Article 2 of the EEG "take-or-pay" contract between two Italian generation firms (whose names are not quotable for privacy reasons), states that the energy buyer is committed to buy 20.000 kW every hour of the day, every day of the week. Only during the months of May, June, July and September the contracted quantity is multiplied by the coefficient Y , the coefficient of capacity reduction during the summer interconnection. During the month of August no trade occurs.

In this case the generator is ensured of the sale of a fixed quantity (capacity and energy) times the stipulated price. Such risk free condition provides positive, secure returns for the investor. Under the basic investment rule (invest if net revenues are expected to be appreciable larger than building and operating costs), the generation firm expects the investment to be profitable.

Discussion about the economic effects of the "take-or-pay-contract"

We can distinguish two different effects, deriving from the use of this kind of agreement.

1) The producer has no competitive pressure to lower costs.

On the efficiency perspective, the generator might have low incentives to keep production costs at a low level. Once the producer is ensured of the sale of a fixed quantity of energy (whatever the market conditions are), he will make no effort in order to efficiently run the plant.

If such guarantee is extended to the entire projected plant output, the generator has a secure market that cannot loose without compensation. Such contract peculiarity creates no impact on economic dispatch because the plant is always called to run, even if other generators have lower costs. Dispatch can, thus, occur out of "merit-order", because of the contractual obligation created by the "take-or-pay" contract.

Efficient system operation might, however, depend on profit motives. For instance, when costs are indexed, the incentive to improve performance focuses on the way to "beat the index" and benefit from the difference.

Moreover, the lack of competition for market share between generators under a "take-or-pay" contract might imply that, even if operated in an efficient way, the generator poses no threat to other generators because it has no spare capacity to capture their market share.

2) The producer faces a low level of risk when entering the electricity market

When the seller is guaranteed the purchase of a quantity that covers the entire projected output of the plant, he has an assured market share that cannot loose without compensation. Under such agreement, in fact, there is no issue of economics dispatch for the plant, even if other plants have lower costs.

This feature, therefore, might provide incentives to invest and enter the electricity market. The absence of high risks and the promise of secure returns might attract investors in the electricity market.

The subsequent entry of additional investors (all with a long-term contract) might compound this problem. However, such contracts can be used for initial procurement, when the risk effect is likely to be relevant and capital in the sector has to be attracted.

3.4.2 Economic Dispatch Contract

Under such agreement, capacity price is related to declared availability and the energy price is paid only for the energy dispatched according to costs. The power producer can declare its available capacity and thus cover its capital costs but it is not guaranteed energy sales (whose price is cost-related and determined at the outset of the contract). Such contracts are used in Jamaica and Dominican Republic.

Proposition 2

The economic dispatch contract (EDC) creates some competitive pressure and system efficiency but increases risks for the generator-investor.

Proof. Under this agreement, the fixed fee parameter is $\alpha = 1$ for the capacity availability part of the contract and $\alpha = 0$ for the energy sales. The incentive parameter can vary ($0 \leq \beta \leq 1$), depending

on the bonuses and penalties for capacity availability. The incentive parameter equals zero ($\beta = 0$) for energy production.

The contract will assume the following form:

$$(4) \quad EDC = \alpha q_K p_K + \beta q_K p_K + \alpha q_E p_E$$

The contract is defined in such a way that the generator-investor is (at least partially¹²) ensured against the risk not to cover its capital costs related to capacity availability. Moreover, the generator is incentivated to produce more capacity than the contractually declared one, because of the bonus payments system, typical of this contractual type. Similarly, if the price for capacity allows the generator to earn returns on capital at a capacity utilization below the target (therefore, reducing the generator's financing risk), penalties are applied, in order to ensure that the generator remains efficient.

Under an economic dispatch contract, the generator will have different returns, mainly depending on the value of β .

1) In order to highlight two extreme situations, we consider the case when $\beta = 1$. The generator's returns will equal:

$$(5) \quad R = 2q_K p_K + q_E p_E$$

Suppose the generator tries to increase its market share by supplying more capacity (under the incentive of a bonus payment $\beta = 1$ and, therefore, higher returns). In this case, it can force other generators to diminish their market share and respond with a strategy aiming at reducing their

capacity costs, so that they can improve availability. These processes can incentivate competitive dynamics and help supplying more capacity.

2) When $\beta = 0$, then the power producer will have:

$$(6) \quad R = q_K p_K + q_E p_E$$

In this case, if the generator offers a capacity amount below contractually declared availability, it loses some market share and diminishes returns.

Discussion about the economic effects of the economic dispatch contract

We can distinguish two different effects, deriving from the use of this kind of agreement.

1) *The producer has some competitive pressure to lower costs.*

Economic dispatch contracts can provide incentives for the electricity producer to generate efficiently and can ensure merit order dispatch.

Suppose, for instance, that the contract sets the availability target below the feasible availability under good operating practices. In this way, the contract reduces the generator's financing risk and thus the incentive for the operator to be efficient.

A bonus payment for availability above the target ($\beta = 1$) can be used as an incentive for higher production. On the contrary, if the price of capacity allows the generator-investor to earn an economic return on capital at a capacity utilization below the target, penalties are provided ($\beta = 0$) to ensure that the generator-investor remains efficient.

¹² See discussion in paragraph 4.2.1.

2) The producer faces a higher risk level than under the "take-or-pay contract", when entering the electricity market. The incentive system, provided by the economic dispatch contract, enhances the risks to invest in power plants and enter the electricity market.

In particular, the generator is not guaranteed for energy sales. Under an economic dispatch contract, in fact, energy prices depend on a cost index. This does not allow that costs savings are transferred to the consumers or are reflected in the prices that affect dispatch decision. If the initial costs (i.e., heat rate) were incorrectly estimated or if the fuel prices diverge from the index, the real costs of generation might differ very much from the costs taken into consideration for dispatch.

Moreover, the generator is guaranteed for a certain capacity level. However, if it wants to "beat" the target and conquer a larger market share, it has to improve availability and therefore invest and risk more than under a "take-or-pay contract". For instance, if the contract sets a target below the feasible availability under correct operating practices, the financing risk of the investor-generator is also reduced. This inefficiency is corrected by the penalty system contained by the contract, which does not allow the generator to follow this strategic behavior and forces him (under the threat of no return) to invest in a higher amount of capacity¹³.

3.4.3 Competitive Pool Contract

Under a competitive pool contract (CPC) prices for energy are bids and are not indexed on contractually pre-determined costs. Generators bid their capacity availability and energy prices. The pool operator then determines economic dispatch and pays for energy on the basis of marginal bid prices and for capacity on the basis of declared availability and a formula that gives signals for long-

¹³ A variation of this contract is the one including "minimum take provisions" for capacity. This agreement combines features of the "take-or-pay" contract and economic dispatch, because it guarantees generators a "minimum take" below normal capacity availability. Such provision can represent a "minimum guarantee" from risks and uncertainty, which may stimulate to entering the sector.

term investments (Bacon, 1995). The system is implemented in Argentina, and it was operating in England and Wales¹⁴ until 31st of December 2000¹⁵.

Proposition 3

The competitive pool contract is the contract with the highest risk degree for the generator-investor and the highest efficiency pressure for the system.

Proof. Under such agreement, the fixed fee parameter α equals 0 for energy and for capacity. The incentive parameter β can vary ($0 \leq \beta \leq 1$), depending on the generator's bid for energy and capacity β . The contract will assume the following form:

$$(7) \quad CPC = \beta[(q_K p_K + q_E (p_E - c)]$$

In this case, we have an extreme risk condition for the investor, who can mitigate it by producing and bidding a high level of capacity availability.

Under such contract, the generator will have different returns, depending on the value of the parameter β .

1) When $\beta = 1$, the generator's returns will equal:

$$(8) \quad R = q_K p_K + q_E (p_E - c_E)$$

¹⁴ In the English Pool, for instance, the spot price is defined daily. Each day, each generating unit notifies the central system operator of the capacity it expects to have available each half-hour of the following day, and the energy price at which it will generate it. If the plant does not wish to operate in every segment, it simply does not bid for that half-hour. The energy offer prices are fixed for the day ahead, and include different costs, like start up costs, no load costs and so on. Each generator also notifies of the prices at which it will provide various ancillary services such as spinning reserve and reactive power. The system operator, then, ranks the generators' announcements in order of price and makes a forecast of what the demand will be in each half-hour of the next day. It sets the SMP, the system marginal price, for each half hour, equal to the level of the marginal bid price, corresponding to the predicted level of demand in that half hour. In this way, generators sell into the spot market and purchasers buy from the spot market.

¹⁵ The pool contracting system is now replaced by the NETA (New Electricity Trading Arrangements).

In this case, if the generator tries to increase its market share by supplying a higher availability (under the incentive of a bonus payment, $\beta = 1$), other generators may lose market share and respond by trying to reduce their capacity costs so that they can improve their availability.

2) When $\beta = 0$, then the power producer will have:

$$(9) \quad R = 0$$

In this case, the generator that cannot keep production costs low and be efficient earns zero rates of returns.

Discussion about the economic effects of the competitive pool contract

We can distinguish two different effects, deriving from the use of this kind of agreement.

1) *The producer has a high competitive pressure to lower cost.*

In principle, this system can be very efficient in producing at the lower prices associated with competitive structures. Generators bid the prices, at which they will sell electricity and this allows prices to be lowered when there is real competition, as generators struggle to enhance or to keep their market shares.

2) *The producer faces the highest level of risk when entering the electricity market under the competitive pool contract.*

The competitive pool contract might provide disincentives to invest and enter the electricity market. The presence of high risks (mainly the risk not to be dispatched, because generation costs are too

high) might deter investors in the electricity market. As shown in equation (8), if the generator's energy bid is above the system marginal price, the generator is not dispatched and its returns equal zero.

Figure 1 illustrates the relationship between contract parameters and different contractual types and economic returns.

FIGURE 1

Table 1 summarizes the analysis carried on in paragraph 3.4.

Contract type	Take-or-pay	Economic Dispatch	Competitive Pool
Contractual structure	$\alpha q_K p_K + \alpha q_E p_E$	$\alpha q_K p_K + \beta q_K p_K + \alpha q_E p_E$	$\beta[(q_K p_K + q_E(p_E - c))]$
Payment for capacity	Related to capacity declared available	Related to capacity declared available	Related to capacity declared available
Payment for energy	Tied to an initial cost estimate and a series of cost indexation factors	Tied to an initial cost estimate and a series of cost indexation factors.	bid
Quantity provisions	Fixed quantity of energy and capacity	Fixed quantity of capacity (corrected with bonuses and penalties system), energy depending on merit order	Capacity and energy depend on merit-order
Investment Incentives	High: the generator is guaranteed for the sale of all contracted energy and capacity	Average: guaranteed sale of capacity. No guaranteed sale of energy (only low costs energy is dispatched)	Low: if not dispatched, the generator does not sell its output. No guarantee for any sales.
Efficiency Incentives	Low: only firm profit motives. No system efficiency.	Average: Pressure on the generator to keep energy costs low, and bonuses and penalties for capacity.	High: it creates pressures on generators to keep costs low. High system efficiency, if no price manipulations occurs.
Countries where contracts are used	Italy, USA, Colombia, Belize, Portugal, Scotland...	Jamaica, Dominican Republic...	England and Wales (until 2001), Norway, Argentina...

3.5. Empirical Perspective: Discussing Some Experiences

Unfortunately, the empirical perspective is scarce and fragmented. Besides the evidence of a massive liberalization trend all over the world, the evidence about the typology of contracts adopted by new generating firms is not relevant.

On the point of view of private investment in the generating sector, the World Bank reports (until 1998) show that in developing countries, for instance, private participation has grown substantially since 1990, with electricity becoming one of the leading infrastructure sectors in attracting private investment. Between 1990 and 1997, the private sector took of the management, operations, rehabilitation, or construction risk of 534 projects with total investment of 131 U.S. dollars¹⁶. In Europe, private participation in electricity has been concentrated in Eastern countries (Hungary, Czech Republic, Turkey). These projects have been implemented under different contractual schemes.

However, it does not exist a systematic information source about which country in the EU and in the world are adopting this or that contract type. The way to efficiently restructure the electricity markets is still under study all over the world. We can only discuss some isolated, benchmark experience.

An interesting comparison can be effectuated between the Argentina and UK restructuring experiences.

Experience in the system in England and Wales shows that there are a lot of difficulties associated with setting up and operating a pool. According to some critics (Bacon, 1996; Mc Carthy, 2000), such system is suitable for large and mature electricity markets, with spare capacity.

In UK, competitive pool contracts were used at a first stage of the restructuring process. However, they are now divested, because they did not work very well on the efficiency direction: the two dominant generators (National Power and Power Gen) learnt how to take advantage of such contractual system and started to play strategically, in order to retain capacity and drive up prices.

¹⁶ All dollar amounts are in 1997 U.S. dollars.

The UK pool rules were complex and left scope for large players in the market to engage in a variety of gaming forms, to the detriment of other market participants. Economically, in fact, the pool embodies the rules of auction theory. However, "there is a serious deficiency once one notes the complexity of devising an optimal set of auction rules for electricity" (Currie, 2000, p. 4). The theoretical auction model, in fact, assumes (for theoretical tractability) that electricity is a homogeneous commodity, at least within each period of trade. This is, however, not the case in reality. Electricity supplied at different points of the grid entails different transmission losses, and more importantly has quite different value because of transmission constraints. Therefore, electricity supplied at different moments within the trading period has different value, depending on the demand of the system. Acceptance of generation from one plant for one period of trade may have well necessary entailed acceptance of supply for adjacent periods because of inflexibilities in turning generation on and off, and these characteristics differ from plant to plant. This kind of "practical" deviation from the theoretical auction theory rule was likely to be exploited by collusive bidders, who artificially created congestion, in order to segment the market and increase bids.

Moreover, the balancing market management favored collusive mechanisms. From the perspective of the system operator, in fact, there is a wide difference between the plants that needs three and a half hours notification to supply and then needs to be ramped down slowly (typically nuclear plants) and capacity that can be turned on ten minutes before (such as pumped storage or partly loaded plant on spinning reserve). Speed of response and different ramp rates all require different rewards, so that there is no common price that can be applied to them. This heterogeneity of pricing has left room for collusive behavior and determined the end of the competitive pool contract system.

The Pool system was abolished and it was introduced the NETA¹⁷ (New Electricity Trading Arrangements), a trading program managed by Ofgem and by the UK Trade and Industry Department. NETA's main aim refers to eliminating all possible regulatory artificial constraints and renders the market as most similar as possible to other commodities markets just intervening for all features that are typical to electricity (non storability, stochastic variation of demand and supply). Under NETA, risks can be diminished by the balancing mechanisms, demand has a higher role: generators can see consumption as a signal to fine-tune their production. All this can help in creating a "real market", where demand and supply meet at the market-clearing price. The main idea, founding the NETA system, is that all costs created for system imbalances have to be beard by those who have created those imbalances and those costs. This is a very "efficient" principle, because it provides incentives for careful behaviours.

In Argentina, competitive pool agreements are adopted for electricity transactions. This country results being one of the leading developing countries in private investment in electricity generation and it results having a successful competitive development in the sector. In Argentina, the deregulation process was a success: plant performance improved; wholesale and retail prices declined; consumers benefited from reduced outages and improved reliability¹⁸. The success of Argentina's electricity market deregulation might depend on the fact that generators have a relative small share of total capacity (contrary to UK, where the two main generators started the "pool gaming procedures"). This feature might have helped hindering collusive strategies and the working

¹⁷ Under the NETA system, electricity transactions are organized in three different (but interacting) markets:

1. long term-bilateral trading;
2. 24 hours ahead (for the coverage of short terms)
3. balancing markets.

In the long term-bilateral markets, participants trade bilaterally on a range of markets (over-the-counter and exchange based), emerging in response to market needs. Long-term provisions helps the participants to secure the majority of their/load. In the short-term market, participants fine tune their positions on-the-day as uncertainty reduces. The balancing market is needed to balance the system in real time and resolve transmission constraints. In such market, the system operator accepts balancing mechanisms bids and offers and calls-off balancing services contracts. In all the three markets, energy prices are bids and there is no capacity payment. In addition, the NETA system implies a particular settlement mechanism. Payments for bilateral contracts are settled between counter-parties. In central settlement, energy imbalances (contract volumes less metered output) are cashed out at unbalanced prices and payments for balancing mechanisms are made.

¹⁸ We believe that Argentina deregulatory process was a success. The recent outages are, in our opinion, the result of transmission problems that could be solved with more investments. The deregulation of the generation segment has demonstrated to work.

of competitive pool contracts.

In California, some authors (Marcus, 2001) attribute the electricity restructuring crisis to the excessive use of "take-or-pay" contracts. Marcus reports that the California State Auditor, after having analyzed the long-term energy contracts signed by the state, concluded that the California Department for Water Resources (CDWR), bought too much power, without enough flexibility and without meeting the legislative requirement to secure renewable power. In particular, such contracts were "take-or-pay-contracts", which prevented operational flexibility and trigger power surpluses.

A coalition of consumers and environmental organizations joined to analyze all the long-term contracts, and found that the state could fix much of the problem by renegotiating some of the "take-or-pay" contracts (in particular the twelve worse contracts¹⁹).

Such agreements were renegotiated by reducing the "take-or-pay" energy straightjacket provision by more than a half. In this way, buying utilities were lightened by the contractual burden to inefficiently purchase off peak energy. In theory, the effects of such renegotiation aimed at reducing the costs of "take-or-pay" contracts by one third and slash the power surplus by more than 50%. However, it is too early to derive the practical effects of policy measure.

3.6. Concluding Remarks

In this chapter we have surveyed three types of power purchase contracts operating in the electricity market, from the most rigid to the most flexible, in order to underline how competitive contracting can increase efficiency pressures and, at the same time, increase investment risk. We have used a Law and Economic approach: we defined a theoretical contractual model, highlighting the tension between the two opposite directions: designing agreements to reduce uncertainty and risk in order to attract private investment and operating the power system as more efficiently as possible. We then

¹⁹ The 12 worse contracts resulted to be: Sempra Energy; Williams Energy; Calpine Los Esteros; Calpine Peakers; Constellation Energy; Coral Energy; Dynegy; Pacificorp; EL Paso Merchant Energy; Alliance Colton; Mirant; Morgan Stanley (Marcus 2001).

used our theoretical model in order to analyse the formal structure of a selected sample of power purchase agreements, really operating in the restructured electricity markets all over the world.

From the above analysis, we can derive that competitive contracting is crucial for ensuring efficient operation. "Take-or-pay" contracts are attractive to producers because eliminate demand risks but do not achieve efficient results. Under this contract, in fact, dispatch can occur out of merit order and excess production of energy, with the buyer being obliged to buy all production, can occur. For instance, in the U.S., early PURPA (the Public Utility Regulatory Policy Act, 1978) projects for creating new generating plants, based on "take-or-pay contracts", created an excess of off-peak energy that the buying utility was obliged to purchase (Bacon, 1995).

The economic dispatch contract can create some competitive pressures: a system of bonuses and penalties that respectively awards capacity availability and punishes capacity shortcuts can force private producers and investors to generate efficiently and can ensure merit-order dispatch. In our opinion, an incentive formula for long-terms contracts with β parameters, can benefit sharing agreements and provide an appropriate way for dealing in the new deregulated electricity market. This is a way to continuously renegotiate the contract and adapt it to changed circumstances.

The competitive pool contract sets the most competitive conditions. Such system worked very well in the Argentina electricity restructuring experience. In England and Wales, on the contrary, a pool system has caused an oligopolistic-strategic situation: the two dominant generators (National Power and PowerGen) have taken advantage of their market power, restricting the capacity offered to the market in order to increase the price of available capacity.

The evidence is, however, still too scarce to derive consistent empirical observations and comments. We would like to conclude, by discussing two important points²⁰ that surely require further research.

First, our analysis was set in a particular scenario: a generator wants to enter the electricity generation segment and it is offered a power purchase contract. Such contact can have different

²⁰ I am very grateful to the referees for suggesting such discussion.

provisions for the trading of capacity and energy (ranging from take-or-pay until competitive pools). Different legal provisions can have different impacts on the generation decision whether to enter the electricity market and on the efficient supply of its output. The analysis was focusing on one single generator. We are, however, aware that reality is more faceted and generators can also trade among themselves. This possibility can enhance efficiency. In a market based on economic dispatch, for instance, the contract prices for energy are predetermined for all generators, but the generators bid availability for the next period (typically the next day)²¹. The dispatch agency or power purchaser determines least cost dispatch on the basis of the contract prices and announces the schedule. Generators can trade energy among themselves, buying from lower costs generators not fully committed in dispatch to meet some of their contractual commitments. Opportunities for trade emerge when actual costs for energy are below the contract prices. The power purchaser is informed of such trades and adjusts the dispatch schedule while paying in accord with the original schedule. This system lowers the total costs of generation, but once again these benefits are not passed on to consumers when generator prices are tied to the cost index. The system can lead to competitive pressure for generators to improve efficiency if actual costs start to diverge from the index. But it is complicated to operate because the power purchaser must determine dispatch in advance and keep records of transactions between companies, and generators need to have sophisticated systems.

Second, in the chapter, we mostly adopted a concept of efficiency, interpreted in the sense of X-efficiency (minimization of production costs). We are, however, aware that efficiency of power has several dimensions. The important question about which are the efficiency impacts of long-term contracts on the merit-order problem, can be only partially answered, by selecting the proper trading agreement. This raises the more general question of the proper role and the competency of the system operator in liberalized electricity markets²². Not only the trade-off between short-run flexibility and long-term contracts based on the availability of plans, but also the constraints of the

²¹ Using the parameters sketched in the theoretical model, we could say that this "generators trading contract" has the parameters α and β equal to 0 for energy trading and $0 \leq \alpha \leq 1$ and $0 \leq \beta \leq 1$ for capacity trading.

²² See Onofri (2001).

transmission network (including system externalities) may play an important role on contractual selection and performance. Electricity markets must match demand and supply continuously over the day in order to maintain network "electrical equilibrium" (electricity cannot be stored). This means that near "real time", generating units must follow the operating instructions of the system operator. The continuous need of balance in the electricity market can jeopardize the performance of energy contracts, and their provisions (including the trade-off between risk-covering and efficiency spurring). Producers may specialize or diversify by load characteristic. For example, some may prefer to compete for long-term base-load contracts. These firms are likely to own hydro and nuclear power plants. Firms with fossil fuel plants might seek to supply base and cycling loads. Producers with gas combustion turbines and co-generators could compete to meet peak loads. Other firms may diversify and be ready to compete for base, cycling, and peak loads contracts. In any case, the system operator will be responsible and will assume the role for the contractual performance in real time of every agreement. It is therefore, important, to consider this role of contractual re-negotiator (role, very well highlighted by the NETA reform) that the system operator has to undertake.

These considerations lead to a final, maybe simplistic comment. Several factors affect power purchase contracts. Sociopolitical, legal, operational, management and technical factors are a serious concern, which must be taken into account in any major long-term investment. All these factors will lead to difficulties in deciding on values for contractual parameters and in understanding their relationships, in order to design efficient power purchase contracts. We are, therefore, aware that a pragmatic "learning-by-doing" approach and some solid field experience will show, in the future, the most proper way to re-organize transactions in the restructured electricity market. .

PART III:
Empirical Framework

4. Price Formation And Legal Provisions In Electricity Contracts: An Empirical Study

4.1. Introduction

Electricity contracts are crucial instruments for the trade of electricity in deregulated markets. Since the seminal work of Joskow and Schmaleensee (1983), it was stressed the need of private negotiations in order to govern electricity transactions. A number of theoretical papers address the problem of electricity contracts design (Newbery, 1995; Green, 1999; Onofri, 2003) and electricity contracts governance and administration (Onofri, 2005).

In this paper, we want to evaluate the effect of legal provisions on electricity contracts price formation. We consider 27 long-term electricity contracts, for the trade of electricity between generators, stipulated during California electricity crisis in 2001. The main research question is whether and how contractual provisions regulating obligations and commitment among the parties affect the wholesale electricity price. We operationalize the contracts' main legal provisions in order to perform an econometric exercise and target the main determinants that affect price in long-term electricity contracts.

Empirical research in energy markets is not characterised by many contributions. A seminal paper about contracts in energy markets is Joskow's (1987) econometric analysis of the duration of nearly 300 coal contracts. Exploiting regional differences in the characteristics of coal and transportation alternatives and variations in contract quantity, Joskow's study shows the duration of coal contracts to be significantly correlated with measures of physical- and site-specificity and dedicated assets

Empirical research in energy markets has also identified a correlation between long-term contracting and specificity in natural gas (Crocker and Masten, 1988) and petroleum coke (Goldberg and Erickson, 1987). Contracting appears less attractive as a way of governing production and exchange, however, where the alternative to contracting is integrated ownership and production.

Empirical research on integration decisions reveals a consistent preference for integration over contracting as the specificity of investments increases (see Joskow, 1988; Crocker and Masten, 1996). Contracting thus appears to be only an imperfect response to the hazards posed by relationship-specific investments. Empirical research suggests, moreover, that the costs and limitations of contracting grow with the complexity and uncertainty of the transaction. In

Goldberg and Erickson (1987) and Crocker and Masten (1988) found that contract duration in petroleum coke and natural gas contracts decreased in periods of increased uncertainty, contrary to what would be expected if risk-sharing were the primary motive for contracting.

Helm and Powell (1992) performed an empirical study of electricity financial forward contracts, which were instituted at privatization between the generators and the regional suppliers in UK. They proposed that the break-up of the first set of "contracts for differences" for electricity led to a structural break in the underlying relationship between the demand for and the price of electricity. They found that this break-up led to a marked increase in prices due to the interdependency between the electricity pool (spot market) and the contract market (forward market).

Craig (1997) replicates and augments the work of Helm and Powell by expanding their data set in order to examine the break-up of the second set of contracts for differences in March 1993 and its effects on electricity prices. By utilizing the methodology of Helm and Powell (1992), it is found that the dissolution of this second set of contracts had a similar effect on the relationship between prices and demand. This supports the view that the contract market should be made more open and subjected to more rigorous examination due to its effects on pool prices.

The paper is a contribution to the empirical literature in contract theory. It empirically investigates the effects of contractual provisions on the determination of price in electricity long-term contracts. The paper is organized as follows. Sections 4.2 – 4.4 describe the California electricity market restructuring, the electricity market crisis and the contracts negotiation procedures. Section 4.5 describes the dataset formation. Sections 4.6 – 4.8 describe selected model specifications, different estimation techniques and discuss the estimation results. Section 4.9 concludes.

4.2. California Electricity Crisis

During spring 2000 until spring of 2001, California²³ experienced an energy crisis that led to skyrocketing natural gas and electricity wholesale prices, which culminated in a regional electricity shortage. The subsequent electricity shortage caused California's electricity system operator (CAISO), to institute 'rolling blackouts' forcibly to adjust the State's electricity demand to the available amount of electricity in the state. Furthermore, the crisis led to the bankruptcy of PG&E, the largest electricity distribution company in the state, and the California Power Exchange, California's electricity marketplace.

In his statement before the US Senate Committee on Governmental Affairs, Paul Joskow stressed that bad market design represented a reason of the Californian crisis. According to Joskow, the causes of California's crisis were *"complex, reflecting a combination of bad market design²⁴, bad regulatory decisions, and unanticipated changes in basic supply and demand conditions, and supplier behaviours which rationally took advantage of opportunities created by these conditions to further increase market prices"*

The main effects of such *"bad market design"*, that generated California's market electricity crisis, can be summarized in four main points: (1) the lack of demand response; (2) the freeze on

²³ California was among the first states in the U.S. to restructure its electricity industry in accordance with the world-wide trend of liberalisation. California's restructuring process was undertaken within a record-breaking time of five years. The main purpose was to reduce the relatively high electricity prices. The process was based largely upon previous experiences in gas and telecommunications restructuring, rather than on experience with other liberalised electricity markets. California began its electricity market deregulation process in the mid 1990s. Two core pieces of the new industry structure, the California Independent System Operator (CAISO) and the California Power exchange (CalPX) and their procedures and tariffs were conceived and set up within three years. When the restructured electricity market started operating on March 31 1998, it was generally considered to be one of the most liberalised electricity markets in the world.

²⁴ The Californian market was organised around two primary institutions: a power exchange (CalPX) and an independent system operator (CAISO). The power exchange and ISO began operation in April 1998. The power exchange ran a day-ahead market using a one-sided bidding arrangement (as did the UK pool) for each hour with a marginal clearing price system, i.e. all bidders were receiving the same price equal to the highest accepted bid. The power exchange was mandatory for the demand and supply of the investor-owned-utilities. The exchange handled roughly 85% of the volume of day-ahead transactions. Hence, participation to the power exchange was mandatory for some players and voluntary for some others. The power exchange provided a day-ahead market and after matching of supply of demand the PX submitted a balanced schedule to the system operator.

electricity retail pricing; (3) the over reliance on the power exchange resulting from the ban on using bilateral contracts; (4) the inefficient transmission pricing system..

Large supply shocks and a large demand shock that hit the state can largely explain the electricity crisis. Firstly, a lack of investment in power plants represents probably the most important reason of the crisis. While demand grew by about 5,500 MW between 1996 and 1999, generating capacity increased by only 672 MW over the same period. At the same time the California economy grew steadily during that period and this led to an increase in demand. This was exacerbated by the fact that retail prices were fixed and thus Californians had no incentives to decrease their demand. In conjunction with these two fundamental reasons a combination of several other factors played a role in the crisis. For instance, poor hydro conditions reduced the generating capacity of the hydroelectric dams while abnormally hot weather increased electricity demand for air conditioning. Additionally, due to environmental rules some power plants could not operate because they did not have emissions credits. Similarly, California's dependence on imported electricity (20% of Californian consumption) became problematic because of a growth in electricity demands in neighbouring States reduced the amount these States were able to export to California. Moreover this period saw a large increase in natural gas prices, which was the fuel of choice for the marginal power plants.

California electricity wholesale markets was deregulated while the retail markets were not and were subject to fixed prices defined for four years. Hence, distribution companies were forced to buy in an unregulated wholesale market and to sell to final customers at a regulated fixed price. The freeze on retail prices created important market distortions because suppliers could charge high prices for some periods without worrying that consumers would reduce their consumption. This feature had disastrous financial consequences for the distribution companies when, in the summer of 2000, wholesale prices rose above the fixed retail price.

An important aspect of the California markets was the limitations on bilateral transactions. Investor-owned utilities were forced to divest much of their fossil-fuel based power plants and not permitted to sign long-term contracts to buy part or all of the output from the plants they had just

sold. Due to this prohibition, the distribution companies were required to buy almost all of the power they needed on the power exchange and on the real-time market run by the ISO. The decision to forbid long term contracts has several explanations. First, following the divestiture of their generation asset the incentives for the investor-owned utilities were important for them to make contracts with the company buying the generation units. There was a fear that at first such possibility would distort the selling price of the asset and the prices for electricity. Second such contracts could be substituted for a utility ownership of the generator and would represent a threat for the creation of a competitive market. In addition, at the beginning of the market, utilities were reluctant to sign long-term contracts because long-term prices were generally higher than the spot prices of the PX. This design appeared problematic when the prices rose dramatically on the power exchange and on the CAISO market.

In addition to the PX, a peculiarity of the Californian market was that anyone other than investor-owned-utilities was allowed to form their own market. These markets were called scheduling coordinators (SCs). The California power exchanges ran an "energy only" market and did not take into consideration the different aspects of physical delivery. This was the responsibility of the California Independent System Operator (CAISO), whose main task was the management of the network operation²⁵. The separation between system operation (CAISO) and power exchange (CalPX) created a complicated set of wholesale markets imperfectly coordinated with one another. The existence of the three markets, day-ahead, real-time and reserve, created uncertainties about which of them would have the best price and thus created even more arbitrage opportunities than would normally exist in a typical market. In particular, the low co-ordination between the PX and the ISO

²⁵ Three major ISO tasks can be distinguished: real time balancing, congestion management and ancillary services. The ISO was running a real-time market to manage the operation of the network. Hence market participants were able to change their day-ahead position by trading in the ISO's real time market. The purpose of this market commonly called a real-time or balancing market, was to price additional generation in the event of a supply shortfall and generation decreases in the event where supply exceed demand. The ISO market was thus critical as it fell at the end of the chronological sequence of markets. The ISO was also operating a "reserve capacity market". Through this market, the ISO purchased reserve capacities for two reasons. One the reserve capacities were used to meet unexpected demand peaks. Two they allowed the ISO to adjust production at different locations within the network to relieve congestion. The ISO also relied on several annual supply contracts with generators to ensure supply availability in constrained area.

was an important limitation for the actual role of the ISO in the market. Hence the separation of the PX and the ISO had important consequences with respect to wholesale market design. On a short-term horizon, day-ahead, hour ahead, no distinction can be made between energy dispatch and use of transmission capacity. Thus, it was a fallacy to separate these two aspects. Moreover the physical feature of contracts on the PX imposed constraints on real-time operation. Since the ISO market was run after the power exchange results, uncertainties existed about whether a generator would receive a higher price if waited for the ISO results. Additionally the pricing rules in the two markets were different in the respective markets of the PX and the ISO. For instance, different price caps created incentives for suppliers during high prices hours to use the ISO real-time market rather than the PX. The existence of various markets offered market participants several opportunities to arbitrage price difference across markets but also created perverse incentives for trading strategies²⁶.

One important controversial feature of the California market was the approach used for transmission pricing. With respect to transmission pricing, the use of pre-determined zones for the management of transmission constraints was problematic due to the existence in some periods of intra zone constraints. The day-ahead transmission market relied on incremental/decremental pairs to balance inter-zonal flows, whereas the real-time market was not confined to matched pairs. Furthermore, the SCs paid the cost of inter-zonal balancing whereas the system operator absorbed the cost of intra-zonal balancing (Chao and Wilson, 1999) which provided poor locational signals. Such an approach encouraged over scheduling of constrained transmission. When the ISO received schedules from the PX and the SCs it had to determine the physical feasibility of the transactions with respect to transmission constraints. Several zones were determined within the ISO system to take into account transmission constraints and possible congestion within a zone was not priced. When such a type of congestion occurred, the ISO paid above market prices to certain generators to use their output to relieve congestion. Moreover due to important transmission constraints an

²⁶ For instance many of market design problems have been identified as early as 1998 by the market surveillance Committee of the California ISO with regard to the market for ancillary services.

important problem for the system operator was to make sure that where there were no substitutes for the output of a specific generator this would operate. Reliability Must-Run Contracts (RMR) were created for this purpose. The price paid by the ISO is necessarily above-market, since there would have been no congestion if the necessary generation units had been willing to operate at the zonal market clearing price. (contracts aimed to compensate a generator forced to run for reliability purposes) when the market price was below their operating costs.

4.3. The Contracts' Institutional and Economic Framework

In the middle of January 2001, the credit ratings of California's utilities were downgraded to junk status, due to financial difficulties caused by extremely high wholesale market prices coupled with frozen, regulated, retail rates²⁷. Generators were unwilling to continue selling electricity to the utilities, and during the two days of rolling blackouts, the State intervened into the power purchasing business in order to keep the lights on in California. To fill the void for a creditworthy power purchaser, the State enlisted its only agency with experience buying and selling power: the Department of Water Resources (DWR). The DWR began spending an average of \$50 million per day, using appropriations from the State's General Fund, to supply about one-third of the electricity used by the customers of California's three investor-owned utilities – the "net short"²⁸ – from the spot market. The prices in the spot market had reached levels an order of magnitude higher than the "normal" prices the state had seen over the past several years. Since the DWR power purchasing responsibilities immediately increased by more than five fold when it began purchasing power on behalf of the customers of California's utilities, the legislature authorized the DWR to enter into long-term contracts in Assembly Bill 1X (AB 1X), in order to decrease the State's exposure to the volatile and expensive spot market. The DWR immediately began to implement a large and

²⁷ Source: Bachrach D.V.(2002).

²⁸ The "net short" is the difference between the electricity demanded by the utility customers, and the electricity supplied by utility-owned generation and qualifying facilities under contract with the utilities.

unprecedented power contracting effort²⁹. Both the DWR and the "seller" (the counterparties (electricity generators) to the DWR electricity contracts) had incentives to sign long-term contracts³⁰. The DWR had intense political and financial pressure to sign contracts quickly, to slow the State's expenditures on electricity, to stabilize the market, and to prevent further blackouts. At the same time, the Seller had an incentive to contract with the DWR because it had become the single monopsonist of electricity in the market and was contracting for the majority of the power the state would need for the coming decades.

The seller's eagerness to contract with the DWR may have been mitigated by the tight supply – demand conditions in the market³¹, which gave the seller more power in negotiations relative to the DWR (since the Seller knew the DWR would need to contract with *most* of them to meet the state's needs). The Sellers were also hesitant to contract with the DWR over concerns of creditworthiness, and the State's commitment to stand by the contracts. In order to overcome all these difficulties, the DWR and the Seller both employed experienced contract negotiators³². Within six months, twenty-seven long-term (three years and longer) contracts had been executed to supply most of the investor-owned utilities' net short over the next years.

"Although the unique conditions surrounding the DWR contracting process may have yielded some contracts executed in a hurry that are more favourable to the Seller as well as average prices

²⁹ The DWR contracts are based on two contract templates that are widely accepted in the electricity industry and were already in use in the Western U.S. The Edison Electric Institute (EEI) and the National Energy Marketers Association developed the main contract used by the DWR. The contract was developed over a two-year period with the collaboration of utilities, generators, marketers, and others. The DWR chose to use this contract because it was familiar and acceptable to seller of electricity, and would thereby allow for expedited negotiations and execution of the contracts. The second contract template was developed by the Western Systems Power Pool. This contract had been in use for some time, and the DWR had previous experience contracting with it.

³⁰ For the theoretical insights explaining contractual parties' incentives to stipulate long-term contracts, see Williams O. (1979; Klein *et al.*, 1978). For empirical applications, see the seminal paper by Joskow (1987).

³¹ The electricity industry is characterized by extremely costly storage; significant capacity constraints in its production and transmission over the network; and highly variable and inelastic demand. An electricity spot market is unlike virtually any other market in that demand and supply must be equalized throughout the electricity grid, at every moment in time, for continuously maintaining network "electrical equilibrium". This feature, coupled with the virtual impossibility of storing electricity, implies that inventories cannot be used, as in most other markets, to mitigate the problem of the lack of available capacity and the resulting increase in prices in periods of high demand.

³² The DWR had negotiators previously from the Los Angeles Department of Water and Power and Southern California Edison, as well as the department's own experienced staff. The DWR also hired consultants familiar with the electricity industry and long-term contracts. In addition, it has The Edison Electric Institute is a U.S. trade association of investor-owned electric utilities.

that are higher than the "norm," as a whole the terms and conditions of the DWR contracts can provide insight into the risk allocation and mitigation practices common in the electricity industry" (Bachrach D.R., 2002, pp 8).

4.4. Long-Term Contracts and Market Organization

The DWR contracts represented an attempt to create a power purchase portfolio, to reduce dependence on real-time spot markets, provide price stability and certainty and to create incentives for the expedite construction of new power plants, peaking facilities and distributed generation. These agreements are signed between the three investor-owned generation utilities, most of which is both hydroelectric or nuclear generation (Buyers) and other electricity generators, most of which is natural gas or renewables generation (Sellers). The DWR acted as a Single Buyer that purchases the amount of energy not otherwise supplied in the wholesale electricity market, in order to meet the uncovered demand.

The market structure, within which the DWR, electricity contracts were negotiated, was a deregulated, partially competitive market, where most electricity transactions were carried on an anonymous power exchange, where the participants bids "quantity-price schedules" for every half an hour of the following day³³. The resulting electricity wholesale prices (for each half hour of the following day) are equilibrium prices derived from an auction bidding procedure.

³³ Power exchanges are regulated institutions, in order to provide uniform, non-discriminatory rules for fair-trading on the power exchange. In power exchanges, each participant selects its own range of price steps and build its own bid based on consumption need, delivery obligations, cost of own production and position on the bilateral market. In general, hourly bids consists of five types of information: name of the participant, bid (sale or purchase), hour of the day (1 to 24 h), quantity of energy and price. Within the same hour, participants are allowed to offer different price-quantity pairs. Within a single hour, each participant can also bid for sale and purchase. The power exchange collects the bids for all players for every trading session and for each hour an aggregated purchase curve and an aggregated sale curve is obtained. The aggregated sale curve is obtained by adding the energy offered in increasing order of prices, regardless of participants. The aggregated purchase curve is obtained in the same way but in decreasing order of prices. The intersection point of the two curves defines the market clearing price (MCP) and the market clearing volume (MCV) for each hour. The sale bids submitted with a price lower or equal to the MCP and the purchase bids with a price equal or higher than the MCP are accepted, while the others are rejected. Once the market-clearing price and market clearing volumes have been determined, spot trades on a power exchange lead to physical delivery. The place of delivery is commonly defined as a hub. In practice, after matching, the power exchange transmits the trading result to the system operator. The power exchange is the counterpart in every trade and its net position is always neutral, i.e. the total volume sold always equal the total volume bought. The system operator can schedule physical flows once they have received the market results.

The DWR contracts electricity prices are wholesale prices, negotiated in long term bilateral markets. The contracts price have three main dimensions: (1) the selling prices for power and energy; (2) the amount of power and energy sold; (3) a set of incentives to improve performance and disincentives to ensure that performance does not fall below a basic standard. The price of capacity is usually related to the capacity declared available. The price of energy is usually tied to an initial cost estimate and a series of cost indexation factors. An initial heat rate and initial fuel and operating and maintenance costs are assessed for the plant, together with the appropriate indexes.

Figure 1: A comparison between Long-Term Contract and Spot Market Electricity Price

Source: Department of Water Resources

Whether power exchanges or bilateral long-term contracting are superior trading practices is a research question that goes beyond the purpose of this paper. Surely, California electricity deregulatory scheme banned long-term contracts (see paragraph 2). However, during the crisis, long term contracts were used as an instrument to secure supply reliability and lower electricity

prices. Figure 1 illustrates a comparison between spot market (forecasted) contract prices and long-term contract prices in the period 2001 and 2010. DWR contract prices are expected to be dramatically lower than spot market prices.

4.5. The Dataset

The analysis of twenty-seven long-term³⁴ natural gas and renewable electricity contracts for electricity, signed by the California Department of Water Resources (DWR) on behalf of California's three investor-owned utilities during the California electricity crisis, forms the basis for the creation of the dataset³⁵. From the analysis of each contract, we have selected the main legal and economic provisions and created the variables we needed to perform our econometric study.

In general, power purchase agreements have three main dimensions: (1) the electricity selling prices (sometimes distinguished in power and energy); (2) the amount of power and energy sold; (3) a set of incentives to improve performance and disincentives to ensure that performance does not fall below a basic standard³⁶.

The DWR contracts contain information about the price at which energy is sold; (setting a minimum and a maximum price range); costs of energy production; quantity of energy produced; contract duration; dispatchability or non-dispatchability provisions³⁷; type of fuel used to produce energy³⁸; type of electricity produced (whether base³⁹, peak⁴⁰, both, summer super peak⁴¹ or

³⁴ We define long-term contracts as those three years in length or longer. However, long-term contracts can be terminated by the parties before the dead-line. Termination rights by the buyer (CDWR) in some of the agreements include, but are not limited to: (1) failure of a new generation unit to meet commercial operating date deadlines within a specified window; (2) failure to achieve certain operating standards (primarily unit availability) at specified levels for specified periods; (3) failure to operate a generating unit within "prudent industry practice" after notice and opportunity to cure such failure. Termination rights by the seller in some of the agreements include, but are not limited to: (1) Lack of maintenance of investment grade credit; (2) failure by CDWR to issue the bonds contemplated by ABIX prior to a set date; (3) failure to make energy payments within specified days after CDWR's receipt of an invoice.

³⁵ Although the DWR contracts were not executed in a fully competitive market, the contracts are based on industry-standard contract templates and therefore may provide broader insights into the contractual practices common in competitively bid contracts. The contracts purchase electricity to supply most of the net short of California's three investor-owned utilities, which represents about one-third of the utility customers' power demand.

³⁶ Onofri L. (2003)

³⁷ Non dispatchable contracts (also known as "must take" or "take or pay") require the DWR to pay for, and the seller to provide, all the electricity scheduled in the contract.

³⁸ In our sample, natural gas, biomass, wind, solar, geothermal, landfill gas.

³⁹ Baseload contracts (7X24) can supply power all day every day

intermittent⁴²); type of pricing mechanism (tolling⁴³, or fixed price⁴⁴); provisions about how to manage risk (fuel price risk⁴⁵; fuel supply risk⁴⁶; performance risk⁴⁷; demand risk⁴⁸; environmental risk⁴⁹ and other type of risk⁵⁰).

The econometric exercises' dependent variable is the contractual price for the supply of the contracted amount of electricity. The price structure is formed by two parts: capacity and energy which is linked to an initial cost estimate and a series of cost indexation factors. The capacity price is paid because the generator declared the plant availability, even if the plant is not ran. Table 1 describes the selected variables and provides descriptive statistical analysis.

⁴⁰ Peak products (6X16) generally can supply power from 6 a.m. to 10 p.m, Monday through Saturday

⁴¹ Summer super peak products (5X8) generally can supply power for 8 hours per day, 5 days a week, from June through October.

⁴² Some electricity generation technologies can only generate electricity intermittently, when the fuel resource is available (e.g. wind and solar).

⁴³ The buyer pays for the cost of the resource used to produce electricity, pays the generator a fee to reserve the use of the facility and pays operating charges when the facility generates power.

⁴⁴ The contract price per MWh is set in the contract.

⁴⁵ The risk that the price of the fuel used to generate electricity will exhibit variability (positive or negative) resulting in an uncertain cost to generate electricity.

⁴⁶ The risk that the fuel supply to a power plant will be unreliable, resulting in the inability to generate electricity in a predictable and dependable manner.

⁴⁷ The risk that either party to an electricity contract will not fulfill its part of the agreement in an optional manner.

⁴⁸ The risk that the electricity that has been contracted for will not be needed as anticipated.

⁴⁹ The financial risk to which parties to an electricity contract are exposed, stemming from both existing environmental regulations and possible future regulations.

⁵⁰ The parties to an electricity contract face numerous other sources of uncertainty (i.e. the risk that the transmission system will be unreliable; or the risk that a party to the contract will default on the contract, by entering into bankruptcy).

TABLE 1

VARIABLE	DESCRIPTION	MEAN	MIN	MAX	STANDARD DEVIATION
MaxPrice	Maximum Price set in the Contract	131.33	58	379	78.93
MinPrice	Minimum Price set in the Contract	76.59	44	141	23.44
Duration	Contract Duration in years	8.92	3	20	4.26
Total Quantity	Contract Total Quantity (GWh)	21648.26	112	93325	27239.44
Costs	Contract Total Power Production Costs (in Million \$)	1493.25	7	6238	1699.421
Tolling Payment	Contract Payment Type	D = 1; 16 Observations			
Fixed Payment	Contract Payment Type. Dummy Variables	D = 1; 11 Observations			
Fuel Supply Risk	Provision regulating the risk that fuel supply to a power plant will be unreliable. Dummy Variable	D = 1; 9 Observations			
Take-or-Pay Contract	Provision requiring the seller to provide all the electricity scheduled in the contract. Non Dispatchable Contract. Dummy Variable	D = 1; 11 Observations			
Construction Incentives	Provision that create incentives for the seller for reaching operation by dead-line. Dummy Variable	D = 1; 17 Observations			
Construction Penalties	Provision that obliges the seller to pay for not reaching operation by dead-line. Dummy Variable	D = 1; 10 Observations			
Availability Incentives	Incentive for availability. Dummy Variable	D = 1; 14 Observations			
Availability Penalties	Contractual Availability Penalties. Dummy Variable	D = 1; 13 Observations			
New units	Provision that signals whether the contract provides for the construction of new power units. Dummy Variable	D = 1; 17 Observations			
Environmental Regulation	Provision about environmental risk, stemming from both existing environmental regulations and possible future regulations. Dummy Variable	D = 1; 7 Observations			
Prevent Regulation	Provision regulating the risk that future laws or regulation, or regulatory review of a contract, will alter the benefits or burdens of an electricity contract to either party. Dummy Variable	D = 1; 13 Observations			
Fuel Supply Risk	Provision that excuses the seller from delivering power if fuel supply is interrupted. Dummy Variable	D = 1; 9 Observations			
Naturalgas	Electricity Generating Resource	D = 1; 18 Observations			
Wind	Electricity Generating Resource	D = 1; 2 Observations			
Biomass	Electricity Generating Resource	D = 1; 5 Observations			
	Dummy Variables	Other Source: geothermal energy			
Base	Electricity Type of Product	D = 1; 13 Observations			
Peak	Electricity Type of Product	D = 1; 7 Observations			
	Dummy Variables	Other contracts produce intermittent or both base power			

4.6. Hedonic Approach and OLS Estimation Results

Formally, we test the following hypothesis: the provisions that set incentives (penalties); increase (decrease) the exchange risk; render more (less) costly the commitment for the Buyer will increase (decrease) the electricity price. In order to test such hypothesis, we use different operationalization methods.

The first exercise consists performing a hedonic method and in interpreting the contractual provisions as "characteristics" positively and negatively affecting the electricity price. The intuition behind the hedonic approach⁵¹ is based on the hypothesis that the prices (of different items) are functions of certain measurable characteristics (such as size, weight, power, speed, etc). The regression methods can be used to estimate by how much the price varies in relation to each of the characteristics. Thus, the price may be described by a simple linear regression⁵² such as:

$$(1) \quad P_i = \alpha_{i,n} + \sum_{i=1}^N \beta_{i,n} x_{i,n} + \varepsilon_{i,n} \quad i = 1, \dots, N; n = 1, \dots, 27$$

$$(2) \quad P_i = \sum_{i=1}^N \beta_{i,n} x_{i,n} + \varepsilon_{i,n} \quad i = 1, \dots, N; n = 1, \dots, 27$$

The dependent variable is the price⁵³ set in each contract n . The dependent variables $x_{i,n}$ are the contractual provisions i , set in each contract n ; $\beta_{i,n}$ are parameters to be estimated and α is the constant. Model (2) does not include a constant in order to avoid multicollinearity problems⁵⁴. Both

⁵¹ The use of hedonic models dates back to Court (1941), Lancaster (1971) and Griliches (1971)

⁵² Our attempt to model the relationships between price formation and contractual provisions included the creation of several dummy variables (e.g. for *resource* and *product*) and multiplicative variables. However, all these specifications performed worse than the one selected in Equation 2. Including too many dummy variables, in fact, generates multicollinearity problems. We also considered log-linear specifications. Regressions results are available upon request.

⁵³ Given that the contracts provide for a minimum and a maximum price threshold, we have regressed the same specification, by using as dependent variables the minimum and the maximum prices.

⁵⁴ The small number of observations and the many dummy variables might represent a cause of multicollinearity. This may lead to unreliable estimates. In order to avoid this problem, we regress a linear specification that does not include a constant. See Verbeek (2000), pp. 38-41.

models include an error term $\varepsilon_{i,n}$. The selected estimation method is the ordinary least squared (OLS). In addition, in order to avoid heteroscedastic residuals, we run the regression using a "robust" estimator for the variance (specifically, the Huber/White/sandwich estimator).

Table 2 and 3 show selected OLS estimation results⁵⁵, when *Price* is the maximum price (*Maxprice*) and the minimum price (*Minprice*)⁵⁶.

TABLE 2 - OLS ESTIMATION RESULTS (with constant)

Dependent Variable	MAX Price	MIN Price	MAX Price	MIN Price
Independent Variables	(1)	(1)	(2)	(2)
Construction Penalties	-81.00*	-21.10	-66.42**	-14.37
Take-or-Pay	-49.46*	-5.67	-44.67*	-0.26**
Availability Penalties	-48.67*	-3.88**	-60.69*	-10.78**
Environmental Regulation	176.35*	21.49	180.43*	16.43
Prevent Regulation	-49.42*	-13.58	-45.61*	-18.30
New Units	-	-	23.39	29.00*
Constant	192.25*	83.88*	177.78*	101.84*
R-Squared	78%	17%	79%	34%

* 5% significance level

**10% significance level

Table 2 reports selected OLS estimation results when the dependent variables are the contract *maximum price* and *minimum price*. As a preliminary remark, it is worth highlighting that those provisions that set penalties (e.g. *Construction Penalties*; *Availability Penalties*) for the Buyer decrease the price; whilst those provisions that make the commitment more risky or costly (e.g. *New Units*) increase the electricity selling price.

⁵⁵ Our attempt to model the relationships between price formation and contractual provisions included the creation of several dummy variables (e.g. for *resource* and *product*) and multiplicative variables. However, all these specifications performed worse than the ones, whose results are presented in Table 2. Including too many dummy variables, in fact, generates multicollinearity problems. We also considered log-linear specifications. Regressions results are available upon request.

⁵⁶ The regression results obtained by using different dependent variable (minimum or maximum price set in the contract, price differential), or different independent variables (e.g. including costs or quantities) are available upon request.

TABLE 3- OLS ESTIMATION RESULTS (without constant)

Dependent Variable	MAX Price (1)	MIN Price (1)	MAX Price (2)	MIN Price (2)	MAX Price (3)	MIN Price (3)	MAX Price (4)	MIN Price (4)
Independent Variables								
Wind	46.15	59.50*	-	-	-	-	-	-
Biomass	87.65	93.00*	44.73	19.64	-	-	-	-
Natural Gas	119.24*	48.80*	-	-	-	-	-	-
Base	13.34	25.48	-	-	-	-	-	-
Peak	93.64*	46.02*	24.13	6.39**	-	-	-	-
Tolling Contract	-	-	-27.66*	61.30	-9.36**	65.72	-	-
Take-or-Pay	-	-	-41.86	0.31**	-37.18	4.08**	-	-
New Units	-	-	46.58*	9.81**	50.62*	-2.92**	28.48*	22.75*
Availability Incentives	-	-	88.92*	10.35	81.03*	11.39	35.09*	36.57*
Construction Incentives	-	-	97.63*	22.23*	100.35*	22.57*	76.57*	41.43*
Prevent Regulation	-	-	-36.87*	-16.15	-36.50*	-13.70	-	-
Environmental Regulation	-	-	190.83*	53.88*	208.83*	65.15*	176.20*	42.12*
Fuel Supply Risk	-	-	-36.67*	-47.84*	-22.68	50.93*	-	-
Duration>10	-	-	-	-	-19.28	-18.56**	-	-
Uncentred R ²	80%	80%	95%	90%	94%	94%	91%	86%

* 5% significance level

**10% significance level

Table 3 reports selected OLS estimation results, when the dependent variables are the contract *maximum price* and *minimum price*. In general, it is interesting to remark that the estimated coefficients for those provisions regulating performance, risks and “*force majeure*” are statistically significant when the dependent variable is the *maximum price*. The variables that affect the formation of the (minimum) price are less related to risk issues and to contractual provisions. The estimated coefficients for the dummy variables capturing the fuel type and electricity product are statistically significant⁵⁷.

This might suggest that the definition of an electricity contract minimum price mainly depends on other structural variables that we did not capture in our dataset and analysis and that contractual

⁵⁷ The same dummy variables are not statistically significant when the dependent variable is the maximum price.

provisions affect the maximum price, but are less preponderant in explaining how the minimum price is formed.

In particular, when the dependent variable is represented by the maximum price, the estimated coefficients for “*Construction Incentives*” are positive and statistically significant. A contractual provision that offers incentives to the seller for reaching operation before the construction dead-line, positively affects the maximum price. Higher prices give the seller an inherent incentive to deliver power in order to earn the profitable payments.

The estimated coefficients for “*Take-or-Pay*” and “*Tolling Contract*” provisions present a negative sign. Tolling contracts and “take-or-pay” provisions reduce risk for the seller and increase it for the buyer, which implies that they reduce the price of power. The estimated coefficients, however, are not statistically significant.

The estimated coefficient for “*Fuel Supply Risk*” is negative and statistically significant. Fuel supply risk is the variable signalling that the contract contains a provision that excuses the seller from delivering power if fuel supply is interrupted. Fuel supply risk is the risk that the fuel supply to a power plant will be unreliable, resulting in the inability to generate electricity in a predictable and dependable manner. When such provision is contained in the contract, it negatively affects the (maximum) price, because it renders the transaction less risky for the seller. In this way, the buyer is compensated for an increase of the contractual transaction by paying a lesser price.

The dummy variable “*Availability Incentives*”⁵⁸ always presents positive, statistically significant estimated coefficients. Since the seller builds and operates the power plant (that provides the electricity sold under a contract), the seller is best able to control the performance of the power plant. Or this reason, the contracts allocate a substantial amount of performance risk to the seller, and

⁵⁸ The general definition of availability is the number of hours that the generation unit is *available* to generate power during a period, divided by the total possible number of hours the unit could have been dispatched during the period as specified in the contract (adjusted for force majeure events and scheduled outages). Contracts also provide the seller an incentive to surpass the guaranteed level of availability. Most of the contracts guarantee availabilities over 95% during the summer and over 90% during the rest of the year.

provide incentives for the seller to perform in a way that reduces the uncertainties faced by the buyer (DWR).

The estimated coefficients for "Environmental Regulation" are positive and statistically significant. Electricity contracts have very different environmental risk profiles by nature of the technologies and fuel sources used to generate the electricity. If new environmental regulations are enacted, the seller (in particular in to non-renewable contracts) will most likely have to bear additional costs. This might positively affect the electricity price.

The other estimated coefficients are not statistically significant. This is particularly surprising for variables like "wind" or "biomass", that represent the electricity generation source and "base" that represent the type of electricity to be produced.

The measure of the goodness of fit, the uncentred R^2 , however, spans from around 80% to 95%, signalling that the model is a good approximation of the observed data

When the hedonic approach is used to regress the same linear models, with a different dependent variable (minimum price), the OLS estimation results change. In this case, most of the variables estimated coefficients are not statistically significant, although the measure of the goodness of fit spans from 80 to 95%.

"Construction Incentives" and "Environmental Regulation" present positive and statistically significant estimated coefficients, like in the specifications where the dependent variable is the maximum price. An interesting difference is that the estimated coefficients for those variables representing the generation resource type and the electricity product are positive and statistically significant.

4.7. SLS Estimation Results

In order to capture the contracts heterogeneity and differences across provisions, we select a different estimation method, which takes into consideration the provisions' endogeneity⁵⁹. Since the price of electricity differs according to the type of generated product (base, peak or both) and to the type of generating resource (gas, wind and so on), to the payment schedule; the produced quantity; the contract duration; the obligation to build a new plant and so on, we try to allow for this heterogeneity by using instrumental variable analysis. We estimate a simultaneous equation model where the instrumental variables (*Newunits*, *Annual quantity*, *Tolling Contract* and *Take-or-pay contract*⁶⁰) depend on selected types of electricity generation resources (wind, gas), electricity product (base, peak) and other contractual obligations. After several checks, we select the following specifications:

$$1. \text{Price}_i = \beta_0 + \beta_1 \text{tollingcontract}_i + \beta_2 \text{takeorpay}_i + \beta_3 \text{environmentalregulation}_i + \beta_4 \text{newunits}_i + \varepsilon_i$$

$$\text{Newunits}_i = \beta_0 + \beta_1 \text{naturalgas}_i + \beta_2 \text{biomass}_i + \beta_3 \text{wind}_i + \beta_4 \text{peak}_i + \beta_5 \text{base}_i + \beta_6 \text{constructionincentives}_i + \beta_7 \text{availabilityincentives}_i + \beta_8 \text{preventregulation}_i + \beta_9 \text{environmentalregulation}_i + \beta_{10} \text{fuel supplyrisk}_i + \varepsilon_i$$

$$i = 1, \dots, 27$$

$$2. \text{Price}_i = \beta_0 + \beta_1 \text{environmentalregulation}_i + \beta_2 \text{newunits}_i + \beta_3 \text{annualquantity}_i + \varepsilon_i$$

$$\text{Annualquantity}_i = \beta_0 + \beta_1 \text{naturalgas}_i + \beta_2 \text{biomass}_i + \beta_3 \text{wind}_i + \beta_4 \text{peak}_i + \beta_5 \text{base}_i + \beta_6 \text{constructionincentives}_i + \beta_7 \text{availabilityincentives}_i + \beta_8 \text{preventregulation}_i + \beta_9 \text{environmentalregulation}_i + \beta_{10} \text{fuel supplyrisk}_i + \beta_{11} \text{takeorpay}_i + \beta_{12} \text{tollingcontract}_i + \varepsilon_i$$

$$i = 1, \dots, 27$$

$$3. \text{Price}_i = \beta_0 + \beta_1 \text{environmentalregulation}_i + \beta_2 \text{takeorpay}_i + \beta_3 \text{newunits}_i + \beta_4 \text{tollingcontract}_i + \varepsilon_i$$

$$\text{Tollingcontract}_i = \beta_0 + \beta_1 \text{naturalgas}_i + \beta_2 \text{biomass}_i + \beta_3 \text{wind}_i + \beta_4 \text{peak}_i + \beta_5 \text{base}_i + \beta_6 \text{constructionincentives}_i + \beta_7 \text{availabilityincentives}_i + \beta_8 \text{preventregulation}_i + \beta_9 \text{environmentalregulation}_i + \beta_{10} \text{fuelsupplyrisk}_i + \beta_{11} \text{takeorpay}_i + \beta_{12} \text{tollingcontract}_i + \varepsilon_i$$

$$i = 1, \dots, 27$$

$$4. \text{Price}_i = \beta_0 + \beta_1 \text{availabilityincentives}_i + \beta_2 \text{annualquantity}_i + \beta_3 \text{takeorpay}_i + \varepsilon_i$$

$$\text{Takeorpay}_i = \beta_0 + \beta_1 \text{naturalgas}_i + \beta_2 \text{biomass}_i + \beta_3 \text{wind}_i + \beta_4 \text{peak}_i + \beta_5 \text{base}_i + \beta_6 \text{constructionincentives}_i + \beta_7 \text{availabilityincentives}_i + \beta_8 \text{preventregulation}_i + \beta_9 \text{environmentalregulation}_i + \beta_{10} \text{fuelsupplyrisk}_i + \beta_{11} \text{takeorpay}_i + \beta_{12} \text{tollingcontract}_i + \varepsilon_i$$

$$i = 1, \dots, 27$$

⁵⁹ The instrumental variable (IV) estimator allows to consistently estimated an equation, when one or more of the explanatory variables are not exogenous.

⁶⁰ The four different instrumental variables were selected on the basis of an economic reasoning: the quantity; the payment scheme; the obligation to build a new generation unit are variables dramatically affecting the price.

where *Price* is the (maximum and the minimum) price set in the contract.

TABLE 4- 2SLS ESTIMATION RESULTS

Dependent Variable	MAX Price	MIN Price	MAX Price	MIN Price	MAX Price	MIN Price	MAX Price	MIN Price
Independent Variables	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(4)
Tolling Contract	-65.50	-13.15	-	-	-3.71	-6.31	-	-
Take-or-Pay	-68.56	20.80	-	-	-33.03	-6.65	96.57*	3.74**
Environmental Regulation	131.78*	13.78	131.29*	4.86	94.42*	8.30*	-	-
New Units	1.90	-18.75	0.19**	-24.09*	-8.13**	-19.66*	-	-
Availability Incentives	-	-	-	-	-	-	-15.69	5.54
Annual Quantity	-	-	0.002	-0.003*	-	-	0.002	-0.003*
Constant	96.69*	81.68	92.18*	101.06*	140.28*	88.07*	189.54*	79.69*
Pseudo R-Squared	45%	9%	53%	30%	56%	12%	42%	13%

* 5% significance level

**10% significance level

Tables 4 shows the 2SLS estimation results. The models perform better when the dependent variable is the *maximum price*, rather than the *minimum price*. In particular, the estimated coefficients for “Take-or-Pay” and “Tolling Contract” provisions present a negative sign but are not statistically significant. The dummy “Environmental regulation” always presents positive and statistically significant estimated coefficients. The instrumental variables (*Newunits*, *Annualquantity*, *Tolling Contracts*, *Take-or-Pay Contract*) present, with some exceptions, statistically not significant estimated coefficients. The pseudo- R^2 spans from 12 to 56%.

4.8. SLS Estimation Results with Payment Schemes and Quantity Provisions as dependent variable

Another way to look at the price determinants is using the pricing mechanism (tolling contract) and the quantity provisions (take-or-pay contract) respectively as dependent variables and the (*maximum*

and *minimum*) price as instrumental variables. In this way, we can simultaneously capture the price and respectively payment scheme and quantity provisions determinants. After several checks, we select the following specifications, spanning from the simplest functional relationship to the most complex.

A. Tolling Contract_i = $\beta_0 + \beta_1$ Maximum Price_i + ε_i
Maximum Price_i = $\beta_0 + \beta_1$ naturalgas_i + β_2 biomass_i + β_3 wind_i + β_4 peak_i + β_5 base_i + β_6 constructionpenalties_i + β_7 availabilitypenalties_i + β_8 preventregulation_i + β_9 environmentalregulation_i + β_{10} fuelsupplyrisk_i + β_{11} takeorpay_i + β_{12} Newunits_i + ε_i
i = 1,..., 27

B. Tolling Contract_i = $\beta_0 + \beta_1$ Maximum Price_i + β_2 naturalgas_i + β_3 availabilityincentives_i + ε_i
Maximum Price_i = $\beta_0 + \beta_1$ naturalgas_i + β_2 biomass_i + β_3 wind_i + β_4 peak_i + β_5 base_i + β_6 constructionpenalties_i + β_7 availabilitypenalties_i + β_8 preventregulation_i + β_9 environmentalregulation_i + β_{10} fuelsupplyrisk_i + β_{11} takeorpay_i + β_{12} Newunits_i + ε_i
i = 1,..., 27

C. Tolling Contract_i = $\beta_0 + \beta_1$ Maximum Price_i + β_2 naturalgas_i + β_3 availabilityincentives_i + β_4 constructionincentives_i + β_5 environmentalregulation_i + ε_i
Maximum Price_i = $\beta_0 + \beta_1$ naturalgas_i + β_2 biomass_i + β_3 wind_i + β_4 peak_i + β_5 base_i + β_6 constructionpenalties_i + β_7 availabilitypenalties_i + β_8 preventregulation_i + β_9 environmentalregulation_i + β_{10} fuelsupplyrisk_i + β_{11} takeorpay_i + β_{12} Newunits_i + ε_i
i = 1,..., 27

D. Tolling Contract_i = $\beta_0 + \beta_1$ Maximum Price_i + β_2 availabilityincentives_i + β_3 constructionincentives_i + β_4 fuelsupplyrisk_i + ε_i
Maximum Price_i = $\beta_0 + \beta_1$ naturalgas_i + β_2 biomass_i + β_3 wind_i + β_4 peak_i + β_5 base_i + β_6 constructionpenalties_i + β_7 availabilitypenalties_i + β_8 preventregulation_i + β_9 environmentalregulation_i + β_{10} fuelsupplyrisk_i + β_{11} takeorpay_i + β_{12} Newunits_i + ε_i
i = 1,..., 27

E. Tolling Contract_i = $\beta_0 + \beta_1$ Minimum Price_i + β_2 naturalgas_i + β_3 availabilityincentives_i + β_4 constructionincentives_i + β_5 environmentalregulation_i + ε_i
Minimum Price_i = $\beta_0 + \beta_1$ naturalgas_i + β_2 biomass_i + β_3 wind_i + β_4 peak_i + β_5 base_i + β_6 constructionpenalties_i + β_7 availabilitypenalties_i + β_8 preventregulation_i + β_9 environmentalregulation_i + β_{10} fuelsupplyrisk_i + β_{11} takeorpay_i + β_{12} Newunits_i + ε_i
i = 1,..., 27

F. Take-or-pay_i = $\beta_0 + \beta_1$ naturalgas_i + β_2 availabilityincentives_i + β_3 Tollingcontract_i + β_4 Maximum Price_i (β_1 Minimum Price_i) + ε_i
Maximum Price_i (Minimum Price_i) = $\beta_0 + \beta_1$ naturalgas_i + β_2 biomass_i + β_3 wind_i + β_4 peak_i + β_5 base_i + β_6 constructionpenalties_i + β_7 availabilitypenalties_i + β_8 preventregulation_i + β_9 environmentalregulation_i + β_{10} logduration_i + β_{11} fuelsupplyrisk_i + β_{12} takeorpay_i + β_{13} Newunits_i + ε_i
i = 1,..., 27

$$G. \text{ Take-or-pay}_i = \beta_0 + \beta_1 \text{constructionincentives}_i + \beta_2 \text{availabilityincentives}_i + \beta_3 \text{Tollingcontract}_i + \beta_4 \text{Newunits}_i + \beta_5 \text{Maximum Price}_i (\beta_1 \text{Minimum Price}_i) + \varepsilon_i$$

$$\text{Maximum Price}_i (\text{Minimum Price}_i) = \beta_0 + \beta_1 \text{naturalgas}_i + \beta_2 \text{biomass}_i + \beta_3 \text{wind}_i + \beta_4 \text{peak}_i + \beta_5 \text{base}_i + \beta_6 \text{constructionpenalties}_i + \beta_7 \text{availabilitypenalties}_i + \beta_8 \text{preventregulation}_i + \beta_9 \text{environmentalregulation}_i + \beta_{10} \text{logduration}_i + \beta_{11} \text{fuelsupplyrisk}_i + \beta_{12} \text{takeorpay}_i + \beta_{13} \text{Newunits}_i + \varepsilon_i$$

$$i = 1, \dots, 27$$

$$H. \text{ Take-or-pay}_i = \beta_0 + \beta_1 \text{naturalgas}_i + \beta_2 \text{availabilityincentives}_i + \beta_4 \text{constructionincentives}_i + \beta_5 \text{Maximum Price}_i (\beta_1 \text{Minimum Price}_i) + \varepsilon_i$$

$$\text{Maximum Price}_i (\text{Minimum Price}_i) = \beta_0 + \beta_1 \text{naturalgas}_i + \beta_2 \text{biomass}_i + \beta_3 \text{wind}_i + \beta_4 \text{peak}_i + \beta_5 \text{base}_i + \beta_6 \text{constructionpenalties}_i + \beta_7 \text{availabilitypenalties}_i + \beta_8 \text{preventregulation}_i + \beta_9 \text{environmentalregulation}_i + \beta_{10} \text{logduration}_i + \beta_{11} \text{fuelsupplyrisk}_i + \beta_{12} \text{takeorpay}_i + \beta_{13} \text{Newunits}_i + \varepsilon_i$$

$$i = 1, \dots, 27$$

$$I. \text{ Take-or-pay}_i = \beta_0 + \beta_1 \text{naturalgas}_i + \beta_2 \text{availabilityincentives}_i + \beta_3 \text{constructionincentives}_i + \beta_4 \text{environmentalregulation}_i + \beta_5 \text{fuelsupplyrisk}_i + \beta_6 \text{preventregulation}_i + \beta_7 \text{Newunits}_i + \beta_8 \text{Maximum Price}_i (\beta_1 \text{Minimum Price}_i) + \varepsilon_i$$

$$\text{Maximum Price}_i (\text{Minimum Price}_i) = \beta_0 + \beta_1 \text{naturalgas}_i + \beta_2 \text{biomass}_i + \beta_3 \text{wind}_i + \beta_4 \text{peak}_i + \beta_5 \text{base}_i + \beta_6 \text{constructionpenalties}_i + \beta_7 \text{availabilitypenalties}_i + \beta_8 \text{preventregulation}_i + \beta_9 \text{environmentalregulation}_i + \beta_{10} \text{logduration}_i + \beta_{11} \text{fuelsupplyrisk}_i + \beta_{12} \text{takeorpay}_i + \beta_{13} \text{Newunits}_i + \varepsilon_i$$

$$i = 1, \dots, 27$$

Tables 5 and 6 report the 2SLS estimation results. The IV estimator is determined by legal and economic contracts. In general, the estimated coefficients for the instrumental variables are statistically significant and present a negative sign, indicating an inverse relationship between price-tolling contracts and price-quantity provision, consistent with the economic theory.

TABLE 5- 2SLS ESTIMATION RESULTS

Dependent Variable	Tolling Contract (1)	Tolling Contract (2)	Tolling Contract (3)	Tolling Contract (4)	Tolling Contract (5)
Independent Variables					
Natural Gas	-	-0.36*	-0.37*	-0.40*	-
Availability Incentives	-	0.31*	0.26	0.21	0.109
Fuel Supply Risk	-	-	-	-	-0.68*
Environmental Regulation	-	-	-0.75	-0.46	-
Construction Incentives	-	-	0.12	0.06	0.183*
Maximum Price	-0.04*	-0.02*	-0.02	-	-0.002*
Minimum Price	-	-	-	-0.002	-
Constant	1.18*	1.00*	0.95*	1.07*	0.94*
Pseudo R-Squared	39%	62%	65%	62%	85%

* 5% significance level

TABLE 6- 2SLS ESTIMATION RESULTS

Dependent Variable	Take-or-Pay (1)	Take-or-Pay (2)	Take-or-Pay (3)	Take-or-Pay (4)	Take-or-Pay (5)	Take-or-Pay (6)	Take-or-Pay (7)	Take-or-Pay (8)
Independent Variables								
Natural Gas	-0.13	-0.12	-	-	-0.37*	-0.55*	-0.15	-0.15
Availability Incentives	0.12	0.12	0.10	0.13	0.27	0.41*	0.43	0.19
New Units	-	-	0.012	0.02	-	-	0.11	0.039
Tolling Contract	0.60*	0.72*	0.63*	0.77*	-	-	-	-
Environmental Regulation	--	-	-	-	-	-	0.69	-0.38
Construction Incentives	-	-	0.05	0.0007	0.16	0.15	0.48*	-0.005
Fuel Supply Risk	-	-	-	-	-	-	-0.36*	-0.37
Prevent Regulation	-	-	-	-	-	-	-0.33	-0.11
Maximum Price (IV)	-0.001	-	-0.001	-	-0.002*	-	-0.005*	-
Minimum Price (IV)	-	0.002	-	0.001	-	-0.002	-	0.002
Constant	0.40	0.001	0.31*	-0.03	0.96*	0.80*	0.84	0.64
Pseudo R-Squared	75%	73%	74%	72%	65%	55%	74%	72%

5% significance level

4.9. Concluding Remarks

The paper has empirically analysed the effects of legal provisions setting penalties and incentives, and regulating the parties' obligations and risks, on electricity contracts price formation. We have considered 27 California long-term electricity contracts for the trade of electricity between generators. We have created a dataset by using the contracts' main legal provisions, in order to perform an econometric exercise and target the main determinants that affect price provisions in long-term electricity contracts. Given that the contacts set a minimum and a maximum price threshold, we have performed separated econometric exercises.

The general result is that the provision increasing (decreasing) the trading risk⁶¹ for the seller increase (decrease) the price; those provisions setting penalties⁶² (incentives⁶³) for the seller decrease the price.

A peculiarity is that the legal provisions regulating obligations and risks and setting incentives and penalties affect the maximum contract price. Estimated coefficients for legal provisions are not statistically significant when the dependent variable is the minimum price. Economic variables (like fuel types, construction costs and so on) are more robust explanatory variables for minimum price.

The general results are robust to different model specifications and estimation techniques.

⁶¹ I.e. tolling contract or take-or-pay contract.

⁶² I.e. construction penalties or availability penalties.

⁶³ I.e. construction incentives or availability incentives.

APPENDIX: SOME EXAMPLES OF ELECTRICITY CONTRACTS LEGAL PROVISIONS⁶⁴

1. Fuel Supply Risk

Fresno Cogeneration Contract: the seller is excused from delivering power if fuel supply or fuel transportation is interrupted except if the interruption is due to Seller's negligence.

Calpeak Contract: the seller is excused from delivering power if fuel supply or fuel transportation is interrupted except if the interruption is due to non-economic reasons.

PacificCorp Contract: the seller is excused from delivering power if fuel supply or fuel transportation is interrupted except if the interruption is due to force majeure in fuel supply or transportation agreement.

Clearwood Contract: the seller is excused from delivering power if fuel supply or fuel transportation is interrupted except if the interruption is due force majeure that include inadequate or excessive geothermal reservoir pressures or temperatures.

2. Prevent Regulation

Allegheny Contract: if a Regulatory Authority orders a change in the contract the price will not change.

Sempra Contract: if a Regulatory Authority orders a change in the contract the adversely affected party may terminate or re-negotiate the contract.

Coral Power Contract: if a Regulatory Authority orders a change in the contract the Seller can terminate the contract (with no termination payment).

⁶⁴ Source: Bachrach D. (2002)

3. Environmental Regulation

Calpine Contract: any cost above a certain threshold (\$5/MWh) generated by a future environmental regulation imposed by a governmental authority is born by the Seller.

GWF Contract: the costs generated by environmental regulation are renegotiated in good faith, but the Seller may terminate.

4. Availability Incentives and Penalties

Capitol Power Contract: if the plant does not meet availability guarantee for 3 consecutive months, the Buyer can terminate.

Alliance Colton Contract: the Buyer can terminate if annual average availability is less than 60% for any two out of three years. If the Seller fails to meet availability guarantee intentionally, then Seller defaults.

Wellhead Contract: the Buyer can terminate if the availability is less than 60% for one year.

5. Power Plant Construction Incentives and Penalties

Sempra Contract: if the unit fails to reach operation despite Seller's reasonable effort, Seller is not liable to provide electricity

Sunrise Contract: the Buyer can terminate the contract with respect to any unit that does not reach operation by dead-line

High Desert Contract: the Seller pays the Buyer a penalty for not reaching operation by dead-line.

5. Testing Williamson Theory On Transaction-Specific Governance Structures: Evidence From The Electricity Markets

5.1. Introduction

The paper is an attempt to test empirically the importance of asset specificity⁶⁵ in influencing the duration of electricity contracts negotiated between electricity generators in the wholesale restructured market and the importance of legal provisions to provide or efficient adaptation on long term contracts.

The main research question is whether the existence of relationship-specific investments to support costs-minimising exchange, provide explanations for the particular organizational arrangements (long-term contracts) observed in the electricity restructured industry.

The theoretical framework is provided by transaction-cost economics (Coase, 1937, Williamson, 1979, 1983; Klein, Crawford and Alchian, 1978), which has been used to analyze organization and contracting practices in a wide range of industries. According to transaction costs theory, profit maximising firms select their governance structure such as to minimise transaction costs. In particular, when exchange involves significant investments in relationship-specific capital, an exchange relationship relying on repeated bargaining is not attractive. *"Once the investments are sunk in anticipation of performance, "hold-up" or "opportunism incentives are created ex post which, if mechanisms cannot be designed to mitigate the parties' ability to act on these incentives, could make a socially cost-minimising transaction privately unattractive at the contract execution*

⁶⁵ Williamson (1983) identifies four types of asset-specificity:

1. *site-specificity*: once sited the assets are very immobile.
2. *physical asset specificity*: when parties make investments in machinery or equipment that are specific to a certain transaction and these have lower values in alternative uses.
3. *dedicated assets*: general investment by a supplier or buyer that would otherwise not be made but for the prospect of transacting a specific (large) amount of coal with a particular partner. If the contract is prematurely terminated, the supplier (who invested) would be with excess capacity/ the buyer would be with unexpected excess demand.
4. *human asset specificity*: workers acquired skills, know-how and information that is more valuable inside a particular transaction than outside it.

stage.” Joskow (1987, p. 169). For this reason, long-term contracts that specify the terms and conditions for future transactions *ex ante* represent a remedy for *ex post* performance problems.

Electricity contracts in restructured wholesale markets are mostly long-term contracts because the activity of generating electricity requires important asset specific investment and a new generator will defer investing in a new plant, until sufficiently long-term contracts will be arranged and cover a sufficient portion of the required investment. At the same time, long term relationships (motivated by asset specific investments) need flexibility and adaptation to the change of contingencies.

In a seminal paper, Joskow (AER, 1987), investigates whether there are relation-specific investments determinants of the contract length (duration) between coal suppliers and electric utilities. The dataset is formed by 277 contracts stipulated in coal markets between utilities and suppliers of coal. The result provide evidence that buyers and sellers make longer *ex-ante* commitments (longer contracts) when relation-specific investments are more important and rely less on repeated spot negotiations over time. This holds in particular for the West Coast large surface mines. Since in that area large mines are the least costs production technology and transportation alternatives are poor, long term contracts represent the best adaptation alternative to minimize transaction costs.

Another important work is the paper by Masten and Crocker (1985, AER), which examines the of “take-or-pay provisions” in contracts between natural gas producers and pipelines from a transaction costs economics perspective. The paper results suggest that “take-or-pay provisions” are an incentive to provide for flexibility in long-term contracts and play an important efficient (transaction costs minimising) role.

More recently, the paper by Chrisholm (1996) investigates why the governance structure in the motion picture industry change from long-term contracts to market exchange. In the early period there was a lot of demand for relationship-specific investments, but then, after 1948, there were some changes (the Paramount Antitrust Case, separation of exhibition, increased competition,

increased popularity of television) from production which reduced the demand for such relationship-specific investments and thus to shortening of contracts between studios and stars.

This paper relies on both the analysis of Joskow (in assuming that the more important are relation-specific investments, the longer will be the period of time over which the parties will establish the terms of trade *ex ante* by contract) and the analysis of Masten and Crocker (in interpreting legal provisions - like “take-or-pay” provisions - as efficient adaptation to long relationships). The paper differs from the cited works because the analysis applies to long-term contracts in restructured electricity markets and because the empirical analysis not only includes economic contract terms (like the exchanged quantity), but also legal provisions that might affect the contractual duration, that represent how the parties regulate and adapt to transaction specific investments.

The work is organised as follows: section 5.2 describes the dataset formation and provides for some descriptive statistic; section 5.3 presents the model specification and the 2SLS estimation results; section 5.4 contains the model specification and the maximum likelihood estimation results. Section 5.5 concludes.

5.2. The Dataset and Descriptive Statistics

The analysis of twenty-seven long-term⁶⁶ natural gas and renewable electricity contracts for electricity, signed by the California Department of Water Resources (DWR) on behalf of California’s three investor-owned utilities during the California electricity crisis, forms the basis for the creation of the dataset⁶⁷.

Table 1 summarizes some of the principal terms of the twenty-seven long-term contracts highlighted in this report. All of the information contained in the table was taken from our review of

⁶⁶ We define long-term contracts as those three years in length or longer

⁶⁷ Although the DWR contracts were not executed in a fully competitive market, the contracts are based on industry-standard contract templates and therefore may provide broader insights into the contractual practices common in competitively bid contracts.

the contracts⁶⁸, except the estimates of the ten-year energy purchases, price range, and ten-year power costs, which are derived from other sources⁶⁹ (e.g. U.S. Energy Information Administration, 2002).

From the analysis of each contract, we have selected the main legal and economic provisions and created the variables we needed to perform our econometric study. In general, the contracts contain information about the price at which energy is sold; (setting a minimum and a maximum price range); costs of energy production; quantity of energy produced; contract duration; dispatchability; type of fuel used to produce energy (natural gas or renewables, like wind, geothermal energy, or biomass); type of electricity produced (whether base, peak or both); type of pricing mechanism (tolling⁷⁰, or fixed price⁷¹); provisions about how to manage risk (fuel price risk⁷²; fuel supply risk⁷³; performance risk⁷⁴; demand risk⁷⁵; environmental risk⁷⁶ and other type of risk⁷⁷). Table 1 contains some variables summary statistics. Table 2 is a correlation matrix of some selected variables that we further use in the regression analysis.

⁶⁸ Source of the contracts text was Marcus (2002).

⁶⁹ The DWR contracts are expected to cost about \$42.6 billion over ten years. The contracts purchase electricity to supply most of the net short of California's three investor-owned utilities, which represents about one-third of the utility customers' power demand. The average price over ten years for the electricity is estimated to be \$70 per MWh. This price would be high in the context of a properly functioning electricity market, but is about one fourth the price that the DWR was paying at the time the contracts were signed. The major assumptions made to calculate these figures are that the DWR is assumed to purchase the maximum amount of energy available under each contract (including the dispatchable contracts), and that the cost of gas is assumed to start at \$10.74 per million Btu in 2001 and to fall to \$4.68 per million Btu in 2010. The long-term DWR contracts, analyzed in this paper account for \$40.3 billion (U.S. Energy Information Administration, 2002).

⁷⁰ The buyer pays for the cost of the resource used to produce electricity, pays the generator a fee to reserve the use of the facility and pays operating charges when the facility generates power.

⁷¹ The contract price per MWh is set in the contract.

⁷² The risk that the price of the fuel used to generate electricity will exhibit variability (positive or negative) resulting in an uncertain cost to generate electricity.

⁷³ The risk that the fuel supply to a power plant will be unreliable, resulting in the inability to generate electricity in a predictable and dependable manner.

⁷⁴ The risk that either party to an electricity contract will not fulfill its part of the agreement in an optional manner.

⁷⁵ The risk that the electricity that has been contracted for will not be needed as anticipated.

⁷⁶ The financial risk to which parties to an electricity contract are exposed, stemming from both existing environmental regulations and possible future regulations.

⁷⁷ The parties to an electricity contract face numerous other sources of uncertainty (i.e. the risk that the transmission system will be unreliable; or the risk that a party to the contract will default on the contract, by entering into bankruptcy).

TABLE 1

VARIABLE	DESCRIPTION	MEAN	MIN	MAX	STANDARD DEVIATION
Duration	Contract Duration in years	8.92	3	20	4.26
Annual Quantity	Annual Contract Quantity (GWh)	2404.492	22.4	9332.5	2806.661
Total Quantity	Contract Total Quantity (GWh)	21648.26	112	93325	27239.44
Costs	Contract Total Power Production Costs (in Million \$)	1493.25	7	6238	1699.421
Tolling Payment	Contract Payment Type. Dummy Variable	D = 1; 16 Observations			
Fixed Payment	Contract Payment Type	D = 1; 11 Observations			
Fuel Supply Risk	Provision regulating the risk that fuel supply to a power plant will be unreliable Dummy Variable	D = 1; 9 Observations			
Take-or-Pay Contract	Non Dispatchable Contract. Dummy Variable	D = 1; 11 Observations			
Construction Incentives	Provision that create incentives for the seller for reaching operation by dead-line Dummy Variable	D = 1; 17 Observations			
Construction Penalties	Provision that obliges the seller to pay for not reaching operation by dead-line Dummy Variable	D = 1; 10 Observations			
Availability Incentives	Incentive for availability ² Dummy Variable	D = 1; 14 Observations			
Availability Penalties	Contractual Availability Penalties. Dummy Variable	D = 1; 13 Observations			
New units	Provision that signals whether the contract provides for the construction of new power units. Dummy Variable	D = 1; 17 Observations			
Environmental Regulation	Provision about environmental risk, stemming from both existing environmental regulations and possible future regulations Dummy Variable	D = 1; 7 Observations			
Prevent Regulation	Provision regulating the risk that future laws or regulation, or regulatory review of a contract, will alter the benefits or burdens of an electricity contract to either party. Dummy Variable	D = 1; 13 Observations			
Naturalgas	Electricity Generating Resource	D = 1; 18 Observations			
Wind	Electricity Generating Resource	D = 1; 2 Observations			
Biomass	Electricity Generating Resource	D = 1; 5 Observations			
	Dummy Variables	Other Source: geothermal energy			
Base	Electricity Type of Product	D = 1; 13 Observations			
Peak	Electricity Type of Product	D = 1; 7 Observations			
	Dummy Variables	Other contracts produce intermittent or both base power			
Duration >10	Number of Contracts lasting more than 10 years Dummy Variables	D = 1; 20 Observations			

TABLE 2: CORRELATION MATRIX

Observation Sample = 27	Duration	Total Quantity	Annual Quantity	Log-Quantity	Take-or-Pay	Tolling Payment	New Units	Availability Penalties	Environmental Regulation
Duration	-								
Total Quantity	0.15	-							
Annual Quantity	0.01	0.96	-						
Log-Quantity	0.03	0.84	0.85	-					
Take-or-Pay	-0.35	0.22	0.21	-0.09	-				
Tolling Payment	0.17	0.01	0.03	0.19	-0.84	-			
New Units	0.37	-0.15	-0.25	-0.16	-0.37	0.37	-		
Availability Penalties	0.08	-0.41	-0.47	0.35	-0.55	0.55	0.62	-	
Environmental Regulation	0.37	-0.15	-0.21	0.02	-0.71	0.71	0.38	0.61	-

5.3. SLS Estimation Results

The hypothesis to test is that the more important are relationship-specific investments, the longer will be the period of time that the parties agree upon in order to implement their exchanges. Therefore, the variation in the contractual length should be directly related to variation in the importance of relationship-specific investments.

We start with estimating a simple relationship (in Equation 1) between the (1) contracts' duration, (2) the contractual quantity⁷⁸ and (3) a dummy variable (*Newunits*), taking the value of 1 when the contracts prescribes for the construction of a new electricity generation plant and zero otherwise. The selected independent variables capture the idea of dedicated assets and physical assets specificity as described in Williamson framework. Building a new plant, for instance, is an important relation-specific investment because if the buyer breaches the contract and does not purchase electricity, the seller cannot easily reconvert the electricity plant for other purposes.

Since the building up of a new generation electricity plant differs according to the type of generated product (base, peak or both) and to the type of generating resource (gas, wind and so on), we try to allow for this heterogeneity by using instrumental variable analysis. We estimate a

⁷⁸Following Joskow (1987), we use the natural logarithm of quantity (Log-quantity) in order to capture potential non-linear relationships among the variables under consideration. Since power plants can produce electricity for around 40 years, the costs of breach are likely to decline over time.

simultaneous equation model where the instrumental variable (*Newunits*), depends on selected types of electricity generation resources (wind, gas), electricity product (base, peak) and on the production costs. An error term is finally added to the empirical specification.

(1)

$$\begin{aligned} \text{Duration}_i &= \beta_0 + \beta_1 \text{Log-quantity}_i + \beta_2 \text{Newunits}_i + \varepsilon_i \\ \text{NewUnits}_i &= \beta_0 + \beta_1 \text{Wind}_i + \beta_2 \text{Natural gas}_i + \beta_3 \text{Biomass}_i + \beta_4 \text{Base}_i \\ &+ \beta_5 \text{Peak} + \beta_6 \text{Construction costs}_i + \varepsilon_i \end{aligned}$$

$$i = 1, \dots, 27$$

The hypothesized relationship between asset specificity and contract duration implies that both β_1 and β_2 should present positive estimated coefficients. The 2SLS estimates (as reported in Table 3, column 1) confirm the above hypothesis.

We continue working with another simple specification that embodies the electricity contracts legal provisions, in order to check how legal provisions affect the contract duration. Legal provisions regulate two opposite requirements. On the one hand, the parties, locked into a bilateral relationship, attempt both to secure their long-term agreement; on the other hand, the parties try to provide for some flexibility in the contract. In fact, long term horizons might require some flexible arrangements in order to adapt to changing circumstances that may occur in a very long-term time span.

Also in this case, we estimate a simultaneous equation model where the instrumental variable (*Newunits*), depends on selected types of electricity generation resources (wind, gas), electricity product (base, peak), on the production costs and on some legal provisions providing or a set of penalties and incentives to the parties behaviour.

After several checks, we select the following specification:

(2)

$$\begin{aligned} \text{Duration}_i = & \beta_0 + \beta_1 \text{Log-quantity}_i + \beta_2 \text{Newunits}_i + \beta_3 \text{Takeorpay}_i + \beta_4 \text{Fixedpayment}_i \\ & + \beta_5 \text{Environmentalregulation}_i + \varepsilon_i \\ \text{NewUnits}_i = & \beta_0 + \beta_1 \text{Wind}_i + \beta_2 \text{Naturalgas}_i + \beta_3 \text{Biomass}_i + \beta_4 \text{Base}_i + \beta_5 \text{Peak}_i \\ & + \beta_6 \text{Constructioncosts}_i + \beta_7 \text{Environmentalregulation}_i + \beta_8 \text{Availabilityincentives}_i \\ & + \beta_9 \text{Constructionpenalties}_i + \beta_{10} \text{Preventregulation}_i + \beta_{11} \text{Fixedpayment}_i \\ & + \beta_{12} \text{Takeorpay}_i + \varepsilon_i \end{aligned}$$

$$i = 1, \dots, 27$$

The hypothesized relationship between asset specificity, contract duration and contract flexibility implies that both β_1 and β_2 should present positive estimated coefficients; whilst β_3 and β_4 should present negative estimated coefficients.

The 2SLS estimates (as reported in Table 3, column 2) confirm the above hypothesis. In particular, the adoption of take-or-pay provisions and fixed payment provisions in long-term contracts can be interpreted in the light of fluctuations in demand or costs, that may make it unprofitable or even inefficient to carry out the original objectives of a contract. By altering incentives to accept or reject delivery, take or pay provisions can induce buyers to release investments to their alternative uses only when it is efficient to do so.

5.4. Maximum Likelihood Estimation Results

We continue the analysis by considering only the population of electricity contracts with the longest duration (ten years and more). In this way, we can refine the analysis by using a sample of longer-term contracts and check whether and how asset-specificity affects the duration of the electricity contracts. In this case, the OLS estimation method would not be efficient because the sampling process might imply that the variance of the error term is not constant but dependent upon the

explanatory variables. To solve for this problem, we can specify the likelihood function of the sample⁷⁹ and then estimate the obtained logit and probit models by maximum likelihood.

After several check, we select the specification expressed in Equation (3).

(3)

$$\begin{aligned} \text{Duration} > 10_i = & \beta_0 + \beta_1 \text{Log-quantity}_i + \beta_2 \text{Newunits}_i + \beta_3 \text{Takeorpay}_i \\ & + \beta_4 \text{TollingPayment}_i + \beta_5 \text{Availabilitypenalties}_i + \beta_7 \text{Preventregulation}_i + \varepsilon_i \end{aligned}$$

$$i = 1, \dots, 20$$

Again the hypothesized relationship between asset specificity and contract duration implies that both β_1 and β_2 should present positive estimated coefficients. The hypothesized relationship between asset specificity, contract duration and contract flexibility implies that β_4 should present positive estimated coefficients; whilst β_3 should present negative estimated coefficients. The difference consists in the obtained estimated coefficients interpretation: building a new power plant, trading a large amount of power, or adopting tolling payments positively affect the probability that the contract lasts ten years or more. The adoption of take-or-pay provisions negatively affects the probability of a long contractual duration.

The maximum likelihood estimation results (reported in Table 4, column 3, for the probit model, and column 4, or the logit model) confirm the hypothesised relationship between asset specificity and contractual duration. The signs of the estimated coefficients are as predicted. The obtained pseudo- R^2 is a relatively high, especially considering that goodness-of-fit measures are generally fairly low for discrete choice models⁸⁰.

⁷⁹ It is common choice to opt for the standard normal distribution function leading to the probit model, and the standard logistic distribution function, which results in the logit model.

⁸⁰ See Verbeek (2000)

TABLE 3- CONTRACT DURATION*

Independent Variable	Duration 2SLS Estimate (1)	Duration 2SLS Estimate (2)	Duration>10 (Probit) (3)	Duration>10 (Logit) (4)
Log-Quantity	0.87 (0.063)	1.31 (0.003)	0.50 (0.057)	1.05 (0.056)
Fixed Payment	-	-7.85 (0.009)	-	-
Tolling Payment			0.84 (0.572)	2.07 (0.504)
Take-or-Pay Contract	-	-5.38 (0.051)	0.05 (0.972)	-0.28 (0.928)
Availability Penalties	-	-	-0.17 (0.863)	-0.43 (0.803)
New units	5.41 (0.039)	3.93 (0.061)	1.60 (0.150)	3.14 (0.151)
Environmental Regulation	-	3.82 (0.104)	-	-
Prevent Regulation	-	-	0.44 (0.702)	0.22 (0.914)
Constant	-2.57 (0.592)	-7.84 (0.119)	-6.25 (0.042)	-12.46 (0.048)
Pseudo R ²	-	-	0.36	0.39
Loglikelihood	-	-	-8.780	-8.405

*P-values of estimated coefficients are shown in parentheses.

5.5. Concluding Remarks

The paper as attempted to test Williamson's theory (about the relationship between asset-specificity and market organizational forms) in the restructured electricity markets. In particular, following Joskow, we attempt to empirically capture the positive relationship between physical assets specificity and the duration of long-term contracts, stipulated between California electricity generators. In addition, following Masten and Crocker, we try to capture the effect of legal provisions and interpret them as efficient instruments for providing flexibility in long-term relationships. As the investment in relationship-specific assets becomes more important, the longer becomes the contractual duration. However, the parties will mitigate the long-term contracts inflexibility, based on *ex ante* bargained terms and conditions, with provisions that allow for

contingent adaptation. The empirical results provide support for the hypothesised relationships and are robust to different model specifications and alternative estimation techniques.

The obvious policy conclusion is that private parties are perfectly able to adapt to the specificity of the transactions in an efficient transaction costs minimising manner. In our opinion, this is the real challenge of electricity markets restructuring: let the parties adapt to the legal and institutional deregulated setting.

Further research should focus on the use of non-parametric analysis that allows to capture relationship among the variables and to analyze data without assuming an underlying distribution.

PART IV

Contracts Administration

6. Electricity Market Restructuring And Energy Contracts: A Critical Note on the EU Commission's NEA Decision

6.1. Introduction

In the early 90's, during the restructuring of the electricity market in UK, the three main Scottish electricity generators stipulated a contract, the Nuclear Energy Agreement. This contract contained provisions for the trade of wholesale electricity in Scotland between Scottish Nuclear (the nuclear based generator) and Scottish Power and Hydro-Electric (respectively, the water and coal based generators). On the basis of the agreement, 74.9% of Scottish Nuclear (SN) output was sold to Scottish Power (SP) and 25.1% to Hydro Electric (HE). Scottish Power and Hydro-Electric were contractually obliged to buy all output for 15 years⁸¹.

The European Commission scrutinized such contract in order to derive the congruity of the agreement to European laws. The EU Commission concluded that the NEA might produce anticompetitive effects mainly because the NEA contractually fixed the energy quantity to be sold. This was against Article 85, paragraph 3 (now 81) of the Treaty, which prohibits those agreements that "*directly or indirectly fix purchase or selling prices or any other trading conditions*"⁸².

The NEA agreement was somehow "saved" because the Commission recognized that the NEA was a necessary requirement for the restructuring of the Scottish electricity market. Whilst The NEA was awarded an exemption⁸³ under Article 85, paragraph 3, the Commission recognized the inner anticompetitive content and potential effects.

⁸¹ The contract will expire in 2005.

⁸² The Commission's report writes that the NEA is anticompetitive because of "the requirement that Scottish Power and Hydro-Electric purchase, on the basis of quotas arranged between them, all the nuclear electricity generated restricts the two companies' sources of supply, with Scottish Power having to purchase 74,9 % of Scottish Nuclear's output and Hydro-Electric 25,1 %. Since they may not deviate from the quotas, they are unable to gain any competitive advantage one over the other" (Source: O.J., 1991).

⁸³ "Pursuant to Article 85 (3) of the EEC Treaty, the provisions of Article 85 (1) are hereby declared inapplicable, for the period between 27 February 1990 and 31 March 2005, to the Nuclear Energy Agreement concluded between Scottish Nuclear Ltd and Scottish Power plc and Scottish Hydro-Electric." (Source: O.J., 1991)

In this paper, we criticize the EU Commission NEA decision and economic reasoning and provide an alternative reading and analytical approach, which lead to opposite results and conclusions (the NEA contract is not anticompetitive and it enhances efficiency in competitive electricity markets).

The paper is organized as follows. Section 6.2 contains the paper motivation and literature survey. Section 6.3 describes the industrial and organizational background. Section 6.4 quickly sketches the main NEA provisions. Section 6.5 explains the theoretical foundations that grounded the EU Commission's decision. Section 6.6 provides a simple analytical framework, in order to compare a competitive electricity market with and without energy purchase contracts that fix quantity. Section 6.7 provides a critical discussion in a Law and Economics perspective and concludes.

6.2. Motivation and Literature Survey

Contracts are crucial policy instruments to organize and manage restructured electricity markets. Following Williamson's transaction costs approach (1979, 1991), long-term contracts represent (imperfect) substitutes of vertical integration, in those markets (like the electricity market), where idiosyncratic transactions matter.

A number of authors (Powell, 1993; Newbery, 1998; Green, 1999; Wolak, 2000) have shown that long-term contracts can reduce wholesale electricity prices in the presence of market power. Powell, Green and Wolak focused on the static impact of contracts on companies' bidding strategies. Newbery has shown that sufficiently long-terms contracts effectively make entry contestable. An entrant, in fact, can simultaneously lock its fuel purchases and electricity sales, removing price risk and sunk costs. Both static and dynamic arguments imply that a high degree of long-term contracting in the electricity wholesale market is likely to reduce prices and, therefore, crucial to the development of the competitive electricity markets.

This paper refers to such literature in the sense that it highlights the importance of contracts in the restructured electricity markets as effective management and organizational instruments.

The note, however, represents a further contribution because it considers and analyses the effects that a third party authority might cause when "interfering" in the parties private trading. It is, in fact, important to consider not only how contract provisions affect the traders' behaviour and the electricity market dynamics, but also how third parties and authorities might affect the contract working and development. Not only the definition of energy contracts provisions, but also the "administration" of the contracts as an indirect regulation form, might affect the restructuring process of the electricity markets.

Even if dated early 90's, we select the NEA contract as a benchmark-case, in order to provide an alternative reading and a case study for eventual, future energy contracts administration and authority decisions.

6.3. Institutional and Empirical Background

The restructuring of Scotland's electricity market is part of a broader project, aiming at liberalizing and privatizing UK electricity sector⁸⁴. The new structure of the electricity industry in Scotland was designed to introduce competition progressively both at the level of electricity generation and at the level of electricity supply⁸⁵. The Electricity Act 1989, and subordinate legislation made there under, set out the framework for the new regulatory system for the electricity industry in Scotland.

⁸⁴ In 1989, total electricity generation in the United Kingdom reached 312 Twh, total net production 292 Twh and total imports 12,9 million Kwh (0,013 Twh). Exports reached 0,8 million Kwh. The energy sources are conventional thermal production (71,6 %), nuclear production (21,7 %) and Hydro-electrical production (2,2 %). Coal is the most important fuel source (62,8 %), followed by oil (17,7 %) and then nuclear (14,7 %). Generating capacity in Scotland reached 11,640 GW on 1 April 1989 and the electricity sent out in the year up to 31 March 1989 reached 29,3 Twh. Nuclear power stations are the most significant source of electricity in Scotland (13 Twh, 44 %), followed by coal fired stations (30 %), hydro (14 %) and then gas oil (10 %). The turnover relative to the production and supply of electricity for the financial year ended 31 March 1989 was £ 11,284 million, 90 % of sales being in England and Wales and 10 % in Scotland.

⁸⁵ At the time of the Electricity Act, the electricity sector in Scotland has substantial overcapacity in electricity generation, which on present estimates is likely to continue at least for the next ten years, and a high concentration of nuclear generation capable of meeting over 50 % of current Scottish electricity demand. Trading with England and Wales is possible through the interconnector which links the transmission grids in Scotland and England.

The restructuring project (like in most countries that have been followed the UK pioneering example) included the breaking up of the formerly vertically integrated companies-typically monopolies under government regulation; the unbundling of the products and services required to produce electricity –generation, transmission, distribution and retailing; the reliance on spot markets as a means to find the most economic use of the available resources consistent with a market equilibrium; and the development of new institutional arrangements to govern access to the transmission network and to provide the required coordination mechanisms.

Until 31 March 1990, Scotland's electricity requirements were met by two publicly-owned corporations, North of Scotland Hydro-Electric Board and South of Scotland Electricity Board, which generated, transmitted and distributed electricity in their assigned geographical areas, covering the north and south of Scotland respectively. In reorganizing the industry in view of privatization, the United Kingdom Government decided to maintain vertical integration in the Scottish electricity industry, since it seemed better suited for the supply of electricity to sparsely-populated areas, which are characteristic of many areas of Scotland.

The United Kingdom Government has, therefore, decided to create two separate electricity utility companies from the two Boards. Scottish Power plc ('Scottish Power') has taken over the non-nuclear business of the South of Scotland Electricity Board and Scottish Hydro-Electric plc ('Hydro-Electric') the business of the North of Scotland Hydro-Electric Board. The Scottish nuclear stations at Hunterston and Torness, which previously were owned by the South of Scotland Electricity Board, are owned and operated by a separately established generating company, Scottish Nuclear Ltd ('Scottish Nuclear'), which remained in public ownership.

Scottish Nuclear does not supply directly to customers, selling all its output under contract to Scottish Power and Hydro-Electric. Under the Electricity Act, in fact, any undertaking generating, transmitting or supplying electricity in Scotland needs a licence issued by the Secretary of State for Scotland or the Director-General for Electricity Supply, unless exempted by order under the Act.

Scottish Power and Hydro-Electric are each by licence obliged and entitled to transmit and supply electricity to customers within their authorized areas. These areas are essentially the same as those of the former Boards. Both utilities are entitled to generate electricity themselves. There is no restriction on the proportion of its electricity requirements which either utility can meet from its own generation resources.

In the view of the United Kingdom Government, it was essential for Scottish Power and Hydro-Electric to have access to a balanced mix of different types of generating capacity in order to be financially viable and capable of independent operation. Therefore, the non-nuclear generating assets of the two former Boards, which had been built to meet Scotland's requirements in their entirety, had to be redistributed between the new companies. The United Kingdom Government, therefore, decided that the necessary restructuring should be achieved by means of contractual arrangements. These agreements should create rights and obligations between the two utilities, in relation to certain of the generating assets and transmission systems of each, effectively replacing ownership of these assets with long-term contractual entitlements, the duration of which, corresponds to the currently expected lifetime of the power stations concerned. These contractual arrangements replaced the former loose non-commercial agreements between the two Boards on cost-sharing and operational matters. The principal contracts between Scottish Power and Hydro-Electric concerned the sharing of coal-fired plant capacity, hydro capacity and gas/oil-fired capacity. Furthermore, Scottish Power and Hydro-Electric divide between them the total output of Scottish Nuclear.

6.4. The Nuclear Energy Agreement

The Nuclear Energy Agreement (NEA) is a contract containing provisions for the trade of wholesale electricity in Scotland. It forms an integral part of the electricity privatization and liberalization scheme in UK, the aim of which is to improve the generation and distribution of electricity. The agreement gives Scottish Nuclear a guaranteed market by requiring Scottish Power and Hydro-Electric to purchase all the nuclear-generated electricity on a "take-or-pay" basis.

The paragraph describes the main contractual provisions.

A) Principles

74.9% of Scottish Nuclear (SN) output is sold to Scottish Power (SP) and 25.1% to Hydro Electric (HE). The NEA requires that while it is in effect, the output from SN's existing facilities (as at 1 April 1990) can only be sold to SP and HE. SP and HE must pay for all the electricity that SN produces and delivers to the Grid, even if SP and HE say they don't want it. If SP and HE may wish to modify SN's output, they will have to issue a Dispatch Instruction⁸⁶. SN must use its best endeavours to maximize output, consistent with safe operation and must use all reasonable endeavours to keep to the Final Generating Plan (see later). Under the terms of the Nuclear Energy Agreement, Scottish Power (SP) and Hydro-Electric (HE) are obliged to purchase all the electricity generated by Scottish Nuclear (SN) from its Hunterston and Torness plant on a "take-or-pay" basis⁸⁷. Scottish Nuclear is obliged to try to produce maximum output from these two nuclear power stations which have together a capacity of 2 400 MW.

Scottish Power will have to take 74,9 % of Scottish Nuclear's output and Hydro-Electric 25,1 %. Scottish Nuclear is not permitted to supply electricity to any other party without the consent of both Scottish Power and Hydro-Electric. Scottish Nuclear Ltd cannot supply power except for Scottish Power and Hydro-Electric unless the contract has been terminated.

⁸⁶ SP may issue a Dispatch Instruction at any time. The most likely reason for its issue lies in keeping the Grid stability. It may require SN to change its declared or current output. It will specify the new output, the time at which the change should start to be made and the duration for which the new output is required. SN is obliged by the Grid Code to accept an instruction to reduce power but not to increase it. In practice, SN will respond to requests for increases in power if it is safe to do so. Permitted Turndowns and Shutdowns are special types of Dispatch Instructions, which request reductions in output or shutdown of a unit. (Source: O.J., 1991)

⁸⁷ The agreement contains provisions for the calculation of the prices to be paid to Scottish Nuclear by Scottish Power and Hydro-Electric. From 1991 to 1994 the price is fixed on the basis of a two-tier structure; a base price per kilowatt hour for the first tranche of 5 000 Gwh and a lower set price for units in excess of 5 000 Gwh, this lower price being similar to the cost of replacement energy to the purchasers. The formula is used for the first four years and taken as a basis for setting prices for the following four years (Source: O.J., 1991).

If SN supplies less than the agreed amount of electricity, the contract distinguishes if this is due to force *majeure* or to different events.

In the case of force *majeure*, SN is exempted from performing, in line with the general contractual principles. If SN is liable for the non-exact execution of contractual performance, then he has to pay the difference to SP and HE.

In cases where SN supplies more than the agreed amount, it is not paid for the extra.

B) Routine Trading

Trading is conducted on a day-to-day basis through Daily Declarations - SN's statement of the amount of electricity it can produce on the following day. The Declaration, together with any Dispatch Instruction, sets the target for measuring SN's output.

Long and medium term planning are done through Generating Plans but payments are based on the Daily Declarations⁸⁸.

SN's Daily Declarations cover the 24-hour period from 0200 on the following day.

The Declaration contains information, for each reactor, on:

- 1) the net energy to be delivered in every half-hour of the day;
- 2) the total net energy in MWh to be delivered during the day;
- 3) an assessment of the ability to ramp the power of the reactor up or down in response to an instruction from SP and HE.

There are very strict time deadlines by which this information must be sent to SP and HE. A Declaration must be sent by 9 a.m. and be revised before 12.45 p.m.

By 1400 p.m., SP and HE must confirm either that they will require all the output declared or that they expect to issue a Dispatch Instruction. If they do not, they are deemed to have required the stated output.

⁸⁸ From the entry of British Energy to the Stock Exchange in July 1996, the price depends primarily on the market price of electricity in England and Wales (Source: O.J., 1991).

C) Operational Planning

Between July and October of each year, SN and SP-HE meet and agree a Final Generating Plan for the coming three years. This plan specifies, for each reactor, the planned outage window, the planned refuelling periods and the planned total MWh on a monthly basis. SP and HE inform SN of any of their operational planning matters, which could result in a reduced need for SN output. Medium term planning is done in similar fashion at quarterly intervals and is, effectively, fine-tuning of the Final Generating Plan using more detailed information. SN has to provide explanations for deviations from its planned output.

C) Life of the Contract

The agreement, which was originally to apply for a period equivalent to the remaining lifetime of the nuclear power stations, i.e. 30 years, has, at the EU Commission's request, been limited to 15 years. This period of validity provides the stability and guarantee necessary for long-term planning and allows the necessary adjustments to be made to the new situation after a reasonable start-up period. The NEA, however, may be terminated earlier if, for example, Scottish Nuclear consistently fails to meet production requirements.

6.5. The European Commission Decision

The guideline underlying most competition policies states that when suppliers are in large numbers and operate under satisfactory informational conditions, price tends to equal marginal costs. This apparently simple guideline is central because of its link to welfare theorems, so that it provides the most robust benchmark in the normative analysis of markets. Indeed, its direct corollary is that policies must be implemented that will prevent all practices favouring deviations from the "price

equal marginal costs" rule. Illegal practices are essentially those that can either create market power (through reduction in the number of competitors or collusion among them), or distort information available to buyers (e.g., hiding characteristics on goods to be traded). These illegal practices are exhibited through their discriminating effects: discrimination through prices (e.g., segmenting markets); discrimination through quantities (e.g., rationing); and discrimination through quality (e.g., misinforming on characteristics).

From the consumer's point of view, the crucial advantage of the fundamental rule is that it should improve one's capacity to choose and, therefore, to allocate resources according to one's preferences. Capacity to choose concerns quality (which requires that some variety exists, i.e., there must be substitutes), quantity (suppliers must be able to meet demand at the price they advertise), and prices (agreements on fixed prices among competitors must be prohibited).

Underlying these principles is one leading idea: an efficient market, i.e., a market pushing suppliers to minimize their costs and allowing buyers to maximize their choices, is one in which there are well-defined firms that can be identified and that compete to attract potential buyers, who can shift to substitutable products. The role of competitive policies is, therefore, to maintain the relevant market structure by preventing any such firm to dominate its market.

Ménard (1998) identified three criteria to make these principles operational on the supply side: (1) independence of decisions among potential competitors must be guaranteed; (2) competitors must remain uncertain about the policy of their rivals; and (3) there must be no barriers to entry. These guidelines can be viewed as an explicit development of the principles embedded in article 85, Section 1 of the founding agreement of the European Community.

The European Commission that scrutinized the NEA decided that it is an agreement between undertakings, within the meaning of Article 85 (1)⁸⁹ of the EEC Treaty that forbids restrictions of competition. In particular, the NEA agreement restricts competition because of two main reasons.

⁸⁹ The following shall be prohibited as incompatible with the common market: all agreements between undertakings, decisions by associations of undertakings and concerted practices which may affect trade between Member States and

First, the requirement that nuclear electricity is sold exclusively to Scottish Power and Hydro-Electric limits Scottish Nuclear's market. Scottish Nuclear is not permitted to supply electricity to any other parties unless the contract has been terminated. If the contract has been terminated, Scottish Nuclear can sell electricity only to other parties not situated in the same geographical area as the purchaser in respect of which the contract is still in force.

Second, the requirement that Scottish Power and Hydro-Electric purchase, on the basis of quotas arranged between them, all the nuclear electricity generated restricts the two companies' sources of supply, with Scottish Power having to purchase 74,9 % of Scottish Nuclear's output and Hydro-Electric 25,1 %. Since they may not deviate from the quotas, they are unable to gain any competitive advantage one over the other.

The Commission, however, found that the Nuclear Energy Agreement meets the necessary conditions for exemption under Article 85 (3) of the Treaty because it forms an integral part of the electricity privatization scheme in UK.

The agreement, which was originally to apply for a period equivalent to the remaining lifetime of the nuclear power stations, i.e. 30 years, has, at the Commission's request, been limited to 15 years.

which have as their object or effect the prevention, restriction or distortion of competition within the common market, and in particular those which:

- (a) directly or indirectly fix purchase or selling prices or any other trading conditions;
- (b) limit or control production, markets, technical development, or investment;
- (c) share markets or sources of supply;
- (d) apply dissimilar conditions to equivalent transactions with other trading parties, thereby placing them at a competitive disadvantage;
- (e) make the conclusion of contracts subject to acceptance by the other parties of supplementary obligations which, by their nature or according to commercial usage, have no connection with the subject of such contracts.

Any agreements or decisions prohibited pursuant to this Article shall be automatically void.

The provisions of paragraph 1 may, however, be declared inapplicable in the case of:

- any agreement or category of agreements between undertakings;
- any decision or category of decisions by associations of undertakings;
- any concerted practice or category of concerted practices,

which contributes to improving the production or distribution of goods or to promoting technical or economic progress, while allowing consumers a fair share of the resulting benefit, and which does not:

- (a) impose on the undertakings concerned restrictions which are not indispensable to the attainment of these objectives;
- (b) afford such undertakings the possibility of eliminating competition in respect of a substantial part of the products in question.

Exemption is granted, pursuant to Article 8 (1) of Regulation No 17, for the period of the validity of the agreement, reduced at the Commission's request from 30 to 15 years, i.e., from 27 February 1990 to 31 March 2005.

Though recognizing the NEA anticompetitive content, the European Commission granted an exemption. The exemption was grounded on the general requirement to liberalize, privatize and restructure the UK electricity sector.

In this paper, we offer another interpretation, which leads to opposite results and conclusions (the NEA contract is not anticompetitive and it enhances efficiency in competitive electricity markets).

6.6. An Alternative Interpretation: A Simple Analytical Framework

In this section, we design a deliberately very simple framework that shows the effects of contractually fixing the quantity in a competitive electricity market. We start by considering that the electricity sector is characterized by a high level of market power that, given the industry characteristics, did not completely "disappear" even after restructuring and privatization⁹⁰.

The electricity industry, in fact, is characterized by extremely costly storage; significant capacity constraints in its production and transmission over the network; and highly variable and inelastic demand. An electricity spot market is unlike virtually any other market in that demand and supply must be equalized throughout the electricity grid, at every moment in time, for continuously maintaining network "electrical equilibrium". This features, coupled with the virtual impossibility of storing electricity, implies that inventories cannot be used, as in most other markets, to mitigate the problem of the lack of available capacity and the resulting increase in prices in periods of high demand. The existence of binding capacity constraints on its production implies that, in periods of high demand, there will typically be one or several firms whose capacity is needed to balance the system, even when its competitors are operating at full capacity. This allows such a firm(s) to ask for

⁹⁰ The fact that a certain degree of market power remains in restructured electricity markets is a well-known problem that is affecting the competitive design of liberalized electricity markets. See Ofgem (2000)

extremely high prices with no risk of losing production. Furthermore, transmission constraints imply that separate markets may be created; depending on supply and demand conditions, as well as on the state of the transmission system, the ability to supply power from one geographic area to another may be severely limited. This gives rise to pocket of local market power where certain firms, insulated from the potential competition in adjacent areas, stand at a monopoly position. The low elasticity of demand and the absence, in most countries, of demand-side bidding, further exacerbates the problems of market power. Given all that, the problem of market power (due to electricity markets features) is not completely solved by competition, even when a non-discriminatory access to the grid becomes guaranteed as a result of the regulatory reform, or cogeneration or substitutes in supply are created by the regulator.

Tirole (1988) has shown that vertical integration, in markets where market power exists, prevents double marginalization. Double marginalization arises when firms at different places in a supply chain both have market power. They will both use their market power to receive a positive margin on their product. Tirole shows that if these firms would be vertically integrated, the total (single) margin would be lower than the sum of the margins in the disintegrated case⁹¹.

Our model describes a market where an energy retailer (Scottish Power) buys energy from the wholesaler (Scottish Nuclear) and resells it to final end-users. For the sake of simplicity, we consider only Scottish Power because it buys around 75% of Scottish Nuclear production and especially because, at the time of the NEA stipulation, the two retailers were active in separate markets not competing between them.

Consider a representative consumer i purchasing energy from the retailer SP. His net utility from consuming electricity equals:

$$(1) \quad u_i = ax_i - \frac{1}{2}x_i^2,$$

⁹¹ The inefficiency of double-marginalization is well-known since the work of Spengler (1950) and Machlup and Taber (1960).

where u_i represents a strictly concave ($u_i' > 0$ and $u_i'' < 0$) utility function of consuming x_i units of electricity and a ($a > 0$) is a parameter.

Maximum utility is reached at the point where electricity price (p_E)⁹² equals marginal costs, which yields the following demand equation:

$$(2) \quad q_i = a - p_E$$

If we multiply by n total number of consumers, we can derive total demand for the retailer as:

$$(3) \quad Q_E = nq_i = n(a - p_E)$$

On the cost side, suppose that the wholesale firm (SN) sells to the retailer according to a constant unit price and the retailer does not have any additional costs than the wholesale price.

Both firms have some market power, therefore, in order to maximize their profits they both choose the monopolistic mark-up over their own costs. Considering market power in the electricity market is a realistic assumption because the electricity market owns unique features that make them particularly vulnerable to the exercise of market power and, to the occurrence, of a double marginalization problem⁹³.

⁹² For simplicity, we assume that consumers' electricity price (p_E) includes transport costs and network access fees. We do not disentangle from the analysis the effects of those costs for two reasons: first because they are not particularly relevant for the analysis at issue. Second because, again, transmission constraints imply that separate markets may be created; depending on supply and demand conditions, and on the state of the transmission system, the ability to supply power from one geographic area to another may be severely limited. This gives rise to pocket of local market power where certain firms, insulated from the potential competition in adjacent areas, stand at a monopoly position (even if legally non-discriminatory access is guaranteed to the grid, the physical characteristics of electricity make that a certain degree of market power will always be present).

⁹³ See Ofgem (2000). The electricity industry is characterized by extremely costly storage; significant capacity constraints in its production and transmission over the network; and highly variable and inelastic demand. An electricity spot market is unlike virtually any other market in that demand and supply must be equalized throughout the electricity grid, at every moment in time, for continuously maintaining network "electrical equilibrium". This features, coupled with the virtual impossibility of storing electricity, implies that inventories cannot be used, as in most other markets, to mitigate the problem of the lack of available capacity and the resulting increase in prices in periods of high demand. The existence of binding capacity constraints on its production implies that, in periods of high demand, there will

The wholesale firm (SN) selects the wholesale price (w_E), given its production costs (C_E) (where $C_E < a$). The retailer firm (SP) will set electricity price (p_E), given its own costs, namely the wholesale price (w_E) (which is higher than (C_E) because the upstream firm has a margin).

6.6.1 Competitive Electricity Market without Quantity Agreements

Suppose that SP's problem is to choose the price (p_E) in order to maximize its profits, given the price SN's wholesale price (w_E).

$$(4) \quad \max \pi_{SP} = (p_E - w_E)[n(a - p_E)]$$

wrt p_E

By taking first order derivative and setting it equal to zero, we obtain that Scottish Power will maximize its profits at a price equal to:

$$(5) \quad p_E = \frac{(a + w_E)}{2}$$

and for a quantity equal to:

$$(6) \quad Q_E = \frac{(a - w_E)}{2}$$

Finally, Scottish Power profits will equal:

typically be one or several firms whose capacity is needed to balance the system, even when its competitors are operating at full capacity. This allows such a firm(s) to ask for extremely high prices with no risk of losing production. Furthermore, transmission constraints imply that separate markets may be created; depending on supply and demand conditions, as well as on the state of the transmission system, the ability to supply power from one geographic area to another may be severely limited. This gives rise to pocket of local market power where certain firms, insulated from the potential competition in adjacent areas, stand at a monopoly position. The low elasticity of demand and the absence, in most countries, of demand-side bidding, further exacerbates the problems of market power.

$$(7) \quad \pi_{SP} = \left[\frac{(a - w_E)}{2} \right]^2$$

Suppose that the wholesale firm SN perfectly anticipates the decision of price setting carried by SP. In particular, SN knows the quantity of electricity that SP will order as a function of the wholesale price. SN problem is to choose w_E , in order to maximize its own profits.

$$(8) \quad \max \pi_{SN} = (w_E - C_E) \left[\frac{(a - w_E)}{2} \right]$$

From the first order condition, and after rearranging, the wholesale firm price is:

$$(9) \quad w_E = \frac{(a + C_E)}{2}$$

Replacing the equilibrium electricity wholesale price into the downstream solution, it is possible to find the equilibrium final price and profits obtained by Scottish Nuclear (the wholesaler) and Scottish Power (the retailer) and the sum of the profits made by the chain.

In the competitive market, without any forms of vertical integration, or long-term contracts, the equilibrium electricity price p_E will equal:

$$(10) \quad p_E = \frac{3(a + C_E)}{4}$$

Scottish Nuclear and Scottish Power profits will respectively equal:

$$(11) \quad \pi_{SN} = \left[\frac{(a - C_E)}{8} \right]^2 \text{ and } \pi_{SP} = \left[\frac{(a - C_E)}{16} \right]^2$$

The sum of the profits made by the chain in this peculiar industrial organizational setting is:

$$(12) \quad PS = \pi_{SN} + \pi_{SP} = \left[\frac{3(a - C_E)}{16} \right]^2$$

6.6.2 Competitive Electricity Market with Quantity Agreements

Consider now the NEA Agreement scenario. Scottish Nuclear and Scottish Power have concluded a long-term agreement that specifies a fixed quantity that the retailer (SP) has to purchase from the wholesaler (SN).

The contract (C) will fix a quantity:

$$(13) \quad Q_C \geq Q_E^{VI}$$

where Q_E^{VI} is the electricity quantity produced when the two firms were vertically integrated.

In case of vertical integration between SN and SP, in fact, the wholesale generator can directly sell to consumers. The resulting vertically integrated firm (VI) problem, therefore, would be the standard problem of a monopolist that maximizes its profits:

$$(14) \quad \max \pi_{VI} = (p_E - C_E)n(a - p_E) \\ \text{wrt } p_E$$

By deriving with respect to p_E , we obtain that Scottish Power will maximize its profits at a price equal to:

$$(15) \quad p_E^{VI} = \frac{(a + C_E)}{2}$$

and for a quantity equal to:

$$(16) \quad Q_E^{VI} = \frac{(a - C_E)}{2}$$

Finally, the vertically integrated firm profits will equal:

$$(17) \quad \pi_{VI} = \left[\frac{(a - C_E)}{2} \right]^2$$

When vertical integration is not possible, specifying a fixed quantity that the retailer (in our case, Scottish Power) has to purchase from the wholesaler (in our case, Scottish Nuclear) has the advantage to overcome double marginalization problems and create the same economic effects, produced under a VI structure.

Therefore, Scottish Nuclear can either define a contract that, for instance, fixes quantity:

$$(18) \quad Q_E^{VI} = \frac{(a - C_E)}{2}$$

or, equivalently, can impose that the retailer should buy at least:

$$(19) \quad Q_C \geq Q_E^{VI}$$

In this way, the retailer would choose the efficient output $Q^* = Q_E^{VI}$. Given that:

$$(20) \quad C_E < w_E;$$

$$p_E^{VI} < p_E \Rightarrow \frac{(a + C_E)}{2} < \frac{3(a + C_E)}{4};$$

$$Q_E^{VI} > Q_E \Rightarrow \frac{(a - C_E)}{2} > \frac{(a - w_E)}{2},$$

then, contractually fixing the quantity to sell and purchase allows the parties to produce more quantity at a least price because it solves the double marginalization problem. Therefore, provisions that contain quantity agreements, instead of displaying anticompetitive effects, can enhance efficient results. If the parties buy base load electricity in the agreed quantities, this might avoid that the purchasers charge a mark-up when re-selling electricity to final consumers and might encourage the purchasers to supply the efficient output.

6.7. Conclusive Remarks: Anticompetitive Effects or Misinterpretation?

This paper has analyzed the Nuclear Energy Agreement (NEA), a long-term "take or pay" contract for the trade of wholesale electricity between Scottish Nuclear and Scottish Power and Hydro-Electric. Since NEA contractually fixed the energy quantity to be sold, the European Commission considered this type of contract rather problematic from the competition policy point of view. We have criticized the EU Commission's NEA decision. We have shown that contractually fixing the quantity in markets where market power exists, helps overcoming double marginalization problems and allows the total (single) margin to be lower than the sum of the margins in the disintegrated case.

In this perspective, we think that the NEA contract does not have anticompetitive effects; on the contrary, given the peculiar structure of the electricity markets, it set provisions, instrumental to the working and the existence of competitive dynamics and represents a valid tool for dealing with market power in electricity markets⁹⁴. The existence of market power in the electricity markets is an obvious remark. The combination of very inelastic short-run demand and supply (at peak times) with the real-time nature of the market (costly storage and grid reliability requirements) makes electricity markets especially vulnerable to the exercise of market power. "*The result is the ability of firms with even modest market shares to exercise market power is greater than in most markets*" (Borenstein and Bushnell, 2000, p.9). In our perspective, a long-term agreement between wholesaler and retailer might help overcoming market power in electricity markets. Most competitive market policies aim at maintaining the relevant market structure by preventing that any firm dominates its market. This economic reasoning has inspired the EU Treaty economic provisions⁹⁵ and the NEA decision⁹⁶. For the EU Commission, in fact, the contract is anticompetitive *ex Article 85*, because it fixes the quantity to be traded. Notwithstanding the acknowledgement that this agreement might restrict competition (*ex lege*), the Commission has awarded an exemption, on the ground that the NEA contract is fundamental to the restructuring of the UK electricity market, and has disposed for some adjustments and changes in the contract content.

In our opinion, studying the relationships between competition and governance structures is another way to design and implement competition policies. This approach, however, might represent a challenge to competition: contractual agreements, for instance, involve some restrictions and/or conditions on quantities (like the NEA), qualities, or prices, which raises the question of the acceptability of these coalitions. Standard competition policies might interfere in the trade-off among governance structures; they are inadequate and might be misinterpreted, when applied to particular organization form like in the case at issue.

⁹⁴ See Fabra and Siotis (2004)

⁹⁵ See Whish (2001)

⁹⁶ See OJ (1991) L 178/31

Our main point is that, in presence of market power, long-term contracts might help reducing prices and increasing efficiency, by avoiding the double marginalization problem. In this perspective, some governance structures (long-term contracts and vertical integration) are better adapted to the characteristics of the transaction at stake.

This perspective does not avoid that other perspectives can be considered in order to interpret the NEA and the EU Commission decision. The NEA might be interpreted and “anyhow saved” as a long-term “take or pay” contract that can be efficient from the risk sharing perspective of investors and resellers, in particular, if demand is stochastic. In this setting, a long-term contract would represent a particular technique, used to manage pricing risks associated with changing market conditions and deregulation in the electricity sector (see, among others, the seminal paper by Chao, 1983 or the recent contribution by Bessembinder and Lemmon, 2002).

PART V:

CONCLUSIONS

7. Conclusions

The EU Directives 96/92/EC and 2004/544 EC represent the cornerstone of the European electricity liberalisation process. However, it provides *"a framework in the loosest sense of the word: its objectives are laid down in general terminology and moreover, member states are given a substantial degree of choice in how they are about introducing more competition into their electricity markets. Indeed the margin is so substantial that it would seem possible for the determined anti-market countries to avoid introducing any meaningful degree of competition at all"* (Hancher, 1997).

Starting from this remark, and on the fact that the Directives are silent on the regulation of electricity trading arrangements, the manuscript contains an economic analysis of electricity wholesale contract. This study aims to understanding electricity market common practices and to scrutinize electricity agreements with economic theory and econometric technique.

In the first chapter, we have surveyed three types of power purchase contracts operating in the electricity wholesale market, from the most rigid to the most flexible, in order to underline how competitive contracting can increase efficiency pressures and, at the same time, increase investment risk. We have defined a theoretical contractual model, highlighting the tension between the two opposite directions: designing agreements to reduce uncertainty and risk in order to attract private investment and operating the power system as more efficiently as possible. We then used our theoretical model in order to analyse the formal structure of a selected sample of power purchase agreements, really operating in the restructured electricity markets all over the world. From the above analysis, we can derive that competitive contracting is crucial for ensuring efficient operation. "Take-or-pay" contracts are attractive to producers because eliminate demand risks but do not achieve efficient results. Under this contract, in fact, dispatch can occur out of merit order and excess production of energy, with the buyer being obliged to buy all production, can occur. The

economic dispatch contract can create some competitive pressures: a system of bonuses and penalties that respectively awards capacity availability and punishes capacity shortcuts can force private producers and investors to generate efficiently and can ensure merit-order dispatch. In our opinion, an incentive formula for long-terms contracts, can benefit sharing agreements and provide an appropriate way for dealing in the new deregulated electricity market. This is a way to continuously renegotiate the contract and adapt it to changed circumstances.

The competitive pool contract sets the most competitive conditions. Such system worked very well in the Argentina electricity restructuring experience. In England and Wales, on the contrary, a pool system has caused an oligopolistic-strategic situation: the two dominant generators (National Power and PowerGen) have taken advantage of their market power, restricting the capacity offered to the market in order to increase the price of available capacity.

The second chapter has empirically analysed the effects of legal provisions setting penalties and incentives, and regulating the parties' obligations and risks, on electricity contracts price formation. We have considered 27 California long-term electricity contracts for the trade of electricity between generators. We have created a dataset by using the contracts' main legal provisions, in order to perform an econometric exercise and target the main determinants that affect price provisions in long-term wholesale electricity contracts. Given that the contacts set a minimum and a maximum price threshold, we have performed separated econometric exercises. The general result is that the provision increasing (decreasing) the trading risk for the seller increase (decrease) the price; those provisions setting penalties (incentives) for the seller decrease the price. A peculiarity is that the legal provisions regulating obligations and risks and setting incentives and penalties affect the maximum contract price. Estimated coefficients for legal provisions are not statistically significant when the dependent variable is the minimum price. Economic variables (like fuel types, construction costs and so on) are more robust explanatory variables for minimum price. The general results are robust to different model specifications and estimation techniques.

The third chapter has attempted to test Williamson's theory (about the relationship between asset-specificity and market organizational forms) in the restructured electricity markets. In particular, it is an attempt to empirically capture the positive relationship between physical assets specificity and the duration of long-term contracts, stipulated between California electricity generators. In addition, following Masten and Crocker, the study to capture the effect of legal provisions and interpret them as efficient instruments for providing flexibility in long-term relationships. As the investment in relationship-specific assets becomes more important, the longer becomes the contractual duration. However, the parties will mitigate the long-term contracts inflexibility, based on *ex ante* bargained terms and conditions, with provisions that allow for contingent adaptation. The empirical results provide support for the hypothesised relationships and are robust to different model specifications and alternative estimation techniques. The fourth chapter is a case-study, which analyzes the Nuclear Energy Agreement (NEA), a long-term "take or pay" contract for the trade of wholesale electricity between Scottish Nuclear and Scottish Power and Hydro-Electric. Since NEA contractually fixed the energy quantity to be sold, the European Commission considered this type of contract rather problematic from the competition policy point of view. We have criticized the EU Commission's NEA decision. We have shown that contractually fixing the quantity in markets where market power exists helps overcoming double marginalization problems and allows the total (single) margin to be lower than the sum of the margins in the disintegrated case. In this perspective, we think that the NEA contract does not have anticompetitive effects; on the contrary, given the peculiar structure of the electricity markets, it set provisions, instrumental to the working and the existence of competitive dynamics and represents a valid tool for dealing with market power in electricity markets. In our perspective, a long-term agreement between wholesaler and retailer might help overcoming market power in electricity markets. Most competitive market policies aim at maintaining the relevant market structure by preventing that any firm dominates its market. This economic reasoning has inspired the EU Treaty economic provisions and the NEA decision. For the EU Commission, in fact, the contract is anticompetitive

ex Article 85, because it fixes the quantity to be traded. Notwithstanding the acknowledgement that this agreement might restrict competition (*ex lege*), the Commission has awarded an exemption, on the ground that the NEA contract is fundamental to the restructuring of the UK electricity market, and has disposed for some adjustments and changes in the contract content.

Our analysis can provide some general remarks for policy guidance. First, a (maybe) obvious policy conclusion is that private parties are perfectly able to adapt to the specificity of the transactions in an efficient transaction costs minimising manner. In our opinion, this is the real challenge of electricity markets restructuring: let the parties adapt to the legal and institutional deregulated setting. Second, studying the relationships between competition and governance structures (long-term contracts might be considered hybrid governance structures) represents a way to design and implement competition policies. This approach may represent a challenge to competition: contractual agreements, for instance, involve some restrictions and/or conditions on quantities, qualities, or prices, which raise the question of the acceptability of these coalitions. Standard competition policies might interfere in the trade-off among governance structures; they are inadequate and might be misinterpreted, when applied to particular organization forms. In the presence of market power, for instance, long-term contracts might help reducing prices and increasing efficiency, by avoiding the double marginalization problem. In this perspective, some governance structures (long-term contracts and/or vertical integration) are better adapted to the characteristics of the transaction at stake.

Finally, several factors affect power purchase contracts. Sociopolitical, legal, operational, management and technical factors are a serious concern, which must be taken into account in any major long-term investment. All these factors will lead to difficulties in deciding on values for contractual parameters and provisions and in understanding their relationships, in order to design efficient power purchase contracts.

A pragmatic "learning-by-doing" approach and some solid field experience will show, in the future, the most proper way to re-organize transactions in the restructured electricity market.

Samenvatting

Decennia lang was de elektriciteitsindustrie over de hele wereld hoofdzakelijk gestructureerd door middel van verticaal geïntegreerde en vooral publieke monopolies. In de afgelopen jaren hebben zich daarin grote veranderingen voorgedaan als gevolg van het liberalisatieproces gericht op de introductie van concurrentie in het energieopwekkende en -leverende segment van de industrie. In Europa heeft de eenduidige doelstelling om een concurrerende elektriciteitsmarkt te creëren, zoals geformuleerd in Richtlijn 96/92 en vervolgens in Richtlijn 2003/53 van het Europees Parlement en de Raad, een onverwacht effect. Hoewel de vorming van pan-Europese enkelvoudige elektriciteitsmarkten de doelstelling van de Richtlijnen was, heeft het reorganisatieproces inmiddels geleid tot 15 min of meer gefragmenteerde markten; daarbij is elke markt tot een ander niveau geliberaliseerd en is aan elke markt op basis van uiteenlopende principes vorm gegeven.

De kritiek op de EU-richtlijnen vormt het uitgangspunt voor dit proefschrift. Het gaat daarbij vooral om kritiek met betrekking tot het gebrek aan bepalingen voor handelsstelsels die nodig zijn om het reorganisatieproces te ondersteunen met het oog op de vorming van een geïntegreerde Europese markt voor elektriciteit. Centraal in dit onderzoek staat de analyse van langdurige handelsovereenkomsten voor elektriciteit op grote schaal. Aangezien in de EU-richtlijnen over dit belangrijke onderwerp wordt gezwegen, was het onderzoek vooral gericht op de beoordeling van en het inzicht in de reactie van marktspelers op de deregulerende dynamica; op de beoordeling van de inhoud van grootschalige elektriciteitscontracten tussen energiebedrijven; en op het gedetailleerde onderzoek van overeenkomsten binnen het strakke kader van economische theorieën, vooral om te kunnen beoordelen of hier een taak is weggelegd voor beleidsmakers.

Dit proefschrift bestaat uit vier originele essays, die binnen een algemeen kader worden gepresenteerd. De essays kunnen worden beschouwd als cognitieve instrumenten die inzicht bieden in het manuscript. Het proefschrift wordt afgesloten met een aantal eindopmerkingen.

Het eerste essay is een analyse van het spanningsveld tussen het ontwerpen van grootschalige elektriciteitsovereenkomsten waarbij de onzekerheid van particuliere investeerders wordt beperkt en het binnen de gereorganiseerde elektriciteitsmarkt zo efficiënt mogelijk leiden van krachtcentrales. Het theoretisch contractmodel dat in dit essay wordt gedefinieerd, benadrukt het spanningsveld tussen twee tegengestelde richtingen: de beperking van onzekerheden en risico's om particuliere investeerders aan te trekken enerzijds, en de doeltreffende bedrijfsvoering van krachtcentrales anderzijds. Dit model wordt gebruikt voor de analyse van de formele structuur van geselecteerde voorbeelden van koopovereenkomsten voor elektriciteit die over de hele wereld worden gebruikt binnen de gereorganiseerde elektriciteitsmarkt.

In het tweede essay wordt beoordeeld wat de gevolgen zijn van wettelijke bepalingen betreffende de prijsbepaling in elektriciteitscontracten. We hebben daartoe 27 langlopende elektriciteitscontracten uit Californië⁹⁷ bekeken en de handel in elektriciteit tussen energiebedrijven bestudeerd. De gegevens zijn verzameld aan de hand van de belangrijkste wettelijke bepalingen in de contracten om een econometrische studie te kunnen uitvoeren en de belangrijkste prijsbepalende factoren voor langlopende elektriciteitscontracten te kunnen benaderen. Over het algemeen zijn deze bepalingen van invloed op de manier waarop het risico van transacties wordt verdeeld tussen partijen en daardoor de transactie meer (of minder) lonend maakt voor de partij die het hoogste (laagste) risico draagt. Deze interpretatie van de resultaten bevestigt de economische theorie over stimuleringsmaatregelen voor agenten. De empirische resultaten ondersteunen de veronderstelling van betrekkingen en zijn krachtig ten opzichte van verschillende modelspecificaties en alternatieve schattingstechnieken.

Het derde essay is één van de eerste pogingen om de theorie van Williamson (over de relatie tussen bedrijfsspecificiteit en organisatievormen op de markt) te testen op de gereorganiseerde elektriciteitsmarkt. Hoe belangrijker de investering in relatiespecifieke bedrijfsmiddelen, hoe langer

⁹⁷ Omdat het moeilijk was om dergelijke overeenkomsten te vinden en de inhoud daarvan te beoordelen is slechts een klein aantal contracten onderzocht.

de contractduur. Partijen zullen de inflexibiliteit van langlopende contracten echter matigen op basis van vooraf onderhandelde bepalingen en voorwaarden met voorzieningen voor eventuele aanpassingen. De empirische resultaten ondersteunen de veronderstelling van betrekkingen en zijn krachtig ten opzichte van verschillende modelspecificaties en alternatieve schattingstechnieken.

Het vierde essay is een case study waarin de relatie tussen langlopende contracten en verticale integratie in de reorganisatie van de elektriciteitsmarkt in het Verenigd Koninkrijk centraal staat. In het begin van de jaren negentig stelden de drie belangrijkste Schotse elektriciteitsmaatschappijen bij de reorganisatie van de elektriciteitsmarkt in het Verenigd Koninkrijk een langlopend "take-or-pay" contract op, de Nuclear Energy Agreement. Daarin waren bepalingen opgenomen voor de grootschalige handel in elektriciteit in Schotland.

De Europese Commissie heeft dat contract bestudeerd om te bepalen in hoeverre deze overeenkomst voldoet aan de Europese wetten. De Commissie erkende de interne anti-concurrerende inhoud en de potentiële gevolgen van het contract. In dit laatste essay wordt kritiek gegeven op het besluit van de Commissie aangaande de Nuclear Energy Agreement en de economische gedachtengang daarover, en geeft een alternatieve lezing en analytische benadering. Deze leidde tot tegengestelde resultaten en conclusies: de Nuclear Energy Agreement is niet anti-concurrerend en vergroot efficiency op concurrerende elektriciteitsmarkten.

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CURRICULUM VITAE

Laura Onofri was born on 17 May 1971 in Rimini, Italy. In 1996, she obtained her university degree in Law from the University of Urbino, Italy, where she got an assistantship for research in economic analysis of law under the supervision of Professor Diego Piacentino.

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Whilst deepening her formation in economics and economic research techniques (with a strong preference for econometrics), she pursued her legal practice and in 2000 passed the Italian State Examination for the enrolment to the Italian Bar of Attorneys.

In September 2002, she got a research fellowship from the Economics Department of the University of Bologna, where she still works on cultural economics topics. From 2004, she teaches Economics of Cultural Goods at the Economic Department of the University of Venice.

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