University of Siena
Doctoral School of Economics

Investment in Power generation: From market uncertainty to policy uncertainty.

Real Options Approach applied to the UK electricity market.

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thesis
submitted to the Department of Economics
and the Committee of Graduate Studies
of the University of Siena
in partial fulfilment of the requirements
for the degree of
Doctor of Philosophy in Economics

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Acknowledgements

I would like to express my gratitude to my supervisor, Jean-Michel Glachant, who has guided me throughout my thesis. I am deeply indebted to him for his encouragement and patience. I am equally grateful to Leonardo Meeus, who has always been available to discuss ideas, even in the very early stages of this dissertation.

This dissertation has been conceived during a period at Ofgem, whose inspiring environment I acknowledge with gratitude. The research was then completed and finalised at the Florence School of Regulation, which comprised an ideal location for researchers engaged in the study of energy regulation.

I spent periods as a visiting researcher during this study at Groupe Reseaux Jean Monnet (GRJM) at the University of Paris XI and the Centre for Competition & Regulatory Policy at City University, London. I wish to thank Yannick Perez and Xeni Dassiou for their hospitality and support. I also wish to thank Antonio Nicita, Luigi Luini and Duncan Sinclair. I have greatly benefitted from their comments and suggestions.

Needless to say, all errors and omissions remain my own responsibility.

Finally I wish to thank Cenza (and Pietro) for her patience and for being supportive and always present during these years.

0. Introduction

In several industries, market participants must make decisions about capacity choice in a situation of radical uncertainty about future market conditions and decide on the level of output to be produced after the state of nature has unravelled. These industries are normally characterised by non–storability and periodic and stochastic demand fluctuations. In these cases capacity determination is a decision for the long term, whereas production is adjusted in the short run.

In the electricity sector, generation takes place just in time, and ought to ensure second by second supply demand balance, but capacities need to be installed well in advance, at times when firms face considerable demand and cost uncertainty when choosing their capacity. For electricity markets it is moreover well-known that demand fluctuates systematically over each day, month or year. It is natural to expect that firms try to anticipate those patterns when they make their investment decisions. This study looks at the main contributions in investment planning under uncertainty, in particular in the electricity market. The relationship between market and "non market" factors in determining investment signals in competitive electricity markets was studied. Electricity generation is generally considered the typical example of an activity that is most effectively carried out by establishing a competitive market. Therefore the thesis tests the ability of competitive "energy only" electricity markets[1] to deliver the desired quantity and type of generation capacity.

The study also investigates the variety of market imperfections operating in electricity generation and their impact on long-term dynamics for generation capacity, the most capital-intensive of the liberalised functions in the electricity supply industry. As a consequence of the liberalisation process, certain economic externalities and the resulting possibilities of market failures were not anticipated from the outset. The thesis adds to the growing literature on the subject of an evaluation of liberalised wholesale electricity markets with regard to the specific policy goals of reliability and affordability of electricity generation. It does so by

[1] As opposed to electricity markets that also provide capacity payments to stimulate investments.

focusing upon the main approaches adopted to address the various risk factors that enter into the picture when designing wholesale supply markets.
The study distinguishes between market-based risks (referred to by Green, R. as the "uncertainty barrier") and policy risks. Policy risks are often referred to as "the missing money problem" and the "regulatory hold up" problem. The research establishes that these factors contribute to cause a sub-optimal level of investment in generation capacity.

The thesis also offers a quantitative examination of market dynamics applied to the UK electricity system that takes into account recent market and policy evolutions. A Real Options Approach (ROA) analysis is applied to study the evolution of the generation mix in UK in the coming years, also as a response to the influence that climate change policy targets play in energy policy debate. Finally, an evaluation is offered of the impact of various policy alternatives to the final generation mix in UK in 2020.

The dissertation is organised as a monographic study and is composed of the following sections: Chapter 1 – provides a review of the factors that affect the level of supply adequacy; Chapter 2 – introduction to ROA analysis applied to investment planning in electricity; Chapter 3 - explores the main characteristics of the British electricity market; Chapter 4 - introduces the framework (Real Option Approach model) chosen to identify and evaluate the generation dynamic in UK in the period 2011-2020. Finally the fifth and last Chapter serves as a summary of the research main conclusions.

A brief description of the main findings is provided below, as a guide for the reader.

Chapter 1 - Offers a comprehensive assessment of the existing literature on *investment in power generation*, departing from a review of the traditional "peak load pricing" literature. In particular the study identifies the main contribution to price dynamics in liberalised electricity markets and how price formation influences *investment signals*. Today, investment decisions are made by several operators that act independently. In the "energy only market", as in UK, these decisions are solely coordinated via the price mechanism, that is expected to convey the correct scarcity signal. We highlight that a number of factors (including exploitation of market power, wholesale price volatility, lack of liquidity in the wholesale and financial market, policy and regulatory risks etc.) contribute to polluting the price signal and generating sub-optimal behaviour.

Chapter 2 - Explores the shortfalls of traditional cash flows evaluation methodologies, conventionally used to assess the financial stream that investments generate. These methodologies have shown to be increasingly unsatisfactory when dealing with flexibility. In addition they proved to be biased in favour of a passive management commitment. The Real Option Approach emerges as a suitable model to model and evaluate correctly investment strategies in a more credible way. ROA allows for an accurate identification and evaluation of the options available, at each point in time, to investors. Typically managers are willing to keep some operational flexibility also at the expense of direct cash flow. Keeping open some strategic and managerial options is just as valuable as direct cash flows. When an investor evaluates the profitability and the risk related to the development of a power plant, while facing uncertainty on the projected electricity and fuel price (and consequently demand), the opportunity to exercise an option to defer an investment (timing) and on the type of plant installed (technology) may be evaluated positively.

Chapter 3 - Identifies the main market dynamic and regulatory provision in place in the UK electricity supply industry. The study found that at the time when the industry was liberalised (1990) there was a generous capacity margin, and the first and second wave of investment, mostly in CCGT (Combined Cycle Gas Turbines), was driven and decided by Regional Electricity Companies, and in a situation of a sizeable gas bubble (with abundant supply of cheap gas) that drove investment dynamics. However this situation changed radically in the last decade. UK electricity spot prices (2001-2009) have been characterised by significant clustered volatility as an effect of price ability/necessity to spike, at times significantly, when a situation of scarcity arises. Significant investment volumes have never been necessary in a truly competitive market environment since liberalisation. In the absence of the clear cost advantage of new technology over the existing one, as in the 1990s, new investment must be driven largely by investors' expectation of future scarcity. The question is: how high the long term expectations of the electricity to gas/coal spread (spark/dark) need to be before generators commit to building the levels of capacity that will be required over the coming years? The study answers this question by designing policy scenarios to reproduce a simplified version of the possible market and policy development over the next decade.

Chapter 4 - The model is finally introduced together with a general overview of the data employed for the empirical analysis. The data derives from the original 'Redpoint Energy' dataset (Dynamic of GB electricity generation investment, 2006) and provides a detailed description of the technical and economic characteristics of the British generation fleet (at unit level) and has been updated with recent plants and investment development. The study uses the classic Kumbaroglu et al. (2008) model applied to UK generation. Electricity prices and fuel costs have been modelled as evolving stochastically and following a Geometric Brownian Motion process, as in the standard literature in ROA. The analysis is based on 3 different scenarios.

Chapter 5 - illustrates the main results of the thesis.

- The model confirms that the UK energy system, under the conditions explained in chapter 4, is able to deliver the required level of generation adequacy in the next ten years (2011-2020). Investment in power generation, given the projected level of electricity and fuel prices, returns positive NPV in each of the scenarios considered.
- The new capacity installation rate will (at least) double, compared to what happened over the last decade, in order to guarantee supply adequacy.
- Climate change policies can easily distort market signals, insulating renewables generation and technology from market dynamics. This in turn reduces the proportion of the market that is effectively opened to competitive forces. As expected, when renewable support policies are undertaken, investments in conventional technologies suffer. This produces distorting effects on the generation mix. Should the climate policy options (premium tariff and/or renewables quotas) persist, the adopted model predicts that they will have a consistent depressing effect on the investment in the technology exposed to market dynamics.
- Finally, policy intervention, rather than market forces, is able to select "artificially" winners and losers, thus potentially undermining, in the long run, the necessary diversity of the energy mix.

1. Investment in power generation

1.1.Security of supply in electricity markets.

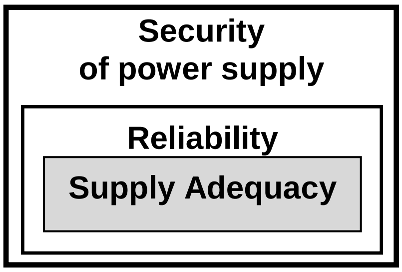
While security of electric power supply seems relatively natural in developed countries, the adaptation of command and control rules that entailed a certain level of security of supply in the monopolistic context to a state of competition has not been trivial. It has represented the transition from a monopolistic organisation to a competitive one. This normally means an increase (rather than reduction) in the level of complexity in the market structure and regulation. For the purposes of this study it is useful to divide the problem of Security of Supply (SoS) into successive stages.

Matters related to security of supply can be defined in many different ways, and the term Security of Supply can mean different things in different countries and in a variety of contexts (Crampton & Stoft, 2006). It also includes a number of different concepts.

Security of supply incorporates the sufficiency of supply sources and/or production capacity to meet peak demand at a reasonable cost (*Supply Adequacy*). It also includes the availability of flexible and reliable import, transmission and production capacity to deliver energy when and where it is required (*Reliability*). Finally, security of supply also takes into consideration the ability of the system to mitigate the risk of one or more sources of supply becoming restricted or very expensive (*Diversity*).
We will adopt the definitions that are used in the sector for issues related to Reliability and Security of supply (UCTE, 2002).

- Supply Adequacy is a measure of the capacity of the power system to serve the aggregate electric power and energy requirements of the customers within the quality standards (voltage limits and ratings) of the system and taking into consideration planned and unplanned outages of the system components.
- Reliability of the system means in general, the ability to deliver at each point in time and at each location of the network, within a specified safety standard, the amount of power desired.

- Security of supply covers a wide range of measures of power system ability to withstand sudden disturbances (such as electric short circuits or unanticipated losses of system components). Security of power supply is a complex concept that involves a number of actions necessary to guarantee system integrity[2]. It includes supply adequacy, reliability and diversity.



In the present work the focus will not be on Security of power supply problem in general, but attention will instead be turned to *Supply Adequacy* and the development of the Generation Portfolio in the medium and long term. This aspect of the Security of Supply (SoS) problem represents the smallest subset of issues and constitutes the basis for the analysis of security of supply. This is a necessary initial step to evaluate SoS and it is included in all the subsequent measures of SoS.

1.2.Supply adequacy issues in electricity markets.

Investment decision under uncertainty in energy markets has attracted significant attention in recent years, and policy makers in many countries are debating whether competitive wholesale electricity markets are providing appropriate incentives to stimulate adequate investment in new generation capacity. Joskow (2006), looking at the evidence deriving from several US markets, finds out that organised wholesale markets are currently failing to

[2] All generating units have a probability greater than zero, that they are not available at a certain time. Therefore the probability that the available generation capacity temporarily is insufficient to meet demand can never be ruled out altogether. More generators reduce the probability of outages, but undoubtedly have a higher cost. The socially optimal volume of generation capacity does not minimise the probability of outages but minimises the total social costs (including the total cost of the electricity supply industry).

support investment in generation capacity, mainly because of the inefficiency of price signals during peak hours. Joskow and Tirole (2004) find that price caps produce inefficiency and sub-optimal level of investments. Capacity payments are able to restore efficient investment incentives, provided that they are available to all the capacity installed and when also consumer's demand is subject to capacity obligations. Grimm and Zoettl (2005) explore the interaction between investment decision and production choice in a two-stage market game theoretic framework. Whenever investors anticipate intervention at the production stage (e.g. price caps), this affects the level of investment.

These recent contributions highlight that policy intervention have a significant effect on the quantity (and type) of additional capacity installed. Those findings are in line with the classic approach to investment under uncertainty, related to traditional concerns over investment adequacy, that characterise the supply and demand of most public utility goods and services (the "peak-load pricing" literature) in the case of non-competitive markets. Non-storability and the periodic fluctuation of demand and supply have a major impact on the economic behaviour of markets presenting these characteristics. A strand of literature[3] starting with Boiteux (1949; 1951) and Steiner (1957) has had an extensive application to the practical problem, starting from regulated monopolies. Optimal investments for a regulated monopolist have been evaluated (together with optimal pricing decisions) when the product is non-storable and demand fluctuates over time. This classical framework, allows the determination of welfare maximising investment in a single technology[4].

It was successively extended to the case of optimal investment in several technologies under the objective of welfare or profit maximisation[5]. This framework was perfectly appropriate to model and evaluate investment decision in electricity markets when it is organised as a single monopolistic vertically integrated entity. In fact this approach performed well when applied to study the most common variety around which the electricity market was organised.

In the last century, the electricity supply has been designed mainly in two variants:

- A vertically integrated public monopoly; or

[3] For an extensive review of the peak load pricing literature refer to Crew et al. (1995)

[4] Oren et al (1985) studied the case of a profit-maximizing monopolist.

[5] In a second best approach, optimal investment choice where analysed maximizing any weighted sum of profit and welfare.

- Different local monopolies for the distribution-retailing phase for small customers and a national firm in the production-transportation phase, integrated by a long-term contractual relationship.

However, this situation changed dramatically in many countries during the 1990s. The starting point was the opening up of the transportation network to TPA – 'third party access'. This first step aimed to promote the wholesale market, breaking up the exclusive right of supply for the owner of the net[6].

This first opening of the network represents an important concession that brings together a series of repercussions in the market. Once the market was freed for some actors, it had to be freed for the so-called "eligible customers". These have a level of consumption comparable with the distributors. Therefore, as it is difficult to establish a minimum level of consumption excluded by this process, the pressure to open up all the nets, including that of distribution, has been resulted in this happening.

The opening up of the network system imposes a new organisational style based on competition between producers. According to this new model there are phases in which competition is possible, and others characterised by monopolies. The distribution and transportation nets are considered natural monopolies, thus controlled by a regulating body that has to ensure access to every firm, whereas the production and the selling (wholesale and retail) are free activities based on competition[7].

The unbundling process[8] goes hand in hand with the opening up of the network system, as a result of the distinction between monopolistic and competitive activity, intended to avoid integrated firms impeding access to the system for competitors, and any anti-competitive behaviour (such as cross-subsiding). The separation had to be undertaken at least at the account level. This new model has been adopted initially in England in 1990, and later was

[6] The introduction of the directive 90/547/CEE introduced the possibility of free transit between producers and wholesale traders of electric energy.

[7] In this general framework many variables can be added, such as the institutions of different categories of client, or the coordination in the system that can rely on a market mechanism or on a mandatory market (typically the market of the day before)

[8] 'Unbundling' is used to mean the separation of the transmission operator from other vertically integrated stages into independent entities. Separation of asset ownership is not required but there are relatively stringent minimum criteria specified to support effective independence and to prevent discriminatory behaviour (e.g. in favour of the generation plant owned by the same company).

implemented by the European Commission with two similar proposals regarding the electricity and natural gas markets[9].

With the liberalisation process of the electricity market, regulated monopolists have been transformed into competing firms.

In addition to the general economic dynamics outlined above, organized competitive wholesale markets for electricity are subject also to a number of specific market imperfections and institutional constraints, which can distort price signals.

In particular wholesale prices are said to be kept artificially below their efficient level. If this situation is allowed to persist it could in turn lead to underinvestment in generation capacity and to higher rates of power supply emergencies and eventual blackouts. In general, there are several groups of problem that relate to competitive wholesale markets that conspire to exacerbate the uncertainty surrounding capacity investment.

Competitive wholesale markets for electricity and energy often fail to provide adequate net revenues to attract investment in generation to meet reliability criteria. Cramton and Stoft (2006) refer to this as the *"missing money"* problem. A limit to the capacity of spot prices to fluctuate (and to spike) to their efficient level, is represented by price caps. In recent years price caps have been proposed (and adopted) in order to limit the exercise of market power in liberalised electricity markets. More recently, economists have questioned the desirability of price caps in electricity markets (Hogan, 2005; Joskow, 2007). Their argument, originating in the findings of the peak load literature, recognise that in a market without price caps, high price spikes during hours of high demand and scarce supply send accurate price signals for investment decisions. Very high price spikes signal scarcity of supply and will thus lead to increased investments activities. In equilibrium market prices will be such as to sustain an optimal investment level.

Price caps at the spot market that fall short from an adequate level of revenue might significantly alter investments decision and might lower firms investment incentives, putting

[9] Proposal COM (1991) 548-1 proposal for a European parliament and council directive concerning common rules for the internal market in electricity and COM (1991) 548-2 proposal for a European parliament and council directive concerning common rules for the internal market in natural gas

seriously into question the desirability of such price caps[10]. This argument is based on the assumption of perfectly competitive investment behaviour.

In addition, it is also argued that short-term price volatility is more extreme and frequent than in other commodity markets, because storage for electricity is too costly for commercial application (Suttleworth, 1997; Hirst & Hadley, 1999; Green, 2004) and this represents another major source of distortion.

Retail customers have no interest in a contract that has a duration of more than two or three years. Therefore a voluntary market (with a decent level of liquidity) for long duration contracts has not emerged so far. The "*uncertainty barrier argument*" is not suggesting that the investment will not be forthcoming, but simply implies that the cost of capital used by investors to evaluate investment in new capacity will take into consideration these additional risks, and should therefore be quite high. This will have the effect of producing electricity prices that are even higher than those that would have been experienced under the old regime of regulated vertically integrated utilities. In the old regime each and every risk factor (market, construction and generator performance risks) was shifted to consumers by fiat through the regulatory process (in the form of tariffs). Shortages of investment are largely attributed to the obstacles posed (mostly by regulators) to the proper functioning of the market, such as price caps (as in the missing money case) or to the administrative procedures (such as permit requirements or planning approval) as in Neuhoff & De Vries (2004). However it is not plainly established that merely removing these obstacles and regulatory risk will suffice to guarantee adequate investment (De Vries & Hakvoort, 2002). Therefore around the world mixed evidence can be seen in the regulatory practice regarding the preferred tools to ensure capacity adequacy. The British system under the pool regime (before 2001) and currently Spain use capacity payments to stimulate investment in generation capacity, while systems on the west coast of USA[11] use capacity requirements (PJM Interconnection, LLC, 2001; Besser et al., 2002).

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[10] Joskow (2007): "As a result many economists assume that the primary source of the Missing Money problem must be the price caps and the related market power mitigation procedures imposed by regulators. That is, that the effort to mitigate market power have had the effect of suppressing energy price too much, especially during scarcity conditions when prices should be very high", p.38.

[11] PJM, the New Yorker Power Pool and the New England Power Pool.

Lastly, another factor that is considered crucial when evaluating the adequacy of new capacity investment is the possibility, for the policy makers, to change market rules and market institutions. The opportunity for regulators to *"hold-up"* market participant by changing the rules that regulate markets, strengthening in this way the constraints on market behaviours, are often judged so great by market participants, that uncertainty about future government policies acts as a disincentive to new investment (Joskow, 2008). Electricity markets, in particular might suffer this imperfection, when extreme spot price can affect a large fraction of the net revenues earned to compensate investors for the capital committed to generation, and often these very high prices take place only on limited hours of the year (a recent example has encouraged the "Energy supply probe"[12] – Ofgem). Capacity choice and generation adequacy is currently fiercely debated also in anticipation of the forthcoming implementation of the EU Large Combustion Plant Directive, and the way different countries will be able to meet their environmental obligations.

For the forthcoming analysis it is worthwhile to clarify that all the concepts behind the definition proposed above can be measured and quantified. However these measures are based on a number of assumptions, and crucially rely on the availability of data related to the system under scrutiny. Generation adequacy can be evaluated when data concerning the available generation capacity (volume) and the corresponding demand are available. These two sets of information will determine whether the available capacity is sufficient to meet the demand. One of the aims of this project is to evaluate under which conditions supply adequacy is met. Moreover another aim is to analyse the impact of different energy policy in the generation mix, and on the timing of investments. There will be an evaluation of how various policy goals (together with other environmental and safety constraints) might interact with the dynamic of the generation portfolio in the UK, in the period 2011-2020.

Various types of factors concur to influence the investment equilibrium and may enter into the final investment decision. These factors (De Vries L, 2004) can be labelled as market or

[12] In February 2008 Ofgem launched the Energy Supply Probe - an investigation into the markets in electricity and gas supply for households and small businesses in the United Kingdom. Although no evidence of major market distortion was found, a number of corrective tools were proposed in order to guarantee the maximum benefit of competition to consumers. The main findings of the supply probe are available here: http://www.ofgem.gov.uk/Markets/RetMkts/ensuppro/Pages/Energysupplyprobe.aspx

policy based. Reference will be made to this classification and the impact of the different factors in electricity investment will be examined.

Typical market based factors are those related to the imperfections that affect the electricity sector. The specific characteristics of supply and demand in electricity market contribute to inhibit the ability of a liberalised energy market to drive adequate investments in generating capacity. Electricity markets are characterised by: i) large variations in demand over the course of the year; ii) the need to balance physically the supply and demand and supply at every point of the network; iii) non-storability of electric power; iv) inability to control power flows to most individual consumers; v) limited use of real time pricing by retail consumers; vi) necessity to rely on non-price mechanism (blackouts) to ration imbalances, because markets cannot clear quickly enough to do so.

In this context in order to make sure that an economic signal (price of the electric power and ancillary services) reaches the market, a mechanism should exist which is able to make consumers' preferences explicit to suppliers.
The supplier should transfer these signals to producers via the market. However such a mechanism does not exist in any energy market at the current time. Its implementation requires profound changes in metering technology, as well as new ways of electricity contracting between suppliers and consumers. The liberalization process in its extreme and more dramatic instance has profoundly changed the role and impact of grids in electricity markets (Meeus, Saguan, Glachant, & Belmans, 2010). Climate change and security of supply policies are driving modern electricity systems towards a progressive decarbonisation. This process is entrenched with other major challenges that grids must face in this context[13]. They consist in the system integration of Distributed Generation (DG), integration of demand and storage, and integration of large scale Renewable Energy Sources (RES) (Perez-Arriaga, 2010). Until the transition toward modern grids is completed the market cannot know consumers' willingness to pay their electricity. Consequently the market today cannot infer what investments in production capacity must be made in order to satisfy consumer demand.

[13] This process requires a profound change in the technological infrastructure as well as a radical regulatory reform. Interested readers might refer to Meeus, et al. (2010) and the reference herein for a more detailed report on the status of the current discussion on the implementation of smart grids.

Policy based risk factors are those related to the various forms that policy intervention may take in energy markets in order to minimise the effects of the specific features of the energy market on consumers. They typically consist in price restrictions, regulatory uncertainty and regulatory intervention.

Price restrictions - A price cap is sometimes required to protect consumers against excessive prices in times of scarcity. This is normally a regulatory intervention with high distorting power when it comes to investment decisions because it is difficult to determine the optimal level of an efficient price cap (see below). While the theory is clear that the maximum price has to be set equal to the average value of lost load (VoLL), there are many methods with widely varying outcomes to value VoLL (Kariuki & Allan, 1996a; Kariuki & Allan, 1996b; Ajodhia, Hakvoort, & Van Gemert, 2002; Goel & Billinton, 1997). As a consequence it is typical to have a long-run average shortage of capacity and too little reliability in most electricity system (Zoettl, 2008). Behind this approach there is a general critique of what the market is able to deliver. Indeed this issue goes hand in hand with the assumption that in the electricity market the market for reliability is normally missing. Reliability is a separate service that requires dedicated regulation and a set of infrastructure. Its absence does not depend on regulatory constraints but rather on a lack of expensive infrastructure in most markets.

Regulatory uncertainty – Investment risk is significantly affected by regulatory intervention. These factors are considered among the main drivers[14] for inadequate generation capacity.

If utility regulation is examined from a transaction cost economics (TCE) perspective[15] consideration is given to the interaction between governments and investors when a service is characterised by some form of natural monopoly features (Spiller 2010,pag. 3). The existing regulatory regime depends merely on the contracting risk that characterises the interaction under scrutiny (Williamson, 1979).

[14] Along with the presence of imperfect information, uncertainty regarding input markets and externalities connected with the generation market (De Vries L. , 2004, page 73).
[15] Based on Williamson, 1976; Williamson, 1973.

Regulation, intended as a particular form of public contracting, is affected by politics, taking into account the institutional setting (Coase, 1964).

Given the specific nature of the investment in the electricity market, the existence of significant economies of scale and widespread domestic consumption, energy markets are subject to the well-known (spoiled) relation between government and utility investors (Williamson, 1976; Williamson, 1993). These interactions (between government and utility investors) may generate very specific policy risks that depend on governmental and third party opportunism[16].

Governmental opportunism consists of the ability (the threats) of governments to change the regulatory framework in order to extract part of the quasi rents of utility investors (Spiller, 1996). This might happen in several forms such as changes in governmental conduct, contract forms and regulatory approach. Investors facing (the threat of) governmental opportunism will either not invest or, most likely, demand a higher rate of return (and even upfront compensation) for the hazard that regulatory hold up poses to the return on investments.

This risk has a fundamental impact on both private investors and publicly-owned utilities.

The former tend to reduce their exposure to this risk (see below) while the latter will normally "sterilize" their cash flows with actions that tend to freeze governmental opportunism. To do so, publicly owned utilities are inclined to hire too many permanent employees, or to grant significant benefits to the manpower, etc.

The mere existence of sunk investments provides the opportunity for politicians and government to behave opportunistically, exposing investors to the risk of expropriation of the quasi rent they enjoy. In the presence of efficient regulation (seen as a particular form of public contracting) some safeguard might be foreseen in order to mitigate (the perception of) these risks. When governments fail to do so investment inefficiency might arise. Those inefficiencies typically are: underinvestment; investment localised only in specific market segments[17]; maintenance expenditure kept at a minimum; investments in technology characterised by a low degree of specificity (and/or smaller scale); and up-front rent extracted via very high prices that might stimulate investments but are likely to be politically

[16] The way public scrutiny is exercised might generate third party opportunism, when interest groups might have the opportunity to challenge the government/utility interaction. These particular aspects of opportunistic behaviour will not be further explored here. Interested readers might refer to Spiller (2009) for a comprehensive review of the subject.

[17] Normally characterised by high returns and short payback periods.

unsustainable, thus even more subject to governmental opportunism in the long run. The creation of a credible regulatory framework that guarantees investors against opportunistic behaviour is critical to generate the right incentive for investors. Nevertheless, even in the most favourable case, investors normally factor in, when called to evaluate their investment portfolio, the exposure to governmental opportunism. This risk conspires to increase the specificity and rigidity of regulation, causing difficulties in adapting to shocks and leading to low-powered incentives. The rationale for developing clearer ex ante rules is linked to the issue of regulatory discretion and the extent to which it exists – something that every regulatory regime has to address.

In most countries with a liberalised market, there is always a desire to provide as much certainty to investors, companies and consumers as possible while ensuring that the regulator has sufficient flexibility to respond to future events. Certainty and predictability helps limit regulatory risk and consequently can lead to a lower cost of finance[18]. Recent regulatory decisions have focused on the degree of regulatory discretion with the New Zealand Input Methodologies[19] as an example of a regulator being mandated by its Government to establish a low discretion environment. Yet there is an indubitable trade off between regulatory discretion and its flexibility. It remains to be decided what is the desired degree of rigidity (or flexibility) and regulatory discretion that strikes the best balance between investor needs and consumer protection in a rapidly changing environment.

An alternative, but potentially complementary, way of establishing credibility is to commit through some form of contractual undertaking as a way of establishing commitment. There are various ways in which an actual or effective contractual undertaking could be established and it normally implies the implementation of a long-term instrument that is part of the

[18] Therefore this should normally lead, ceteris paribus, to an incentive to invest.
[19] Input methodologies involve setting upfront regulatory methodologies, rules, processes, requirements and evaluation criteria that are directly (or indirectly) relevant for applying the regulatory instruments for undertaking the Commission to determine upfront input methodologies for services regulated under Part 4 of the Act. Currently these are electricity lines, gas pipelines, and specified airport. Examples of methodologies that are required to be established by the Commission include cost of capital, valuation of assets, allocation of common costs, treatment of taxation and pricing methodologies. Under the updated Act, the purpose of the input methodologies is described as being to promote certainty for suppliers and consumers in relation to the rules, requirements, and processes applying to a particular regulation. Commerce Commission, Regulated Industries (New Zealand) at http://www.comcom.govt.nz/.

regulatory process. Table 1 below summarizes the main aspects of setting up ex ante rules and contractual undertaking in the UK energy regulatory environment.

Table – 1 – Strategies for Regulatory commitment

Aspects	Ex Ante Rules	Contractual Undertaking
Degree of commitments	Limited unless the rules are enshrined in some form of undertaking	Strong, especially if in a contract since compensation could be sought
Ability to commit	If incorporated into a determination or a published document then Judicial Review should be possible if the rules are not applied. Whether this is sufficiently strong is a concern. Even if followed through a company could still choose to appeal and it is not clear if the Competition Commission would accept the ex ante rules.	From the legislation and licence structure Ofgem could propose, for example, a longer control period without requiring any legislative change. So, in principle Ofgem could commit through a licence amendment and this would only be subject to Judicial Review (any stakeholder) or appeal to the Competition Commission (CC) (the licensed companies). Of course, a future regulator could choose to review, if the control is in the public interest, or a company could seek to have the clause disapplied. The latter faces specific time limits while the former could be appealed to the CC.
Predictability	Provided that the approach is employed, there is greater predictability of what the value set at a determination will be.	Depends on the approach adopted. It is possible for there to be significant regulatory discretion when the estimate is set but then predictability during the period – which could be a long time.

Based on: (CEPA, 2010) - "RPI-X@20: providing financeability in a future regulatory framework"

1.3. Investment dynamics in electricity markets

The way in which a well functioning electricity market should work, in order to deliver, via price signals, investment incentives in a liberalised environment will now be examined. Then, a comparison will be made of the features and the implications for a real (imperfect) electricity market, with special attention paid to the features of the British market. In addition a short overview on how electricity supply was ensured before liberalisation will be presented. This section will focus on the way investment equilibrium is reached in liberalised electricity markets in order to guarantee generation adequacy. In theory, periodic price spikes should provide optimal investment incentives in an energy only market. However several factors could contribute to cause a significant deviation from the social optimum.

The way in which economic and non economic factors contribute to such deviation and their relevance to investment behaviour will be examined, focussing mainly on environmental and CO_2 abatement policy role.

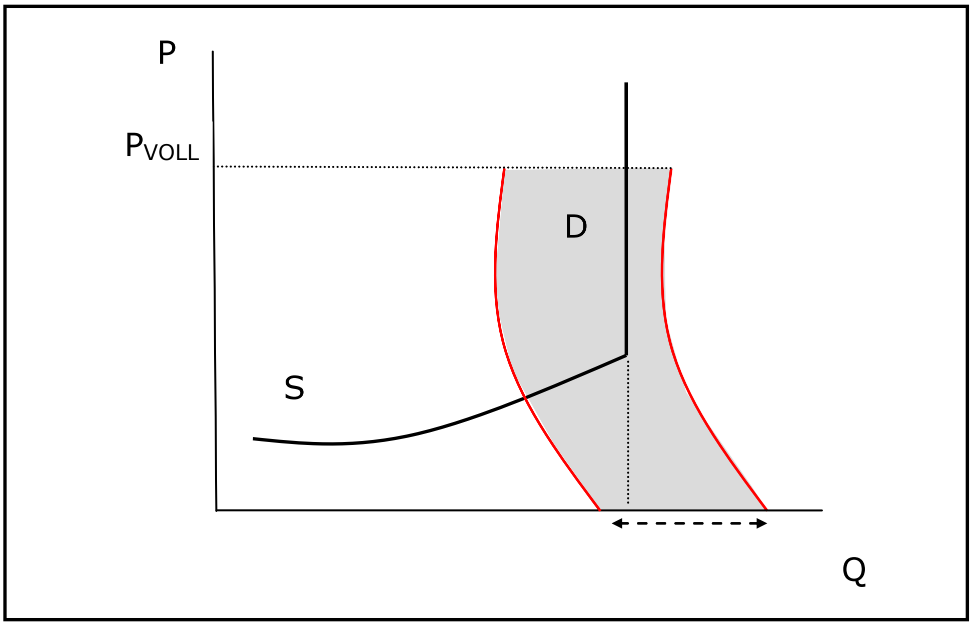
1.3.1. Market based approach

Assuming that consumers' willingness to pay is observable, and reflected by some form of price mechanism, a properly functioning energy market would deliver the optimal level of supply security because if the risk of shortage is too high, consumers would be willing to pay a producer to invest in additional capacity or supplies to reduce the risk to the optimal level, while if the risk of shortage is too low, consumers would not be willing to pay producers a price high enough to cover the full costs of the marginal capacity on the system, and so producers would withdraw capacity or supplies.

Caramanis et al (1982) show that investors in a well-defined unregulated market will provide sufficient investment in generating capacity. A necessary requirement for this to happen is that demand is sufficiently price elastic so that the supply and demand functions always intersect. Key to this argument is how the price is set at a time when there is supply shortage and how supply and demand curves behave in a market in which the price-elasticity of demand is insufficient to guarantee that they match continuously.

In the short term the supply function is almost static, it varies according to the availability of generating units, and it has a well-defined maximum capacity, whereas the demand fluctuates continuously. Figure 1 below shows a range of possible demand curves and the area in grey represents a confidence interval. In a system such as the one depicted in figure 1, there is a possibility (positive and different from zero) that supply and demand do not intersect. In this case there will be a supply shortage and demand will be rationed in order to maintain system stability. The typical rationing method when such an event happens is a non-price mechanism (blackouts). When this disequilibrium situation materialises, the market does not clear and there is no equilibrium price, and moreover, there is no theoretical price limit. In a decentralised system, where there is retail competition, retail companies that have a "short" position are required to purchase electricity in the balancing market. In the situation depicted some form of price cap is required in order to protect the consumer against excessive prices (Hobbes, Inon, & Stoft, 2001b; Ford, 1999; Stoft, 2002), in particular when consumers are not directly involved in real time price setting (De Vries L., 2007). This is the indicated P_{VOLL} in the figure (an indication on how this price is determined will be set out in the reminder of this section).

Figure 1 – Low demand price elasticity allows for the possibility of non-price equilibria



Furthermore, in a market where there is no retail competition there is the need for a rationale to establish a maximum price. Although companies detaining regional monopolies would be able to interrupt service to a group of customers in order to adjust the demand according to market price, this solution opens even bigger questions, on the ability of the supply companies to assess customers' willingness to pay, absent a contractual clause that states at what price (compensation) customers are willing to be disconnected. Moreover the political and social repercussions of a blackout (service interruption) are normally large enough to discourage any attempt to pursue this option, and might justify astronomically high price spikes.

A price cap is a regulatory tool able to influence generators' revenues. The higher the cap, the higher the revenues at times of scarcity, and, as a consequence, the larger the investment for peaking units. This should somehow compensate the incentive to underinvest linked to regulatory uncertainty that is discussed above. Therefore a price cap should be carefully designed and set in order to fulfil this crucial function (see section 1.5).

1.3.2. Variety of risk in electricity markets.

In this section, the characteristics of electricity markets are examined and how these markets should function to deliver the necessary level of investment to achieve the optimal level of security of supply is described. And we will also look at the different sources of risks and the main implication for power generation investment choices.

Different studies use different definitions of risk. Knight, in his seminal paper (1971), aims to distinguish between uncertainty and risk, by ascribing the term uncertainty to a situation where it is not possible to parameterise the variability of outcomes, and using risk when outcomes are variable within some expected probability distribution which can be parameterised[20]. For example, the UK Climate Impacts Programme (Willows & Connell 2003) adopts a widely used definition of risk. They refer to uncertainty as describing the quality of our knowledge concerning risk. In this report, we use the term ’risk’ in a more general sense to mean a factor that creates uncertainty in the financial returns of an investment[21].

The act of investment involves exchanging a lump sum of money now in return for an income stream in the future. Companies will make this exchange if the expected project returns are high enough to cover the initial lump sum as well as compensating them for taking on the project risks. Project risks arise from many sources (International Energy Agency, 2003). These range from the general (e.g. macroeconomic, political and force majeur risks) to the more project-specific.

These risk factors affect different technologies in different ways. They may lead to a re-ordering of the relative attractiveness of the various investment options facing a generation company compared to a more static analysis that does not include risk (International Energy Agency, 2003). This is why it is important to look at the effects of risk on projects. This is true to a greater or lesser extent for all the different risk factors. For example, technical risks

[20][But] uncertainty must be taken in a sense radically distinct from the familiar notation of Risk, from which it has never been properly separated. The term “Risk” […]means in some cases quantity susceptible of measurement . […] We shall accordingly restrict the term “uncertainty“ to cases of the of the non quantitative type. (pp. 19-20).
[21]For a review of the argument see H. Nowotny, et al (2001) and Vercelli, A. (1995).

vary considerably between technology types[22], and will be an important element of investment decision-making, since all else being equal companies would prefer to invest in lower risk technologies. This section focuses on the role of electricity price risk. Although all generation technologies within a given market are subject to largely the same time of day price of electricity[23], the level of exposure to this price risk varies considerably between generating technologies. As a result, electricity price risk turns out to be an important factor affecting technology choice in investment appraisal.

If electricity prices were fixed or extremely stable then it would be possible to capture many of the risk factors using levelised costs, also known as Electricity Generation Cost (EGC). The constant-money levelised lifetime cost method is a cost methodology (International Energy Agency, 2005) used to assess the generation cost of different generation options. It is a methodology employed to compare between electricity generation options. It allows calculating electricity generation costs on the basis of net power supplied to the station busbar[24], where electricity is fed to the grid. While this approach is considered a valuable tool for comparing alternative options for electricity generation and assessing their relative competitiveness in a coherent and transparent framework, it does not reflect the investors' perception of financial risk in liberalised markets. The EGC approach is not a substitute for the economic analysis of the electricity system, that must be carried out at the national level, but constitutes a cost estimate for different generation sources and technologies. The levelised cost methodology discounts the time series of expenditure to its present value in a specified base year[25]. This method allows for the calculation of the economic merit order of different candidate power plants, derived from the comparison of their average lifetime levelised costs. In turn the EGC per kWh of electricity generated is the ratio of the total expected expenses over the lifetime of a project versus total expected outputs[26].

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[22] A detailed description of the source of risks linked to the different type of technology will be presented in the model description.

[23] Some generators may receive additional payments for the provision of electricity system services, based on contracts issued by the System Operator. See http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/contracts/

[24] In electrical power distribution, a busbar is a thick strip of copper or aluminium that conducts electricity within a switchboard, distribution board, substation or other electrical apparatus. Busbars are used to carry very large currents, or to distribute current to multiple devices within switchgear or equipment.

[25] $EGC = \sum_t^n I_t + M_t + F_t/(1+r)^t / \sum_t^n E_t/(1+r)^t$ where EGC is the Average lifetime levelised electricity generation costs; I_t is the investment expenditure in year t; M_t is the operation and maintenance costs; F_t is the Fuel expenditure in year t; E_t is the electricity generation in year t and; r is the discount rate (Electric Power Research Institute, 1997)

[26] International Energy Agency, 2005.

Prior to the liberalisation of energy markets, under monopoly conditions, energy firms were able to pass on all costs of investment to energy consumers. For example, in the electric power sector, where most of the companies were state owned, utilities could expect the cost of their prudently incurred investments in power generation, including an adequate rate of return, to be recovered from consumers. This implies that the electricity sector under vertically integrated state owned monopoly was a risk-free market. The main risk was constituted by unfavourable regulatory decisions and excessive costs due to bad project management. In such an environment the risk associated with investments was not a direct concern of the energy company. Increased costs, if demonstrated to be incurred prudently, could be passed on as increased prices. In addition, even in the case where the utilities could borrow against the state guarantee, then the taxpayers were ultimately responsible if sufficient money could not be raised by increasing power prices. In this environment, energy companies where insulated from risk, because it was transferred from investors to consumers (taxpayers). Obviously the economic incentive to take account of such risks was almost zero when companies had to face investment decisions.

The level of financial risk in competitive markets is likely to be high when compared to pre-liberalised conditions, but in theory it ought to be possible to capture the implications of this through adjustments to the finance assumptions used to generate levelised costs by changing the interest rate applied to the project. Indeed recent analysis of levelised costs undertaken to inform policy, generally uses ‘private sector’ discount rates. By assumption these are higher than those used under public sector conditions or to represent ‘social’ discount rates (Leach, Anderson, Taylor, & Marsh, 2005).

However in many countries, and certainly in Britain, electricity prices are not fixed or insulated from risk, hence levelised costs cannot capture electricity price risks. Price risks arise because of uncertainties about future prices for electricity. These in turn arise for a range of reasons, from large scale economic events or political changes, to volatility in fuel prices or problems with power stations. Market structures under liberalised markets differ between countries and are subject to change over time, either as a result of regulatory changes or through merger, consolidation or new market entrants. These factors altogether have a significant impact on price behaviour and market conduct and performance.

Markets may be highly competitive, with many companies competing within separate functions (e.g. generation, supply, distribution) or dominated by an oligopoly (or even monopoly) of vertically integrated generation and supply companies. The degree of ‘unbundling’ of functions (e.g. generation from transmission) will affect the levels of competition. Aguerrevere (2003) has shown how these market features have a major impact on investment dynamics.

However merger and consolidation activity may at least partially offset regulatory unbundling, as at least some functions are reintegrated. For example, in the British market merger activity has created ‘reintegrated’ generation and supply companies and resulted in the exit of most ‘merchant’ generators[27]. Many supplier/generators also own distribution networks. These factors affect price volatility. To understand the implications of price uncertainty and fluctuation for investors it is first necessary to understand how wholesale electricity prices are formed, and what sets them.

1.3.3. Electricity price formation

Two of the characteristics of energy markets (gas and electricity) that are often cited as making them different to other markets are the inelasticity of demand and the limited capability for storage, particularly in electricity. Supply needs to fluctuate continuously in response to changing demand, driving volatility in market prices as the cost of the marginal unit of supply changes, and the market shifts between surplus and scarcity. Prices can spike to very high levels under these circumstances.

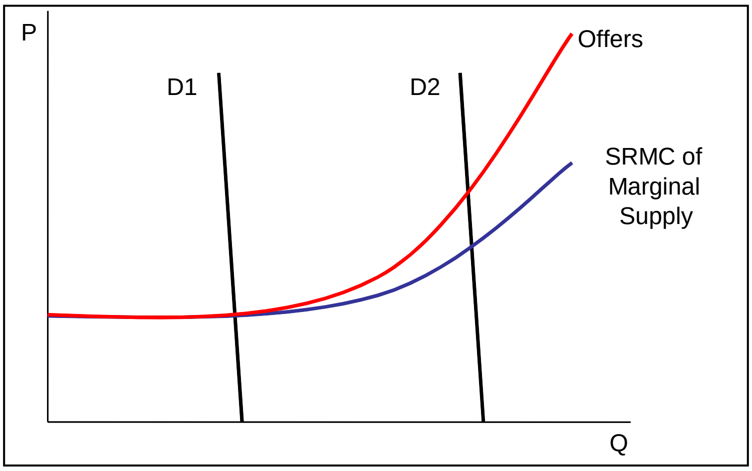
The inelasticity of demand in part reflects the high value that most customers place on the continuous availability of electricity, but it is also a consequence of current limitations in metering technology and the market arrangements. The consumption of domestic and small commercial users is only metered on a monthly or quarterly basis, with their demand pattern ‘deemed’ based on standard profiles. Hence, they have no means of reacting to short term price signals, and as a result a large tranche of customers, who may have different personal values for continuous energy supply at different times, are treated as a single inelastic block of demand. In the future this is likely to change as the roll-out of smart meters, and other

[27] See Gaballo, G., Rubino A., (2011) for a review of this issue from an educative learning perspective

smart technologies, such as remotely controlled domestic appliances, should allow smaller customers to react to price and increase the elasticity of demand. This will guarantee a better correspondence with the estimated and the observed consumers' willingness to pay.
The existing characteristics of the electricity supply industry (briefly mentioned above), requires that suppliers make forward arrangements with producers in advance to buy energy and with transporters and/or the system operator to deliver it to their customers.

The System Operator (SO) also has the role of residual energy balancer where aggregate supply and demand does not match or there are locational imbalances in real time. In electricity, production sources are generally local to the market[28] (with only limited interconnection). Hence, the electricity price is typically set by local supply/demand balances[29]. In electricity, security of supply requires sufficient investment in production and transmission capacity in the local market[30], although additional SO to SO interconnections contribute to providing additional security margins for national markets.
Gas and electricity markets become again linked due to the amount of gas-fired generation capacity in the market. This drives a high degree of correlation between electricity and gas prices, since the production costs of the marginal generator are predominantly set by the costs of burning gas. As in any market, prices are set in electricity markets based on the interaction of supply and demand. The market should clear where the supply curve intersects the demand curve as illustrated in figure 2.

Fig.2 Market clearing prices.



[28] Whereas in gas they are becoming increasingly internationalised.
[29] Whereas the gas price is increasingly set by regional or global supply/demand balances.
[30] Whereas in gas, security of supply also requires sufficient investment in other producing countries, and in transportation infrastructure.

Two different levels of demand are shown on the diagram, D1 and D2 (Borenstain & Holland, 2005). At demand level D1, competition between producers[31] means that they are offering close to their short run marginal costs (SRMC). The market determines the “dispatch” of plants according to their cost characteristics. The spot price electricity at any given time of the day is set by the short-run marginal cost of the last generator to be dispatched (i.e. the most expensive) at that time on the system. These are the system marginal plant, for that particular time of day will set the price of electricity (i.e. acting as price makers) and all other plant on the system will be price takers. A way of ranking the relative cost of the different generation plant is given by the merit order[32]. The merit order is a way of ranking available sources of energy, especially electrical generation, in ascending order of their SRMC of production, so that those with the lowest marginal costs are the first ones to be brought online to meet demand, and the plants with the highest marginal costs are the last to be brought on line.

Short-run marginal costs include all the variable costs, including fuel costs, variable operating and maintenance costs, CO_2 and other environmental costs borne by electricity producers (Holland & Mansur, 2006). They exclude fixed costs such as capital depreciation and fixed operating and maintenance costs. Hence the lowest short run marginal costs plants are referred to as “baseload” generators, are usually high capital cost but low or zero fuel cost technologies such as nuclear and renewables. The newest and most efficient fossil fuel plants may also run “baseload”. Fuel price and plant efficiencies for the system marginal plant(s) determine the short run price of wholesale electricity. This also implies that fuel price volatility is reflected in the wholesale electricity prices and indeed fuel price increases are eventually passed through to consumers. Hence, to an extent, fossil fuel generators have a degree of natural “hedge” against fuel prices fluctuations because changes in fuel prices are reflected in changes to electricity prices.

[31] The term ‘producers’ is used in this paper to include electricity generators and parties with access to import and storage capacity, i.e. those parties that apply to supply energy on the day.

[32] The merit order was the method used in the electricity market of Great Britain when electrical power generation was the responsibility of a single integrated utility (the CEGB). After privatisation of the sector this was replaced by a more complex bidding system, the electricity pool, in 1990 (Helm & Powell, 1992)

However it should be emphasised that not all electricity is traded at spot price. Companies will often use a variety of trading activities and contract structure to help manage the price risks, including forward delivery and more complex financial derivative contracts. Some contracts can be as long as 15 years, set in a way which removes much of the price risk for the duration of the project. The reasons that long term fixed price contracts are rare appear complex, and not fully documented. Possible reasons include the attempt to free market participants from binding arrangements that could reduce liquidity at the time when the liberalisation package was implemented. Nevertheless the result is that significant long-run fuel price uncertainty is not usually hedged through contractual arrangements.

Another important source of electricity price risk results from the long run (years to decade) investment dynamics that arise in competitive electricity markets. These may tend toward a boom and bust cycle; hence price risks also came into play over longer timescales. In competitive markets, producers receive a signal to invest through the product price. When electricity supply is becoming tight relative to demand, and this reflects a shortage of generation capacity, prices should rise creating the incentive to invest in new capacity. Ford (1999) explains how risk-averse investors tend to wait until they are reasonably certain that they can make a profit. He also noted that investors tend to overreact , in part because they do not know their competitors' plan.

Since it takes several years to bring a new power plant on line, this process requires some judgement in advance of likely impending shortfalls in the market. The time lag between the investors' decision to build new generation capacity and the moment it goes on line is the main determinant for the creation of investment cycles.

As the investment environment becomes less predictable, long investment lead increases the uncertainty, especially with regard to future demand and operating costs. This aggravates the cyclical behaviour and causes investors to wait longer. Timing in the investment can be critical. Overcapacity could lead to periods of several years of low prices (close to short run marginal costs). These are too low to encourage new entry. As plant retire, demand increase or environmental legislation restrict obsolete plants' running hours, the market gradually becomes tighter until average prices "spike" up and above the threshold for new entry. At this point there might be a race to bring new plant on line to make the most of the higher prices, which once again causes a return to a period of low prices and low investment until the next price spike. Such pricing behaviour can be described as a dynamic equilibrium, as long as a sufficiently long time perspective is taken (Dixit & Pindyck, 1994). However this type of "herding behaviour" creates challenges both for companies and policy makers. Given these uncertainties, investors will require large discount rates, effectively driving average long-run prices higher than would be without this source of uncertainty. Finon et al (2004) questioned whether competitive markets will provide timely investment in new capacity.

Given the particular characteristics of electricity, capacity shortfalls can even lead to interruption as well as price spikes. The threat of these cycles also challenges policy makers, who may face political pressure due to consumer dissatisfaction with the price spikes, and/or in the face of perspective capacity shortages in future years. An expectation of policy intervention in the market may create additional uncertainty and in the long run create an extra barrier to investment (Robinson & Taylor, 1998).

Most electricity systems started liberalisation with ample capacity, so high prices have mostly not yet occurred[33]. This transition effects raises the appearance that the political promise at the outset of the liberalisation, that the same or better service would be provided at lower prices, indeed is being met. If, as happened in 2008 and previously in the California crisis, a period develops in which prices are many times higher than in the past, the consumer may consider this as a failure of the liberalisation and demand intervention, for instance by imposing a lower price cap. This happened during the California crisis, where even a brief period of high prices proved to be unacceptable by consumers (Liedtke, 2000).

The political risk associated with extremely high prices, whether these are economically efficient or not, means that there is a risk that the government intervenes and lowers the maximum price during a price spike. Hence price volatility itself brings about regulatory risk at least until sufficient experience has been gained with liberalised markets (Oren S., 2000; Newebery, 2001).

At a time of low demand (D1), or excessive generation, the market clears close to the SRMC of the marginal supply. However, at the higher demand level, D2, the market is less well supplied and producers increase their offers above their SRMCs, and the market price reflects a degree of scarcity pricing. There are two reasons why producers may increase their offers:

[33] Although in 2008 there was a steady increase in electricity prices in most countries and in particular the UK.

Recovery of fixed costs. Producers need to be able to recover their fixed costs and earn a return on equity otherwise they would close their asset or not invest in the first place. If infra-marginal rents are insufficient in this respect, and provided competitors are in similar positions, producers should be able to price up during periods of scarcity. In an over-supplied market this would not be the case (Bushnell, 2005).

Pricing in risk premia. In selling forward, producers are at risk of a failure in their asset and having to buy replacement energy in the very short term to meet their contractual obligations. As the supply curve steepens with a tightening market, the expected cost of replacement energy increases (possibly sharply), increasing the risk premium they require in order to sell forward.

A third reason why producers might be able to increase prices is that they are able to exercise market power due to the inelasticity of demand (this issue will only be discussed briefly in this thesis[34]).

Investments in electricity and gas markets are driven by the expectation of positive earnings across the economic lifetime of the asset (which may be twenty years or more). The investment case may be made on the expectation that the costs of the asset are lower than the marginal (market price setting) sources of supply, i.e. it can generate 'infra-marginal' rent even in a well-supplied market, and/or on an expectation of scarcity i.e. that prices will rise due to a shortage of supply to meet demand.

However is important to note that many other factors may enter the picture and in this way influence the way investors perceive the opportunity/risk balance when planning a new investment. Some of them are illustrated below to provide a comprehensive picture of the recent dynamics in energy markets.

[34] For a review of the argument see Joskow, P. L. and J. Tirole (2000).

1.3.4. Market failures.

The British market provided evidence that they have broadly worked to date in delivering physical security of supply. Price volatility could be an indication that the market is not functioning well. This, and other potential obstacles to a well functioning market, will be discussed in this section.

The main characteristics of the electricity market[35] normally produce highly volatile prices and a chance that the market does not clear. In these circumstances, when demand and supply functions do not intercept, the only way to keep the system physically stable is to impose random service interruptions. In this situation the market price is undetermined in theory, which in practice means that sellers have unlimited market power.

Exploitation of market power

The potential for exploitation of market power in the electricity and gas sectors has been an issue of concern to regulators since the markets first began to be deregulated in the 1980s. Certain characteristics of electricity markets in particular, such as limited storability, a lack of available substitutes, very low short-run elasticity of demand, and (at times) the existence of transmission- related constraints, may make electricity markets particularly susceptible to the potential exploitation of market power by generators. This market power may often be transient or intermittent in nature[36], but in any case, because of the limited scope for demand-side adjustment to short-term price changes, it can result in very high costs to consumers and/or competitors during the periods when it is unduly exploited. That is, the lack of price elasticity in electricity markets (and to a lesser extent in gas markets) means that the demand curve in the very near term is almost vertical (i.e. consumers are likely to continue to consume at the same level irrespective of the prices). This reflects not only consumer behaviour, but also limitations in current metering technology and the settlement rules whereby not all customers will change their behaviour in response to price signals since they are not exposed to them and hence have no incentive to do so.

[35] Non-storability, the presence of a price inelastic section in the supply curve, and the inelasticity of the (observed) demand.

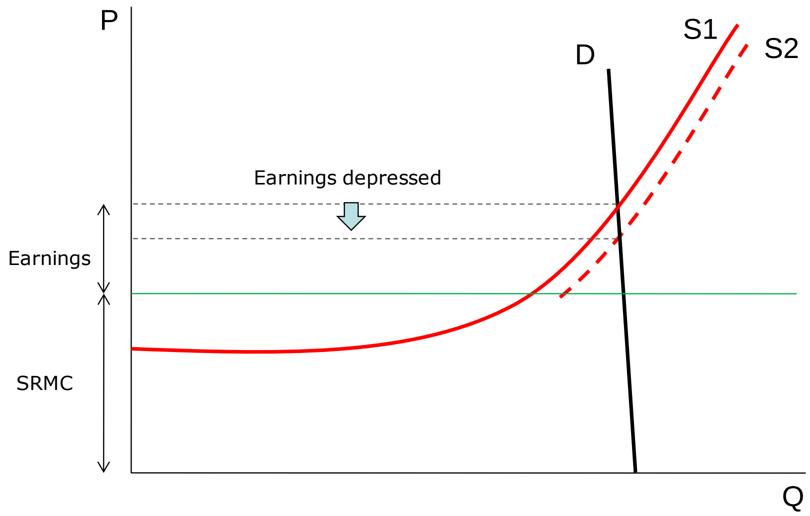
[36] A recent enquiry of DG Competition has revealed that the electricity market in several countries in Europe suffers a number of market imperfections (vertical integration, lack of access to infrastructure). The prime concerns regard an excess of market concentration in most national markets, a lack of liquidity, preventing successful new entry, too little integration between Member States' markets, an absence of transparently available market information and a distrust in the pricing mechanisms. The report is available on the Commission's web site: http://ec.europa.eu/competition/sectors/energy/inquiry/index.html

Furthermore, the system operator (SO) must keep the electricity system in balance on a minute-by-minute basis, which means that it is often buying power on behalf of customers/suppliers over a very short time period where no effective demand side response is feasible. Due to the long lead times associated with new entry in the generation sector and with the expansion of the transmission network, market power may not be eroded over time (and certainly not in the short to medium term) through increased competition as quickly as would occur in other markets. The inelasticity of demand means that prices can rise sharply, and this can create opportunities to exploit market power. However, as discussed above, price spikes play an important role in delivering security of supply. Without them, producers may be unable to cover their fixed costs and earn a return on capital[37]. Differentiating 'legitimate' scarcity pricing from exploitation of market power can create significant challenges for regulators, and in some jurisdictions, the challenge has been avoided by implementing price caps and separate mechanisms for rewarding capacity in their electricity markets. An example of exploitation of market power might be withholding capacity in the short-term market (where there is no technical justification for doing so), or delaying future investment to hold up or increase prices. A recurrent paradox facing incumbents is that if they invest in additional capacity they may depress their own profit margins. For example, an investment in a peaking plant might erode the scarcity rents that it is seeking to capture. As a result, incumbents have little incentive to invest in spare capacity and private investment will always fall short of the optimal social level[38]. This is illustrated by figure 3 below. By increasing supply (from S1 to S2) with its investment, prices may fall and this could reduce the expected earnings of the investment and across the company's portfolio.

[37] Baseload investors may also require price spikes since the infra-marginal rents earned, the difference between the cost of the marginal supply and their own short run costs, may be insufficient to meet the required return on equity.

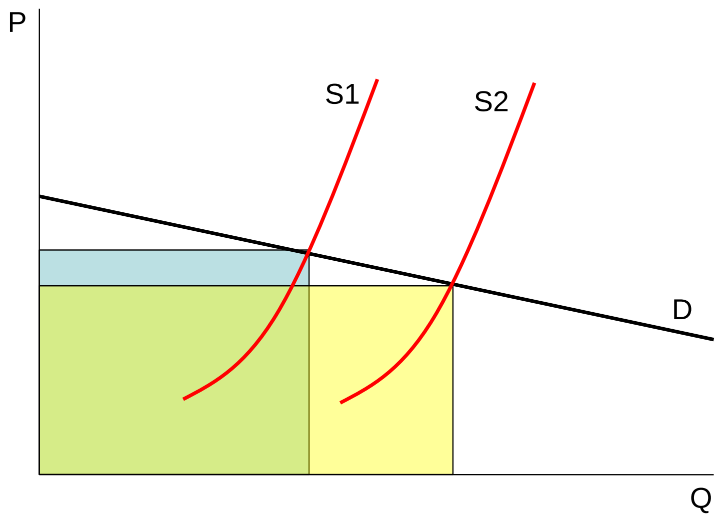
[38] Reliability is indeed a public good. Due to the random nature of service interruptions, the reliability of electric service is non-excludable and non-rival, also to the extent that it is a function of generating capacity. Since the reliability is the same for everyone on the network, consumers are not able to contract individually for a higher level of reliability. Therefore they have no incentive to pay generating companies for generating capacity which improves reliability, but only for the electricity that they consume. This means that liberalised electricity markets will tend towards an equilibrium volume of installed generating capacity which is lower than the social optimum.

Figure 3 .- Investment dynamic and prices.



However, if the market is competitive it should still be profitable for the incumbent to invest if it can increase market share at the expense of its competitors since it is better off making the investment itself, even if it depresses prices, than allowing a competitor to build first and take the market share (while equally depressing prices). This is illustrated by the company's own supply and demand curves shown below (figure 4). Here the demand curve represents the market. As the company increases its supply it depresses prices. (In a perfectly competitive market the demand curve would be flat and the company would be a pure price taker and unable to move the market.)

Figure 4.- Investment timing and prices in competitive markets



In this example the blue box represents the company's revenues prior to the investment, and the yellow box its revenues after the investment – the price has dropped but the quantity has increased. If the expected increase in revenues (the difference in size of the yellow and blue boxes) is sufficient to cover the cost of the investment then it is profitable for the company to proceed even if this results in lower prices (and the company would be worse off if another player had built the capacity and it was unable to offset the effect of falling prices by expanding market share).

Furthermore, the company may be able to protect itself from lower future prices by contracting its output in advance. There should be willing buyers since without the investment prices would rise much higher.

The argument that incumbents are not actively competing for market share against each other and/or entry is restricted only holds over the longer term. There is no strong evidence in the UK electricity (and gas markets) to suggest that this has generally been the case. Furthermore, future developments in technology that should improve the responsiveness of the demand side, such as smart meters and smart appliances, will reduce the potential for exploitation of short-term market power by producers.

Anyway there may be some instances where regulators need to intervene to protect consumers, and other market players, from the exploitation of market power. If there is inadequate demand side response, there is a risk that generators exploit short term market power by pushing prices up at times of system stress beyond the level that some consumers would be willing to pay. Another relevant example here might be the exploitation of locational market power whereby a producer may be able to withhold capacity and/or push up prices with no risk of eliciting a response from the demand side which is not exposed to the locational price signals (and hence by definition is price inelastic). The risk increases where there is little prospect of entry and greater competition from the supply side.

Cyclical investment and wholesale price volatility

Notwithstanding the fact that in a competitive market there should be no incentive to withhold investment, the size of certain investments means that a degree of cyclicity is likely, as the evidence from the UK market to date bears out. Investments such as interconnectors, LNG terminals and storage whose values are driven by price spreads have the ability, given their size relative to the market, to move prices significantly. Hence, investments may not be made immediately even if the short-term market signals suggest they should[39].

In order to proceed with the project, an investor needs to be able to sell capacity forward to buyers who foresee potential future scarcity, so that their earnings are locked in (at least partially) even if price spreads subsequently fall. A hiatus in investment might follow a new build as some players[40] may be able to benefit from reduced spreads in the spot market as supply expands. However, if no-one acted to underpin the investment, for instance in gas pipelines, the new infrastructure would not have been built in the first place and all parties (that were short of gas in the UK) would suffer from the higher spreads. The cycle then repeats as the expectation of future scarcity grows again, and there will be companies willing to contract with investors for new import infrastructure.

As a result, prices might fluctuate above new entry costs and fall below new entry costs either side of major investments. However, this is arguably a market feature rather than a failing of the market. Where it could become a problem is if the cycles become amplified due to exploitation of market power or risk aversion such as that which may result from the credit crisis. This point is discussed further below.

Lack of liquidity in wholesale and financial markets

As discussed above, having the means to manage risk and stabilise earnings volatility are critical to being able to finance the large scale investments required in electricity and gas supply. Without sufficient tools to manage or mitigate the risks, the cost of capital may increase to the point where investment can only proceed, if it all, when prices are already signalling a security of supply problem. This is because the riskier the project, the harder it is to raise debt, requiring a greater proportion of equity which is typically more expensive.

The introduction of retail competition into the electricity changed the risk landscape for energy suppliers. They could no longer pass on the risk of their investment decisions to a captive customer base, and hence were less willing to enter into long term power purchase and gas supply agreements with generators/producers which could be used to underwrite

[39] This would not be a problem if investment sizes were small since they would have little effect on market price
[40] Sometimes referred to as free-riders

investments. Some commentators, notably Helm (Helm & Powell, 1992), believe that this is a market failure and call for the re-franchising of retail businesses.

However, the markets have found ways of managing price risk. For example, forward markets have developed although liquidity has been quite low, particularly in electricity. Some investments have taken place on a 'merchant' basis without long term contract cover, more notably in gas where liquidity is better. In comparison, in the oil market with a very liquid global forward market (with maturities up to 7 years out) it is common for upstream investments to take place without long term contracts in place.

Vertical integration has been both a cause of, and a market response to, low forward liquidity, with companies looking to use a relatively 'sticky' mass market customer base as a hedge (albeit only partial) to support upstream investments. Price risk can be reduced but not eliminated with this strategy. Strong balance sheets have allowed utilities to fund these investments, and enter into long term agreements with independent producers, where the residual price risk would make financially leveraging projects difficult.

Investment has been able to proceed on this basis in the UK. The concern now is that the credit crisis is further restricting wholesale as well as financial liquidity, reducing the availability and increasing the cost of tools to manage risk, whilst increasing the risk aversion of investors and lenders. This is a potential threat to security of supply which is discussed below.

Incorrect pricing of reserve and firm load disconnection

As mentioned above, the demand for electricity is very volatile. Spare production/supply capacity is required to cover the variations in consumers' requirements driven by the combination of limited storage and weak demand side response to price variations. Since electricity cannot easily be stored, a certain minimum level of reserve must be held on the system at all times. Reserve is also required to cover unexpected failures in supply.

It is the role of the System Operator (SO) to provide this reserve (or linepack and operating margins in the case of gas), and to act as balancer of last resort. It also has the responsibility of ensuring that the system is balanced at each point on the network, whereas market players are only incentivised to balance at the national level.

The actions of the SO have an important impact on the market. The use of reserve (and linepack/operating margins in gas) act a buffer on the system, and are to an extent a surrogate for short term demand side response, yet the true cost of this energy may not be reflected in the market price. Without the deployment of reserve, prices might have risen much higher. Furthermore, the SO may have access to 'free options'[41] such as voltage control and firm load disconnection, when the true value of energy should be the value of lost load. Whilst potentially countering short-term market power, this dampening of price spikes may reduce the incentives on suppliers to contract sufficiently to cover their peak positions. In other words, the actions of the SO may prevent the market from clearing at the true market value of energy, and ultimately lead to insufficient investment in peaking capacity.

Pricing of unforeseen outcomes

The recent financial crisis has demonstrated the impact that unforeseen events can have on the market. The risk management practices of many banks did not appear to cater for the outcomes that have since transpired, and several banks had insufficient reserve capital to cover the losses incurred. In the absence of government intervention, this could have led to a systematic failure of the global banking system. This suggests historical market behaviour was relied upon too heavily to assess future risks, and insufficient emphasis was placed on stress testing. The implication is that risk was being underpriced in the market.

The question is whether the same could happen in the energy markets. In the financial sector, the underpricing of risk may lead to insufficient reserve capital; in the energy sector it may lead to insufficient capacity or contracted supplies. The parallels are not exact since a systematic failure in the energy markets, which are predominantly physical, is unlikely. However, the risk management practices of energy companies may not be geared up to deal with low probability/high impact events.

Policy risk

Electricity and gas are strategic industries and hence are historically subject to high degrees of policy intervention. Arguably, liberalisation has resulted in significantly less government involvement in the sector. However, the need to impose environmental targets may reverse

[41] These options are free because there is no market price for them, but they do have costs for the system.

this trend. This introduces a high degree of policy risk. There is a basic tension between investors wanting certainty and policy makers (at the national and EU levels) wanting to retain flexibility in light of uncertainties surrounding the costs and potential of different low carbon technologies. Ultimately policies should be about balancing the risk of the costs of achieving environmental objectives between investors and consumers.

However, policy uncertainty either encourages investors to adopt a "wait and see" strategy or increases the risk premia they require on their investments. Both can increase costs for consumers by pushing up market prices. At the same time environmental policies may require additional investments to meet tighter standards, or for some capacity to close.

The problem is particularly acute for investments such as nuclear, carbon capture and storage (CCS) and renewables that rely not on a tangible commodity that consumers need (energy), but on markets created by government to reflect benefits to society (carbon reduction). However, it also affects investment in other technologies whose earnings will be impacted by the share of the market captured by low carbon technologies and their impact on wholesale prices.

Policy risk presents a potential risk to security of supply in the UK markets. The UK has committed itself to delivering 15% of its primary energy needs from renewable sources by 2020, and the Government has accepted the recommendations of the Committee on Climate Change that greenhouse gas emissions should be cut by 80% from 1990 levels by 2050, with interim carbon budgets. The possible implications of these policies on security of supply are discussed below.

Regulatory risk

Regulatory risk is another key feature of electricity and gas markets. We have explained how policies intervention may cause prices in electricity not to rise high enough to support new investments, particularly because regulators will be unwilling to allow prices to spike during periods of system tightness due to concerns surrounding market power. This is the second cause of the missing money problem (the incorrect pricing of reserve being the other) identified above.

Aside from these more direct interventions, potential earnings can be affected by other future decisions by regulators, for example changes to the basis for charging for or allocating transmission capacity or changes to trading arrangements.

Investors are looking for certainty. In markets where regulatory risk is deemed to be high, this may increase the risk premium on investments.

Regulators have to strike a balance between sufficiently addressing market power concerns and improving the efficiency of the market arrangements, versus maintaining investor confidence.

There is little evidence to suggest that regulatory risk has deterred investment in UK markets. Ofgem has consistently highlighted the need for prices to spike to incentivise suppliers to contract to cover peak positions against which generators can invest in peaking capacity. However, future regulatory risk could be a concern when coupled with climate change and policy risk.

Information failures

Companies may not have sufficient information to be able to make investment decisions. This may be because the information does not yet exist, for example awaiting a major policy decision, or that the best information is only available to certain players, such as incumbents or the SO. Information risk is not unique to electricity and gas markets, but the problems arising from it may be more acute due to the highly technical nature of the physical delivery of energy.

Like policy and regulatory risk, information risk encourages wait-and-see behaviour. It can be mitigated, although never completely eliminated, through greater efforts to disseminate information to potential investors. Initiatives such the Energy Markets Outlook act to improve information for market players, and reduce the risk of information failures in the market.

External constraints

Another significant feature of electricity markets is the importance of the transmission networks. To connect new sources of supply requires sufficient transmission capacity to transport the energy to customers. This requires co-ordination between the investor, typically a non-regulated commercial enterprise, and the transmission operator, which is a regulated business. Provided incentives on network investment are appropriate, and investors in energy supply are confident that they can be connected in a timely fashion, this particular feature of electricity and gas markets should not in itself present a barrier to security of supply.

A key objective of the Transmission Access Review is to ensure timely connections and efficient utilisation of the transmission network. It is hoped that this will accelerate the connection of renewables projects in Scotland and Wales. However the five-year connection time for a conventional plant, even in non-constrained parts of the network, could become the rate limiting factor for new investment.

Another potential barrier to new investment is obtaining planning consent. Initiatives proposed under the Planning Bill are designed to speed up the process and therefore reduce the risk to security of supply.

Different social value of security of supply

The optimal level of security of supply has been described as the level where customers would rather accept the risk of a shortage than spend more money to reduce it further. However, due to a number of externalities, the value that private customers place on supply security may differ from that of wider society. Examples of such externalities are the safety risks associated with a major failure of the gas network, or permanent economic damage caused by widespread energy shortages. These externalities may not be reflected in energy market prices. As a result, it should be concluded that capacity to produce and deliver energy is a public good and that the market cannot be relied upon to deliver the socially optimal level of security of supply.

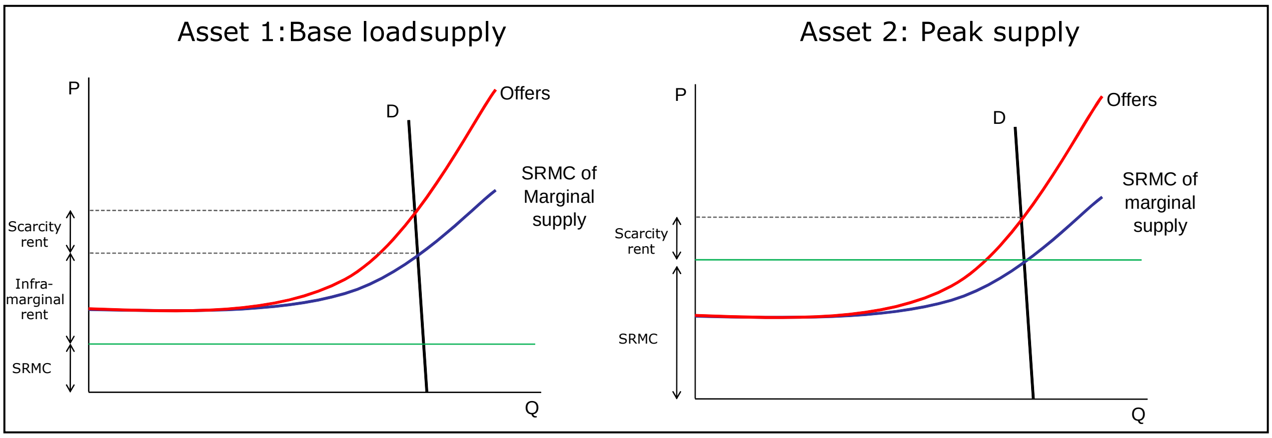
In reality it is complex to define and measure the socially optimal level of security of supply. Hence, it is difficult to judge whether the markets have delivered this to date, or to design appropriate interventions to achieve it

1.4.Price dynamics in liberalised markets.

After a review of the risk factors that influence market behaviors, an overview of the price dynamics that should guarantee, in a liberalized market, the efficient level of investments is provided here. The typical behavior of a base load supply unit and a peal supply unit will be described.

The earnings potential for two different types of asset for a particular period depend on their SRMC. On the left, Asset 1 has low short run costs (shown as the green line) and expects to produce at a high utilisation ("baseload"). The asset earns infra-marginal rent by having production costs less than the marginal supply, and when demand is sufficiently high will earn an additional scarcity rent, although it may or may not require these additional earnings to make the investment economic. Asset 2 on the right has high short runs costs and only produces infrequently when demand is high (peaking). Since it is the marginal source of supply it earns no infra-marginal rent, and relies on its ability to increase its offer price to generate scarcity rents.

Fig.5 Marginal and infra-marginal revenues.



Future earnings for both assets are uncertain. The infra-marginal rent earned by Asset 1 will depend on its production costs relative to those of the marginal supply, both of which may fluctuate. The scarcity rents will reflect the overall supply/demand balance, and because investments tend to be lumpy with long lead times, often with complex planning and regulatory requirements, there will inevitably be variations in supply margins driving variations in scarcity rents.

As a result, investments, particularly in peaking assets which rely solely on scarcity rents, may have their earnings concentrated into periods of high prices, interspersed with periods where they may only able to cover their short run costs[42]. It is important to note that scarcity rents may not need to be able to provide a return on equity, since peaking assets may already be fully written down. Hence, provided they can cover their annual fixed costs they should remain open. In the electricity market the normal cycle of investment is for new entry at baseload, and this typically more efficient plant displaces a less efficient plant which then runs at progressively lower load factors until it becomes peaking. Hence, price signals to keep assets open may be as, if not more, important as signals to build new assets.

Electricity and gas production and supply are capital intensive businesses – for example, a 800 MW combined cycle gas turbine plant costs around £500Mln., 1600 MW new nuclear plant around £3bn[43]. To make investments of this scale, and to raise the necessary finance, producers need to be able to manage the price risk associated with spot market volatility. They can achieve this in a number of ways: by entering into long-term contracts with suppliers or directly with customers, through trading in the forward markets, or possibly by a strategy of vertical integration whereby they can 'internalise' the price risk within the business. From the example above, Asset 1 may seek to sell its output under a long term agreement to fix its earnings and Asset 2 may be able to sell a peak price option, effectively forsaking earnings from future price spikes in return for an upfront premium. A willing buyer for such a product might be a supplier looking to hedge the risk of price spikes. By entering into such agreements companies set a forward price for energy which provides important signals for investment. Where the market expects production costs or scarcity to increase in the future the forward price rises, and vice versa.

If the markets are operating efficiently, players should be able to arbitrage any systematic differences between short term and long term prices, meaning that there should be a close relationship between prices across all time horizons. Hence, short-term signals in cash-out should be reflected through the spot and forward markets, and provide longer term signals for investment (Glachant & Saguan, 2007). Any differences between the average spot and longer term prices reflect the risk premium associated with contracting forward, which can be

[42] Earnings volatility is also a feature of other capital intensive industries such as oil production and refining, and mining.
[43] For a review of the Investment costs and options "Dynamics of GB Electricity Generation Investment" Summary Report (2006)

positive or negative depending on future expectations of market tightness. If the market is expected to be short, then producers are in a stronger position and can charge an additional risk premium, whereas if the markets are expected to be long, suppliers may be able to demand a discount. The relationship between risk premia and market tightness may not be symmetrical since the distribution of spot prices tends not be normal, but skewed toward higher prices – prices tend to jump up more than they jump down[44]. Figure 6 summarises how an efficiently functioning market provides the signals for different players to take actions that impact on supply adequacy over different timeframes, from investing in long term capacity on the right to real-time balancing on the left.

[44] This is true because plants are subject to unplanned failures.

1.5.Investment signals before liberalisation.

The existence of the externalities/imperfections described in the section (above) is not denied when policy makers set artificially the electricity price at time when there is supply scarcity. The optimal level of generation adequacy is achieved when customers would rather accept the risk of a shortage than spend more money to reduce it further. This is when the expected cost to consumers of 'unserved energy' or 'lost load', the Value of Loss Load – VoLL[45] (Stoft, 2002), exactly matches the cost of the marginal unit of supply. It is a widespread assumption that electricity markets could deliver the optimal level of capacity for reliability if regulation only refrained from artificially imposing a cap on prices (Crampton & Stoft, 2006). When scarcity is signalled by sufficiently high price spikes, it is generally accepted that efficient markets should provide sufficient investment incentives, at VoLL. Stoft (2002) shows that in a competitive market, a price cap set at VoLL provides an optimal level of investment in generating capacity, with an efficient duration of power interruptions (De Vries L., 2003). Also in a market with these features and with fully inelastic demand, where prices are revealed ex post, spot pricing for electricity is viable. However, in this case rolling black outs[46] (RBO), as explained by Neuhoff et al., (2004) at time when there is scarcity and the price has hitten the price cap, will cause inefficiencies, because consumers' preferences are not homogenous, and a non price instrument (such as a rotataing power cut) can have an inferior rank in the scale of preferences of some consumers, that will not be able to opt for higher peak price rather than disconnection.

However, this is not a failure that is simply related to the liberalisation process in the electricity sector. In fact, even a public enterprise with a perfectly rational and omniscient regulator would face the same dilemma[47] of setting the VoLL at the right level, a nearly impossible task, that in addition to the problems listed above, exposes generation to an even

[45] Joskow and Tirole (2004) provide a tractable definition of VoLL depending on the type of shortages (anticipated or not).

[46]Rolling black-outs are conceptually different to a total system collapse. During RBO the System Operator sequentially sheds relatively small fractions of total demand to match available supplies in a controlled fashion, while during a system collapse (black-out) both demand and generation shuts down over a large area in an uncontrolled fashion. During a rolling blackout, available generation is extremely valuable (its value is VoLL), while available plants are almost valueless when the system collapses.

[47] Joskow (1976) provides a survey of marginal cost pricing by regulated utilities and Chao (1983) shows the joint impact of uncertainty about demand and supply.

greater price risk in real time. Moreover, generous price caps might encourage generators to withhold supply to create shortages, at the expense of system reliability.

Under the electricity pool in England and Wales (up to 2001), the wholesale market provided for capacity payments to be paid to all generators scheduled to supply during hours when supply was unusually tight (i.e. when the Loss of Load Probability –LoLP- was relatively high[48]). Also other countries relied on capacity payment[49] to stimulate investment. Conversely the wholesale market in England and Wales under the New Electricity Trading Arrangements (NETA) after 2001 abandoned the capacity payment; because of the possible exercise of market power and Texas had never had capacity payment and/or obligations.

Before the liberalisation of electricity markets, the security of electricity supply was generally enforced by a single electric utility, vertically integrated, and controlled by public authorities. The mission of this company was to build and maintain an electric system able to meet consumer demand, and to operate it safely. The single electricity utility was a service provider able to guarantee the sequence of product and the combination of goods necessary to deliver electric power to the final consumer. In order to do so, the electricity industry, normally via a vertically integrated monopolist, had to determine the level of investments in production capacity, that was established by comparing the investment cost of the potential capacity expansion plan to the savings that this new capacity would guarantee in the total production cost （Finon et al., 2008）.

However, since consumers' demand and the availability of generation units are subject to stochastic fluctuation, and can only be known exactly close to real time, there is always some probability, greater than zero, the demand could exceed aggregate supply. As a consequence, the electric utility and public authorities had to agree on a reasonable limit, that should set the threshold between an investment necessary to guarantee the desired level of security of supply and an unfeasible investment, proven to be too costly for the guarantee of consumers' security of supply.

[48] Pool price was the sum of the expected value of two possible outcomes: a) demand met, and b) demand not met. When there was a constraint instruction, a correspondent value of $LoLP \neq 0$ entered the following calculation:

$$\text{Pool Purchase Price (PPP)} = \text{SMP} + \text{LoLP} *(\text{VoLL-SMP})$$

The second term on the RHS of the equation above represented the capacity payment, and was the difference between the market price and the regulated VoLL. VoLL was set at £2000 in 1990, and adjusted by the regulator each year. This payment mechanism was dropped in 2001 when the New Electricity Trade Arrangements (NETA) system was introduced.

[49] California, Argentina, Chile and Colombia (see Joskow 2006).

This reasonable limit, also defined as "investment criteria"[50], could take various forms. The investment criteria can be explicitly defined as a unique VoLL for consumers. The electricity utility would then design its capacity expansion plan such that on average (i.e. given a set of demand and production availability scenarios) the last megawatt hour produced by the electric system would cost as much as the VoLL. In practice, the VoLL criterion was translated into a number of hours of power interruption (loss of load expectation)[51]. In other cases the Transmission System Operator (TSO) is obliged to maintain a minimum level of capacity margin. Though investment criteria can take various forms, it is still possible to find some equivalence: for instance, given the shape of the demand curve, and the capacities in each generation technology, it is possible to calculate a capacity margin percentage in terms of a unique loss of load expectation.

The general reform that has affected the network industries since the beginning of the 1980s, attempting to transform vertically integrated monopolies into network industries characterised by competitive markets (telecom, railways, airlines) affected also the electric power sector and led to the liberalisation of electricity markets, adopted through European Directives 1996/92/EC and 2003/54/EC. The liberalisation has separated the missions of security of supply, and allocated them to different entities. Investment planning in production capacity is taken care of by electricity producers. This activity is no longer regulated by public authorities. Investment planning in transmission capacity is taken care of by the transmission owner, whereas the system operator is in charge of operating the electric system. In most systems, the transmission owner and the system operator are the same regulated entity (the UK being one exception in Europe).

Thus today investment decisions in production capacity are made by several operators, independently. An operator will decide to invest if the investment is expected to improve the profits of the operator's portfolio. In other words, there is no coordination between companies to reach the optimal capacity expansion plan collectively, as defined by the former public utility's methodology. Yet, according to the theoretical economics of electricity markets, the investments decided by the competing electricity producers should be equivalent to the investments of a public monopoly which tries to maximize the entire society's welfare. However, in both situations, the true maximization of the society's welfare can only be

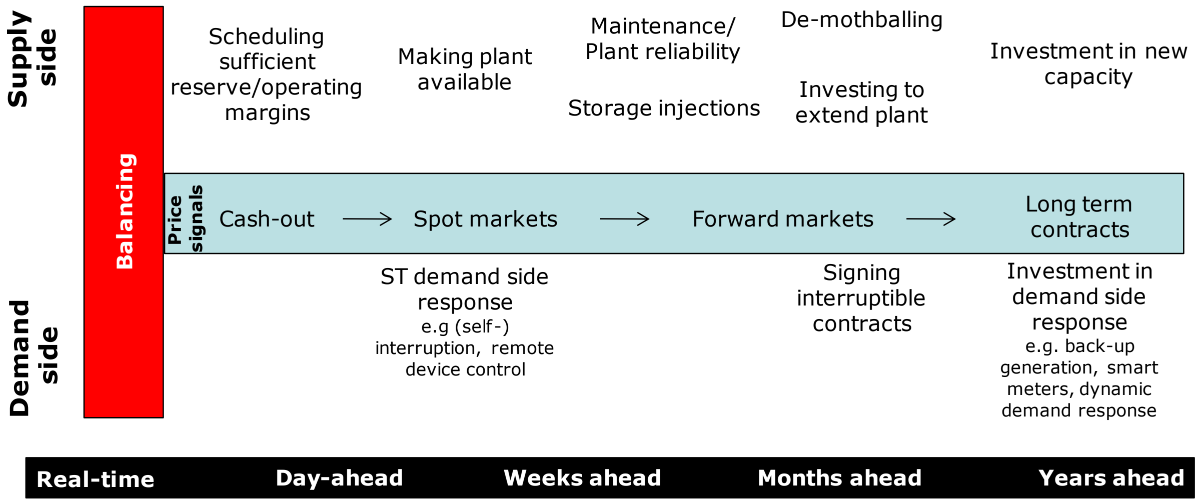
[50] See Finon et al., 2008
[51] This is the case of France (Pignon et al., 2007).

reached if consumers' true willingness to pay for electricity in periods of scarcity is known (Joskow and Tirole, 2007).

In fact the way the VoLL parameters are set is crucial to determine the adequacy of the system. If the price cap is set on the basis of market power concerns, operating reserve limits are based on security criteria—not adequacy, and other key procedures, such as out of market purchases, are often not set at all. Together these parameters and procedures determine the scarcity price distribution that makes or breaks the profitability of investment. Were they to be set generously, the market would over invest. Set as they typically are, investors back away from the adequate level of capacity. Investors are fully aware of this link, but it is consistently ignored in the process of market design. The consequence is a chaotic solution to the resource adequacy problem and a nearly inevitable bias towards under-investment.

As seen above, price uncertainty is not the only factor affecting investment dynamics; other risks, linked to regulatory uncertainty, enter the picture. A few of them (regulatory hold up, regulatory intervention during a shortage, price cap) have been analysed in the section above. These factors should be taken into consideration when investment decisions are considered. While electricity price uncertainty is reflected, though imperfectly, in a sequence of markets that together comprise what is called "the electricity wholesale market", other sources of uncertainty need to be explicitly taken into consideration from investors. Ways of doing this will be explored in the remainder of the thesis.

Fig.6 - Ideal Market signal and investment dynamic



2. Real Option Analysis applied to electricity markets

2.1. How to address risk?

Electricity markets in the future will call for additional, and an incrementally higher quantity of electric power, but produced generating fewer greenhouse gas emissions. These objective need to be satisfied at the same time and against a background of increasing global competition. Abundant energy with low (or no) CO2 emission are the main drivers of future market developments. How these needs will combine in energy markets?

Providing for the necessary power generation (that is forecast to amount to 11 trillion USD up to 2030[52]) will need timely investment, which responds to market signals. In addition, investments will need to promote the development of affordable new technologies and also have a reduced carbon footprint. There is a radical uncertainty as to the level and quality of investment that will be finally made.

The International Energy Agency (IEA, 2007) has correctly pointed out that factors affecting energy invetsment also include national economy, government policies and regulation, the energy markets, technological advances, as well as operations and the maintenance of new technologies. All these factors (in addition to those explained in section 1.3.4.) have significant impact when it comes to evaluating the risk attached to each portfolio of power investors.

In particular the erratic development of global energy markets, coupled with increasingly unpredictable energy policies and government environmental policies are making the cash inflow of an energy investment project progressively less certain.

It is crucial, therefore, to design a combined quantitative evaluation of the impact of energy market uncertainty and policy uncertainty together with an applied empirical analysis in order to have an indication of the qualitative and quantitative policy uncertainty and its impact on investment behaviour.

The potential feedback of business to policy risk is a relevant interaction to explore, and it is in particular important for the assessment of the effectiveness of both climate and energy policy. The analysis proposed here and that will be undertaken of the impact of energy policy

[52]IEA World Energy Outlook 2006 – Reference Scenario

on investment decisions, applied to the UK electricity market, suggests that in most cases business decision will be different under condition of policy uncertainty and that therefore policies may need to be designed differently or made more stringent than expected.

This section provides insight into investment behaviour in the power sector, the way such behaviour are affected by policy uncertainty and an estimate of the existing methodology for the evaluation of the impact of uncertainty on the investment environment, with a special emphasis on the Real Option Approach (ROA).

Project evaluation for investment was based on traditional methodologies, such as discounted cash flow[53] (DCF) that was widely used prior to the liberalisation process, also in consideration of the stable environment that power utilities were facing at that time. The purpose of the DCF calculation is to assess the financial inflow that an investment will generate, adjusted for the time value of the money. Various and different types of discount rate can be used, generally employing the appropriate weighted average cost of capital (WACC) that mirrors the risk attached to the cash flow, including a risk free rate and specific premium that depend on the particular industry (project) that needs to be financed.
This standard approach has shown to be increasingly unsatisfactory when dealing with management's flexibility to adapt to unexpected changes in market dynamics. DCF assume a passive management commitment to a certain static strategy. Donaldson and Lorsch (1983) revealed the increasing discrepancy between traditional finance theory and corporate reality. They confirmed that managers are willing to keep some operational flexibility also at the expense of some direct cash flow. This demonstrates that they consider keeping open strategic and managerial options just as valuable the direct cash flows.

It is now commonly accepted that traditional DCF techniques cannot fully quantify market and modern policy risks and uncertainties. The real options approach (ROA) offers a more credible tool to evaluate investment strategies. For example management may be able to defer, expand, abandon or alter a project at various stages of its useful operating life. When new information arrives and uncertainty over future cash flows and market conditions

[53]A financial method to evaluate an investment project. All future cash flows, estimated at the appropriate interest rate, including incoming and outgoing revenues, constitute the Net Present Value (NPV) of an investment that normally represents the value of the cash flow of the project evaluated.

decreases (or is eventually resolved) managers might want to keep the opportunity to react to the mutated circumstances and to capitalise on future opportunities.

Box 1 – The failure of Traditional Capital Budgeting

An example applied to the experimental application of Carbon Capture Storage (CCS) technology might clarify what could be the difficulties in treating with traditional tools (DCF) the existence of an option.

A power generation company is willing to evaluate the opportunity of an investment in a CCS facility that will allow a coal fired power plant to operate also under the LCPD and under the new more stringent emission limits related with Industrial Emission Directive [54].

The installation of the CCS equipment will allow the plant to operate at maximum capacity one year after the installation if the kit will lower emissions below the new (tighter) LCPD standards. Therefore the plant should normally be able to operate base-load generating a cash flow of £18m. (good conditions $V^{+}=18$), whereas if the retrofit is not able to reach the desired level of abatement the plant shall be only able to run limited number of hours[55] that will generate a cash flow of £6m. (bad conditions $V^{-}=6$). The two outcomes are possible with identical probability (q=0.5) given the fact that the CCS technology is still at its early stages. However, the British government, wishing to support the project, has offered to guarantee the investors by allowing a 1 year "emission restriction holiday" if the bad conditions occur, granting a 1 year contract that buys the base load generation however the experimental installation performs (full operating level) also if the bad conditions materialise (e.g. the plant in question also with the new retro-fit and CCS operates above the new emission limits).

[54] The Industrial Emissions Directive (IED) consolidates the Large Combustion Plant Directive (LCPD) – see note above - and six other industrial emission Directives in an effort to tighten the emissions limit and simplify regulation. As of May 2009, the IED is in the process of being finalised by the by the European Parliament and the Council of Ministers trough the co-decision procedure. The proposed implementation date of the IED is 1 January 2016.While the current environmental provisions will continue to apply, from 2016 the IED will toughen the constraint on emissions in three aspects: a) it applies to plant with a capacity more than 20MW; b) IED tightens NOx emission limits and c) it includes gas turbines licensed before 27 November 2002.

[55] The original proposal drafted by the Commission requires plants to comply with the NOX emission limits values (ELVs) from 2016 or close. Only limited derogations have been proposed for peak load plants in operation before 2016 that do not operate more that 1500 hour per year. In order to comply with the commission proposals all coal would be required to fit the Selective Catalytic Reduction (SCR) equipment at an estimated cost of £80/KW and £160/KW, close or apply for derogation. The choice that each affected plant makes will depend on the prevailing electricity and commodity market conditions at the time. In this thesis, an estimate has been made of the impact of the Commission's proposals on thermal generating capacity. In total 32 GW would be affected by the IED, of which 3963MW is expected to close.

In the absence of government guarantee the project's cash flow has an expected rate of return of (or risk adjusted discount rate) of *k*=20%, while the applied risk free rate in this example is *r*=8%. A calculation is provided here of the Present Value (PV) of this project V and the abandonment put option provided by the guarantee (P).

In this case the government guarantee is like a put option available to the generator allowing the company to receive the "guaranteed" 1 year contract worth £ 18m. In good condition the guarantee is worthless (P^+=0) whereas under the bad conditions it would be worth £ 12m (P^-= 18-6). If the DCF calculation is applied to the project without the guarantee there is:

$$V = \frac{E(C_1)}{1+k} = \frac{qV^+ + (1-q)V^-}{1+k} = \frac{0.5*18+0.5*6}{1+0.20} = 10 \qquad (1)$$

For the value of the project with the guarantee there is:

$$V^* = \frac{0.5*18+0.5*(6+12)}{1.20} = 15 \qquad (2)$$

So the value of the put option provided by the guarantee would be estimated as the difference of the project's value with and without the guarantee (V^*-V= 15-10=5). This calculation assumes that the payoff of the put option is subject to the same risk and therefore there will be applied the same discount factor. However, this assumption is misleading and plainly wrong, because the government guarantee will alter the risk of the project and, therefore, the applied discount rate. With the application of the guarantee the project is now riskless and the relevant discount factor should be *(r)*. The calculation of the V^* is then 18/1.08 =16.67. This means that the correct value of the guarantee is now 16.67-10= 6.67

The correct value of the option (abandonment put option) means that the adopted discount rate is -10% (because in this case the guarantee act as an hedge). This is consistent with the calculation:

$$V^* - V = \frac{0.5*0+0.5*12}{1+(-0.10)} = 6.67$$

This means that the DCF calculation underestimates the value of the guarantee offered by the government. The difficulty of determining the correct discount rate that should be applied is independent of the put exercise price (in this case V^+ =18).

This simple example illustrates how difficult is to determine the correct discount rate even where a simple abandonment option is involved. The failure of a traditional capital budgeting system is broader and goes beyond the well-known problem of managerial bias in forecasting cash flow; the DCF techniques have been shown to be likely to be biased against capital investments with operating and strategic adaptability. The DCF techniques were originally developed to value passive investments in bonds and stocks and allowed no flexibility to defer or otherwise alter the project. For a paradigmatic case in which DCF returned biased results see Bower (1970)[56].

The essence of the ROA is that many investments (and investment in power generation certainly) can be structured in terms of the options they create. For example, the opportunity to invest in a project or to expand the production facilities is like a call option on the investment opportunity. The option is exercised by making the investment expenditure. One key difference is that, unlike financial options, real options may not be proprietary so that its exercise may involve strategic pre-emptive motives.

2.2.ROA to investment planning

There are several types of real options that offer significant flexibility to the managers and allow them to operate capital-investment opportunity in an efficient way. Some of them are illustrated here with special reference to their application to power plant projects.

When an investor is evaluating the profitability and the risk related to the development of a power plant this normally requires, as for most investment projects, a series of outlays at different time stages.

Starting a project requires an initial investment linked to the preliminary study of the plant asset development, to determine the appropriate fuel source, to decide where the plant should

[56] There is an abundant literature on the shortfall of the adoption of DCF techniques in strategic planning. The classic references are Hayes and Abernathy (1980), Hayes and Garvin (1982), Kester (1984) and Myers (1987).

be located plus the expenses related to the administrative and authorisation procedure. Initiating the project therefore requires some preliminary costs *(l_1).* The actual construction will only start at a subsequent stage with additional outlays *(l_2)* linked to the building of the necessary facility. Generation can begin only when the construction phase is completed. The power plant is able to generate cash flow when the operating stage starts, following the final outlay *(l_3).* At each stage of the construction and operating phase the investor can exercise some options. For example he might decide, if market conditions deteriorate, to *defer the investment* (up year T_1). Or he might decide to *default during staged construction*. Conversely if market outlook is positive he might *expand the scale of the operations*. Other typical option include the possibility to *shut down for a period and restart operation* (mothball) when the market turns more favourable, and finally there is the option to *refurbish the plant* (normally making it compliant to stricter regulation). There are several categories of real options commonly applied to management's study. Based on Trigeorgis (2001, 1996), some examples of the options that can be encountered in various industries are presented below, with a particular focus on energy industry applications, showing schematically their implication for the flexibility (and value) of a project.

2.2.1. Option to Defer Investment

The initial outlay *(l_1)* enables the management to start some of the preliminary activities and in particular a detailed project assessment, that typically allows the gaining of a better oversight of the project details. In particular it will grant the ability to defer the investment for up to *n* years (depending on the particular investment and operations). Investors in this case benefit from the resolution of uncertainty about electricity prices, demand or crucial decision that affect the regulatory framework. Management will invest the outlay *(l_2)* (i.e. exercise its option to proceed with the project) only if the electricity price increase sufficiently, but will not commit to the project (thus saving the planned outlays) if prices decline.

Before the expiration of the authorisation window, the investment opportunity's value will be: $max(V-l_1,0)$. The option to defer is thus analogous to an American call option[57] on the gross

[57] An American (call or put) option may be exercised at any time up to the specified maturity. In contrast, a European option may be exercised only at maturity.

present value of the completed project's expected operating cash flow, *V*, with an exercise price equal to the required outlay, l_1. In this case early investment implies sacrificing the value of the option to wait, this option values loss is like an additional investment opportunity cost, justifying investment only if the value of the cash benefits, *V*, actually exceeds the required outlay by a substantial premium. The option to wait is particularly valuable in the energy industry because of the high uncertainties and the long investment horizons.

2.2.2. Option to Abandon Investment (during staged construction).

Investments in large and complex projects normally take place in a number of staged outlays that must be incurred over time. The fact that investments are phased creates an option to abandon the investment at each of the given stages. Therefore this can be seen as an opportunity (from the point of view of the investor) to value the instalment cost outlay (e.g. l_2) to proceed to the subsequent stage and can be valued as a compound option. This possibility is particularly valuable in highly uncertain, long development, capital-intensive industries (such as large generation plants in the energy industry).

2.2.3. Option to Expand

When energy prices or demand scenarios turn out more favourable than expected some projects might have the option to expand the scale of production (by *x* percent) by incurring a follow on cost (l_E). This is typically possible when the generation plant is composed of several units. The investment with such possibility can be viewed as the base scale project plus a call option on future investment [i.e. $V+max(xV-l_E, 0)$]. It is also possible that managers have opted deliberately for a more expensive technology that guarantees the possibility to expand when the market condition make this option valuable.

2.2.4. Option to Mothball

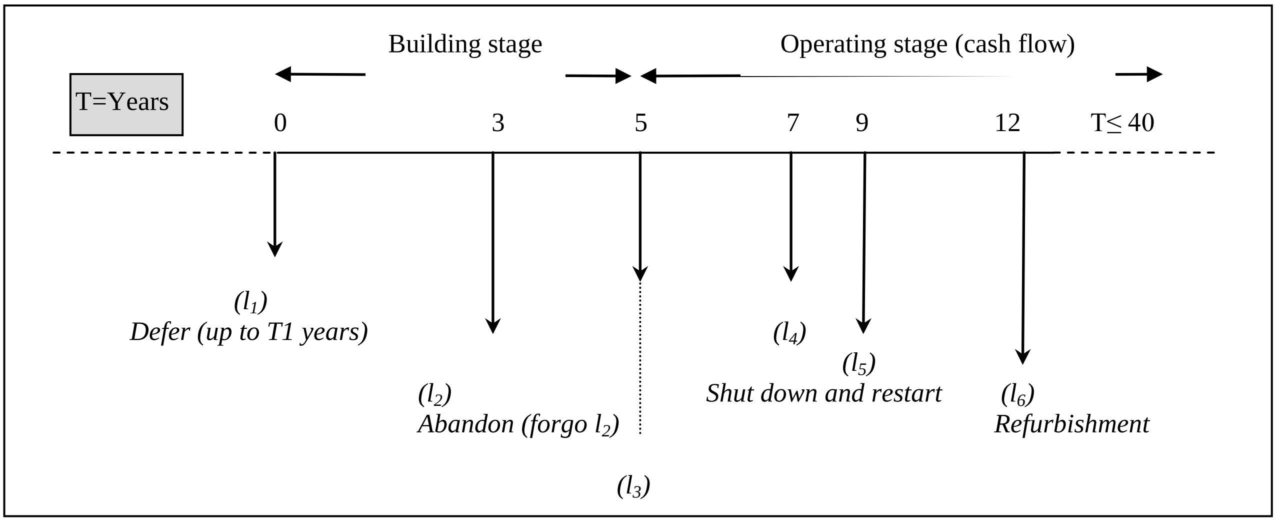
Energy generation plants after the investment takes place do not have to generate in each and every period, and under each and every market condition. In fact is often the case that when electricity prices and/or demand levels are not sufficient to cover the variable operating costs (e.g. maintenance), it might be better to suspend, temporarily, operations. This option is often exercised by plants with quite high short run marginal costs at time when demand is low for long periods (in summer for instance) and it is particularly true for plants where the costs of switching between the operating mode and idle mode are relatively small. Therefore operating the plant each year might be seen as a call option to acquire that year's cash revenues *(C)* by paying the variable cost of operating (l_V) as exercise price, i.e., $max\ (C- l_V,0)$.

2.2.5. Option to Refurbish the Plant

Stricter (or simply different) environmental regulation might require that generation plants need to be refurbished and/or be made compliant to different emission standards, at a later stage of their useful life. In particular is possible that the generation plant can be designed to apply different technologies and to convert to a higher standard of emission. This will be reflected in a upfront cost that is incurred at the outset and that a company is willing to pay for the implementation of such a flexible technology over the cost of a rigid alternative that confer no or less choice (positive premium). Process flexibility is valuable in feedstock dependent facilities such as oil, electric power and chemicals.

In the ROA evaluation provided in chapter 3 the option to expand the capacity basis and the option to defer an investment are studied, whereas in Rubino (2009) the study of the impact of the LCPD is based on the possibility (options) to refurbish and mothball generation plants.

Figure 7 – representation of a generic project requiring a series of outlays (l's) allowing the management the flexibility to defer, to abandon, to mothball, or to refurbish the investment.



2.3.Risk exposure of utilities in liberalised markets. Evaluation tools.

Before liberalisation, the vertically integrated utilities developed a mix of base, medium and peak load units and retained old units as reserve. Utilities, often state owned, were mostly concerned with system reliability, also because they could usually pass the costs on to consumers. In competitive markets, the only motive for investment is profit. Generating companies are no longer responsible for system reliability, also because nowadays utilities only see and serve part of the market. The question is whether in a competitive environment, market decisions that are optimal from the perspective of generating companies lead to an outcome that is desirable from the perspective of society. In this study what will be the likely outcome, in terms of generation portfolio, of different policy options.

Traditionally investment projects are evaluated with the Net Present Value (NPV) method (Ross, Westerfield, & Jaffe, 2002). It involves discounting the expected cash flows from a project at a discount rate that reflects the risk of those cash flows (using the risk adjusted discount rate). In this approach the adjustment for risk is made to the discount rate. An alternative approach is to make the adjustment for risk to the cash flows, and to discount the resulting certainty equivalent cash flows, instead of the expected cash flows, at the risk-free rate of interest. The NPV approach is usually employed in practice because it is normally easier to estimate the risk adjusted discount rate than the certainty-equivalent cash flows (Schwartz & Trigeorgis, 2004).

Many academics and practitioners now recognise that the NPV rule and other discounted cash flow (DCF) approaches to capital budgeting are inadequate in that they cannot properly capture management flexibility to adapt and revise later decisions in response to unexpected market developments. Traditional NPV makes implicit assumptions concerning an expected scenario of cash flows and presume management’s passive commitment to a certain strategy, so that the project is initiated immediately and is operated continuously at base scale until the end of its pre-specified expected useful life.

In the actual marketplace, characterised by change, uncertainty and competitive interactions, however, the realisation of cash flows will probably differ from what management expected initially. As new information arrives and uncertainty about market conditions and future (expected) cash flows is gradually resolved, management may have valuable flexibility to alter its operating strategy, in order to capitalise on favourable future opportunities or mitigate loss. For example management may be able to defer, expand, contract or abandon or otherwise alter a project at different stages during its useful operating life. Management's flexibility to adapt its future actions in response to altered future market conditions expands an investment opportunity's value by improving its upside potential and while limiting the downside losses relative to management's initial expectation under passive management. This asymmetry produces an expanded NPV made of the static NPV and the option value of operating strategic adaptability. This means that the traditional NPV should not be scrapped, but rather should be seen as a starting point for an option based, expanded NPV analysis.

This value is manifest as a collection of real options embedded in capital investment opportunities, having as an underlying asset the gross project value of expected operating cash flows. Many of these real options occur naturally (e.g. option to defer, abandon, shut down), while others may be planned and built-in at some extra costs (e.g. to expand capacity, to switch to a different technology -input and output-, to fit appliances to respond to regulatory requirements)

After the introduction of competition and the restructuring process in energy markets, there is a growing uncertainty surrounding the level and types of investments that will be made in the generation sector in the coming years, with implications for security of supply, carbon dioxide emissions and costs to consumers. As the uncertainty increases, the classical deterministic discounted cash flow modelling approach to capacity investment planning needs to be complemented by other methods in order to deal with potential fluctuation in demand and price trajectories (Dyner and Larsen, 2001). The real option approach (ROA) to investment decision planning provides an attractive opportunity to evaluate power generation investment alternatives in a deregulated market environment, also in consideration of the characteristics of most of these investments expenditures :

First the expenditure is largely irreversible, meaning that they are sunk costs that cannot be recovered. Second, the investments can be delayed, giving the firm an opportunity to wait for new information to arrive about prices, costs and other market conditions before it commits resources.

The ROA has been borrowed from finance, and it basically questions the underlying assumption of traditional capital budgeting methods and seeks gains from deferring irreversible investment expenditure (in contrast to the "now or never" position implicit in traditional NPV analysis). The real options revolution arose in part as a response to the dissatisfaction of corporate practitioners, strategist and some academics with traditional capital budget techniques. Well before the development of real options, corporate managers were grappling intuitively with the elusive elements of managerial operating flexibility and strategic interactions. Early critiques (Dean, 1951; Hayes & Abernathy, 1980) recognised that standard DCF criteria often undervalued investment opportunities leading to myopic decision, underinvestment and eventual loss of competitive position, because they either ignored or did not properly value important strategic considerations. Decision theorists further maintained that the problem lay in the application of the wrong valuation techniques altogether, proposing the use of simulations and decision tree analysis to capture the value of future operating flexibility associated with many projects (Hertz, 1964; Magee, 1964)

The term "Real Option" can be traced to Myers (1977), who first identified investments in real assets as mere options. The quantitative origin of real options derives, of course, from the seminal work of Black, and Scholes and Merton in pricing financial options.

A real option is a permit with different value at different time periods to undertake some business decision, typically an option[58] to make a capital investment. In contrast to the financial options a real option is not tradable, but presents, as in the financial case, opportunity costs which fundamentally influence investment behaviour. A firm can use real option to cope with investment uncertainty and flexibility. With such options, the firm will be able to flexibly manage its irreversible investment capitals, and at the same time, taking into

[58] In finance a option is a right, and not an obligation, to trade a given asset in the future at an established future price known as the exercise price (or strike price).

account the uncertainties and risks of future cash flow. The underlying asymmetry that provides the right, but not the obligation to exercise the option is the main added value of the ROA.

ROA theory and modelling in power sector investments and climate change is developing quickly (Frayer and Uludere, 2001; Keppo and Lu, 2003; Laurikka 2005a, 2005b).
Given the wide range of uncertainties and flexibilities inherent in energy investment decision, the real option technique proves to be a valuable instrument also because the deregulation of energy markets has substantially added to the overall risk and uncertainties associated with energy investment decisions. Since now both electricity and fuel price are volatile and fluctuate, substantial challenges have arisen in both the timing and ultimate decision-making process.

We have seen that a main feature of the RO approach is the inclusion of the possibility of delaying an investment and evaluating the value of waiting as part of the decision-making problem, which allows for a much richer analysis than if this aspect is neglected. In addition, it may help to avoid erroneous conclusions from overly simplistic investment modelling, as has been frequently criticised (see Venetsanos et al., 2002; Awerbuch and Berger, 2003). The value of waiting can be explained as follows: if a company invests at time t, it gets the expected present value of the revenues minus the cost. In contrast, if it waits and invests at time (t+1), a real option might arise that, if exercised, yields a higher net profit. In dynamic programming the sequence of investment decisions is broken up into two parts, one that addresses the immediate choice, and one that addresses all subsequent remaining decisions. For the case of a multi-period evaluation, this leads to a model formulation that can be solved recursively.

The dynamic decision framework then allows a systematic comparison of the expected net present values from immediate investment and from waiting to invest, respectively. The ability to introduce and value the temporal flexibility in an irreversible investment decision represents the main distinction between real options and a conventional decision analysis based on NPV calculations. Applications of the RO approach to investment planning in the electricity sector, however, have only started to penetrate the literature in recent years and,

therefore, are still very limited in number. Frayer and Uludere (2001), for instance, conduct a RO analysis on two generation assets in a regional market under volatile electricity prices.
In contrast, Keppo and Lu (2003) make use of the RO approach, in order to introduce uncertainty for the electricity price, which is assumed to be affected by the investment behaviour of a large producer. Botterud and Korpas (2004) investigate the adequacy of power generation capacity in liberalised electricity markets and how/what regulatory mechanisms could ensure sufficient electricity supply.

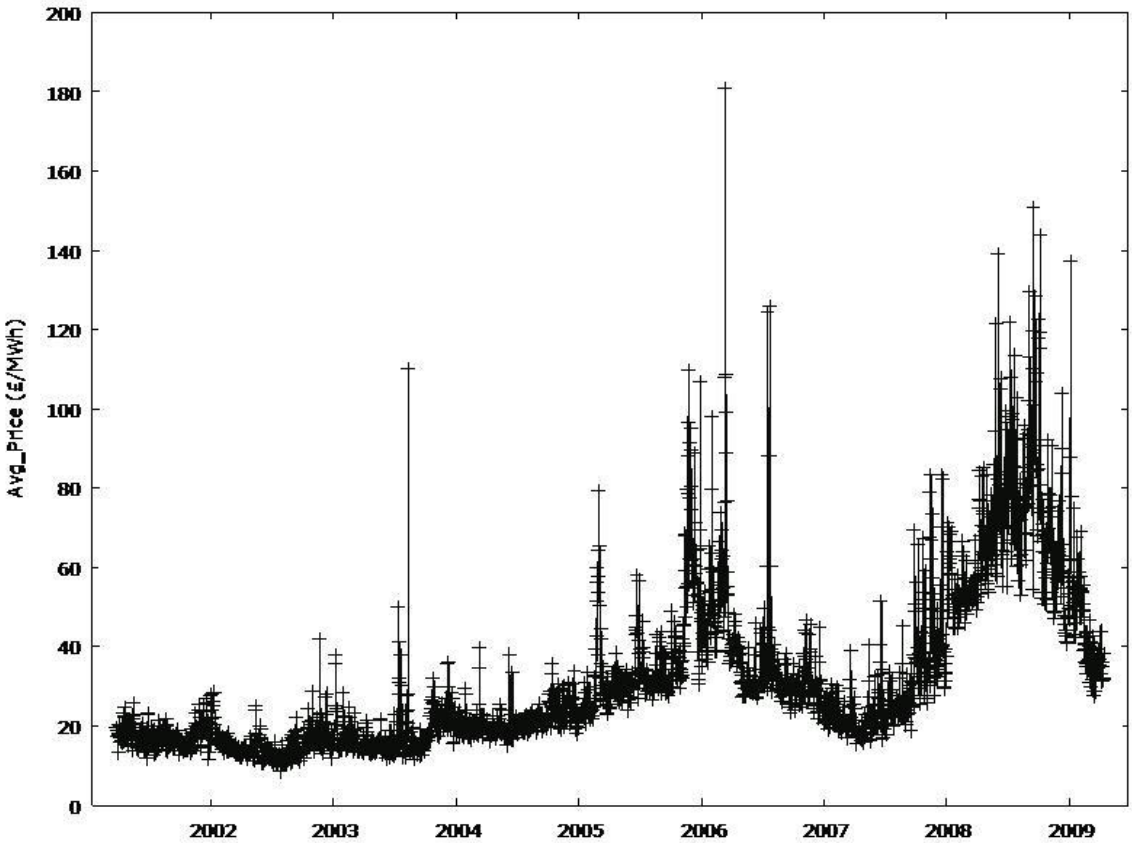
For a real option to exist in the first place the investment cash flow must have some sort of underlying uncertainty. As suggested by Dixit and Pindyck (1994), uncertainties are the key value drivers of a real option. So the first step is to identify the most important uncertainties, the next one is to distinguish the real options that are available. To that end, the agents involved in the decision making process (regulators, utilities management, public authorities) must possess the flexibility to respond to these uncertainties as they arise. Some of the causes of uncertainty in electricity production and investment in energy assets are well known and include electricity prices, fuel costs, consumer demand, plant availability, cost and time of construction, price of emission allowances, weather conditions, financial uncertainties and societal and political pressures.
With regards to the last point, it is important to mention the effect societal pressures will have on the availability of carbon intensive generation in different countries, or on the cost of emission allowances, or on environmental obligations. These will be explored in the remainder of the thesis.

3. UK electricity market

3.1.How the markets have worked to date in the UK.

Since the British electricity market was liberalised back in the late 1980s and early 1990s, markets have operated fundamentally as described earlier in this study (please refer to chapter 1.5). There has been price volatility, periods of scarcity pricing (most notably in winter 2005/06), forward markets have developed and investments have been made. There has been sufficient spare capacity on the system for firm demand to have been met throughout. Where there has been firm demand unserved this has been due to transmission and distribution network failures rather than inadequacy of supply. However, consumers have been exposed to considerable volatility in prices reflecting the fluctuating supply/demand balance and increasing exposure to international gas markets. Figure 8 and 9 (below) shows that dramatic price spikes are recurrent in UKPX spot prices.

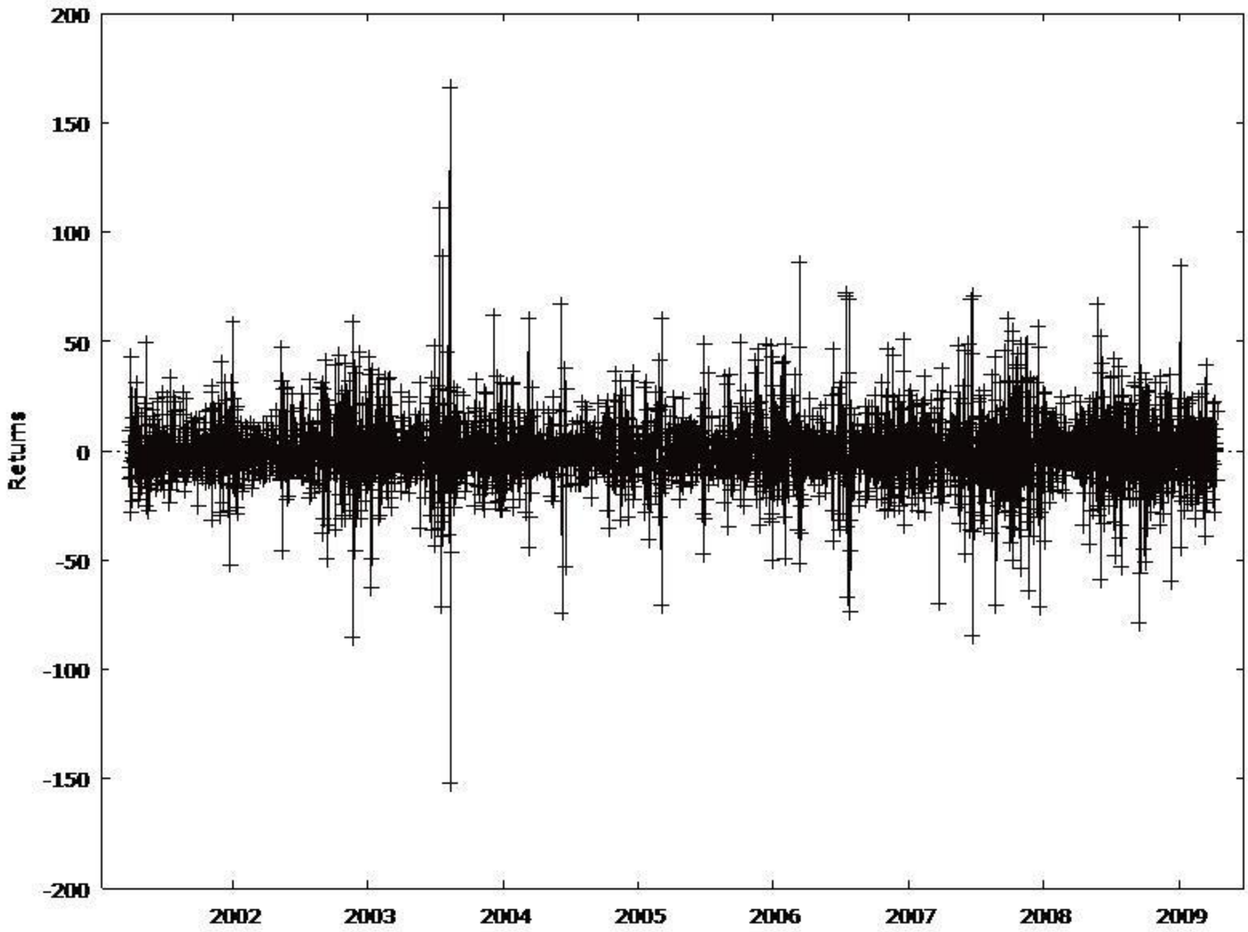
Figure 8 – Average daily prices for 27/03/01 to 14/04/09 – from 141120 half hourly observation.



Source: own calculation based on UKPX spot prices.

The British electricity spot price has therefore exposed consumer and market operators to severe volatility. Figure 9 shows that spot electricity prices in UK are characterised by clustered volatility, where period of intense price volatility have been followed by more stable price trends.

Figure 9 – Return on half hourly prices (from 27/03/01 to 14/04/09)



Source: own calculation based on UKPX spot prices.

However since 1990, over 30 GWs of new generation capacity (around 40% of total capacity) and around 125 bcm/yr of new gas import capacity (around 125% of annual demand) has been added to the system (Ofgem, 2008). In addition there is currently around 7.2 GW of additional gas-fired generation capacity under construction. Liquidity in the electricity market has not developed to the same extent as in gas, which helps to explain a somewhat different approach to financing generation projects.

In the early 1990s many of the CCGTs were financed with long-term (15 year) power purchase agreements with the Public Electricity Supply (PES), companies which were still protected by regional franchises and regulated prices (Simmonds, 2002). By the time that these had fallen away, the spark spreads[59] were sufficiently large that it was possible to finance new plant on a 'merchant' basis with no long-term contracts in place (see fig. 12). This lead to oversupply and a less concentrated market which, when combined with the introduction of NETA in 2001, resulted in a collapse in wholesale prices. Over the two decades since privatisation and liberalisation, the electricity and gas markets in the United Kingdom have delivered secure supplies and substantial investment.

The analysis here is based on the British electricity supply industry. The UK was chosen for the reason of data availability, but also because here the liberalisation and successive privatisation process started in the late 1980s and already in 1990 the electricity industry was split into generation, transmission, distribution and supply, which were then privatised separately. The aim of this study is to capture how firms decide (strategically) on the timing when to add further capacities.

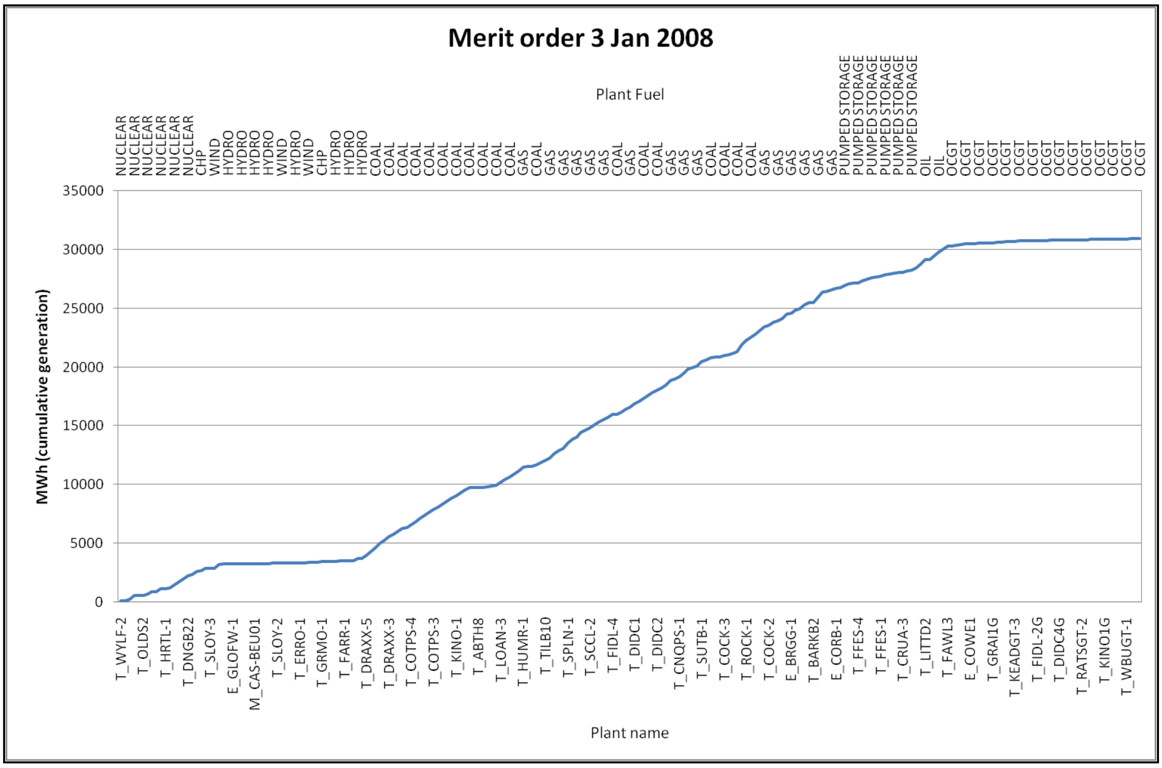
The power industry was liberalised in 1990 with a generous capacity margin. The nationalised industry had followed an engineering led investment policy aimed at replacing older plants and ensuring a high degree of supply reliability. Investment decision-making since privatisation has been more complex.

The first wave of investment was driven by the Regional Electricity Companies to be able to gain some incumbent generators. Given the lack of competition on the supply side, much of the initial risk was passed on to end-users. The chosen technology was CCGTs because of the low capital costs.

[59] The difference between the electricity price and short run cost of generating with gas

As gas became cheaper during the 1990s and the existing coal-fired generators tended, in the relatively uncompetitive condition that then applied, to price above new entry cost, a second wave of CCGT investment took place. Also at that time the SRMC of a new CCGT was significantly lower than the SRMC of coal generation, ensuring a high load factor and since coal rather that new gas plant would likely be displaced in the event of oversupply. The current situation does not show a similar uncontroversial advantage any longer for gas plants, as Fig. 10 below shows. infact are gas plants rather than cola plant that tend to be the marginal price setting plants.

Figure 10 – Merit order in UK electricity market



Source: author's own calculation based on Ofgem (2009) and NETA reports website data

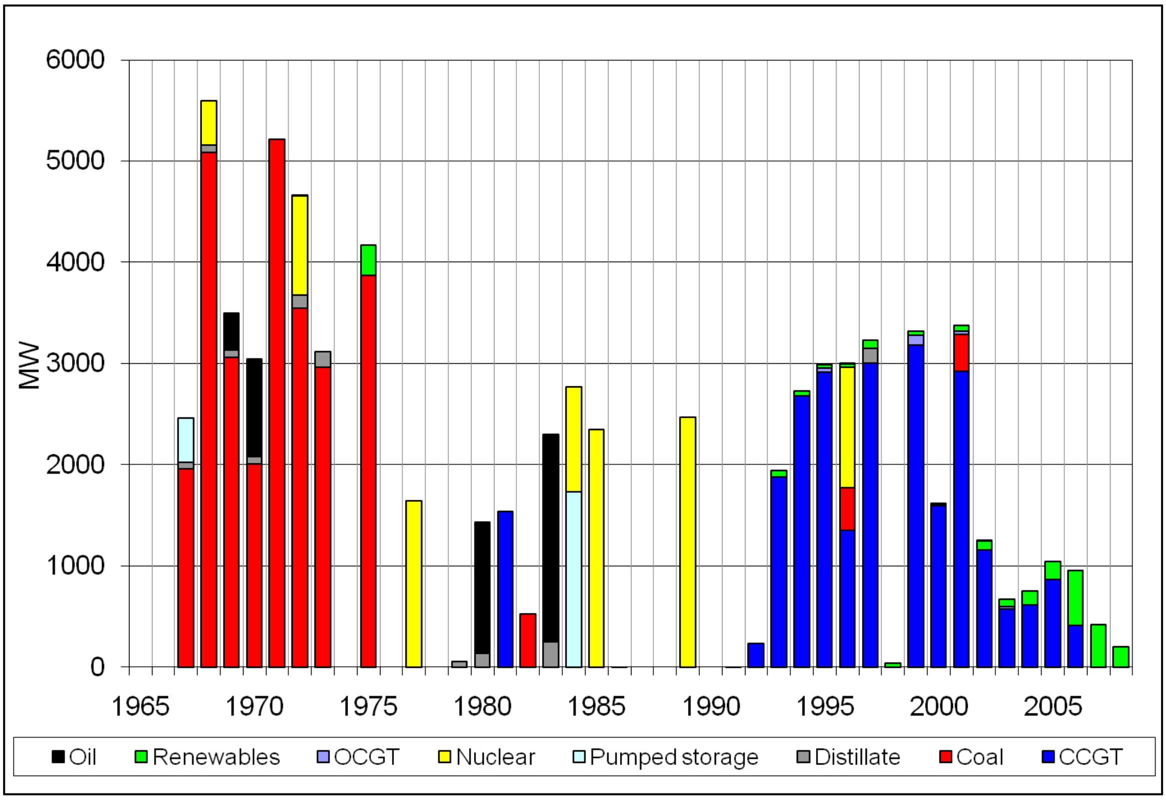
The situation stopped with the gas moratorium in 1998[60] and by the time the stricter consent policy was lifted in 2000, the market no longer looked so welcoming for new CCGT investment.

[60] http://www.publications.parliament.uk/pa/cm199798/cmselect/cmtrdind/404iv/ti0402.htm

This was also a combination of events: the introduction of New Electricity Trading Arrangements (NETA) in 2001 with forced divestment of a price setting plant by the large generators, and rising UK gas prices. Since then investment in new gas stations has been sporadic, normally driven by particular stations affecting specific location or players.

In the absence of clear cost advantage of new technologies over existing technologies, new investment must be driven largely by investors' expectation of future scarcity. The dynamic of the market had not been tested under these conditions until now. However, notwithstanding other specific strategic reasons for investing, the question is how high the long term expectations of the electricity to gas (spark) spread or the electricity to coal (dark) spread need to be before generators commit to building the levels of capacity that will be required over the next years.

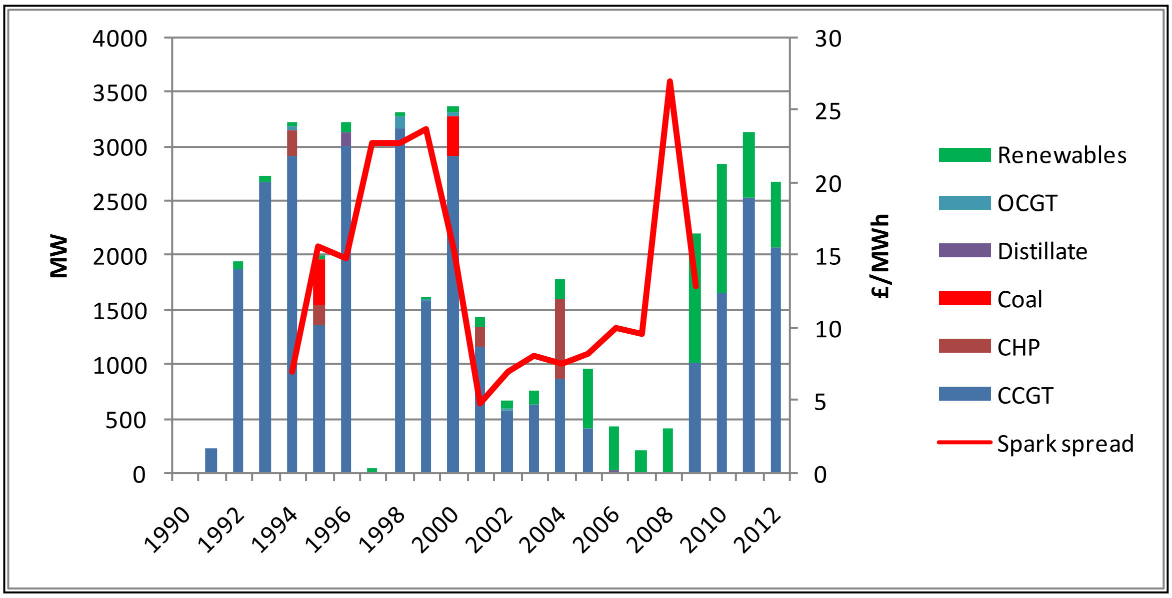
Figure 11 – Capacity addition by year



Source: BERR - Annual Tables: Digest of UK Energy Statistics (DUKES) 31/7/2008

Recent history shows that investment in new plants, other than renewables which were subsidised under the Renewables Obligation[61], slowed dramatically. This can be seen in the chart below. There is a clear relationship between the spark spread and the amount of investment in CCGT. The growth in renewables investment associated with the introduction of the Renewables Obligation in 2001 can also be seen.

Fig 12 - Capacity addition in UK vs Spark spread



Source: Ofgem, 2009; National Grid and BERR (Digest of UK Energy Statistics).

What followed was a period of vertical integration with the larger players buying up distressed assets as mainly US companies exited the market in the wake of the Enron collapse. The period of rapid growth in vertical integration, which followed the collapse of Enron in

[61] The Renewable Obligation (RO) adds a specific requirement for suppliers to source increasing proportions of electricity from renewable generation or pay a buyout price, the proceeds of which are recycled to suppliers in proportion to the renewable electricity they supplied. This would require suppliers to source a certain percentage of their generation from low-carbon generation. Suppliers would have to present certificates to demonstrate they had met their obligation and these certificates would have a value, giving the low-carbon generator an additional revenue stream. To meet their obligations, suppliers can present Ofgem with enough Renewable Obligation Certificates (ROCs) or make a buy-out payment. They can also use a combination of ROCs and buy-out to meet their obligations. The buy-out price per ROC (or per MWh prior to 2009-10) of electricity is normally adjusted by Ofgem each year to reflect changes in the Retail Prices Index. It was £30 per MWh in the base year, 2002-03. The buyout price in 2009-10 is £37.19. The buy-out price will be £36.99 per ROC in 2010-11. RO provides support, for onshore and offshore wind, biomass and renewable CHP. The availability of capital and operating support for a 20 year period (subject to the 2037 end date for the RO) reduces the perceived financial risks associated with these newer technologies and hence allows them to participate in the UK electricity market. Source: Ofgem, 2011.

2001/2 and the exit of a number of active wholesale market participants, saw traded volumes halve in two years (liquidity has failed to recover significantly since).

Industry structure is a key concern also with respect to the increase in vertical integration in the GB electricity market. That in turn might lead to underinvestment. Ofgem in its Supply Probe (2008) maintain that vertical integration has had a detrimental impact on wholesale market liquidity. It is argued that vertically integrated companies do not need to access the wholesale market, as their own plant will "provide the necessary price and volume protection". In this respect, the European Commission's 2006 energy sector inquiry[62] noted "vertical integration of generation and retail reduces the incentives to trade on wholesale markets. This might lead to a drying up of wholesale markets. Illiquid wholesale markets are a barrier to entry as they are characterised by higher price volatility. Volatile wholesale markets might oblige new entrants to enter as a vertically integrated generator and supplier, which is more difficult". Vertical integration became the principal method of managing price risk in the absence of a liquid wholesale market.

Recent experience suggests that this is a model that can support new investment with a number of gas plant totalling 7 GW[63] in various stages of development; the large utilities seemingly willing to invest against reasonably 'sticky' mass market (domestic and small commercial customer) bases.

[62] DG Competition report on energy sector inquiry, SEC(2006)1724, 10 January 2007; p128 and p. 169

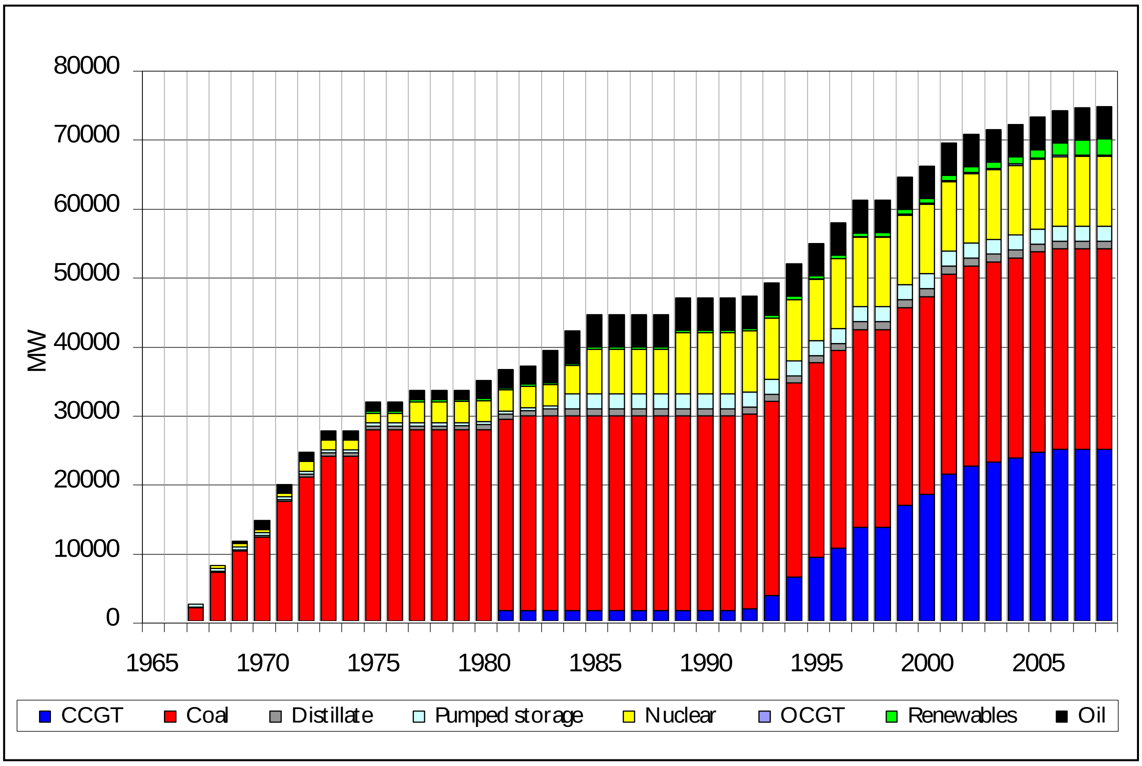
[63] The construction plant already into advanced realisation are: Langage (Centrica), Grain (EON), Staythorpe (RWE), Marchwood (SSE), and West Burton (EdF), and they total 7.2 GW of installed capacity.

3.2. How will UK markets work in the future?

In order to assess the ability of the existing market arrangements to guarantee that investments with the appropriate timing and quality can be delivered, the remainder of the thesis studies the UK investment model for the next 10 years.

Nowadays in the UK there are six[64] large market players and a few independent generators, that provide a rare example of investment decision under uncertainty in a competitive electricity market. In addition there are a number of key challenges currently facing the British electricity market. These include the varying pattern of demand growth, forced retirement of nuclear and coal plants for safety and environmental reasons, the role that the generation sector will be expected to play in cutting carbon dioxide emissions in the battle against climate change and the increasing reliance on imports to meet primary energy needs. Some of these factors will be briefly described , followed by a description of the method used to determine the model parameters.

Fig.13 - Generation fleet in the UK (1965-2008)



Source BERR - Annual Tables: Digest of UK Energy Statistics

[64] Recently reduced to five after EDF's acquisition of British Energy, the only remaining privatised entity from the CEGB.

3.2.1. Main challenges and emerging scenarios

Market demand: electricity is subject to two different and contrasting trends in modern societies. On one hand there is an upward pressure determined by innovation and the availability of new electronic devices, and therefore new ways to use electricity, both in private houses and industrial plants, and on the other, against this, energy efficiency improvement in appliance design is exerting a downward pressure on demand which is moderating the growth.

To construct fluctuating demand, a departure is made from half hourly market prices (from the APX UK and half hourly quantity consumed (from National Grid) for the years 2001-2009 to compute annual demand. The value of elasticity is chosen in line with other studies that estimate demand for electricity (see Ljensen, 2006, for an overview of recent contribution on that issue). For the short run the range of values is between 0.1 and 0.5, and long run elasticity is between 0.3 and 0.7[65]. In our empirical analysis we use an elasticity of 0.4, in line with the most recent literature.

Closure and reliability of nuclear plant: Britain's existing fleet of nuclear stations is aging. Sizewell A (420 MW) and Dungeness A (446 MW) closed as scheduled at the end of December 2006. The remainder of the first generation Magnox nuclear stations[66] built in the 1950s and 1960s were due to close by 2010. Oldbury (434 MW) closed in 2009, and Wylfa (980 MW) will close in 2012. These shutdowns are driven by environmental requirements affecting the Magnox reprocessing plant in Sellafield.

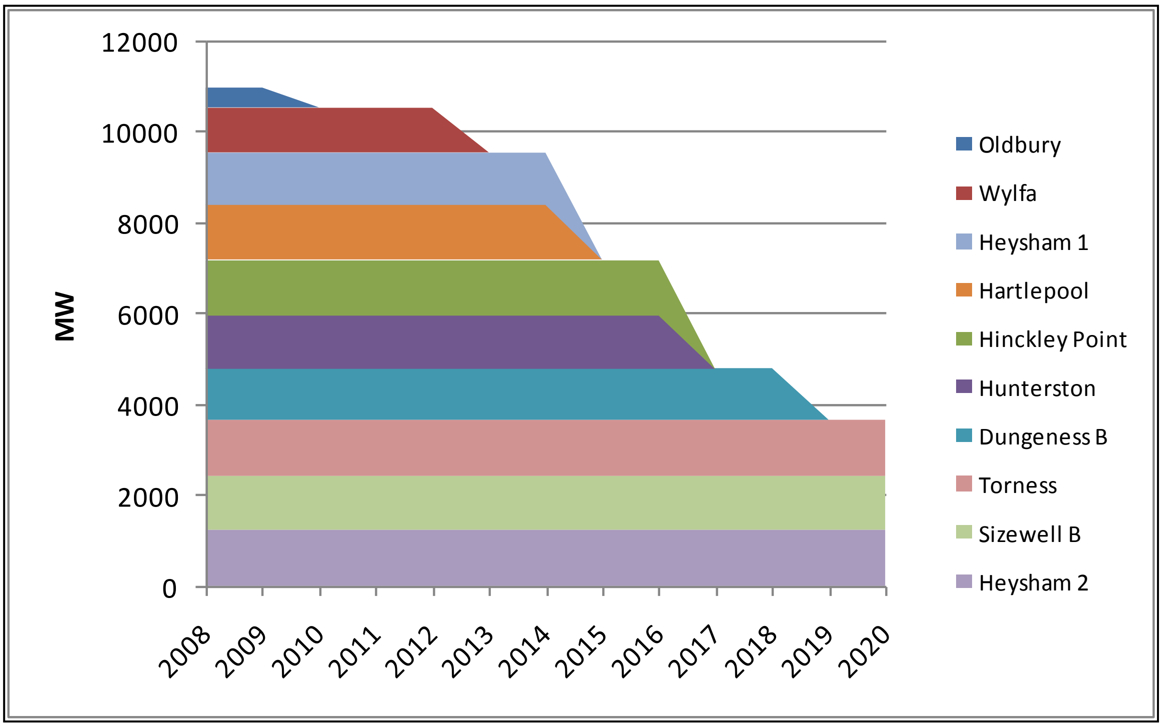
The position of the Advanced Gas-Cooled Reactors (AGRs) which make the remainder of the nuclear fleet, apart from the Pressurised Water Reactor (PWR) at Sizewell B, is less clear. Unlike Magnox, these stations have no hard deadline by when they must close, but they are free to put forward safety cases for lifetime extension as and when they can demonstrate that extended operation is safe. The plants are however complex and have had significant reliability problems, which may increase as the plants get closer to the end of their operation

[65] see Beenstock, Goldin, & Nabot (1999), Bjorner & Jensen, (2002), Filippini & Pachauri, (2004), Boonekamp (2007).

[66] Magnox reactors are pressurised, carbon dioxide cooled, graphite moderated reactors using natural uranium (i.e. unenriched) as fuel and magnox alloy as fuel cladding. Boron-steel control rods were used. The design was continuously refined, and very few units are identical.

lifetimes. According to published closure dates, Hinkley Point B and Hunterston B will close in 2011, and Dungeness and Haysham I in 2014. This represents a loss of further 4.7 GW of capacity. Whilst short lifetime extensions are possible for these four plants, it is likely that of the 11.8 GW nuclear fleet in 2010, only two AGRs and, Torness and Haysham 2, and the PWR Szewell B, will remain on the system by 2020, a total of 3.6 GW.

Fig. 14 – Generation capacity by nuclear station – base case scenario (non optimistic)



Source: Ofgem (2009), Project discovery – Energy market Scenarios

In addition in January 2008 the government concluded that it was in the public interest that new nuclear power stations should have a role in meeting future electricity demand, alongside other low-carbon technologies[67]. It was therefore decided (BERR, 2008) that the government would take active steps to open up the way to the construction of new plants.

However, it is for the energy companies to fund, develop and build new nuclear station in the UK, including meeting the full costs of decommissioning and their full share of waste management costs. So far a number of proposals to build new nuclear power station have

[67] BERR (2008), A White Paper on Nuclear Power (pag 134)

been announced. These estimates are also incorporated in the model here although it seems to be quite an optimistic estimate from EDF to have more than 9 GW of generation available by 2016.

Environmental Obligations: the Industrial Emissions Directive (IED)[68] consolidates the LCPD[69] and six other industrial emission Directives in an effort to tighten the emissions limit and simplify regulation. The IED has being finalised by the European Parliament and the Council of Ministers through the co-decision procedure. The implementation date of the IED is 1 January 2016. While the current environmental provisions will continue to apply, from 2016 the IED will toughen the constraint on emission in three aspects: a) it applies to plants with a capacity of more than 20M ; b) IED will tighten NOx emission limits; and c) it includes gas turbines licensed before 27 November 2002. An estimation of the impact on the UK generation fleet is provided in Rubino (2010).

The decline in indigenous gas supplies and the need to make demanding cuts in carbon emission levels, represent unprecedented challenges, which will grow over the next two decades. Large parts of UK's aging energy infrastructure will need replacement and, at the same time, a rapid progress towards the substantial decarbonisation of British economy is also necessary. Ofgem estimates that up to £200 billion of investment might be required by 2020 alone, in the face of huge global demand for investment in energy infrastructure, volatile commodities prices, and the ongoing effects of the financial crisis.

Reducing CO2 emissions from the generation sector: a key requirements of energy policy will be to reduce carbon dioxide (CO2) emissions on a global basis, either by reducing them in UK or by purchasing allowances which will allow for their reduction elsewhere. The three main low carbon generation technologies are renewables, nuclear and thermal plants fitted with carbon capture and storage (CCS).

[68] The IED directive has recently being codified with the Directive 2008/1/EC of the European Parliament and of the Council of 15 January 2008 concerning integrated pollution prevention and control.
[69] The consolidated version of the Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants

Based on these stylised facts there will be an evaluation, applying a ROA analysis, of the development of the capacity additions in UK over the next decade (2011-2020). The following section will provide an overview of the model employed and of the construction of the 3 scenarios that will help to identify some general policy implications.

4. Chapter 4 - Model description and empirical analysis

A period-by-period evaluation of irreversible investment alternatives under uncertainty will be performed. It is assumed that an association of power producer evaluates at time t capacity additions $X_{i,v}$ for each technology I (plant type) of vintage v (indicating the year in which the investment decision is taken).

The capacity planning for new investments is perfectly expressed by the exercise of two main options (see section 2.2.). Investors want to evaluate at each point in time the option to invest in additional generation capacity (so the opportunity to make a capacity investment) and the option to defer the investment decision. The decision maker has the flexibility to decide the most profitable technology among the available possibilities and can determine the most appropriate timing for the investment to take place. The model employed is based on Kumbaroglu, et al. (2008), but in contrast to this formulation allows for the evaluation of the profitability of new investment capacity (and not only expansion of the existing one).

The price dynamic has been expressed by a Geometric Brownian Motion (GBM) process. Following Pindyck (1999) we assume that a GBM with sthocastically fluctuating drift is a close approximation of the true underlying process.

The evaluation at each time t has to maximize the net present value, $NPV_t\ (X_{i,\,v=t})$:

$$NPV_t(X_{i,v=t}) = max\left\{\begin{array}{l} (a)\sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} p_z\left(1+r\right)^{-(z-t)} L_{i,z,v=t}\theta_{i,z,v=t} \\ (b)-\left\{\forall \sum_i L_{i,z,v} > d_z \left| \sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} p_z\left(1+r\right)^{-(z-t)} \left\{L_{i,z,v=t}\theta_{i,z,v=t} - d_z\right\}\right.\right\} \\ (c)-\sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} vc_{i,z,v=t}\left(i+r\right)^{-(z-t)} L_{i,z,v=t}\theta_{i,z,v=t} \\ (d)-\sum_i fc_{i,v=t}X_{i,v=t} \\ (e)+\dfrac{1}{1+r}E_t\left(NPV_{t+1}\left(X_{i,v=t+1}\right)\right) \end{array}\right\} \qquad \textbf{(3)}$$

where:

- p_z is the electricity price (modelled as a stochastic process, see below),
- r is the real interest (discount) rate,
- $L_{i,z,v}$ stands for the load of plant type i of vintage v in year z,
- $\theta_{i,z,v}$ denotes the corresponding duration (in hours),
- d_z is peak power demand,
- $X_{i,v}$ is the capacity installed of plant type i in year v,
- $vc_{i,z,v}$ denotes variable costs,
- $fc_{i,v=t}$ denotes fixed costs,
- lt stands for lead time,
- el denotes economic lifetime of the generation plant.

Terms *(a)* and *(b)* of equation *(3)* represent the revenues accruing from electricity sales. When the available capacity exceeding peak demand *(b)* is subtracted from total revenues *(a)*[70]. Those two terms combined provide the net revenues from generation sold as a net effect.
When the total available capacity, fulfil the following condition $\sum_i L_{i,z,v}\theta_{i,z,v} \leq d_z$ (which implies that the level of demand is less or equal the available capacity available installed) then the revenues are given by term *(a)* of equation *(3)*:

$$\boldsymbol{\sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} P_Z\,(1+r)^{-(z-t)} L_{i,z,v=t}\theta_{i,z,v=t}} \;\textit{(4)}$$

Which means that all the generation available at that specific point in time will produce electricity, and will generate a strand of revenues.
Whereas when $\sum_i L_{i,z,v}\theta_{i,z,v} > d_z$ then:

$$\boldsymbol{\sum_i \sum_{z=t+lt(i)}^{t+lt(i)+el(i)} P_Z\,(1+r)^{-(z-t)} d_z} \;\textit{(5)}$$

[70] Excess generation, in reality, is able to generate extra strands of revenue when it is used for reserve or balancing purposes, or when it is provided following capacity mechanism obligations. In the model presented in this paper, no revenues arising from ancillary service will be considered.

Meaning that in this situation generation plants are dispatched according to their merit order (increasing Short Run Marginal Cost) and in order to satisfy the demand realised at time *t*.

Terms *(c)* and *(d)* in equation ***(3)*** represent the NPV of operation and maintenance and investment costs, respectively. Where the variable costs ($vc_{i,z,v}$) are calculated starting at the end of the lead time, when plants are on line and can generate electric power and will last for the whole duration of the economic lifetime of the plant, whereas fixed costs ($fc_{i,v=t}$) are paid starting from the first year when the investment decision takes place.
Finally the last term *(e)* characterises the continuation value, that is equal to the sum of *NPVs*, valued at time *t*, that accrue from investing in later periods.

The model is therefore composed of a term describing the revenues accruing in the immediate period and the strand of revenue deriving from the periods before it . This is consistent with Bellman's fundamental optimality condition in Dixit and Pindyck (1994). The model optimally chooses investment for the period *v=t*, and then, via dynamic optimisation in order to determine the decisions for the latter periods by working forward.
Each plant starts its operation directly after the construction lead time has elapsed, $lt_{(i)}$, and for a duration equal to that of its economic lifetime, $el_{(i)}$. Lead time and economic lifetime are technology specific. The construction time depend on the complexity of the plant involved (see table 1). The construction time goes from 1 to 6 years and is derived from the International Energy Agency (2005) and redpoint Energy (2006).

The first four components of the objective function (revenues *(a)* and *(b)*, variable costs *(c)* and fixed costs *(d)*) relates to each plant when investment decisions are taken in year *t*. For each successive year (from *t+1* on) the decision at time *t* is incorporated in the first constraint, that describes electricity generation from previously installed power plants.
Equation *(6)* guarantees that total power generation would be sufficient to meet peak load demand in year *z* *(d_z)*, where *m* represent reserve margin, expressed as a percentage of the demand.

$$\sum_i \sum_{v=z-lt(i)-el(i)}^{z-lt(i)} L_{i,z,v}\theta_{i,z,v} \geq d_z(1+m)$$
$$\forall t + lt(i) + el(i) \geq z \geq t \qquad \textbf{(6)}$$

Equation *(6)* represents the first constraint and captures the fact that in this market prices do not adjust immediately merely to demand/supply conditions but also consider some issue related to security of supply and system stability. It is reasonable to believe, given the high undesirability of power rationing in most countries, that imposing a margin *(m)* is a realistic assumption in most markets and it is consistent with Kumbaroglu, et al. (2008). Policy makers are likely to intervene whenever installed capacity falls short of meeting peak load plus a margin for potential outages.
The demand for electricity is price elastic and is given by:

$$\boldsymbol{d_t\,(p_t) = \alpha p_z^{\varepsilon_z}} \textbf{ (7)}$$

Where α is a scale parameter, and ε_z is the price elasticity of electricity demand. Price elasticity is considered here to be time dependent, to facilitate the incorporation of smart metering change out programme and demand-side response improvement (if and when they will occur in the future). Equation *(7)* allows to connect the model, although partially, to market interaction.
The second obvious constraint is that output from each plant does not exceed available capacity, and is given by equation *(8)* below.

$$L_{t,z,v} \le a_i X_{i,v} \;\; \forall t + lt(i) + el(i) \ge z \ge t + lt(i),\; v \le t \quad (8)$$

Where a_i is the availability factor (or de-rated capacity) for plant type *i*, that simply reflects the percentage of time that a plant can be effectively used.
Likewise equation *(9)* describes the third constraint on the productivity of the plant, comparing its actual production with the amount of power the plant would have produced if had run at full capacity for the whole year.

$$L_{i,z,v} \frac{\theta_{i,z,v}}{8760} \le cf_i X_{i,v} \;\; \forall t + lt(i) + el(i) \ge z \ge t + lt(i),\; v \le t \quad (9)$$

Where *cf* is the capacity factor that describes the productivity of the plant during the year.

Constraint *(6)*, *(8)* and *(9)* introduce uncertainty from the availability and technical characteristics of plants, whereas the following constraint account for uncertainty for both input and output prices.

The trajectory of electricity prices is based in a Geometric Brownian Motion (GBM), a log normal diffusion process with the variance growing proportionally to the time interval. So the price increment is given by:

$$\Delta p_z = p_{z-1}\left(\mu\Delta_z + \sigma\varepsilon\sqrt{\Delta_z}\right) \quad (10)$$

Where μ and σ represent mean drift rate and percentage volatility respectively, Δ_z indicated the time increment, and ε is a standard normal variable $\varepsilon \sim N(0,1)$.

Equation *(11)* takes into account fuel price variability via a similar GBM process for variable costs.

$$\Delta vc_{i,z,v} = vc_{i,z-1,v}\left(\mu\Delta_z + \sigma\varepsilon\sqrt{\Delta_z}\right) \quad (11)$$

Where μ is the expected growth rate given by:

$$\mu = e^{\frac{\ln\left[\frac{p_z}{p_{z-1}}\right]}{z-(z-1)}} - 1 \quad (12)$$

and σ is again the annual volatility of the prices expressed as a percentage change.

Both in equation *(10)* and *(11)* the volatility is calculated on a annual basis and is given by:

$$\sigma = \sqrt{\frac{1}{N}\sum_{t=1}^{N}\left\{\frac{[p_z - p_{z-1}]}{p_{z-1}} - \left(\overline{\frac{p_z - p_{z-1}}{p_{z-1}}}\right)\right\}^2} \quad (13)$$

The NPV calculated recursively in this way does not include the existing generation. The investors can only influence the capacity added to the system. Investors need to assess how best to serve the residual demand by new capacity under given price quantity pairs.

The total amount of capacity that is added to the system, is given by:

$$\mathbf{X}_{\mathbf{i,t}}^{\mathbf{total}} = \sum_{\mathbf{z=t+lt(i)}}^{\mathbf{t+lt(i)+el(i)}} \mathbf{X}_{\mathbf{i,Z}} \quad \textbf{\textit{(14)}}$$

where $X_{i,z}$ indicates the quantity of additional capacity, for each technology, that is added to the system when the investment decision is taken and that only generates fixed costs, whereas $X_{i,t}$ represent the capacity added to the system and that is running and generating revenues and variable costs. It is important to note that there is a difference in timing and typically the running capacity implies that the construction lead time has elapsed.

The model formulation is concluded.

4.1. Data and scenarios

Operational and cost data of existing power plants for the period 1966-2008 are taken from the Digest of United Kingdom energy statistics 2008 of the Department for Business, Innovation and Skills[71] (BIS), Ofgem (various sources cited) and from redpoint Energy (2006) and are summarised in table 2 below. Historical data on fuel prices for the period 2001-2009 is from Bloomberg[72]. Spot electricity prices for the same period are from APX UK[73].

The historical costs and prices have been used to estimate the mean drift and volatility parameters of the electricity and fuel price according to a GBM process. All drift and volatility assumptions are summarised in the technical appendix (table A6) which illustrates the assumption in stochastic trajectories. The projections are the average results of 5000 randomised simulations that have been performed in Solver©.

The prices of fossil fuels are predicted to slightly increase in the next 10 years with the exception of coal. This reflects the increasing limitation that coal usage is experiencing and the increased costs of carbon emissions.

The electricity price projections are depicted in fig A1 and described in table A6 (in Appendix 1 of this thesis). Figure 15 below presents an average of the simulations and correspondent standard deviations. The prices are predicted to start to increase to reach a maximum by 2016, at the end of the first LCPD. Until then, a significant number of plants will go off the system and energy margins will be considerably reduced. There are a several critical factors related to price projections such as the price elasticity of electricity demand (discussed above) and the choice of the appropriate discount rate.

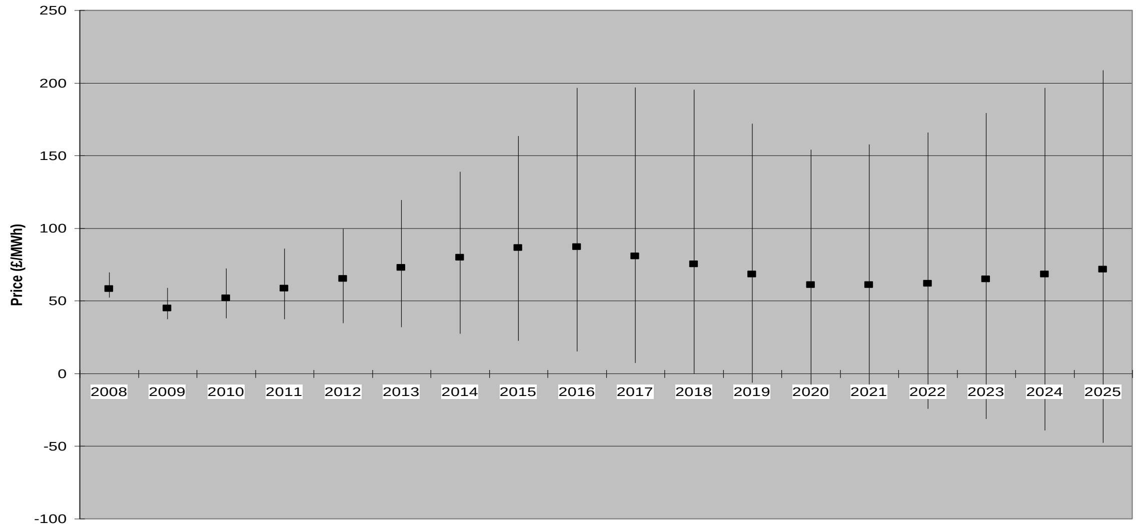
Cost of Capital: In our analysis we assume that the risk adjusted rate is calculated using CAPM. Where the weighted Average Cost of Capital (WACC) is used. WACC is the rate of

[71] http://www.berr.gov.uk/energy/statistics/publications/dukes/page45537.html
[72] http://www.bloomberg.com/markets/commodities
[73] http://www.apxgroup.com/index.php?id=199

return that investors require, weighted according to the proportion of the equity and debt elements of investments. Using data retrieved from the annual reports of the major utilities in the UK a WACC of 8.6% is calculated[74].

Other factors that enter the calculation of the profitability of different technologies and that therefore determine the investment timing and size is represented by the annuities. Total investment costs are annualised (according to the allowed WACC) and distributed for the lifespan of the investment.

Figure 15 – Average projected prices (£/MWh) and standard deviations.

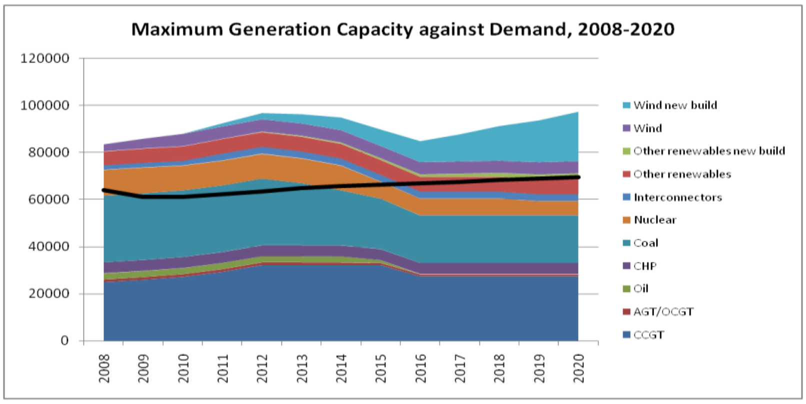


Source: Author's own calculation based on APX UK half hourly spot prices in the period 2001-2009

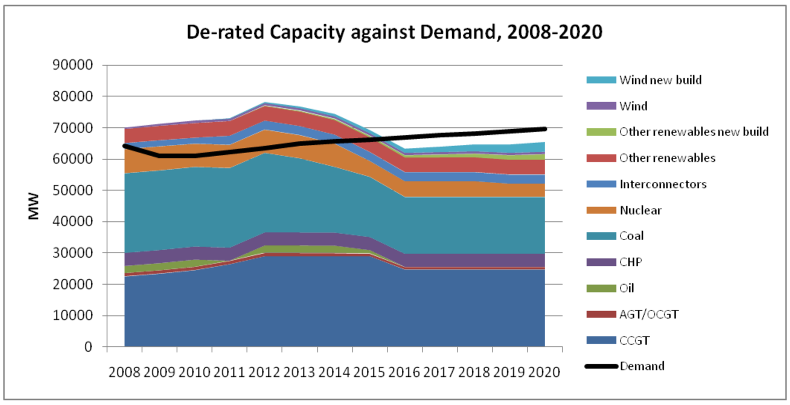
Finally in order to obtain a realistic picture of the generation portfolio available currently in the UK, the average plant availability at peak demand rather the maximum potential output is considered(indicated in table A7 of the Appendix). The situation in the near future is illustrated in figure 16 (below).

[74] See Fama (1996).

Figure 16 – Maximum versus de-rated capacity against demand.



Source: author's own calculation based on redpoint Energy (2006)



De rated capacity is the correct capacity value that should be considered, especially with the increasing penetration of intermittent renewable generation (wind in particular), that normally has a nominal capacity much higher than the de rated one.

The current outlook of the next decade shows that after the entry into force of the LCPD there will be a significant reduction of the margin and even the possibility that part of the expected demand remains unserved after 2016. These results are based on the currently installed generation capacity and on the planned addition up to 2020. They show that existing market conditions are unable to guarantee supply adequacy over the medium/long run. In fact the British market is predicted to encounter growing difficulty in satisfying its own demand especially at peak time for the contemporaneous action of growing demand and entry into force of the LCPD that is likely to affect the profitability, therefore the regular operation, of a significant part of peak load generation plants. This situation is likely to be exacerbated by the

Climate Change policy targets that require (and incentivise, although less generously than elsewhere) a significant penetration of RES generation.

The current situation is an intersecting starting point to evaluate, via ROA, how investors might react to different energy policies. Therefore we shall evaluate how market players will react to future environmental policy obligation and to nuclear power plants support. How these policy intervention will affect British generation mix in 2020 will be evaluated. The impact of the following scenarios, developed to evaluate various policy frameworks, will be analysed:

- **"Energy Only Market" scenario:** This scenario sets the baseline against which other and more extensive policy intervention will be evaluated. It consists of a continuation of the existing policy, with no provision of targeted involvement in the determinants of the generation mix. Markets participants have to deal with classic market uncertainty and they do not expect policy makers to favour one technology over the other.
  Each technology can develop an unrestricted level of generation capacity. This scenario does not require the meeting of any emission targets regarding carbon free generation.
  Some limitation on the maximum annual level of additional capacity allowed each year has been imposed (set at 5GW/year).

- **"Optimistic Nuclear" scenario: the** British government has recently expressed its support for the nuclear alternative in the UK generation mix (See section 3.2.1 above) for the coming years, provided that nuclear investors shall cover their investments and decommissioning costs. Therefore, under the "Optimistic Nuclear" scenario, this possibility is allowed, also granting an extension to the operational life of some of the existing nuclear plants. This scenario will evaluate the consequences for the British energy mix

- **“Climate Policy” scenario:** this scenario considers as binding constraints the requirements of the EU. The EU has set a series of demanding targets, also known as “20-20-20” that include:
    1. A reduction in EU greenhouse gas emissions of at least 20% below 1990 levels
    2. 20% of EU energy consumption to come from renewable resources
    3. A 20% reduction in primary energy use compared with projected levels, to be achieved by improving energy efficiency.

  The second target translates into a series of demanding national objectives. For the UK the target resulted in 15% of the renewable fraction. This means that the compulsory share of renewable sources in total electricity generation of 22% would meet this requirement (House of Lords, 2008). This scenario therefore requires that this target becomes a binding constraint, that ensures that the generation mix complies with this requirement.

  Imposing a constraint on the generation mix is equivalent to a change in the revenues (therefore the cash flow) that renewable sources can achieve. This means that, by changing “artificially” the quantity generated by the decarbonised fraction, there is, de facto, an increase in the revenues or decrease in the O&M cost for renewable sources.

  A binding target of this kind is equivalent to a feed in tariff (FiT) intervention, commonly adopted to support renewable, or is equivalent to a significant decrease of the WACC value applied to renewable sources. Both interventions are able to pollute market signals and to alter significantly the final generation mix, as will be seen in the next section.

Table 2 Candidate and existing power generation technology: costs, assumed availability and construction lead times.

Plant type	Capital costs	Annuitised capital costs	Fixed operating costs	Variable operating costs	Construction time $lt_{(i)}$	Economic lifetime	Annual availability	Decommissioning costs	Operational life
Units	*£/kW*	*£/kW/yr*	£/KW/yr	£/MWh	*years*	*years*		*£/kW*	*years*
CCGT	600.00	78.37	7.00	2.00	3	20	87%	0	20
Coal (ASC)	1,300.00	162.81	24.20	1.55	4	25	86%	0	25
Coal (IGCC)	1,400.00	175.34	34.50	1.6	4	25	86%	0	25
Coal (ASC + CCS)	2,200.00	275.53	53.70	9.90	4	25	86%	0	25
Nuclear (new)	2,000.00	254.06	56.60	0.00	6	30	82%	611	40
Onshore wind (High)	1,200.00	149.77	44.40	0.00	1	20	32%	0	20
Onshore wind (Medium)	1,200.00	149.77	44.40	0.00	1	20	32%	0	20
Onshore wind (Low)	1,200.00	149.77	44.40	0.00	1	20	32%	0	20
Offshore wind (High)	2,800.00	357.49	46.00	0.00	2	20	36%	0	20
Offshore wind (Low)	2,800.00	357.49	46.00	0.00	2	20	36%	0	20
Biomass regular	2,500.00	319.19	100.00	2.00	2	20	86%	0	20
Biomass energy crop	2,500.00	319.19	100.00	2.00	2	20	86%	0	20
CHP	3,000.00	383.03	7.00	1.50	2	20	91%	0	20
Wave	4,000.00	510.70	68.41	0.00	2	20	30%	0	25
Tidal Stream	4,000.00	510.70	68.41	0.00	2	20	30%	0	25
Tidal Range	3,800.00	458.06	68.41	0.00	4	30	30%	0	25
Biowaste	3,600.00	459.63	100.00	2.00	2	20	86%	0	40
Biogas	6,600.00	842.66	100.00	2.00	2	20	61%	0	20
OCGT	350.00	44.69	18.01	1.50	2	20	95%	0	20

4.2.Results

The model described above is coded and solved in Solver® and evaluates a ROA application to the data set and scenarios illustrated earlier.

4.2.1. General results

The three scenarios share some basic outcomes that can be considered as a constant feature in the UK electricity market in the coming years.

Firstly in each scenario the capacity additions start directly from 2011, the first year of the period considered. This illustrates immediately that the forecasted margin reduction requires immediate decision from investors, which need to be available on line when several plants will retire in 2016 and generation scarcity kicks in. The simulated price trend also encourage early entry.

In addition in each of the considered scenarios the capacity added to the system generates positive (although very close to zero) NPV. This confirms that "energy only markets", also in the hybrid version presented in two of the scenarios considered in this analysis is a viable option from a business perspective.

Another common feature is that investment in gas plants remains an option, although with a different level of penetration for the three considered scenarios. Gas plant penetration in the different scenarios is still significant, as it is apparent from fig. 17 and 18 (below).

This is true for various reasons: a) gas plants have been the major addition to the system in recent years and b) gas plant require little capital expenditure and short lead times (comparable to those of wind plants). Finally it is interesting to note that the installation rate in the coming 10 years has to double (or more) compared to what happened in the previous decade, when around 11GW were added to the system, as opposed to a minimum of 21GW and a maximum of 35GW of new generation that should go online according to the results obtained.

This confirms the herding behavior that often large sunk investment shows in a liberalised market. A period of limited investments followed by a period of sustained investment is typical and, as explained herein, reflects the inability to signal, via efficient price mechanism, scarcity in generation.

Fig. 17 – Generation mix in 2010 and 2020 under different scenarios (percentage)

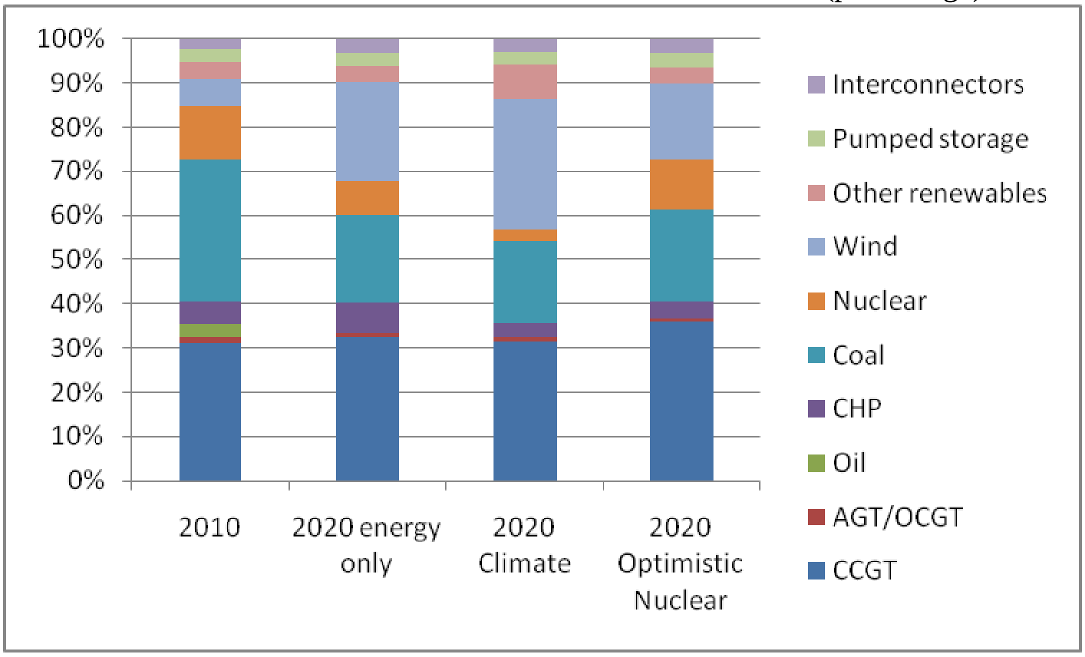
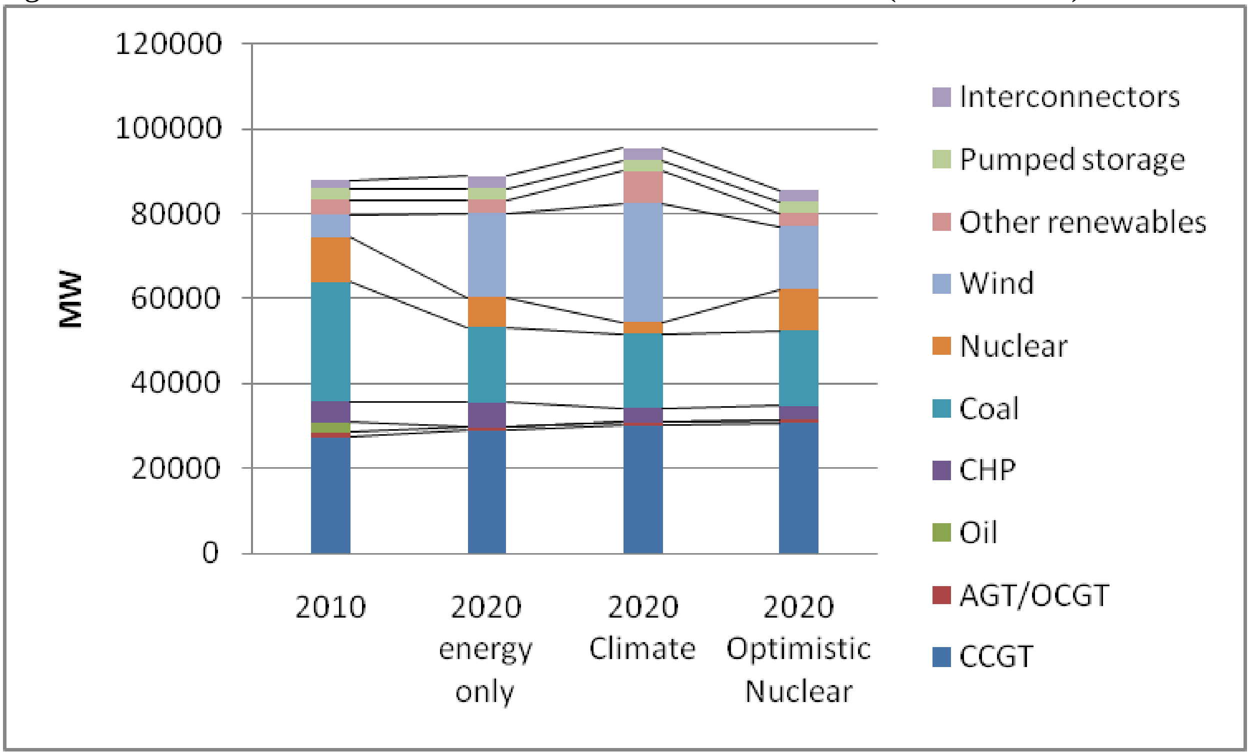


Fig. 18 – Generation mix in 2010 and 2020 under different scenarios (MW installed)

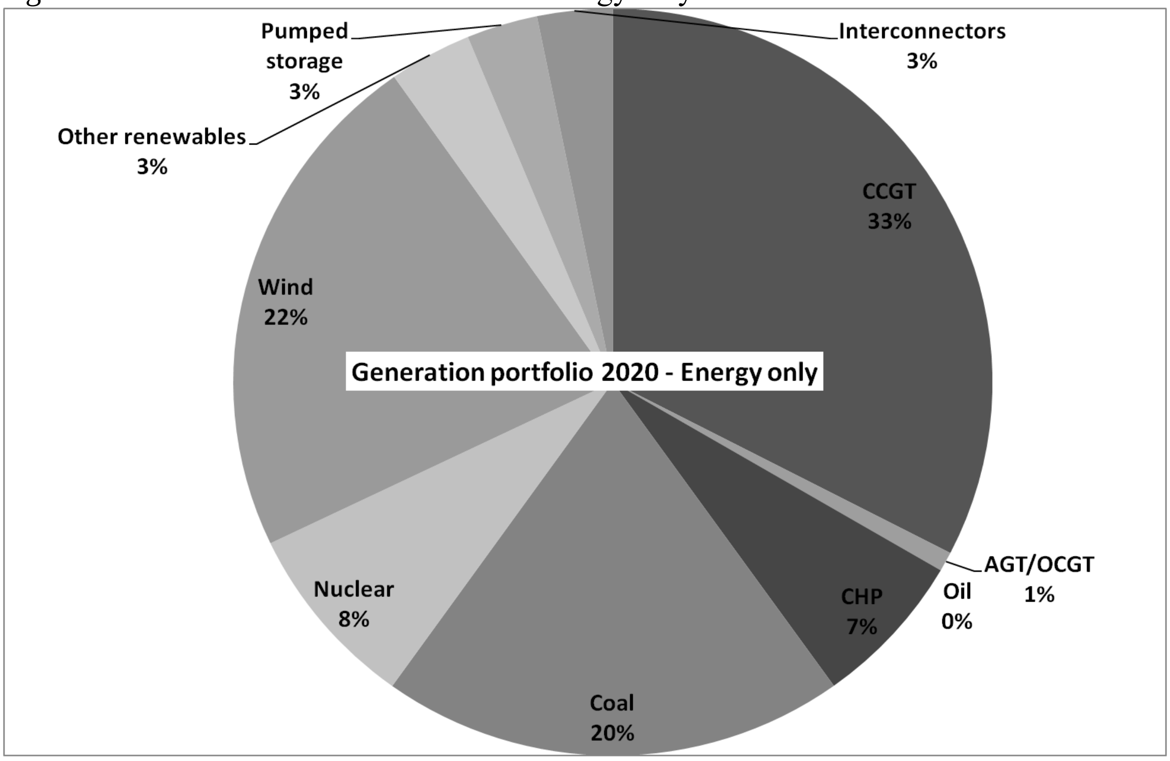


4.2.2. “Energy Only Market”

The “Energy Only Market” scenario constitutes the base line scenario that reflects the continuation of current energy policy in place in the UK. No targets are imposed on the energy mix, and there is no binding constraint on the technology choice. The system sees 28GW of newly installed capacity in the 10 year period considered, that just cover plants retirement. More than half of the newly installed capacity come from renewable sources (16 GW), where wind generation is the only significant non-fossil generation added to the system, with a slight dominance of onshore wind.

Starting from the initial part of the period considered, there is an increase in Nuclear generation. Around 5GW of nuclear generation are added to the system, just before 2014. However, these addition fail to compensate the contemporaneous plant retirements. One of the reasons why nuclear plant additions are not foreseen after 2014 is that the construction time imposed with the model is 6 years. This means that the revenues stream, eventually accruing from nuclear plant installation, are outside the period considered for this calculation and therefore cannot be appreciated in it.

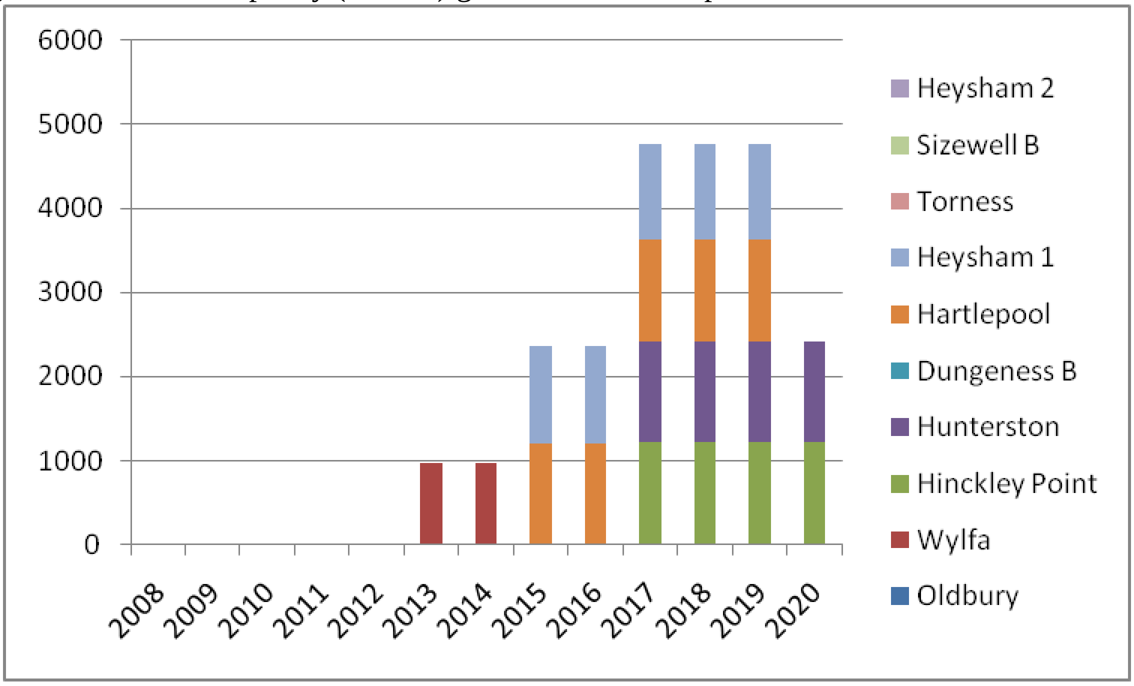
Figure 19 – Generation Portfolio 2020 – “Energy only”



4.2.3. “Optimistic Nuclear”

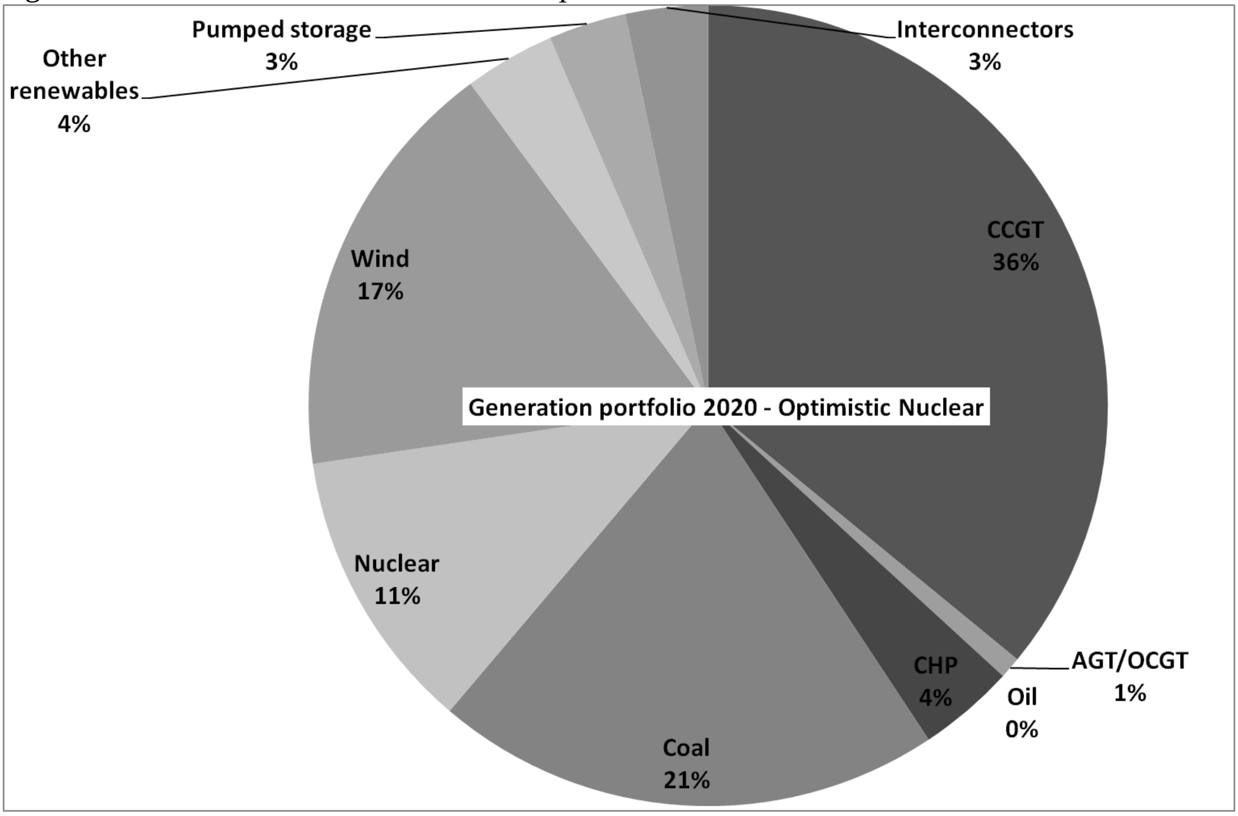
Under this scenario favorable to nuclear generation the optimistic nuclear retirement plan is assumed as an initial condition, that allows an extension of the operational life of an additional 2.4 GW in 2020, compared to the base case for nuclear retirement considered in the other scenarios.

Fig 19 – Additional capacity (in MW) granted under the optimistic nuclear scenario.



Thanks to the availability of 6.1 GW of nuclear generation until 2020, the extension of the operational life of 5 existing nuclear plants, in particular in years when the decline of other conventional fuel plants will be remarkable, because of the entry into force of the LCPD, and the additional installation, in the very early stages of the period considered of extra 3.7 GW, this scenario requires only 21 GW of additional generation capacity installed to guarantee supply adequacy in the period considered. This is possible due to the robust availability and efficiency (compared to other technologies) granted by nuclear plants. The total installed capacity at the end of 2020 is less than 86 GW, that represents the minimum of the total installed capacity foreseen by the three different scenario and a slight reduction of installed capacity compared to the situation in 2010 (from 87GW installed in 2010 to 85.5 GW in 2020).

Figure 18 – Generation Portfolio 2020 – “Optimistic Nuclear”

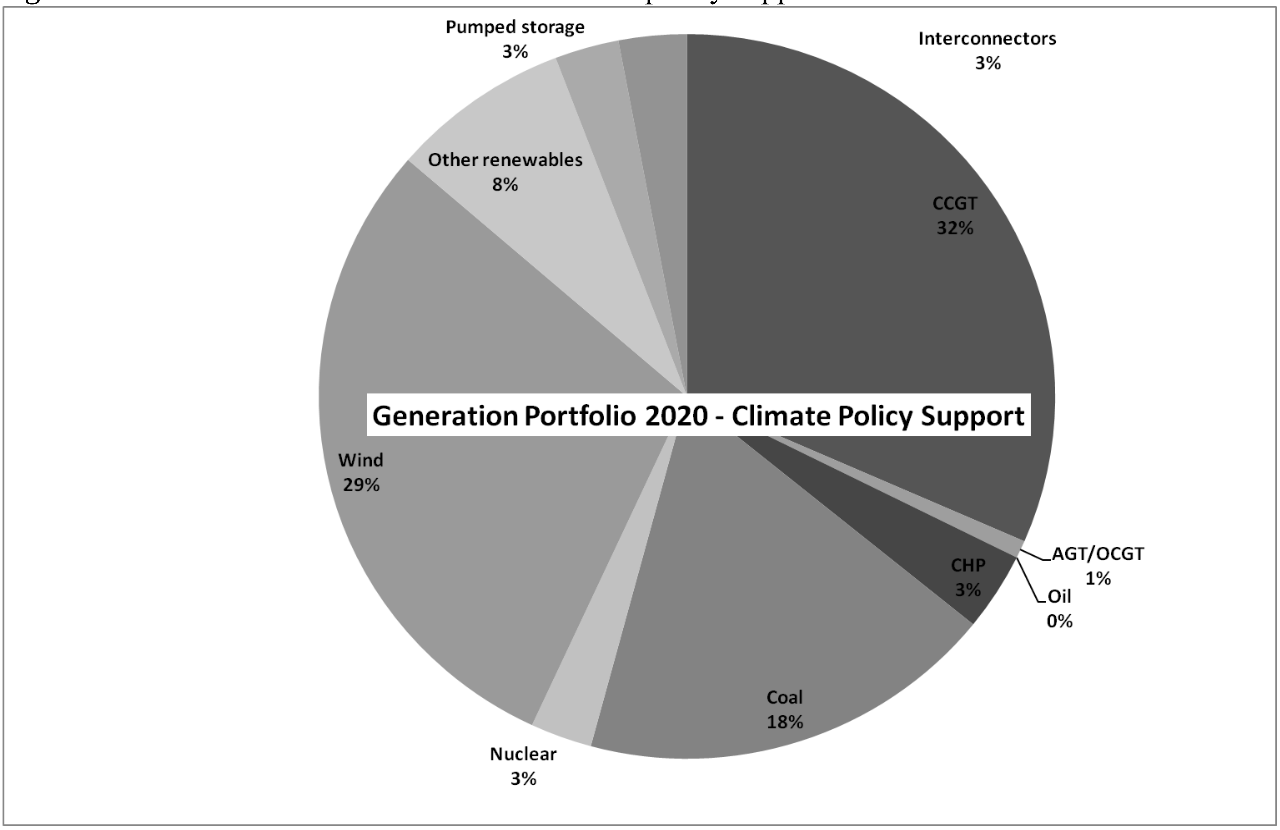


4.2.4. “Climate Policy Support”

This scenario reflects the intention of the policy makers to guarantee that by 2020 at least 22% of the total energy supplied is satisfied by renewable generation. This condition is fulfilled by adding a binding constraint to the model, by allowing a growing staged addition of RES to the system. Capacity additions reflect this supplementary constraint and are therefore quite different to what is observed in the “Energy Only Market” scenario. There is, on average more than 2GW addition of wind (offshore and onshore) capacity each year, with a total in excess of 10 GW for both technologies for the whole period. Wind generation capacity added in 10 year is 24GW.

Also 6 GW of gas-fired plants are added to the system, in particular after 2015 when a significant share of plants subject to the LCPD directive will be forced to retire. In total around 35GW of new capacity is added to the system, including some minor volumes of other renewable plants. It is interesting to note that under this scenario nuclear plants do not represent a viable option. The final share of non fossil fuels in the generation mix in 2020 is around 43%.

Figure 19 – Generation Portfolio 2020 – “Climate policy support”



5. Conclusions

This dissertation aims to contribute to the theoretical and empirical debate on the ability of a liberalised energy market to deliver the required level of supply adequacy. The study after a thorough revision of the main theoretical contributions to the investment dynamics in electricity market has reviewed the different type of risk affecting energy markets (and the electricity market in particular). It has been found that these risks depend on a number of market imperfections existing in the energy markets and in particular on the limited capacity of the current price mechanism to convey the necessary information on scarcity. This is particularly true when policy intervention aims at limiting the natural fluctuation of spot prices.

In particular the current inability of the demand side to convey its true willingness to pay to the supply side, due to the way the network delivers electricity and because of the existing metering limitation, necessitate some form of policy intervention on the maximum level that electricity prices can reach (VoLL or price caps) at peaks time. Setting an optimal price cap, beside its intrinsic complexity, in the absence of efficient demand response management, requires anyway some degree of arbitrariness as to how this limit should be determined.
Altogether the specific characteristics of the electricity market mentioned above have restricted the ability of the liberalised market to deliver the level of supply adequacy via pure market mechanism. Regulatory and political intervention had to set almost everywhere ad hoc targets and standards.

In the face of these intrinsic limitations energy markets are facing growing pressure to play an increasing role in climate change policy. Energy supply should be able to deliver, in the immediate future, a significant decarbonisation of its fuel sources. In particular the European Union has proposed an ambitious target for 2020, establishing that 20% of the internal energy consumption should come from renewable resources.

The fulfilment of the provisions able to satisfy at the same time supply adequacy, decarbonisation of electricity generation and the existence of a competitive market pose a classic policy tri-lemma. Granting supply adequacy at the same time with a substantial fuel decarbonisation in competitive markets could present some degree of incompatibility[75] with existing market design.

The current model applied in the electricity market in the UK relies on pure market dynamics to deliver the necessary level of supply adequacy. In addition price formation in the UK electricity market is determined by the interaction of demand and supply, therefore theoretically spot prices are left free to fluctuate, and even to spike, to their optimal level.
The British electricity market for these reasons represents a natural place to study, with the appropriate methodology, what the level of generation adequacy that market mechanism can deliver over the medium run is (in the period 2011-2020).
A Real Option analysis was performed to determine the generation portfolio that, given the initial generation mix, and taking into account a long-term trajectory for the electricity and fuel price dynamics, would maximise the NPV of future cash flow.
Three possible market scenarios have been successfully simulated, two of those imposing different constrains to the original market model considered: the first imposes the extension of the operational life of some nuclear plants, whereas the second guarantees premium tariffs to renewable generation.

The results have shown that pure market mechanism, albeit able to guarantee a reasonable level of adequacy of supply, even in the difficult situation generated after LCPD retirement (in 2016) and projected to cope with the existing 20-20-20 targets, does not ensure a growth ratio of renewable resources in line with the more ambitious long-term (2050) targets. Also

[75] Liberalised competitive markets are able to deliver supply adequacy, but cannot guarantee, in the absence of heavy market distortion, that the type of generation added to the system is compliant with climate policy requirements. Vice versa it would be possible to satisfy the condition for adequate supply also in line with climate policy requirements if it was decided not to rely on market mechanism, therefore returning to some form of the earlier command and control model.
Finally the requirements for supply adequacy should be eased, allowing for non market mechanism (black outs), to determine the level of security of supply optimally, then the market mechanism would be able to deliver, the new, much lower, level of supply under the restricted emission policy constraints.

taking into account the inability of current market solution to justify massive investment in nuclear.

Nevertheless, the climate policy scenario, while supporting the penetration of renewable generation, depress the revenues for each of the other energy sources that, in this case, are not insulated by market and price dynamics. Granting a premium tariff, or other equivalent allowances, only to a part of the portfolio mix raises the perceived risk of investors on the remaining technologies. FiT represent attractive options for policy makers to achieve renewable targets, but does not guarantee long term viability for a well functioning and balanced market in general, that will have a biased tendency to invest in the part of the market that is insulated from competition dynamics.

The remaining case considered, “optimistic nuclear”, does not substantially alter the “rules of the game” but temporarily allows for a derogation of part of the technology mix. This option has showed the lowest level of capacity addition to the system. This could be explained by the fact that this option does not insulate any of the various available technologies from market dynamics, while simply granting a limited derogation for five of the existing nuclear plants.

From the stylised facts emerged from the three scenarios modelled in the analysis above, some policy implications can be drawn that present a degree of general validity:

- In a competitive liberalised market when one segment is insulated from market dynamics, it tend to attract investment, at the expense of the rest of the market;
- General market risk perception in the electricity market, and in each market in general, is an average of the various parts (sub markets) composing it. If in one segment the market risk is reduced to zero, it means that somewhere else market risk is increasing;
- Climate change policy in energy markets might cause policy makers to pick up winners and losers, disregarding market performance.

These brief consideration leads to the following conclusion: climate change policy in the electricity sector can easily distort market signals, polluting prices and therefore market behaviour. In order to guarantee market players, policy makers might be tempted to expand premium tariffs (such as FiT) increasingly to a larger share of the market. This would effectively mean relinquishing the liberalised and vertically de-integrated market model that has emerged over the last few decades in the UK. Picking one (type of) technology, in order to achieve Climate Policy targets, also has an immediate effect on the composition of the optimal portfolio mix. Apart from technical consideration as to the feasibility of such a solution, this instance is, in the long run, detrimental for the security of supply of the system, because it reduces the diversity of the portfolio. Careful consideration should be given to this instance in planning policy intervention in the near future.

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Appendix 1

This section includes the main results, calculations and assumptions used to run the model.

This data is based on published sources and reports, and mostly refers to redpoint Energy (2006) and BERR (2008).

Table A1 - This worksheet sets out the generating capacity of existing and proposed interconnectors until 2020 (in MW)

	Existing Interconnector		
	IFA	Britned	Total
2008	2000	0	2000
2009	2000	0	2000
2010	2000	0	2000
2011	2000	1000	3000
2012	2000	1000	3000
2013	2000	1000	3000
2014	2000	1000	3000
2015	2000	1000	3000
2016	2000	1000	3000
2017	2000	1000	3000
2018	2000	1000	3000
2019	2000	1000	3000
2020	2000	1000	3000
Note that these figures assume maximum capacity is available			

Source: (redpoint Energy, 2006)

Table A2 and A3

Exchange rates

p_DollarPound	1,60
p_EuroPound	1,20

Conversion factors

p_GJMWh	3,60
p_thermMWh	34,12

Table A4 – Parameters adopted for the fuel and generation cost

Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)	CV (GJ/t)	Raw units	Raw 2010	Raw 2011	Raw 2012	Raw 2013	Raw 2014	Raw 2015	Raw 2016	Raw 2017
Biomass energy crops	-	-		£/GJ	7,08	6,89	6,27	6,45	5,89	6,52	5,80	5,16
Biomass regular	-	-		£/GJ	4,75	4,80	4,22	3,93	4,42	3,94	3,85	4,18
Coal	0,34	0,25	25,10	$/t	90,04	96,87	82,93	87,48	53,60	33,88	27,34	31,22
Fuel oil	0,28	0,25	41,00	$/t	338,03	491,88	677,26	939,60	1.012,56	1.104,63	610,89	726,69
Gas	0,19	-		p/th	56,33	77,51	57,35	62,48	76,06	86,51	118,73	110,26
Gas oil	0,36	0,25	43,00	$/t	606,69	742,68	780,17	783,54	985,16	954,17	1.096,74	1.282,82
None	-	-		-								
Nuclear	-	-		£/GJ	0,50	0,54	0,52	0,49	0,57	0,57	0,63	0,59
Carbon				€/t	14,92	16,64	14,31	19,19	19,05	24,87	32,22	43,57
Fuel	**Carbon intensity (t/MWh)**	**Transportation cost (£/GJ)**	**CV (GJ/t)**	**Raw units**	**Raw 2018**	**Raw 2019**	**Raw 2020**	**Raw 2021**	**Raw 2022**	**Raw 2023**	**Raw 2024**	**Raw 2025**
Biomass energy crops	-	-		£/GJ	9,51	8,06	7,56	8,25	8,37	9,24	8,82	8,56
Biomass regular	-	-		£/GJ	4,51	4,23	4,18	3,56	3,27	3,03	2,53	2,79
Coal	0,34	0,25	25,10	$/t	79,13	77,98	84,98	83,92	74,69	95,16	89,26	122,20
Fuel oil	0,28	0,25	41,00	$/t	227,32	446,27	277,71	307,96	513,20	627,65	831,02	1.200,14
Gas	0,19	-		p/th	26,28	29,72	30,79	29,75	17,47	14,90	12,84	13,12
Gas oil	0,36	0,25	43,00	$/t	1.052,65	1.142,98	1.037,16	847,54	947,86	919,38	909,98	643,04
None	-	-		-								
Nuclear	-	-		£/GJ	0,66	0,62	0,70	0,68	0,68	0,69	0,69	0,70
Carbon				€/t	20,93	19,16	24,55	27,14	30,88	21,00	13,68	13,43

Source: redpoint Energy (2006), and author's own calculations.

Table A5 – Plants' decision (at unit level) based on the ROA applied to the LCPD as result from Rubino (2010).

						Closure dates		
	Base	Original	Czech	UK		Original	Czech	UK
EW-ABERTHAW 1	Derogation	Fit SCR	Derogation	Derogation		2025	2020	2023
EW-ABERTHAW 2	Derogation	Fit SCR	Derogation	Derogation		2025	2020	2023
EW-ABERTHAW 3	Derogation	Fit SCR	Derogation	Derogation		2025	2020	2023
EW-BARRY 1	Derogation	Fit SCR	Derogation	Derogation		2025	2020	2023
EW-BARRY 2	Derogation	Fit SCR	Derogation	Derogation		2025	2020	2023
EW-BRIGG	Derogation	Close	Close	Derogation		2015	2015	2023
EW-CORBY	Derogation	Close	Close	Close		2015	2015	2015
EW-COTTAM 1	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-COTTAM 2	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-COTTAM 3	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-COTTAM 4	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-DAMHEAD CREEK	Derogation	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-DEESIDE	Close	Close	Close	Derogation		2015	2015	2023
EW-DIDCOT B1	Derogation	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-DIDCOT B2	Derogation	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-DRAX 1	Fit SCR	Fit SCR	Fit SCR	Fit SCR		2025	2025	2025
EW-DRAX 2	Fit SCR	Fit SCR	Fit SCR	Fit SCR		2025	2025	2025
EW-DRAX 3	Fit SCR	Fit SCR	Fit SCR	Fit SCR		2025	2025	2025
EW-DRAX 4	Fit SCR	Fit SCR	Fit SCR	Fit SCR		2025	2025	2025
EW-DRAX 5	Fit SCR	Fit SCR	Fit SCR	Fit SCR		2025	2025	2025
EW-DRAX 6	Fit SCR	Fit SCR	Fit SCR	Fit SCR		2025	2025	2025
EW-EGGBOROUGH 4	Close	Derogation	Derogation	Derogation		2020	2020	2023
EW-EGGBOROUGH 1	Close	Derogation	Derogation	Derogation		2020	2020	2023
EW-EGGBOROUGH 2	Close	Derogation	Derogation	Derogation		2020	2020	2023
EW-EGGBOROUGH 3	Close	Derogation	Derogation	Derogation		2020	2020	2023
EW-FERRYBRIDGE C1a	Derogation	Derogation	Derogation	Derogation		2020	2020	2023
EW-FERRYBRIDGE C1b	Derogation	Derogation	Derogation	Derogation		2020	2020	2023
EW-FIDDLERS FERRY 1	Close	Derogation	Derogation	Derogation		2020	2020	2023
EW-FIDDLERS FERRY 2	Derogation	Derogation	Derogation	Derogation		2020	2020	2023
EW-FIDDLERS FERRY 3	Derogation	Derogation	Derogation	Derogation		2020	2020	2023
EW-FIDDLERS FERRY 4	Close	Derogation	Derogation	Derogation		2020	2020	2023
EW-FIFOOTS 1	Derogation	Derogation	Derogation	Derogation		2020	2020	2023
EW-FIFOOTS 2	Derogation	Derogation	Derogation	Derogation		2020	2020	2023
EW-FIFOOTS 3	Derogation	Derogation	Derogation	Derogation		2020	2020	2023
EW-KILLINGHOLME 2	Derogation	Close	Close	Derogation		2015	2015	2023
EW-KILLINGHOLME 1a	Derogation	Close	Close	Derogation		2015	2015	2023
EW-KILLINGHOLME 1b	Derogation	Close	Close	Derogation		2015	2015	2023
EW-KINGS LYNN A	Derogation	Close	Derogation	Derogation		2015	2020	2023
EW-LITTLE BARFORD	Derogation	Fit SCR	Derogation	Derogation		2025	2020	2023
EW-LYNEMOUTH 1	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-LYNEMOUTH 2	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-LYNEMOUTH 3	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-PETERBOROUGH	Derogation	Close	Close	Derogation		2015	2015	2023
EW-RATCLIFFE 1	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-RATCLIFFE 2	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-RATCLIFFE 3	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-RATCLIFFE 4	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-ROOSCOTE	Close	Close	Close	Close		2015	2015	2015
EW-RUGELEY B1	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-RUGELEY B2	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-RYE HOUSE	Derogation	Close	Derogation	Derogation		2015	2020	2023
EW-SHOTTON DEESIDE	Derogation	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-SOUTH HUMBER BANK P	Derogation	Close	Derogation	Derogation		2015	2020	2023
EW-SOUTH HUMBER BANK P	Derogation	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-WEST BURTON 1	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-WEST BURTON 2	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-WEST BURTON 3	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-WEST BURTON 4	Fit SCR	Fit SCR	Fit SCR	Derogation		2025	2025	2023
EW-CDCL	Derogation	Fit SCR	Fit SCR	Derogation		2025	2025	2023
SC-LONGANNET 1	Close	Derogation	Derogation	Derogation		2020	2020	2023
SC-LONGANNET 2	Close	Derogation	Derogation	Derogation		2020	2020	2023
SC-LONGANNET 3	Close	Derogation	Derogation	Derogation		2020	2020	2023
SC-LONGANNET 4	Close	Derogation	Derogation	Derogation		2020	2020	2023
SC-PETERHEAD	Derogation	Close	Close	Derogation		2015	2015	2023
SC-FIFE POWER	Derogation	Fit SCR	Fit SCR	Derogation		2025	2025	2023

Source: Rubino (2010)

Figure A1 – Realisation of electricity price (simulation)

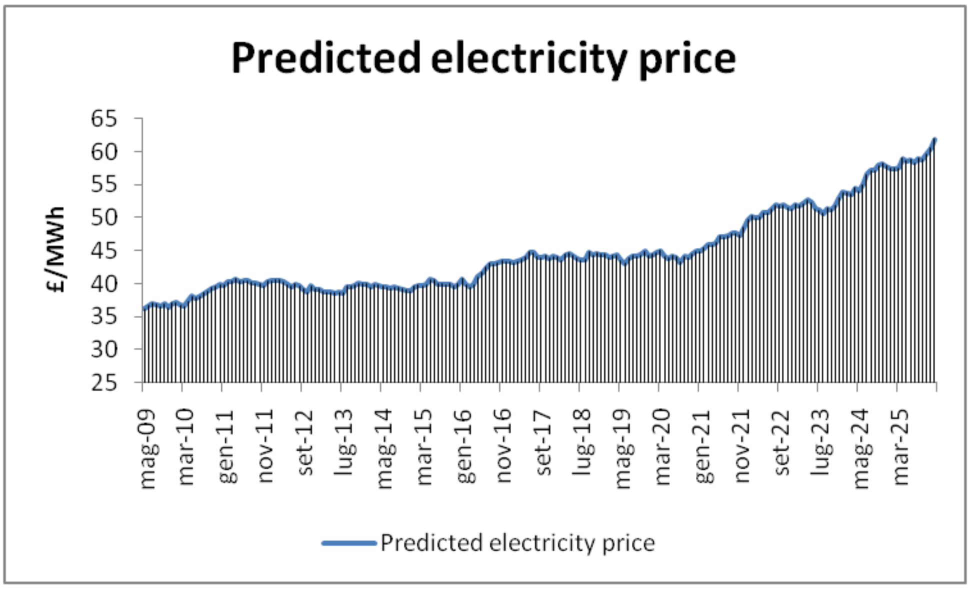


Table A6 – Observed parameters for electricty trajectories

	Data GBM		
Year	**StdDevp of Daily Returns**	**Count of Year**	**Yearly Volatility**
2001	0,134160652	280	224,5%
2002	0,157162185	365	300,3%
2003	0,215514384	365	411,7%
2004	0,134658467	366	257,6%
2005	0,152576126	365	291,5%
2006	0,18233037	365	348,3%
2007	0,216927589	365	414,4%
2008	0,177164822	366	338,9%
2009	0,179012972	104	182,6%
(blank)			
Grand Total	0,175217071	2941	
	Full Sample	2002-2009	2003-2009
Slope	-0,088236188	-0,092374318	-0,10340273
Intercept	2,789769342	3,057218387	3,716148406
Std Error	8,378205331	8,765600201	9,336812512
Long Run Mean	**31,61706565**	**33,0959779**	**35,93859084**
Volatility	3,773727713	3,775665915	3,849128468

Table A7 - GBM parameters for the fuel and electricty trajectories

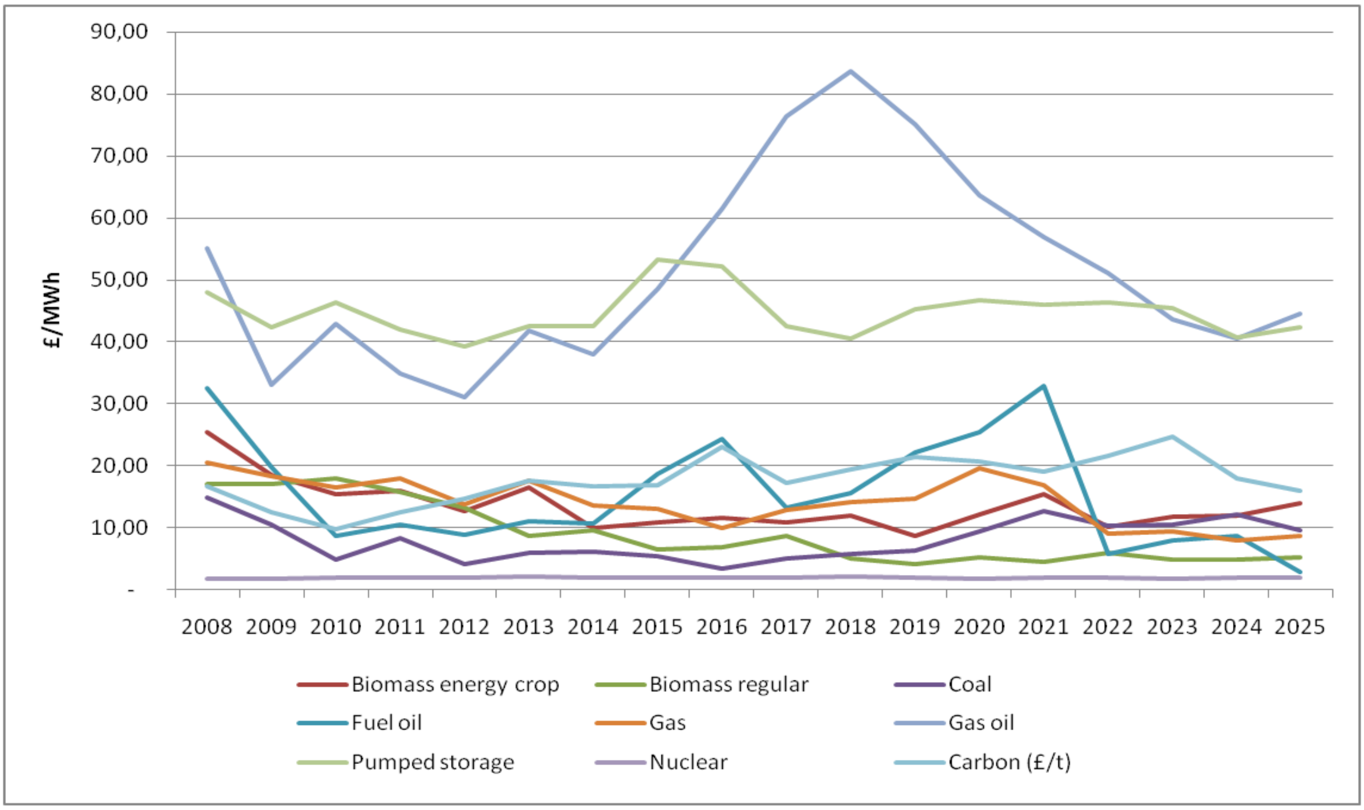
Fuel	σ (volatility)	μ 2010-2015	μ 2016-2025
Biomass energy crop	0,100	0,010	0,010
Biomass regular	0,100	0,010	0,010
Coal	0,234	0,005	0,005
Fuel oil	0,350	0,035	0,008
Gas	0,193	0,011	0,006
Gas oil	0,193	0,011	0,006
Electricity	0,263	0,0028	0,0028
Nuclear	0,050	0,010	0,010
Carbon	0,234	0,005	0,005

Table A8 – De-rated availability

Average availability of plant at peak demand	
Thermal plant	95%
Existing nuclear	70%
New nuclear	90%
Wind	30%
Interconnectors	95%

Source: redpoint Energy (2006)

Figure A1 – Realisation of fuel prices (simulation)



Appendix 2 - Summary of plant characteristics at unit level

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
EW-ABERTHAW 1	RWE	Coal	2,00	34,80	Coal	1	Coal	0,34	0,25
EW-ABERTHAW 2	RWE	Coal	2,00	34,80	Coal	1	Coal	0,34	0,25
EW-ABERTHAW 3	RWE	Coal	2,00	34,80	Coal	1	Coal	0,34	0,25
EW-ABERTHAW GT	RWE	AGT	0,10	10,36	GT	1	Gas oil	0,36	0,25
EW-BAGLAN BAY	IPP	CCGT	0,40	20,77	Gas	1	Gas	0,19	-
EW-BARKING	IPP	CCGT	1,50	25,07	Gas	1	Gas	0,19	-
EW-BARRY 1	CENTRICA	CCGT	1,50	20,51	Gas	1	Gas	0,19	-
EW-BARRY 2	CENTRICA	CCGT	1,50	20,51	Gas	1	Gas	0,19	-
EW-BRIGG	CENTRICA	CCGT	2,50	26,02	Gas	1	Gas	0,19	-
EW-BRIMSDOWN	EON	CCGT	0,40	25,25	Gas	1	Gas	0,19	-
EW-CONNAHS QUAY 1	EON	CCGT	0,80	27,43	Gas	1	Gas	0,19	-
EW-CONNAHS QUAY 2	EON	CCGT	0,80	27,43	Gas	1	Gas	0,19	-
EW-CONNAHS QUAY 3	EON	CCGT	0,80	27,43	Gas	1	Gas	0,19	-
EW-CONNAHS QUAY 4	EON	CCGT	0,80	27,43	Gas	1	Gas	0,19	-
EW-CORBY	EON	CCGT	2,50	24,97	Gas	1	Gas	0,19	-
EW-CORYTON	IPP	CCGT	0,40	24,95	Gas	1	Gas	0,19	-
EW-COTTAM 1	EDF	Coal	2,00	41,07	Coal	1	Coal	0,34	0,25
EW-COTTAM 2	EDF	Coal	2,00	41,07	Coal	1	Coal	0,34	0,25
EW-COTTAM 3	EDF	Coal	2,00	41,07	Coal	1	Coal	0,34	0,25
EW-COTTAM 4	EDF	Coal	2,00	41,07	Coal	1	Coal	0,34	0,25
EW-COWES GT	RWE	OCGT	0,10	21,48	GT	1	Gas oil	0,36	0,25

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
EW-DAMHEAD CREEK	SP	CCGT	0,40	24,98	Gas	1	Gas	0,19	-
EW-DEESIDE	INTERNATIONAL POWER	CCGT	2,50	27,58	Gas	1	Gas	0,19	-
EW-DERWENT	INTERNATIONAL POWER	CCGT	1,50	30,07	Gas	1	Gas	0,19	-
EW-DIDCOT A1	RWE	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
EW-DIDCOT A2	RWE	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
EW-DIDCOT A3	RWE	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
EW-DIDCOT A4	RWE	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
EW-DIDCOT A GT	RWE	AGT	0,10	12,51	GT	1	Gas oil	0,36	0,25
EW-DIDCOT B1	RWE	CCGT	0,80	24,47	Gas	1	Gas	0,19	-
EW-DIDCOT B2	RWE	CCGT	0,80	24,47	Gas	1	Gas	0,19	-
EW-DINORWIG	INTERNATIONAL POWER	PS	80,00	24,12	Pumped storage	3	None	-	-
EW-DRAX 1	DRAX	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-DRAX 2	DRAX	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-DRAX 3	DRAX	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-DRAX 4	DRAX	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-DRAX 5	DRAX	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-DRAX 6	DRAX	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-DRAX GT9	DRAX	AGT	0,10	18,28	GT	1	Gas oil	0,36	0,25
EW-DRAX GT10-12	DRAX	AGT	0,10	18,28	GT	1	Gas oil	0,36	0,25
EW-DUNGENESS A	BNFL	Nuclear	0,40	39,77	Nuclear	2	Nucl ear	-	-
EW-DUNGENESS B1	BE	Nuclear	0,40	46,85	Nuclear	2	Nucl ear	-	-

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
EW-DUNGENESS B2	BE	Nuclear	0,40	46,85	Nuclear	2	Nuclear	-	-
EW-EGGBOROUGH 4	BE	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-EGGBOROUGH 1	BE	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-EGGBOROUGH 2	BE	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-EGGBOROUGH 3	BE	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-FAWLEY	RWE	Oil	0,40	18,98	Oil	1	Fuel oil	0,28	0,25
EW-FAWLEY GT	RWE	AGT	0,10	8,68	GT	1	Gas oil	0,36	0,25
EW-FAWLEY COGEN	RWE	OCGT	0,10	21,48	GT	1	Gas oil	0,36	0,25
EW-FERRYBRIDGE C1a	SSE	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-FERRYBRIDGE C1b	SSE	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-FERRYBRIDGE C2a	SSE	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-FERRYBRIDGE C2b	SSE	Coal	2,00	42,72	Coal	1	Coal	0,34	0,25
EW-FERYBRIDGE C GT	SSE	AGT	0,10	18,28	GT	1	Gas oil	0,36	0,25
EW-FFESTINIOG	INTERNATIONAL POWER	PS	75,00	17,52	Pumped storage	3	None	-	-
EW-FIDDLERS FERRY 1	SSE	Coal	2,00	43,17	Coal	1	Coal	0,34	0,25
EW-FIDDLERS FERRY 2	SSE	Coal	2,00	43,17	Coal	1	Coal	0,34	0,25
EW-FIDDLERS FERRY 3	SSE	Coal	2,00	43,17	Coal	1	Coal	0,34	0,25
EW-FIDDLERS FERRY 4	SSE	Coal	2,00	43,17	Coal	1	Coal	0,34	0,25
EW-FIDDLERS FERRY GT	SSE	AGT	0,10	18,73	GT	1	Gas oil	0,36	0,25
EW-FIFOOTS 1	IPP	Coal	2,00	34,80	Coal	1	Coal	0,34	0,25
EW-FIFOOTS 2	IPP	Coal	2,00	34,80	Coal	1	Coal	0,34	0,25
EW-FIFOOTS 3	IPP	Coal	2,00	34,80	Coal	1	Coal	0,34	0,25

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
EW-GRAIN	EON	Oil	0,40	24,54	Oil	1	Fuel oil	0,28	0,25
EW-HARTLEPOOL	BE	Nuclear	0,40	54,13	Nuclear	2	Nuclear	-	-
EW-HEYSHAM 1	BE	Nuclear	0,40	51,34	Nuclear	2	Nuclear	-	-
EW-HEYSHAM 2	BE	Nuclear	0,40	51,34	Nuclear	2	Nuclear	-	-
EW-HINKLEY POINT	BE	Nuclear	0,40	41,29	Nuclear	2	Nuclear	-	-
EW-INDIAN QUEENS	INTERNATIONAL POWER	OCGT	5,00	18,47	GT	1	Gas oil	0,36	0,25
EW-IRONBRIDGE 1	EON	Coal	2,00	38,98	Coal	1	Coal	0,34	0,25
EW-IRONBRIDGE 2	EON	Coal	2,00	38,98	Coal	1	Coal	0,34	0,25
EW-KEADBY	SSE	CCGT	0,80	25,93	Gas	1	Gas	0,19	-
EW-KILLINGHOLME 2	CENTRICA	CCGT	2,50	28,40	Gas	1	Gas	0,19	-
EW-KILLINGHOLME 1a	EON	CCGT	2,50	28,39	Gas	1	Gas	0,19	-
EW-KILLINGHOLME 1b	EON	CCGT	2,50	28,39	Gas	1	Gas	0,19	-
EW-KINGS LYNN A	CENTRICA	CCGT	2,50	26,94	Gas	1	Gas	0,19	-
EW-KINGSNORTH 1	EON	Coal	2,00	38,68	Coal	1	Coal	0,34	0,25
EW-KINGSNORTH 2	EON	Coal	2,00	38,68	Coal	1	Coal	0,34	0,25
EW-KINGSNORTH 3	EON	Coal	2,00	38,68	Coal	1	Coal	0,34	0,25
EW-KINGSNORTH 4	EON	Coal	2,00	38,68	Coal	1	Coal	0,34	0,25
EW-KINGSNORTH GT	EON	AGT	0,10	14,24	GT	1	Gas oil	0,36	0,25
EW-LITTLE BARFORD	RWE	CCGT	0,80	25,53	Gas	1	Gas	0,19	-
EW-LITTLEBROOK	RWE	Oil	0,40	24,54	Oil	1	Fuel oil	0,28	0,25
EW-LITTLEBROOK GT	RWE	AGT	0,10	14,24	GT	1	Gas oil	0,36	0,25

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
EW-LYNEMOUTH 1	IPP	Coal	2,00	45,96	Coal	1	Coal	0,34	0,25
EW-LYNEMOUTH 2	IPP	Coal	2,00	45,96	Coal	1	Coal	0,34	0,25
EW-LYNEMOUTH 3	IPP	Coal	2,00	45,96	Coal	1	Coal	0,34	0,25
EW-MEDWAY	SSE	CCGT	1,50	24,99	Gas	1	Gas	0,19	-
EW-OLDBURY	BNFL	Nuclear	0,40	35,88	Nuclear	2	Nuclear	-	-
EW-PETERBOROUGH	CENTRICA	CCGT	2,50	26,73	Gas	1	Gas	0,19	-
EW-RATCLIFFE 1	EON	Coal	2,00	38,98	Coal	1	Coal	0,34	0,25
EW-RATCLIFFE 2	EON	Coal	2,00	38,98	Coal	1	Coal	0,34	0,25
EW-RATCLIFFE 3	EON	Coal	2,00	38,98	Coal	1	Coal	0,34	0,25
EW-RATCLIFFE 4	EON	Coal	2,00	38,98	Coal	1	Coal	0,34	0,25
EW-RATCLIFFE GT	EON	AGT	0,10	14,54	GT	1	Gas oil	0,36	0,25
EW-ROCKSAVAGE1	SSE	CCGT	1,50	27,79	Gas	1	Gas	0,19	-
EW-ROCKSAVAGE2	SSE	CCGT	1,50	27,79	Gas	1	Gas	0,19	-
EW-ROCKSAVAGE3	SSE	CCGT	1,50	27,79	Gas	1	Gas	0,19	-
EW-ROOSCOTE	CENTRICA	CCGT	2,50	27,63	Gas	1	Gas	0,19	-
EW-RUGELEY B1	INTERNATIONAL POWER	Coal	2,00	38,98	Coal	1	Coal	0,34	0,25
EW-RUGELEY B2	INTERNATIONAL POWER	Coal	2,00	38,98	Coal	1	Coal	0,34	0,25
EW-RUGELEY B GT	INTERNATIONAL POWER	AGT	0,10	14,54	GT	1	Gas oil	0,36	0,25
EW-RYE HOUSE	SP	CCGT	2,50	25,30	Gas	1	Gas	0,19	-
EW-SALTEND 1	INTERNATIONAL POWER	CCGT	0,40	27,60	Gas	1	Gas	0,19	-
EW-SALTEND 2	INTERNATIONAL POWER	CCGT	0,40	27,60	Gas	1	Gas	0,19	-
EW-SALTEND 3	INTERNATIONAL	CCGT	0,40	27,60	Gas	1	Gas	0,19	-

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
	POWER								
EW-SEABANK PHASE 1	SSE	CCGT	0,80	22,31	Gas	1	Gas	0,19	-
EW-SEABANK PHASE 2	SSE	CCGT	0,40	22,31	Gas	1	Gas	0,19	-
EW-FELLSIDE	BNFL	CCGT	2,50	27,82	Gas	1	Gas	0,19	-
EW-SHOREHAM	SP	CCGT	0,40	22,81	Gas	1	Gas	0,19	-
EW-SHOTTON DEESIDE	IPP	CCGT	0,80	27,62	Gas	1	Gas	0,19	-
EW-SIZEWELL A	BNFL	Nuclear	0,40	40,92	Nuclear	2	Nuclear	-	-
EW-SIZEWELL B	BE	Nuclear	0,40	48,01	Nuclear	2	Nuclear	-	-
EW-SOUTH HUMBER BANK PHASE 1	CENTRICA	CCGT	2,50	27,59	Gas	1	Gas	0,19	-
EW-SOUTH HUMBER BANK PHASE 2	CENTRICA	CCGT	1,50	27,59	Gas	1	Gas	0,19	-
EW-SUTTON BRIDGE 1	EDF	CCGT	0,80	26,77	Gas	1	Gas	0,19	-
EW-SUTTON BRIDGE 2	EDF	CCGT	0,80	26,77	Gas	1	Gas	0,19	-
EW-SUTTON BRIDGE 3	EDF	CCGT	0,80	26,77	Gas	1	Gas	0,19	-
EW-TAYLORS LANE GT	EON	OCGT	0,10	18,71	GT	1	Gas oil	0,36	0,25
EW-TEESSIDE 1	IPP	CCGT	2,50	31,02	Gas	1	Gas	0,19	-
EW-TEESSIDE 2	IPP	CCGT	2,50	31,02	Gas	1	Gas	0,19	-
EW-TILBURY 1	RWE	Coal	2,00	38,68	Coal	1	Coal	0,34	0,25
EW-TILBURY 2	RWE	Coal	2,00	38,68	Coal	1	Coal	0,34	0,25
EW-TILBURY 3	RWE	Coal	2,00	38,68	Coal	1	Coal	0,34	0,25
EW-TILBURY GT	RWE	AGT	0,10	14,24	GT	1	Gas oil	0,36	0,25
EW-WEST BURTON 1	EDF	Coal	2,00	41,07	Coal	1	Coal	0,34	0,25
EW-WEST BURTON 2	EDF	Coal	2,00	41,07	Coal	1	Coal	0,34	0,25
EW-WEST BURTON 3	EDF	Coal	2,00	41,07	Coal	1	Coal	0,34	0,25

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
EW-WEST BURTON 4	EDF	Coal	2,00	41,07	Coal	1	Coal	0,34	0,25
EW-WEST BURTON GT	EDF	AGT	0,10	16,63	GT	1	Gas oil	0,36	0,25
EW-WYLFA	BNFL	Nuclear	0,40	45,04	Nuclear	2	Nucl ear	-	-
EW-GREAT YARMOUTH	RWE	CCGT	0,40	24,08	Gas	1	Gas	0,19	-
EW-CDCL	EON	CCGT	0,40	26,23	Gas	1	Gas	0,19	-
EW-IMMINGHAM1	IPP	CCGT	0,40	28,45	Gas	1	Gas	0,19	-
EW-IMMINGHAM2	IPP	CCGT	0,40	28,45	Gas	1	Gas	0,19	-
EW-SPALDING 1	CENTRICA	CCGT	0,40	26,57	Gas	1	Gas	0,19	-
EW-SPALDING 2	CENTRICA	CCGT	0,40	26,57	Gas	1	Gas	0,19	-
SC-LONGANNET 1	SP	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
SC-LONGANNET 2	SP	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
SC-LONGANNET 3	SP	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
SC-LONGANNET 4	SP	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
SC-COCKENZIE 1	SP	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
SC-COCKENZIE 2	SP	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
SC-COCKENZIE 3	SP	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
SC-COCKENZIE 4	SP	Coal	2,00	36,95	Coal	1	Coal	0,34	0,25
SC-TORNESS	BE	Nuclear	0,40	45,12	Nuclear	2	Nucl ear	-	-
SC-HUNTERSTON	BE	Nuclear	0,40	45,12	Nuclear	2	Nucl ear	-	-
SC-PETERHEAD	SSE	CCGT	2,00	40,88	Gas	1	Gas	0,19	-
SC-FIFE POWER	SSE	CCGT	2,00	36,98	Gas	1	Gas	0,19	-
SC-CHAPEL CROSS	BNFL	Nuclear	-	-	Nuclear	2	Nucl ear	-	-
SC-GRANGEMOUTH	IPP	CCGT	2,00	36,98	Gas	1	Gas	0,19	-
SC-CRUACHEN	SP	PS	75,00	13,40	Pumped	3	None	-	-

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
					storage				
SC-FOYERS	SSE	PS	75,00	13,40	Pumped storage	3	None	-	-
SC-SCOT HYDRO	IPP	Hydro	0,40	12,51	Hydro	2	None	-	-
EW-LANGAGE1	CENTRICA	CCGT	0,40	14,38	Gas	1	Gas	0,19	-
EW-LANGAGE2	CENTRICA	CCGT	0,40	14,38	Gas	1	Gas	0,19	-
EW-MARCHWOOD1	SSE	CCGT	0,40	18,85	Gas	1	Gas	0,19	-
EW-MARCHWOOD2	SSE	CCGT	0,40	18,85	Gas	1	Gas	0,19	-
EW-STAYTHORPE	RWE	CCGT	0,40	25,82	Gas	1	Gas	0,19	-
EW-IMMINGHAM3	Other	CCGT	0,40	28,45	Gas	1	Gas	0,19	-
SC-GLENDOE	SSE	Hydro/RO C	0,40	12,51	Hydro	2	None	-	-
EW-PEMBROKE	RWE	CCGT	0,40	28,45	Gas	1	Gas	0,19	-
GB-NEWRENEWOTHER	Other	ROC	-	-	Other renewables	2	None	-	-
EW-GRAIN CCGT	EON	CCGT	0,40	23,86	Gas	1	Gas	0,19	-
EW-SEVERN BARRAGE	Other	Severn Barrage	-	56,00	Barrages and Tidal Range	2	None	-	-
EW-MERSEY TIDAL	Other	Mersey Tidal	-	56,00	Barrages and Tidal Range	2	None	-	-
GB-SEVERN	Other	CCGT	-	-	Gas	1	Gas	0,19	-
GB-Demonstration CCS	Other	Coal	-	-	Coal	1	Coal	0,34	0,25
GB-WEST BURTON CCGT	EDF	CCGT	-	-	Gas	1	Gas	0,19	-
GB-OTHER7	Other	CCGT	-	-	Gas	1	Gas	0,19	-
GB-OTHER8	Other	CCGT	-	-	Gas	1	Gas	0,19	-
GB-OTHER9	Other	CCGT	-	-	Gas	1	Gas	0,19	-
GB-OTHER10	Other	CCGT	-	-	Gas	1	Gas	0,19	-
EW-CHP1	IPP	CHP	2,50	30,00	Gas	1	None	-	-
EW-CHP2	IPP	CHP	0,75	32,67	Gas	1	None	-	-

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
ROC Onshore wind - EON	EON	Onshore wind	-	40,00	Wind	2	None	-	-
ROC Onshore wind - RWE	RWE	Onshore wind	-	40,00	Wind	2	None	-	-
ROC Onshore wind - SSE	SSE	Onshore wind	-	40,00	Wind	2	None	-	-
ROC Onshore wind - ScotPwr	SP	Onshore wind	-	40,00	Wind	2	None	-	-
ROC Onshore wind - Centrica	CENTRICA	Onshore wind	-	40,00	Wind	2	None	-	-
ROC Onshore wind - EdF	EDF	Onshore wind	-	40,00	Wind	2	None	-	-
ROC Onshore wind - Other	IPP	Onshore wind	-	40,00	Wind	2	None	-	-
ROC Offshore wind - EON	EON	Offshore wind	-	68,00	Wind	2	None	-	-
ROC Offshore wind - RWE	RWE	Offshore wind	-	68,00	Wind	2	None	-	-
ROC Offshore wind - SSE	SSE	Offshore wind	-	68,00	Wind	2	None	-	-
ROC Offshore wind - ScotPwr	SP	Offshore wind	-	68,00	Wind	2	None	-	-
ROC Offshore wind - Centrica	CENTRICA	Offshore wind	-	68,00	Wind	2	None	-	-
ROC Offshore wind - EdF	EDF	Offshore wind	-	68,00	Wind	2	None	-	-
ROC Offshore wind - Other	IPP	Offshore wind	-	68,00	Wind	2	None	-	-
ROC Hydro	IPP	ROC	-	68,00	Other renewables	2	None	-	-
ROC Landfill gas	IPP	ROC	-	97,00	Other	2	None	-	-

Plant	Company	Type	VOM	Fixed cost	Category	Deg. Group	Fuel	Carbon intensity (t/MWh)	Transportation cost (£/GJ)
					renewables				
ROC Sewage gas	IPP	ROC	-	97,00	Other renewables	2	None	-	-
ROC ACT	IPP	ROC	-	97,00	Other renewables	2	None	-	-
ROC Solar PV	IPP	ROC	-	97,00	Other renewables	2	None	-	-
EW-non ROC waste	IPP	Non-ROC	-	97,00	Waste energy	2	None	-	-
ROC generation - Other	IPP	ROC	-	97,00	Other renewables	2	None	-	-