The UK Electricity Markets: Its Evolution, Wholesale Prices and Challenge of Wind Energy

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by

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Declaration

In accordance with Regulations for Higher Degrees by Research, I hereby declare that this thesis now submitted for the candidature of Doctor of Philosophy is a result of my own research and independent work except where reference is made to published literature. I hereby certify that the work embodied in this thesis has not already been submitted in candidature for any other institute of higher learning.

All errors remain my own.

Candidate:

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Abstract

This thesis addresses the problems associated with security of the electricity supply in the UK. The British electricity supply industry has experienced a significant structural change. Competition has been brought into the electricity industry and a single wholesale electricity market of Great Britain has been established. The evolution of the British electricity market raises new challenges, such as improving the liquidity of wholesale markets and developing clean energy. The wholesale electricity prices are less transparent and trading arrangements are very complex in the British electricity market. In this thesis a fundamental model, called a stack model, has been developed in order to forecast wholesale electricity prices. The objective of the stack model is to identify the marginal cost of power output based on the fuel prices, carbon prices, and availability of power plants. The stack model provides a reasonable marginal cost curve for the industry which can be used as an indicator for the wholesale electricity price. In addition, the government‘s targets for climate change and renewable energy bring new opportunities for wind energy. Under the large wind energy penetration scenario the security of the energy supply will be essential. We have modelled the correlations between wind speed data for a set of wind farms. The correlation can be used to measure the portfolio risk of the wind farms. Electricity companies should build their portfolio of wind farms with low or negative correlations in order to hedge the risk from the intermittency of wind. We found that the VAR(1) model is superior to other statistic models for modelling correlations between wind speeds of a wind farm portfolio.

Key words: Electricity supply industry, competition, trading arrangements, wholesale prices, stack model, climate change, wind energy, energy security, portfolio risk.

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Chapter1 Introduction

The UK electricity industry has changed radically in the last two decades. Structural change and regulatory reform had a major impact on the UK electricity supply industry (ESI). Several other countries have used the British experience to restructure their electricity industries. The consequent development of wholesale electricity markets in the UK has been a focus for many academic studies.

The purpose of this dissertation is to extend these studies in a number of ways. These include the development of a marginal cost pricing model of short-run wholesale energy prices and the analysis of forecasting models for wind energy, which is likely to have a strong bearing on spot electricity prices in the future. The thesis also reviews the evolution of the British electricity industry, showing how this new research relates to the current market structure. In what follows, we explain how these themes are linked. We begin by reviewing the evolution of the UK electricity market.

Thus, following Mrs Thatcher's radical reforms of the public sector, the previously nationalised British ESI was privatised in 1990. The components of the ESI were unbundled into four sectors: generation, transmission, distribution, and supply. The transmission and distribution sectors are both natural monopolies. The main objective of the reform was to bring competition into the generation and supply sectors. A wholesale electricity spot market, the Pool, was set up after privatisation in England and Wales. Market power in the generation sector was a significant problem under the Pool mechanism. It was no surprise that the pricing mechanism of the Pool was criticised for being manipulated by the two large generation companies, PowerGen and National Power. The argument was that this duopoly exercised market power to manipulate the market price (there was a uniform price in the Pool), by changing the electricity output or offer prices.

The regulator replaced the Pool with the new electricity trading arrangements (NETA) in England and Wales in 2001. The regulator argued that NETA was more in line with arrangements being adopted in other competitive commodity and energy markets than was the Pool (Offer 1998d). In 2005, NETA was extended to Scotland under the British Electricity Trading and Transmission Arrangements (BETTA). Since the introduction of NETA, there has been a growing degree of vertical reintegration of the ESI. There have been mergers between generating and supply companies as well as mergers between electricity supply, water, and gas companies. There are many retail packages of electricity and gas available to consumers. However, this should not be seen as necessarily implying that the retail market is competitive. In fact, retail prices tend to move quite sluggishly. In contrast, wholesale electricity prices are volatile. They are also less transparent than retail prices because of the extremely complicated pricing mechanism under NETA and BETTA. The majority of electricity trading is carried out through bilateral contracts for which traded prices are not revealed. Moreover, there are power exchanges, futures markets, and balancing markets for electricity trading. The amount of research on this relatively new market is limited.

The difficulty of understanding fluctuations in the British wholesale electricity price is the main motivation for our research. There are two main categories of electricity pricing models: stochastic models and fundamental models. Stochastic models are proposed for modelling spot price dynamics in different commodity and financial markets. These models are widely used to model the unique characteristics of spot electricity prices, such as seasonality, mean reversion, jumps and volatility.

We have examined these characteristics of the British spot electricity price. However, the one of the main contributions of the study is to develop a fundamental model, called a stack model. The objective of the stack model is to identify the marginal cost of power output based on the fuel prices, carbon prices, and availability of power plants in the wholesale electricity market. This price can be regarded as an indicator of market wholesale prices, which can help the market participants to determine their trading strategy. The stack model provides the marginal cost curve for the generation industry. This marginal cost curve can be updated to take account of changes in input costs, such as fuel prices, carbon costs and load factors.

Another function of the stack model is that it can be used to examine the level of security of the energy supply. The thesis describes some experiments conducted using the stack model including the variation of capacity. One variation is on carbon and fuel prices whilst another concerns different levels of penetration of wind farms. A further variation includes how transmission constraints may impact on wholesale prices.

The electricity market is designed to work as other commodity markets under NETA/BETTA. A balancing market has been developed to keep the electricity system in physical balance at all times in order to maintain the security and quality of supply. In real time, both demand and supply are subject to variations that cause imbalance of the system. Imbalance is costly and settled by the system operator. The system operator must have access to spinning or immediately available reserves, the cost of which will increase as the magnitude of the imbalance increases (Milborrow 2001).

Electricity companies and traders come into the balancing market to buy or sell electricity at the spot price. By this means they adjust their supplied electricity level to equal to the volume of their bilateral contracts. For example, a supplier may need to buy more electricity to meet the short position of their contract. A generator may need to sell extra electricity generated (which means they generate more electricity than the amount of their contracts) to the spot market to generate additional revenue. Nevertheless, the main price and reverse price associated with the balancing mechanism are very volatile. There are arguments that the imbalance settlement of NETA causes difficulties for renewable energy companies in both financial and physical terms. Due to intermittency of renewable sources they are a potential cause of imbalance and thus exposed to high imbalance charges. It has been suggested that large-scale aggregation by wind generators might be a solution to the problem (Milborrow 2001).

Since wind is the only ‘fuel’ to power the wind turbines, intermittency of wind can cause the electricity output pattern of wind farms to fluctuate. The intermittency of winds is stochastic. The short term fluctuations of wind farm output require system balancing services. The long term variations have impact on the reliability of the system in meeting peak time demand. On average there is around one hour per year in summer when over 90% of the UK experiences low wind speed conditions, however these extreme weather conditions occurs around one hour every five years in winter. The UK experiences a seasonal maximum in wind power availability during winter and an increase in wind power availability during the day times compared to night times. (Sinden 2007)

The government has set a series of targets for developing renewable energy and dealing with climate change. The government believes that successful renewable energy technologies are the main route by which the goal of a low carbon economy can be achieved. At present, it appears that the majority of renewable energy will have to be delivered by wind, since wind power generation is the most developed technology available at present.

Another research question included in this thesis is to what extent wind energy outputs are "risky" in the sense of being positively correlated. Or are they effectively independent? Energy companies who own a large-scale aggregation of wind farms need to manage the associated risks of fluctuated wind energy output, due to the intermittency of wind. The idea is that electricity companies' portfolios are composed of diverse wind farms at different locations. A portfolio of wind farms with a negative correlation or no correlations of wind energy output has low portfolio risk. The wind energy output of this portfolio will not be affected when wind speed increases in one part of the country and decreases in another part of the country. I have investigated the correlations associated with wind turbine output can be measured by using the correlation of wind speed at those wind farms using a variety of statistical models, one of which, Vector Autoregression models takes account of cross-site correlations.

This thesis is organised in the following way. Chapter 2 reviews the evolution of British ESI. It summarises the features of British ESI in terms of generation, demand, technology, and regulation in the process of evolution. It also explores the development of the wholesale market and trading arrangements. This helps us to understand the complexity of the British electricity market and helps place the subsequent analysis in context. Chapter 3 examines the characteristics of British electricity spot prices by developing a stack model for forecasting the marginal cost curve for the generation industry and illustrating some of its properties. The first part of Chapter 4 reviews British renewable energy policy and its development. It explains the main issues associated with a large wind energy scenario. Then different methodologies are used to model the correlations of wind speed in order to assess the portfolio risk of wind farms. Chapter 5 concludes the study.

Chapter 2 The evolution of British electricity market

1. Introduction

It has been twenty years since the British government privatised the electricity supply industry. The first country to reform its electricity industry was Chile, which commenced reform in 1978. However, reforms in the British ESI were more radical. The liberalisation and restructuring of British ESI has become a case study for industrial reform throughout the world.

The evolution of the British electricity market refers to the reform of competition and regulation in the electricity industry rather than technical evolution. The purpose of the reform was to create a new world of competition and choice in the electricity industry.

There are four components of the industry. These components are generation, transmission, distribution and supply. The generation sector is the production process of electricity in power stations. Transmission refers to the transportation of electricity through high voltage cables (the so called 'grid'). Distribution is the transportation of electricity at lower voltages and facilities to final customers. Supply refers to the sale of electricity to final customers.

The construction and maintaining electricity transmission and local electricity distribution systems requires large sunk capital costs and capital equipment "with significant visual environmental impact" (Pollitt and Newbery 2000). The transmission and distribution sectors are often considered to be natural monopolies. The key concept of the reform was that "it is possible and desirable to separate the transportation from the thing transported" (Hunt & Shuttleworth 1996b). The objectives of the reform in the British ESI were to unbundle its sectors, regulate the natural monopoly of wire businesses, and improve competition in the generation and retailing sectors.

The following key questions need to be addressed before any further research is applied. What is the structure of the British electricity industry? What are the rationales behind the reforms? How do electricity markets work? Why do we need electricity markets?

This chapter provides the background and foundation for my PhD thesis. It enables me to understand the process of evolution in the British ESI and the pricing mechanisms under different trading arrangements. This chapter is organised as follows: Section 2 discusses the evolution of electricity industry in chronological order. It describes and discusses the features of the British ESI in terms of generation, demand, regulation, and technology. There are economic, regulatory, and political reasons for privatising the industry and introducing new electricity trading arrangements. In section 3 the wholesale electricity markets, the Pool and NETA, are introduced. It compares the pricing rules under different market mechanisms. The last section is the conclusion.

2. History of the British ESI

2.1 Nationalised industry 1947-1989

The British ESI was nationalised by the Labour government under the Electricity Act 1947. The nationalised British ESI exhibited considerable 'structural diversity', in having four grids, three regulatory systems, and two regulators (Pollitt & Newbery 2000). There was one grid for England and Wales, one for Northern Ireland, and two in Scotland. The three regulatory systems were based on the three separate jurisdictions. Thus the regulator in

Northern Ireland was different from that in Scotland, who in turn was different from that in England and Wales.

The ESI in England, Wales, and Southern Scotland was nationalised in 1947 as the British Electricity Authority (BEA). In the period between 1947 and 1955 the BEA and 12 Area Boards were responsible for the generation, distribution, and retailing of electricity in England and Wales. In the South of Scotland the two boards controlled by the BEA were the South East Scotland Electricity Board and the South West Scotland Electricity Board. These boards were integrated into the BEA generation activity and were responsible for distribution and supply of electricity in the region. However, the North of Scotland Hydro-electric Board (NSHB or NSHEB), which had controlled the electricity supply in the North of Scotland from 1943, remained independent of the BEA.

In England and Wales the BEA was replaced on 1 April 1955 by the Central Electricity Authority (CEA) under the Electricity Reorganisation (Scotland) Act 1954. This resulted in the merger of the two Scottish Area Boards and the associated electricity generation and distribution plants into the South of Scotland Electricity Board (SSEB). Thereafter, the vertically integrated Scottish ESI was under the control of the SSEB and NSHB.

There were further reorganisations of the British ESIs in England and Wales in 1957. The Central Electricity Generating Board (CEGB) was established to replace the CEA under the Electricity Act 1957. The CEGB was a vertically integrated statutory monopoly due to control of the electricity generation and bulk transmission. The 12 Area Boards acted as regional distribution monopolies which were responsible for local distribution, metering, billing, customer advice, and ancillary activities. The CEGB had determined the ‘principal organizational features of the industry for the subsequent 30 years' (Vickers & Yarrow 1998). In addition, they had interconnectors with Scotland and France with which it could trade electricity.

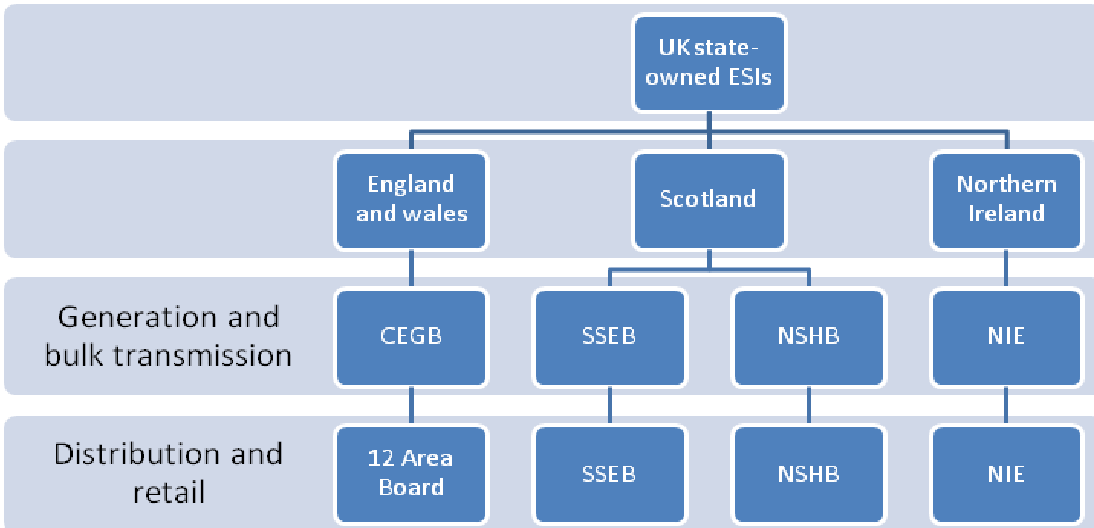
The vertically integrated Scottish ESI was export-constrained by the capacity of the inter-connector to England. The capacity of the Scotland to England interconnector had been initially upgraded from 800MV (Megawatt) to 1200MV, and then up to 2000MV (Pollitt & Newbery 2000). The capacity of this interconnector is currently being strengthened to carry power at the rate of 2200MV[1].

Northern Ireland Electricity (NIE) was a single state-owned vertically integrated company, which was established by statute in 1972. It was physically separated from the rest of the United Kingdom until the construction of an inter-connector (500MV) with Scotland was completed in 2001.

The structure of British ESIs in each region remained stable from 1947 to 1989. The public owned ESIs were a traditional regulated monopoly. Figure 2.1 describes the integrated structure of the British state-owned ESIs in three regions. The Electricity Council was established as a regulatory watchdog that facilitated coordination and set rates in England, Wales, and Scotland. The CEGB and Area Boards were both represented on the coordinating body of the Electricity Council.

[1] http://www.scottish.parliament.uk/business/committees/enterprise/inquiries/rei/ec04-reis-shawalan.htm

Figure 2.1. The structure of the British nationalised ESIs 1957-1989



Source: "The changing face of the electricity markets in the UK" (Tovey, 2003).

Supply and demand

In 1948 the BEA operated 297 power stations with a total generating capacity of 12,900 MW (Surrey 1996). In 1958, the CEGB inherited 262 power stations with a capacity of 24.34GW (gig watt), and annual sales of 40.3TWh (terawatt hours). The electricity output increased rapidly in the 1960s due to a huge programme of power-station and transmission-line construction. By 1971 the CEGB owned 187 power stations with a total capacity of 49.28GW and had annual sales of 184TWh (Wood 2008).

During this period of nationalisation the total generating capacity was increasing despite the declining number of power stations. This was partly due to an increase in power plant size and some of the country's largest coal-fired and nuclear stations started producing power. In the 1970s increasing demand and larger power stations in operation required more power to be transferred around the country. Consequently a 400kv super-grid was completed in this decade. This has enabled the transmission network as whole to take advantage of economies of scale.

The main features of the British ESI in terms of generating capacity, plant mix, and electricity sales in 1987 are summarised in Table 2.1 (Surrey 1996). The nationalised British ESI had generating capacity of over 63GW and annual sales of electricity were more than 256TWh. The British ESI had been developed as a large-scale monopolistic industry in the preceding four decades.

Table 2.1 Main features of British ESI, 1987

Capacity by type	Capacity (MV)	Electricity generated (GWh)	Consumer category	Number (thousands)	Sales (GWh)
Fossil fuel	50,263	226.382	Domestic	22,383	93,254
Nuclear	6,519	50,282	Farm	263	4,109
Hydro	4,085	3,312	Industry/Commercial	2,103	153,689
Other	3,001	512	Other	5	5,137
Total	**63,868**	**280,488**	**Total**	**24,754**	**256,189**

Source: ***"The British electricity experiment" (John Surrey 1996), page16.***

In response to forecasted growth in electricity demand and fears of a shortfall of local coal production, the CEGB improved its hydro power plants, nuclear plants and built new oil plants. Despite the diversification of primary fuel sources, the ESI remained heavily dependent on British deep-mined coal. By the late 1980s, the CEGB met around 75 percent of the fuel requirement from coal and 20 percent from nuclear power (Surrey 1996).

Bulk supply tariffs (BSTs) for distributor (Area Boards) applied to purchases of power from the CEGB. BSTs were the wholesale electricity prices of nationalised electricity industry and were the mechanism for passing all the CEGB costs to the Area Boards and then to final electricity consumers (Surrey 1996). This price mechanism had been altered several times and became highly complex price. BSTs were paid by distributors (Area Boards) for purchasing power from the CEGB and were set on long run marginal costs (LRMC) bases. Each Area Board then distributed and sold its electricity to customers in each region at its own tariffs. The BSTS have two-part charges: one charging for capacity of both generation and transmission, and another one is the variable costs of energy and regionally differentiated losses. The Area Boards offered a variety of tariffs with various forms of peak-hour capacity charges. Whilst the pricing had been complex, the investment planning and particularly investment delivery was poor, slow and costly, and there were few incentives to deliver cost efficiency.

2.2. Problems of state ownership and the process of privatisation

The nationalised ESI was extensively seen as essential to aid economic recovery following the Second World War. It was successful in expanding the electricity capacity and transmission infrastructures. However, the regulatory system reflected an “inefficient equilibrium that only privatisation appeared capable of upsetting” (Gilbert 1996).

Electricity generation was highly dependent on coal during the four decades of state-owned ESI development. There was little incentive to improve the efficiency of generators and no incentive to develop Combined Heat and Power plants (CHP). This was because the sale of heat was not included in the Electricity Council's articles of association (Essex, 2004) and the development of renewable energy was limited. In England and Wales, the CEGB dominated the electricity market and was responsible for the planning and transmission of the electricity supply. As a result, there was no incentive for independent producers to develop renewable electricity since they were unable to sell the electricity to the market.

In addition, the productivity of nationalised ESI in terms of fuel efficiency or use of labour was criticised in the 1970s and 1980s. In the 1970s, the British state-owned utilities produced a level of productivity significantly lower than that of public utilities in other comparable OECD countries (Floud & McClosky 1994). Table 2.2 shows that the British labour productivity in the state-owned electricity industry was significantly less than that in the German and American ESI.

Table 2.2 Comparative labour productivity in network monopolies, 1970-4

Industry	Date	West German output per man/ UK output per man	US output per man/ UK output per man
Gas	1975	2.21	3.32
Electricity	1975	2.11	3.54
Water	1975	0.99	1.97
Railways	1970	1.08	3.95
Local bus/rail	1970	1.34	1.45
Post and telecom	1970/2	1.08	2.28-3.17

Source: Floud & McClosky(1994) Page 189.

In the 1980s, privatisation became the centrepiece of the policy programmes of the Thatcher government (Surrey 1996). The term 'Privatisation' means the government sells the state-owned business to the private sector. In the period between 1979 and 1997 more than £60 billions of state assets were sold to the private sector and the share of employment accounted for by state owned industries fell from over 7 percent to less than 2 percent (Parker 1998). The privatisation of natural public utility sectors began with the sale of telecommunications (1984), followed by gas supply (1986), water and sewerage services (1989), electricity supply (1990) and the railways (1993-1996).

In the early years of Thatcher government reform of the British ESI was implemented to encourage more independent generation. The Energy Act 1983 was introduced to create competition and remove monopoly power from the electricity supply boards. This was intended to open up the industry to new entrants. However, it failed to create sufficient competition and small scale entrants to the market were deterred due to the dominance of the CEGB (Einhorn 1994).

The White Paper 1989 and the Electricity Act 1989 set out the regulatory reform of the British ESI. This reform was seen as a radical and successive means to create competition in the non-natural monopoly sectors of the ESI. The new structure of the electricity supply and generation sectors broke up the vertically integrated structure of the nationalised ESI. A regulatory framework for the natural monopoly sectors-transmission and distribution was established.

Privatisation

The restructuring of the British ESI coincided with the privatisation of the industry. The UK government began this process in 1989 and privatised it through initial public shares offerings in 1990. It divested modern nuclear power stations in 1996 and finally deregulated the market in 1998, resulting in all consumers being able to choose suppliers freely.

In England and Wales the UK government radically restructured the electricity industry on 31st March 1990. The new industry structure was composed of three generating companies: National Power (52 percent of total capacity at that time), PowerGen (33 percent), and Nuclear Electric (15 percent). National Power obtained 60 percent of conventional generating capacity with 40 power stations (about 30GW capacity). The remaining 40 percent of conventional generating capacity with 23 stations (20GW capacity) were placed in PowerGen. Nuclear Electric consisted of 12 nuclear stations (8GW capacity). The National Grid Company (NGC) was separated from the generating companies but got 2GW of pumped storage generation as well as the high voltage grid. The 12 Area Boards were restructured to form 12 Regional Electricity companies (RECs) providing distribution and retailing services.

There were numerous companies offered for sale. The above four companies were vested as public limited companies on 31 March 1990. National Power and PowerGen initially sold sixty percent of their shares on March 1991. The remaining shares in both companies' were sold in February 1995. Nuclear Electric remained in public ownership until July 1996. NGC was transferred to the joint ownership of the RECs, which in turn were sold to the public in December 1990. The RECs each had two separate functions: distribution and retail supply. These functions must be accounted for separately. The government retained a ‘golden share’ in each REC until March 1995, giving it the power to block any takeover or merger.

The electricity industry in Scotland was restructured in a different way. On 31 March 1990, the Scottish ESI was integrated into two geographically distinct companies. The North of Scotland Hydro-Electric Board became Scottish Hydro-Electric (later Scottish & Southern Energy). Non-nuclear assets of the South of Scotland Electricity Board were transferred to Scottish Power plc. These two vertically integrated companies were privatised in June 1991. They were free to sell into the English market using the English pool price as the reference price for Scottish trading, and operating under the same system of regulation (Pollitt & Newbery 2000). The nuclear stations were placed in a state-owned company called Scottish Nuclear. It entered into a contract for all its output with Scottish Power and Hydro-electric for the next 15 years. In 1996 Scottish Nuclear became a subsidiary of British Energy which was privatised shortly after.

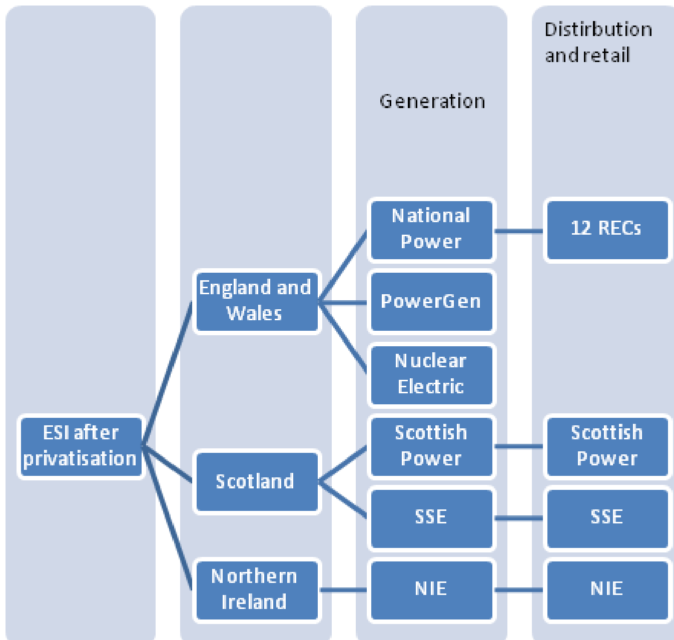
At privatisation the Government took the decision to leave existing structure in Scotland largely intact (Littlechild 1996). This was significantly in contrast to the reorganisation of the industry in England and Wales, due to the relatively small size of the Scottish system, only around one-eighth of the size that in England and Wales. It was considered that vertical integration had been a successful industry structure in Scotland, and that it had particular beneficial features in serving sparsely populated areas. Firstly, Littlechild argued that the “restructuring contracts” which to provide each of the companies with a balanced mix of generating plant had influenced the degree of competition that was likely or possible between the two companies. Secondly, in Scotland, the companies as suppliers were predominantly purchasing from their own generation sources which imposed an explicit limit on the price they can charge in respect of generation (Littlechild 1996). Thirdly, although there was no electricity market in Scotland, generators were allowed to contract directly with consumers with non-discrimination terms. However, there were no means of ensuring generators' outputs match their consumers demand.

After privatisation, there was a substantial overall increase in output of Scottish generation- up 28% between 1989/1990 and 1994/1995. Whilst Scottish demand had grown at only a modest rate, export to England and Wales had increased significantly reflected in an increase in market share of the interconnectors. There had been a pattern of falling price to consumers in England and Wales after privatisation. However, in Littlechild's paper, he provided evidence to show that there were different patterns of falling price in Scotland and England and Wales. In Scotland there had been steady and then falling prices for domestic consumers.

A Northern Ireland Electric company (NIE) containing transmission, distribution, and retailing assets, was established in 1993. The four generating plants were sold to trade buyers in 1992. Until 1999 there was no competitive trading system as all electricity was sold to the power procurement business of NIE under long-term contracts, effectively a single buyer system (Pollitt & Newbery 2000).

Figure 2.2 summarises the structure of ESI after restructuring and privatisation. The ESI in England and Wales was de-integrated. The generation sector was separated from transmission, distribution, and retail sectors. In Scotland and Northern Ireland the ESIs were vertically integrated, but with separate accounting regimes for generation, distribution, and retail.

Figure 2.2. The structure of ESI after privatisation.



The Electricity Council was replaced by a new system of independent regulation. It was headed up by the director general of electricity supply supported by the Office of Electricity Regulation (OFFER), to regulate the privatised electricity industry in England, Wales and Scotland.

After privatisation there was a major shift from coal to natural gas with the purchases of British coal falling from 74 million tonnes in 1991 to 30 million by 1996 (Newbery & Pollitt 1997). This decrease led to lower carbon dioxide emissions and the lifting of the European ban on burning gas to generate electricity. However, it had a huge negative impact on the British coal industry. The massive decline of the coal industry led to employment levels falling by 243,000 through the privatisation (Newbery & Pollitt 1997).

2.3. Discussion of the rationale behind privatisation

A major objective of privatisation was to improve economic efficiency. However, there were also political reasons for restructuring. In 1972 and 1974, striking coal miners caused major disruption to British electricity supplies. Margaret Thatcher became Prime Minister on 4th May 1979. She moved to reduce or eliminate union power, partly by means of privatising UK utilities – a traditional seat of union power.

In addition, the processes of restructuring and privatisation are separate dimensions of change. The British electricity industry was restructured prior to privatisation. There were both structural and ownership reasons to reform the British ESI. Firstly, the British electricity industry might learn a lesson from the reform of the British gas industry, the most relevant privatisation prior to that of the electricity industry. The gas industry was privatised as one entity—British Gas (BG). It was argued that BG as a public monopoly was basically transformed into a private monopoly. In favour of this arrangement was the notion that the single firm may take advantage of internalising externalities. However, it was argued that it was a 'cosy monopoly business' (Hawley 1999), which would need strictly regulated intervention to benefit consumers. As a monopoly it is hard to set up a competitive operating framework, raising the question of whether or not the company should have been broken up prior to privatisation. In 1996 BG was split into two separately listed companies, BG and Centrica. This was achieved by drawing a distinction between functional sectors. BG comprises extensive global exploration and production activities as well as the gas pipeline and storage network. Centrica provides the retail services in the UK. The process of the British ESI reform was different from the reform of the British Gas industry. In England and Wales the CEGB was initially split into three companies in order to break up the monopoly, and was then privatised. In addition, the NGC got the transmission networks which remained a natural monopoly.

Secondly, if a government decides it wants to privatise its electricity industry, it needs to place a value on the asset (Hunt & Shuttleworth 1996a). The value of an asset is the net present value of future cash flows the asset can earn. It is difficult to measure the value of the whole ESI because each sector has a different nature and regulation. The government needs to provide sufficient information to investors and also to assure the security and supply of electricity. Reforms in the ESI were not only to change management an ownership but also to change the industry structure to improve competition. Privatisation only meant changing ownership but restructuring was necessary to make competition feasible.

In the electricity industry it is feasible to separate four different functional sectors. The transmission and distribution sectors own the infrastructure or monopoly franchise. In order to avoid negative externalities (for example, duplication of networks) and improve the security of the network it is necessary to keep networks as a natural monopoly, but with direct government regulation. However, there are many generators and retail service companies in the relevant markets. It also makes 'entry contestable' which is 'the ability of entrants to lock in the entry price with a contract as in generation' (Newbery & Pollitt 1997). Therefore, separating potentially competitive parts of the industry (generation and retail sectors) from the natural monopoly network is feasible. As a result the British government restructured the electricity industry shortly before privatisation.

2.4 Privatised British ESI 1990-2001

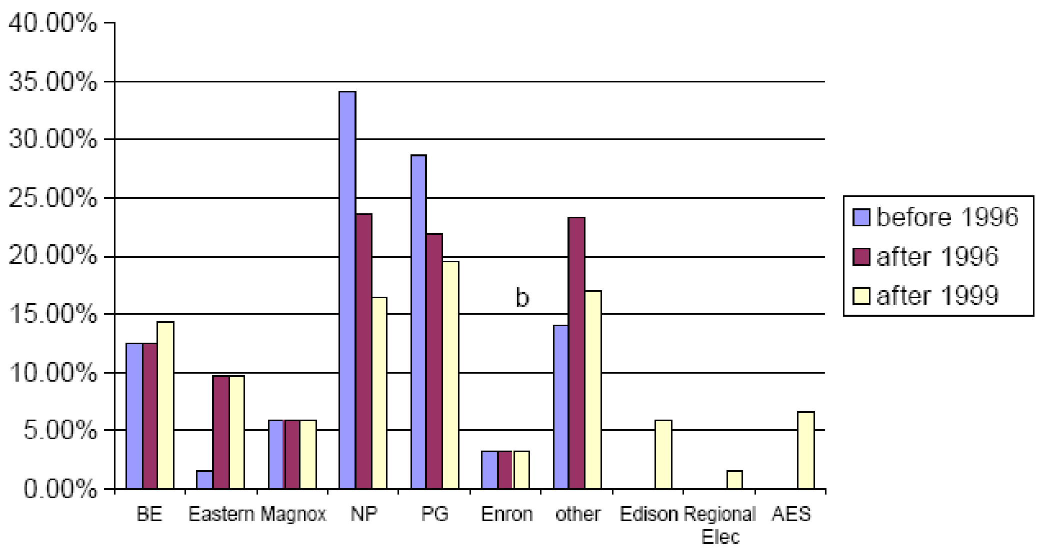
Since 1990 the electricity industry in England and Wales has experienced considerable de-integration from the structure which preceded privatisation. In 1990 the industry was split into four components: generation, transmission, distribution, and supply. The transmission and distribution grids had separate ownership from generation plants. They were regulated monopolies that provided open and comparable access at reasonable rates. It is widely accepted that competitive markets are feasible in electricity generation and supply sectors.

There has been extensive criticism of the level of competition in electricity generation. In the first three years operation of the Pool the high concentration of generation plants was criticised. The potential for serious market power problems has been indicated through oligopoly simulation analysis, since suppliers face extremely inelastic demand and entry requires long lead times (Green & Newbery 1992). By the end of 1993, the regulator had decided that Pool prices were at unjustifiable levels and that more competition would be needed to bring them down (Green 1996).

The structure of generation was changed again. The generators discarded plants to rival companies on two occasions. Once in order to avoid referral to the Monopolies and Mergers Commission (MMC) and once in return for being permitted to merge with the electricity retailers (Green 2006). National Power divested 4GW and PowerGen divested 2GW of coal-fired plants to Eastern Group in 1996. They later divested their capacity again and in 1999 the two dominate companies had less than 25% market share. The change in market shares in generation is described by Bunn and Martoccia (2005), as shown in Figure 2.3. The level of competition in generation was improved following the decline in market share of two dominating generation companies,

They found that the value of Hirshman-Herfindahl Index (HHI), defined as the sum of the squared market shares of the companies in the market, was around 1600 following the divestments of 1996. This is often used as a normative index of the adequacy of competition and had come down from 3800 when the industry was restructured in 1990. Further divestments in 1999 resulted in an HHI value of around 1100. This is well below the US antitrust mergers threshold of 1800, generally taken as a benchmark for a competitive market (Bunn & Martoccia 2005).

Figure 2.3. Declining market shares in generation.



Source: Page 307 (Bunn & Martoccia 2005)

Table 2.3 presents the capacity and market share for each generator in 1990 and 1998. The market share of the two main generators, National Power and PowerGen, were reduced to 27 percent and 25 percent respectively. The new entrants had market share of 12 percent in 1998 with generation capacity of 7.3 GW. The surplus of capacities was created in England and Wales after market restructure. One potential reason could be that the new combined-cycled gas turbines (CCGT) were profitable investments. Another reason is that coal-fired power plants are incentivised to stand by for operation due to the high capacity payments. The capacity payments are collected from customers as a prorated uplift similarly to other uplift charges such as transmission charge (Oren 2000).

Table 2.3. Generators' capacity and market share in 1990 and 1998.

	1990		1998	
	Capacity (GW)	Market share (%)	Capacity (GW)	Market share (%)
National Power	30	47	17	27
PowerGen	19	30	15.4	25
Eastern	0	0	6.7	11
Nuclear Elect	8.7	14	7.3	12
Magnox Elect	0	0	3.1	5
New entrants	0	0	7.3	12
First Hydro	2.1	3	2.1	3
Interconnectors	2.9	5	3.2	5
Other	0.2	1	0.2	1
Total	62.8	100	62.3	100

Source: "Preview of electricity trading arrangements" (Offer 1998c).

The effects of entry were also studied by Green and Newberry in their 1992 paper. They found that the new generators made the entry decision based on whether the current average annual spot price exceeds the entrant's costs. Theoretically, existing generators had incentives to set lower prices to deter entrants. In practice however, IPPs (Independent Power Producer), usually with equity participation by RECs, signed 15-year contracts with their REC for the sale of electricity and also had contracts to purchase gas. They could lock in future prices and hence avoid the risk of retaliatory pricing behaviour by the incumbents (Pollitt & Newbery 2000). Those potential entrants made the generation market contestable. The “dash for gas” resulted in over 14GW out of 62GW total capacity being CCGT by 1998.

Figure 2.4. RECs in England, Wales and Scotland in 1990.

Source: National Grid Company

Figure 2.4 shows the location of 14 RECs in Scotland, England and Wales. The government implemented restructuring in the local distribution and retail sectors and laid out a three-step timetable for introducing competition into retailing. After the industry was privatised in 1990, the 5000 consumers with more than 1MW demand were free to contract with any supplier. These consumers account for approximately a third of total electricity demand, although all other consumers were in captive market in which local RECs had franchise monopoly. In 1994 between 45,000 to 50,000 customers with a demand of 100kW to 1MW were free to choose their supplier. In 1998 the whole retail market deregulated, meaning that all customers in the UK are now free to choose their suppliers. Even small businesses and domestic customers had access to competition in 1998. Customer choice is critical in forcing the generator to adopt the least-cost fuel choices and limit the franchise monopoly power of RECs.

In Scotland two electricity companies were vertically integrated, thus generation prices in Scotland were regulated. The regulator used a formula that would lead two Scottish electricity companies to converge with prices in England by the mid 1990s (Green 2006).

2.5. RPI-X regulatory regime

The country's transmission and distribution sectors remained natural monopolised and were regulated by the OFFER and since 1999 by the Ofgem- Office of gas and electricity market. Transmission was still a monopoly through the NGC, although the networks were open to use by other parties and operated on a price cap basis. Access to the distribution operation of the RECs was regulated so that any seller of electricity had equal right to use the associated distribution network. This required regulation to limit prices and to ensure that the network was adequate to the task of securing competitive supplies.

Under the traditional RPI-X system proposed by Littlechild in 1983 and in use in telecoms, gas, airports, water as well as in electricity, there is a relatively simple but powerful balance between:

- Obligations to deliver outputs (obligations to connect, to develop an economic and efficient network, to meet planning standards, etc.) and
- Incentives to reduce costs (Crouch 2006).

In each REC, the overall distribution charges were price-capped at RPI-X (retail price index). X is generally considered to be a productivity factor, and equals average cost reduction of comparable firms. The firms' incentives to reduce operating costs (OPEX) were stronger than capital expenditure (CAPEX) throughout the first review period, partly due to the greater use of comparative analysis mimicking competitive pressure in this area (Crouch 2006). The reason is that the link between input of CAPEX and output - in terms of changes in the performance of the assets - is much less immediate for CAPEX than it is for OPEX, so companies can defer capital expenditure more easily (NAO 2002). Therefore, the allowed revenues for RECs were capped under this framework. Ofgem instituted rolling (five year) retention periods for CAPEX for the electricity distribution sector with effect from 1 April 2000. This allows companies to realize the benefits of their cost reduction efforts over a set period of time, or until the next review cycle comes due[2].

Ofgem's primary objective, as defined in the Electricity Act 1989 is to protect the interests of electricity and gas consumers, where appropriate through promoting competition. For network monopolies, Ofgem protects consumers' interests through a system of incentive

[2] http://actrav.itcilo.org/actrav-english/telearn/global/ilo/frame/elect2.htm#RPI-X: Price Caps Versus Rate-of-Return Regulation

regulation. The incentives to reduce costs arise because companies that do so get to keep the benefits for a period of time (Crouch 2006). Ofgem reported in 2002 that Ofgem's use of this RPI-X framework to control monopoly suppliers' prices had resulted in substantial efficiency savings and price reductions for consumers, but found that regulators should continue to consider risks inherent in the RPI-X approach, which could distort incentives for investment[3].

There are several criticisms of the RPI-X framework. Firstly, Helm (2003) criticised that "RPI-X does not encourage investment, and truncates the management of the networks into five-year periods, creating a mismatch between the time horizon of asset management and investment decisions, and those which are profit-maximizing under RPI-X." The "sweating of assets" may have contributed to underinvestment in electricity infrastructure in last decade. It is because that forward-looking price-setting period is long enough for shareholders to reap some of the benefits of cost efficiencies. This raised questions about the trade-off between low prices and the level of network renewal and investment. In addition, there was a deviation from competitive market that RPI-X set fixed prices for a fixed period. The regulation did not measure or create incentives for the companies' true output efficiency. The further criticism of the RPI-X framework is that it fails to incorporate aspects of the public interest other than economic efficiency (Helm 2003). Such as social and environmental issues need to be taken into account and which may arise within the five-year period.

[3] http://www.parliament.uk/documents/commons-committees/energy-and-climate-change/NAO%20Briefing%20for%20ECCC%20on%20Performance%20of%20Ofgem_P1%20(2).pdf

2.6. NETA—reintegrated industry 2001-2005

The New Electricity Trading Arrangement (NETA) was introduced in England and Wales on 27th March 2001, replacing the Pool with a system of voluntary bilateral markets and power exchanges. The government attempted to reduce the high electricity prices in England and Wales and reduce the concentration among generators. NETA was operated by ELEXON, the Balancing and Settlement Code Company (BSCCo). All licensed electricity companies were obliged to sign the BSC and other parties could also opt to do so.

There was a growing degree of vertical reintegration of the ESI. In the electricity industry there had been mergers between generating and supply companies as well as mergers between electricity supply, water, and gas companies. The size of generating companies had been approximately in proportion to their own consumer base. The vertically integrated structure for industry developed from 1996 onwards.

By the end of May 2005 the generation sector was decentralised leaving more than 40 major generators of which the “Big Six” dominated the British gas and electricity market. Table 2.4 lists the percentage of distribution capacity for those companies. The generation plants were owned by British Energy at that time. However, British Energy de-listed from the London Stock Exchange on 3 February 2009 and is now part of EDF Energy. The combination of EDF Energy and British Energy formed one of the UK’s largest energy companies.

Table 2.4. Percentage distribution of capacity for "Big Six" energy companies. (at the end of May 2005)

Company	Capacity (% of British ESI total capacity)
British Energy	15%
RWE	12.3%
E.on UK	11.8%
Scottish & Southern Energy	11.3%
Scottish Power	8%
EDF	6%

Source: BERR statistic.

The other five companies are integrated energy companies owing both generation and retail operations. The ownership structure of each supplier is summarised in Table 2.5 in 1990, 2001 and 2004.

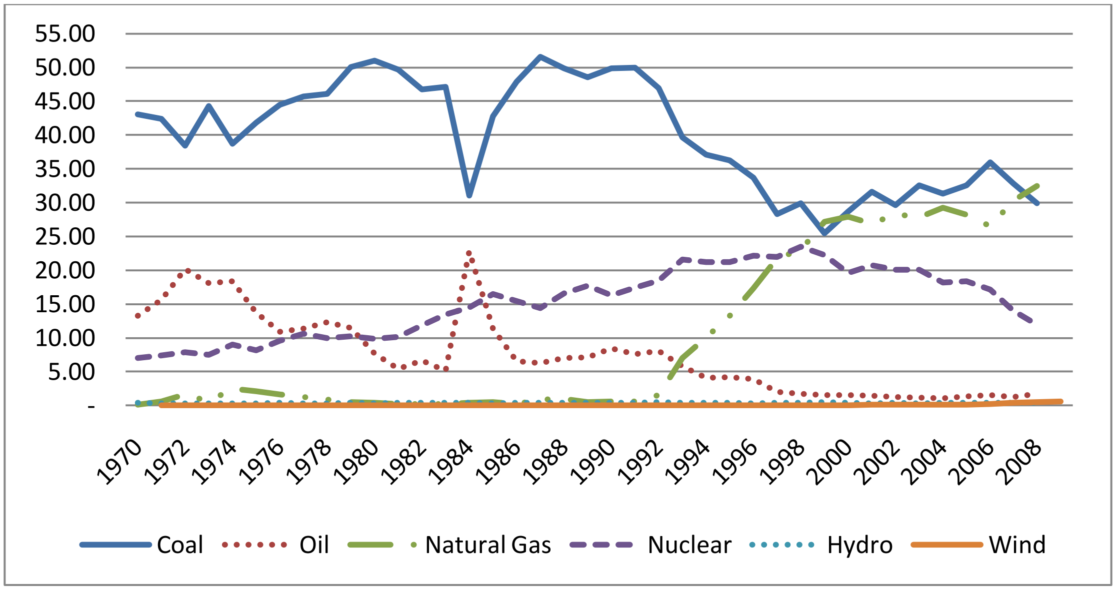
Table 2.5 Ownership structure of electricity suppliers.

RECs in 1990	In 2001	In 2004
Midlands **Yorkshire** **Northern**	Innogy	Npower (REW)
Eastern **Norweb**	TXU (USA)	PowerGen (E.on)
Scottish Hydro-electric **Southern** **SWALEC**	SSE	SSE
London **SWEB** **SEEBOARD**	EDF	EDF
Scottish Power **Manweb**	Scottish Power	Scottish Power
East Midlands	PowerGen	PowerGen (E.on)

Source: Wikipedia.

In April 2004 Scottish Hydro Electric-Southern Electric (SSE) acquired Atlantic Electric and Gas. Powergen purchased TXU's British generation and retail operations. These mergers raise competition concerns. The concentration of electricity was even higher after the German utility group E-on completed a takeover of PowerGen.

Figure 2.5 Fuel input for electricity generation 1970-2008



Source: BERR.

Figure 2.5 shows the distribution of fuel input for electricity generation from 1970 to 2008. Prior to the privatisation of the British ESI, the fuel input for electricity generation depended heavily on coal and oil. The UK experienced a year-long coal mining strike between 1984 and 1985. From Figure 2.5 it is clear that oil as an input increased significantly together with a dramatic reduction of coal input during this period. Throughout the late 1980s and 1990s there was a massive shift by the newly privatised electricity companies towards generation using natural gas. This became known as the "Dash for gas". By 2000, 39% of the UK's electricity came from gas-fired stations compared to less than 1% in 1990. The key drivers for this shift were the development of North Sea gas and later gas turbines had higher efficiency. Another main reason for "Dash for gas" was the domestic gas market, which was gradually opened up from April 1996. Until then, British gas was vertically integrated and signed long-term contracts for beach deliveries of gas. The gas industry has been gradually unbundled, a spot market has emerged, and the spot price of gas was about half the old contract price after privatisation. New gas was therefore cheaper and new suppliers can offer considerable discounts on the British Gas price, effectively stranding the old contracts[4] in late 1990s.

There has been continuing reliance on fossil fuel for generation under NETA with the rise in gas prices prompting a slight increase in the proportion of coal in the supply mix in recent years (2000-2007). The UK has recently become a net importer of gas since 2004. The nuclear fraction has declined as power plants age and some nuclear plants are out of service for repairs.

Renewable sources still make up a very small portion of the generating mix. Wind energy is the fastest growing type of renewable energy, but there are frequent difficulties in gaining planning consent for onshore and offshore turbines. Although the government is committed to generating 10% of electricity from renewable sources by 2010, it is extremely unlikely that the target will be reached[5]. The government has plans for a new generation of coal-fired power plants provided it is proven that they can reduce their emissions[6]. In addition, the government has given a green light to plans for replacement nuclear stations – a significant shift in outlook from the time of the 2003 Energy White Paper. Renewable polices will be discussed in the Chapter 4 of this thesis.

During the 1990's there were two separate Regulators, OFFER and Office of Gas Regulation (OFGAS). In June 1999, the two separate Regulators were merged into Office

[4] http://www.econ.cam.ac.uk/faculty/newbery/files/iaee.pdf
[5] There are 6.9% of electricity from renewable sources in 2010.
[6] http://news.bbc.co.uk/1/hi/uk_politics/8014295.stm

of Gas and Electricity Markets (Ofgem), to recognise the important link between Gas and Electricity. At the same time it was appreciated that there could be a conflict of interest between the duties of the Regulator and its responsibility in consumer protection. A new body, Energywatch, was established as a result of the Utilities Act in 2000. In 2002 the electricity system operator NGC, merged with the corresponding gas operator (TRANSCO) to form National Grid Transco (NGT) (Tovey 2003).

Criticisms of NETA

The generating and retailing sectors have become more competitive after privatisation and restructuring. However, there are concerns about the new market structure under NETA. NETA does not provide any obvious means of dealing with transitory shocks which create a suddenly shortage and send prices soaring upwards (Bidwell & Henney 2004). In these cases, NETA would be vulnerable to the threat of intervention by regulatory and political authorities. The anticipation of such intervention to cap prices has had a dampening effect on investment incentives. This problem seems to be prevalent in electricity markets and underlies the various capacity payments and obligations used around the world to smooth out rewards for building capacity and to provide a more continuous stimulus to investment (Bidwell & Henney 2004). The implications of the lack of such arrangements creating a barrier to security of supply in the UK is worthy of further investigation.

NETA has created specific problems for renewable and intermittent generators. This is because, given a system designed with large-scale coal and nuclear in mind, "there is little balancing capacity for renewable on the system and the transmission network is ill-designed to cope" (Helm 2002). The arrangement of intermittent and remotely located small-scale embedded generation is very expensive. The NETA arrangements create a further disadvantage to such production by deterring investments which would assist in the transition to a more renewable-intensive energy balance.

2.7. BETTA- - A single wholesale electricity market

NETA was extended to Scotland following the British Electricity Trading and Transmission Arrangements (BETTA) on 1st April 2005. The principles and market mechanisms remain unchanged. The purpose of BETTA is to facilitate the creation of a single, integrated, and competitive wholesale electricity market covering the whole of Great Britain (GB).

This involves:

- A single GB system operator

- Common rules and charging arrangements for connecting to and using the transmission system;

- A common set of balancing and settlement arrangements.

In general terms, the distribution of demand and generation across the GB transmission system is such that much of the generation capacity is located in or towards the northern regions, while much of the demand is located in the southern areas of the system. Therefore power broadly flows from the north to the south, particularly at peak time. The stability and consistency of the system are maintained by the sole GB system operator.

The NGC has published a seven year statement about the objectives of development for the British ESI[3].The aggregate power station capacity is projected to rise from 76.3GW in 2006.07 to 94.5GW by 2012/13. The largest proportion of the overall increase is due to CCGT plant at 53.4%[7]. The second largest proportion of the increase is due to wind energy, with on-shore wind accounting for 27% and off-shore wind accounting for 18.2% of the increase. On this basis, the capacity of CCGT plant would overtake that of coal in 2008/09. By 2011/12, CCGT capacity would exceed coal capacity by 4.6GW and account for 35.6% of the total transmission contracted installed generation capacity. Similarly, wind generation capacity (both on-shore and off-shore) is set to rise to 9.4GW by 2012/13. Newly installed capacities will change the composition of the generation sector, thereby changing the marginal costs of power plants. Power stations across the UK are coming to the end of their natural life. The majority of the current fleet of nuclear power stations will be decommissioned by 2020. These plants currently make up approximately 16 per cent of electricity generation. There are further plans to decommission coal-fired power stations. Power stations generating a minimum of 20GW will need to be replaced in the next 10 to 15 years[8]. In addition, BETTA will facilitate economies of scale in transmission system operation and imbalance measurement and settlement, by means of a single operator replacing the current three operators.

3. Developments in the British electricity market

The restructuring and reform in the British ESI has not only unbundled the ownership and improved competition in generation and supply, but has also resulted in the wholesale

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[7] http://www.nationalgrid.com/uk/sys_06/print.asp?chap=3

[8] http://www.osec.ch/internet/osec/de/home/export/countries/gb/export/economic_report.-ContentSlot-55341-File.File.pdf/EnergySectorReport2008-invest_en.pdf

electricity market operating more like a commodity market. This section describes and compares the different electricity trading arrangements within the relevant wholesale markets. It helps us to understand the rules of electricity trading and the development of these rules.

3.1 The liberalised market –The Pool, 1990-2001

The establishment of a wholesale electricity market (the Pool) in 1990 has been one of the main achievements from the process of restructuring and privatisation of the electricity industry. The Pool was the basic design for determining the electricity price in the original British wholesale electricity market (England and Wales) through which all publicly supplied electricity was sold.

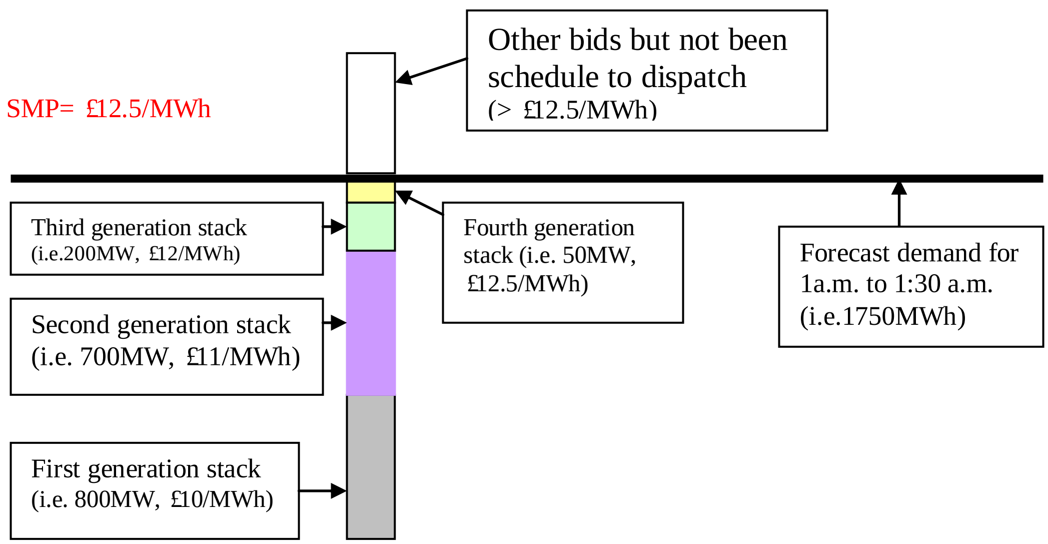
3.1.1 The Pool mechanism

The Pool was a mandatory uniform-price auction and day-ahead spot market. It was mandatory because generators with a capacity greater than 100MW were required to sell electricity units via the Pool. In addition, all suppliers and large users were required to buy electricity from the Pool. All electricity was despatched by the NGC. The NGC was both the independent system operator and the independent market operator, which ran the market's clearing, settlement and payment systems. All generators were required to follow instructions from the NGC in order to maintain the balance between generation and demand.

Therefore, the Pool was a central despatch mechanism. The NGC decided whether a generating unit would be despatched based on a "price merit order". The generators submitted bids to the NGC for the various amounts of power they were willing to sell at various prices and for time periods during the following day. In other words, generators submitted bids to the NGC in order to generate electricity. The NGC produced a forecast of demand (plus any reserve required) for each half hour period of the following day and then scheduled the generators' offers to meet this level of demand. The NGC would stack the generating units (which were bid by generators for specific half hour) by price ascending order until the forecasted demand had been met. This could be seen as a supply curve by stacking the bids in price merit order (Bower 2000). The NGC would then begin planning the operational despatch of plants and calculate the half-hourly system marginal price (SMP) for the following day. The SMP was the cost of generation from the most expensive generation plant accepted by the NGC, based on a forecast of demand with transmission constraints ignored. Figure2.6 presents the process of generators bidding in the Pool for a particular half hour segment. Thus, the merit order was established through this competitive process for each half hour, ranking each generating unit by price.

Theoretically, the profit-maximising strategy for the owner of a single plant is to bid at marginal cost in the competitive wholesale market. The SMP was then intended to reflect the short-run marginal cost of electricity. However, to ensure system security during peak demand load, it was requested that certain selected stations had generating sets available. Therefore, there was an additional payment called the capacity payment which was paid to generators for each unit of capacity declared available to generate, regardless of whether or not it was called upon. It was irrespective of output and calculated on the day prior to trading. The capacity payment was a kind of financial incentive for maintaining some additional (peak load) generation capacity in the event that demand exceeded consumption forecast (EIA 1997). The capacity payment was not the actual cost, and it was based on the expected cost of power cuts. This capacity payment is formula driven which relates actual demand to the capacity of the system (Robinson 2000).

Figure2.6 Example of merit order and SMP



Source: The changing face of the Electricity Markets in the UK (Tovey 2003).

The expected cost of power cuts was the difference between the economic value of the load which cannot be met and the short-run marginal cost of meeting it. The government set the first item as the Value of Lost Load (VOLL). The SMP was believed to be equal to the short-run marginal cost. Hence, the capacity payment was calculated as equal to the Loss of Load Probability (LOLP) multiply the expected cost. The LOLP represented a statistical likelihood that the demand would not be met. This was calculated by a computer programme.

Capacity Payment = LOLP * [VOLL- max (SMP, the set's bid price)]

PPP = SMP + Capacity Payment

PSP = PPP + uplift

LOLP-the Loss of Load Probability, the risk that demand will exceed capacity.
VOLL-The Value of Lost Load, which was set to reflect the cost of demand exceeding supply at £2/KWh in 1990. Since then it had been updated in line with the retail price index.
If the generator's bid price is less than SMP, it will be despatched.
Source: "Power markets and market power" (Newbery 1995).

The successful bidders or dispatched generators received the Pool purchase price (PPP), which was composed of the SMP and capacity payment. However, other failed bidding generators were able to receive the capacity payment if they were selected to be the reserve plants. The RECs paid a uniform Pool sell price (PSP) on the demand side of the Pool. The PSP was equal to the PPP for off peak load demand. However, for peak load demand the PSP would be made up of the PPP and uplift. This additional element included energy uplift and unscheduled availability payments. The energy uplift covered the cost of calling on additional plants to run in order to meet deviations from forecasted demand, and replace plants that had become unavailable through outages or generators' availability re-declarations. The unscheduled availability payments were made to generating stacks which were not included in the NGC's despatching schedule. These payments were bid in the day-ahead market to encourage investment in capacity for peak load demand in the same way as capacity payments operated. In addition, consumers paid many other costs, such as ancillary services and the costs of maintaining the transmission system.

In addition to the Pool, most generators and suppliers entered into bilateral contracts. The standard contract was the Contract for Difference (CfD). It was introduced to the market at the beginning of the liberalisation process in 1990. It specified a strike price and volume. The PPP price was the underlying price of the CfDs. If the Pool price in any time period was higher than the CfD's strike price, then the generator would refund the purchaser the difference between the actual Pool price and the strike price for that period. In a similar way, an REC would pay the generator the difference when the PPP price was less than the strike price. The CfD was a kind of financial contract, so generators were not required to produce electricity in order to meet their contractual obligations.

There was also a market for Electricity Forward Agreements (EFAs) which allowed the main components of electricity price uncertainty to be hedged on a short term basis. The EFAs were more standardised than the CfDs. There were several types of EFAs, each of them covering a specific time period within a day, for several days, and with a length of contract which could vary from 1 to 52 weeks. The EFAs were negotiated with the help of a broker, while the CfDs were privately negotiated.

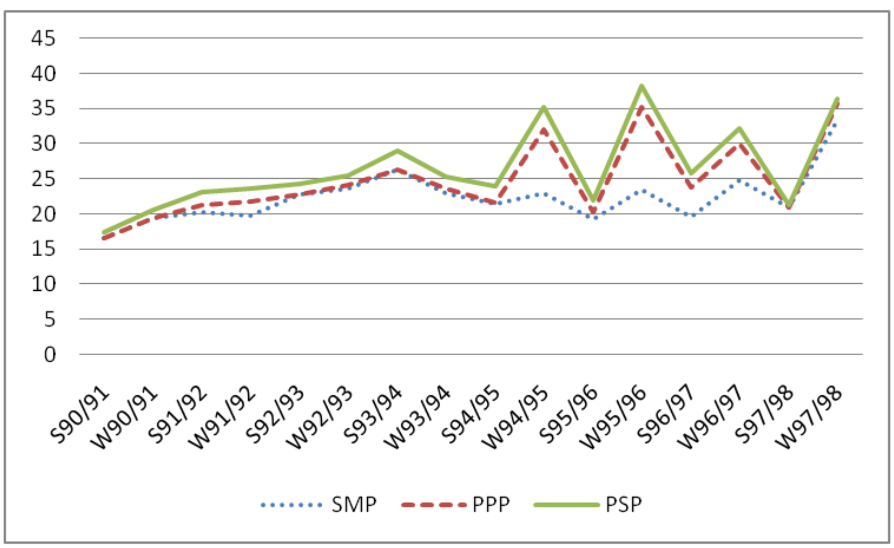
3.1.2 Criticisms of the Pool mechanism

The Pool mechanism was criticised extensively during its 11 years life. It was possible for the market to be manipulated by big generators due to the poor market design which invited strategic bidding by suppliers (Woo, Lloyd, & Tishler 2003). The market exhibited poor price signalling and inadequate performance as a shadow market (Midttun & Thomas 1998). The market has been criticised for being only half a market, meaning that there were supply bids but no demand-side (HC 1992).

The profit-maximising strategy for the generator should be to bid at marginal cost. The British system, however, was dominated by only two large generation companies (National

Power and PowerGen) from 1990-1996. Green and Newberry (1992) concluded that the effective duopoly had set the price for over 90 percent of the first three years of operation and the market power existed. It is clear that these two companies had the market power and incentive to manipulate the price due to a lack of competition in the generation market (Offer 1998a). In 1996 and 1999, the two companies were required by the regulator and the government to sell some of their generating plants to other companies in order to increase diversity in the market. However, this effort failed as evidence showed that 'National Power and PowerGen raised their prices in winter of 1997–98, sacrificing market share to Eastern and other generators in a successful attempt to keep Pool prices up while fuel costs continued to fall'(Newbery 1998;Offer 1998b).

Figure2.7. Electricity Pool average weekday prices. S- Summer; W- Winter. (£/MWh)



Data source: Electricity Pool annual report 1997/98. (Electricity Pool 1997)

The main way in which the duopoly manipulated the market was that big generators took advantage of the capacity payment mechanism. This mechanism was seriously misconceived in that it rewarded shortage rather than rewarding new investment as was originally intended (Thomas 2006). Figure2.7 shows the average summer and winter weekday SMP, PPP, and PSP prices in the Pool from 1990 to 1998. The gap between SMP and PPP was due to capacity payments and uplift. It is clear that the electricity pool prices were more than the SMP, especially in winter. The capacity payments were both volatile and unpredictable. The generators could simply manipulate the Pool price by withdrawing plants from the market at key times in order to raise the LOLP factor and consequently the capacity payment. The erratic price signals that this produced were a strong disincentive for buyers and sellers to trust the Pool for their sales or purchases. The calculation for capacity payments rests on the VOLL which has been criticised for being arbitrary and potentially too high (HC 1992). Green(1999) provided a detailed description of the interaction between the capacity payment mechanism and market power. He found that in practice many of the perceived problems in the Pool were the result of market power, rather than the basic design of the Pool which was capable of sending the right price signals to generators.

3.2 Liberalised market –NETA/BETTA

NETA was designed to provide greater competition in the wholesale market, whilst maintaining a secure and reliable electricity system. It is a system of self-despatch rather than central-despatch (the Pool). NETA is based on bilateral trading between generators, suppliers, customers, and traders. The majority of electricity has been traded through the OTC (over-the-counter) market and power exchanges (ELEXON 2004).

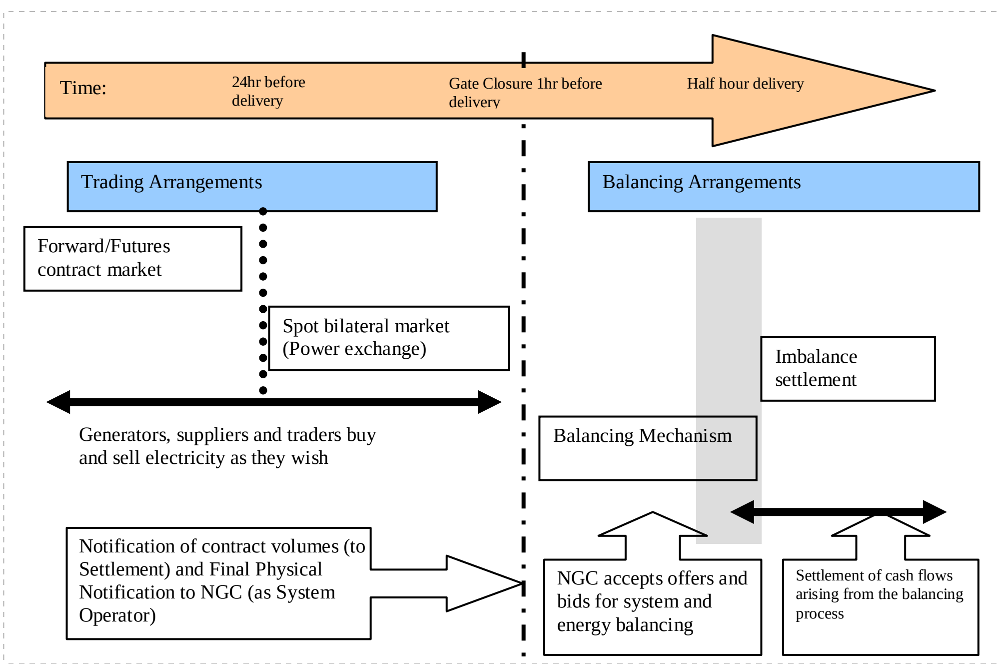
Under NETA the electricity market is designed to work as other commodity markets. However, electricity differs form other commodities. It is both difficult and costly to store significant quantities of electricity. Therefore, it is necessary for NETA to keep the electricity system in physical balance at all times in order to maintain security and quality of supply.

3.2.1 Market design under NETA/BETTA

There are four main components to the electricity market under NETA. Figure2.8 is the overview of the electricity market based on NETA. Firstly, a forwards and futures market which allow contracts for electricity to be struck over timescales ranging from several years up to 24h ahead of a given half hour period. Power is traded through long-term confidential contracts, meaning that only the trading volumes of the contracts are disclosed to the regulators and not the price. Therefore, there is no ‘marker price’ in NETA (Thomas 2006). Secondly, short-term power exchanges (from 1 to 24 hours before consumption), give participants the opportunity to ‘fine tune’ their contract positions in a simple and accessible way (Ofgem 2001). In this spot market the deals are bilateral, and are settled at the price registered on the power exchange. Thirdly, there is a balancing mechanism market through which the NGC accepts offers and bids for electricity in close to real time. This enables the NGC to balance supply and demand. The generators are required to inform the NGC of the plants they are contracted to operate and the output from each plant (without the contract prices) prior to gate closure. Retailers must declare the amount they are contracted to buy, and this should be the amount they expect their consumers to consume. The fourth part is an imbalance settlement process. This process makes payments to and from those market participants whose contracted positions do not match their actual metered electricity production or consumption. It also settles other costs of balancing the system.

Under the NETA/BETTA arrangements the NGC takes responsibility for the security of electricity supply. The market participants, especially brokers and speculators do not need to take responsibly for electricity supply security. The balancing mechanism provides a means by which the NGC can buy or sell additional energy close to real-time to maintain energy balance, and also to deal with other operational constraints of the Transmission System. Approximately 2 percent of electricity demand was bought and sold by the NGC through this mechanism (Ofgem 2002).

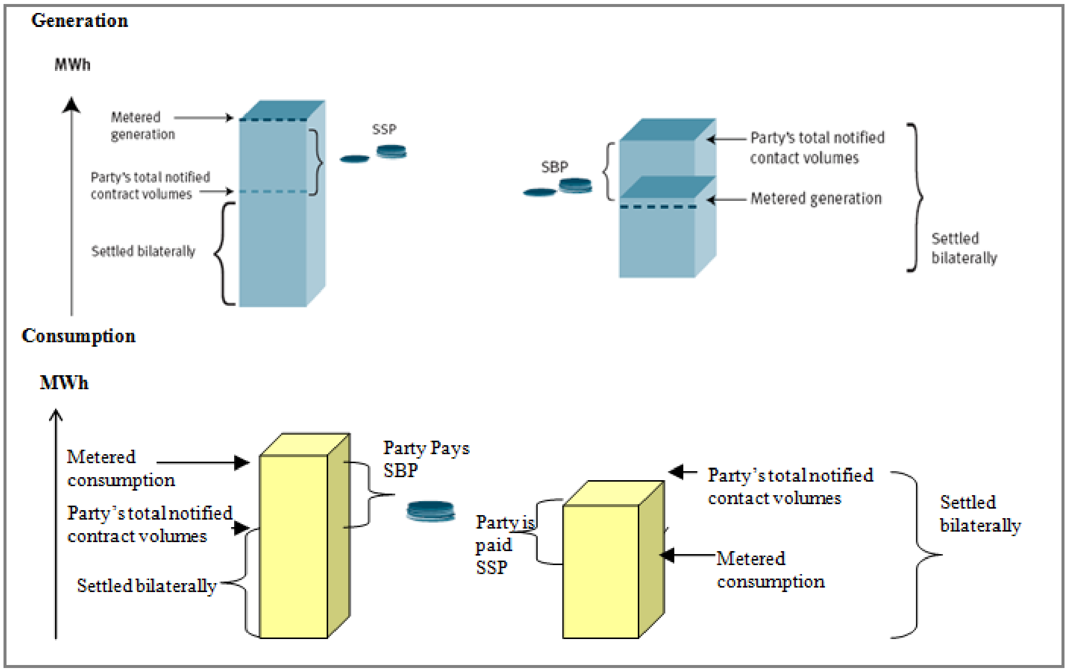
Figure2.8 Overview of market structure under NETA/BETTA



Source: National Grid Company

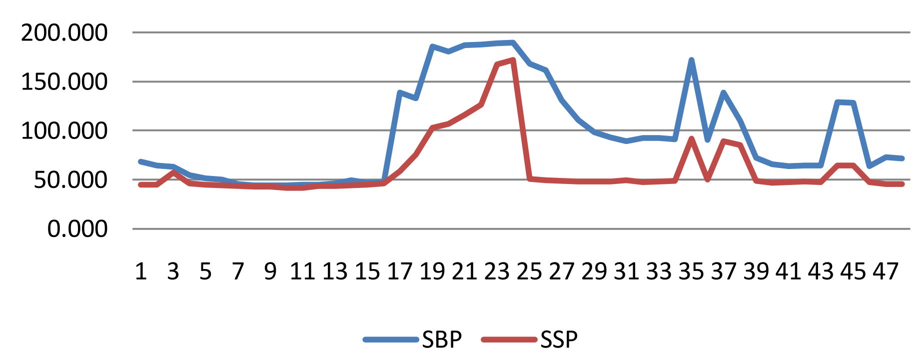
The generators may generate more or less energy than they have sold through bilateral contracts during the process of electricity production and trading. Suppliers may purchase more or less power through bilateral contracts than their customers' actual consumption and traders may buy more or less energy than they have sold. Such circumstances are regarded as being 'in imbalance' and the 'energy imbalances' have been bought or sold from or to the system (ELEXON 2006). The balancing mechanism allows electricity companies and traders to submit offers to sell energy (by increasing generation or decreasing consumption) to the system. These participants also can submit bids to buy energy (by decreasing generation or increasing consumption) from the system, at a price of the company's choosing. This process is called imbalance cash-out. The NGC accepts offers and bids as necessary in order to balance the system. The NGC will take the lowest priced offers and accept the highest priced bids. Figure 2.9 illustrates this process of imbalance settlement. The 'cash-out' or imbalance prices, the system buy price (SBP) and system sell price (SSP), applied to imbalances are derived largely as the weighted average prices of these accepted balancing mechanism offers and bids.

Figure2.9 Energy imbalance and imbalance cash out



Source: National Grid Company

Figure2.10. One sample of Daily SBP and SSP (£/MWh)



Data source: EXELON

Figure2.10 provides an example of half-hourly SSP and SBP. The date (7th June 2008) has been randomly chosen. It illustrates the gap between SSP and SBP. There is a large gap during the peak time. If the energy companies have a short position or deficit at peak times they will have to buy energy in the balancing market at the price paid at SBP. Hence, energy companies usually prefer to have a surplus or long position in order to avoid this price risk,.

In addition, since the introduction of NETA three main power exchanges have been developed: UKPX, APX power UK, and UK IPE (International Petroleum Exchange). The power exchanges are competitive wholesale markets in which futures and forward contracts are traded and electricity spot prices are issued.

In 2002 APX power UK was appointed as NGC's agent for notifying PGBT contracts (Pre-Gate Closure BMU Transaction). APX Power UK contributes data to ELEXON and was also appointed a Market Index Data (MID) provider by ELEXON on 25 February 2002. The role of MID provider is to formulate the cash-out imbalance prices on a daily basis and to offer authoritative industry benchmark indices. I have used this MID to analyse the characteristics of spot electricity prices in Chapter 3.

3.2.2 Impacts on the electricity price

Since NETA was initially proposed in 1998, the wholesale price has fallen by 40 percent (Ofgem 2002). There are a range of views on the extent to which the reduction of the wholesale price was caused by NETA itself (Borenstein 2000; Thomas 2006; Helm 2002). It has been argued that improvements in efficiency and productivity due to the reform have contributed significantly to the cut in price. It is difficult to identify the reasons for the short-term volatility of the wholesale prices. The new arrangements have made it harder for prices to be manipulated due to more complex pricing mechanisms than were in place in the Pool.

The price paid for electricity by domestic consumers have not significantly reduced since NETA was implemented, although they have fallen broadly in line with the trend in suppliers' overall costs since 1998 (Helm 2002). The electricity prices paid by industrial and commercial consumers have fallen by 18 percent since the introduction of NETA. In contrast, retail prices have fallen little, reflecting the far higher cost of supplying domestic consumers. These costs have risen due to new environmental costs and the substantial costs of processing changes to supplier (Thomas 2006).

4. Conclusion

The nationalised British ESI was a monopoly. The CEGB had monopoly power in the generation and high voltage transmission of electricity. Local Area Boards dominated the low voltage distribution and retailing business of electricity. This structure deterred new entrants and restricted competition in the industry. The purpose of the reform was to privatise the industry to improve the level of efficiency and competition. Four functional sectors were separated prior to privatisation. The transmission and distribution sectors were left to remain as a natural monopoly in order to avoid negative externalities and improve the security of the network. However, they were subject to direct government regulation. The generation and supply sectors were contestable markets rather than monopolies, thus they were privatised and reintegrated during a further restructuring process. The reform brought about benefits in terms of productivity, quality of services, and new investment. Furthermore, it allowed the demand side to participate the market.

The electricity market (the Pool) was not a perfectly liberalised market after privatisation. The Pool was designed to act a spot market to match the supply with demand for electricity.

However, the Pool prices were criticised for being subject to manipulation by oligopolistic electricity companies. The implementation of capacity payments and CfDs caused speculating activities by market participants, and consequently higher Pool price volatility.

The Pool was replaced by NETA. The aim of NETA was to provide greater competition in the wholesale market, while maintaining a secure and reliable electricity system. Currently, there is a single integrated and competitive wholesale electricity market in the United Kingdom after NETA was extended to Scotland under BETTA. The wholesale electricity market is composed of a forward/futures market, short-term power exchanges, balancing mechanism, and an imbalance settlement market. The pricing mechanism for wholesale electricity is becoming increasingly complex and wholesale prices are experiencing higher volatility. This suggests that consumers gain limited benefit from falling wholesale prices. One reason for this is that the increasing degree of reintegration enables suppliers to make profits from price discrimination. A further reason is that wholesale electricity is lacking in transparency.

I have examined the evolution of the British ESI and the developments in market design. In section 2.6, I have showed the process of vertically re-integration of generation and supply sectors in electricity industry. It is logical to combining risky generation with the offsetting risks of downstream customers to reduce the price risks under the market design of BETTA. However, all customers, whether domestic or business, can choose their supplier, thereby putting suppliers into competition. In addition, with more than 200 participants in BETTA, electricity wholesale market is workable competitive. The focus of the research now moves to the spot wholesale electricity prices. One reason for this is that the spot price strongly influences the contract price (Green 1992&2003). Furthermore, in competitive market, a transparent price acts as an indicator for electricity companies when making decisions on trading, new investment in infrastructures, and new technology.

Chapter3 Wholesale electricity prices and a Stack model: The British experience

1. **Introduction**

The most common feature of previous efforts to restructure the UK electricity market has been the promotion of competition in generation and supply. The UK now has over seventy licensed suppliers of electricity and gas. This has resulted in suppliers offering several thousand separate electricity tariffs to each domestic consumer. Several companies now package electricity and gas together in order to attract new customers. All consumers are now free to change their power supplier in the UK. In a competitive and well-functioning electricity market the price should reflect the true costs to companies of generating electricity (including other ancillary services) and the value at which consumers are willing to buy electricity. For example, higher electricity prices are the main incentive for investment in new electricity generation capacity or transmission infrastructures, as firms see that there are profitable returns to be made. Furthermore, a rise in electricity price can also encourage consumers to be more energy efficient.

The wholesale trading of electricity is diversified in bilateral contracts, spot market trading, futures market trading, and balancing market trading. The British wholesale markets for electricity are very complex. The BETTA arrangements are based on bilateral trading between generators, suppliers, customers and traders. There are a series of markets operating on a rolling half-hourly basis on which contracts are traded. The generators are required to self-despatch their power plants under BETTA. This means that they select which plants run to meet contractually required electricity volumes, rather than being centrally despatched by the system operator (National Grid Company). It is expensive to store electric power in significant amounts, which means that power generation and consumption need to be continually matched each second. There is a balancing mechanism in order to ensure the system operator maintains power balance in close to real-time, except from in the case of electricity forward/futures and spot markets. These three stages of the wholesale markets are optional for market participants. However, the imbalance settlement process is compulsory for those participants.

One of the main contributions of this PhD thesis is to develop a fundamental model (called the stack model) for simulating wholesale electricity prices in the United Kingdom. We are trying to construct industry marginal cost curves which can be the firm's social marginal costs which might be agreed with central plan or the Department of Climate Change, or we can focus on private costs of firms without considering costs of externalities. Here, I am trying to predict what will happen in the market. As a result, the stack model is to construct the marginal cost of generation in the electricity wholesale market. Its objective is to identify the marginal cost of electricity generation. Its main inputs are fuel prices, carbon prices, demand forecasts, and availability of power plants in the wholesale electricity market. This price can be regarded as an indicator of the wholesale price which can help the market participants to determine their trading strategy, new entrants to measure the profitability of this market, and also help regulators to understand fluctuations in market prices.

2. Background

2.1 Literature review

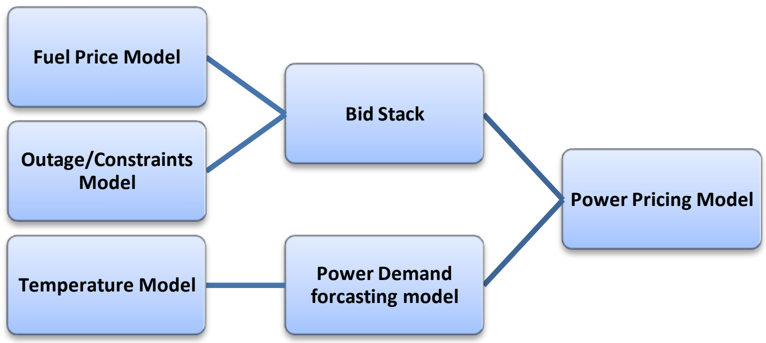
The non-storability of electricity makes the electricity market different from financial markets and other commodity markets. This is one of the reasons why so many different models are used for pricing and hedging electricity derivatives.

There are two main categories of electricity pricing models: stochastic models and fundamental models. There have been various stochastic models proposed for modelling spot price dynamics and for market risk management. It is well accepted that there are unique characteristics of spot electricity prices, such as seasonality, mean reversion, jumps and volatility. As a result, many stochastic models been developed in order to deal with the unique properties of electricity prices. Weron *et al.* (Weron, Bierbrauer, & Truck 2004) used the jump diffusion model and regime switching model to determine the main characteristics of electricity spot price dynamics through use of the Nord Pool daily average system prices. It was found by Geman and Roncoronithat that the single jump and upward-jump models generate misspecification for the estimated value of risk. This model succeeded in explaining the behaviour of spot electricity prices in three major U.S. power markets (Geman & Roncoroni 2006). Some authors have built models based on the Heath-Jarrow-Morton (HJM) approach. Benth (Benth & Koekebakker 2008) summarised the literature on the HJM approach and used it for pricing electricity swaps in Nord Pool. These stochastic models are used for pricing financial derivatives and most of them focus on addressing the characteristics of spot electricity prices. However, they provide limited explanatory insights into price formation (Karakatsani & Bunn 2008).

The fundamental electricity price models are based on competitive equilibrium models for the electricity market. The British electricity generation sector is becoming an increasingly competitive market after many years of privatisation and reform. The electricity prices are obtained from a model for the expected production costs or marginal costs of electricity and the expected demand or consumption of electricity. Since electricity prices are set by supply and demand, one approach is to model the supply function or a production-based model for forward contract pricing (Eydeland & Geman 1999). The fundamental models typically require comprehensive data sets which tend to be difficult to collect and maintain. Furthermore, it is often laborious to use the fundamental models to create numerous spot price scenarios (Vehvilainen & Pyykkonen 2005).

An outline of my model is that it is a combination of a stochastic model and a fundamental model. In other words it is a hybrid process for modelling electricity prices. Figure 3.1 shows the process of power pricing (Eydeland & Geman 1999). In general power prices tend to be dramatically volatile under extreme weather conditions. The prices become disconnected from the cost of production and may be driven higher by scarcity in the market due to generation shortages or transmission constraints. The stack model considers the formation of electricity prices as well as stochastic factors. By using a power demand forecast model we can address the properties of seasonality and jumps in the electricity price. The NGC provides a comprehensive demand forecast model which provides the demand data for my stack model. The stack model enables us to determine the formation of wholesale electricity prices.

Figure 3.1 Modelling electricity price process



Source: "Fundamentals of electricity derivative pricing", (Eydeland & Geman 1999).

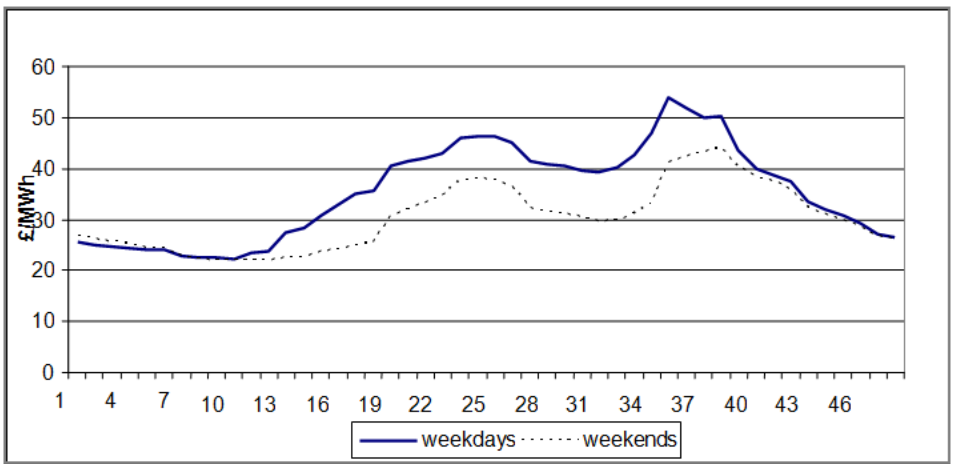
2.2 The behaviour of wholesale electricity prices

It is useful to consider the parallels between wholesale electricity price and the price of other types of commodity. The wholesale electricity price has its own special characteristics due to the unique qualities of electricity. The storing of significant quantities of electricity is both difficult and costly. As a result, the power exchange needs to continually balance the generation and consumption. We examine these price behaviours using the half-hourly market index price data (MID) which is from ELEXON and provided by APX power UK. MID is used in imbalance settlement to calculate the reverse price for each settlement period. The sample begins on 1st Jan 2005 and ends on 29th Oct 2007, for a total of 49,536 observations.

2.2.1 Regular intraday variation

The graph in Figure 3.2 shows an intraday variation. It presents the average half hourly electricity MID price measured in pounds per megawatt hour (£/MWh) for weekdays and weekends. In the case of both price sets the price begins to increase at approximately a 12th half hourly period, which is 6 a.m. and when the work day begins. The prices reach the first peak at around the 24th half hourly period, which is 12 a.m. and then fall back between the 26th and 31st half hourly periods. The prices touch another peak as the demand builds between 4 p.m. and 5p.m. The prices begin to fall thereafter as demand shifts primarily to residential usage and the workday ends.

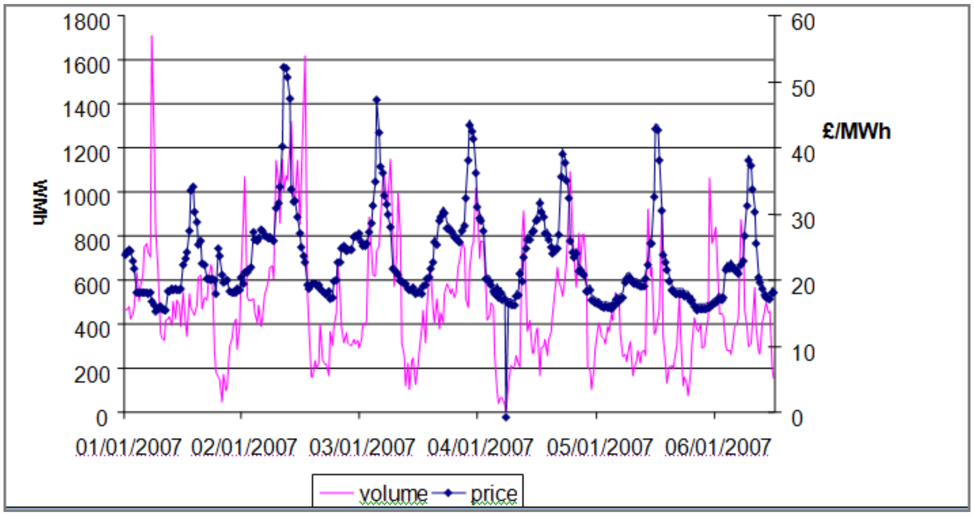
Figure 3.2. Average half-hourly electricity MID prices from 1st Jan 2005 to 29th Oct 2007



Source: Half hourly MID from ELEXON provided by APX Power UK.

Figure 3.3 shows a sample of half hourly electricity MID prices and the volume of trading for the time period 1st Jan 2007 to 7th Jan 2007. The units of the right vertical axis are £/MWh and the left vertical axis units are MWh. Figure 3.3 clearly illustrates the daily usage pattern with price variation and its persistence over time. In general, demand and price move together in approximately the same direction.

Figure 3.3. Half hourly electricity MID prices and volume for the period 1st Jan 2007 to 7th Jan 2007



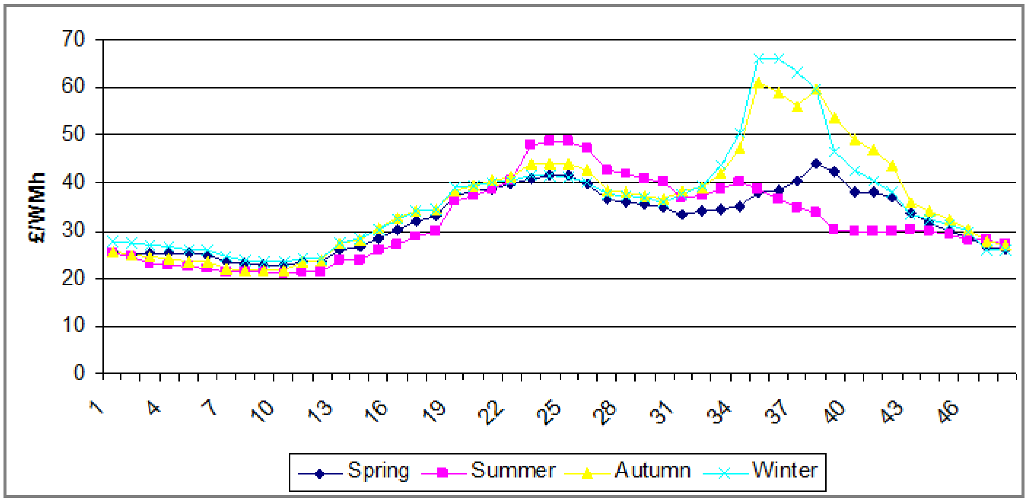
Data source: MID from ELEXON provided by APX Power UK.

2.2.2 Seasonal effect

In this study the term seasonality refers to periodic fluctuations. Seasonality is quite common in economic time series. Electricity prices change by time of day, week, month, and year in response to cyclical fluctuations in demand and weather conditions. If seasonality is present it must be incorporated into the time series model.

The seasons have been divided simply by defining spring as starting on 1st March, summer on 1st June, autumn on 1st September, and winter on 1st December. It is clear that end user demand shows strong seasonality. Those regions which rely on hydropower plants or wind power plants also follow seasonal patterns on the supply side. The seasonal pattern is therefore an essential component in any model of electricity prices. The strong seasonality for energy outputs of renewable power plants will affect the short term wholesale price in our stack model. This will be discussed further in this chapter.

Figure 3.4. Average MID half hourly electricity prices by season



Data Source: MID from ELEXON provided by APX Power UK.

There are several graphical techniques that can be used for detecting seasonality. Figure 3.4 gives us a simple example of a seasonal component. It plots the average half hourly MID electricity prices for each season. In the summer the electricity price peaks at 12a.m. till 2p.m. when it is the hottest and the consumption reflects air conditioning usage. Another peak occurs at around between 5p.m. and 8p.m. during the winter months. This is closely associated with the duration of sunshine and temperature. Thus, the seasonal fluctuations in demand and supply translate into the seasonal behaviour of spot electricity prices.

The seasonal adjustment is a statistical technique which eliminates the influences of weather, holidays, the opening and closing of schools, and other recurring seasonal events from economic time series. This permits easier observation and analysis of cyclical, trend, and other non-seasonal movements in the data. The series becomes smoother and it becomes easier to compare data from month to month when seasonal fluctuations are eliminated. Bierbrauer *et al.* (Bierbrauer *et al.* 2007) summarised the academic literature on the seasonal patterns in modelling electricity prices. They concluded that Bhanot (2000) uses dummy variables or piece-wise constant functions, an approximation by sinusoidal functions is applied by Pilipovic(1997) and Weron et al.(2004), whereas Simonsen(2003) and Weron et al. (2004) approximate the underlying periodical structure by a wavelet decomposition. Furthermore the Census X-11 method, developed at the Census Bureau, is a widely used method of seasonal decomposition and adjustment. A detailed summary of this method is provided by U.S Census Bureau. However, this method is beyond the scope of this study and will not be discussed.

2.2.3 Volatility

A key difference between electricity power exchange or electricity markets and other commodities markets is that electricity markets have distribution and transmission constraints. The problems of storage, capacity and transmission constraints, and the need for markets to be balanced in real time can cause electricity prices to be highly volatile. The marginal cost of transmission becomes infinite once constrained. The average price was £33.79/WMh, minimum price was 0 £/WMh (6th period on 05th Jan 2007), and the maximum price was £476.91/WMh (36th period on 29th Dec 2005) for my selected data set. Inventories cannot be used to smooth price fluctuations due to the special characteristics of electricity. The temporary demand and supply imbalances in the market are difficult to correct in the short-term. This results in more extreme price movements in electricity markets than in other commodity markets (Bierbrauer, Menn, Rachev, & Truck 2007).

2.2.4 Mean reversion

Mean reversion is a tendency for a stochastic process to remain near or tend to return over time to a long-run average. In other words, it suggests that prices and returns eventually move back towards the mean or average of underlying products. This mean or average can be the historical average of the price, return, or another relevant average such as the growth in the economy or the average return of an industry. Electricity prices are generally regarded to be mean-reverting. For example, suppose we observe that electricity prices jump from £35/WMh to £350/WMh due to unexpected plant outages or transmission constraints. Most market practitioners would agree that it is highly probable that prices will eventually return to their average level once the cause of the jump goes away. In this case they believe that when there is an increase in demand, generators with higher marginal costs will enter the market on the supply side pushing prices higher. Conversely when demand returns to normal the generators will leave the market and prices will fall. This is one of the principal assumptions of my stack model. Therefore one might expect that electricity prices would have shown strong mean reversion characteristics.

We can capture the phenomena of mean reversion mathematically, with a modification to the random walk assumption (Blanco & Soronow 2001).

$$s_{t+1} - s_t = \alpha\,(s^* - s_t) + \sigma\,\varepsilon_t$$

α (s^* - s_t) is the mean reversion component.

$\sigma\,\varepsilon_t$ is random component.

s^* is the mean reversion level or long run equilibrium price.

s_t is the spot prices.

α is the mean reversion rate.

σ is the volatility.

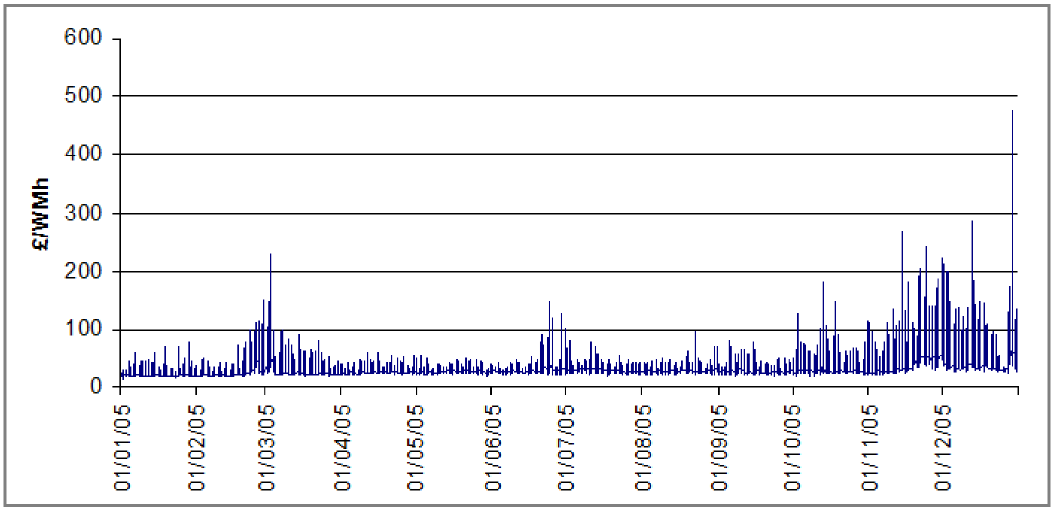
ε is the random shock to price from *t* to *t+1*.

In addition, Alexander (2008) summaries this mean reversion process and defines a mean reversion mechanism with a drift term for a stationary continuous time process. He proved that a mean reversion process is a stationary AR(1) model.. The stack model may show mean reverting characteristics even though it does not specifically model these stochastic behaviours. This is because the model reflects the underlying data on demand and supply, which itself has a tendency towards mean reversion. Thus, consumer demand, at least over the short to medium term, tend to return to an "equilibrium" level which reflects demand absent the effects of intra-day and seasonal variation etc.

2.2.5 Jumps and spikes

Figure 3.5 clearly shows that spot electricity prices exhibit infrequent but large spikes or jumps. Similarly as previously discussed above in the volatility section, price jumps tend to occur due to sudden outages or failures in the power grid and lead to a large increase in prices in a very short amount of time. Such price jumps are unpredictable discontinuities in the price process from a modelling point of view.

Figure 3.5 Half hourly MID electricity prices for 1st Jan 2005 to 31st Dec 2005.



Data source: MID from ELEXON provided by APX Power UK.

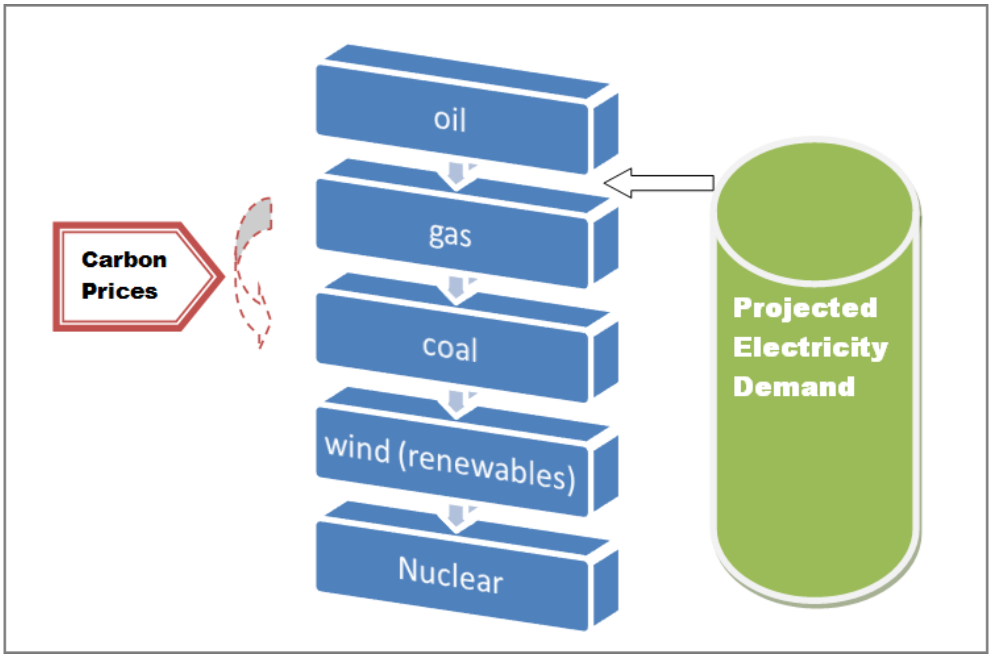
These spikes are typically interpreted as the result of a sudden increase in demand, and when demand reaches the limit of available capacity the electricity price exhibit positive price spikes. These price spikes are short-time intervals where the price process exhibits non-Markovian behaviour and where prices increase or decrease significantly in a continuous way. The typical explanation for these phenomena is a highly non-linear supply-demand curve in combination with the non-storability of electricity (Weron, Bierbrauer, & Truck 2004). In relation to spikes, the use of ARCH, GARCH, and TGARCH as possible mechanism for modelling these behaviours are beyond the scope of this study and are not discussed in this chapter.

3. Methodology

This section discusses the development of a stack model for pricing in the British wholesale electricity market. The definition of "stack" in computer science is an abstract data type based on principle of "Last In First Out" (LIFO). However, for modelling the wholesale electricity price, I have used "stack" based on the principal of "First In First Out (dispatched)" (FIFO). Here, "stack" is the available generation capacity. The generation unit with lowest marginal cost of generation bids and comes in first. The stack is built up as other generation units with increasing marginal cost are brought in to provide the aggregate electricity output of the UK. The stack is completed when the stacked generation capacity meets the forecast demand of electricity for a particular time period. Figure 3.6 shows the stack process. One way of thinking of the model is that by explicitly modelling marginal costs of generation it can be used to determine the short-run supply curve of the UK power generation industry.

There are several differences between the stack model and the Pool price mechanism. Firstly, in the stack model the wholesale electricity price is the most expensive marginal cost of the last capacity unit stacked-in. However, in the Pool the system price is the most expensive price that electricity companies bid into the system for their capacity unit. Secondly, the stack price reflects the fundamentals of electricity generation. Therefore, it is a reasonable indicator for electricity companies to determine the contract price or offer price in the spot market. The Pool price on the other hand has been proven to be manipulated by the "duopoly" (Green 1999; Newbery 1998; Newbery & Pollitt 1997). Hence, these two price processes are theoretically different.

Figure 3.6 The process of bidding into the stack model.



3.1 Assumptions of the stack model

The stack model assumes that the wholesale electricity market is competitive. A number of issues have arisen that relate to the competitiveness of the wholesale electricity market in the UK. The electricity market structure may be oligopolistic rather than perfectly competitive. Although electricity is an identical product, there are a limited number of producers. There are also transmission constraints which isolate consumers from the effective reach of many generators, and transmission losses which discourage consumers from purchasing power from distant suppliers (Wen & David 2001). Moreover, traditionally the electricity industry was highly capital intensive which resulted in barriers to entry. Due to the limited number of generating companies operating in a given geographic region, there may have been opportunities for excess profits under the Pool mechanism through strategic bidding.

The structure of the British electricity market was dramatically transformed after NETA and BETTA went live, due to several regulatory, technological, and economic changes. There are not only generators and suppliers but also large consumers, bankers, brokers, and electricity companies which participate in the electricity wholesale markets. Liquid wholesale electricity markets may enhance the competition in both the generation and supply market. They also provide investment signals to market participants and reduce the possibility of parties manipulating prices. There are methods of improving low liquidity in the British wholesale electricity market including increasing the transparency of existing markets and providing a reliable reference price for electricity trading in UK. There are also a number of measures suggested by Ofgem on how to improve market liquidity, see Table 3.1.

Table 3.1 Potential measures to improve market liquidity.

- Changes to market/governance arrangements such as reintroduction of self supply restrictions;
- Introducing an obligation on large/vertically integrated participants to auction a certain proportion of their generation output;
- Greater information provision by vertically integrated companies;
- Introduction of regulated/subsidised intermediaries/market makers;
- Further interconnection/integration with European markets;
- Reform of cash-out arrangements, such as a move to a single cash-out price or exempting parties below a certain threshold from exposure to imbalance price;
- Measures to make credit/collateral requirements more efficient and potentially ease the burden on smaller participants; and
- Changes to industry structure.

Source: "Options for delivering secure and sustainable energy supplies", (Ofgem, 2010)

In summary, the wholesale electricity market is competitive in theory but not necessarily in practice. In the stack model we have assumed that generation companies engage in marginal cost pricing. This is because we take the view that the oligopolistic nature of the power generation industry is reflected more in the retail market than in the wholesale market (see below). The competition in wholesale prices should maximise the sum of consumer surplus and producer surplus in the regulated industry. The wholesale electricity price is set by supply and demand in the wholesale market and is equal to the marginal cost of the last capacity-unit in the stack model during a specific time period. These companies are willing to sell their output at the wholesale market price as long as their marginal costs are less than the market price. The marginal cost price rule is efficient but it may leave electricity companies incurring an economic loss.

Under the current market structure and trading arrangements it is possible that vertically integrated energy companies' profits will become immunised against the level of wholesale prices, providing that their generation and retail amounts are balanced. In other words, a vertically integrated company could engage in competitive behaviour in one sector and try to reduce competition in another sector in an attempt to increase profits. However, this strategy may hurt the final consumers and competition in the electricity industry. For example, a vertically integrated supplier who owns upstream generating plants could use its generation business to offer unfair terms to its competitors and new entrants in the supply sector. It could reduce the competition and discourage new entry into both sectors. In addition, in 2007 the 'Big 6' firms constituted 55% of the electricity output. Drax Power reports that the Big 6 control approximately 75% of price setting power plants when part ownership, controlling interests, and the contractual arrangements of these vertically integrated firms are taken into account(House of Commons 2008).

As a result, the Big 6 might be willing to set the wholesale electricity price close to their marginal cost of generation, in order to deter new entry and create distress among the generation-only companies. It is difficult to find an indicative retail electricity-only price in the market. The mechanism for setting British wholesale electricity prices is extremely complicated. One approach to estimate the price is to use a stack model. Moreover, another issue with the stack model is that the problem of transmission constraints is assumed to be solved and transmission has no influence on the wholesale electricity prices. There are several reasons for excluding the costs associated with transmission constraints from the stack model. Firstly, the basic version of the stack model is a theoretical model for identifying the marginal cost of generation. The costs of transmission, which also takes account of transmission constraints and losses, could be passed on to the consumers. These are not included in this version of my stack model and I have assumed that these costs are a part of the retail electricity pricing mechanism. Secondly, the system operator has identified significant transmission constraints and they are able to manage the main constraints during peak times. If the system and other factors remain the same, then the management of transmission constraints is dependent on the local level of generation output and demand. Furthermore, local transmission system constraints limit the output of onshore wind energy and other types of renewables. The stack model only includes the renewable power plants which have already been integrated into the national grid. Therefore, the associated costs of transmission constraints are not taken into account. However, these costs can be added into the extended version of the model which includes the self dispatch strategy of electricity companies and other uncertainties of power plant operation.

Transmission constraints arise wherever the market provision of generation is not compatible with meeting the security of supply requirements for a given level of demand and transmission system availability (Auckland 2006). There are two significant transmission constraints in the system. The first one is located at the lines connecting the system in Scotland and the system in England. This constraint is known as the Cheviot constraint after its location. Another significant transmission constraint is the constraint within the Scottish transmission network. The electricity generators in this constrained area occasionally behave unusually in terms of their self dispatch. Furthermore, the offer prices in the balancing mechanism are relatively high at certain times. This is believed to be the main reason for a sudden increase in the constraint management costs internal to Scotland (incurred by NGET) from November 2005 onward (Abd Jamil 2007).

3.2 Structure of stack model

There are two processes in the stack model. One is the process of calculating the marginal cost of generation. The other is the process of matching the available capacity and the forecast demand. Table 3.2 shows the calculation of marginal cost for different fuel type power plants. This section introduces the quantitative method of the stack model.

Table 3.2. Marginal cost calculation in the stack model.

$MC= [(F / \alpha) + E *\varphi] / \rho$

Where MC is Marginal Cost £/MWh

F is Fuel Price function £/ unit

α is standard conversion factor, here needs to pay attention to the unit difference.

E is carbon emission price (£/tonne of CO_2)

φ is carbon intensity for particular fuel generation plant (tonne of CO_2/GWh)

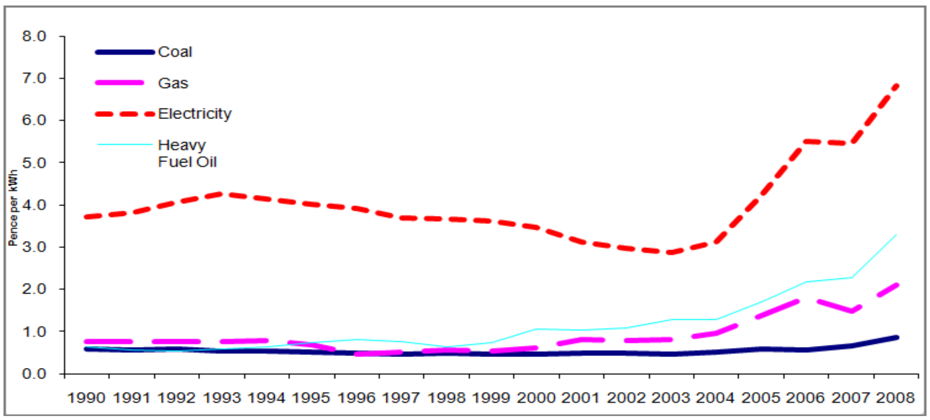
ρ is the efficiency function of ρ(energy efficiency, available of plant)

3.2.1 Fuel prices

The fuel price is one of the main variables in my stack model in calculating the marginal costs of generation for different types of power plants. The uncertainties and volatilities in market prices for primary energy carriers have a short-run impact on the operating decisions and long-run impact on the investment and strategic decisions for electricity companies. Recent research (Mohammadi 2009) has demonstrated a stable long-run relationship and bi-directional long-run causality between coal price and real price for electricity.

The proportion of net electricity supplied by fuel input in the UK for 2008 was 46 percent from natural gas, 31 percent from coal, 13 percent from nuclear, 1 percent from oil, 6 percent from renewable energy sources including hydro, and 3 percent from imports (DUKES 2008). The majority of electricity generated is produced from natural gas, coal, and nuclear energy. Therefore, the price of primary energy carriers' account for a major proportion of wholesale electricity prices in the UK. The price volatilities of coal, natural gas, and oil can directly impact on the cost of generating electricity. Thus, the stack model can respond to exogenous shocks originating in the fuel markets. The shocks in each fuel market would result in variations in the marginal cost in the stack model. Figure 3.7 shows the similar trends between fuel prices for coal, gas, electricity, and oil in the manufacturing industry. There is a positive correlation been electricity prices and fuel prices.

Figure 3.7 Fuel prices for manufacturing industry, cash terms, 1990 to 2008.



Source: DECC energy statistics qep314.

The futures market for natural gas, coal, and oil are mature and fuel prices in different locations would not normally differ by more than the transportation costs from the fuel futures market prices in the UK. However, there are no public markets or financial markets for nuclear or renewable energy. Sources of energy such as wind, hydro, and other renewable sources are not transportable and are therefore transformed into electricity on-site. Nuclear raw materials such as uranium are kept under strict control due to concerns regarding the security and peaceful uses of nuclear power. Nuclear plants are expensive to build but are cheap to operate in comparison to thermal power plants. They are generally intended as base load plants. Therefore, in the stack model the marginal costs of nuclear, wind power and hydro power plants are zero.

Renewable energy power plants such as nuclear plants and wind farms always come into the stack model first due to their "zero marginal cost" of production. If capital costs are ignored, wind and nuclear plants have the lowest marginal costs. In other words, their capacities stack in the model first from an energy and economic efficiency point of view.

The government's objectives on climate change are another important issue. Renewable plants play an essential role in meeting the target of a 60% reduction in carbon dioxide emissions. The government has proposed a renewable energy penetration target of 20% by 2020 (Energy White Paper 2003). Therefore, renewable power plants, particularly wind farms, have priority to come into the stack model assuming they are available.

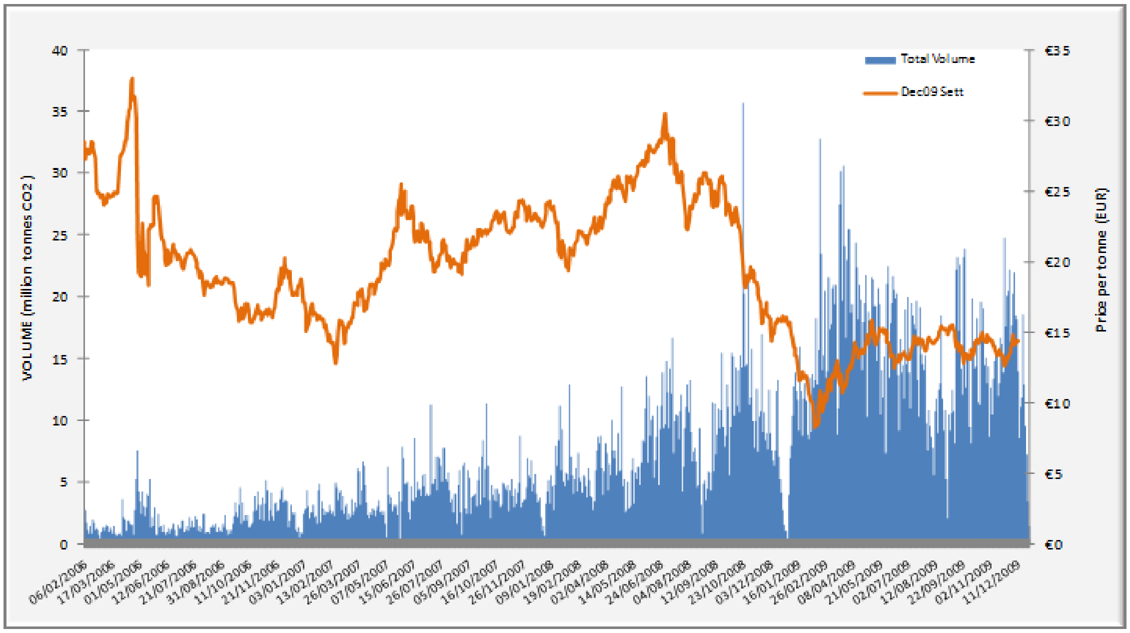
3.2.2 Carbon prices

The carbon emission price plays an important role in the stack model. It is part of the marginal cost for generators with coal, gas, CCGT, and oil fired plants. In theory, the opportunity cost of allocated emission allowance (free or not) will be passed on, since power producers will add the opportunity cost of carbon dioxide into the short run marginal cost. This factor can affect the order of coal fired plants and gas fired plants in the model. The carbon price could increase the marginal costs of coal fired plants more than that of gas fired plants due to the different ratio of carbon intensities.

The European Union Greenhouse Gas Emission Trading Scheme (EU ETS) is the fundamental principal of EU member states' climate policy and was created on 1st January 2005. Under this scheme the CO_2 emission allowances are tradable across Europe on exchanges and over-the-counter trades. The aim of the EU ETS is to provide a cost efficient way of reducing emissions by using a market-based ‘cap and trade’ system. The electricity industry is the most dominant player within the scheme. There are three phases of the scheme: 2005-2007, 2008-2012 and 2013-2020. The second and third phases are interconnected meaning that the transfer of banked or borrowed allowances is allowed between phases two and three (Chevallier, Ielpo, & Mercier 2009). Figure 3.8 is an example of monthly price and volume for carbon futures contracts. The carbon futures price has fluctuated dramatically over the past four years. The price of EU Allowances (EUAs) typically rises when gas prices rise, since the higher cost of gas encourages energy firms to switch to cheaper but more carbon-intensive coal-fired power plants. This in turn increases their demand for carbon allowances.

A strong carbon price is important for encouraging firms to develop low-carbon technologies, since the more it costs to emit carbon, the more likely they are to look to alternatives (Young 2010). The development of new “clean coal” technology is addressing the problem of carbon emission. The UK government has signalled that it will proceed with a new generation of clean coal fired power plants. Potentially as many as four new plants will be built if they can be fitted with technology to trap and store CO_2 emissions underground (BBC 2009). However, at current Phase II of EU ETS and without further international agreement, investors consider that the carbon price is unlikely to rise fast enough to compensate for the potential impacts of the price volatility that result from gas setting the price. The cost of gas is a much more significant driver of the electricity price than the cost of carbon, for example DECC analysis suggests that in 2020 a 50 per cent increase in the cost of carbon allowances would be offset by just a 15 per cent reduction in the cost of gas (HM Treasury 2010).

Figure 3.8 Carbon futures contracts: price and volume (ECX EUA)



Source: ECX EUA futures data 2009. http://www.ecx.eu/Settlement-Prices.

The majority of allowances is currently allocated free of charge, but Member States were permitted to auction up to 5% of allowances in Phase I and up to 10% of allowances in Phase II. With Phase II due to end in 2012, Phase III of the EU ETS will run from 1 January 2013 to 31 December 2020. It will be gradually phasing-out the free allocation of allowances that took place in Phases I and II and replacing that with a system of allowance allocations through auctions.

One main consequence of the change in Phase III of EU ETS on energy sector is that the overall cap in Phase III will inevitably be far more stringent than in previous phases. In the UK, and across most of the EU, there will be 100% auctioning in the power sector. This is likely to result in an increase in prices of commodities covered by the EU ETS, as the higher cost of carbon is passed on to the consumer[9]. The regulator Ofgem has assumed Carbon price to rise to €50/t by 2025 under the Green Transition and Green Stimulus scenarios as a result of tightening of the EU-ETS and achieving a global agreement on climate change at Copenhagen (Ofgem 2009). We have examined this scenario in the experiment of high carbon prices in section 4.2. The results in stack model simulation results indicate that marginal cost of generation in the market will increase due to a higher carbon price and the marginal costs of coal-fired power plants will be greater than that of gas-fired power plants.

3.2.3 Thermal efficiency

Thermal efficiency is another factor which has been taken into account in the stack model. This is the measure of the efficiency and completeness of combustion of the fuel. It is defined as the ratio of energy output to the energy input or heat from the combustion of the fuel. From a technical point of view, the thermal efficiency of a typical pulverised coal power plant is less than that of a CCGT. The average thermal efficiency of CCGT was 51 per cent in 2008 and it was 4.9 per cent more than in 2004. However, the average thermal efficiency of a coal fired power plant (36 per cent) and nuclear power plant (37.9 per cent) has been stable over the past five years (DECC 2008).

The thermal efficiency is measured in terms of the delivered energy and heating value of the fuel. Thus, it is one factor affecting the marginal cost of generating. The average values of thermal efficiency for different power plants are used in the basic version of the stack model. The value of this variable will reflect the level of technology implemented in the

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[9] http://www.carbonretirement.com/content/eu-ets-phase-iii-new-rules-game

power plant at time of construction. At present, we use the average thermal efficiency for each generation type. The model may be developed to incorporate information on variations in thermal efficiency by type.

3.2.4 Demand, plant capacity, and load factor

The stack process is complete when the available plant capacity equals the electricity demand at a specific time-period (half hour or one hour). Therefore the availability of each power plant is an input item in the stack model. It can accommodate variations in output such as when plants are closed due to malfunction or for maintenance purposes. The stack model is sufficiently flexible to deal with these situations.

The load factor is the measurement of this availability. In the electricity industry, load factor is a measure of the output of a power plant relative to the maximum output it could produce. Normally a power plant cannot operate at its maximum output all of the time due to maintenance, transmission constraints, and weather conditions. This is particularly true for wind farms. Some power plants may operate at less than efficient average load factor due to transmission constraints. Alternatively power plants may operate at high level of efficiency when they can produce and despatch consistently. Therefore a higher load factor means greater total output and a lower cost per unit. If the load factor of zero marginal cost power plants is increased, the wholesale electricity prices would be reduced. The average load factor has been used in the basic version of the stack model. However, the real time individual load factor for each major power plant can be used as a model input to improve the performance of the stack model, providing the relevant information is available.

3.3 Data

The projected demand data is taken from the National Grid. The NGC's role as the system operator is to ensure the electricity supplied is always equal to electricity demanded. The National Grid has built a model to predict the demand in electricity. Factors considered in their model include weather forecasts, historical demand trends, and special TV events such as popular football matches. Therefore, I have used the electricity demand data from National Grid.

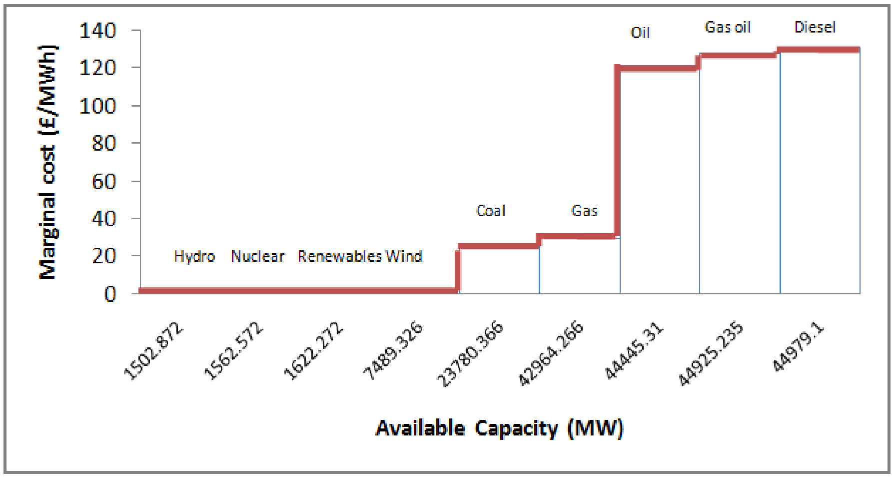
The capacity of power stations in the UK (updated to May 2009), is another input for the stack model. This data set includes the capacity, location, company information, year of construction, and fuel type for each power station in the UK. Together with the plant load factor and thermal efficiency, the stack model can predict the amount of electricity supplied at a particular time period. The data set comes form the "Plant capacity: United Kingdom-DUKES5.7 and DUKES5.10" provide by DECC.

The price of futures contracts for coal, oil, gas, and diesel are used as fuel price variables. These prices come from the prevalent fuel exchanges. The gas price data comes from APX Gas UK's market spot prices. The coal price data comes from e-coal.com market indicator prices. The oil price is the crude oil spot price from upstreamonline.com. The price of gas oil and diesel come from US energy information administration. We assume that the fuel spot prices in the UK are the same as the international prices. Carbon prices come from the ICE EUA daily contract prices. In the case of electricity companies the contract price of purchasing fuel can be used rather than the price from financial markets when using the stack model.

4. Empirical results

This stack model is written using STATA10. The inputs of the model are level of demand, capacity of plants in operation, fuel prices, and carbon prices. The values of these variables are written into the model for a half hour time slot. Figure 3.9 represents an example of the outcomes of the stack model.

Figure 3.9 An example of model output from the stack model (average load factors).



The vertical axis is the marginal cost of power plants (£/MWh). The red line represents the marginal cost curve of generation for power plants. The calculation of marginal cost is based on the method described in Table 3.2. Table 3.3 shows the value of variables in the stack model and these can be updated in response to the change in parameters. In the stack model nuclear plants and renewable plants are assumed to have zero marginal cost. Hence they are first to stack in the model. Coal fired plants normally come into the model next due to their lower marginal cost. However, the order of coal fired plants and gas fired plants may change in relation to the variation in carbon price, fuel price, and new technology. The oil, gas oil, and diesel fired plants have the highest marginal cost and therefore are usually brought them only at peak demand. Figure 3.9 is therefore the effective short-run supply curve for UK electricity generation.

The horizontal axis represents the generation output stack (MW). The available capacity of power plants is calculated based on the average load factor in this version of the stack model. However, it is possible to use the generation capability of each power plant at a particular time in the stack model. Thus, the stack model can provide an accurate picture of short-run supply in UK energy generation industry. This can be followed through time to show how marginal costs may have changed in response to changes in fuel prices, technology, capacity etc.

The average level of demand at the peak load is around 50 GWh based on information from the NGC. The price of fuel and carbon can be updated at any time following the price changes in relative markets. If the level of demand is 50 GWh then the UK power generation mix would consist of nuclear, renewables, gas, coal, and oil power plants. If the level of demand is 20 GWh, the mix would mainly be nuclear, renewables and coal power plants. If nuclear power stations are offline or there no wind, then the generation mix would consist mainly of coal, gas, and oil plants.

Table 3.3 Input values of the stack model experiment.

Plants	Fuel Price	Conversion factor	Carbon intensity (kgC/KWh)	Thermal efficiency	Load factor
Gas	42.5p/therm	29.3071 KWh/therm	0.0518	0.51	0.693
Coal	65.39 £/tonne	8.14 MWh/tonne	0.0817	0.36	0.567
oil	50.13 £/barrel	1.64 MWh/barrel	0.0709	0.26	0.405
Gas oil	1.19 £/gallon	36.7 KWh/gallon	0.068	0.26	0.405
Diesel	1.22 £/gallon	36.7 KWh/gallon	0.068	0.26	0.405
Nuclear	-	-	-	-	0.494
Wind	-	-	-	-	0.4
Hydro	-	-	-	-	0.354
Other renewables	-	-	-	-	0.3
Carbon	11.84 £/tonne				

Source: data as described in section 3.3.

Power plants usually have an outage schedule for maintaining their performance. This issue is related to the outage management of power plants which considers factors including plant activities, company policies, and technology. This requires a substantial amount of information and it is beyond the scope of this study. However, the stack model is capable of dealing with the planned or unplanned outage of power plants. For example, in the summer there will be a significant amount of capacity from nuclear and coal power plants taken out of the stack to deal with maintenance. The stack model could accommodate this situation by adjusting the database of generation capacity.

To illustrate its operation, I will discuss four experiments using the stack model. These are as follows:

1. The capacity margin
2. Variation in fuel price and carbon price.
3. Different penetration levels for wind farms.
4. Transmission constraints.

The reason I choose these four experiments is that I focus on examining security of the energy supply and different marginal cost curves of production under different scenarios, especially high wind energy penetration scenarios. In addition, I also want to provide a generation map for a particular time slot in order to highlight the issues associated with transmission constraints.

4.1 Capacity margin and generation capability

The capacity margin is an important factor for ensuring the security of the energy supply. Capacity margin is defined as the difference between generating capability and peak-time demand. The generation capability represents the maximum output with all available power stations in the stack model. A certain amount of capacity margin is usually required by the system operator. In other words the generation capacity is required to meet the expected demand of the system, even under conditions of unexpected power plant failure during peak load or unusual increases in demand.

It has been claimed by Ofgem that the energy supply will be relatively secure until around 2015. However, the unprecedented combination of the global financial crisis, tough environmental targets, increasing gas import dependency, and the closure of ageing power stations is likely to challenge the security and sustainability of energy supplies (Ofgem 2010).

In the UK there are 320 major power stations each with more than 1 MW capacity, and with a total capacity of 78,268 MW. However, 113 of these power stations were built before 1980. A large part of the ageing energy infrastructure will need replacement by 2020 at an estimated cost of £200bn (Young 2010).

Therefore, the marginal cost of the stack model has been calculated under the scenario of aging nuclear power stations being taken out of service. There are 10 nuclear power stations in the UK with the capacity of 10,137 MW contributing approximately 13 per cent of the total generation capacity. The oldest plant was built at 1967 and nine of them were built prior to the 1990s. These aging nuclear power stations are to be shut down in the next decade, as shown in Table 3.4.

Table 3.4 Nuclear power stations operating in UK

Nuclear reactors	Capacity (MW)	Built year	Expected shutdown
Oldbury (Magnox)	434	1967	Dec 2010
Wylfa (Magnox)	980	1971	Dec 2010
Hinkley (British Energy)	840	1976	2016
Hunterston (British Energy)	860	1976	2016
Dungeness (British Energy)	1040	1983	2018
Hartlepool (British Energy)	1190	1984	2014 (2019?)
Heysham1 (British Energy)	1160	1984	2014 (2019?)
Heysham2 (British Energy)	1240	1988	2023
Torness (British Energy)	1205	1988	2023
Sizewell B (British Energy)	1188	1995	2035

Source: DECC energy statistics Duke5.11 and World nuclear association.

In this experiment the marginal cost of nuclear stations is assumed to be very high (£500/MWh), see Table 3.5. Therefore, the nuclear stations will not stack into the system as long as the system capacity is capable of meeting the demand. It implies that aging nuclear stations are withdrawn from the system. Based on the average load factor, if electricity demanded is more than 38GWh, then oil plants will stack into the model. If electricity demanded is more than 40GWh there will be no sufficient capacity to meet the demand. Therefore, the marginal cost of generation will be extremely high. Table 3.6 summarises the marginal costs of production for each type of power plants for this experiment.

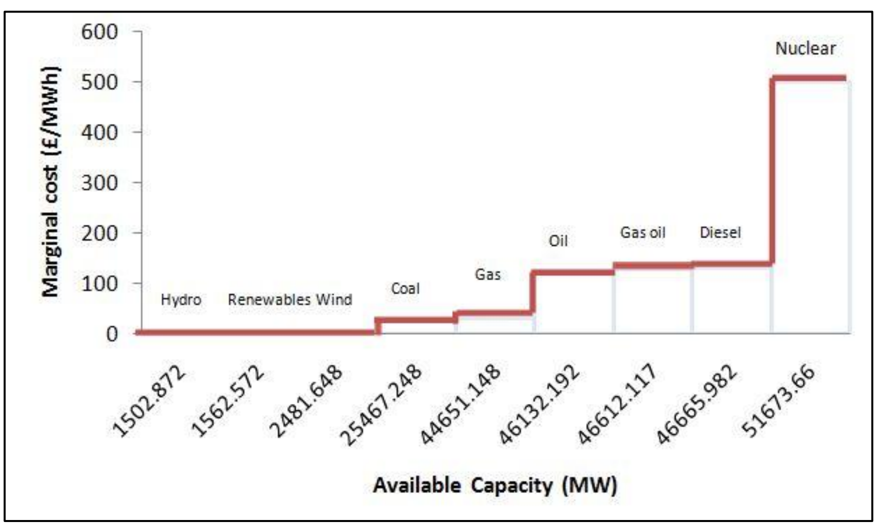
Table 3.5 Input values for the stack model—experiment 1(withdraw nuclear stations).

Plants	Fuel Price	Conversion factor	Carbon intensity (kgC/KWh)	Thermal efficiency	Load factor
Gas	42.5p/therm	29.3071 KWh/therm	0.0518	0.51	0.693
Coal	65.39 £/tonne	8.14 MWh/tonne	0.0817	0.36	0.567/0.8
oil	50.13 £/barrel	1.64 MWh/barrel	0.0709	0.26	0.405
Gas oil	1.19 £/gallon	36.7 KWh/gallon	0.068	0.26	0.405
Diesel	1.22 £/gallon	36.7 KWh/gallon	0.068	0.26	0.405
Nuclear	500	-	-	-	0.494
Wind	-	-	-	-	0.4
Hydro	-	-	-	-	0.354
Other renewables	-	-	-	-	0.3
Carbon	11.84 £/tonne				

Table 3.6 Marginal cost curve for experiment 1(withdraw nuclear stations).

	MC	MW(Stacked)
hydro	0	1502.872
other renewables	0	1562.572
wind	0	2481.648
coal	25.00	18772.64
gas	29.63	37956.59
oil	120.79	39437.63
gas oil	127.80	39917.56
diesel	130.95	39971.42
Nuclear	500	51673.66

Figure 3.10 Stacked capacity and marginal cost for generation at load factor of 0.8 for coal-fired plants.



In another scenario of this experiment (Figure 3.10), the coal-fired power plants are assumed to generate constantly with a higher load factor (0.8) and other variables remain constant. It is possible for the peak load to be met without nuclear power stations.

However, the system price would be set by the marginal cost of oil-fired power plants. In this case, the oil-fired plant would be required to serve during the peak time causing a dramatic increase in the system marginal cost. The system buy price in the balancing market will be much higher than the stack model system price if electricity companies are unable to meet the volume of their contracts. As a result, the wholesale and retail electricity prices would be likely to increase significantly.

A new generation of nuclear power stations would be one way to ensure there are sufficient power supplies, since nuclear power provides reliable, cost-effective, and low-carbon energy. The UK government has announced significant plans for energy projects and 10 potential new sites for nuclear energy. Ensuring there is sufficient capacity margin in the system is one factor which encourages new investment in the infrastructure. Another option is to invest heavily in renewable technologies. However, it seems unlikely that by 2015 that there will be sufficient renewable capacity which is responsive to consumer demand to make up for the shortfall caused by nuclear plant closure.

4.2 Carbon and fuel prices

The use of carbon capture technology is one method of meeting targets for the reduction of greenhouse gas emissions. However, this technology is very expensive and is on a demonstration rather than operation level. Therefore, thermal stations have to buy carbon allowance for paying a charge for pollute.

In this experiment the carbon and fuel price is allow to change. In one scenario the carbon price rises to £50 per tonne and other variables remain the same. Figure 3.11 shows the marginal cost curves for a low carbon price (£11.84 per tonne) and high carbon price (£50 per tonne). It is clear that marginal costs for thermal power plants will increase as the carbon price increases. However, the marginal cost for coal-fired plants will be greater than that of gas-fired plants, since coal-fired plants have higher carbon intensity.

Furthermore, gas prices can change the order in which types of power plant come into the stack model. Natural gas prices have fluctuated frequently compared to the relatively stable coal price. Figure 3.12 shows the historical natural gas price index in the UK from October 2008 to February 2010. The price of natural gas has plunged dramatically. Hence the marginal cost of gas fired plants should react to this change. If the values of other variables remain the same, then the marginal cost of coal fired plants will be more than that of the gas fired plants when the price of gas is less than 35 pence per therm. Table 3.7 displays the results from the stack model. The marginal cost for power plants varies as the carbon price and fuel prices vary.

Figure 3.11 Marginal cost curves based on different carbon prices.

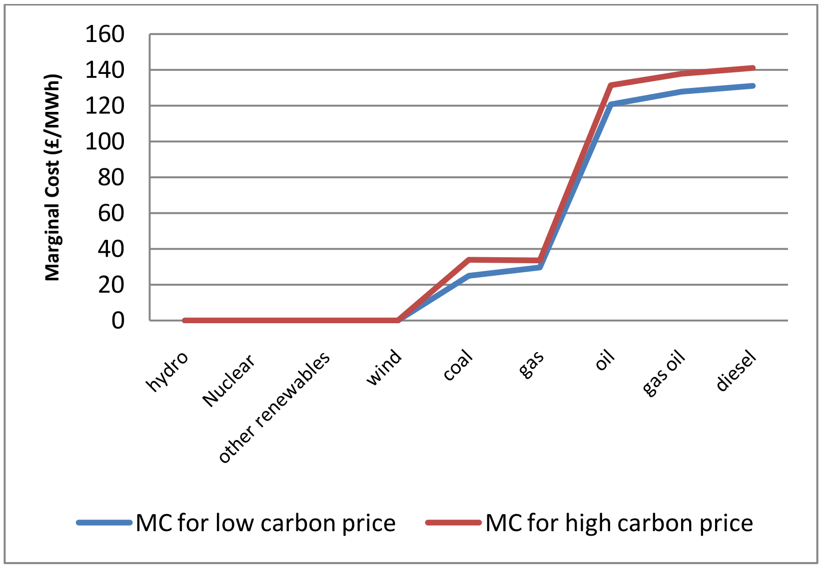
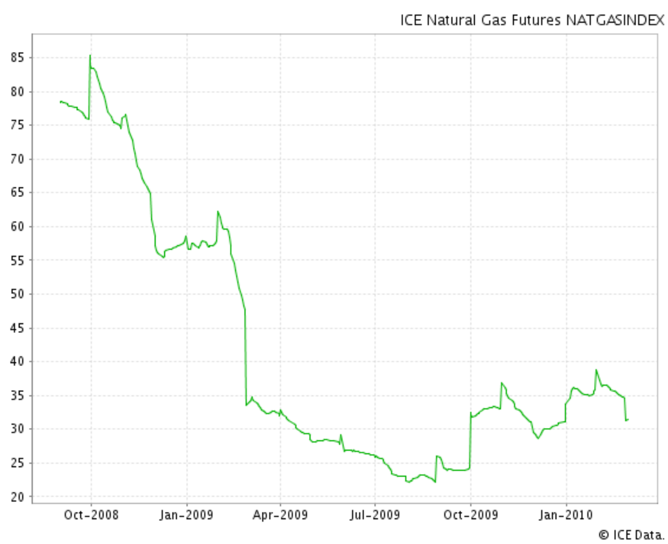


Figure 3.12 Natural Gas price index in the ICE UK.



Source: ICE natural gas index

Table 3.7 Marginal costs of generation.

	Fuel Price	MC	Fuel Price*	MC*	MC**
Hydro	0	0	0	0	0
Nuclear	0	0	0	0	0
Other renewables	0	0	0	0	0
Wind	0	0	0	0	0
Coal	65.39 £/tonne	25.00138	65.39 £/tonne	25.00138	33.66
Gas	42.5p/therm	29.63709	30.50p/therm	21.60852	25.48
Oil	50.13 £/barrel	120.7943	50.13 £/barrel	120.7943	131.2
Gas oil	1.19 £/gallon	127.8084	1.19 £/gallon	127.8084	137.78
Diesel	1.22 £/gallon	130.9524	1.22 £/gallon	130.9524	140.93
Carbon	11.84 £/tonne				£50 /tonne

*** Gas price reduces to 30.50 pence per therm.**

**** Carbon price increases to £50 per tonne.**

4.3 Wind Farms

There are 114 wind farms with a capacity of more than 1MW in the stack model. The total capacity of onshore and offshore wind farms is 2297.69 MW, which is just less than 3 percent of the total generation capacity. The British government has set a target of achieving renewable energy penetration of 20 percent by 2020 in the 2003 Energy White Paper. The current renewable energy penetration in the stack model is 8.5 percent including pumped storage. In addition, the intermittency of wind impacts on the output of wind farms, thus the average load factor of wind farms is 40 percent in the UK.

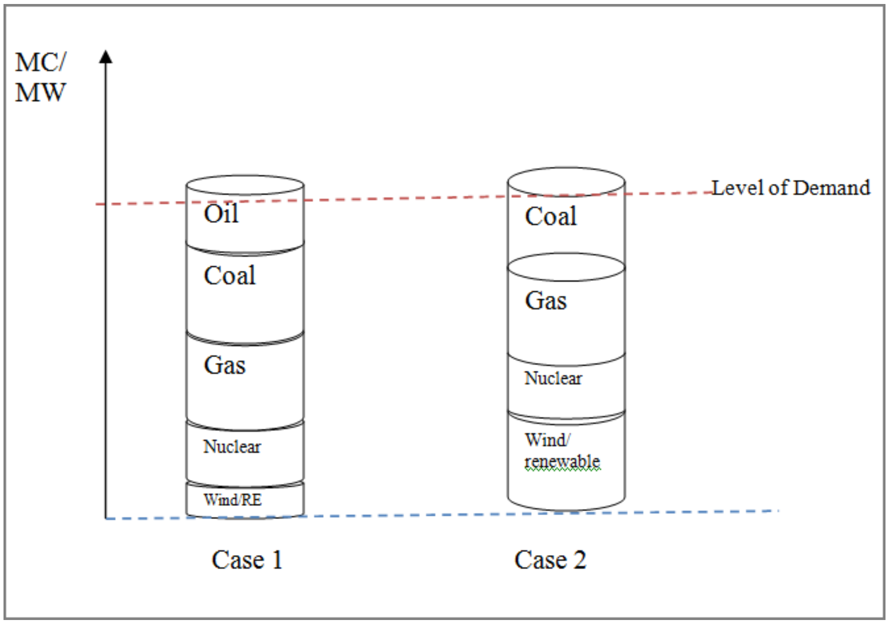
There are two scenarios which have been simulated in the stack model. In the first scenario all wind turbines are offline under the extreme weather conditions. In the second, using the same average load factor, the capacity of wind farms is increased by four times in order to meet the government's target for renewable energy penetration.

The results from the first simulation show that the marginal cost is set by the coal-fired power plants during the off peak times. The fuel price and carbon price remain the same as those of the case in Section 4.2. The system is able to meet the base load. During the peak time the marginal cost is set by the gas fired power plants if average load factor is taken into account. However, system marginal cost can be increased significantly if oil or gas oil fired plants need to be called in the stack model to meet the peak load.

The capacity of wind farms will need to quadruple to meet the renewable energy target by 2020. An assumption of the simulation is that the new generation of nuclear power stations will replace the old ones. If the values of other variables are kept constant, the results indicate that oil and gas oil fired power plants would not be needed in the stack model to serve the peak load. The system marginal cost is set by the gas fired power plants during the peak times. However, this conclusion ignores the issue of intermittency which is addressed in Chapter 4. If there is a significant probability that wind power availability falls short of its rated capacity, the system will have to build reserve capacity to cover against this eventuality.

In another case, half of the old nuclear power stations will be retired by 2020 and the new nuclear power stations are not yet available. Even if all wind farms are operating at capacity, the marginal cost will be determined by gas oil or oil fired power plants which will be required to generate electricity during peak times. The system marginal cost will be very high.

Figure 3.13 Stack models with different output levels of wind energy.



In summary, if wind penetration increases dramatically in the UK as has occurred in Germany, the variation of outputs from wind farms can affect the wholesale electricity prices. Figure 3.13 illustrates two scenarios with different levels of wind energy output. In case 1 the available capacity of wind farms is not significant in the stack model with other factors remaining constant. Thus the price is set by the marginal cost of oil-fired power plants. In case 2 the available capacity of wind farms increases significantly, and as a result the price is set by marginal cost of coal-fired plants which is much lower than that of oil-fired plants.

Under the large wind energy scenario, it is recognised that the intermittency of wind power in a situation where it is contributing a substantial share of total electricity generation will mean a reduction in the load factor for conventional generators. Thus conventional power plants -gas-fired plants as reserved generation have to run less efficiently. This raised the question that “Will the new conventional power stations be profitable in this environment?”

The security of power supply has been highlighted in the stack model experiments. The UK electricity industry needs more new investment in generating capacities to replace the aged power plants as well as to back up the intermittent renewable power plants. The stronger financial signal or subsidiary is essential to motivate new investment. In other words, the new conventional power stations need to be profitable. Therefore the Government again proposed capacity payments to compensate available capacities recently. This targeted payments to encourage security of supply through the construction of flexible reserve plants or demand reduction measures (so-called negawatts) to ensure the lights stay on[10]. In addition, new investment in gas-fired power plants is closely related to UK gas production or reserve. As UK gas production falling since 2004, there will need to be much more gas storage. However, this topic is beyond the scope of this thesis.

4.4 Transmission constrains

A further function of the stack model is that it can provide information on the regions in which electricity has been generated. Figure 3.14 is a generation map of peak demand load and Figure 3.15 is a generation map of off-peak demand load. It is clear that during peak times the capacity stacks in South East region were double that of the off-peak time. This is due to the majority of power plants in the South East using coal, gas, gas oil or oil as energy input. The principle of the stack model is that plants using clean energy come into the model first, hence power plants in South East are more likely to serve only at peak demand.

[10] http://www.decc.gov.uk/assets/decc/Consultations/emr/1041-electricity-market-reform-condoc.pdf

The majority of the hydro and wind power plants in the UK are based in Scotland. Therefore the region consistently produces a high proportion of the supply in the stack. However, transmission constrains of 2200MW between England and Scotland can reduce the export levels from Scotland to England. Consequently, the power plants in Scotland will run less efficiently.

Figure 3.14 Generation map of the peak demand load.

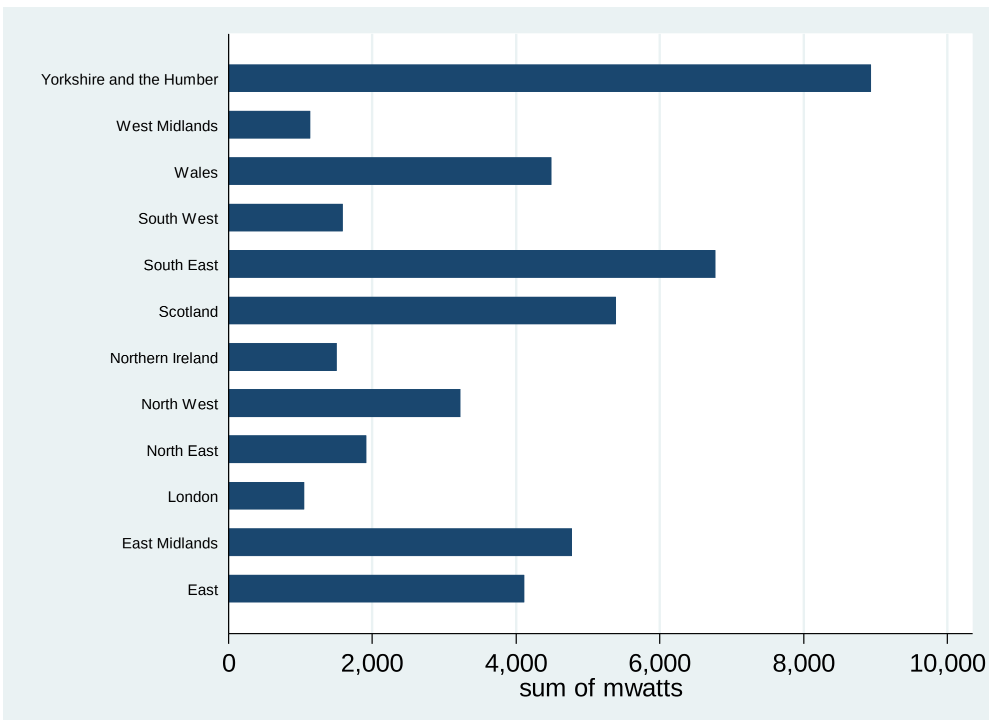
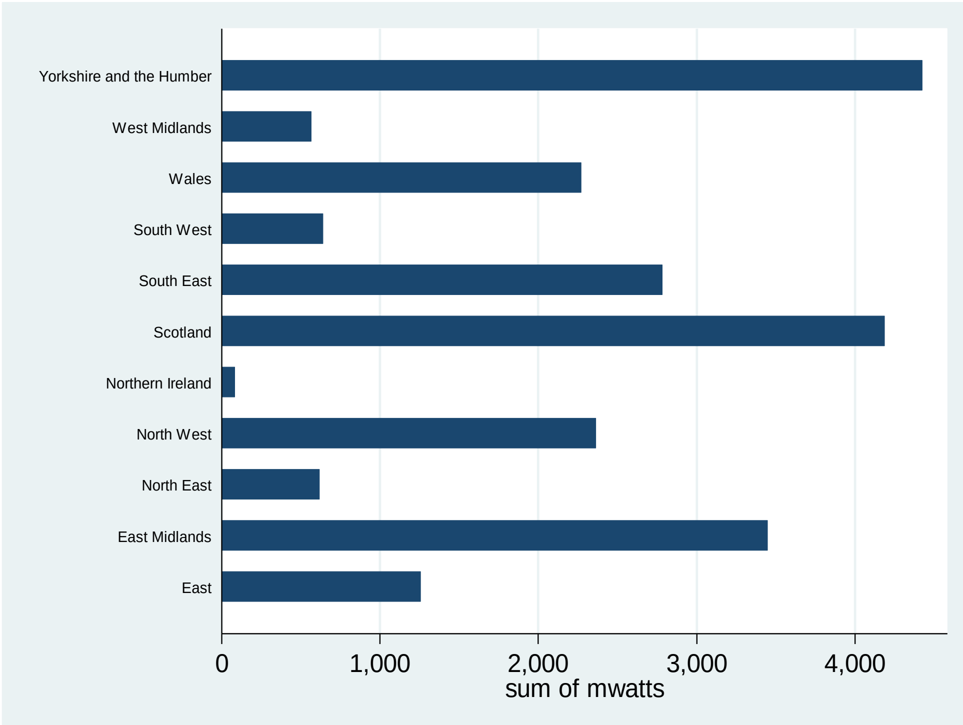


Figure 3.15 Generation map of the off-peak demand load.



In terms of investment, it may be more efficient to increase the capacity of the inter-connector before further development of wind energy in Scotland or offshore.

4.5 Model extension

The availability of power plants in the stack model is measured by the average load factor of different fuel types. However, the availability and capability of each individual power plant can vary. The extension of the stack model is to allow the dynamic adjustment of output. This can be performed using STATA Mata programme.

In addition, the ROC (Renewable Obligation Certificate) price is not an input in the basic version of the stack model because we believe that it is not a part of price formation. ROC price either can add upon the wholesale electricity price as an up-lift or pass on to consumers at retail market. However it is reasonable to discuss the effects of the ROC scheme on the electricity market. Higher ROC prices will provide financial support and incentives to renewable generation or even have influence on the bidding behaviour of electricity companies in the wholesale markets. Firstly the Renewable Obligation is ensuring that substantial onshore and offshore wind generation is built. Most renewable generation technologies are dominated by capital, however offshore wind, energy-from-waste and biomass waste plants have high operating costs. Renewable plants, with the exception of most existing hydro, tend to be commercially viable only because of financial support through the sale of ROCs and their exemption from the climate change levy (MacDonald 2010). Moreover, it might be more expensive to run power plant at lower factor or shunt it down than keep it in operation steadily. So it is possible for a renewable generator to offer a negative electricity price or price which is less than operation costs in the balancing market in order to sell its outputs but get valuable ROC price as subsidiary. As a result, it proves our assumption of the stack model that renewable generation units come into the model first with “zero marginal cost of production”. However, there are still price risks of ROC due to the design of the RO (further discussion of RO in Chapter 4, section 2). As a result, there are uncertainties for investors over the future price of ROC. Some argue this could lead to a dampening effect on investment. There remains a risk that further evolution in the operation of the RO will either over-reward or under-reward necessary investment (HM Treasury 2010).

There is an argument that RO provides no inventive to invest in developing new technologies, only in improving the efficiency of mature ones, contrary to what happens when using a feed-in tariff (FiTs) system. As a market based tool, the ROC system only defines a target to be achieved and lets the market decide how reach the optimum. In this way, the cheaper technologies are selected first, and investment in newer technologies will only be possible when all the cheap options have been explored[11]. This means that there is no incentive to develop new technologies, only to maximize the efficiency of the cheaper ones. In the UK the main focus has been onshore wind.

Premium feed-in tariffs which offer a premium over and above the wholesale market price, have been used in nations including Denmark, Germany and Spain to encourage investment in renewables. This fixed price is set in a contract that usually lasts for 15-20 years. Comparing with the UK system, the FiT have a smaller investment risk. The prices contracted in on year will be higher than the ones contracted in the following year, meaning that late entry need to use more efficient technology to be able to compete[12]. Thus the ROC scheme is very expensive with the payments being invariant to the electricity price and volatile. A Fit scheme can be more targeted, give more certainty (long-term contract), and should be less expensive. Therefore, there would be an extension for stack model experiment that what electricity price is going to be if the policy shifts from ROCs to FiTs.

5. Conclusion

Ofgem claims that the restructured British electricity industry is competitive. The wholesale trading of electricity is diversified in bilateral contracts, spot market trading, futures market trading, and balancing market trading. The ability to forecast the wholesale

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[11] http://www.shvoong.com/social-sciences/economics/2064385-economic-efficiency-uk-policy-renewable/
[12] http://www.shvoong.com/social-sciences/economics/2064385-economic-efficiency-uk-policy-renewable/

price is important for market participants. This issue has been a particularly important topic after the wholesale market was established.

There are several fundamental and statistical models for identifying electricity prices. Spot electricity prices have unique characteristics, such as regular intraday variation, seasonal effect, mean revision, jumps and spikes. The volatility of spot electricity price can be determined from prevalent time series statistic models.

The objective of this chapter is to define a method for identifying the fundamentals of the wholesale electricity price. The marginal cost of generation calculated by the stack model represents the price fundamentals. The stack model provides a reasonable simulation of the short-run system marginal cost of generation and considers fuel price, carbon price, technology, demand load, and capability of power plants. The stack model also provides the system marginal cost and generation map for a particular time slot. The flexibility of the stack model enables us to predict long-term marginal cost of generation as well. It requires replacing spot price of fuel, carbon with forward of futures prices. Demand of power is highly correlated with historical demand trends. Weather forecasts and special events are also can be predicted in long-term. One difficulty is the development of new technology which has impact on the efficiency of power generation. Therefore, it is possible to simulate long-term electricity wholesale prices which are important for electricity companies to make long-term bilateral deals.

It is straightforward to adjust the fuel price, carbon price, and capacity availability. The empirical result shows that renewable power plants cannot currently influence the system marginal cost due to low penetration. However, if the government's renewable energy target is been achieved then the system marginal cost will be set by coal fired plants rather than expensive oil fired plants during the peak time.

Moreover, the security of the energy supply will be challenged in the next decade as a result of aging nuclear power plants. If capacity is not replaced the system capacity margin could be negative, meaning that the electricity supply will not be sufficient to meet the demand. Furthermore, carbon price contributes to the marginal cost of generation for fuel combustion plants. The variation in carbon prices can change the order of coal fired plants and gas fired plants in the stack. At present coal fired plants have lower marginal cost than that of gas fired plants.

Transmission constraints are not included in the basic stack model due to the limited availability of relevant information. However, it remains an important issue in the wholesale market. Due to the transmission constraints plants which are located particularly far from urban areas, such as some distant wind farms have to operate less efficiently.

The stack model is highly flexible and easy to update. The extended version of the stack model can include the dynamic availability and capability of each power plant, although this requires a significant amount of additional data and information.

Chapter4 Assessing the portfolio risk of wind farms: implications for large wind power penetration in the UK power market

1. Introduction

In the UK energy white paper 2003 the government set a target of achieving renewable energy penetration for electricity generation of 20% by 2020. In other words 20% of the electricity supply would be provided from renewable sources. This rapid expansion of renewable energy is planned in Britain to help counter climate change. A secondary aim is to enhance energy security following the run down of North Sea oil resources. If one takes only the domestic production into account, the UK has met its Kyoto Protocol target for cutting greenhouse gas emission in 2008. However, there are continuous adjustments of the British government's renewable energy policy and targets. The government's goals of dealing with climate change, especially of reducing carbon dioxide emission are becoming increasingly challenging.

The government believes that successful renewable energy technologies are the main route by which the goal of a low carbon economy can be achieved. The majority of renewable energy will have to be delivered by wind energy, since wind power generation is the most developed technology available at present. However, in 2007 only 2% of the UK's energy came from wind power compared with 29% in Denmark, 20% in Spain, and 15% in Germany[13]. In order to meet the government's targets the number of wind turbines on land in Britain is likely to grow from just above 2,000 at present to 5,000 by 2020, according to the British Wind Energy Association (McCarthy 2008). An even greater increase in the number of wind turbines is planned for offshore wind farms, with turbines installed in the

[13] http://news.bbc.co.uk/1/hi/uk/7959912.stm

seas around Britain's coasts. The number is likely to increase from fewer than 150 at present to approximately 7,500 by 2020 (McCarthy 2008). As a part of these extensive plans, considerations need to be given to connections with transmission networks, environmental issues, and levels of investment. Since wind power generation depends on wind speed, the intermittency of wind impacts on the output of wind farms. Therefore the impact of wind power generation on the running of the electricity system should also be taken into account. It also adds extra costs for system balancing and transmission. Increasing wind power penetration needs additional reserve capacity to maintain the energy supply. This implies investment in alternative forms of generation suited to balancing wind power and additional grid capacity. Both imply additional costs for system operation.

The research question asked in this chapter is to what extent wind energy outputs are correlated across the country or if they can be considered independent. Electricity companies usually own more than one wind farm. They need to manage the associated risks of fluctuating wind energy output, due to the intermittency of wind speed. The numbers of wind farms will increase if the government's energy target is to be achieved. Therefore, it is essential for electricity companies to assess their portfolio risk of their wind energy, which are likely to comprise diverse wind farms in different locations. The generation portfolio of an electricity company can contain different types of power plants. However, this study is focused on the risk of supply which is associated with the correlation between wind farms. Thus, the portfolio means a wind farms portfolio in this study.

Modern portfolio theory is widely used in financial markets. Investor portfolios are composed of diverse types of assets. Investors must take account of the interplay between asset returns when evaluating the risk of a portfolio. The offsetting pattern of returns on assets stabilises the risk of the overall portfolio, then investors can control or hedge the portfolio risk. Similarly, a set of wind farms for an electricity company is like a set of equities for investors. Electricity consumers are risk averse – they place a high value on security of power supply. In turn, this implies that power companies are risk-averse. They also care a lot about energy supply security, which is similar to risk-averse investors wishing to avoid losses. If wind turbine outputs are independent or negatively correlated, then wind energy could be considered a low risk source of energy. If wind turbine outputs are highly correlated then wind is a risky form of power generation. Association between wind power levels at different locations can be measured using linear correlation coefficients. The correlation of wind turbine *outputs* can be approximated by using the correlation of wind *speeds.*

In the large wind energy penetration scenario, electricity companies have to build a portfolio of wind farms with low risk. Low risk implies wind farms within the portfolio are not correlated at all or they are negatively correlated. The wind energy output of a portfolio will not be affected when wind strength increases in one part of the country and decreases in another part of the country. With trading, the individual companies may be able to reduce risk through trades of supply in different parts of the country. However, this will not remove the *systemic* risk that is associated with the total output of the wind farm system. To examine the systemic risk associated with wind generation, we have fitted a variety of models to British wind speed data in order to investigate the underlying stochastic structure of wind speeds and the consequent effect on power generation at wind farms.

In fact, most of the power companies have a mixture of production system- coal, gas, oil and renewables. There is a trade off between increasing the risk of power delivery by building more wind farms and paying more for ROCs or failing the RO. I have restricted this research to a portfolio only have a number of wind farms and got the conclusion of invest in wind farms that are negatively correlated to reduce overall portfolio risks. However, this might not be hold if a power company decides to buy more ROC and build more gas-fired power plants in its generation portfolios, but this is beyond the scope of this thesis.

The first part of this chapter (Section2) presents the background of UK renewable energy developments based on the UK climate change and renewable energy policies. It examines the government's current targets for the electricity industry and discusses the difficulties for the government in meeting those targets. Section3 discusses earlier studies on the impact on the electricity system under increasing wind energy penetration. Section4 presents different methodologies for modelling correlation of wind speed. This section also compares and contrasts the results from our models. Section5 discusses methods for converting wind speed into power output. The final part is the conclusion.

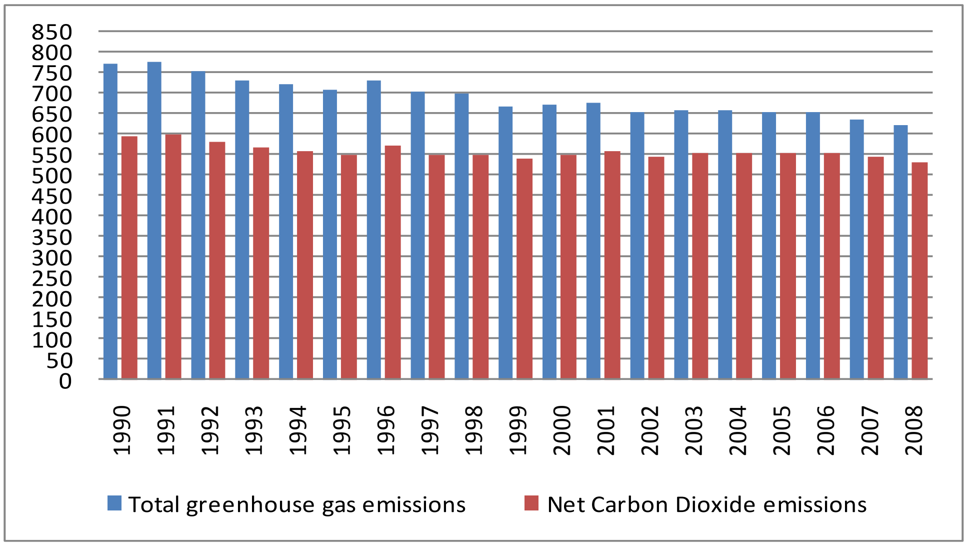
2. Background of UK renewable energy policies and developments

2.1. Dealing with Climate Change

The UK government has set a series of guidelines to measure and tackle the greenhouse gas emission. The greenhouse gases targeted for reduction are Carbon Dioxide (CO_2), Methane, Nitrous Oxide, Hydrofluorocarbon, Perfluorocarbon, and Sulphur Hexafluoride. The UK's legally binding target under the Kyoto Protocol agreed in 1997 was to reduce its greenhouse gas emissions by 12.5% below that of 1990 levels (base year) between 2008 and 2012. The UK government and its devolved administrations had set a separate domestic goal of a 20% reduction in CO_2 emissions below 1990 levels by 2010 (DETR 2000). In 2003, the Energy White Paper adopted a long term goal to put UK on the path to cutting CO_2 emissions by some 60% by about 2050, with considerable progress towards this by 2020 (DETR 2006). The Climate Change Act 2008 has also set legally-binding targets for the UK to reduce its greenhouse gas emissions by at least 80% below 1990 levels by 2050 and CO_2 by at least 26% below 1990 levels by 2020.

The targets for reducing greenhouse gases are challenging. The Department of Energy and Climate Change (DECC) states that the UK's greenhouse gas emission fell to about 9% below 1990 levels in 1998 and around 17.4% lower than 1990 levels in 2007. The reduction in greenhouse gas emissions since 1990 has been driven by privatisation and liberalisation of energy supply industries, increased energy efficiency, pollution control measures in the industrial sector, and other policies that reduced emissions of non-CO_2 greenhouse gases (DETR 2006). The UK's greenhouse gas emissions fell by 19.07% in 2008 compared with 1990 levels, excluding the purchase of carbon credits under emissions trading schemes. This puts the UK well ahead of its Kyoto Protocol target. The UK has become one of the leading countries when it comes to tackling climate change.

Figure 4.1 UK greenhouse gas and Carbon dioxide emissions ($MtCO_2e$) 1990-2008.



Data Source: DEFRA Economics and Statistics (DEFRA 2007) and (DECC 2009).

However, the trend in reduction of CO_2 emissions indicates that the government is highly unlikely to meet its targets for 2010 and 2020. Figure 4.1 describes the entire time series of UK greenhouse gas and CO_2 emissions from 1990 to 2008. CO_2 emissions fell by only around 6.4% below base year levels in 2006 and around 10.2% lower compare to 1990 levels in 2008. CO_2 emissions have stabilised since the 1990s energy industries revolution. There has been no significant reduction in CO_2 emissions over the past five years. If this situation continues it is likely that the UK government will fail to meet its CO_2 reduction target for 2010.

The government's statistics of greenhouse gas emission have been criticised as "creative" (Jowit 2009). The calculations ignore the emissions associated with the large merchandise imports by the UK as well as the impact of international aviation and shipping. In other words, the UK statistics ignores the amount of carbon outsourced. Dieter Helm (2008) found that the UK's greenhouse gas emissions in 2005 instead of falling by over 15% since 1990 actually rose by around 19%, if carbon outsourcing is included. Based on his calculations the UK's remarkable emissions cuts over the past two decades appear less impressive.

2.2. Renewable energy targets

A wide application of renewable and clean energies is one way to meet the government's emission targets. The majority of the UK's greenhouse gas emissions comprises of CO_2. It comes primarily from transport, households, business and fossil fuel fired power plants. The combustion of coal, natural gas, and to a lesser extent oil for electricity generation contributed to around 30% of CO_2 emissions in 2004 (SDC, 2005). In the 2003 Energy White Paper, the government argued that successful renewable energy technologies would be the main method of achieving a low carbon economy since most renewable energy sources do not produce CO_2.

Consequently, in 2000 the government set a target of 10% of electricity supply from renewable energy sources by 2010. A further target of 20% of electricity from renewable energy by 2020 was announced in 2006.

Table 4.1 presents the current renewable electricity targets for EU countries. It is ranked by the order of the percentage of renewable energy penetration excluding hydro power. The 2010 target for the UK is 9.3% renewable energy penetration excluding hydro power and less than the EU target of 12.5%. In 2007 approximately 5% of electricity in the UK was generated from renewable sources including hydro power. The volume of electricity from renewable sources needed to be doubled in three years to meet the 2010 target.

Table 4.1: 2010 targets for renewable electricity of EU countries.

	including hydro	Excluding hydro
Denmark	29.0%	29.0%
Finland	35.0%	21.7%
Portugal	45.6%	21.5%
Austria	78.1%	21.1%
Spain	29.4%	17.5%
Sweden	60.0%	15.7%
Italy	25.0%	14.9%
Greece	20.1%	14.5%
EU	22.1%	**12.5%**
Netherlands	12.0%	12.0%
Ireland	13.2%	11.7%
Germany	12.5%	10.3%
UK	10.0%	**9.3%**
France	21.0%	8.9%
Belgium	6.0%	5.8%
Luxembourg	5.7%	5.7%

Source: EU directive2000.

In order to achieve these goals and encourage investments in new renewable electricity capacity, the Renewables Obligation (RO) and Climate Change Levy (CCL) system were introduced. These provide indirect subsides to renewable energy generators. The CCL is a tax on energy used by business and the non-domestic sector. Electricity produced from renewable sources is exempt from CCL.

The RO requires licensed electricity suppliers to source a specific and annually increasing percentage of the electricity they supply from renewable sources. The UK currently has over seventy licensed suppliers of electricity and gas. In 2005 the government passed ‘The Renewables Obligation Order 2005’ requiring energy companies to derive 6.7% of the energy they provide to their customers from renewable sources. The current level is 9.1% for 2008/2009 rising to 15.4% by 2015/2016. However, in 2007 only 5% of the UK's electricity supply came from renewable sources, with 4.9% from RO eligible sources[14].

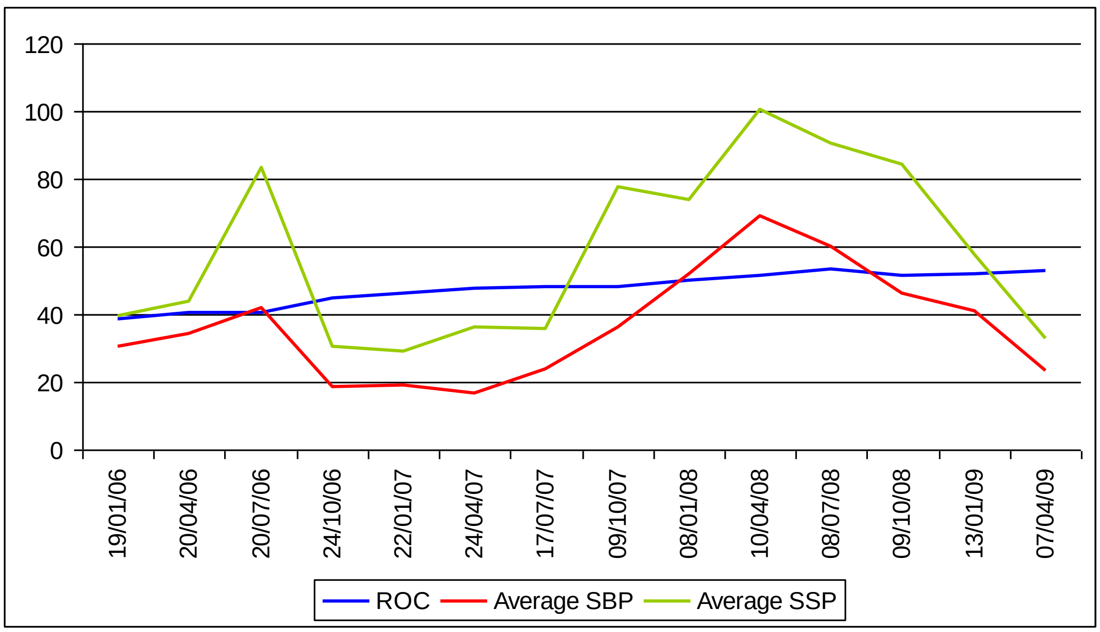
A Renewables Obligation Certificate (ROC) is issued to an electricity generator accredited by the Office of the Gas and Electricity Markets (Ofgem) for eligible renewable electricity generated within the UK. A single ROC is issued for each megawatt hour (MWh) of eligible renewable output generated. ROCs can be sold to suppliers on the open market which is administered by the Non-Fossil Purchase Agency Ltd (NFPA) and Ofgem. In other words, in order to meet the RO requirement either an integrated electricity company needs to generate the required percentage of renewable electricity or their integrated suppliers need to buy the appropriate amount of ROCs. Suppliers who sell electricity to consumers and do not own renewable generation plants have to buy ROCs on the open market, otherwise fines can be imposed.

All electricity suppliers must prove to Ofgem that they have met the RO requirement by producing ROCs at the end of the year. If a supplier fails to meet this obligation it must pay a so-called "buy-out" fine for every MWh sold that was not from renewable sources. The buy-out payments from suppliers who have insufficient ROCs are redistributed to other suppliers in proportion to the number of ROCs they present. The buy-out price was £30 per MWh in 2002/2003. It is adjusted by the RPI annually[15]. Missing the RO by even a small amount can be very expensive. For example, EDF Energy Customers PLC had an RO of 2,883,887MWh in 2006/2007. It was left with a 2% shortfall despite succeeding in meeting

[14] http://www.berr.gov.uk/whatwedo/energy/sources/renewables/index.html
[15] http://www.berr.gov.uk/files/file21130.pdf

98% of its RO through ROCs, obliging it to pay £2,005,000 in buy-out fine (Constable 2008). Constable and Barfoot found that the buy-out fines (plus interest), to be redistributed totalled £217,888,311 and the total number of ROCs submitted was 12,868,408. This meant that each supplier who sufficiently produced ROCs received £16.04 back per certificate for England and Wales in the period 2006/2007(Constable 2008). This is an additional source of income for renewable generators.

Figure 4.2: Daily ROC prices, average System Buy Price (SBP) and average System Sell Price (SSP) (£/MWh).



Data source: ROC price from NFPA. SBP and SSP prices from NETA reporting (www.bmreport.com)

Figure 4.2 describes the daily average ROC, System Buy Price (SBP) and System Sell Price (SSP) prices. The ROC prices are higher than the SBP for the majority of the time shown on Figure 4.2. The ROC price has slowly increased and maintained a relative high level. It is quite steady compared to more volatile SSP and SBP prices. ROCs have increased the profitability of renewable energy generation as the certificates can currently sell for more than SBPs. Therefore renewable generators are rewarded by the RO mechanism. This provides additional incentives for the production of additional renewable capacity.

However, there are also negative impacts of RO. Some companies who failed to meet their RO target became insolvent and consequently failed to pay their fines. TXU UK LTD and Maverick Energy Ltd were companies in receivership that had failed to meet their RO target for 2002-2003 and failed to pay the required fines[16]. Furthermore, high ROC prices have increased wholesale electricity costs. The major suppliers have been able to pass these higher costs on to the consumers. As a result the electricity prices have increased and consumers have to pay more for electricity even though there is no explicit 'green tariff'. The BERR (2008) stated that current climate change policies have added an additional 14% to domestic electricity bills and 21% to industrial electricity bills, much of this from the RO and the CCL (BERR 2008). The Latest report from Ofgem suggests that the domestic energy bill could rise by 14%-60% by 2020 to fight the global warming (Adam 2009).

Another main driver of the renewable energy target is the security of energy supply which depends on the diversification of supply. Increasing international competition for energy resources with increasing scarcity and difficulty of accessing and extracting fossil fuel reserves has been identified as one of the main threats to the UK's overall energy security. Furthermore, renewable energy can reduce the dependency on imported fossil fuels. The government believes that increased investment in the UK to meet a 15% renewable energy target will reduce annual UK gas imports by 12%-14% by 2020 (DECC, 2009).

[16] http://www.nowap.co.uk/page7.html

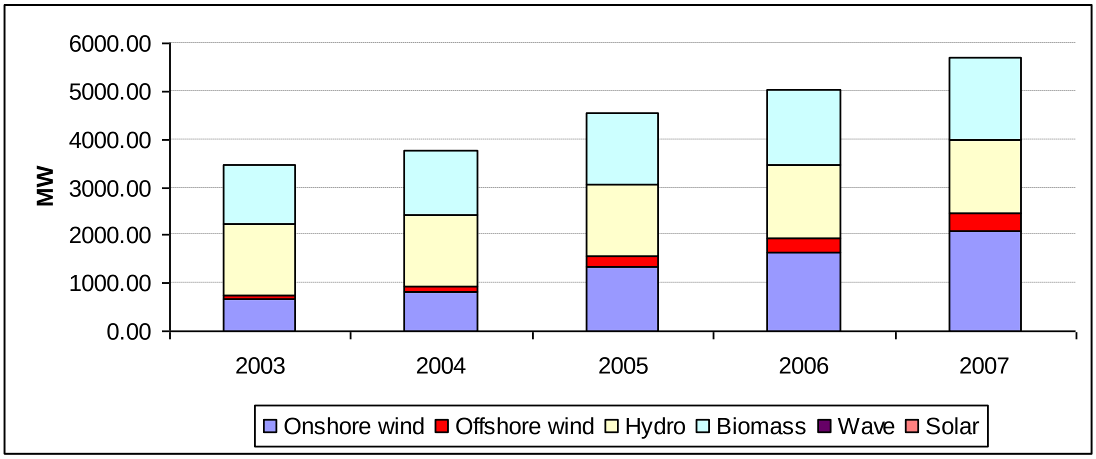
Therefore, renewable energy targets would require a revolutionary and structural change of the energy generating sector in the UK. The UK's renewable electricity supply still requires around a four-fold increase to meet the 2020 target. It is an opportunity and challenge for the electricity industry.

2.3. British renewable energy and wind farms

There is significant growth in developments in renewable energy generation around the world. Denmark has successfully transformed its energy sector. In 1970 Denmark was 99% dependent on foreign energy sources such as oil and coal. However, Denmark has become a net exporter of natural gas, oil and electricity today. Denmark has the largest portfolio of wind projects in the world, integrated in to its power grid (21.6%, 3GW in 2006). Germany has the largest installed wind capacity with over 20 GW and an average annual penetration level of 5% in 2005. In Germany, Schleswig-Holstein had achieved a wind penetration of 28% by 2005. Both Denmark and Germany have high capacity interconnector with other countries allowing export of surplus wind production and the import of power when wind production is low (Porter 2007).

The UK has significant renewable sources and penetration of renewable electricity supply has been increasing, although the total penetration level of renewable electricity supply is still very low (less than 7% in 2007). Figure 4.3 shows that across the UK as a whole, onshore wind power is the renewable technology with the most significant operational installed generating capacity with a total of approximately 2084MW in 2007. This capacity had increased to 2,735MW by 2008. This represents more than half of the total renewable energy generating capacity in the UK. It is the dominant renewable technology in Scotland, Wales, and Northern Ireland.

Figure 4.3: Renewable generation capacity 2003-2007.

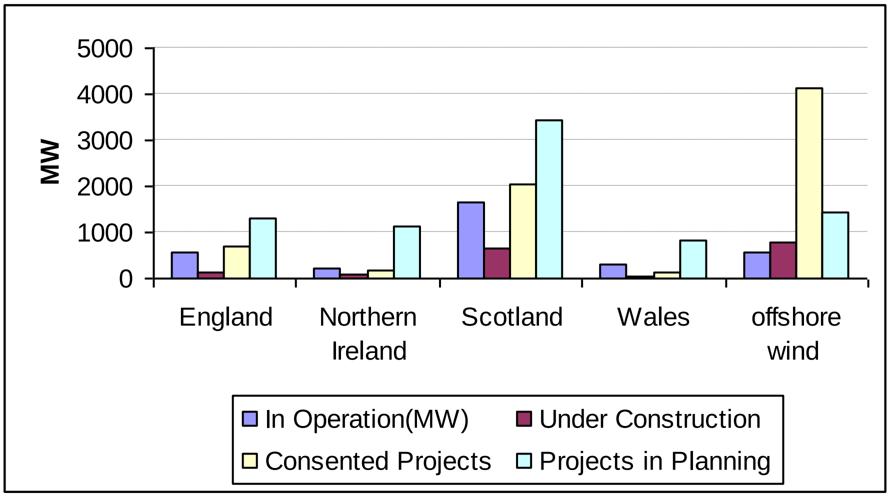


Data source: BERR DUEKS7.4

Another significant source of renewable electricity is hydro. There is little scope for increased capacity due to location and environmental considerations. Landfill gas is currently the most significant source of biomass based renewable generation but its potential for growth is limited in the short run as most large landfill sites are already being exploited and the importance of landfill sites may decline even further in future as available sites are depleted (DECC 2008). The generation capacities of wave and solar power are currently very small at 0.5MW and 14.3MW respectively.

Figure 4.4 shows the current operational and planned wind farm capacity in the UK. There are 209 wind (onshore and offshore) projects with 2387 turbines currently in operation, providing a total capacity of 3301.59MW (2008). There are 41 wind farms with 596 turbines under construction which will add a further 1697.05MW to the overall capacity.

Figure 4.4: Wind farms in UK in 2008.



Data source: BWEA statistics[17]

Green wind energy will play a major role in achieving a low-carbon economy. The UK has written ambitious carbon reduction targets into law, cutting carbon emission by 80% by 2050. Therefore, studies on renewable energy and electricity markets are essential to improve the transparency and then drive investment in low-carbon energy.

3. Literatures review of issues for large wind penetration scenarios in the UK

3.1. Intermittency and wind resources

Intermittency is an attribute of many renewable resources. For wind power it can be due to varying strength or complete absence of wind. As wind is the only 'fuel' to power the wind turbines, intermittency of wind can cause the electricity output patterns of wind farms to fluctuate. The intermittency of winds is stochastic. The short term fluctuations of wind farms output require system balancing services which are used under NETA/BETTA

[17] http://www.bwea.com/statistics/

market arrangements. The long term variations have impact on system reliability to meet peak time demand.

Farmer et al (1980) studied the impact of intermittency of wind energy when the CEGB was in place. Relevant research was done by Gardener and Thorpe as well (Milborrow 2001). Since our research is based on post-NETA/ BETTA electricity market, we will focus on the post-NETA studies.

The report "*Wind power and the UK wind resource*" by the Environmental Change Institute at Oxford University presents an overview of the characteristics of the UK wind resources in terms of its patterns of availability and variability (ECI 2005). DTI, BWEA, and the then Energy Minster Malcolm Wicks were positive about the report but overoptimistic about the UK wind energy at that time. Their perception was that the report confirmed the UK has the best wind resources in Europe[18]. However, the report simply compared the UK's wind capacity factors to that of Denmark and Germany. It is inadequate to draw the above conclusion; even though Denmark and Germany are the leading countries of wind power generation in the European continent. Firstly, capacity factor or load factor describes energy produced by a generator as a percentage of that which would be achieved if the generator were to operate at maximum output 100% of the time (Gross 2006). For wind farms, the capacity factor is calculated as the volume of electricity generated by the turbines divided by the theoretical maximum output of those turbines under ideal wind condition. In this report, they found the ideal wind condition for a typical 2.5MW modern wind turbine is when the wind speed is between $14ms^{-1}$ and

18http://www.bwea.com/media/news/141105.html

25ms^{-1}. Within this wind speed range, the power output of turbines is constant at maximum output level. Therefore, the capacity factor is a measure of operational performance of wind turbines. It is related to the variation of wind speed but it does not describe the availability and variability of wind resources. Secondly, the report used the average capacity factor to represent the wind resources of each country. However, the characteristics of wind resources can vary significantly on different sites or in regions within the same country. For example, the average load factor was around 15% for Germany as a whole in 2004. However, the average load factor in that year was around 28% in the Schleswig-Holstein region which had considerably higher wind penetration. Thus the average capacity factor is not a good indicator for comparing wind resources of different countries. Moreover, Germany had more than 16GW of wind capacity at the end of 2004, providing more than one third of the world's wind capacity at 26 billion kWh[19]. Therefore, the report did not provide enough evidence to prove that UK has the best wind resource in Europe.

Sinden's *paper* (Sinden 2007) is based on the above report and provides an excellent presentation of characteristics of UK onshore wind farms' output. He identified long-term trends in the average seasonal and durable availability of UK wind resources. He found low wind speed events have a limited impact on the UK and high wind speed events are extremely rare. On average there is around one hour per year in summer when over 90% of the UK experiences low wind speed conditions, although these extreme weather conditions occurs around one hour every five years in winter. Furthermore, he identified the long-term variability in wind power output together with seasonal patterns of wind power availability.

19http://pathsoflight.us/musing/?p=202

The UK experiences a seasonal maximum in wind power availability during winter and an increase in wind power availability during the day times compared to night times. He also examined the relationship between average wind power output and electricity demand levels by analysing capacity factors of wind farms. He found that during periods of high electricity demand, the average capacity factor of wind farms can reach up to 37%, but during periods of low electricity demand this number falls to around 13%.

Oswald et al. (2008) built an eight region model to assess the degree of fluctuations in wind power output in the UK and the consequences of any volatility on the control and utilisation of individual generation plant on the grid. They assumed the wind farm capacity to be 25GW on the UK grid system. They also assumed the level of demand remains stable at 407 TWh (2005 level). In their study, 25 GW capacities of wind farms would deliver 16% of the British electricity demand when the load factor of wind farms is 30%. This ratio will be 18.8% if load factor is 35%. In this case the electricity industry will meet the government's renewable electricity target by 2020. Their model uses hourly wind speed recorded in January of 1996 to 2005 and the monthly energy outputs from Ofgem at eight locations. Their model suggests that wind power swings of 70% within every 12 hour period are to be expected in winter. Due to the volatility of wind power, the residual demand on other power sources would vary over the month between 5.5 and 56GW. Therefore, the utilisation of large centralised plants will be reduced on average and they will have to deal with much larger variations in demand. This may encourage generators to install low-cost and low-efficiency plants rather than high-efficiency base load plants. The calculations for overall carbon savings might be adjusted to include this effect. They also demonstrate that electricity demand in Britain can reach its annual peak with a simultaneous diminution of wind power to very low levels in Britain and neighbouring countries (Oswald 2008).

However, we believe it is inappropriate to use only eight locations to represent the impact of the assumed scenario of 25GW wind farms on the British electricity system. The locations of their sites are spread around the west of the island and one on the east. They use eight regions due to the limitation of wind farm output data. Therefore, their results may be biased due to the regions they have selected. In addition, the analysis of the impact of variable wind on individual conventional generators does not answer the question "Will British weather provide reliable electricity?" (Gross & Heptonstall 2008) Furthermore, Gross and Heptonstall agree with Oswald *et al*. (2008) that the average load factor for conventional plants would decline in a large renewable electricity scenario. They do not believe it is necessary to keep large additional capacity of thermal plants to run as base load. Gross and Heptonstall argue that the main issue is that wind power and nuclear would be competing to meet minimum demand. However, we do not believe that this is the problem.

Electricity demand is correlated with weather, especially cold weather in the UK. The UK experiences significantly higher electricity demand during winter than in summer. Electricity demand is higher during the day and early evening than overnight and in the early hours of morning. Sinden (2007) found that this pattern of electricity demand is similar to the pattern of the wind volatility in the UK. He found a trend of increasing energy production from wind power during the period of high electricity demand. Therefore, during the period of minimum demand the wind farms tend to experience low load factors. The wind farms' activities will not have to be curtailed to let nuclear power stations serve minimum base load priority.

There are two hypothetical methods for dealing with the problem of wind intermittency under the large wind penetration scenario. One novel solution is the electric car infrastructure which would integrate wind power and transport using renewable energy[20]. The infrastructure would incorporate charging points and battery swapping stations. These stations would be situated at locations that ensure the cars always have 100 miles of driving capacity. Thus the storage battery can be charged during off-peak hours or when the system has a surplus of electricity supply. According to the alternative method, pumped storage power plants would provide a green energy resource for temporarily storing energy generated by wind farms and other renewable resources. In this method water would be pumped uphill to a reservoir during low-demand periods or excess wind energy output, and then allowed to flow downhill to turbines during periods of high-demand. The difficulty of this method is the transmission constraints between wind farms and pumped storage. These two methods are potentially able to back up wind energy and deal with wind intermittency. However, these methods are only likely to be a benefit in the long term since neither technology is likely to be realised in the near future.

3.2. The impact of variable wind power output on the electricity system

There are studies which assess the impact of variable wind power output on the electricity system by using statistical analysis and power system simulation.

[20] http://www.niassembly.gov.uk/io/research/2009/1309.pdf

Strbac (2002) in association with ILEX Energy reported to the DTI regarding the system costs of additional renewables in 2020. They used scenario analysis to investigate the 'plausible range' of system costs in 2020 under various 'combinations of demand, mixes of renewable technology, and volumes of renewable generation'. This study quantified the additional system costs that would occur if 10% of electricity is supplied from renewable sources in 2010, and 20% or 30% renewable electricity penetration by 2020. Additional annual system costs were broken down by three sources- balancing and capacity, transmission, and distribution. They found that under the large renewable electricity scenario, in particular wind, the balancing and capacity cost is the main or dominant part of the system cost due to maintaining system security. The capacity cost is the cost of additional capacity required to maintain system security. In their study they assume that additional capacity is provided by open cycle gas turbine plants (OCGE). They found that balancing and capacity costs may vary between £143m to £284m (based on 2002 prices) under 20% renewable penetration in 2020 (Strbac 2002).

Dale *et al.*(2004) examined costs where 20% of electricity came from renewable sources by 2020. They assumed all the renewable electricity is sourced from wind energy. They determined the extra costs of the renewables scenario by comparing the total cost of a 20% wind scenario with a scenario where a similar amount of energy is generated by gas-fired plants. The implications of this alternative scenario were examined using sensitivity analysis. They found that the extra cost would rise if the capital costs of wind generation fall more slowly than anticipated, but would fall if gas prices rise more rapidly than has been assumed or if wind plants are more efficient. The total additional cost is estimated to be around 0.3p/kWh. Furthermore, £2.5bn to £4bn of transmission investment is required by the NGC in order to accommodate wind energy (Dale *et al.* 2004).

The costs associated with the government's renewable energy target are subject to a number of uncertainties. The above papers made the estimation under specific assumptions. The global economic downturn has affected the renewable energy industry. In some cases investment in new wind farm projects has been suspended or cancelled. The demand for wind turbines has fallen as a result and turbine producers having been forced to cut prices. Therefore the capital cost of wind turbines may decrease.

3.3. Modelling wind energy output

The previous section discusses the impacts of variable wind energy output on the electricity system. The Transmission System Operator (TSO) and Ofgem need to evaluate the relevant system costs and demand of investments in the National Grid for maintaining system security as the level of penetration of wind energy into the grid rises. The TSO needs to balance the electricity demand and supply second by second. The fluctuation of wind energy output has significant impact on SBP, SSP, and volume. Under the large wind energy penetration scenario, the TSO faces greater difficulties in balancing the national grid system. Thus modelling wind energy output is essential to the TSO for predicting and managing the volatility in the amount of balancing units. Therefore the TSO can avoid or reduce the balancing problems.

In addition, at the risk of extremely high SBP in the balancing market, the renewable electricity generators have to be able to model accurate output and bid into the market. As discussed in previous chapters of this thesis, when a wind power plant fails to fulfil the bilateral contract it is compelled to buy a certain amount of electricity from the TSO in the balancing market or from spot markets. Thus it can be exposed to the risk of price volatility.

The electricity companies which own both conventional power plants and wind farms may change their trading strategy under the large wind energy penetration scenario. It is possible for them to run their conventional power plants inefficiently, since the insufficient electricity supply may cause high system prices. The wind farm output creates sources of income from electricity selling, ROC, CCL and redistributed buy-out payments. On the other hand, they keep the conventional plant capacity available until the TSO calls. In this way, they could make a significant profit from trading in the balancing market.

The impact of higher wind energy penetration on conventional power plants has been discussed in the literature. Weigt(2009) has analysed the extent to which wind energy can replace capacities of fossil fuel power plants based on the German wind injection and demand data for 2006 through to June 2008. The results indicate that the wind potential in Germany will not allow a significant reduction in capacities of fossil fuel power plants. He also found that a reduction in fossil fuel prices would reduce the benefit from wind energy, assuming all other factors remain equal. In particular coal and gas prices have a strong impact on the price of electricity, whereas nuclear and lignite will only have relatively minor influence (Weigt 2009). Moreover, the variation of load flows from wind farms in the interconnected grid system may influence the dispatch and re-dispatch of electricity generated by the conventional power plants. In addition, Berry (2005) found that wind energy can provide a cost effective hedge against natural gas price volatility or price increases. These findings are based on his analysis of the costs of marginal conventional generation given the historical probability distribution of natural gas prices, the cost of wind energy, wind integration costs, transmission costs for wind energy, the capacity value of wind, and environmental benefits of wind energy for a hypothetical utility in the South western United States (Berry 2005).

Moreover, investors are more cautious in the current economic circumstances. Hence the modelling of wind farm output and analysing wind energy price risk in the balancing market are essential to wind farm owners or potential investors. However, it is a good investment opportunity due to the policy of financial support from the government. The organisation Consultancy Emerging Energy Research predicts that Europe's 20 largest utilities will double their investment in green power over the next five years, having allocated $13.3bn for renewable ventures to date (Refocus 2006). Therefore modelling wind energy production and assessing the portfolio risk of wind farms become more important as the level of installed capacity continues to increase.

4. Modelling hourly mean wind speed in the UK--Methodology and results

A wind farm's output is influenced by the intermittency of wind and variation of wind speed. The processes of modelling wind speed are the main methods in determining the patterns of wind farm output. These methods minimise the overall variation of outputs for a wind farm portfolio. In the large wind energy penetration scenario, modelling the electricity output of wind farms is essential for maintaining system security. In addition, electricity companies with large wind capacities need to manage their financial risks in the balancing market and electricity spot market. This is closely related to operational and financial hedging strategies of companies exposed to wind-related risk. The system operator can make detailed schedules and plans to ensure the security and balance of the system based on those models. The simulating of wind speed distribution at a given location and time period has become the prevalent method of estimating the output of wind farms and to determine the 'wind power density'. The distribution of wind energy at different wind speeds is called wind power density, and it is calculated by multiplying the power of each wind speed with the probability of each wind speed (Celik 2003).

A straightforward way of calculating the matrix of correlation coefficients for a wind farms output is by using the wind farms real output data, for example hourly or half hourly time series. However, the data for all wind farms is not publicly available. Due to this limitation most research includes only a few sites. Harrison has also presented the correlation of Ontario wind farm power output by using hourly power output measurements from 5 farms for the year August 2007 to July 2008[21].

Due to the shortage of wind farm output data we first need to determine the wind speed distribution of each site. However, we cannot use average (daily or monthly) wind speed data to determine the average output of a wind farm since the average wind speed data is insufficient to describe the potential power output. A modern wind turbine operates under a wind speed of between $4ms^{-1}$ and $24ms^{-1}$(ECI 2005). For example, let us assume that there are two sites A and B that have the same average monthly wind speed of $15ms^{-1}$, but at site A the wind blows constantly at $15ms^{-1}$ meaning the wind turbine at site A can operate at full capacity all the time. At site B the wind blows at $30ms^{-1}$ for half of the time, and at

[21] www.amherstislandwindinfo.com/harrisoncorrelationpaper.pdf

0ms^{-1} for the other half. Although the average wind speed at site B is 15ms^{-1}, the wind turbine does not work at all at either velocity. These two extreme situations are both unrealistic, but emphasise the importance of wind speed distribution.

4.1. Data

The historical British on-shore wind speed data is the input for our statistical models. Two main data sets are used here. One is the hourly wind speed data from 144 wind speed observation sites of the Met Office at 2008[22]. Another data set is the operational on-shore wind farms from the British Wind Energy Association (BWEA). The wind speed data I have used was observed for each hour during 2008. There might have been yearly variations in wind speed. Table 4.2 displays the location and name for each site. These 10 sites are chosen from the group of 144 wind speed observation sites to provide a reasonable spread across the UK. There is no specific issue, other than volume of results, from extending the number of sites.

Table 4.2. Names and locations of 10 sample sites.

Srcid	Srcname	Postcode	latitude	longitude
48	KINBRACE, HATCHERY	KW11 6	58.231	-3.921
212	STRATHALLAN AIRFIELD	PH3 1	56.326	-3.729
326	DURHAM	DH1 4	54.768	-1.585
1006	PRESTWICK NO 2	KA9 2	55.501	-4.584
1190	LAKE VYRNWY NO 2	SY10 0	52.757	-3.464
1346	CHIVENOR	EX31 4	51.089	-4.149
1395	CAMBORNE	TR14 0	50.218	-5.33
16581	ROSEHEARTY	AB43 4	57.698	-2.121
16725	WAINFLEET NO 2	PE24 4	53.088	0.274
18930	MILDENHALL NO 2	IP27 9	52.388	0.535

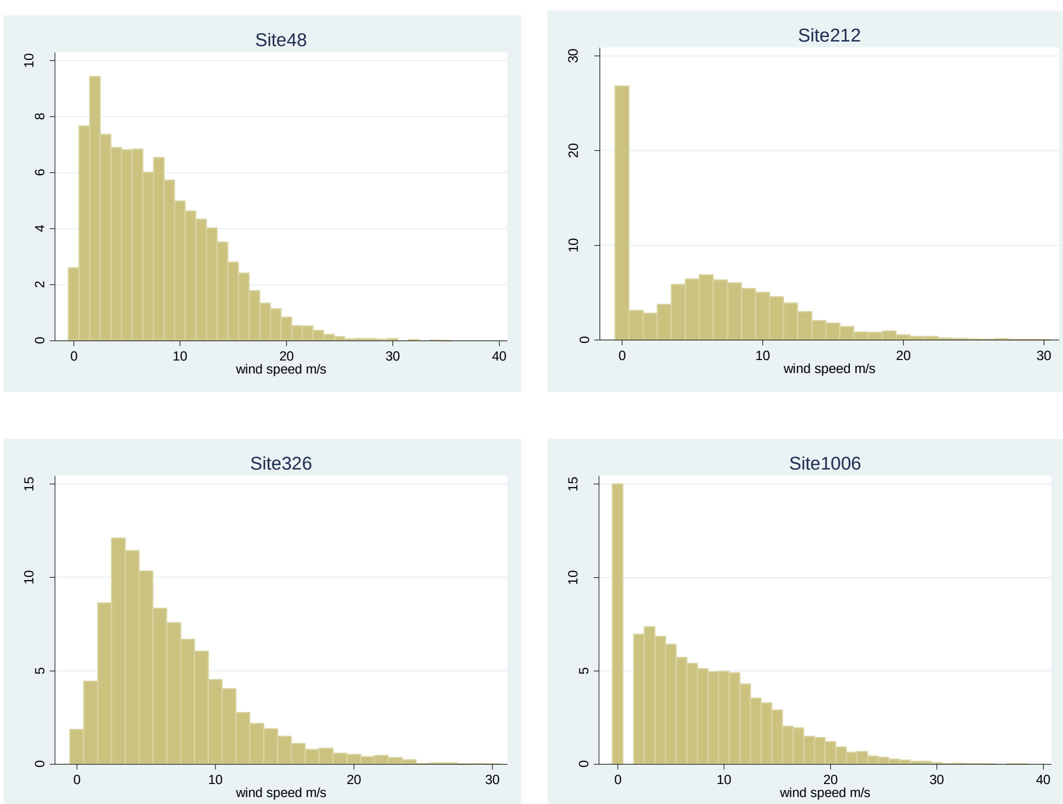
Source: Met Office

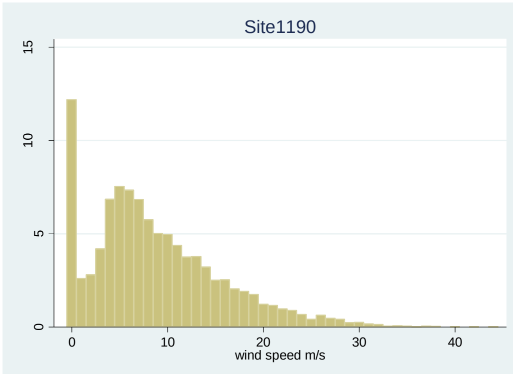
[22] The UK hourly weather data table www.badc.ner.ac.uk

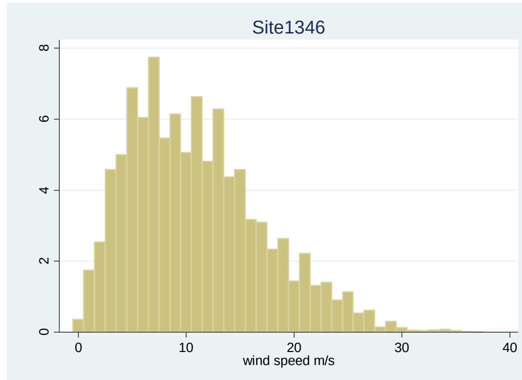
4.2. Overview of methodologies

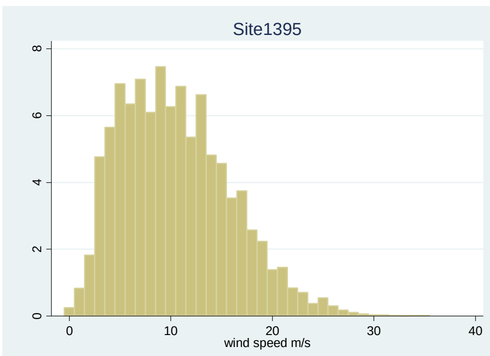
This section describes how I have modelled wind speed taking all the ten sites together. Figure 4.5 is the histogram of average hourly wind speed during the year at each site. This shows the percentage distribution of each wind speed level for the ten sites. There are four sites which experienced a relatively high number of “quiet hours” when wind speed is zero. They are site 212, site 1006, site 1190, and site 18930. These histograms show how wind speeds vary at each site. It is clear that the average hourly wind speed is non-normally distributed. Specifically, they often have fatter tails than a normal distribution.

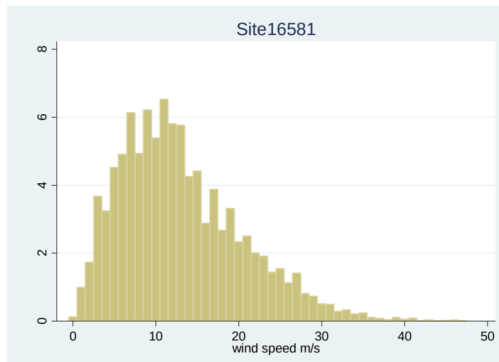
Figure 4.5. Histogram of wind speeds for 10 sites.

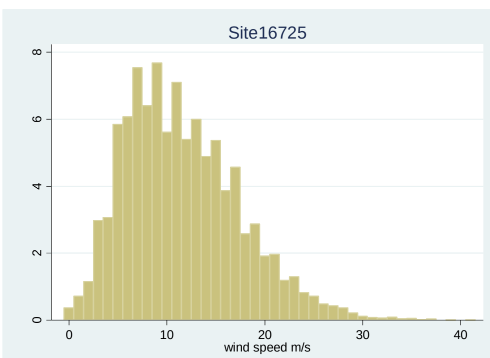


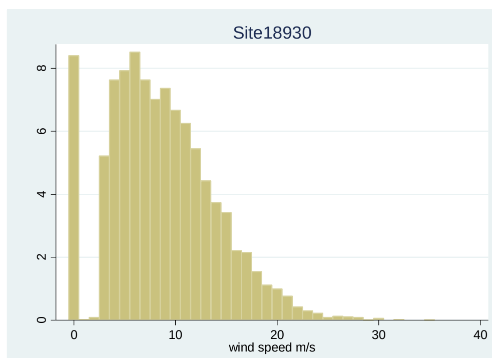












Site No.	Mean	Std. Dev.	Variance	Skewness	Kurtosis
48	7.791334	5.512322	30.38569	0.812073	3.436035
212	6.173839	5.556225	30.87163	0.764986	3.245261
326	6.750228	4.664167	21.75445	1.257541	4.811117
1006	7.894725	6.330774	40.0787	0.842515	3.50721
1190	8.812045	6.857279	47.02228	0.945649	3.843393
1346	10.98838	6.24153	38.9567	0.695004	3.137491
1395	10.52188	5.426912	29.45137	0.592071	3.092658
16581	13.03136	7.375889	54.40373	0.832484	3.600254
16725	11.60987	5.868366	34.43772	0.695947	3.462022
18930	8.673424	5.228178	27.33384	0.553968	3.372335

The Weibull distribution is a commonly used distribution for modelling wind speed, and is a continuous probability distribution. We can use this to model wind speed distribution at each location independently. It is currently beyond existing statistical capabilities to jointly model a number of wind farms with the Weibull distribution, because the multivariate Weibull is not commonly available in statistical packages.

The usual Weibull distribution is independent of the sequence of observations. So if the order of observations changed there will be no effects on the estimated parameters. Thus there is no possibility of modelling autocorrelation with this distribution. There are no commonly available algorithms to model an autocorrelated wind speed pattern using the Weibull distribution.

At the point when the stack model takes account of the order of wind speed data, time series models analysis come into play. By using only information on the past wind speed and the error term, univariate time series models are constructed. The ARMA (Autoregressive Moving Average) family of models are well known and widely used to model the time series of wind speed at one location or observation site. The downside of using an ARMA model is that its error term is assumed to be normally distributed with a zero mean, constant variance, and zero autocorrelation, which may not be appropriate, given that the Weibull formulation appears superior to the normal for modelling wind speeds.

GARCH (Generalised autoregressive conditional heteroscedasticity) models are used to detect non-linear behaviour or volatilities in the wind speed time series. It allows the conditional variances of the error term to be dependent on past own lags. GARCH type model also allow for a period of high or low volatility in wind speed. GARCH models can only be used for individual locations and also assume a normally distributed error term.

Some of these models have been applied to single wind farms. However, the comparison between different models has not previously been performed and no one has modelled wind farms jointly with a Vector Autoregression (VAR) model. VAR models simultaneously estimate the correlation of wind speed data from many different sites. VAR is a multiple- time series generalisation of AR models. It helps us to model correlations of wind speed for a wind farm portfolio. Thus energy companies or investors can predict the wind energy output for a combination of wind farms in order to reduce the systematic risk. The following sections will discuss and describe these models in detail.

4.3. Modelling wind speed at a single site with the Weibull probability distribution

The wind turbine manufacturers and energy companies use the Weibull distribution to assist them in selecting a wind turbine with the 'optimal cut-in speed and cut-out speed'[23]. This is because the wind speed distribution describes 'the amount of hours on a particular site where the wind speed levels fluctuate'[24].

The two parameter Weibull distribution is the most widely used and cited mathematical expression to describe the wind speed probability distribution and other renewable energy sources, such as solar. The Rayleigh and Weibull distribution on wind energy has been used since the 1970s (Justus 1978).

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[23] http://www.reuk.co.uk/print.php?article=Wind-Speed-Distribution-Weibull.htm
[24] http://www.wind-energy-the-facts.org/en/part-i-technology/chapter-2-wind-resource-estimation/local-wind-resource-assessment-and-energy-analysis/the-annual-variability-of-wind-speed.html

4.3.1. Two parameter-Weibull distribution formulation

In the notation of Justus at el., the Weibull probability distribution function with two parameters, the shape factor k (dimensionless) and the scale factor c (m/s) is:

$$p(v) = \left(\frac{k}{c}\right) * \left(\frac{v}{c}\right)^{k-1} * e^{-\left(\frac{v}{c}\right)^{k}} \qquad \text{for } 0 < v < +\infty \qquad (1.1)$$

The cumulative Weibull distribution is:

$$p(v_x) = p(v \leq v_x) = \int_0^{v_x} p(v)d(v) = 1 - e^{-\left(\frac{v_x}{c}\right)^{k}} \qquad (1.2)$$

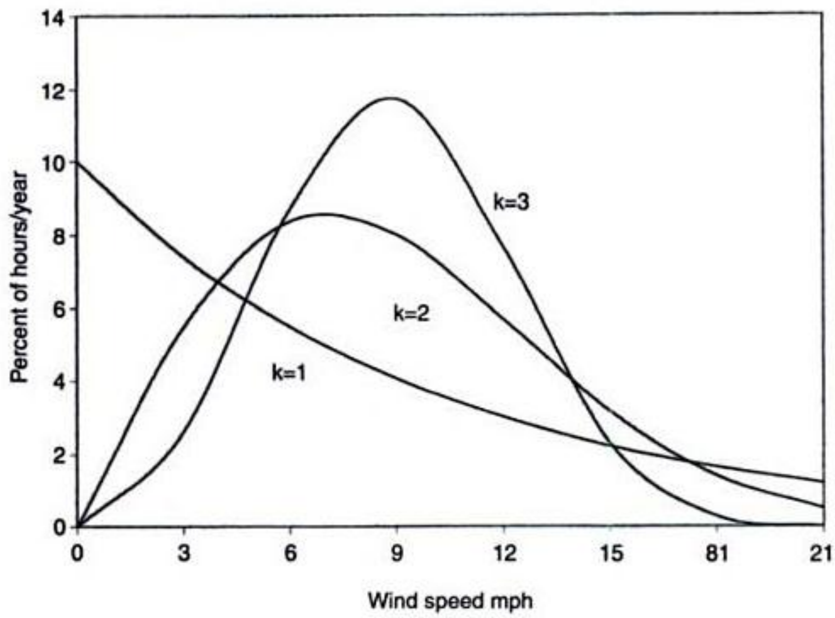
And the mean $\bar{v}$ is:

$$\bar{v} = c * \Gamma\left(1 + \frac{1}{k}\right) \qquad (\Gamma \text{ is the gamma function.}) \qquad (1.3)$$

The scale factor *c* is closely related to the mean wind speed $\bar{v}$, and they indicate how windy the site is on average. The shape factor *k* measures the width of the distribution. The peaked or positive kurtosis distribution means that the wind speeds tend to be very close to a certain value. Furthermore, the Weibull distribution allows 'satisfactory estimates of the skewness of the wind speed distribution, if the Weibull distribution has a shape parameter k, then the distribution of the cubed speed also follows a Weibull distribution' (Celik 2003).

As summarised in Patel (2006), the Weibull distribution with k=1 is called exponential distribution, which is usually used in reliability studies. For k > 3, it approaches the normal distribution. Figure 4.6 is an example of plot of the Weibull distribution for k=1, 2 and 3 when the scale factor c is 10. The curve with k=2 is the typical wind speed distribution found in most sites.

Figure 4.6. The Weibull probability distribution function with scale factor c=10m/s, and shape factor k = 1, 2 and 3.



Source: Page35, Figure 3.7 Patel (2006)

In Northern Europe and most other locations around the world, the value of shape factor k is approximately 2[25]. If the shape parameter k equals 2, the Weibull distribution is known as a *Rayleigh distribution*.

When $\lambda = \dfrac{1}{c}$, formula (1.1) is: $p(v) = 2\lambda^2 v * e^{-(\lambda v)^2}$ (1.4)

[25] http://www.reuk.co.uk/print.php?article=Wind-Speed-Distribution-Weibull.htm

4.3.2. Parameter estimation

Daily and monthly patterns of variations or seasonality of wind speeds distribution could be measured by using the Weibull distribution. The daily effect can be detected using 23 hour dummy variables. The fit of two parameter- Weibull distribution indicates that hourly average wind speed is larger during the daytime between 9am to 7pm than compared to the hourly average wind speed during the night. Table 4.3 shows analysis of the results for the two-parameter Weibull fit with hourly dummy variables for site326.

Then $y_t = \alpha + \sum_{d=1}^{23} \beta_d j_d + v_t$, where
β_d is the hourly dummy variable. j_d is the hour of the day.
y_t is the wind speed.

v_t follows the Weibull distribution $v_t \sim W(c,k)$, $p(v) = \left(\frac{k}{c}\right) * \left(\frac{v}{c}\right)^{k-1} * e^{-\left(\frac{v}{c}\right)^k}$

The windiest time of day is usually 1-2pm, and this also happens to be the period of peak electricity demand. The coefficients of hourly dummy variables for the peak time periods are significant for comparing test statistics with critical values.

Table 4.3 Two-parameter Weibull fit with hourly dummy variables for site 326.

ML fit of two-parameter Weibull distribution   Number of obs = 8600
  Wald chi2(23) = 268.48
Log likelihood = -23770.637   Prob > chi2 = 0.0000

	Coef.	Std. Err.	z	P>|z|	[95% Conf.	Interval]
c						
_Ihour326_1	.1635047	.3593513	0.45	0.649	-.5408109	.8678203
_Ihour326_2	.0026743	.3591425	0.01	0.994	-.701232	.7065807
_Ihour326_3	.0212601	.3606678	0.06	0.953	-.6856359	.7281561
_Ihour326_4	.0031517	.3600079	0.01	0.993	-.7024508	.7087543
_Ihour326_5	.0394524	.360643	0.11	0.913	-.6673949	.7462997
_Ihour326_6	.1611251	.3635424	0.44	0.658	-.5514049	.8736552
_Ihour326_7	.4785208	.3693272	1.30	0.195	-.2453471	1.202389
_Ihour326_8	.661085	.3700218	1.79	0.074	-.0641444	1.386314
_Ihour326_9	1.190805	.3712973	3.21	0.001	.4630757	1.918534
_Ihour326_10	1.860669	.3753601	4.96	0.000	1.124976	2.596361
_Ihour326_11	2.127693	.3809217	5.59	0.000	1.381101	2.874286
_Ihour326_12	2.409577	.3876957	6.22	0.000	1.649708	3.169447
_Ihour326_13	2.543353	.3841058	6.62	0.000	1.79052	3.296187
_Ihour326_14	2.339932	.3826258	6.12	0.000	1.59	3.089865
_Ihour326_15	2.12016	.3704921	5.72	0.000	1.394008	2.846311
_Ihour326_16	1.616845	.3607919	4.48	0.000	.9097056	2.323984
_Ihour326_17	1.413076	.3652598	3.87	0.000	.69718	2.128972
_Ihour326_18	.7501541	.3629291	2.07	0.039	.038826	1.461482
_Ihour326_19	.6413446	.3655469	1.75	0.079	-.0751141	1.357803
_Ihour326_20	.192088	.3587798	0.54	0.592	-.5111076	.8952835
_Ihour326_21	-.0039742	.3538527	-0.01	0.991	-.6975127	.6895643
_Ihour326_22	.0092434	.3562012	0.03	0.979	-.6888981	.7073849
_Ihour326_23	-.0190643	.346346	-0.06	0.956	-.6978899	.6597614
_cons	6.846048	.2504898	27.33	0.000	6.355097	7.337
k						
_Ihour326_1	-.0071226	.0853242	-0.08	0.933	-.174355	.1601098
_Ihour326_2	-.0427396	.0843084	-0.51	0.612	-.2079809	.1225017
_Ihour326_3	-.0535456	.0840024	-0.64	0.524	-.2181872	.111096
_Ihour326_4	-.0445177	.0847405	-0.53	0.599	-.2106061	.1215707
_Ihour326_5	-.0374944	.0852657	-0.44	0.660	-.204612	.1296233
_Ihour326_6	-.0388465	.0852313	-0.46	0.649	-.2058968	.1282038
_Ihour326_7	-.0177045	.0862232	-0.21	0.837	-.1866989	.15129
_Ihour326_8	.0080082	.0872488	0.09	0.927	-.1629963	.1790128
_Ihour326_9	.1077033	.0903976	1.19	0.233	-.0694729	.2848794
_Ihour326_10	.2141527	.0934364	2.29	0.022	.0310207	.3972846
_Ihour326_11	.2101488	.0935365	2.25	0.025	.0268206	.3934769
_Ihour326_12	.2075126	.0930595	2.23	0.026	.0251193	.3899059
_Ihour326_13	.2602008	.0944757	2.75	0.006	.0750319	.4453697
_Ihour326_14	.2335819	.0928917	2.51	0.012	.0515175	.4156462
_Ihour326_15	.2912704	.0940728	3.10	0.002	.1068911	.4756496
_Ihour326_16	.2774263	.0942722	2.94	0.003	.0926561	.4621964
_Ihour326_17	.1933592	.0917973	2.11	0.035	.0134397	.3732786
_Ihour326_18	.0805879	.0880976	0.91	0.360	-.0920802	.253256
_Ihour326_19	.0322129	.0863593	0.37	0.709	-.1370481	.201474
_Ihour326_20	-.0057461	.0857132	-0.07	0.947	-.1737409	.1622488
_Ihour326_21	-.0072174	.0854415	-0.08	0.933	-.1746796	.1602447
_Ihour326_22	-.008468	.0857711	-0.10	0.921	-.1765763	.1596402
_Ihour326_23	.0664164	.0876177	0.76	0.448	-.1053112	.238144
_cons	1.532971	.0611743	25.06	0.000	1.413072	1.652871

Figure 4.7 plots the scale factors from the modelling result in Table 4.3. The value of the scale factor peaks in hours from 11 to 15 and then falls again. The wind speed peaks in the middle of the day due to the sun activity. The sun provides the atmosphere with energy and this energy translates into wind. Therefore the wind speed is highest when the sun is highest rather than during evening hours.

Figure 4.7 Scale factor with hourly dummy variables for site326.

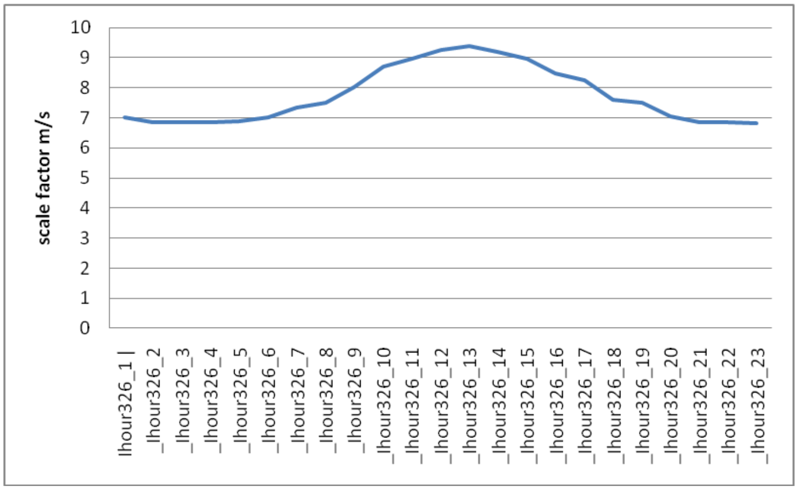


Table 4.4 shows the estimated Weibull parameters with monthly dummy variables for site326. $y_t = \alpha + \sum_{m=1}^{11} \gamma_m l_m + v_t,$

where γ_m is the monthly dummy variable. l_m is the month of the year.

y_t is the wind speed.

$v_t \sim W(c,k)$

The average wind speed is higher in winter months than in summer months. It shows the weather is windier in January than December. The windiest months are February and March, but the test statistics for the coefficients of the dummy variables for these two months are less significant than for other months.

Figure 4.8 Scale factors with monthly dummy variables for site326.

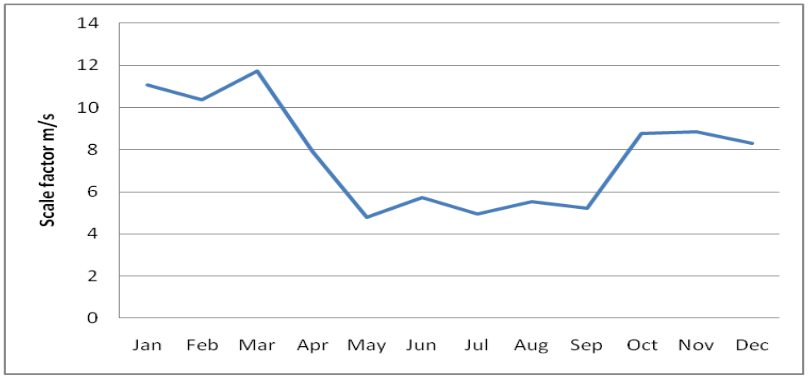


Figure 4.8 plots the monthly effect of wind speed at site326 based on the coefficients from Table 4.4. It shows that January, February, and March are the windiest months during the year at site326. The recent wintry weather in Britain was wet, snowy, and windy, which may have affected the operation of wind turbines. However, I have not discussed this topic in this study due to a shortage of relevant information.

Table 4.4. Two-parameter Weibull fit with monthly dummy variables for site326.

ML fit of two-parameter Weibull distribution

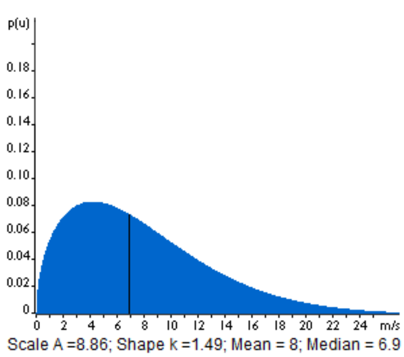
Log likelihood = -22660.917

Number of obs = 8600
Wald chi2(11) = 2515.02
Prob > chi2 = 0.0000

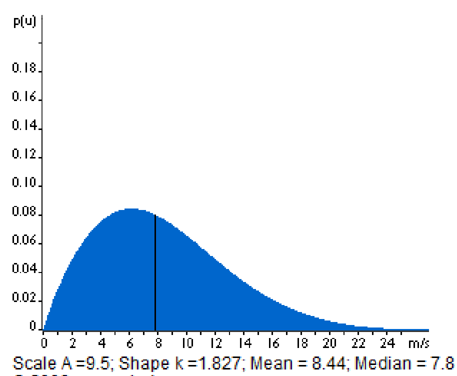
	Coef.	Std. Err.	z	P>|z|	[95% Conf.	Interval]
c						
_Imonth326_2	-.7206997	.3446157	-2.09	0.036	-1.396134	-.0452653
_Imonth326_3	.6509834	.3166437	2.06	0.040	.0303731	1.271594
_Imonth326_4	-3.15635	.2878172	-10.97	0.000	-3.720461	-2.592239
_Imonth326_5	-6.297993	.2522627	-24.97	0.000	-6.792419	-5.803568
_Imonth326_6	-5.348439	.2732355	-19.57	0.000	-5.883971	-4.812907
_Imonth326_7	-6.141723	.2580835	-23.80	0.000	-6.647558	-5.635889
_Imonth326_8	-5.552348	.2646549	-20.98	0.000	-6.071062	-5.033634
_Imonth326_9	-5.875477	.2577279	-22.80	0.000	-6.380614	-5.370339
_Imonth32~10	-2.318278	.294596	-7.87	0.000	-2.895675	-1.74088
_Imonth32~11	-2.235534	.3009696	-7.43	0.000	-2.825424	-1.645644
_Imonth32~12	-2.782125	.3110864	-8.94	0.000	-3.391844	-2.172407
_cons	11.08507	.2355213	47.07	0.000	10.62345	11.54668
k						
_Imonth326_2	-.146495	.071708	-2.04	0.041	-.28704	-.00595
_Imonth326_3	.328236	.0796728	4.12	0.000	.1720803	.4843917
_Imonth326_4	.0842915	.0744431	1.13	0.258	-.0616143	.2301973
_Imonth326_5	.2300492	.075862	3.03	0.002	.0813623	.3787361
_Imonth326_6	-.1761036	.0696726	-2.53	0.011	-.3126594	-.0395477
_Imonth326_7	-.0039325	.0731894	-0.05	0.957	-.147381	.139516
_Imonth326_8	-.0369142	.0719579	-0.51	0.608	-.177949	.1041207
_Imonth326_9	.1566728	.0765064	2.05	0.041	.006723	.3066226
_Imonth32~10	.0944208	.0738632	1.28	0.201	-.0503484	.23919
_Imonth32~11	.0392154	.0760471	0.52	0.606	-.1098342	.1882651
_Imonth32~12	-.1553563	.0716266	-2.17	0.030	-.2957418	-.0149709
_cons	1.825581	.0515326	35.43	0.000	1.724579	1.926583

Figure 4.9 presents the general annual pattern of wind speed distribution and estimated Weibull factors for the 10 sample sites. The values of two parameters for Weibull distribution are estimated by STATA10. The graphs of Weibull distributions are created using a Weibull distribution plotter programme[26], based on the estimated parameters. Figure 4.9 shows that the annual Weibull distributions of wind speeds are skewed. Certain sites have occasionally experienced very high wind speeds but this was very rare. Moderate wind speeds occurred with larger frequency. However, the calculation and plot of the Weibull distribution omitted the data when wind speed is zero. Therefore the scale factor or average wind speed may be overestimated. The value of estimated shape factors (*k*) are between 1 and 3. The Weibull distribution model can be extended to all British wind speed observation sites.

Figure 4.9. Weibull fit for 10 sites and their estimated Weibull factors.

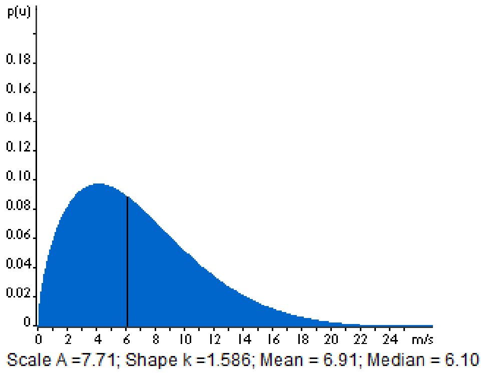


Site48 Location: Kinbrace, Hatchery
Weibull factor: c= 8.86
k = 1.49

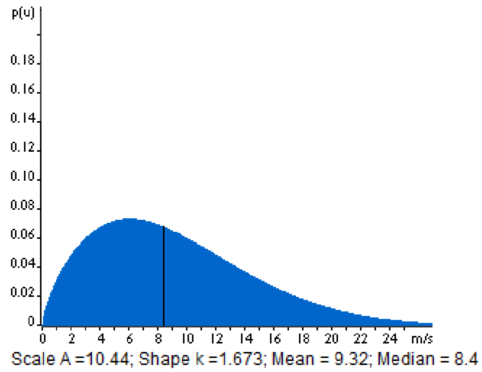


Site212 Location: Strathallan Airfield
Weibull factor: c= 9.498
k = 1.827

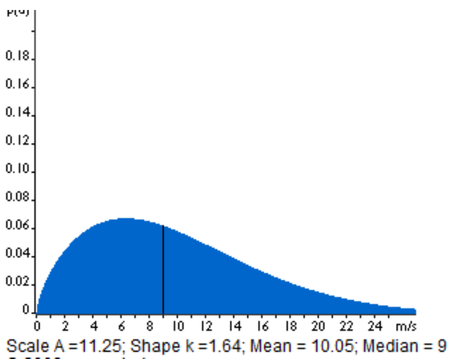
[26] http://www.windpower.org/en/tour/wres/weibull/index.htm



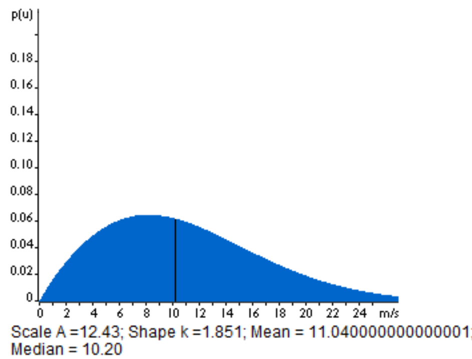
Site326 Location: Durham
Weibull factor: c= 7.706
k = 1.586



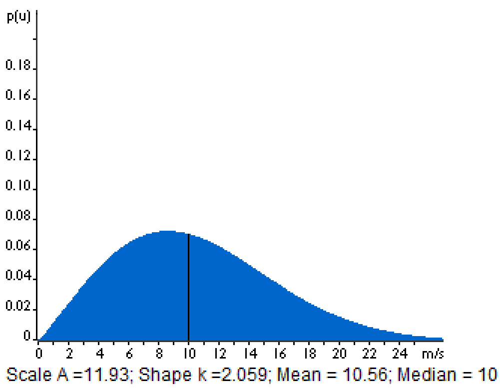
Site1006 Location: Prestwck No.2
Weibull factor: c= 10.444
k = 1.673



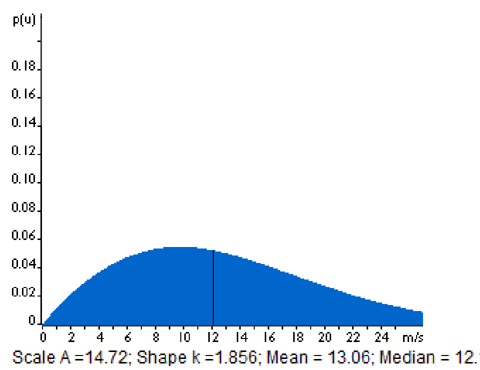
Site1190 Location: Blackpool
Weibull factor: c= 11.253
k = 1.64



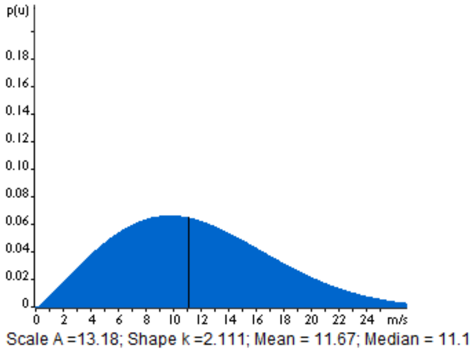
Site1364 Location: Totnes No2
Weibull factor: c= 12.432
k = 1.851



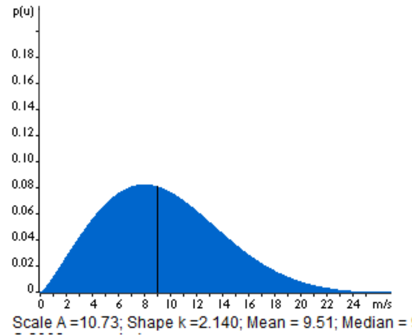
Site1395 Location: Camborne
Weibull factor: c= 11.926
k = 2.059



Site16581 Location: Rosehearty
Weibull factor: c= 14.717
k = 1.856



Site16725 Location: Wainfleet No2
Weibull factor: c= 13.177
k = 2.111



Site18930 Location: Mildenhall No2
Weibull factor: c= 10.733
k = 2.140

4.3.3 Disadvantages of the Weibull distribution

The Weibull distribution could be used to describe the hourly, daily, and monthly patterns of wind speeds variations. However, it does not take into account the correlation between neighbouring wind farms and it excludes any form of autocorrelation. Another disadvantage of this estimated Weibull distribution is that the model omits observations when wind speed is zero. Table 4.5 (a) and (b) show the two-parameter Weibull fit with hourly and monthly dummy variables for site212 and site326. The estimated average wind speed or scale factor c for site212 (10.62) is greater than the estimated value for site326 (10.18). However, site212 actually experiences more quiet hours than site48 (see Figure 4.5). In this case the Weibull distribution alone is insufficient to draw the conclusion that wind energy output from site 212 will be greater than the output from site48.

Table 4.5(a). Two-parameter Weibull fit with hourly and monthly dummy variables for site212 and 326

ML fit of two-parameter Weibull distribution — Number of obs = 6429
Wald chi2(34) = 1246.00
Log likelihood = -18031.276 — Prob > chi2 = 0.0000

	Coef.	Std. Err.	z	P>|z|	[95% Conf.	Interval]
c						
_Ihour212_1	-.2691127	.4075091	-0.66	0.509	-1.067816	.5295905
_Ihour212_2	-.0009113	.4098907	-0.00	0.998	-.8042823	.8024596
_Ihour212_3	.1755322	.4228836	0.42	0.678	-.6533044	1.004369
_Ihour212_4	.2040729	.4336293	0.47	0.638	-.6458248	1.053971
_Ihour212_5	.3205954	.4184916	0.77	0.444	-.4996331	1.140824
_Ihour212_6	.4863865	.406614	1.20	0.232	-.3105622	1.283335
_Ihour212_7	.171603	.4127134	0.42	0.678	-.6373004	.9805064
_Ihour212_8	.814851	.3970365	2.05	0.040	.0366737	1.593028
_Ihour212_9	1.308383	.4066989	3.22	0.001	.5112674	2.105498
_Ihour212_10	1.717747	.4045806	4.25	0.000	.9247839	2.510711
_Ihour212_11	1.708301	.3973821	4.30	0.000	.9294466	2.487156
_Ihour212_12	2.126071	.3916415	5.43	0.000	1.358468	2.893674
_Ihour212_13	2.224185	.3968924	5.60	0.000	1.44629	3.00208
_Ihour212_14	2.614831	.3965384	6.59	0.000	1.83763	3.392032
_Ihour212_15	2.577117	.3850786	6.69	0.000	1.822377	3.331857
_Ihour212_16	2.151757	.3856501	5.58	0.000	1.395897	2.907617
_Ihour212_17	1.755297	.3880068	4.52	0.000	.994818	2.515777
_Ihour212_18	1.515751	.3840962	3.95	0.000	.7629364	2.268566
_Ihour212_19	.7023202	.3792724	1.85	0.064	-.04104	1.44568
_Ihour212_20	.2026974	.3772773	0.54	0.591	-.5367526	.9421474
_Ihour212_21	-.145291	.3830948	-0.38	0.704	-.8961431	.605561
_Ihour212_22	-.3382198	.3959934	-0.85	0.393	-1.114353	.437913
_Ihour212_23	-.1045964	.4039328	-0.26	0.796	-.8962902	.6870974
_Imonth212_2	1.176409	.4238598	2.78	0.006	.3456593	2.007159
_Imonth212_3	-.7153899	.3515376	-2.04	0.042	-1.404391	-.0263888
_Imonth212_4	-2.99816	.3370724	-8.89	0.000	-3.658809	-2.33751
_Imonth212_5	-4.899843	.3157021	-15.52	0.000	-5.518608	-4.281078
_Imonth212_6	-2.836176	.3372671	-8.41	0.000	-3.497207	-2.175144
_Imonth212_7	-3.71473	.3279941	-11.33	0.000	-4.357587	-3.071874
_Imonth212_8	-4.221478	.3378932	-12.49	0.000	-4.883736	-3.559219
_Imonth212_9	-4.753882	.3479691	-13.66	0.000	-5.435889	-4.071875
_Imonth21~10	-1.482391	.3462539	-4.28	0.000	-2.161036	-.8037458
_Imonth21~11	-.2820482	.3863519	-0.73	0.465	-1.039284	.4751875
_Imonth21~12	-1.672979	.4352185	-3.84	0.000	-2.525992	-.8199667
_cons	10.62385	.4063349	26.15	0.000	9.827445	11.42025
k						
_Ihour212_1	-.0296754	.1315844	-0.23	0.822	-.2875761	.2282254
_Ihour212_2	.0200576	.1358684	0.15	0.883	-.2462396	.2863548
_Ihour212_3	-.0138539	.1365292	-0.10	0.919	-.2814461	.2537384
_Ihour212_4	-.1162392	.1315426	-0.88	0.377	-.3740579	.1415795
_Ihour212_5	.0462582	.1366416	0.34	0.735	-.2215544	.3140708
_Ihour212_6	.2039386	.1432673	1.42	0.155	-.0768602	.4847374
_Ihour212_7	-.102842	.1295927	-0.79	0.427	-.3568391	.1511551
_Ihour212_8	.1662893	.140411	1.18	0.236	-.1089111	.4414897
_Ihour212_9	.0886128	.1356028	0.65	0.513	-.1771638	.3543894
_Ihour212_10	.1352031	.1349175	1.00	0.316	-.1292303	.3996366
_Ihour212_11	.1454593	.1340201	1.09	0.278	-.1172152	.4081338
_Ihour212_12	.2739294	.136408	2.01	0.045	.0065747	.5412841
_Ihour212_13	.200734	.1322738	1.52	0.129	-.0585179	.4599859
_Ihour212_14	.2956208	.1359363	2.17	0.030	.0291907	.562051
_Ihour212_15	.4728601	.1429543	3.31	0.001	.1926749	.7530453
_Ihour212_16	.3424225	.1382656	2.48	0.013	.0714269	.613418
_Ihour212_17	.2358714	.1358691	1.74	0.083	-.0304271	.5021699
_Ihour212_18	.282942	.137925	2.05	0.040	.012614	.55327
_Ihour212_19	.178467	.1349586	1.32	0.186	-.0860469	.442981
_Ihour212_20	.1466927	.1337651	1.10	0.273	-.1154821	.4088674
_Ihour212_21	.0638659	.1334988	0.48	0.632	-.197787	.3255187
_Ihour212_22	.000521	.1338266	0.00	0.997	-.2617744	.2628164
_Ihour212_23	.0755209	.1374006	0.55	0.583	-.1937793	.3448212
_Imonth212_2	.1265391	.0879525	1.44	0.150	-.0458447	.2989228
_Imonth212_3	.453746	.089747	5.06	0.000	.2778451	.6296469
_Imonth212_4	.4343051	.094878	4.58	0.000	.2483476	.6202626
_Imonth212_5	.6598491	.1036004	6.37	0.000	.4567962	.8629021
_Imonth212_6	.5062698	.097728	5.18	0.000	.3147264	.6978133
_Imonth212_7	.3925121	.0914748	4.29	0.000	.2132247	.5717994
_Imonth212_8	.2108141	.0917357	2.30	0.022	.0310153	.3906128
_Imonth212_9	-.0498212	.0867287	-0.57	0.566	-.2198063	.120164
_Imonth21~10	.3902003	.0876793	4.45	0.000	.2183522	.5620485
_Imonth21~11	.3624478	.0997327	3.63	0.000	.1669753	.5579204
_Imonth21~12	-.2434089	.0812458	-3.00	0.003	-.4026477	-.0841701
_cons	1.647021	.1087171	15.15	0.000	1.43394	1.860103

Table 4.5(b). Two-parameter Weibull fit with hourly and monthly dummy variables for site212 and 326

ML fit of two-parameter Weibull distribution — Number of obs = 8600
Wald chi2(34) = 3572.77

```
Log likelihood = -22350.273                        Prob > chi2     =     0.0000

------------------------------------------------------------------------------
             |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
c            |
 _Ihour326_1 |   .1110596   .2245147     0.49   0.621    -.3289812    .5511004
 _Ihour326_2 |  -.0407133   .2241438    -0.18   0.856    -.4800271    .3986005
 _Ihour326_3 |    .034066   .2250783     0.15   0.880    -.4070793    .4752114
 _Ihour326_4 |   .1247718   .2284561     0.55   0.585    -.3229939    .5725375
 _Ihour326_5 |   .1123967   .2282279     0.49   0.622    -.3349218    .5597152
 _Ihour326_6 |   .1917777   .2321495     0.83   0.409    -.2632271    .6467824
 _Ihour326_7 |   .4997241   .2398489     2.08   0.037     .0296288    .9698194
 _Ihour326_8 |   .8154335    .246377     3.31   0.001     .3325434    1.298324
 _Ihour326_9 |    1.43575   .2539973     5.65   0.000     .9379242    1.933575
_Ihour326_10 |   1.907379   .2580551     7.39   0.000       1.4016    2.413158
_Ihour326_11 |   2.252225   .2665529     8.45   0.000     1.729791    2.774659
_Ihour326_12 |   2.556788   .2753612     9.29   0.000      2.01709    3.096487
_Ihour326_13 |   2.623745   .2741383     9.57   0.000     2.086443    3.161046
_Ihour326_14 |   2.454707   .2717702     9.03   0.000     1.922047    2.987367
_Ihour326_15 |   2.399624   .2655317     9.04   0.000     1.879192    2.920057
_Ihour326_16 |   1.980677   .2561336     7.73   0.000     1.478664    2.482689
_Ihour326_17 |    1.70127   .2554523     6.66   0.000     1.200593    2.201948
_Ihour326_18 |   1.112167   .2508704     4.43   0.000     .6204705    1.603864
_Ihour326_19 |   .6323376   .2393392     2.64   0.008     .1632415    1.101434
_Ihour326_20 |   .1412666   .2289574     0.62   0.537    -.3074816    .5900148
_Ihour326_21 |  -.0274125   .2217528    -0.12   0.902      -.46204    .4072151
_Ihour326_22 |   .1390883   .2297602     0.61   0.545    -.3112335    .5894101
_Ihour326_23 |   .0749255    .217876     0.34   0.731    -.3521036    .5019546
_Imonth326_2 |  -.7879225   .3401457    -2.32   0.021    -1.454596   -.1212492
_Imonth326_3 |   .5912243   .3154517     1.87   0.061    -.0270497    1.209498
_Imonth326_4 |  -3.289263    .283134   -11.62   0.000    -3.844195    -2.73433
_Imonth326_5 |  -6.411011   .2482087   -25.83   0.000    -6.897491   -5.924531
_Imonth326_6 |  -5.457854   .2675623   -20.40   0.000    -5.982267   -4.933442
_Imonth326_7 |  -6.252665   .2528982   -24.72   0.000    -6.748336   -5.756993
_Imonth326_8 |  -5.629386   .2603396   -21.62   0.000    -6.139642    -5.11913
_Imonth326_9 |  -5.865072   .2550024   -23.00   0.000    -6.364867   -5.365276
_Imonth32~10 |  -2.447348   .2891454    -8.46   0.000    -3.014063   -1.880634
_Imonth32~11 |   -2.19708   .3007318    -7.31   0.000    -2.786504   -1.607657
_Imonth32~12 |   -2.71184   .3128046    -8.67   0.000    -3.324925   -2.098754
       _cons |   10.18111   .2817483    36.14   0.000     9.628893    10.73333
-------------+----------------------------------------------------------------
k            |
 _Ihour326_1 |   .0143824   .1068803     0.13   0.893    -.1950992    .2238639
 _Ihour326_2 |  -.0437294   .1051933    -0.42   0.678    -.2499045    .1624458
 _Ihour326_3 |  -.0533617   .1052762    -0.51   0.612    -.2596993     .152976
 _Ihour326_4 |  -.0768948   .1055898    -0.73   0.466    -.2838471    .1300574
 _Ihour326_5 |  -.0630506   .1061259    -0.59   0.552    -.2710536    .1449524
 _Ihour326_6 |  -.0819698   .1054766    -0.78   0.437    -.2887002    .1247606
 _Ihour326_7 |  -.0767163   .1062571    -0.72   0.470    -.2849763    .1315437
 _Ihour326_8 |  -.0861769   .1068048    -0.81   0.420    -.2955105    .1231568
 _Ihour326_9 |   .0012178   .1101226     0.01   0.991    -.2146185     .217054
_Ihour326_10 |   .1479007   .1132616     1.31   0.192    -.0740879    .3698893
_Ihour326_11 |   .1084535   .1126551     0.96   0.336    -.1123465    .3292536
_Ihour326_12 |   .0847862    .111485     0.76   0.447    -.1337203    .3032927
_Ihour326_13 |    .131911   .1124008     1.17   0.241    -.0883905    .3522124
_Ihour326_14 |   .1104446   .1109725     1.00   0.320    -.1070575    .3279467
_Ihour326_15 |   .1372659   .1113876     1.23   0.218    -.0810498    .3555816
_Ihour326_16 |   .1223467   .1123605     1.09   0.276    -.0978758    .3425692
_Ihour326_17 |   .0505334   .1100543     0.46   0.646     -.165169    .2662358
_Ihour326_18 |  -.0806095   .1056297    -0.76   0.445    -.2876398    .1264209
_Ihour326_19 |  -.0295247   .1053612    -0.28   0.779    -.2360288    .1769794
_Ihour326_20 |  -.0444441   .1049637    -0.42   0.672    -.2501692    .1612811
_Ihour326_21 |  -.0025082    .106369    -0.02   0.981    -.2109876    .2059713
_Ihour326_22 |  -.0860963   .1043909    -0.82   0.410    -.2906986     .118506
_Ihour326_23 |   .0930974   .1096709     0.85   0.396    -.1218537    .3080485
_Imonth326_2 |  -.1042698   .0720406    -1.45   0.148    -.2454668    .0369272
_Imonth326_3 |    .343005   .0790336     4.34   0.000      .188102     .497908
_Imonth326_4 |   .1652743   .0751149     2.20   0.028     .0180518    .3124968
_Imonth326_5 |   .4660302   .0804392     5.79   0.000     .3083723     .623688
_Imonth326_6 |  -.0598661   .0715964    -0.84   0.403    -.2001925    .0804602
_Imonth326_7 |    .195116   .0775507     2.52   0.012     .0431193    .3471126
_Imonth326_8 |   .0737054   .0735637     1.00   0.316    -.0704767    .2178876
_Imonth326_9 |   .2395739   .0777815     3.08   0.002      .087125    .3920227
_Imonth32~10 |   .1917406   .0754197     2.54   0.011     .0439208    .3395604
_Imonth32~11 |   .0383284   .0753608     0.51   0.611     -.109376    .1860328
_Imonth32~12 |  -.1784471    .070659    -2.53   0.012    -.3169363   -.0399579
       _cons |   1.807827   .0906653    19.94   0.000     1.630126    1.985527
------------------------------------------------------------------------------
```

4.4. Time series modelling

The Weibull distribution calculates the frequency distribution of the wind speed in individual wind farms. For each site the hourly time series wind speed data is considered "independent" by the Weibull distribution. Nevertheless, short-term wind speed time series "is of high dependence" (Aksoy *et al.* 2004). The time series properties of wind speed provide another way of attempting to understand their variation.

Both the speed and direction of wind could be predicted by using physical or meteorological information, such as descriptions of orography, roughness, obstacles, and meteo (Lei *et al.* 2009). However, in the short term the physical or meteorological conditions may be best understood by looking at the recent history rather than having a model that treats the past as irrelevant for forecasting the present. For this reason the time series analysis tools could be used to model the wind speed from historical wind speed data for individual sites.

4.4.1 Univariate time series--ARMA models

ARMA models are used to capture the persistent effects within time series. Modelling with the ARMA process will enable us to decide the correlation of current hourly wind speed with the wind speed of a few hours ago.

4.4.1.1 ARMA model formulation

In Table 4.6, where u_t is a random process with zero mean and constant variance σ^2. $\phi_1 \cdots \phi_i$ are autoregressive coefficients which quantify the dependence of wind speed y_t on its past values $y_{t-1} \cdots y_{t-i}$. Autoregressive of order p means that the current value of y depends on past values in a process with p lags. ARMA model helps us to determine whether there is significant inertia within the British hourly wind speed time series. For this type of modelling, unlike the Weibull case, the order of the observations is critical.

The ARMA model (Box & Jenkins 1976) has been widely used by researchers to predict the hourly average wind speed time series. Torres et al. used the ARMA model to predict the hourly average wind speed up to 10 hours in advance for five locations in Spain (Torres *et al.* 2005). They found that the errors with ARMA models for modelling 10 hours in advance are between 12% and 20% smaller than with the persistence model. The "persistence model" implies that the average wind speed forecast for the next hour is simply equal to the average wind speed for the current hour (Kavasseri & Seetharaman 20009). Daniel and Chen have made forecasts for 1 to 6 hours in advance. They detected a deterioration of the results when the forecast was made for a period more than 2 hours in advance when applying the ARMA model to three years time series data in Jamaica (Daniel & Chen 1991).

In addition, Aksoy *et al*. (2004) used four years of hourly wind speed data from one meteorology station in Diyarbakir, a south-eastern Anatolian city, to compare the predicted performance of the different models. They found the second-order autoregressive AR(2) model is preferred to AR(1). Similarly, Nfaoui *et al*. (1996) determined that an AR(2) model is capable of more accurately simulating the wind speed series for one location.

Table 4.6 ARMA Model Specification

An autoregressive model of order p , denoted an AR (p), can be expressed as

$$y_t = \mu + \sum_{i=1}^{p} \phi_i y_{t-i} + u_t \qquad \text{(2.1) (Brooks, 2002)}$$

A moving average model of order q , denoted a MA(q), can be expressed using sigma notation as

$$y_t = \mu + \sum_{i=1}^{q} \theta_i u_{t-i} + u_t \qquad \text{(2.2) (Brooks, 2002)}$$

u_t is white noise disturbance term which is assumed to be normally distributed .

Then the general ARMA (p,q) is in the form

$$y_t = \mu + \sum_{i=1}^{p} \phi_i y_{t-i} + \sum_{i=1}^{q} \theta_i u_{t-i} + u_t \qquad \text{(2.3)}$$

For forecasting wind speed, y_t is the value of wind speed at time t .

Moreover, there are several other types of time series models based on ARMA models. Kavasseri and Seetharaman examined the use of fractional-ARIMA or f-ARIMA models to model and forecast wind speeds on the one-day-ahead and two-days-ahead horizons by using the wind speed time series from four potential wind generation sites in North Dakota. The f-ARIMA process is characterised by a slow decay in its autocorrelation function compared with a standard ARIMA process. They suggested that the f-ARIMA model is the most appropriate for modelling both short term and long term wind speed, and is able to improve the accuracy of forecasting by an average of 42% when compared with the persistence method (Kavasseri & Seetharaman 20009).

My aim is to identify the order of p,q for the ARMA model using British hourly wind speed data. In order to obtain appropriate estimators from ARMA, it is necessary to use stationary wind speed time series. The augmented Dickey-Fuller test is performed to identify whether or not the one year hourly wind speed time series data are stationary. The null hypothesis is that the variable contains a unit root, and the alternative is that the variable was generated by a stationary process. The Dickey-Fuller test results for unit root on site326 in Table 4.7 shows that the negative test statistic is less than critical value, thus the null hypotheses is rejected. The hourly wind speed time series is stationary. In addition, there is insufficient evidence to prove a trend, i.e. that this area is inevitably windier than previous short-term time periods. Tests at the other sites show similar results.

Table 4.7. Dickey-Fuller test on site326

Dickey-Fuller test for unit root   Number of obs = 8751

---------- Interpolated Dickey-Fuller ---------

	Test Statistic	1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	-22.444	-3.430	-2.860	-2.570

MacKinnon approximate p-value for Z(t) = 0.0000

The Dickey-Fuller test allows us to reject the null hypothesis of a unit root. In order to make the error term white noise, the test should include sufficient lags in the testing regression. Table 4.8 indicates that the test statistic *t*-ratio allows us to reject the null hypothesis of the second unit root.

Table 4.8. Augmented dickey-fuller test for unit root on site326

Augmented Dickey-Fuller test for unit root   Number of obs   =   8705

	Test Statistic	1% Critical Value	5% Critical Value	10% Critical Value
		Interpolated Dickey-Fuller		
Z(t)	-15.148	-3.960	-3.410	-3.120

MacKinnon approximate p-value for Z(t) = 0.0000

D.nwinds~326	Coef.	Std. Err.	t	P>|t|	[95% Conf. Interval]	
nwindspe~326						
L1.	-.0790723	.00522	-15.15	0.000	-.0893046	-.0688399
LD.	-.2693882	.0111463	-24.17	0.000	-.2912375	-.2475389
L2D.	-.0683067	.0114886	-5.95	0.000	-.0908271	-.0457864
L3D.	-.0097763	.0114718	-0.85	0.394	-.0322638	.0127112
L4D.	.0011186	.0113679	0.10	0.922	-.0211651	.0234022
L5D.	.0065089	.0107323	0.61	0.544	-.0145288	.0275467
_trend	-.0000286	8.84e-06	-3.23	0.001	-.0000459	-.0000113
_cons	.6609792	.0617581	10.70	0.000	.5399186	.7820398

Some researchers believe that the wind speed experiences seasonality and cyclic behaviour. Torres et al. (2004) considered that the evolution of the hourly wind speed during the day is not stationary but exhibits cyclic behaviour. They raised each one of the observed hourly values to the same index to make the distribution approximately Gaussian. Their data set contained nine-year monthly data. However, our analysis covers hourly data over a period of one year. Therefore, I cannot check for the type of cyclical behaviour identified by Torres. However in the short term the physical or meteorological conditions won't change dramatically and may be best understood by looking at the recent history rather than having a model that treats the past as irrelevant for forecasting the present. For this reason the time series analysis tools could be used to model the wind speed from historical wind speed data for individual sites. Thus we believe 12 months hourly wind speed data is credible.

4.4.1.2 Estimation of ARMA family models

Table 4.9 is a list of a series estimated using ARMA models for the hourly wind speed at site326. I have used wind speed data for one random site to present the models. By comparing the test statistics it is seen that the majority of coefficients of the models are statistically significant, except for ARMA (2,1) and ARMA(2,2). The significance of test statistics drops dramatically in these two models. $\hat{\varepsilon}_t$ is a white noise process with zero mean and constant standard deviation $\hat{\sigma}$.

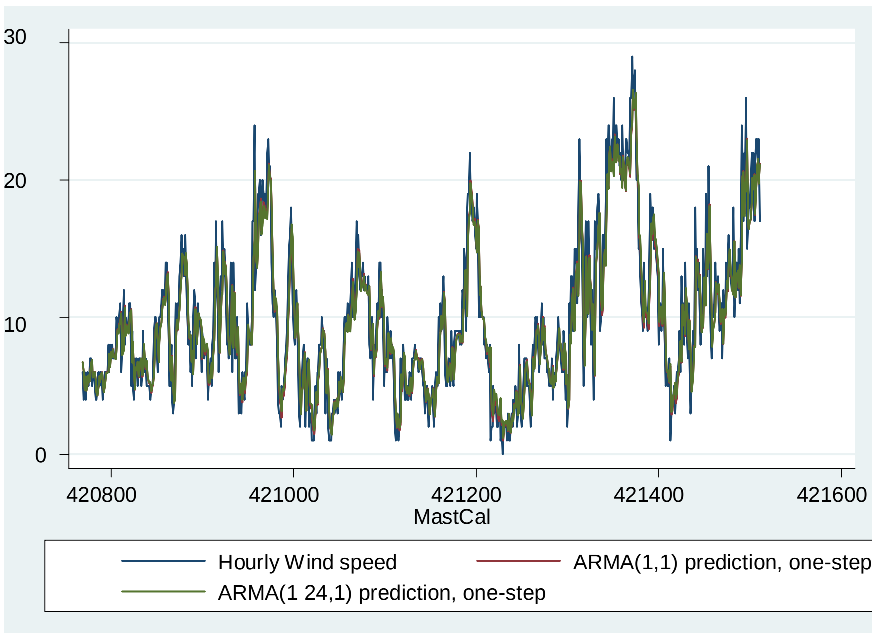
Additional criteria have been used for model selection. The well known criteria are Akaike's Information Criterion (AIC) (Akaike 1973) and Schwarz's Bayesian Information Criterion (BIC or SC) (Schwarz 1978). Both criteria are likelihood-based and represent a different trade-off between 'fit', as measured by the 'log likelihood' value, and by the number of free parameters, *p+q+1* (Verbeek 2004). By measuring the AIC and BIC for this series of models we find that the ARMA(1,1) model has minimum AIC, and the ARMA(1 24, 1) model has minimum BIC. The BIC criterion can be preferred on the basis that it has the property that 'it will almost surely select the true model' (Verbeek 2004).

Table 4.9 Estimated models for hourly wind speed on site326.

	Estimated models	Log likelihood	AIC	**BIC**
AR(1)	$y_t = 6.74 + 0.891 y_{t-1} + \hat{\varepsilon}_t$ (29.01) (211.41) $\hat{\sigma} = 2.116$	-19008.23	38020.452	**38034.609**
AR(2)	$y_t = 6.737 + 0.669 y_{t-1} + 0.249 y_{t-2} + \hat{\varepsilon}_t$ (22.44) (85.62) (31.42) $\hat{\sigma} = 2.049$	-18729.07	37464.141	**37485.376**
AR(3)	$y_t = 6.735 + 0.653 y_{t-1} + 0.205 y_{t-2} + 0.065 y_{t-3} + \hat{\varepsilon}_t$ (20.99) (80.30) (21.19) (7.53) $\hat{\sigma} = 2.045$	-18710.53	37429.061	**37457.374**
AR (1,24)	$y_t = 6.729 + 0.868 y_{t-1} + 0.051 y_{t-24} + \hat{\varepsilon}_t$ (21.57) (191.71) (10.37) $\hat{\sigma} = 2.105$	-18964.91	37935.811	**37957.046**
ARMA (1,1)	$y_t = 6.734 + 0.974 y_{t-1} - 0.291 \hat{\varepsilon}_{t-1} + \hat{\varepsilon}_t$ (20.37) (281.12) (-32.66) $\hat{\sigma} = 2.045$	-18710.7	37427.391	**37448.626**

ARMA (2,1)	$y_t = 6.734 + 0.905 y_{t-1} + 0.039 y_{t-2} - 0.252 \hat{\varepsilon}_{t-1} + \hat{\varepsilon}_t$ (20.58) (28.03) (1.35) (-7.88) $\hat{\sigma} = 2.045$	-18710.11	37428.222	**37456.536**
ARMA (2,2)	$y_t = 6.735 + 1.127 y_{t-1} - 0.171 y_{t-2} - 0.474 \hat{\varepsilon}_{t-1} + 0.066 \hat{\varepsilon}_{t-2} + \hat{\varepsilon}_t$ (20.61) (1.69) (-0.27) (-0.71) (0.34) $\hat{\sigma} = 2.045$	-18710.04	37430.075	**37465.468**
ARMA (1&24, 1)	$y_t = 6.772 + 0.935 y_{t-1} + 0.219 y_{t-24} - 0.282 \hat{\varepsilon}_{t-1} + \hat{\varepsilon}_t$ (16.16) (246.30) (6.06) (-30.98) $\hat{\sigma} = 2.041$	**-18695.55**	**37427.421**	**37391.108**

Figure 4.10. Predicted hourly wind speed data for site326



The ARMA(1,1) and ARMA(1& 24,1) models have been run using the hourly wind speed data for site326 in January 2008. Figure 4.10 plots the predicted values or fitted values of two models and the real average hourly wind speed data. The plot line of the ARMA(1&24,1) model is overlapping on the line of the ARMA(1,1) model, although there are minor differences in predicted values. The horizontal axis of Mastcal on Figure 4.10 represents the time series of hours from 1:00 1st January to 23:00 31st January in my STATA programme. However, the hourly wind speed data which I have used are supplied as integers which suggest the possibility of a small amount of measurement error. As indicated, these models can be applied to all wind farms or other sites to forecast the individual wind speed time series. A forecast would normally be carried out at least 1 hour and up to 24 hour in advance. In our model, the coefficients are statistically significant and indicate that wind speed is related to day-ahead wind speed and previous wind speed.

Hourly and monthly dummy variables can be added into the ARMA models. Table 4.10 shows the estimated coefficients for ARMA(1,1) with hourly dummy variables. It is windier between 10am to 5pm at site326. It is less windy in the early morning. Table 4.11 shows the estimated coefficients for ARMA(1,1) with monthly dummy variables. Their values suggest that this site experiences stronger wind during the winter months.

Figure 4.11 Monthly and hourly effect of wind speed at site326.

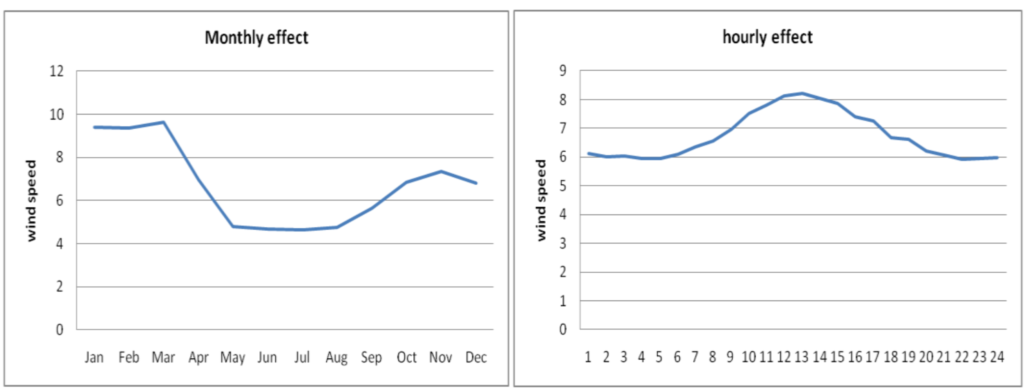


Figure 4.11 plots the modelling results from ARMA(1,1) in Table 4.10 and Table 4.11. It shows similar monthly and hourly effects as that of the Weibull distribution.

Table 4.10 ARMA(1,1) with hourly dummy variables for site326

```
ARIMA regression
Sample:  420769 - 429551, but with gaps        Number of obs      =      8764
                                               Wald chi2(25)      = 101066.68
Log likelihood = -18587.26                     Prob > chi2        =    0.0000

------------------------------------------------------------------------------
             |                 OPG
nwindspe~326 |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
nwindspe~326 |
 _Ihour326_1 |   .1318477   .1203044     1.10   0.273    -.1039446      .36764
 _Ihour326_2 |   .0269203    .139759     0.19   0.847    -.2470024     .300843
 _Ihour326_3 |   .0578417   .1539311     0.38   0.707    -.2438578    .3595412
 _Ihour326_4 |  -.0165544   .1627966    -0.10   0.919    -.3356298     .302521
 _Ihour326_5 |  -.0311992   .1786967    -0.17   0.861    -.3814384    .3190399
 _Ihour326_6 |   .1228435   .1797178     0.68   0.494    -.2293969    .4750839
 _Ihour326_7 |   .3823718   .1865456     2.05   0.040      .016749    .7479945
 _Ihour326_8 |   .5838626   .1905914     3.06   0.002     .2103103    .9574149
 _Ihour326_9 |    .992902   .1925279     5.16   0.000     .6155542     1.37025
_Ihour326_10 |   1.547142   .1972207     7.84   0.000     1.160597    1.933688
_Ihour326_11 |   1.838227   .1947184     9.44   0.000     1.456586    2.219868
_Ihour326_12 |   2.146847   .1947172    11.03   0.000     1.765208    2.528486
_Ihour326_13 |   2.234046   .1963972    11.38   0.000     1.849115    2.618978
_Ihour326_14 |   2.076323    .195368    10.63   0.000     1.693409    2.459237
_Ihour326_15 |   1.879889   .1940626     9.69   0.000     1.499533    2.260244
_Ihour326_16 |   1.429342   .1882229     7.59   0.000     1.060432    1.798252
_Ihour326_17 |   1.276508   .1846653     6.91   0.000     .9145706    1.638445
_Ihour326_18 |   .6893164   .1791829     3.85   0.000     .3381244    1.040508
_Ihour326_19 |   .6267627   .1700451     3.69   0.000     .2934804    .9600451
_Ihour326_20 |    .228052   .1624433     1.40   0.160    -.0903311     .546435
_Ihour326_21 |   .0813936   .1491096     0.55   0.585    -.2108559    .3736431
_Ihour326_22 |  -.0530268   .1322569    -0.40   0.688    -.3122455     .206192
_Ihour326_23 |  -.0403837   .1140866    -0.35   0.723    -.2639893    .1832219
       _cons |   5.977818   .3617455    16.52   0.000      5.26881    6.686826
-------------+----------------------------------------------------------------
ARMA         |
          ar |
         L1. |   .9518718   .0032012   297.35   0.000     .9455975    .9581461
          ma |
         L1. |  -.3252873    .008787   -37.02   0.000    -.3425095   -.3080651
-------------+----------------------------------------------------------------
      /sigma |   2.016799   .0112216   179.73   0.000     1.994805    2.038793
------------------------------------------------------------------------------
```

Table 4.11 ARMA(1,1) with monthly dummy variables for site326.

```
ARIMA regression

Sample:  420769 - 429551, but with gaps        Number of obs      =      8764
                                               Wald chi2(13)      =  68758.04
Log likelihood = -18685.57                     Prob > chi2        =    0.0000

------------------------------------------------------------------------------
```

```
             |                 OPG
nwindspe~326 |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
nwindspe~326 |
_Imonth326_2 |  -.0619982   .7799584    -0.08   0.937    -1.590689    1.466692
_Imonth326_3 |   .2065788   .8432176     0.24   0.806    -1.446097    1.859255
_Imonth326_4 |  -2.463991    .868964    -2.84   0.005    -4.167129    -.760853
_Imonth326_5 |  -4.639325    1.16019    -4.00   0.000    -6.913255   -2.365395
_Imonth326_6 |  -4.722618   1.092929    -4.32   0.000     -6.86472   -2.580516
_Imonth326_7 |  -4.763693   1.099199    -4.33   0.000    -6.918083   -2.609302
_Imonth326_8 |  -4.652556   1.099215    -4.23   0.000    -6.806978   -2.498135
_Imonth326_9 |  -3.783235   .9581771    -3.95   0.000    -5.661227   -1.905242
_Imonth32~10 |  -2.569999   .8411156    -3.06   0.002    -4.218555   -.9214423
_Imonth32~11 |  -2.073846   .9166504    -2.26   0.024    -3.870448   -.2772442
_Imonth32~12 |  -2.595538   .9171547    -2.83   0.005    -4.393129   -.7979482
       _cons |    9.41804   .6067473    15.52   0.000     8.228837    10.60724
-------------+----------------------------------------------------------------
ARMA         |
          ar |
         L1. |   .9322764   .0038992   239.09   0.000      .924634    .9399188
          ma |
         L1. |  -.2810992   .0092257   -30.47   0.000    -.2991812   -.2630171
-------------+----------------------------------------------------------------
      /sigma |   2.039556   .0112681   181.00   0.000     2.017471    2.061641
------------------------------------------------------------------------------
```

4.4.1.3 Limitations

The use of raw wind speed time series as an input is rarely used in previous academic papers. The time series were first transformed in order to avoid non-stationarity or to impose normal-type distributions in most of cases (Alexiadis *et al.* 1998; Daniel & Chen 1991; Contaxis & Kabouris 1991; Hu *et al.*1991). In these papers the wind speed data has been collected over a longer time period than used here, such as 7years. Some of their data is for short intervals- half hour to 10-minutes. It may be necessary to convert the wind speed data to be stationary as these authors have. However, the wind speed data do not appear to be non-stationary for the time span I have used as shown by the Dickey-Fuller test. In addition, it has been argued that the ARMA family models tend to underestimate the wind speed since they can not accommodate shocks caused by extreme weather conditions.

4.4.2 ARCH-GARCH model

The above class of estimated models (see Table 4.9) are linear models. For example, the AR(1) model estimates the property of the linear estimator which is the correlation in time series of wind speed at a single site.

$$y_t = \phi y_{t-1} + u_t$$

If the model is transferred to be a stochastic differential equation model, then

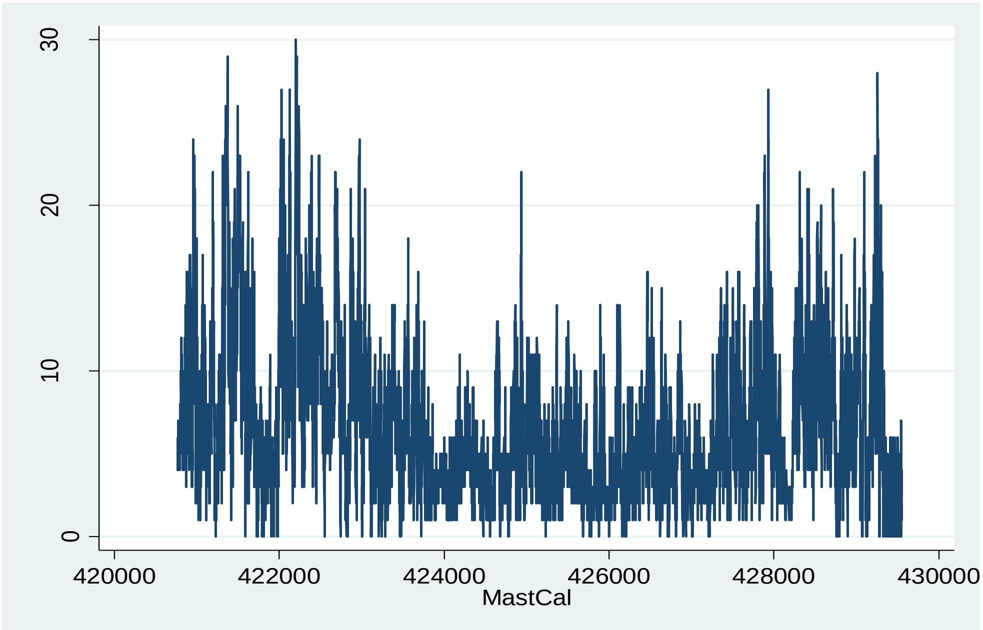
$$dy = -(1-\phi) y dt + d\xi(t)$$

Where $\xi(t)$ is a white noise process.

And $\quad dt = y_t - y_{t-1}$

The Weibull distribution analysis showed that the wind speed distributions have fat tails and excess peaking at the mean. Moreover, the previous simulation of ARMA models showed volatility in wind speed. A linear specification might not be sufficient to describe all of wind speed data. The ARCH and GARCH models are widely used non-linear models for modelling behaviour and forecasting volatility. They can also be used to detect non-linear behaviour in wind speed time series. For this reason, I will now examine whether a GARCH based model might provide a better fit for the data that I have used in my previous experiments. This model may be used to test whether the volatility of wind speed is autocorrelated.

Figure 4.12 Real hourly wind speed for site326 from 1st January to 31 December 2008.



An important feature of the wind speed time series is described in Figure 4.12. This volatility clustering describes the tendency of periods of high wind speed to be followed by periods of high wind speed within a short interval. The current level of volatility is closely correlated with the level of volatility observed during the immediately preceding time period. It is a reasonable characteristic for wind speed in reality. Therefore, this model may be used to test whether the volatility of wind speed is autocorrelated.

4.4.2.1 ARCH-GARCH model formulation

The ARCH –GARCH family models are used to model the phenomenon referred to in the section above. For ARCH models, the 'autocorrelation in volatility' is modelled by allowing the conditional variance of the error term, σ_t^2, to depend on the immediately previous value of the squared error (Brooks 2002).

$$\sigma_t^2 = \alpha_0 + \alpha_1 u_{t-1}^2 \qquad \text{ARCH(1)}$$

The GARCH models allow the conditional variance to be dependent on its previous lags.

$$\sigma_t^2 = \alpha_0 + \alpha_1 u_{t-1}^2 + \beta\sigma_{t-1}^2 \qquad \text{GARCH(1,1)}$$

Table 4.12. ARCH-GARCH model specifications. Source: (Brooks 2002)

ARCH (q) Model

$$y_t = \beta_1 + \beta_2 x_{2t} + \beta_3 x_{3t} + ... + \beta_j x_{jt} + u_t \qquad u_t \sim N(0, h_t)$$

$$h_t = \alpha_0 + \alpha_1 u_{t-1}^2 + \alpha_2 u_{t-2}^2 + ... + \alpha_q u_{t-q}^2$$

GARCH (p,q) Model

$$\sigma_t^2 = \alpha_0 + \sum_{i=1}^{q} \alpha_i u_{t-i}^2 + \sum_{i=1}^{p} \beta_j \sigma_{t-j}^2$$

In order to ensure that the ARCH family models are appropriate for modelling wind speed data, it is sensible to run the Engle (1982) test for the presence of ARCH effects in the residuals. The GARCH-type models can then be estimated due to fact that GARCH models are an extension of ARCH models and help to overcome some of the limitations of ARCH models, such as difficulties of identifying q and non-negativity constraints. Furthermore, GARCH models are more parsimonious compared to ARCH models and avoid over-fitting (Brooks 2002).

4.2.2.2 Estimation of coefficients

The test is run on the data for site326. There are 8,764 hourly wind speed observations during the whole year of 2008. Firstly, the AR(1) model is estimated on site326 data based on the model specification in previous section. The residuals are then retrieved. The test is a joint null hypothesis that all q lags of the squared residuals have coefficient values which are not significantly different from zero. We set the value of q = 5. Table 4.13 provides the test statistics of coefficient values for 5 lags. The $\chi^2(q)$ statistics are significantly greater than the critical value, and as a result the presence of ARCH effects is suggested in the wind speed data.

Table 4.13. LM test for autoregressive conditional heteroskedasticity (ARCH) on site326

lags(p)	chi2	df	Prob > chi2
1	478.890	1	0.0000
2	550.093	2	0.0000
3	648.169	3	0.0000
4	676.176	4	0.0000
5	703.921	5	0.0000

H0: no ARCH effects vs. H1: ARCH(p) disturbance

Table 4.14 is the ARMA(1 24, 1)-GARCH(1,1) model specification for site326 data. The coefficients of the ARCH-GARCH equations are highly significant when comparing the test statistics with critical values. The sum of the coefficients on the squared error (u_t^2) and lagged conditional variance (σ_{t-1}^2) is approximately 0.995, which implies that 'shocks to the conditional variance' will be highly persistent (Brooks, 2002). Figure 4.13 plots the simulated hourly wind speed for site326 data from 1st January to 31st January 2008 and the real average wind speed. Table 4.15 presents the results of the above model re-estimated including monthly dummy variables. $y_t = \beta_1 + \beta_2 x_{2t} + \beta_3 x_{3t} + ... + \beta_j x_{jt} + u_t + \sum_{m=1}^{11} l_m$

Table4.14. ARCH family regression -- ARMA disturbances

Sample: 420769 to 429551, but with gaps

Number of obs	=	8764
Wald chi2(3)	=	65376.79
Prob > chi2	=	0.0000

Log likelihood = -17903.89

wind speed	Coef.	OPG Std. Err.	z	P>|z|	[95% Conf.	Interval]
wind speed						
_cons	5.180125	.2000063	25.90	0.000	4.78812	5.572131
ARMA						
ar						
L1.	.9264098	.0047142	196.51	0.000	.9171701	.9356496
L24.	.0275059	.0039683	6.93	0.000	.0197282	.0352837
ma						
L1.	-.2794666	.0119854	-23.32	0.000	-.3029576	-.2559757
ARCH						
arch						
L1.	.0774534	.0042202	18.35	0.000	.0691819	.0857249
garch						
L1.	.917987	.0040942	224.22	0.000	.9099625	.9260114
_cons	.0315314	.0047297	6.67	0.000	.0222613	.0408015

Figure 4.13. Predicted hourly wind speed by GARCH(1,1) for site 326.

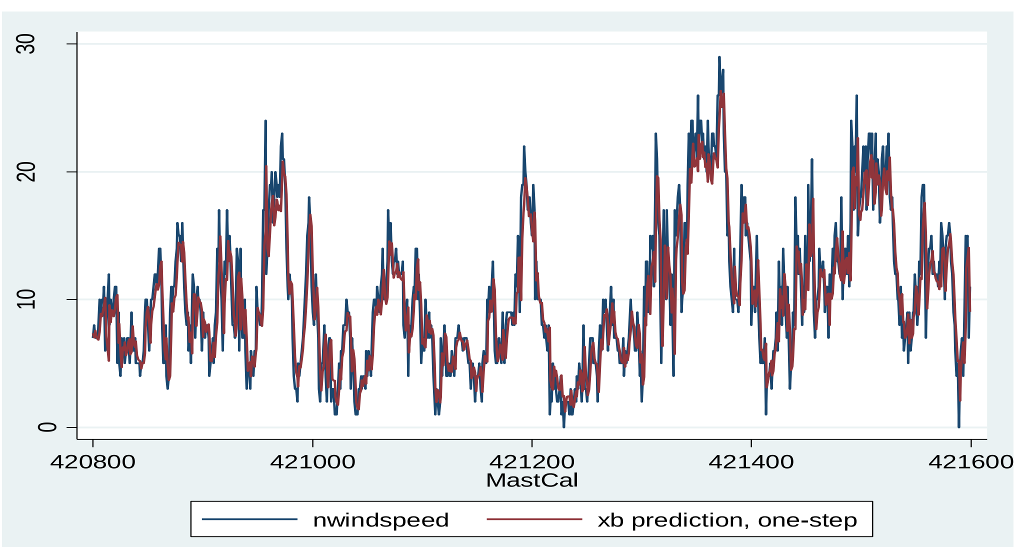


Table 4.15. ARMA(1&24,1)-GARCH(1,1) model with monthly dummy variables

ARCH family regression -- ARMA disturbances

Sample: 420769 - 429551, but with gaps   Number of obs = 8764
Distribution: Gaussian   Wald chi2(14) = 51330.66
Log likelihood = -17875.92   Prob > chi2 = 0.0000

	Coef.	OPG Std. Err.	z	P>|z|	[95% Conf.	Interval]
nwindspe~326						
_Imonth326_2	-1.137702	.9418015	-1.21	0.227	-2.983599	.7081948
_Imonth326_3	1.592027	.7489045	2.13	0.034	.1242012	3.059853
_Imonth326_4	-2.227601	.7384482	-3.02	0.003	-3.674933	-.7802693
_Imonth326_5	-3.627625	.7903526	-4.59	0.000	-5.176688	-2.078563
_Imonth326_6	-3.738259	.7763161	-4.82	0.000	-5.259811	-2.216707
_Imonth326_7	-3.609279	.7841112	-4.60	0.000	-5.146109	-2.072449
_Imonth326_8	-3.565075	.8140488	-4.38	0.000	-5.160581	-1.969569
_Imonth326_9	-3.013208	.7637929	-3.95	0.000	-4.510214	-1.516201
_Imonth32~10	-2.61126	.7791056	-3.35	0.001	-4.138279	-1.084242
_Imonth32~11	-3.177696	.93479	-3.40	0.001	-5.009851	-1.345541
_Imonth32~12	-2.076823	.8791346	-2.36	0.018	-3.799895	-.3537507
_cons	7.724114	.5636112	13.70	0.000	6.619457	8.828772
ARMA						
ar						
L1.	.9187423	.0050376	182.38	0.000	.9088688	.9286158
L24.	.0207875	.0041239	5.04	0.000	.0127047	.0288702
ma						
L1.	-.2746861	.0122276	-22.46	0.000	-.2986517	-.2507205
ARCH						
arch						
L1.	.0791515	.0043444	18.22	0.000	.0706365	.0876664
garch						
L1.	.9163586	.0041905	218.67	0.000	.9081453	.9245719
_cons	.0320564	.0047752	6.71	0.000	.0226972	.0414157

Figure 4.14 Monthly effect modelled by ARMA(1 24,1)-GARCH(1,1) model

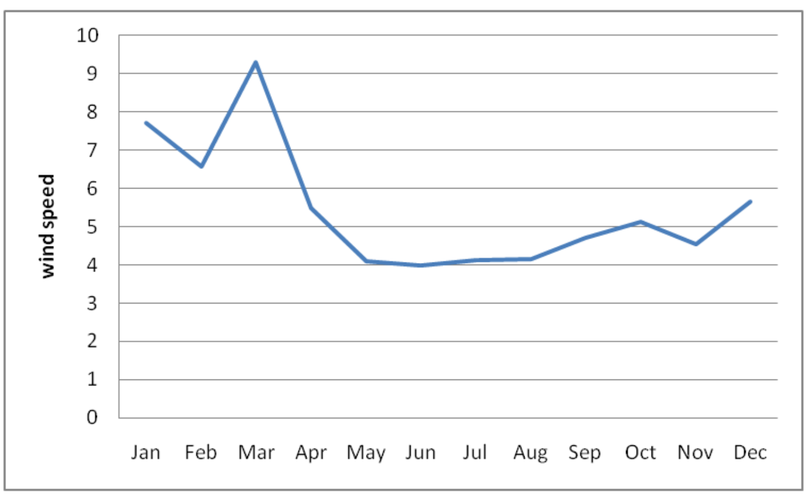


Figure 4.14 shows the monthly effect of wind speed based on the modelling result from ARMA(1 24,1)-GARCH(1,1) process. It shows a pattern of monthly effect which is similar to that of the Weibull distribution and ARMA family. This model provides a good prediction of volatility in wind speed because the coefficient estimated on σ_{t-1}^2 is very high and it is significant. The model proves the volatility in wind speed is highly persistent. Figure 4.13 shows the good prediction of volatility in wind speed because the predicted wind speed data vary in the same pattern as the real wind speed data in site326.

4.5 Multivariate models--Vector autoregressive models

The time series models described in previous sections have focused on variations of single equation models or univariate time series models. A VAR model is a multiple-equation system or a multiple-time series generalisation of AR models. It allows the value of a variable to depend on more than just its own lags or combinations of white noise terms (Brooks 2002). VAR models simultaneously estimate the interrelationship between more than one endogenous variable. It allows us to take the interdependence between different wind speed time series into account.

VAR is the formal model most closely to measure the correlation between wind speeds in different wind farms. It allows us to include all the wind farms of the portfolio in the model. Thus it is the closest method to our notion of the portfolio theory to test the correlation. The downside of using VAR is that the error terms are less specific for wind speed than those of the Weibull distribution.

VARs have been used primarily in macroeconomics to capture the relationship between important economic variables (Kapetanios *et al.* 2008; Valadkhani 2004; Lee 1997). VARs are also widely used to measure the stock price-volume relation (MacDonald & Power 1995; Kaliva & Koskinen 2008; Bohl & Siklos 2004). However, few studies have been done on the renewable energy sector using VARs. Ewing *et al.* examined the interdependence in wind speed data measured in the same location at four different heights by using a VAR model. They found that a multiple-equation system or VAR is capable of capturing the underlying cross-variable dynamics for wind at various heights[27].

In my research, I have put ten sites/wind farms into a portfolio. The VAR model is used to analyse the interrelationships between different time series data on wind speed within the portfolio. The dynamic impact of random disturbances or shocks caused by extreme weather conditions on the system of variables or portfolio can be captured using a VAR model. The VAR has been used to forecast the dynamics of the state of nature for wind at various locations.

4.5.1 VAR model formulation and selection without exogenous variables

$$y_t = \alpha_1 y_{t-1} + \alpha_2 y_{t-2} + \cdots + \alpha_p y_{t-p} + \beta x_t + u_t$$

where y_t is a ***j*** vector of endogenous variables.

x_t is a ***k*** vector of exogenous variables, $\alpha_1 \cdots \alpha_p$ and β are matrices of coefficients to be estimated and u_t is a vector of innovations that may be contemporaneously correlated with

[27] http://www.ecu.edu/cs-educ/econ/upload/ecu0607.pdf

each other. However they are uncorrelated with their own lagged values and uncorrelated with all of the right-hand endogenous and exogenous variables.

The variables y_t included in the VAR model are wind speed from ten different sites within my portfolio. The ten wind farms within the portfolio are the same as those I have discussed in the previous section in connection with the univariate time series analyses. All variables to be included in the VAR are required to be stationary in order to carry out joint significance tests on the lags of the variables. As with the test results from the previous section on ARMA, all variables were subjected to augmented Dickey- Fuller tests. The test results show that variables do not contain unit root. Therefore, the original 10 wind speed time series are inputs for the VAR. The VAR model with exogenous variables will be discussed in a later section.

Information criteria AIC and BIC for univariate time series model selection can be used in VAR as well to determine the appropriate lag lengths. There are three steps to calculate the AIC and BIC for the VAR.

(1) The determinant of the residual covariance is described as:

$$\left|\hat{\Omega}\right| = \det\left(\sum_t \hat{u} \cdot \hat{u}' \Big/ T - \rho \right)$$

where ρ is the number of parameters per equation in the VAR model, and T is the number of observations.

(2) The log likelihood value is computed assuming a multivariate normal Gaussian distribution as:

$$\ell = -\frac{T}{2}\{j(1+\log 2\pi) + \log|\hat{\Omega}|\ \}$$

(3)The AIC and BIC are calculated as:

$$AIC = \frac{-2\ell}{T} + \frac{2n}{T}$$

$$BIC = \frac{-2\ell}{T} - \frac{n \cdot \log T}{T}$$

where $n = j(k + \rho j)$ is the total number of estimated parameters in the VAR model (Brooks 2002).

I have calculated the values of AIC and BIC based on the VAR without exogenous variables. Table 4.16 shows that value of AIC, BIC, and degree of freedom for VAR models with different lags which are computed using STATA 10. According to Table 4.16, the VAR model with a lag length equal to 4 has the minimum AIC and BIC values, but has the largest number of estimated parameters. Theoretically, this 4^{th}-lag VAR model is preferred to other models. However, the number of estimated parameters increases dramatically when a 4^{th} lag is used.

Table 4.16. AIC and BIC for VAR models with different lag length.

Model	Degree of freedom	AIC	BIC
Lag1	110	369144.5	**369912**
Lag2	210	356748.1	**358208.5**
Lag3	310	346585.1	**348732.2**

Lag4	**410**	**337126.1**	**339954.6**

Furthermore, within the framework of the VAR system of equations the significance of 4 lags of each of the individual site is examined jointly with an F-test as shown in Table 4.17. It clearly shows that most of the coefficients on individual lags are not significant for all 4 lags. The values of the coefficients and degrees of significance vary with the lag length for different sites. The current wind speed for each site is significantly correlated with its own 1st lag wind speed. The value of each individual site's 1st lag coefficients are similar and approximated to 0.60 in VAR(4). Thus, the current wind speed for each individual site is closely related to its own lagged value and this result is in accord with the conclusions from our univariate time series models. The values of coefficients for endogenous variables with other lag lengths are relatively small. As the number of lag length increased, values of lagged coefficients reduce further, and most of them are not statistically significant. One possible explanation for this might be that as the distances between each pair of wind farms vary, the correlation of lagged wind speed between wind farms falls as distances between them increase.

Table 4.17. A Part of the VAR(4) model result for the 10 sites portfolio.

```
Vector autoregression

Sample:  420773 - 429551, but with gaps          No. of obs      =      7323
Log likelihood =   -168153                       AIC             =  46.03661
FPE            =  4.66e+07                       HQIC            =   46.1694
Det(Sigma_ml)  =  4.17e+07                       SBIC            =  46.42286

Equation           Parms      RMSE     R-sq      chi2     P>chi2
----------------------------------------------------------------
nwindspeed48         41     2.70692   0.7594   23117.52   0.0000
nwindspeed212        41     2.44331   0.8088   30986.89   0.0000
nwindspeed326        41     1.97366   0.8259   34736.01   0.0000
nwindspeed1006       41     2.62236   0.8291   35535.42   0.0000
nwindspeed1190       41     2.87569   0.8263    34841.3   0.0000
nwindspeed1346       41     2.49569   0.8417   38949.11   0.0000
nwindspeed1395       41      2.0919   0.8519   42114.82   0.0000
nwindspeed16581      41     2.83282   0.8530   42494.31   0.0000
nwindspeed16725      41     2.16049   0.8651    46943.2   0.0000
nwindspeed18930      41     2.26073   0.8142   32092.37   0.0000
----------------------------------------------------------------
------------------------------------------------------------------------------
             |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
nwindspeed48 |
nwindspeed48 |
         L1. |   .6508229   .0118403    54.97   0.000     .6276163    .6740295
         L2. |   .1445416   .0139942    10.33   0.000     .1171134    .1719699
```

L3.	.0349278	.0140458	2.49	0.013	.0073985	.0624571
L4.	-.017661	.0120113	-1.47	0.141	-.0412028	.0058808
nwindspe~212						
L1.	.0566484	.0129996	4.36	0.000	.0311696	.0821272
L2.	.0149068	.0152489	0.98	0.328	-.0149805	.0447942
L3.	-.0165042	.0152808	-1.08	0.280	-.0464539	.0134455
L4.	-.0190302	.0129208	-1.47	0.141	-.0443545	.0062942
nwindspe~326						
L1.	.0787499	.0160378	4.91	0.000	.0473165	.1101833
L2.	.0018914	.018593	0.10	0.919	-.0345502	.0383331
L3.	-.0304114	.0186644	-1.63	0.103	-.0669929	.0061702
L4.	-.0527438	.0161301	-3.27	0.001	-.0843582	-.0211293
nwindsp~1006						
L1.	.052044	.0121944	4.27	0.000	.0281435	.0759446
L2.	.0143937	.0144429	1.00	0.319	-.0139138	.0427012
L3.	-.0168754	.0145052	-1.16	0.245	-.045305	.0115542
L4.	.0007515	.0124077	0.06	0.952	-.0235671	.0250701
nwindsp~1190						
L1.	.0172653	.0111147	1.55	0.120	-.004519	.0390497
L2.	-.0149027	.0134347	-1.11	0.267	-.0412344	.0114289
L3.	.0128102	.013444	0.95	0.341	-.0135395	.0391599
L4.	-.0315589	.0112952	-2.79	0.005	-.053697	-.0094208
nwindsp~1346						
L1.	.015744	.0128438	1.23	0.220	-.0094294	.0409175
L2.	-.0084303	.015415	-0.55	0.584	-.0386431	.0217825
L3.	.0091607	.0153912	0.60	0.552	-.0210054	.0393269
L4.	-.0230389	.0125222	-1.84	0.066	-.0475819	.0015041
nwindsp~1395						
L1.	.038073	.015184	2.51	0.012	.008313	.0678331
L2.	-.0324372	.0189919	-1.71	0.088	-.0696607	.0047863
L3.	.008624	.0190607	0.45	0.651	-.0287344	.0459823
L4.	-.0255901	.015526	-1.65	0.099	-.0560205	.0048404
nwinds~16581						
L1.	.0393059	.0112469	3.49	0.000	.0172625	.0613494
L2.	.0055889	.0138769	0.40	0.687	-.0216093	.0327871
L3.	-.0113334	.0138507	-0.82	0.413	-.0384802	.0158134
L4.	-.0078405	.0111152	-0.71	0.481	-.0296259	.0139448
nwinds~16725						
L1.	.0475031	.0149641	3.17	0.002	.0181739	.0768322
L2.	-.0040548	.0182833	-0.22	0.824	-.0398893	.0317798
L3.	-.0059053	.0182886	-0.32	0.747	-.0417503	.0299397
L4.	-.0152053	.0149423	-1.02	0.309	-.0444917	.0140811
nwinds~18930						
L1.	.0427024	.0142795	2.99	0.003	.0147151	.0706897
L2.	-.0388563	.0161479	-2.41	0.016	-.0705057	-.007207
L3.	.0091903	.0162088	0.57	0.571	-.0225785	.040959
L4.	-.0240874	.0141396	-1.70	0.088	-.0518004	.0036257
_cons	.6900856	.0940239	7.34	0.000	.5058021	.8743691
nwindspe~212						
nwindspeed48						
L1.	.038499	.0106873	3.60	0.000	.0175523	.0594456
L2.	.021386	.0126315	1.69	0.090	-.0033712	.0461432
L3.	-.0126183	.012678	-1.00	0.320	-.0374668	.0122301
L4.	-.0392199	.0108416	-3.62	0.000	-.0604691	-.0179707
nwindspe~212						
L1.	.6262845	.0117337	53.37	0.000	.6032869	.6492821
L2.	.1296749	.0137639	9.42	0.000	.102698	.1566517
L3.	.0328339	.0137927	2.38	0.017	.0058007	.0598671
L4.	.0070266	.0116626	0.60	0.547	-.0158316	.0298848
nwindspe~326						
L1.	.0622367	.014476	4.30	0.000	.0338643	.090609
L2.	.0200576	.0167824	1.20	0.232	-.0128353	.0529504
L3.	-.0073633	.0168468	-0.44	0.662	-.0403825	.0256558
L4.	-.0234776	.0145593	-1.61	0.107	-.0520134	.0050581
nwindsp~1006						
L1.	.0936116	.0110069	8.50	0.000	.0720385	.1151846
L2.	.0296681	.0130364	2.28	0.023	.0041172	.0552189
L3.	.0067386	.0130926	0.51	0.607	-.0189225	.0323997
L4.	-.0423235	.0111994	-3.78	0.000	-.0642739	-.0203731
nwindsp~1190						
L1.	.0156018	.0100323	1.56	0.120	-.0040612	.0352647
L2.	.0009923	.0121264	0.08	0.935	-.0227751	.0247597
L3.	.0021033	.0121348	0.17	0.862	-.0216804	.025887
L4.	-.0018883	.0101952	-0.19	0.853	-.0218706	.0180939
nwindsp~1346						
L1.	-.0010364	.0115931	-0.09	0.929	-.0237583	.0216856
L2.	.0087157	.0139138	0.63	0.531	-.0185549	.0359864
L3.	-.0193522	.0138924	-1.39	0.164	-.0465807	.0078763
L4.	-.0007867	.0113027	-0.07	0.945	-.0229396	.0213663
nwindsp~1395						
L1.	.007567	.0137053	0.55	0.581	-.019295	.034429
L2.	-.022842	.0171424	-1.33	0.183	-.0564406	.0107565
L3.	.0189905	.0172046	1.10	0.270	-.0147298	.0527109
L4.	-.0260528	.0140141	-1.86	0.063	-.0535198	.0014143
nwinds~16581						
L1.	.0026706	.0101516	0.26	0.792	-.0172263	.0225674
L2.	.0030012	.0125255	0.24	0.811	-.0215484	.0275508
L3.	.0042054	.0125019	0.34	0.737	-.0202978	.0287086
L4.	-.0031018	.0100328	-0.31	0.757	-.0227657	.0165621
nwinds~16725						
L1.	.0115204	.0135069	0.85	0.394	-.0149526	.0379934
L2.	.0163297	.0165028	0.99	0.322	-.0160152	.0486746
L3.	-.0224748	.0165076	-1.36	0.173	-.0548291	.0098796
L4.	-.0152476	.0134872	-1.13	0.258	-.0416821	.0111868
nwinds~18930						
L1.	.0478241	.0128889	3.71	0.000	.0225622	.0730859
L2.	-.0092451	.0145754	-0.63	0.526	-.0378124	.0193221
L3.	-.0062721	.0146304	-0.43	0.668	-.0349472	.0224029
L4.	-.0149907	.0127626	-1.17	0.240	-.040005	.0100236
_cons	.2636001	.0848677	3.11	0.002	.0972626	.4299377

Part of model result omission

nwinds~16725						
nwindspeed48						
L1.	.0197085	.0094502	2.09	0.037	.0011865	.0382306
L2.	.0016454	.0111693	0.15	0.883	-.0202461	.0235369

L3.	-.0174862	.0112105	-1.56	0.119	-.0394583	.004486
L4.	-.0109303	.0095867	-1.14	0.254	-.0297198	.0078593
nwindspe~212						
L1.	.0022217	.0103755	0.21	0.830	-.0181139	.0225573
L2.	-.0026861	.0121707	-0.22	0.825	-.0265403	.0211681
L3.	-.0229003	.0121961	-1.88	0.060	-.0468043	.0010037
L4.	.0011989	.0103126	0.12	0.907	-.0190135	.0214112
nwindspe~326						
L1.	.1084452	.0128003	8.47	0.000	.083357	.1335335
L2.	-.0050944	.0148398	-0.34	0.731	-.0341799	.023991
L3.	-.011895	.0148968	-0.80	0.425	-.0410921	.0173021
L4.	-.036757	.0128741	-2.86	0.004	-.0619897	-.0115244
nwindsp~1006						
L1.	.0028682	.0097328	0.29	0.768	-.0162078	.0219441
L2.	.0181204	.0115274	1.57	0.116	-.0044729	.0407136
L3.	-.0153811	.0115771	-1.33	0.184	-.0380719	.0073096
L4.	-9.19e-06	.009903	-0.00	0.999	-.0194188	.0194004
nwindsp~1190						
L1.	.0513993	.008871	5.79	0.000	.0340124	.0687862
L2.	-.0011751	.0107228	-0.11	0.913	-.0221913	.0198412
L3.	.0022381	.0107301	0.21	0.835	-.0187926	.0232688
L4.	.0037638	.0090151	0.42	0.676	-.0139055	.021433
nwindsp~1346						
L1.	.0321559	.0102511	3.14	0.002	.012064	.0522477
L2.	-.019461	.0123033	-1.58	0.114	-.043575	.0046529
L3.	.0066684	.0122843	0.54	0.587	-.0174084	.0307451
L4.	-.0252488	.0099944	-2.53	0.012	-.0448375	-.0056601
nwindsp~1395						
L1.	.0214082	.0121189	1.77	0.077	-.0023444	.0451608
L2.	-.0148732	.0151582	-0.98	0.326	-.0445826	.0148363
L3.	.0197116	.0152131	1.30	0.195	-.0101055	.0495288
L4.	.013527	.0123919	1.09	0.275	-.0107607	.0378147
nwinds~16581						
L1.	.0074494	.0089766	0.83	0.407	-.0101444	.0250431
L2.	-.0067911	.0110757	-0.61	0.540	-.028499	.0149168
L3.	.0114792	.0110547	1.04	0.299	-.0101876	.0331461
L4.	-.0152184	.0088715	-1.72	0.086	-.0326061	.0021693
nwinds~16725						
L1.	.7097565	.0119434	59.43	0.000	.6863478	.7331652
L2.	.0947969	.0145926	6.50	0.000	.066196	.1233978
L3.	.00972	.0145968	0.67	0.505	-.0188893	.0383292
L4.	-.0031114	.011926	-0.26	0.794	-.026486	.0202632
nwinds~18930						
L1.	.14112	.011397	12.38	0.000	.1187823	.1634577
L2.	-.0302394	.0128883	-2.35	0.019	-.0555	-.0049789
L3.	-.0074423	.0129369	-0.58	0.565	-.0327981	.0179136
L4.	-.0520426	.0112853	-4.61	0.000	-.0741614	-.0299238
_cons	.7048252	.075044	9.39	0.000	.5577416	.8519088
nwinds~18930						
nwindspeed48						
L1.	.0338788	.0098887	3.43	0.001	.0144974	.0532603
L2.	.0016251	.0116876	0.14	0.889	-.0212821	.0245323
L3.	-.0341551	.0117306	-2.91	0.004	-.0571467	-.0111634
L4.	-.0226219	.0100315	-2.26	0.024	-.0422832	-.0029605
nwindspe~212						
L1.	.0146159	.0108569	1.35	0.178	-.0066632	.035895
L2.	.0005712	.0127354	0.04	0.964	-.0243898	.0255322
L3.	.0055052	.012762	0.43	0.666	-.0195079	.0305183
L4.	-.0176737	.0107911	-1.64	0.101	-.0388238	.0034764
nwindspe~326						
L1.	.068569	.0133942	5.12	0.000	.0423168	.0948213
L2.	-.0105096	.0155283	-0.68	0.499	-.0409446	.0199254
L3.	-.0119445	.0155879	-0.77	0.444	-.0424962	.0186073
L4.	-.0239507	.0134714	-1.78	0.075	-.0503541	.0024527
nwindsp~1006						
L1.	.0113585	.0101844	1.12	0.265	-.0086025	.0313195
L2.	.0205103	.0120622	1.70	0.089	-.0031313	.0441518
L3.	-.0310107	.0121143	-2.56	0.010	-.0547542	-.0072672
L4.	-.0010052	.0103625	-0.10	0.923	-.0213154	.0193049
nwindsp~1190						
L1.	.0403499	.0092826	4.35	0.000	.0221563	.0585435
L2.	.0122759	.0112203	1.09	0.274	-.0097155	.0342673
L3.	-.0132359	.011228	-1.18	0.238	-.0352424	.0087706
L4.	-.0087343	.0094334	-0.93	0.355	-.0272234	.0097548
nwindsp~1346						
L1.	.0522761	.0107268	4.87	0.000	.031252	.0733001
L2.	-.0075231	.0128741	-0.58	0.559	-.0327559	.0177097
L3.	.0162442	.0128542	1.26	0.206	-.0089496	.0414381
L4.	-.0106773	.0104581	-1.02	0.307	-.0311748	.0098203
nwindsp~1395						
L1.	.0290483	.0126812	2.29	0.022	.0041936	.053903
L2.	-.0256099	.0158615	-1.61	0.106	-.0566978	.005478
L3.	-.0011422	.015919	-0.07	0.943	-.0323428	.0300584
L4.	.0076303	.0129669	0.59	0.556	-.0177842	.0330449
nwinds~16581						
L1.	.0223157	.009393	2.38	0.018	.0039056	.0407257
L2.	-.0013636	.0115896	-0.12	0.906	-.0240788	.0213515
L3.	-.0020888	.0115676	-0.18	0.857	-.024761	.0205834
L4.	-.0003413	.0092831	-0.04	0.971	-.0185357	.0178532
nwinds~16725						
L1.	.1927582	.0124976	15.42	0.000	.1682634	.2172531
L2.	.0106649	.0152696	0.70	0.485	-.019263	.0405928
L3.	-.0575201	.0152741	-3.77	0.000	-.0874567	-.0275834
L4.	-.0327408	.0124794	-2.62	0.009	-.0571999	-.0082817
nwinds~18930						
L1.	.5355048	.0119258	44.90	0.000	.5121307	.558879
L2.	.1215674	.0134863	9.01	0.000	.0951348	.148
L3.	.0475692	.0135371	3.51	0.000	.0210369	.0741015
L4.	.0136168	.0118089	1.15	0.249	-.0095283	.0367618
_cons	-.0381506	.0785259	-0.49	0.627	-.1920585	.1157574

The estimation of unrestricted VAR requires that the same lag length of 4 for all of the endogenous variables is used in all equations. In this case, each single increase in the number of lags results in the number of estimated parameters increasing by 100. The formula $n = j(k + \rho j)$ determines the number of estimated parameters and this is a polynomial expansion in this VAR Gaussian model. Thus the overparameterisation is one of the major problems with VAR. It will be difficult to see which sets of variables have a significant effect on each dependent variable and which do not for a VAR that includes longer lags (Brooks, 2002). Therefore, I have decided to use VAR(1) to identify the interdependence of different wind speed time series data by taking the value of estimated parameters and overparameterisation into account.

4.5.2 Granger Causality test

Since a reduced form VAR is employed to estimated wind speed, each equation can effectively be estimated using OLS. The VAR(1) without exogenous variables is chosen.

$y_t = c + \alpha_1 y_{t-1} + u_t$ where c is a vector of constants.

The model specification for 10site portfolio can be written as:

$$y_{48,t} = c_1 + \alpha_{1,1} y_{48,t-1} + \alpha_{1,2} y_{212,t-1} + \alpha_{1,3} y_{326,t-1} + \cdots + \alpha_{1,10} y_{18930,t-1} + u_t$$

$$y_{212,t} = c_2 + \alpha_{2,1} y_{48,t-1} + \alpha_{2,2} y_{212,t-1} + \alpha_{2,3} y_{326,t-1} + \cdots + \alpha_{2,10} y_{18930,t-1} + u_t$$

$$y_{18930,t} = c_{10} + \alpha_{10,1} y_{48,t-1} + \alpha_{10,2} y_{212,t-1} + \alpha_{10,3} y_{326,t-1} + \cdots + \alpha_{10,10} y_{18930,t-1} + u_t$$

The above VAR models indicate the interdependent relationships between the 10 sites. The wind speed for time t for each site can be estimated by including wind speed data for a previous time period from all 10 sites. In other words, this VAR model assumes that the lagged values of the 10 sites can explain the current value of each site. However, evaluation of the significance of variables in the VAR and joint correlation need to be tested. This test can be referred to as a causality test. Granger described the causality and feedback test approach to the question of whether changes in one variable cause changes in another variable (Granger 1969). The argument follows that if y_1 causes y_2, lags of y_1 should be significant in the equation for y_2. If this is the case and not vice versa, it can be said that y_1 'Granger-causes' y_2 or that there exists unidirectional causality from y_1 to y_2 (Brooks 2002). The use of the F-test to jointly test for the significance of the lags on the explanatory variables is in effect the same as tests for 'Granger causality' between these variables. The Grange causality does not mean that the changes in one variable are the real reason for the changes in another variable. It identifies the correlation between the current value of one variable and the past values of different variables.

In our case, the current wind speed of one site, for example site48, can be explained by the past values of its own wind speed at the same site. This has already been examined in the ARMA models. However, current wind speed for site48 might be explained by the past values of site212, in other words they are correlated. Thus the question is whether or not the explanatory power of the model would be improved by adding the lagged values of other sites into the model. Table 4.18 shows a section of the Granger Causality test result. It indicates that the lagged value of wind speed at site212 causes the current value of wind speed at site48. Since the test statistic $\chi^2(27.365)$ is greater than the critical value

$\chi^2(1,0.05)=3.84$, it can be said that 'lagged wind speed at site212 causes current wind speed at site48'. On the other hand, the test statistic $\chi^2(34.814)$ is greater than the critical value $\chi^2(1,0.05)=3.84$ for lagged wind speed at site48, thus the lagged wind speed values at site48 Granger causes current wind speed at site212'. If both sets of lags are significant it would be said that there is 'bi-directional causality' or 'bi-directional feedback'. In contrast, lagged values of wind speed at site326 cannot Granger cause the current wind speed values at site48 (2.35) and lagged wind speed values at site48 cannot Granger cause the current wind speed at site 326 (1.245). It is worth noting that the Granger causality test results do not mean that the previous wind speed at site212 is physically caused by the current wind speed at site48. It merely indicates the joint correlation between wind speed data at these two wind farms.

Table 4.18. The Granger Causality test (one part of the result).

Equation	Excluded	chi2	df	Prob > chi2
nwindspeed48	nwindspeed212	27.365	1	0.000
nwindspeed48	nwindspeed326	2.3526	1	0.125
nwindspeed48	nwindspeed1006	46.753	1	0.000
nwindspeed48	nwindspeed1190	1.0026	1	0.317
nwindspeed48	nwindspeed1346	1.8267	1	0.177
nwindspeed48	nwindspeed1395	.86494	1	0.352
nwindspeed48	nwindspeed16581	26.501	1	0.000
nwindspeed48	nwindspeed16725	.34489	1	0.557
nwindspeed48	nwindspeed18930	.32398	1	0.569
nwindspeed48	ALL	292.39	9	0.000
nwindspeed212	nwindspeed48	34.814	1	0.000
nwindspeed212	nwindspeed326	50.871	1	0.000
nwindspeed212	nwindspeed1006	240.04	1	0.000
nwindspeed212	nwindspeed1190	5.0491	1	0.025
nwindspeed212	nwindspeed1346	3.2573	1	0.071
nwindspeed212	nwindspeed1395	4.9711	1	0.026
nwindspeed212	nwindspeed16581	.08253	1	0.774
nwindspeed212	nwindspeed16725	3.3361	1	0.068
nwindspeed212	nwindspeed18930	6.9745	1	0.008
nwindspeed212	ALL	675.05	9	0.000
nwindspeed326	nwindspeed48	1.2453	1	0.264
nwindspeed326	nwindspeed212	32.167	1	0.000
nwindspeed326	nwindspeed1006	107.2	1	0.000
nwindspeed326	nwindspeed1190	97.08	1	0.000

```
|     nwindspeed326     nwindspeed1346 |  16.671     1    0.000    |
|     nwindspeed326     nwindspeed1395 |   14.66     1    0.000    |
|     nwindspeed326    nwindspeed16581 |  52.912     1    0.000    |
|     nwindspeed326    nwindspeed16725 |  8.7533     1    0.003    |
|     nwindspeed326    nwindspeed18930 |  .60203     1    0.438    |
|     nwindspeed326                ALL |  701.78     9    0.000    |
|------------------------------------+--------------------------|
```

Table 4.19 is the distance matrix for the 10 sites. The statistical significance of Granger causality drops dramatically with increasing distance. For instance, the lagged wind speed at site 212, 1006, and 16581 is significantly correlated to current wind speed at site48 since these three sites are closer to site48 than other sites. Therefore, the distance matrix is important for building a wind farm portfolio.

Table 4.19. The distance matrix of 10 sites. (Kilometers)

site ID	48	212	326	1006	1190	1346	1395	16581	16725	18930
48	0.00	212.43	464.10	311.57	609.54	792.59	901.79	208.72	737.67	816.73
212		0.00	294.58	131.95	397.17	582.82	700.05	234.91	572.36	645.22
326			0.00	343.26	305.87	498.19	654.49	331.04	278.60	354.39
1006				0.00	328.86	491.55	591.09	366.71	603.03	666.02
1190					0.00	200.12	349.69	568.71	417.27	446.56
1346						0.00	162.98	767.62	539.64	540.46
1395							0.00	903.33	699.90	695.26
16581								0.00	577.57	660.09
16725									0.00	83.07
18930										0.00

Table 4.20. A part of VAR(1) result for the portfolio.

```
------------------------------------------------------------------------------
             |      Coef.   Std. Err.      z    P>|z|     [95% Conf. Interval]
-------------+----------------------------------------------------------------
nwindspeed48 |
nwindspeed48 |
         L1. |   .7840005   .0072963   107.45   0.000     .7697001    .7983009
nwindspe~212 |
         L1. |   .0438098   .0083747     5.23   0.000     .0273956     .060224
nwindspe~326 |
         L1. |    .016124   .0105123     1.53   0.125    -.0044797    .0367277
nwindsp~1006 |
         L1. |   .0533735   .0078059     6.84   0.000     .0380743    .0686727
nwindsp~1190 |
         L1. |  -.0069126   .0069035    -1.00   0.317    -.0204433    .0066181
nwindsp~1346 |
         L1. |  -.0107583   .0079599    -1.35   0.177    -.0263595    .0048428
nwindsp~1395 |
         L1. |    .007546   .0081138     0.93   0.352    -.0083568    .0234489
nwinds~16581 |
         L1. |   .0274275   .0053279     5.15   0.000     .0169851    .0378699
nwinds~16725 |
         L1. |   .0055085   .0093798     0.59   0.557    -.0128755    .0238925
```

nwinds~18930						
L1.	-.0059128	.010388	-0.57	0.569	-.026273	.0144473
_cons	.6091264	.0868817	7.01	0.000	.4388413	.7794115
nwindspe~212						
nwindspeed48						
L1.	.0387279	.0065637	5.90	0.000	.0258633	.0515926
nwindspe~212						
L1.	.7408407	.0075339	98.33	0.000	.7260745	.7556068
nwindspe~326						
L1.	.06745	.0094568	7.13	0.000	.048915	.085985
nwindsp~1006						
L1.	.1087948	.0070221	15.49	0.000	.0950316	.1225579
nwindsp~1190						
L1.	.0139549	.0062104	2.25	0.025	.0017828	.0261271
nwindsp~1346						
L1.	-.0129236	.0071607	-1.80	0.071	-.0269583	.0011111
nwindsp~1395						
L1.	-.0162742	.0072992	-2.23	0.026	-.0305803	-.001968
nwinds~16581						
L1.	-.0013769	.0047929	-0.29	0.774	-.0107709	.0080171
nwinds~16725						
L1.	-.0154121	.008438	-1.83	0.068	-.0319503	.0011261
nwinds~18930						
L1.	.0246796	.009345	2.64	0.008	.0063637	.0429955
_cons	.1583617	.0781586	2.03	0.043	.0051737	.3115497

The Granger causality test and F-test will suggest which of the endogenous variables in the VAR system have statistically significant impacts on the future values of each of the variables in the system. In our case, Tables 4.18, 4.19, and 4.20 present the estimated wind speed data at site 48 using the relationship:

$$y_{48,t} = 0.609 + 0.784 y_{48,t-1} + 0.044 y_{212,t-1} + 0.053 y_{1006,t-1} + 0.027 y_{16851,t-1} + u_{1,t}$$

$$(107.45) \qquad (5.23) \qquad (6.84) \qquad (5.15)$$

There are statistically significant impacts on the current wind speed at site 48 from the wind speed at sites 212, 1006, and 16581, one hour in advance of the current speed. The wind speed at other sites within the portfolio has no significant correlation with site 48. The VAR(1) can be applied to all sites to indicate the interdependence of different wind speed time series.

4.5.3 Impulse response function

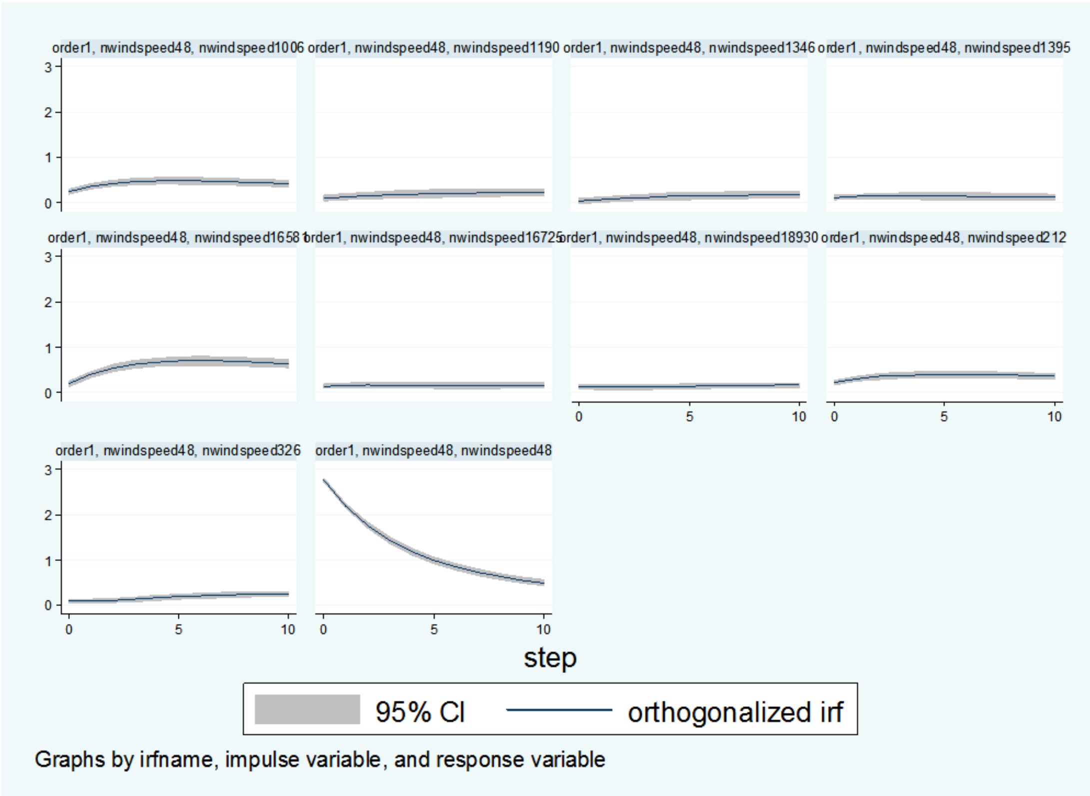
The correlations or interdependences between variables have now been identified. However, joint F-test results will not reveal whether changes in the value of a given variable have positive or negative effects on other variables in the system or the length of time it take for these effects to materialise. Therefore the Granger causality may not tell us the complete story about the interactions between the variables of a system. The impulse response functions can be used to produce the time path of the dependent variables in the VAR model, as well as shocks from all the explanatory variables. Impulse responses measure the time profile of the effect of a shock, or impulse on the expected future values of a variable. If the system of equations is stable then any shock should decline to zero. An unstable system would produce an explosive time path. Therefore, if there is a reaction in one variable to an impulse in another variable, we may say the latter has caused the former (Lutkepohl 2007).

Impulse responses trace out the responsiveness of the dependent variables in the VAR model to shocks to each of the variables (Brooks 2002). These shocks can be exogenous shocks or innovations in one of the variables. In other words, a shock to y_{48} not only directly affects y_{48} but also gets transmitted to all of the other endogenous variables through the dynamic structure of the VAR. For example, a change in the innovations $u_{1,t}$ will change the current value of y_{48}. The shock will also change all future values of endogenous variables, since lagged y_{48} appears in all other equations for other sites. It traces out the responses of each site to the shocks or forecast errors in the disturbance terms of site48.

The process of formula derivation for the impulse response function has been summarized in several academic publications. For example, Brooks'(2002) and Lutkepohl's(2007) described the formulas for impulse response function and used the impulse response function to analyse macroeconomic issues. I have used STATA10 to run the impulse response functions on my portfolio. There are many combinations of the impulse response relationships for each pair of sites.

The response is often portrayed graphically with time horizon on the horizontal axis and response on the vertical axis. I have shown an impulse response function for an impulse from the wind speed at site48 on the wind speed at the ten sites of the portfolio in the VAR (Figure 4.15). This graph shows the impulse response functions of the VAR system over time after a one-time, one unit shock on the error terms at site 48. It is clear from Figure 4.15 that the site where the error term originates from gives the biggest response, which in this case is site48. The responses at other sites depend on the values of the coefficient of the estimated VAR model. The responses at site212, 1006, and 10581 are bigger than the others and these results are in accordance with the Granger causality. The responses will be greater when sites are closer to each other. Although the response at site48 is strong, as time elapses it declines to zero.

Figure 4.15. Impulse response function from a VAR of wind speed at different sites as responses to a unit impulse in the wind speed at site48.



It is convenient to use STATA to get impulse response functions for each pair of sites. It allows us to determine the interaction of wind speed between wind farms. It also helps us to find out the degree of intensity and the length of the effect that a shock of wind speed at one site would have on other sites.

4.5.4 VAR with exogenous variables

The values of exogenous variables are independent from the values of the other variables in the system. A VAR process can be affected by other observable variables that are determined outside the system of interest. Exogenous variables can be stochastic or non-stochastic. The VAR(1) with exogenous variables can be defined as:

$$y_t = \alpha_1 y_{t-1} + \beta x_t + u_t$$

We use a vector of exogenous variables x_t to represent hourly and monthly dummy variables. The wind speed time series is subject to seasonality. The VAR(1,q) model may capture this effect and measure it's intensity.

Table 4.21 shows the exogenous parameters that are estimated for the VAR(1,23) model. There are 23 exogenous variables in the vector to present the hourly dummy variables. At most sites the hourly effects are significant at peak hours during the day. This indicates that those locations experience greater wind speed during the peak hours of around 8am to 4pm.

Table 4.21. Coefficients and test statistics for hourly dummy variables

	site48		**site212**		**site326**		**site1006**		**site1190**	
	coef.	z	coef.	z	coef.	z	coef.	z	coef.	z
hr2	0.32	1.39	0.04	0.17	0.14	0.82	0.27	1.20	0.32	1.31
hr3	0.23	1.03	-0.11	-0.57	-0.15	-0.90	0.15	0.69	0.28	1.22
hr4	0.15	0.69	0.02	0.12	-0.02	-0.12	0.30	1.38	0.12	0.51
hr5	0.31	1.40	0.17	0.85	-0.09	-0.55	0.19	0.88	0.20	0.88
hr6	0.30	1.36	-0.04	-0.18	-0.08	-0.48	0.14	0.66	0.26	1.12
hr7	0.46	2.09	0.28	1.39	0.14	0.85	0.47	2.19	0.16	0.68
hr8	0.54	2.45	0.10	0.50	0.21	1.31	0.26	1.21	0.14	0.62
hr9	1.03	4.70	0.40	2.05	0.19	1.20	0.60	2.84	0.86	3.72
hr10	1.13	5.18	0.69	3.49	0.33	2.04	0.68	3.23	0.68	2.94
hr11	1.18	5.40	0.86	4.37	0.55	3.37	0.65	3.04	0.89	3.84
hr12	1.24	5.62	0.65	3.28	0.27	1.65	0.48	2.27	0.72	3.11
hr13	1.30	5.93	0.64	3.25	0.34	2.11	0.54	2.54	0.37	1.59
hr14	0.95	4.32	0.52	2.65	0.10	0.62	0.25	1.18	0.13	0.56
hr15	0.84	3.81	0.41	2.05	-0.15	-0.91	0.47	2.20	-0.03	-0.12
hr16	0.59	2.69	-0.08	-0.43	-0.24	-1.45	0.17	0.80	0.08	0.33
hr17	0.37	1.69	0.02	0.10	-0.51	-3.13	-0.02	-0.07	-0.37	-1.57
hr18	-0.07	-0.31	-0.30	-1.51	-0.29	-1.79	-0.20	-0.95	-0.53	-2.30

hr19	0.11	0.51	-0.28	-1.44	-0.67	-4.12	-0.57	-2.67	-0.53	-2.27
hr20	0.32	1.44	-0.30	-1.52	-0.19	-1.17	-0.43	-2.00	-0.39	-1.66
hr21	0.05	0.23	-0.28	-1.44	-0.46	-2.84	-0.51	-2.42	-0.31	-1.35
hr22	0.14	0.62	-0.27	-1.36	-0.23	-1.45	-0.30	-1.40	0.13	0.58
hr23	0.16	0.75	-0.32	-1.61	-0.24	-1.49	0.01	0.04	0.31	1.32
hr24	0.22	1.02	-0.19	-0.98	-0.05	-0.28	0.33	1.57	-0.01	-0.02
	site1346		**site1395**		**site16581**		**site16725**		**site18930**	
	coef.	z	coef.	z	coef.	z	coef.	z	coef.	z
hr2	0.07	0.31	-0.07	-0.38	-0.18	-0.76	-0.21	-1.17	0.10	0.55
hr3	0.00	0.01	-0.23	-1.35	-0.13	-0.57	0.05	0.26	-0.05	-0.28
hr4	-0.13	-0.64	-0.09	-0.51	0.22	0.96	-0.09	-0.54	0.03	0.16
hr5	-0.08	-0.38	-0.08	-0.45	-0.02	-0.09	-0.09	-0.50	-0.05	-0.26
hr6	-0.39	-1.96	0.03	0.15	-0.11	-0.46	0.05	0.32	0.20	1.10
hr7	0.02	0.1	-0.01	-0.06	-0.19	-0.82	0.20	1.15	0.48	2.61
hr8	0.24	1.18	0.14	0.84	0.04	0.19	0.47	2.73	0.47	2.57
hr9	0.58	2.92	0.32	1.91	0.04	0.17	0.59	3.43	1.03	5.73
hr10	0.68	3.42	0.57	3.37	-0.38	-1.67	0.60	3.46	0.71	3.94
hr11	0.52	2.63	0.73	4.33	0.00	-0.01	0.54	3.13	1.17	6.44
hr12	0.68	3.41	0.48	2.81	-0.08	-0.35	0.66	3.82	0.98	5.41
hr13	0.53	2.66	0.28	1.66	-0.36	-1.55	0.28	1.60	0.81	4.45
hr14	0.29	1.44	0.38	2.25	-0.56	-2.41	0.13	0.76	0.46	2.51
hr15	0.52	2.6	0.21	1.25	-0.68	-2.92	0.05	0.27	0.43	2.38
hr16	-0.03	-0.16	-0.09	-0.51	-0.85	-3.67	-0.30	-1.75	-0.05	-0.25
hr17	-0.39	-1.95	-0.35	-2.03	-0.93	-4.01	-0.72	-4.17	-0.16	-0.85
hr18	-0.51	-2.57	-0.52	-3.09	-0.56	-2.45	-0.75	-4.33	-0.31	-1.70
hr19	-0.72	-3.58	-0.49	-2.91	-0.56	-2.45	-0.51	-2.96	-0.32	-1.77
hr20	-0.62	-3.09	-0.56	-3.30	-0.49	-2.13	-0.73	-4.21	-0.40	-2.19
hr21	-0.54	-2.71	-0.47	-2.77	-0.44	-1.92	-0.47	-2.73	-0.07	-0.36
hr22	-0.46	-2.28	-0.42	-2.50	-0.15	-0.66	-0.14	-0.80	0.11	0.59
hr23	-0.07	-0.33	-0.27	-1.61	-0.32	-1.41	-0.07	-0.40	0.19	1.06
hr24	-0.33	-1.63	-0.18	-1.05	-0.02	-0.10	-0.20	-1.17	0.13	0.74

Figure 4.16 plots the hourly parameters for the 10 sites. The sites display a similar daily pattern with the exception of site16581. The reason for this could be that the location of site16581 is near Fraserburgh, which is on North-East coast. All other sites are located in the middle of the country or west coast.

Figure 4.16.Hourly effects in the VAR(1,23) of the portfolio.

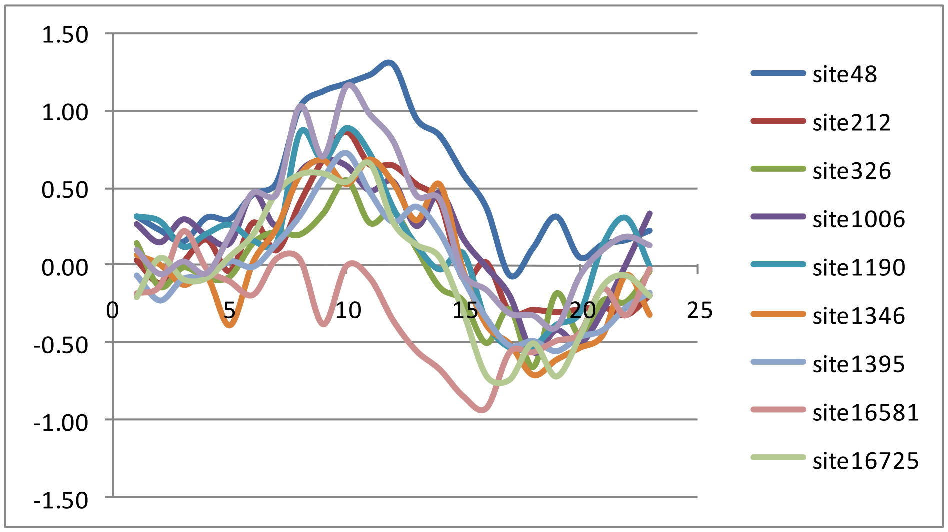
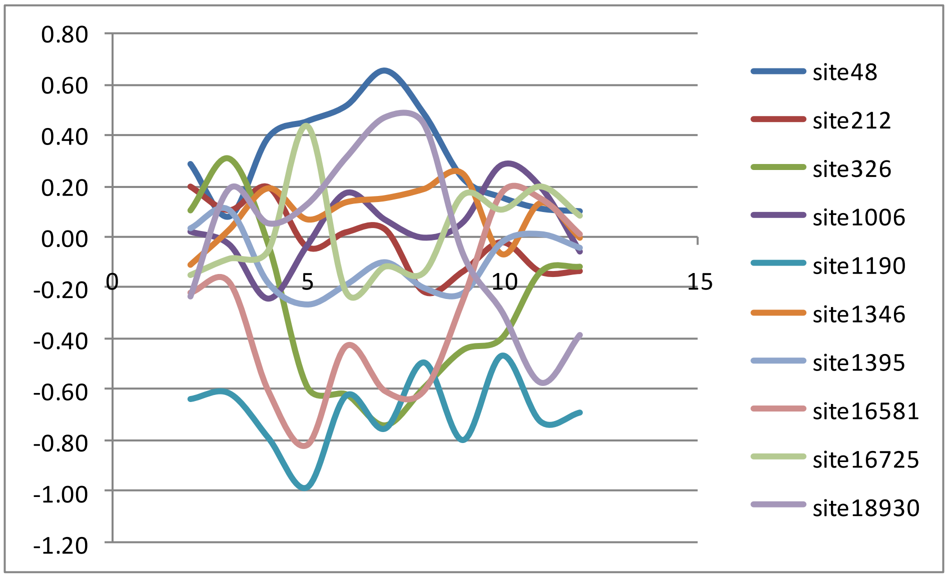


Table 4.22. Coefficients and test statistics for monthly dummy variables

	site48		site212		site326		site1006		site1190	
	coef.	z	coef.	z	coef.	z	coef.	z	coef.	z
mm2	0.29	1.84	0.20	1.40	0.10	0.92	0.02	0.17	-0.64	-3.91
mm3	0.08	0.50	0.10	0.73	0.31	2.67	-0.03	-0.17	-0.62	-3.71
mm4	0.39	2.49	0.19	1.37	-0.03	-0.26	-0.24	-1.57	-0.79	-4.78
mm5	0.46	2.83	-0.04	-0.27	-0.59	-5.02	-0.03	-0.19	-0.99	-5.81
mm6	0.52	3.24	0.02	0.13	-0.62	-5.33	0.18	1.15	-0.63	-3.74
mm7	0.66	4.10	0.03	0.20	-0.74	-6.35	0.07	0.46	-0.76	-4.48
mm8	0.48	3.11	-0.21	-1.52	-0.59	-5.21	0.00	0.01	-0.50	-3.02
mm9	0.23	1.44	-0.13	-0.94	-0.45	-3.83	0.06	0.40	-0.80	-4.77
mm10	0.15	1.00	-0.02	-0.15	-0.40	-3.57	0.29	1.94	-0.47	-2.91
mm11	0.11	0.70	-0.14	-0.98	-0.14	-1.20	0.20	1.32	-0.73	-4.45
mm12	0.10	0.64	-0.13	-0.95	-0.12	-1.03	-0.05	-0.36	-0.69	-4.22
	site1346		site1395		site16581		site16725		site18930	
	coef.	z	coef.	z	coef.	z	coef.	z	coef.	z
mm2	-0.11	-0.79	0.03	0.28	-0.22	-1.36	-0.15	-1.23	-0.23	-1.81
mm3	0.03	0.19	0.10	0.85	-0.18	-1.09	-0.09	-0.69	0.19	1.48
mm4	0.19	1.33	-0.18	-1.49	-0.61	-3.72	-0.05	-0.43	0.06	0.43
mm5	0.07	0.46	-0.26	-2.12	-0.82	-4.90	0.44	3.43	0.13	0.99
mm6	0.14	0.93	-0.19	-1.52	-0.43	-2.60	-0.22	-1.73	0.32	2.39
mm7	0.15	1.04	-0.10	-0.80	-0.61	-3.66	-0.12	-0.92	0.47	3.58
mm8	0.19	1.32	-0.20	-1.66	-0.61	-3.74	-0.14	-1.14	0.45	3.46
mm9	0.25	1.70	-0.22	-1.79	-0.25	-1.50	0.17	1.31	-0.06	-0.49
mm10	-0.07	-0.50	-0.02	-0.18	0.18	1.11	0.11	0.89	-0.29	-2.30
mm11	0.13	0.94	0.01	0.09	0.15	0.94	0.20	1.61	-0.57	-4.44
mm12	-0.01	-0.04	-0.04	-0.36	0.01	0.07	0.08	0.68	-0.38	-2.97

Table 4.22 and Figure 4.17 show the monthly effects which are identified by the VAR(1,11) model. The monthly effects vary among different sites. The wind speed at site48 shows a typical monthly effect. It is windier during the summer months. However, site1190 appears to be less windy than any other site.

Figure 4.17.Monthly effects in the VAR(1,11) of the portfolio.



5. Converting from wind speed to power output

I have modelled the correlations between wind speed data in a wind farm portfolio. However, a wind speed portfolio is different from a wind energy output portfolio. This section introduces a technique, “wind power curve”, which is used to convert wind speed data into energy output for a wind turbine. This is an extension of the wind farm portfolio theory.

It has been suggested that modelling wind turbine power output should be based on modelling wind speed rather than directly on time series forecasting of wind power

(Alexiadis *et al.* 1998). The size of a wind turbine and the wind speed at each site are strongly related to power output. The turbine design and local wind speed of a wind farm is significantly affected by the terrain in which it is located. However, as is made clear above, we assume that the hub heights of turbines are the same. Furthermore, we do not take terrain conditions into account. This is mainly due to a shortage of relevant information rather than attempting to generalise and simplify the model.

Some studies have opted to convert wind speed into wind power. The energy produced by a wind turbine is equal to the power output multiplied by the operating hours. The power output derived from a specific wind power curve depends on the size and type of wind turbine.

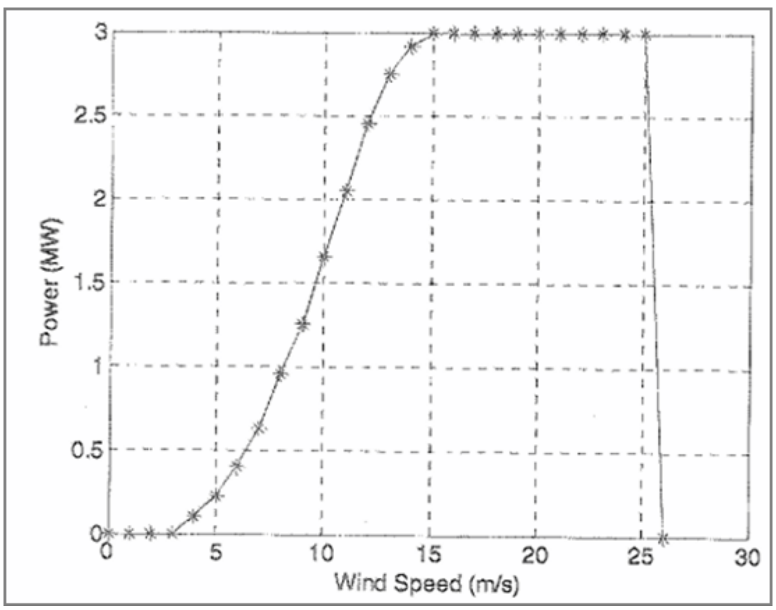
Mclean and Garrad Hassan and Partners (GH) (2008) produced an equivalent power curve including such factors as array losses, topographical losses, electrical losses, availability etc. They also took into account the possible future developments in wind turbine power curves and hub heights. They produced a series of wind power curves for Stall-regulated turbines. Stall-regulated turbines currently make up a significant proportion of the installed wind capacity exclusively in Germany and Denmark (McLean 2008).

Miranda and Dunn (2007) used a power law to initially convert wind speed at 10metres above ground level into wind speed of a hub height of 80metres.

$$\frac{V_1}{V_2} = \left(\frac{H_1}{H_2}\right)^{\alpha}$$

where V_1 and V_2 are the wind speed at height H_1 and H_2 respectively. α is an empirically derived coefficient that reflects atmosphere stability conditions. In their study, the value of α is 1/7. After the wind speed time series is scaled to the established hub height of 80metres, they then converted these into power using a normalised wind power curve. They used the power curve of 3MW Vestas V90 wind turbine. Then they studied the generation adequacy by combining this wind model with the generation data in the GB Seven Year Statement. Figure 4.18 is the normalised wind power curve for 3MW Vestas V90 wind turbine.

Figure 4.18 Vestas V90 (3MW) wind turbine power curve.



Source: Page6, Figure 6 (Miranda and Dunn, 2007).

Sinden and ECI (2005) introduced a power curve for a Nordex N80 wind turbine. The rated capacity of Nordex N80 is 2.5 MW. The rated capacity of a wind turbine represents the maximum power that each individual wind turbine can produce under suitable wind conditions (ECI 2005).

Table 4.23 is the conversion table of wind speed to power output for a Nordex N80 (2.5MW) wind turbine. At between 14ms^{-1} and 25ms^{-1} the power output of this wind turbine has reached a maximum, and essentially remains constant irrespective of changes in wind speed (ECI 2005).

If wind speed data at two wind farms from different locations are negatively correlated, it is not necessarily the case that portfolio risk of energy output in these two wind farms is low. This is because the wind speed at these two wind farms may not be in the range of between 14 ms^{-1} and 25 ms^{-1}. If this happens, wind energy output from these two wind farms may be zero. As a result the security of energy supply of this portfolio of wind farms is low. In summary, wind speed and correlations between wind speeds of the portfolio are both essential for assessing the portfolio risk of wind energy output.

Table 4.23 Conversion of wind speed to power output for a 2.5MW wind turbine.

Wind speed at hub height			Power output
ms^{-1}	mph	km/hr	kW
< 4	< 9	< 14	0
4	9	14	15
5	11	18	105
6	14	22	255
7	16	25	440
8	18	29	675
9	20	32	985
10	23	36	1,330
11	25	40	1,690
12	27	43	2,020
13	29	47	2,315
14	32	50	2,500
15	34	54	2,500
16	36	58	2,500
17	38	61	2,500
18	41	65	2,500
19	43	68	2,500
20	45	72	2,500
21	47	76	2,500
22	50	79	2,500
23	52	83	2,500
24	54	86	2,500
25	56	90	2,500
> 25	> 56	> 90	0

Source: "Wind power and the UK wind resource" (ECI 2005).

6. Conclusion

In this study, the British renewable energy policies and climate change policies have been reviewed. The majority of key issues regarding the renewable energy industry and electricity industry have been discussed. It is important to understand the background and current situation of green electricity. Wind farms play an increasingly important role in providing a climate-friendly source of energy to enable the government to meet its relevant environmental targets.

The government has recently announced a new Renewable Energy Strategy (RES) (2009). It lays out the government's 2020 targets for renewable and low-carbon energy. It sets a goal of generating 30 percent of the UK's electricity from renewable sources and a further 10 percent from low carbon sources such as nuclear and clean coal plants. These new targets will accelerate the rollout of renewable and low-carbon technologies as part of its wide-ranging Low Carbon Transition Plan[28]. This provides a new opportunity for wind electricity in the current economic recession. The UK Climate Change Secretary Ed Miliband has stated that there will be around 10,000 wind turbines onshore and offshore around UK to meet the renewable energy target[29].

The reliability of wind electricity supply and security of the electricity transmission system are more essential under a large wind energy penetration scenario, intermittency of wind impacts on the output of wind farms and the running of an electricity system. Therefore, the area of interest is modelling the output of wind farms.

In this study, I have used econometric methods to model the wind speeds of a set of wind farms. I have found that correlations between wind speeds for a set of wind farms provides a method of assessing the portfolio risk of wind farm output. The modelling results from different models are all based on the British wind speed data from onshore wind farms and wind speed observation sites. These experiments have not been conducted before.

There are several other methods, such as ANN (Artificial Neural network). However, it is beyond the scope of this study. We find VAR(1) models provide a good estimate of

[28] http://www.reuters.com/article/gwmCarbonEmissions/idUS276585079820090716
[29] http://www.telegraph.co.uk/comment/columnists/christopherbooker/5858989/How-can-wind-turbines-generate-so-much-lunacy.html

correlations between the wind speed time series for a portfolio of a number of wind farms simultaneously. Table 4.24 summarises the advantages and disadvantages of different models based on the results form previous sections.

At present the number of offshore wind farms in Britain is quite small, but the offshore wind farms will play an increasing important role. These models can also be used to analyse the performances of the offshore wind farms.

Table 4.24. Summary of wind speed forecasting models.

Model	Advantages	Disadvantages
Weibull-Rayleigh distribution	1. Relate to type or manufacturing of wind turbines. 2. Direct viewing of patterns of wind speed distribution.	1. Cannot be used to estimate future wind speed. It describes the historical wind speed distribution. 2. For individual wind turbine. 3. Considering the current wind speed data is independent to previous wind speed data.
ARIMA	1. Including the correlation between current wind speed data and previous wind speed data. 2. Can estimate the future wind speed data based on historical wind speed data only. 3. Flexible model selection and derivative models.	1. Requiring input data is stationary. 2. For individual wind turbine or wind farm. 3. Do not consider the correlation between wind turbines. 4. Linear model and do not include the volatility.
ARCH-GARCH	1. Measuring the volatility of wind speed at each site. 2. Combination with ARMA model gives a good estimation of wind speed time series.	1. For individual wind turbine or wind farm. 2. Do not consider the correlation between wind turbines.
VAR	1. A multiple-time series generalisation of AR models.	1. Difficulties of identifying the restrictions of the model.

	2. Simultaneously estimates the interrelationship between more than one endogenous variable. 3. Very flexible of model selection. 4. Impulse response function to produce the time path of the dependent variables in the VAR, to shocks from all the explanatory variables.	2. Over parameterisation.

In conclusion, this study implies that if interconnected grids of wind power are used on a large scale, it will be important to model the correlation of wind energy output for a set of wind farms in order to assess the portfolio risk. This should help wind farm owners to hedge the electricity price risks and secure the energy supply. It is also vital for the system operator to balance the system and operate the balancing mechanism under a large wind energy penetration scenario. The VAR(1) model is superior to other statistic models for modelling correlations between wind speeds for a wind farm portfolio.

This chapter discusses what kind of econometric model we should choose to measure the variation and correlation of wind speed. However, it has further implications on the decision-making process of electricity companies and investors who are risk averse. The benefits of lower output risks come from investment in wind farms that are negatively correlated in this research. The power company should choose a location where have better wind resource than other sites to build wind farms. The ARMA(1,1) and ARMA(1 24,1) model will help them to find out the variation in wind speeds and wind speed distribution at a particular site for a certain time period. Moreover, if a power company decides to build wind power only portfolio, it needs to manage the risks of this portfolio which causes by the intermittency of wind speed. The VAR(1) model can measure the correlation of wind speeds in this portfolio. Thus, companies should invest in wind farms of which wind energy outputs are negatively correlated.

Chapter 5 Conclusion

In Great Britain, the wholesale electricity market comprises bilateral trades, spot and futures markets and the balancing mechanism. Each of these provides important functions for market participants.

From the supplier's perspective, the primary function of energy markets is to manage the risks of variance (surprises) in future prices. Electricity suppliers buy electricity at the wholesale market and sell to the consumers at retail prices. The short run price elasticity of residential demand for electricity is relatively small: consumers do not reduce their electricity consumption when electricity price increases in the short run. This is partly because there are no obvious substitutes for electricity in making available some services e.g. broadband, television and refrigeration and, where alternatives are available, significant investment is required before substitution is possible e.g. heating. Therefore, the short run demand for electricity can be predicted by considering weather forecasts, historical demand trends, and special TV events such as popular football matches. Suppliers usually have a fixed tariff price for consumers, but the volume of consumption varies on a daily, weekly and seasonal basis. Producers must provide the amount of power they have agreed to the National Grid or face imbalance charges. Consequently, they may need to buy electricity in the spot market in order to adjust their position. This also means they are exposed to the risk of price volatility. The electricity suppliers may occasionally pay more for purchasing electricity from the wholesale market than the price they charged to their consumers. There have been instances when extremely high prices in the balancing market and spot market during the peak times have been caused by unexpected power outage or increases in demand. One way of hedging the risk of price volatility is to enter into the forward/futures market. If suppliers expect the wholesale electricity price to rise in the future, for example in 3 months, they will buy futures/forward contracts at a lower price paid now but the electricity will be delivered in 3 months. An alternative method is to forecast the spot prices in order to take advantage of trading.

The generators also face risks from future electricity and fuel prices, and carbon prices. The cost of generation is comprised of fuel costs (including transportation), emission costs, cost of shut down and switch on, and the efficiency of power stations. The generators need to manage the risks associated with emissions and also with selling electricity and buying fuel ahead of delivery. Therefore, generators also use energy markets to enter different types of contract to reduce potential price risks. A high electricity selling price for generators is one of the primary incentives for new investments in infrastructures and new technology.

This highlights the importance of market participants forecasting electricity prices. In this thesis both stochastic and fundamental models for electricity pricing have been investigated. I have examined the unique characteristics of spot electricity prices. These prices experience seasonality, mean reversion, jumps and volatility in Great Britain. The development of the stack model is one of the main contributions of this PhD thesis. The stack model is a fundamental model used to simulate wholesale electricity prices in the United Kingdom. The objective of the stack model is to identify the marginal cost of electricity generation. The model consists of five components. These components are demand forecast, station capacity availability forecast, fuel cost, wind energy forecast, and status of interconnectors. This basic version of the stack model assumes that transmission constraints and variation of capacity of interconnectors have no influence on the wholesale electricity price.

The stack model uses demand and supply to determine the wholesale electricity price based on the marginal cost pricing rule. My experiments show that the stack model provides a reasonable simulation of short run marginal cost curve and supply curve for the British electricity industry.

A key principal of the stack model is that renewable power plants and nuclear plants stack into the model first because they have "zero" marginal costs. The energy output of wind farms varies due to the intermittency of wind. Therefore, the variation of wind energy output should impact on the wholesale price from the stack model. In the large wind energy penetration scenario the capacity of wind energy is required to be 13 GW from onshore wind and 18 GW from offshore wind by the UK Renewable Advisory Board (RAB)[30]. Under ideal weather conditions, wind farms can generate the bulk amount of electricity, thus the generation stack will be made up of renewables, nuclear, and gas or coal (the cheapest option) power plants. In contrast, wind energy outputs are reduced dramatically due to quiet weather, meaning the generation stack will be made up of nuclear, gas, coal, and oil power plants. The wholesale price will be equal to the marginal cost of oil fired plants.

The wind energy is treaded as a single participant in the basic version of the stack model. The available capacities of wind farms come into the stack model firstly due to the "zero marginal cost of generation". However, the intermittency of wind energy output is not

[30] http://www.docstoc.com/docs/22042135/EU-wind-energy-industrial-capacity-to-meet-2020-targets

reflected in the stack model because this requires load factor information for each of the wind farms. The average load factor of 40% for UK wind farms is an input in the stack model in both low and high penetration scenarios. However, the intermittency of renewable energy has impact on the load factor of both renewable power plants and conventional power plants. In order to study the intermittency of wind energy output, we build a portfolio of wind farms to examine the correlation and variation of wind speed in each site. This has further implications on the extension of the stack model. It is possible to measure the impacts of intermittency of wind energy output on the wholesale electricity prices and new investment on conventional power generation capacities.

As a result wind energy forecasting should be taken into account. A further contribution of this PhD thesis is to model the correlations of wind energy in Great Britain. I have attempted to determine to what extent wind energy outputs are correlated across the country or if they are effectively independent. In order to examine this issue I have applied modern portfolio theory. I have assumed that electricity companies have a portfolio of wind farms composed of diverse wind farms in different locations. The correlations between wind speeds are used to measure the portfolio risk.

I have examined the characteristics of wind speed in Great Britain using several different statistical models. The Weibull distribution, ARMA, and GARCH models are used to model the wind speed at single location. The Weibull distribution is independent of the sequence of observations. If the order of observations changes there will be no effects on the estimated parameters. It is not currently possible to have an autocorrelated wind speed pattern modelled by the Weibull distribution. However, the pattern of wind speed has impacts on the wholesale prices of the stack model. Thus, univariate time series models are constructed using only information on the past wind speeds and the error term. I have found that the ARMA(1,1) and ARMA(1& 24,1) models provide a better fit for wind speed than other ARMA family models. The main disadvantage of using an ARMA model is that its error term is normally distributed with a zero mean, constant variance, and zero autocorrelation. The GARCH model is constructed in order to reflect autocorrelation in the volatility of wind speed. It allows the conditional variances of the error term to depend on past own lags. GARCH type models also allow for a period of high or low volatility in wind speed. However, GARCH models are also used for each individual location. The comparison between these different models has not been previously preformed, and is therefore a further contribution of this PhD thesis.

In addition, I have modelled wind farms jointly with various vector autoregression (VAR) models. This is the only method that allows for inter-dependence between the outputs of different wind farms. This gives another method for energy companies or investors to assess the portfolio risk. It also helps us to model wind energy output when using the stack model.

Further research

I have listed several suggested points for continuing to improve the performance of the stack model. In addition, there are some areas of further research I would like to undertake to broaden the understanding of the British wholesale electricity market.

The basic version of the stack model provides the outline for a price forecasting model of wholesale electricity. There are components of the stack model that can be more specific.

1. Coal and gas fired plants could be grouped into high efficiency plants and low efficiency plants. CCGT has a higher level of thermal efficiency than traditional gas fired plants. The efficiency of clean coal power plants will be greater than that of old coal fired plants. And they also have lower carbon emission costs.
2. The basic version of the stack model uses the average load factor to measure the availability of generation capacity. Industry users can calculate the generation capacity for the system in real time. It is easier for industry users to acquire information on planned and unplanned outages of generation capacity and power plants status.
3. The stack model could be made more flexible to combine the age and efficiency of the plants. The lower efficiency of aging power plants will increase the marginal cost of generation.

I have used historical wind speed data to measure the correlation of wind energy. I would like to undertake further research on the pattern of wind energy output. This will require a database of real wind energy output for a set of wind farms. The amount information available on this area is currently limited.

I would also like to develop a pricing model for electricity forward contracts. There are a series pricing models for financial assets. There is value in developing a pricing model if wholesale electricity markets can function as commodity markets or financial markets. Although current trading prices are confidential in the United Kingdom, there is a growing trend of interest in this area.

Appendix. Power stations in the Stack model (updated on May 2009).

Company	Station	Type	Capacity MW	build year	region
EPR Eye Ltd	Eye, Suffolk	AWDF	13	1992	East
E.On UK	Steven's Croft	biomass	44	2007	Scotland
GDF Suez teesside Limited	Teesside Power Station	CCGT	1875	1992	North East
RWE Npower Plc	Didcot B	CCGT	1390	1998	South East
E.On UK	Connahs Quay	CCGT	1380	1996	Wales
Centrica	South Humber Bank	CCGT	1285	1996	Yorkshire and the Humber
International Power / Mitsui	Saltend	CCGT	1200	2000	Yorkshire and the Humber
Barking Power	Barking	CCGT	1000	1994	London
E.On UK	Killingholme	CCGT	900	1993	Yorkshire and
Spalding Energy Company Ltd	Spalding	CCGT	860	2004	East Midlands
Seabank Power Limited	Seabank 1	CCGT	812	1998	South West
EDF Energy	Sutton Bridge	CCGT	803	1999	East
Scottish Power	Damhead Creek	CCGT	800	2000	South East
Rocksavage Power Co. Ltd	Rocksavage	CCGT	748	1998	North West
Coryton Energy Company Ltd	Coryton	CCGT	732	2001	East
Scottish Power	Rye House	CCGT	715	1993	East
Scottish & Southern Energy plc	Medway	CCGT	688	1995	South East
Centrica	Killingholme	CCGT	665	1994	Yorkshire and the Humber
RWE Npower Plc	Little Barford	CCGT	665	1995	East
Premier Power Ltd	Ballylumford C	CCGT	616	2003	Northern Ireland
International Power / Mitsui	Deeside	CCGT	500	1994	Wales
RWE Npower Plc	Great Yarmouth	CCGT	420	2001	East
Seabank Power Limited	Seabank 2	CCGT	410	2000	South West
Coolkeeragh ESB Ltd	Coolkeeragh	CCGT	408	2005	Northern Ireland
Centrica	Peterborough	CCGT	405	1993	East
Corby Power Ltd	Corby	CCGT	401	1993	East Midlands
E.On UK	Cottam Development Centre	CCGT	400	1999	East Midlands
Scottish Power	Shoreham	CCGT	400	2000	South East
E.On UK	Enfield	CCGT	392	1999	London
Centrica	Kings Lynn	CCGT	340	1996	East

Centrica	Glanford Brigg	CCGT	260	1993	Yorkshire and
Centrica	Barry	CCGT	230	1998	Wales
Centrica	Roosecote	CCGT	229	1991	North West
E.On UK	Sandbach	CCGT	56	1999	North West
E.On UK	Castleford	CCGT	56	2002	Yorkshire and the Humber
E.On UK	Thornhill	CCGT	50	1998	Yorkshire and the Humber
Drax Power Ltd	Drax	coal	3870	1974	Yorkshire and the Humber
Scottish Power	Longannet	coal	2304	1970	Scotland
EDF Energy	West Burton	coal	2012	1967	East Midlands
EDF Energy	Cottam	coal	2008	1969	East Midlands
E.On UK	Ratcliffe	coal	2000	1968	East Midlands
British Energy	Eggborough	coal	1960	1967	Yorkshire and the Humber
RWE Npower Plc	Aberthaw B	coal	1586	1971	Wales
Scottish Power	Cockenzie	coal	1152	1967	Scotland
International Power / Mitsui	Rugeley	coal	1006	1972	West Midlands
E.On UK	Ironbridge	coal	970	1970	West Midlands
RWE Npower Plc	Tilbury B	coal	1063	1968	East
Uskmouth Power Company Ltd	Uskmouth	coal/bio mass	363	2000	Wales
Scottish & Southern Energy plc	Fiddler's Ferry	coal/bio mass	1980	1971	North West
Scottish & Southern Energy plc	Ferrybridge C	coal/bio mass	1960	1966	Yorkshire and the Humber
RWE Npower Plc	Didcot A	coal/gas	1958	1972	South East
E.On UK	Kingsnorth	coal/oil	1940	1970	South East
AES	Kilroot	coal/oil	600	1981	Northern Ireland
Scottish & Southern Energy plc	Lerwick	diesel	67.2	1953	Scotland
Scottish & Southern Energy plc	Stornoway	diesel	26	1950	Scotland
Scottish & Southern Energy plc	Kirkwall	diesel	16.2	1953	Scotland
Scottish & Southern Energy plc	Loch Carnan, South Uist	diesel	10	1971	Scotland
Scottish & Southern Energy plc	Bowmore	diesel	6	1946	Scotland
Scottish & Southern Energy plc	Arnish	diesel	3	2001	Scotland
Scottish & Southern Energy plc	Tiree	diesel	2.5	1945	Scotland
Scottish & Southern Energy plc	Barra	diesel	2.1	1990	Scotland
Scottish & Southern	Fife Power Station	gas	123	2000	Scotland

Energy plc					
RGS Energy Ltd	Knapton	gas	40	1994	Yorkshire and the Humber
Scottish Power	Pilkington - Greengate	gas	10	1998	North West
British Energy	Sevington District Energy	gas	10	2000	South East
British Energy	Bridgewater District Energy	gas	10	2000	South West
Scottish & Southern Energy plc	Chippenham	gas	10	2002	South West
British Energy	Aberdare District Energy	gas	10	2002	Wales
British Energy	Solutia District Energy	gas	10	2000	Wales
Scottish Power	Ravenhead	gas	9	1999	North West
Immingham CHP LLP	Immingham CHP	gas CHP	1240	2004	Yorkshire and the Humber
Derwent Cogeneration	Derwent	gas CHP	214	1994	East Midlands
Magnox North Ltd	Fellside CHP	gas CHP	180	1995	North West
Gaz de France	Shotton	gas CHP	180	2001	Wales
EDF Energy	London Heat & Power Company (Imperial College)	gas CHP	9	2000	London
EDF Energy	Barkantine Heat & Power Company	Gas CHP	1.4	2000	London
RWE Npower Plc	Cowes	gas oil	140	1982	South East
E.On UK	Taylor's Lane GT	gas oil	132	1979	London
RWE Npower Plc	Littlebrook GT	gas oil	105	1982	South East
RWE Npower Plc	Didcot GT	gas oil	100	1972	South East
Drax Power Ltd	Drax GT	gas oil	75	1971	Yorkshire and the Humber
RWE Npower Plc	Tilbury GT	gas oil	68	1968	East
RWE Npower Plc	Fawley GT	gas oil	68	1969	South East
E.On UK	Grain GT	gas oil	55	1978	South East
RWE Npower Plc	Aberthaw GT	gas oil	51	1971	Wales
International Power / Mitsui	Rugeley GT	gas oil	50	1972	West Midlands
EDF Energy	West Burton GT	gas oil	40	1967	East Midlands
E.On UK	Ratcliffe GT	gas oil	34	1966	East Midlands
Scottish & Southern Energy plc	Fiddler’s Ferry GT	gas oil	34	1969	North West
E.On UK	Kingsnorth GT	gas oil	34	1967	South East
Scottish & Southern Energy plc	Ferrybridge GT	gas oil	34	1966	Yorkshire and the Humber
RWE Npower Plc	Little Barford GT	gas oil	17	2006	East
Western Power Generation	St Marys	gas oil	6	1958	South West
Western Power	Lynton	gas oil	2	1961	South West

Generation					
International Power / Mitsui	Indian Queens	gas oil/kerosene	140	1996	South West
Baglan Generation Ltd	Baglan Bay	gas turbine	575	2002	Wales
Citigen (London) UK Ltd	Charterhouse St, London	gas/gas oil CHP	16	1995	London
EDF Energy	Thames Valley Power	Gas/Gas oil CHP	15	1995	London
Scottish & Southern Energy plc	Peterhead	gas/oil	1540	1980	Scotland
Scottish & Southern Energy plc	Keadby	gas/oil	749	1994	Yorkshire and the Humber
Premier Power Ltd	Ballylumford B	gas/oil	540	1968	Northern Ireland
Scottish & Southern Energy plc	Burghfield	gas/oil	47	1998	South East
Scottish & Southern Energy plc	Chickerell	gas/oil	45	1998	South West
Scottish & Southern Energy plc	Sloy	hydro	153	1950	Scotland
Scottish & Southern Energy plc	Glendoe	hydro	100	2008	Scotland
Scottish & Southern Energy plc	Errochty	hydro	75	1955	Scotland
Scottish & Southern Energy plc	Fasnakyle	hydro	69	1951	Scotland
Scottish & Southern Energy plc	Clunie	hydro	61	1950	Scotland
E.On UK	Rheidol	hydro	49	1961	Wales
Scottish & Southern Energy plc	Lochay	hydro	45	1958	Scotland
Scottish & Southern Energy plc	Rannoch	hydro	45	1930	Scotland
Scottish & Southern Energy plc	Clachan	hydro	40	1955	Scotland
Scottish & Southern Energy plc	Glenmoriston	hydro	39	1957	Scotland
Scottish & Southern Energy plc	Deanie	hydro	38	1963	Scotland
Scottish & Southern Energy plc	Luichart	hydro	34	1954	Scotland
Scottish & Southern Energy plc	Tummel	hydro	34	1933	Scotland
Scottish Power	Tongland	hydro	33	1935	Scotland
Magnox North Ltd	Maentwrog	hydro	28	1928	Wales
Scottish & Southern Energy plc	Inverawe	hydro	25	1963	Scotland
Scottish Power	Glenlee	hydro	24	1935	Scotland
Scottish Power	Kendoon	hydro	24	1936	Scotland

Scottish & Southern Energy plc	Aigas	hydro	20	1962	Scotland
Scottish & Southern Energy plc	Kilmorack	hydro	20	1962	Scotland
Scottish & Southern Energy plc	Ceannacroc	hydro	20	1956	Scotland
Scottish & Southern Energy plc	Invergarry	hydro	20	1956	Scotland
Scottish & Southern Energy plc	Grudie Bridge	hydro	19	1950	Scotland
Scottish & Southern Energy plc	Mossford	hydro	19	1957	Scotland
Scottish & Southern Energy plc	Shin	hydro	19	1958	Scotland
Scottish & Southern Energy plc	Orrin	hydro	18	1959	Scotland
Scottish & Southern Energy plc	Quoich	hydro	18	1955	Scotland
RWE Npower (Npower Renewables Ltd)	Dolgarrog High Head	hydro	18	2002	Wales
Scottish & Southern Energy plc	Culligran	hydro	17	1962	Scotland
Scottish & Southern Energy plc	Finlarig	hydro	17	1955	Scotland
Scottish & Southern Energy plc	St. Fillans	hydro	17	1957	Scotland
Scottish & Southern Energy plc	Livishie	hydro	17	1962	Scotland
Scottish & Southern Energy plc	Torr Achilty	hydro	15	1954	Scotland
Scottish & Southern Energy plc	Nant	hydro	15	1963	Scotland
Scottish & Southern Energy plc	Pitlochry	hydro	15	1950	Scotland
RWE Npower (Npower Renewables Ltd)	Dolgarrog Low Head	hydro	15	2002	Wales
Scottish Power	Earlstoun	hydro	14	1936	Scotland
Scottish Power	Carsfad	hydro	12	1936	Scotland
Scottish & Southern Energy plc	Cashlie	hydro	11	1959	Scotland
Scottish Power	Bonnington	hydro	11	1927	Scotland
Scottish & Southern Energy plc	Cassley	hydro	10	1959	Scotland
RWE Npower (Npower Renewables Ltd)	Cwm Dyli	hydro	10	2002	Wales
Scottish & Southern Energy plc	Fasnakyle Compensation Set	hydro	8	2006	Scotland
Scottish & Southern Energy plc	Striven	hydro	8	1951	Scotland

Scottish & Southern Energy plc	Gaur	hydro	8	1953	Scotland
Scottish & Southern Energy plc	Allt-na-Lairige	hydro	6	1956	Scotland
Scottish & Southern Energy plc	Loch Gair	hydro	6	1961	Scotland
Scottish Power	Stonebyres	hydro	6	1927	Scotland
RWE Npower (Npower Renewables Ltd)	Kielder	hydro	6	2006	Yorkshire and the Humber
Scottish & Southern Energy plc	Foyers Falls	hydro	5	1968	Scotland
Scottish & Southern Energy plc	Sron Mor	hydro	5	1957	Scotland
Scottish & Southern Energy plc	Lubreoch	hydro	4	1958	Scotland
Scottish & Southern Energy plc	Dalchonzie	hydro	4	1958	Scotland
Scottish & Southern Energy plc	Kingairloch	hydro	4	2005	Scotland
Scottish & Southern Energy plc	Lairg	hydro	4	1959	Scotland
Scottish & Southern Energy plc	Lednock	hydro	3	1961	Scotland
Scottish & Southern Energy plc	Achanalt	hydro	3	1956	Scotland
Scottish & Southern Energy plc	Cuaich	hydro	3	1959	Scotland
Scottish & Southern Energy plc	Cuileig	hydro	3	2002	Scotland
Scottish & Southern Energy plc	Mullardoch Tunnel	hydro	2.4	1955	Scotland
RWE Npower (Npower Renewables Ltd)	Braevallich	hydro	2	2005	Scotland
RWE Npower (Npower Renewables Ltd)	Garrogie	hydro	2	2005	Scotland
Scottish & Southern Energy plc	Culligran Compensation Set	hydro	2	1962	Scotland
Scottish & Southern Energy plc	Lochay Compensation Set	hydro	2	1959	Scotland
Scottish & Southern Energy plc	Mucomir	hydro	2	1962	Scotland
Scottish & Southern Energy plc	Kilmelfort	hydro	2	1956	Scotland
Scottish & Southern Energy plc	Lussa	hydro	2	1952	Scotland
Scottish & Southern Energy plc	Loch Ericht	hydro	2	1962	Scotland
Scottish & Southern Energy plc	Storr Lochs	hydro	2	1952	Scotland

Scottish Power	Drumjohn	hydro	2	1985	Scotland
RWE Npower (Npower Renewables Ltd)	Inverbain	hydro	1	2006	Scotland
Scottish & Southern Energy plc	Loch Dubh	hydro	1	1954	Scotland
Scottish & Southern Energy plc	Chliostair	hydro	1	1960	Scotland
Scottish & Southern Energy plc	Kerry Falls	hydro	1	1951	Scotland
Scottish & Southern Energy plc	Loch Dubh	hydro	1	1954	Scotland
Scottish & Southern Energy plc	Nostie Bridge	hydro	1	1950	Scotland
Scottish & Southern Energy plc	Foyers	hydro/pumped storage	300	1974	Scotland
Western Power Generation	Roseland	kerosene	5	1963	South West
Western Power Generation	Princetown	kerosene	3	1959	South West
Scottish & Southern Energy plc	Thatcham	light oil	10	1994	South East
Scottish & Southern Energy plc	Five Oaks	light oil	8.9	1995	South East
EPR Glanford Ltd	Glanford	meat & bone	13	1993	East
Scottish & Southern Energy plc	Wheldale	mines gas	8	2002	Yorkshire and the Humber
British Energy	Heysham 2	nuclear	1240	1988	North West
British Energy	Torness	nuclear	1205	1988	Scotland
British Energy	Hartlepool	nuclear	1190	1984	North East
British Energy	Sizewell B	nuclear	1188	1995	East
British Energy	Heysham1	nuclear	1160	1984	North West
British Energy	Dungeness B	nuclear	1040	1983	South East
Magnox North Ltd	Wylfa	nuclear	980	1971	Wales
British Energy	Hunterston B	nuclear	860	1976	Scotland
British Energy	Hinkley Point B	nuclear	840	1976	South West
Magnox North Ltd	Oldbury	nuclear	434	1967	South West
RWE Npower Plc	Littlebrook D	oil	1370	1982	South East
E.On UK	Grain	oil	1300	1979	South East
RWE Npower Plc	Fawley	oil	968	1969	South East
EPR Thetford Ltd	Thetford	poultry litter	39	1998	East
EPR Scotland Ltd	Westfield	poultry litter	12	2000	Scotland
International Power / Mitsui	Dinorwig	pumped storage	1728	1983	Wales

Scottish Power	Cruachan	pumped storage	440	1966	Scotland
International Power / Mitsui	Ffestiniog	pumped storage	360	1961	Wales
EPR Ely Limited	Elean	straw/gas	38	2001	East
company	description	type	mwatts	built	region
South East London Combined Heat & Power Ltd	SELCHP ERF	waste	32	1994	London
Scottish Power	Black Law	wind	124	2005	Scotland
Scottish & Southern Energy plc	Hadyard Hill	wind	120	2005	Scotland
Braes of Doune Windfarm	Braes of Doune	wind	72	2006	Scotland
Fred Olsen	Paul's Hill	wind	64.4	2005	Scotland
RWE Npower (Npower Renewables Ltd)	Little Cheyne	wind	59.8	2008	South East
Fred Olsen	Rothes	wind	51	2004	Scotland
Fred Olsen	Crystal Rig Windfarm	wind	50	2003	Scotland
Scottish & Southern Energy plc	Minsca	wind	37	2008	Scotland
Beaufort Wind Ltd	Carno	wind	34	1996	Wales
Scottish & Southern Energy plc	Drumderg	wind	32	2008	Scotland
E.On UK	Bowbeat	wind	31.2	2002	Scotland
Scottish Power	Penryddian & Llidiartywaun	wind	31	1992	Wales
Scottish & Southern Energy plc	Slieve Divena	wind	30	2008	Northern Ireland
Scottish & Southern Energy plc	Dalswinton	wind	30	2008	Scotland
Scottish Power	Beinn an Tuirc	wind	30	2001	Scotland
Scottish Power	Beinn Tharsuinn	wind	30	2007	Scotland
Scottish Power	Cruach Mhor	wind	30	2004	Scotland
RES-Gen Ltd	Black Hill	wind	29	2006	Scotland
Scottish Power	Greenknowes	wind	27	2008	Scotland
EDF Energy Renewables	Bicker Fen	wind	26	2008	East Midlands
RES-Gen Ltd	Altahullion	wind	26	2003	Northern Ireland
Centrica	Glens of Foudland	wind	26	2005	Scotland
RES-Gen Ltd	Gruig	wind	25	2009	Northern Ireland
Fenland Windfarms Ltd	Red Tile	wind	24	2007	East Midlands
Ardrossan Windfarm	Ardrossan	wind	24	2004	Scotland
Scottish Power	Whitelee	wind	23	2007	Scotland
HG Capital	Tyr Mostyn & Foel Goch	wind	21	2005	Wales

Scottish & Southern Energy plc	Tappaghan	wind	20	2005	Northern Ireland
Scottish & Southern Energy plc	Artfield Fell	wind	20	2005	Scotland
Beaufort Wind Ltd	Llyn Alaw	wind	20	1997	Wales
Scottish & Southern Energy plc	Tangy	wind	19	2002	Scotland
E.On UK	Stags Holt	wind	18	2007	East
Scottish Power	Wether Hill	wind	18	2007	Scotland
Scottish Power	Callagheen	wind	17	2006	Northern Ireland
Beaufort Wind Ltd	Novar	wind	17	1997	Scotland
Scottish Power	Dun Law	wind	17	2000	Scotland
Scottish Power	Coldham	wind	16	2006	East
Fenland Windfarms Ltd	Deeping	wind	16	2006	East Midlands
Fenland Windfarms Ltd	Glass Moor	wind	16	2006	East Midlands
RWE Npower (Npower Renewables Ltd)	Knabs Ridge	wind	16	2008	North East
Scottish Power	Hagshaw Hill	wind	16	1995	Scotland
E.On UK	Deucheran Hill	wind	15.75	2001	Scotland
Scottish Power	Barnesmore	wind	15	1997	Northern Ireland
Cemmaes Windfarm Ltd	Cemmaes	wind	15	2002	Wales
EDF Energy Renewables	Walkaway	wind	14	2008	North East
RES-Gen Ltd	Lendrum's Bridge	wind	13	2000	Northern Ireland
Scottish Power	Hare Hill	wind	13	2000	Scotland
Fenland Windfarms Ltd	Red House	wind	12	2006	East Midlands
RES-Gen Ltd	Altahullion2	wind	12	2007	Northern Ireland
Scottish Power	Coal Clough	wind	10	1992	North West
Scottish Power	Wolf Bog	wind	10	2008	Northern Ireland
Beaufort Wind Ltd	Bryn Titli	wind	10	1994	Wales
Beaufort Wind Ltd	Mynydd Gorddu	wind	10	1996	Wales
E.On UK	Out Newton	wind	9.1	2002	Yorkshire and the Humber
Scottish & Southern Energy plc	Bessy Bell	wind	9	2008	Northern Ireland
Scottish & Southern Energy plc	Bin Mountain	wind	9	2008	Northern Ireland
Beaufort Wind Ltd	Taff Ely	wind	9	1993	Wales
Llangwyryfon Windfarm Ltd	Llangwyryfon	wind	9	2003	Wales
Yorkshire Windpower Ltd	Ovenden Moor	wind	9	1993	Yorkshire and

High Hedley Hope Wind Ltd	Langley Park	wind	8	2008	North East
High Hedley Hope Wind Ltd	Broomhill	wind	8	2008	North East
RES-Gen Ltd	Lough Hill	wind	8	2007	Northern Ireland
Beaufort Wind Ltd	Bein Ghlas	wind	8	1999	Scotland
Scottish & Southern Energy plc	Spurness	wind	8	2004	Scotland
E.On UK	High Volts	wind	7.8	2004	North East
Beaufort Wind Ltd	Lambrigg	wind	7	2000	North West
K/S Winscales	Winscales 2	wind	7	2005	North West
Cold Northcott Windfarm Ltd	Cold Northcott	wind	7	1993	South West
E.On UK	Rhyd-y-Groes	wind	7	1992	Wales
Yorkshire Windpower Ltd	Royd Moor	wind	7	1993	Yorkshire and the Humber
Ardrossan Windfarm	Ardrossan Extension	wind	6	2008	Scotland
Scottish Power	Carland Cross	wind	6	1992	South West
Beaufort Wind Ltd	Trysglwyn	wind	6	1996	Wales
RES-Gen Ltd	Dyffryn Brodyn	wind	6	1994	Wales
E.On UK	Oldside	wind	5.4	1996	North West
High Hedley Hope Wind Ltd	High Hedley 2	wind	5.2	2008	North East
High Hedley Hope Wind Ltd	Trimdon Grange	wind	5.2	2008	North East
E.On UK	Hare Hill	wind	5.1	2004	North East
E.On UK	Holmside	wind	5.1	2004	North East
Beaufort Wind Ltd	Kirkby Moor	wind	5	1993	North West
E.On UK	Bessy Bell	wind	5	1995	Northern Ireland
Scottish Power	Corkey	wind	5	1994	Northern Ireland
Scottish Power	Elliots Hill	wind	5	1995	Northern Ireland
Scottish Power	Rigged Hill	wind	5	1994	Northern Ireland
RES-Gen Ltd	Forss2	wind	5	2007	Scotland
RWE Npower (Npower Renewables Ltd)	Burgar Hill	wind	5	2007	Scotland
RES-Gen Ltd	Four Burrows	wind	5	1995	South West
E.On UK	St Breock	wind	4.95	1994	South West
E.On UK	Askam	wind	4.62	1999	North West
E.On UK	Lowca	wind	4.62	2000	North West
RWE Npower (Npower Renewables Ltd)	Hameldon Hill	wind	4.5	2007	Northwest
E.On UK	Siddick	wind	4.2	1996	North West
Great Orton	Great Orton	wind	4	1999	North West

Windfarm Ltd					
RWE Npower (Npower Renewables Ltd)	Bilbster	wind	3.9	2008	Scotland
Scottish & Southern Energy plc	Bu	wind	3	2002	Scotland
RWE Npower (Npower Renewables Ltd)	Hollies	wind	2.6	2008	East
E.On UK	Blood Hill	wind	2.25	1992	East
Beaufort Wind Ltd	Tow Law	wind	2	2001	North East
K/S Winscales	Winscales 1	wind	2	1999	North West
RES-Gen Ltd	Forss	wind	2	2003	Scotland
E.On UK	Rheidol	wind	2	1997	Wales
High Hedley Hope Wind Ltd	High Hedley 1	wind	1.8	2001	North East
Kirkheaton Wind Ltd	Kirkheaton	wind	1.2	2000	North East
Beaufort Wind Ltd	Farr	wind	92	2006	Scotland
Beaufort Wind Ltd	Ffynnon Oer	wind	32	2006	Wales
Beaufort Wind Ltd	Windy Standard	wind	22	1996	Scotland
Beaufort Wind Ltd	Bears Down	wind	10	2001	South West
Beaufort Wind Ltd	Causeymire	wind	48	2004	Scotland
Centrica	Barrow Offshore Windfarm	wind offshore	90	2006	North West
Vattenfall Wind Power	Kentish Flats	wind offshore	90	2005	South East
E.On UK	Scroby Sands	wind offshore	60	2005	East
Beaufort Wind Ltd	North Hoyle	wind offshore	60	2003	Wales
Scottish & Southern Energy plc	Beatrice	wind offshore	10	2007	Scotland
E.On UK	Blyth Offshore	wind offshore	4	2000	North East

Source: Digest of UK energy statistics 5.7

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