Re-energizing Britain

Promoting investment in our energy future

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Executive Summary

- UK energy policy priorities are simple – security of supply, reduced carbon emissions and lower prices. But ensuring security of supply, especially with declining base-load generating capacity from 2014 onwards, is paramount. Expanding the Renewables Obligation (RO) into a Low Carbon Obligation (LCO), including nuclear, would benefit all three aims.

- The Government must focus on the investment programmes of the six integrated energy companies in the UK - EdF, E.On, RWE, Iberdrola, Scottish and Southern Energy (SSE) and Centrica. The UK's energy fate, from 2014 onwards, depends upon this sextet; unless they invest sufficiently in new generation plant, power cuts are not just possible, but probable.

- To deliver new nuclear build in the UK, the Government should be pro-active in securing planning approvals and in facilitating the necessary fund-raising, especially through implementing the LCO proposal. Whilst EdF and the E.On/RWE joint venture have expressed interest in UK new nuclear build, their priorities could change, especially if September's general election in Germany brings about a reversal of the nuclear phase-out policy.

- Despite the recent approval for 4,000 MW of new fossil-fuel capacity, major uncertainty remains regarding new coal-fired plant and Russian gas supplies. For E.On's Kingsnorth project, full Government approval should be granted promptly. And, given the expected dependence upon future Russian gas supplies, diversification of both fuel sources and suppliers is essential.

- The UK's gas storage capacity is about 10% of that of Germany – a very exposed position. It is incumbent upon the Government to give a high priority to delivering gas storage projects; without them, UK energy supplies are greatly at risk. Aside from Centrica's planned investments, very few other gas storage projects will secure both planning approval and financing.

- More generally, the financial crisis – including soaring public debt – is affecting all utilities, which must now pay a higher borrowing premium over base rates. Inevitably, this scenario will adversely impact their investment plans. With its £22.7 billion of net debt, National Grid may need to reassess its UK investment programme: its role in connecting renewables plants to the Grid is crucial.

- Worryingly for the future of UK energy supply, both EdF and E.On are now cutting back their expansion plans. EdF is rumoured to be seeking buyers for some of its UK distribution assets, whilst E.On's net debt has risen to almost £40 billion.

1 Outline of the Report

This report seeks to analyse key aspects of the UK energy sector, which has undergone various shocks in recent years. Looking forward, there is real concern about future base-load generation capacity, especially from 2014 onwards.

Part 2 focuses on the most important energy issues – security of supply, carbon emissions and prices.

Part 3 analyses the development of the UK electricity supply industry, especially the role of gas, which became far more important in the privatised sector from 1990 onwards.

The three main generation sources – coal, gas and nuclear – are reviewed in some detail in Parts 4 to 6. Part 7 addresses the prospects for renewable generation.

In Part 8, comparative generation costs between coal, gas and nuclear are analysed. Inevitably, any irrefutable conclusion about relative generation costs is impossible, given the importance of the initial assumptions. Nevertheless, data from EdF, E.On and RWE have been compared.

Parts 9 and 10 discuss network investment and consumer prices respectively. In Part 11, the impact of the unprecedented financial crisis is reviewed, which is having a major impact on the UK electricity generation sector.

Part 12 discusses other topical industry issues, including fuel poverty, smart meters and calls for the imposition of a Windfall Tax, whilst Part 13 offers some concluding remarks.

Appendix I lists the chronological events that have created the UK electricity supply industry. Whilst most of the latter dates refer to UK events, there are other pivotal developments, such as the construction by Thomas Edison of the world's first power station in New York in 1882 and the Chernobyl disaster in 1986, which have had profound global implications.

Appendix II provides a glossary of the various energy-related acronyms used in this report.

Unlike most academic publications, this report unashamedly focuses far more on the six integrated energy companies in the UK, who will make their own critical investment decisions – which will determine the UK's energy fate – rather than on overall energy policy objectives as laid down by the Government and other involved parties.

2 Introduction

In recent years, the energy issue has moved rapidly up the UK political agenda. Irrespective of the adoption of the low carbon policy, it is widely recognised that any power cuts would be infinitely more damaging than was the case during the early 1970s. Whilst manufacturing industry is now less important, the IT sector, which now embraces most domestic households, is highly dependent upon the non-stop availability of electricity: household goods, such as freezers – and their contents – are equally vulnerable.

Furthermore, much of the public transport network depends upon electrical power being continuously available. Given that background, every politician knows that avoiding lengthy power cuts is absolutely paramount.

As such, within current UK energy policy, there are three abiding issues – security of supply, carbon emissions and prices. This trio combines to drive UK energy policy decisions – these issues are certainly not mutually exclusive since there is considerable interaction between them.

Security of Supply

The security of supply issue is becoming increasingly important. In the new computer age, supply interruptions are far more serious – and costly – than previously. Consequently, every effort needs to be made to minimise risks to the security of supply.

In particular, with National Grid's plant margin close to the long-standing 16%-19%, there will be real concerns about base-load availability from 2014 onwards, especially since some renewable plants are likely to cause dislocation to the National Grid transmission network.

In 2014, some large coal-fired plants are due to be closed down as provided for under the EU's Large Combustion Plant Directive (LCPD). New nuclear build is unlikely to materialise before 2018 at the earliest. Consequently, there is a substantial gap when the security of supply risk becomes far more pertinent.

Indeed, in its 2007 Energy White Paper, the Government concluded that the UK needs 25 GW of new capacity to be installed by 2020. Currently, the UK has 76 GW of generating capacity.

Carbon Emissions

Central to the Government's over-arching environmental agenda is its determination to reduce emissions, especially of carbon dioxide. In particular, power station emissions, despite the installation of Flue Gas Desulphurisation (FGD) equipment at some plants, remain a serious environmental issue.

To minimise carbon emissions, various legislative measures have been taken. They include the establishment of the EU's Emissions Trading Scheme (ETS), the promotion of non fossil-fuel power generation and ongoing efforts to deliver further energy savings.

The future of the EU's ETS remains unclear. Initially, when the ETS started in 2005, carbon emission allocations to the companies were effectively free. But new carbon emissions criteria will apply from 2013, which are expected to include heavy manufacturing, oil, aviation and petrochemicals businesses.

More specifically, the base date used by the Department for Business, Enterprise and Regulatory Reform (BERR) for regulating carbon emission reductions is 1990. During that year, 161.5 million tonnes of carbon (MtC) were emitted, much of it either by heavy manufacturing industry or by electricity generators.

BERR, in the annex to its 2007 White Paper, published its own carbon emissions projections, which are calculated on an ETS carbon price of £17.50 (€20) per MWh until 2010 and rising to £21.90 (€25) per MWh thereafter: these figures have been adjusted to reflect the current £/€ exchange rate.

This data, which is reproduced in Figure 1 below, is based on three different scenarios arising from the White Paper's proposed measures, including the pronounced switch from fossil-fuel generation and the resulting reductions in carbon emissions.

Prices

Until recently, on the back of rising gas prices, wholesale and retail energy prices had risen sharply – a subject of considerable controversy amongst consumer groups. In particular, industrial and commercial users have suffered, notably those who have signed up to energy supply contracts of three years' duration.

The pronounced fall in global oil prices, which is now being followed by weaker gas prices, has enabled energy companies to announce price cuts. However, these relatively modest reductions do not compensate for the substantial price increases put through over the last three years.

Consumer groups argue, with some justification, that the six integrated energy companies do not compete aggressively enough with one another. The reality is that, in recent years, most have been seriously impacted by rising gas prices, which can account for up to 70% of the operating costs of a Combined Cycle Gas Turbine (CCGT) plant. Inevitably, to preserve profit margins, companies seek to pass through the impact of higher gas input costs.

It has also been suggested that the UK energy supply market should be referred to the Competition Commission. It is doubtful whether lengthy deliberations by this body would be effective in creating a more competitive supply market, which is dominated by international energy players.

The most serious shortcoming in the supply market is that the industry structure, particularly after the introduction of the New Electricity Trading Arrangements (NETA) in 2001, coalesced around six well-financed vertically integrated companies that continue to dominate the market to this day.

Figure 1: BERR's carbon emission projections (millions of tonnes of carbon emissions)

Projections	1990	2005	2006	2020
Baseline	161.5	151.5	146.5	151.2
With Low White Paper Impact	161.5	151.1	136.1	128.9
With Average White Paper Impact	161.5	151.1	135.7	126.5
With High White Paper Impact	161.5	151.5	135.2	119.2

Source: Annex to White Paper 2007

3 Electricity Industy Developments

Mixed Energy Policy

Whilst energy issues often provoke widespread debate, there is near unanimity that the UK should adopt a mixed policy in terms of generation sources, embracing gas-fired, coal-fired and renewables plant. There is less consensus on new nuclear build, although public opposition appears to have mellowed in recent years as security of supply concerns have increased, consumer prices have risen sharply and the low carbon agenda has become more politically important.

Generation Chronology

Historically, the UK has relied heavily upon coal-fired plant and the coal-mining industry to produce the necessary raw material. During and shortly after World War I, some one million coal miners worked at about 1,000 pits. As capacity expanded during the 1930s, iconic plants, such as the Battersea Power Station, were constructed. Coal's predominance continued in the difficult years after the end of World War II.

The 1950s saw major change with the construction of the world's first nuclear plant at Calder Hall in Cumbria, commissioned in 1956. Whilst further nuclear plant was built in the 1960s, the former Central Electricity Generating Board (CEGB) placed considerable faith in new oil-fired plant.

However, in the 1970s, there was still heavy dependence upon coal. The miners' strikes of both 1972 and particularly in 1974 had a massive impact – and caused lengthy nationwide power cuts. Simultaneously, oil plants became uncompetitive following the quadrupling of world oil prices in 1973/74.

As the coal industry declined, a further – and very bitter – miners' strike took place in 1984, lasting almost a year. Several UK new nuclear build projects came to a sudden end following the Chernobyl disaster in 1986, although the new Pressurised Water Reactor (PWR) at Sizewell B was eventually built.

Importantly, the privatization of much of the electricity supply industry in the early 1990s was instrumental in creating the 'dash for gas', which enabled many new CCGT plants to be constructed: they operated at a noticeably higher efficiency level than standard coal-fired plants.

This pronounced switch in fuel sources since 1970 is illustrated in Figure 2 below.

It is now over 20 years since the first steps were taken to break up the UK electricity supply industry. The subsequent structural changes have been fundamental as the concept of vertically integrated electricity suppliers has become dominant – replacing the many separate businesses that had been created from the then omnipotent CEGB.

Figure 2: UK generation Sources (%)

Source	1970	1980	1990	2000	2002	2006
Conventional Thermal	86	86	78	41	39	38
Nuclear	10	12	20	22	22	19
CCGT (Gas)	0	0	0	35	36	36
Others	0	0	0	0	0	4

Source: Annex to White Paper 2007

The initial flotation in late 1990 comprised the 12 Regional Electricity Companies (RECs) in England and Wales, whose two key business streams were electricity supply and its distribution. The RECs were sold primarily on the basis of their strong cash flow, which was driven by their monopoly – and price-regulated – distribution business: the profit contribution from the more risky supply element was relatively minor. Each REC also owned a share of the (then unquoted) National Grid.

Subsequently, the two non-nuclear generators in England and Wales – National Power and PowerGen – were privatised. They were followed shortly afterwards by the two integrated Scottish electricity companies – ScottishPower and Scottish Hydro-Electric; the latter is now Scottish and Southern Energy (SSE).

In 1993, Northern Ireland Electricity was floated. It was followed by two ill-fated privatizations, Railtrack and British Energy, both of which faced profound financial problems, after the Hatfield train crash and the introduction of NETA respectively. In the latter's case, a heavily dilutive debt-for-equity swap was eventually agreed.

Over the last 20 years, the UK electricity supply industry, particularly its English and Welsh element, has undergone massive change. Consolidation, overseas ownership, productivity surges, regulatory shortcomings, the switch to NETA, soaring gas prices and the environmental agenda have all had profound effects.

Significantly, despite the broad consensus for a mixed energy policy, virtually all major investment in new generation plant since 1990 has been in CCGTs. Furthermore, the impact of high gas prices has been wide-ranging, and an unhealthy degree of future dependence on Russian gas imports has undoubtedly raised the supply risk.

4 Coal-fired Plant

Historically, coal-fired plant has been crucial in meeting UK electricity demand. Large coal-fired plants still account for a substantial part of overall UK generation capacity, as Figure 3 below shows.

Inevitably, UK coal-fired generation performance has been closely linked with the fortunes of the coal-mining industry, which was at the height of its dominance between World War I and the late 1950s. But the subsequent years have been far less kind to the coal industry as the volume of readily accessible reserves has diminished.

The crippling strikes of the early 1970s and 1984 seriously damaged coal's prospects, which were already receding in the face of dwindling accessible coal resources, the onset of nuclear power and the availability of other fossil-fuel sources, including oil and gas.

So pronounced has been the decline in domestic coal production that, by 2004, just eight deep-mined pits remained in operation. The only major domestic coal-mining company, UK Coal, has experienced difficult times, but its former Hatfield colliery, near Doncaster, was re-opened in 2006, and it is expected to provide coal for Powerfuel's planned 900 MW Integrated Gasification Combined Cycle (IGCC) plant nearby.

There is no doubt, too, that the massive setback of the collapsed Selby project, in which such high hopes had been vested in the 1980s and early 1990s, was a major negative for new coal investment: geological shortcomings played a crucial role in its demise.

Figure 3: Coal-fired plant with capacity of over 1,000 MW

Plant	Owner	Capacity (MW)^	Commissioning Date
Drax	Drax	4,000	1974
Longannet	Iberdrola	2,400	1970
Cottam	EdF	2,000	1969
Ratcliffe	E.On	2,000	1968
West Burton	EdF	2,000	1967
Fiddlers Ferry	SSE	2,000	1971
Ferrybridge	SSE	2,000	1966
Didcot A*	RWE	2,000	1972
Eggborough	EdF	1,960	1967
Kingsnorth*	E.On	1,940	1970
Aberthaw B	RWE	1,500	1971
Tilbury B*	RWE	1,428	1968
Cockenzie	Iberdrola	1,200	1967
Rugelely	International Power	1,000	1972

*^ The capacity figures quoted are, in most cases, taken from company web-sites. * Other fuel options. Source: Companies/BERR.*

To fuel the UK's coal-fired plants, imported coal volumes have risen strongly. Russia, South Africa, Australia, North America and Colombia have all been competing aggressively to sell their coal to EU energy markets at competitive prices.

More generally, rising gas prices and the long indecision about new nuclear build have given renewed hope to the UK coal industry. After all, no large coal-fired plant – the obvious market for domestic coal output – has been built in the UK since the second Drax unit was commissioned in 1986.

Perhaps the most persuasive evidence of optimism for coal-fired generation in the UK has been provided by the Drax plant, with its near 4,000 MW of capacity – one of the largest power plants outside Japan. Back in 2002, Drax was virtually bankrupt as the collapse of TXU Energy seriously reduced the market for its output. With its retro-fitted FGD equipment – at a £700 million cost in the 1980s – Drax is better positioned than most in today's environmentally sensitive markets.

Until recently, the reconstituted Drax Group was a member of the UK's elite FTSE-100 companies. Currently, its market valuation is £1.7 billion, a remarkable figure for a business that effectively comprises just one power plant.

In recent years, two of the six integrated energy companies, RWE and E.On, have turned their attention to designing effective clean coal plant.

RWE, which has been at the heart of Germany's Ruhr-based coal industry for over a century and is heavily focussed on clean-coal research and development, has recently secured approval to build a 2,000 MW CCGT plant at Pembroke: it also plans to retro-fit a Carbon Capture and Storage (CCS) facility nearby. Furthermore, RWE's Tilbury project is one of three plants now under consideration by the Department of Energy and Climate Change (DECC) as it seeks to choose a demonstration plant for new post-combustion CCS technology.

E.On's most important UK project is the proposed – and controversial – new coal-fired plant at Kingsnorth in Kent. Subject to an agreement on the installation of CCS facilities, this plant is expected to be given full approval. E.On has also undertaken a feasibility study regarding the construction of a clean coal plant at Killingholme on Humberside, which would use IGCC technology, but on a pre-combustion basis.

In reality, any major UK coal revival will have to address environmental issues. All large generating plants are now subject to much tougher legislation, from within the UK, the EU and via the Kyoto Treaty.

The enactment of the LCPD gives rise to heavy expenditure to comply with much tougher emission standards. Alternatively, plants could be 'opted out'. Nine old fossil-fuel plants, accounting for about 10% of UK capacity, are now expected to close by 2015 or earlier.

It is clear that, between 2014 and the commissioning of new nuclear plant from 2018 onwards, plant margins will be very low – consequently endangering security of supply. Hence there is a strong case for delaying – on security of supply grounds – some of these planned plant closures brought about by the LCPD.

Figure 4 shows the expected closure dates, based on output projections, for these opt-out plants: the data is sourced from Utilyx.

Looking forward, given the risks presented by the ETS to returns on new coal-fired plant, it is clear that any potential investors will have to address in detail the financial impact of emissions legislation.

In terms of the ongoing mix of fossil-fuel generation plant, much will depend upon the long-term relative prices of coal and gas, as well as such environmental drivers as the ETS.

Figure 4: Projected closure dates

Plant	Owner	Capacity (GW)	Projected Closure
Cockenzie	Iberdrola	1.2	9/2010
Tilbury	RWE	1.1	12/2010
Kingsnorth	E.On	2.0	10/2011
Didcot A	RWE	2.1	4/2012
Ferrybridge	SSE	1.0	5/2013
Ironbridge	E.On	1.0	11/2011
Fawley	RWE	1.0	12/2015
Grain	E.On	1.4	12/2015
Littlebrook	RWE	1.2	12/2015

Source: Utilyx (as amended)

Carbon Prices

With regard to carbon emissions permits, there is no doubt that the major fossil-fuel generators have benefited greatly from their free issue as their robust share price performance – at least until recently – indicates.

As such, there is a compelling case for arguing that these generators, such as the most notable beneficiary, RWE, should pay considerably more for their carbon emission permits, whether through the UK or the EU.

This issue is both complex and politically controversial, especially as electricity companies have derived conspicuous benefit – via an effective 'cost pass through' of notional carbon emission costs – from the ETS to date. Figure 5 below, which shows the 2007 comparisons, is based on data from Point Carbon.

After 2012, the existing ETS regime is due to expire. However, the extent to which free carbon emissions permits will be granted, especially to German companies – such as RWE, the EU's largest polluter – and to Polish generators, is not yet decided.

For the longer term, this uncertainty is also deterring investment in new generation facilities, since it makes it even more complex to project the likely rate of return from such projects. In particular, after 2014, the serious security of supply concerns will become more manifest unless potential investors have a clearer view about longer-term carbon pricing trends.

To address these concerns, some form of 'belt and braces' regime within the ETS structure may be the best way forward to secure finance for investment in new generation plant. Furthermore, these carbon pricing arrangements could be correlated with the proposed Low Carbon Obligation (LCO), thereby giving greater financial certainty to the revenue profile of each major generator, which should bring down the cost of capital.

Other political issues lie at the heart of the EU's carbon abatement strategy. Over the next year, key general elections are scheduled, which may reshape the carbon agenda. In the UK, where a general election will be held by early June 2010, the Conservative Party's Energy Review has supported a 'cap and trade' carbon regime.

In Germany, the general election this September could presage a fundamental energy policy re-think, especially if the CDU/CSU – in coalition with the FDP – secures enough seats not only to obviate the need for a renewed Grand Coalition but also to enable it to reverse the nuclear phase-out policy that was controversially enacted in 2001.

Figure 5: Power generators carbon dioxide emissions (2007)

Company	Country	Emissions in Tonnes (m)	Cost of Emissions* (€bn)	Cost as % of Revenues*
RWE	Germany	142.9	2.0	4.8
Vattenfall	Sweden	86.0	1.2	7.9
E.On	Germany	81.2	1.1	1.6
Endesa	Spain	66.8	0.9	5.2
EdF	France	56.0	0.8	1.3
Polish Energy	Poland	55.0	0.8	13.3
ENEL	Italy	54.9	0.8	1.8
PPC	Greece	53.0	0.7	14.2
CEZ	Czech Rep.	38.3	0.5	8.4
Electrabel	Belgium	32.6	0.5	3.3

** Based on a carbon price of €13.80 per tonne. Source: Point Carbon (as amended).*

5 Gas-fired Plant

During the run-up to electricity privatization in the 1980s, the prospects for new gas-fired generation became brighter. Cheap gas was relatively abundant and EU rules had been relaxed to allow gas to be widely used in generation plant. Moreover, new CCGT plant designs had driven efficiency levels to over 50%, a material improvement of the 35% typical of coal-fired plant.

As such, it was no surprise that the UK participated in the 'dash for gas' as new CCGT plants were built from the early 1990s onwards – the Tees-side plant being the first major UK plant to be gas-fired. Virtually all large generation plants built over the last 20 years in the UK have been fuelled by gas.

Figure 6 below shows those CCGT plants that have a capacity of over 1,000 MW.

In addition, there are several large gas-fired stations currently under construction, notably RWE's 1,650 MW plant at Staythorpe, E.On's 1,275 MW plant at Grain and EdF's 1,300 MW plant at West Burton.

In February 2009, DECC gave Section 36 approval to two new CCGT plants, RWE's 2,000 MW project at Pembroke and Centrica's 1,020 MW project at King's Lynn. Both sites have sufficient land on which to retro-fit a CCS plant.

The key cost component for a CCGT is the gas itself. In recent years, gas prices have risen substantially on the back of strong oil prices – a trend that is now being reversed. At its peak, the gas cost accounted for almost 70% of total CCGT operating costs.

Figure 7 (over) shows the rise in spot prices for gas since 2003 – the sharp spikes in early 2006 reflect the short suspension of supplies by Gazprom through Ukraine's pipelines.

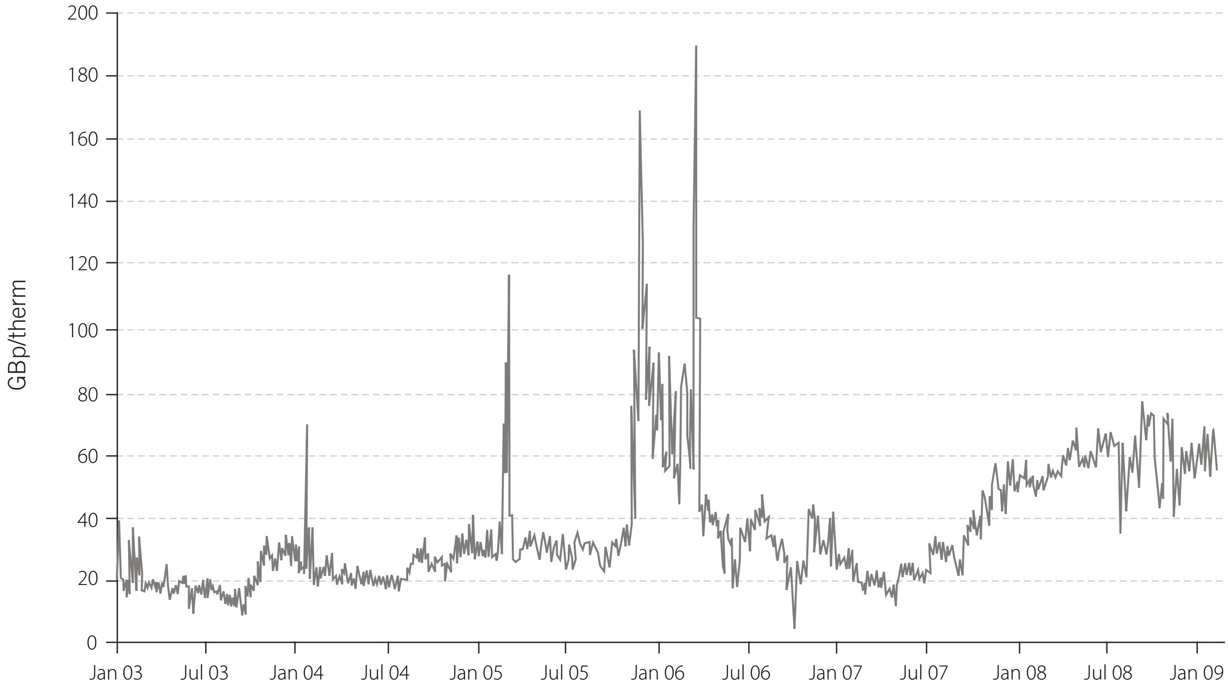
With gas-generated output now crucial for UK generation, gas supplies and prices are now key issues. In view of the pronounced decline in North Sea gas production, the UK will increasingly rely on gas imports, most of which will emanate from relatively unstable regions, such as Russia and the Middle East.

Figure 6: Major gas-fired plants

Plant	Owner	Capacity (MW)^	Start-up date
Tees-side	GdF Suez	1,875	1992
Peterhead	SSE	1,550	1980*
Connah's Quay	E.On	1,420	1996
Didcot B	RWE	1,360	1998
South Humber Bank	Centrica	1,260	1997
Saltend	International Power	1,200	2000
Seabank	BG/SSE	1,140	2001
Barking	Thames Power	1,000	1995

*^ The capacity figures quoted are, in most cases, taken from company web-sites. * Conversion from oil firing. Source: Companies/BERR.*

Figure 7: Natural gas spot price/UK national balancing point



Source: Spectron Group, Bloomberg

Gas Politics

The importance of gas politics has risen in recent years, especially in view of the vulnerability of gas exports through Ukraine's pipelines. Since January 2006, supply interruptions have seriously affected many Eastern European countries.

Despite EU efforts to address the risks of long-term over-dependence on Russian gas imports, individual countries have signed contracts with Gazprom, whose policy of bilateral negotiations has proved both successful and divisive. In this respect, Germany has played a leading role through its participation in the Nord Stream pipeline project.

Aside from the key price issue, political instability within the leading gas exporting countries is an obvious area of concern. Norway is by far the most stable of the major gas suppliers to the EU. In Russia, by contrast, political risk remains a serious problem. The same is true of other gas exporting countries. Algeria has suffered, for years, from politically motivated terrorist activities, whilst other Middle Eastern countries, with substantial gas reserves, are also subject to political upheaval.

Gas Transport

Aside from the concerns about the reliability of gas producers, it is also very relevant to assess the transport routes to UK landfall sites. Amongst the most concerning is the fact that over 80% of Russia's gas exports to the EU pass through Ukraine, which is sharply split between regions supporting the West and the industrial eastern area where support for Russia remains strong.

Nonetheless, various infrastructure projects have recently come on stream, which should materially reduce the UK's long-term exposure to interruption of its gas imports.

In terms of size, the 750-mile long Langeled pipeline from Norway's Ormen Lange field is probably the most important of these investments, since it can transport over 20 billion cubic metres (bcm) of gas per year into the UK. By comparison, total UK gas usage is projected to rise from 91 bcm per year in 2007 to 107 bcm in 2018: over 50% of this latter figure is expected to be met by imports.

Gas pipeline imports are being supplemented by three other major developments. First, the annual import capacity – the reverse flow – of the existing Bacton to Zeebrugge pipeline has been raised progressively from the original 8.5 bcm in 1998 to over 25 bcm currently.

Secondly, a new interconnector has been built between Bacton and the North Dutch landfall site at Balgzand. The capacity of this pipe is some 15 bcm per year.

Thirdly, new Liquified Natural Gas (LNG) facilities have been built, most notably National Grid's plant at Grain. In May, the South Hook LNG terminal at Milford Haven was opened – it is the largest and most advanced LNG terminal in Europe. However, LNG cargoes are notoriously subject to last minute diversions to satisfy a sudden spate of demand in a major gas market.

Within mainland Europe, the 1,220 kilometre Nord Stream pipeline between Russia and Western Europe, part of whose route will be under the Baltic Sea, is under construction. In time, it will transport approximately 55 bcm of gas per year, much of which is destined to meet German demand.

The UK's gas supply risk is heightened by its comparative lack of storage facilities. Only the offshore Rough facility, acquired by Centrica in 2002, can store substantial amounts of gas; currently, it accounts for almost 80% of the UK's total gas storage capacity. By comparison with the UK's worryingly low 15 days of gas storage capacity, the equivalent French figure is 99 days, and for Germany it is 122 days.

Various gas storage projects are under consideration. Centrica has recently acquired a 75% stake in the Baird gas storage project, which has a capacity equivalent to half that of the Rough site. Another leading gas company, the Italian-based ENI, has paid £210 million to Tullow Oil for a 52% share in the technically complex Hewett gas project. This project has a storage capacity of 5 bcm and, once completed, would support the UK's seasonal swings in gas demand.

Portland Gas, which has demerged from Egdon Resources, is currently seeking to raise funds for the development of a deep underground salt cavern facility at Portland in Dorset. There is also the potential of the Esmond project, from which Star Energy, now owned by the Malaysia-based Petronas, has recently withdrawn, leaving EnCore Oil to decide whether or not to proceed.

In the North West, Gateway plans to construct an offshore gas storage facility – at 750 metres below the seabed surface. Canatxx, too, has recently submitted an application for a £300 million onshore gas storage project at Preesall in Lancashire.

For the Government, raising the UK's gas storage capacity has to be a priority. To that extent, it needs to put pressure on both the six integrated energy companies and the leading oil and gas companies, especially ENI, to undertake the necessary investment. Given the current credit crisis, smaller companies seeking to develop gas storage facilities are likely to face real problems in raising the necessary finance – irrespective of the planning problems that several have encountered already.

Future Gas Demand

In assessing the degree of risk to which the UK is exposed, it is instructive to analyse the gas demand figures that have been published by E.On: the figures cover the 27 EU members, as well as Norway, Switzerland and Turkey.

E.On estimates that, in 2007, there was Western European demand – the EU plus that from Norway, Switzerland and Turkey – for 530 bcm of gas. By 2015, on a mid-range scenario, it projects demand rising to just over 630 bcm. The mid-range figure for 2020 is 675 bcm.

In addressing how such rising demand could be met, E.On has concluded that, between 2007 and 2020, the percentage covered by EU indigenous gas production will have fallen from 35% to 18% of demand.

Most significantly, however, the 53% of demand currently supplied by the combination of the EU and Norway falls away sharply. By 2020, this segment, on E.On's figures, will account for just 31%, 13% of which will be produced by Norway.

It is expected that Algeria will contribute a fairly consistent 9% over the next 11 years, provided that there are no major political upheavals. A slightly lower contribution will be made by other non-EU imports, including LNG from Qatar and the Far East.

For 2020, E.On has allocated 28% for Russian imports, although this figure excludes any gas that is sent through the Nord Stream pipeline.

Even if the total Russian component is assumed to reach 34% by 2020, E.On still calculates that there is a supply gap of 16%. Such a scenario is undoubtedly worrying, especially given the pronounced risks attached to the 28% that has been earmarked for non-Nord Stream Russian gas imports.

Gazprom

Given this apparent dependence upon future Russian imports, there is real concern as to whether Gazprom and other gas suppliers can fulfil their long-term contracts.

Undoubtedly, Gazprom has massive gas resources, equivalent to about 17% of proven global reserves. The more serious issue is whether sufficient new fields come on stream at the right time to meet rising demand. For many years, Gazprom has been relying on older gas fields, whose output has been steadily declining.

Moreover, the financial crisis, exacerbated by much lower energy selling prices, is putting real pressure both on Gazprom's cash flow and consequently on its investment plans. It seems certain that the combination of far lower selling prices, a seriously weak currency and rapidly rising debt will cause Gazprom to cut back on some of its planned investment. The technically very challenging, but highly important, Shtokman project may either be scaled back or deferred.

In the light of all these uncertainties affecting Russia's dominant gas exporting company, it is self-evident that the long-term gas price risk is very real. The price spikes resulting from the brief suspension of supplies via Ukraine's pipeline in January 2006 underline the level to which prices could soar if there were prolonged interruptions to gas supplies – for whatever reason.

Importantly, the risk to EU importers, including the UK, is not purely one of gas availability. In replicating the policies adopted by the Organisation of Petroleum Exporting Countries (OPEC), which remains a very influential cartel, Gazprom could decide, perhaps in league with other suppliers such as Iran and Qatar, to sell its gas at substantially above the free market price.

6 Nuclear Plant

Nuclear power was first generated in a Chicago squash court in 1942, whilst the world's first nuclear power station opened at Calder Hall in Cumbria in 1956.

Over the subsequent 20 years, the UK was very reliant upon the first generation Magnox plants for its nuclear output. Although the Magnox stations had modest capacities by today's standards, their contribution to UK electricity generation became increasingly important in the 1960s and 1970s.

The major investment in second generation nuclear build took place between the mid 1970s and the late 1980s, although the Sizewell B Pressurised Water Reactor (PWR) was not finally commissioned until 1995. The other seven post-Magnox nuclear plants, whose performance has been variable, are all Advanced Gas-Cooled Reactor (AGR) plants, which were developed from indigenous UK technology.

Figure 8 (over) shows the current AGR plants in operation, along with the PWR at Sizewell B, and their projected decommissioning dates, which may be extended – on a plant-by-plant basis – subject to approval by the Nuclear Installations Inspectorate (NII). These plants are now majority-owned by EdF following its acquisition of British Energy; Centrica has recently bought a minority 20% stake in this plant portfolio from EdF.

Irrespective of the success of nuclear investment since the 1950s, the world's perception of nuclear power generation changed dramatically on April 26th 1986. On that day, as a result of an unbelievably irresponsible experiment that went disastrously wrong, Reactor Number 4 at the Chernobyl nuclear power plant in modern-day Ukraine exploded.

Aside from the heavy loss of life, both immediate and subsequent, the environmental impact was massive, both in Ukraine and in SE Belarus: the cost of clearing up after this disaster was colossal.

The Chernobyl disaster – and the contained Three Mile Island accident in the US in 1979 – put an effective end to new nuclear build in the Western World for virtually a generation. But several new nuclear plants have been constructed in recent years in Asia, most notably in Japan.

However, since the publication of the 2003 Energy White Paper, which virtually ruled out any new nuclear build, the UK energy environment has changed considerably.

Whilst high energy prices remain an enduring concern, it is security of supply – especially in terms of base-load generation – that has moved most rapidly up the political agenda. After all, every UK nuclear plant, except Sizewell B, is due to close down by 2023, unless life extensions are granted.

Moreover, the new nuclear build option offers very material benefits on environmental grounds. Its carbon emissions balance sheet, even after allowing for uranium mining emissions, is far more environmentally friendly than both gas-fired and especially coal-fired plant – unless, of course, a Chernobyl-type disaster takes place.

New Nuclear Build

These factors have been instrumental in the Government's U-turn in 2007 to give the go-ahead for new nuclear build in the UK. Whilst renewables generation has its place, especially in terms of providing onshore generated wind-power, the real need is for competitively priced base-load output – something that the renewables sector is generally unable to offer.

With regard to potential investors in new nuclear build, the real focus will be on the six integrated energy companies – EdF, E.On, RWE, Iberdrola, SSE and Centrica.

Figure 8: UK Second generation nuclear plants

Plant	Capacity (MW)	Commissioning Date	Decommissioning Date
Heysham 2	1,250	1989	2023
Torness	1,250	1988	2023
Hinkley Point B	1,220	1976	2016
Hartlepool	1,210	1989	2014
Hunterston B	1,190	1976	2016
Sizewell B*	1,188	1995	2035
Heysham 1	1,150	1989	2014
Dungeness B	1,110	1985	2018

**PWR Design. Source: British Energy*

By far the largest nuclear player is EdF, which has a generation capacity of over 128,000 MW and is currently valued by the market at around £57 billion: the French Government's shareholding currently exceeds 80%. Despite its rapidly rising net debt, EdF should not lack access to financial resources but it already has a heavy new nuclear build programme in France. The first of its third generation plants is under construction at Flamanville in Normandy, whilst the go-ahead for the second plant at Penly, near Dieppe, has just been given.

EdF has also acquired invaluable experience in overcoming all the political, planning, regulatory and financial obstacles that beset any nuclear power station investment.

Undoubtedly, EdF is very interested in participating in new nuclear build in the UK and has even suggested – probably optimistically – that its first UK nuclear plant will be commissioned in late 2017. EdF plans to build two plants at Hinkley Point and two at Sizewell.

The other possible investors in UK new nuclear build are the two German companies, E.On, which is currently undertaking a £40 billion investment programme, and RWE. They recently formed a joint venture, which seeks to build at least 6,000 MW of new nuclear capacity in the UK.

Whilst neither company historically has lacked access to funds, both – and especially E.On – have a very lengthy list of alternative investment projects and potential acquisitions. In E.On's case, its 2008 full-year figures were accompanied by a profits warning; it also confirmed a sharply rising net debt figure of £39 billion. Furthermore, E.On has announced plans to cut back on its investment – which could include new nuclear build in the UK.

Moreover, with a key general election in Germany this September, which could result in the reversal of the nuclear power phase-out programme that was agreed in 2001, both E.On and RWE will be on stand-by to undertake a heavy new nuclear build programme in their domestic market.

A further joint venture for new nuclear build has been signed by Iberdrola, the owner of ScottishPower, and SSE; GdF Suez is also participating in this joint venture. Whether it results in any of these three companies investing substantially in UK new nuclear build remains doubtful.

Given its strong supply business and comparatively modest generation activities, it is no surprise that Centrica is keen to take on more generation exposure. It has bought 20% of the eight nuclear plants owned formerly by British Energy but now part of EdF's portfolio, as well as signing up to large nuclear power off-take contracts.

Centrica recently raised £2.2 billion through a well-supported rights issue to finance this acquisition. However, with falling gas prices, Centrica may also decide to buy further gas field interests in addition to its recent stake-building in Venture Production.

In terms of the nuclear power technology, the NII has been assessing two designs – the Evolutionary Power Reactor (EPR), which is currently being built in Olkiluoto in Finland, and the Westinghouse AP 1000. Significantly, the latter is the only one of the new nuclear designs to have secured approval from the US-based Nuclear Regulatory Commission (NRC).

In reality, it seems probable that EdF will choose the EPR for any new nuclear build in the UK. If either E.On or RWE does decide to pursue new nuclear build here, the Westinghouse AP 1000 is likely to be the favoured design.

General Electric has been selling its Boiling Water Reactor (BWR) plants to leading Asian clients. It remains focussed on its nuclear construction operations but its key markets are now the US and parts of Asia.

With regard to suitable sites, the recent acquisition of British Energy by EdF has enabled the latter to become the owner of the most obvious sites for new nuclear build in the UK – Hinkley Point and Sizewell being its preferred options.

Various Magnox sites also offer some attractions. The Nuclear Decommissioning Authority (NDA) has recently held an auction of its most suitable sites for new nuclear build, which raised £387 million. The E.On/RWE joint venture purchased the Oldbury and Wylfa sites, whilst EdF acquired the Bradwell site.

Whilst EdF may use its own balance sheet to fund any new nuclear build in the UK, other consortia may decide to form an IPP (Independent Power Project), with shareholdings being allocated to various parties according to their equity involvement. A similar structure was used to finance the Olkiluoto 3 plant in Finland.

Undoubtedly, long-term lenders will be very eager to see a substantial equity component within this financing structure so that there is a considerable incentive on the participating utilities and plant construction companies to minimise any over-runs.

Serious cost and time over-runs at Olkiluoto 3, along with budgetary concerns at Flamanville, are hardly reassuring – both of these, however, are First-of-a-Kind (FOAK) plants. In its 2008 figures, the French-based Areva, the world's leading nuclear company and builder of EPRs, projected a £1.5 billion loss in respect of its involvement in the Olkiluoto 3 project.

Given the long-term nature of investing in new nuclear build, the contractual arrangements will be crucial in seeking to raise the necessary funds. City scepticism is also widespread in the light of the near collapse of British Energy in 2002 and the poor performance of some IPP investments.

Nuclear Costs

Financial modelling of new nuclear build projects shows quite clearly that the WACC (Weighted Average Cost of Capital) figure is crucial in determining rates of return. In its 2008 Nuclear White Paper, BERR published a very wide range for the WACC of between 7% and 12% – in the latter case, new nuclear build is clearly unfinanceable.

The current financial crisis, and especially the massive rise in public sector debt, means that assessing the cost of long-term lending is more complex than previously. Nonetheless, so far in 2009, National Grid and SSE have raised £2 billion: the former issued a 22-year bond, with a 7.375% coupon, that was priced at 320 basis points (bp) over gilts.

In Europe, EdF and E.On have both successfully accessed the bond market in recent months. Nevertheless, there would be a significant nuclear premium attached to any lending for new nuclear build in the UK.

To provide financial incentives for new nuclear build through lowering the WACC, the Government could require the six integrated energy companies to sign up to long-term nuclear supply contracts on a similar basis to the current requirements of the Renewables Obligation (RO). In essence, an extended Low Carbon Obligation (LCO) would be prescribed. Clearly, the more robust the off-take contracts are for the seller of the nuclear output, the more effective they would be in lowering the WACC.

Furthermore, as a direct result of the credit crisis, the premium between gilt-edged stock yields and those for investment-grade corporate bonds has widened. If a Treasury debt indemnity – similar to the previous Network Rail arrangements – were offered for new nuclear build projects, this concession would undoubtedly have a pronounced downward impact on the overall WACC.

The capital cost of new nuclear build is clearly a key variable. In recent years, the cost per MW has risen sharply as demonstrated by the Olkiluoto 3 project. This trend is partly due to rising demand but is also a result of higher specialist steel prices. In its Nuclear White Paper in 2008, BERR had indicated a figure of £1.25 million per MW.

However, based on a capital cost of between £1.5 million to £2.5 million per MW, long-term off-take contracts being in place, a Treasury indemnity and a 35% equity to 65% debt ratio, a WACC of around 7.5% might well be achievable.

On the basis of these financial criteria, the total producation cost should lie within a range of £35 and £41 per MWh. In terms of running expenses over a 40-year plant life, the operating and maintenance costs are estimated at between £5 and £6 per MWh.

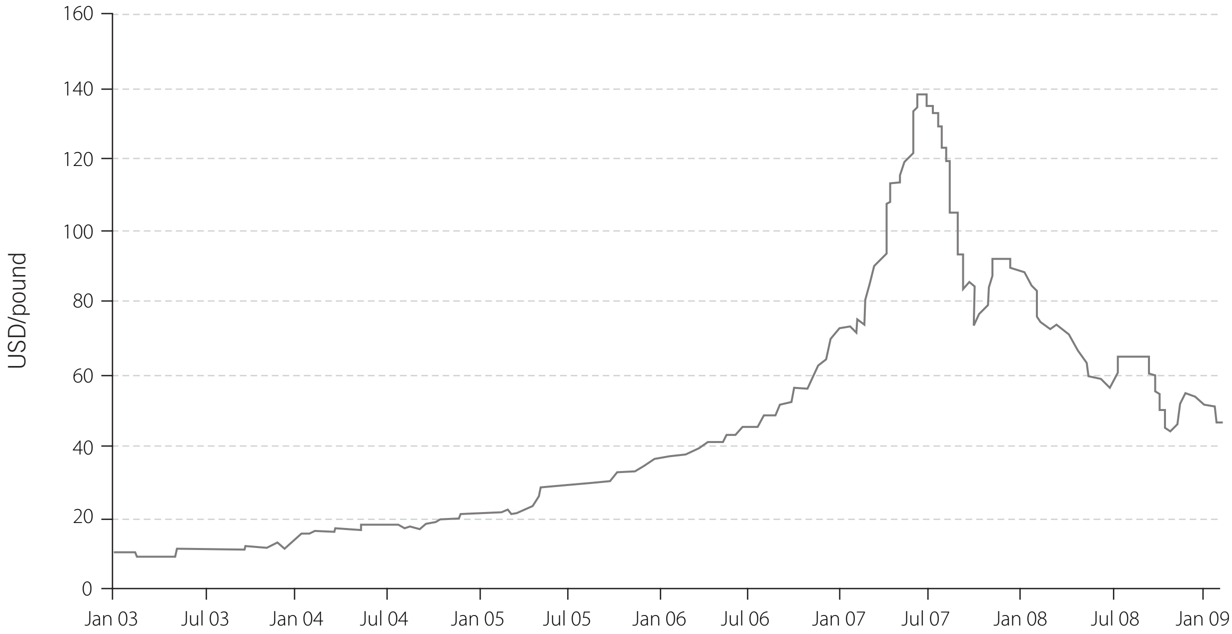
The fuel costs should lie between £3 and £4 per MWh. As Figure 9 shows, uranium prices have fallen back sharply from their recent peak in 2007, which was primarily attributable to many countries embracing new nuclear build projects.

The waste and decommissioning costs are assumed to be about £1 per MWh, a distinctly modest amount since most of the expenditure is deferred for many decades.

Clearly, any financial projections would be adversely impacted by extensive planning delays, which the new 'fast track' planning approval system seeks to minimise. Nevertheless, delays on the planning front are very likely – the nuclear industry still remembers the record-breaking 340-day Sizewell B enquiry in the 1980s.

In order to address the underlying concerns on planning issues for key infrastructure projects, the Government introduced a

Figure 9: Uranium price movements



Source: Bloomberg

Planning Bill, which received Royal Assent last November. The Planning Act 2008 enables the Government to issue a National Policy Statement (NPS), which should hasten approval for infrastructure projects, such as new nuclear build and airport extension plans.

Under this Act, a specialist Infrastructure Planning Commission (IPC) is to be appointed. The expectation is that unnecessarily prolonged planning enquiries for such projects can be avoided. However, a recent Conservative Party document indicated that an incoming Conservative Government would abolish the IPC.

Furthermore, the absence of any long-term solution to the waste disposal problem has been widely cited as grounds for vetoing any new nuclear build applications. Yet the UK has operated nuclear power plants for over 50 years without such a solution being in place.

In 2006, the Committee on Radioactive Waste Management (CoRWM) recommended deep disposal in a nuclear repository. Whilst no individual site was proposed, the likelihood is that it will either be within or close to the existing Sellafield complex in Cumbria.

Despite approval in principle from the Government, the delivery of any new nuclear build in the UK will be an immense challenge. Whilst real progress has been made over the last 18 months, many doubts about the deliverability of new nuclear build in the UK remain.

Amongst the more serious concerns are:

- A major accident at one of the 440 or so existing nuclear plants that materially delays the revival of new nuclear build;
- The difficulty of financing such long-term projects as the financial crisis worsens on the back of massive public borrowing levels;
- The inability of private sector investors in new nuclear build projects to demonstrate to their shareholders that the very long-deferred financial returns justify the risks involved;
- Prolonged depressed oil and gas prices arising from a long-lasting global recession;
- Extensive planning delays, despite the Planning Act 2008;
- Major policy changes or indecision, especially with a UK general election due by early June 2010;
- Serious time and cost overruns, as demonstrated by the Olkiluoto 3 project on which Areva has already sustained heavy losses;
- More attractive alternative nuclear projects, notably in China or the US, becoming available to EdF;
- A U-turn in German nuclear policy following this September's general election, which may persuade E.On and RWE to focus more on their domestic market.

7 Renewables

A pronounced switch to embrace renewables technology has been instigated by the EU. In 2007, the EU announced its commitment to a 20% share of final EU energy consumption being met from renewable sources – a very ambitious target.

On the back of heavy national subsidies, Germany and Spain have become the leaders in developing renewable generation plants. In Germany's case, the availability of feed-in tariffs has been key, especially with respect to solar power development. In Spain, Iberdrola, the world's leading renewables company, has been very prominent in building and operating onshore wind plant.

In the UK, the Government has also accorded a high priority to promoting renewable generation, although its recent espousal of nuclear power suggests that there are real concerns about the extent to which renewables can deliver – and especially in terms of contributing to new base-load requirements.

Currently, most of the UK's renewables investment has centred on the six integrated energy companies, who have little difficulty in financing them.

E.On, RWE and Centrica have been the most notable renewables investors in England. Centrica seeks to develop a 1,400 MW wind project pipeline, subject to economic and funding considerations.

North of the border, both the Iberdrola-owned ScottishPower and SSE have been very prominent in investing in wind power, a growing industry in Scotland. Moreover, local planning legislation is far more amenable to wind projects there.

Wind

Onshore wind generation is now seen as a relatively mature technology with comparatively little operational risk. The main concerns are grid connections and planning – as the landmark Whinash ruling in the Lake District has demonstrated. In addition, output levels, especially in England where the output of many turbines is less than 30%, remain disappointing. However, in Scotland, the Whitelee wind farm has just been opened, with 140 turbines and total capacity of 322 MW.

Offshore wind, where the turbines are larger, is still facing many serious problems, including the high prices of offshore turbines, delayed grid connections and installation bottlenecks, along with the real increase in the WACC due to the current credit crisis.

The Round 2 delays are a reflection of these inherent risks. The problems of the London Array have been widely publicised, with both Shell (which has now withdrawn from the project) and E.On publicly questioning whether the expected financial returns justify the many risks. Following agreement to raise the Renewable Obligation Certificate (ROC) payments to 2x per MWh generated, Phase 1 of this project is now expected to proceed, with 175 turbines and 630 MW capacity: the estimated cost is £2 billion.

It is questionable whether offshore wind in the UK will ever become a material generator of power. Despite the Government's recent announcement of a further £525 million of financial support for the sector, it seems likely that progress over the next few years will be slow. Indeed, there is a strong case for the Government to redirect its energies to ensure that new nuclear build remains on track, rather than trying to kick-start offshore wind projects, where the finances are already very stretched and the eventual output is intermittent.

Other Technologies

Hydro-power is especially important for SSE. At flotation, the former Scottish Hydro-Electric – the predecessor of SSE – inherited a large portfolio of hydropower plants. However, in terms of constructing new small hydropower plants, few suitable sites have emerged – most of the best sites have already been exploited.

As a result of high electricity prices, the operating margins for SSE's embedded hydro-power assets have been impressive. SSE has recently commissioned its 100 MW hydro-plant at Glendale near Loch Ness.

Biomass and waste-to-energy are still, in many cases, dogged by various uncertainties, including planning. After many false starts and increasingly generous ROC payments, the biomass market has finally attracted major investment. In a 60:40 joint venture with Siemens, Drax Group has confirmed its plan to build three 300 MW biomass plants in the Humber-side area at a total cost of around £2 billion.

Wave and tidal power continue to be faced by technical challenges as the ocean's energy resources around the UK coastline prove difficult to tame. However, DECC has recently announced five possible schemes to harness power from the River Severn.

The most ambitious proposal is the construction of a barrage across the river between Cardiff and Weston-Super-Mare, with a capacity of 8,460 MW. DECC has suggested a cost of £20.9 billion for this scheme. At the other end of the scale, the smallest of the five schemes is the Beachley Barrage, whose capacity would be just 625 MW, at a projected cost of £2.3 billion. Given the many uncertainties – financial, commercial, environmental, political and legal – none of these five schemes may ever materialise.

For solar and fuel cells technology, despite high hopes, it is still early days in the UK: commercial operation still seems many years away.

Financing Renewables

Whilst there is general political agreement to back the development of renewable power, through such mechanisms as the NFFO (Non Fossil-Fuel Obligation) and the RO, the reality is that most renewables investment is being undertaken by the six integrated energy companies.

For these companies, securing the requisite finance should not be problematic. Whether an acceptable return can be earned, given the long-term uncertainties of renewables subsidies, remains to be seen.

At the other end of the market, where renewable energy projects are effectively start-ups, raising the necessary finance is a very different proposition. The ideal build-up scenario for a renewables company is best illustrated by Airtricity, the highly successful Irish wind company, which was recently split up and sold to E.On and SSE. Having built its first onshore wind farm with just 12 MW of capacity at Culliagh in County Donegal in 2000, Airtricity's UK and EU wind assets, with almost 400 MW of capacity, were sold less than eight years later to SSE.

In terms of financing, the current renewables generation scenario is also far from ideal, with various complex financial arrangements, ranging from NFFOs to ROCs in operation.

Yet the current level of renewables generation remains inadequate to meet the Government's ambitious targets. Even if there were a switch to a feed-in tariff regime, small renewables businesses would still find it difficult to raise the necessary initial project finance.

Given the high cost of subsidies, their inability to generate base-load power and the negative implications for the grid and ongoing planning problems, the Government will need to address the problems faced by renewables investors if it wishes its aggressive roll-out targets to be met. The current renewables generation figure of 3% is poor when set against those for Spain and Germany, especially given the heavy subsidies currently on offer to renewable generators in the UK.

Two particular reforms merit close analysis. First, it is clear that some renewables can deliver and many do not; hence, the need for more focus. The world's most successful renewables company, Iberdrola Renovables, has expanded almost exclusively on the back of onshore wind, although it does have some aspirations for solar power in the long term.

Secondly, there is a strong case for introducing feed-in tariffs with long-term off-take arrangements instead of the ROC regime, whose underlying value per MWh is currently being boosted by a general lack of UK renewables investment.

Carbon Capture and Storage

In pursuance of the low carbon agenda, a high priority is being accorded by the UK Government to developing CCS technology. In particular, the Government is focussing on technology that minimises carbon emissions through the application of post-combustion processes, whereby the carbon dioxide is removed after hydrocarbon combustion.

The Government plans to give the go-ahead for the construction of a post-combustion pilot plant in the UK, along with up to three other coal-fired projects, including those using pre-combustion technology. These plants will receive public funding via a levy mechanism.

In Germany, Vattenfall has built a 30 MW pilot plant at Schwarze Pumpe, near Spremberg, which is located to the south of Berlin. At this oxyfuel plant, the carbon dioxide is compressed and then liquefied. Looking forward, there is every expectation that the plant can be suitably scaled up.

Despite the quest to establish large-scale CCS plants, virtually all carbon sequestration activities are based around the relatively low technology of the direct injection of carbon dioxide into depleted gas-fields. Figure 10 lists the key data for six CCS plants that are currently in operation worldwide.

Figure 10: Operating CCS plants

Plant	Lead Companies	Location	Technology	Opening Date
Sleipner West	Statoil Hydro	Norwegian West Coast	Gas Injection	1996
K12-B	GdF/TNO	North Sea (Dutch)	Gas Injection	2004
Snohvit	Statoil	Barents Sea	Gas Injection	2007
In Salah	Sonatrach/BP/Statoil	Algeria	Gas Injection	2004
Weyburn	SaskPower	Saskatchewan Canada/ North Dakota, US	Gas Injection	2000
Schwarze Pumpe	Vattenfall	Brandenburg, Germany	Carbon Capture	2008

Source: Future Energy Strategies

8 Comparative Generation Costs

In analysing the finances of generation businesses, it is instructive to compare the relative generation costs per MWh of coal, gas, nuclear and renewables. Inevitably, key assumptions have to be made, which are central to assessing the competitiveness of each type of plant, especially in terms of fuel and carbon emission costs.

In 2005, EdF published its own comparative generation data, which reveals both capital and operating costs – this data is set out in Figure 11.

E.On has also published similar but more recent figures, which are calculated on a base-load output of 8,000 hours of electricity production per year: they are shown in Figure 12 (over). E.On has used two carbon emission cost assumptions – €20 per tonne and €40 per tonne.

The economics of coal-fired plants are very dependent upon coal price assumptions, although their competitiveness will also be adversely affected by high carbon emission costs. If there is a major differential in domestic coal prices and the CIF UK imported coal price, this is very likely to impact coal sourcing decisions.

Based on a $50 per tonne coal price and a carbon emission cost of €16 per tonne, EdF has calculated a generation price from a new greenfield coal-fired plant of €58 per MWh. In £ sterling terms, this equates to £51 per MWh. E.On's latest data, based on a carbon emission cost of €20 per tonne, produces a price of €54 per MWh, equivalent to £47 per MWh.

RWE has also published some recent generation data, although its calculations are based on a mid-merit output scenario of just 5,700 full hours per year. Its calculated cost, based on a £67 per tonne cost for coal – well above the current cost – and a carbon emission cost price of €16 per tonne, is £64 per MWh.

In terms of gas-fired generation, the fuel itself has accounted for – until very recently – almost 70% of the operating costs of a CCGT plant. Consequently, the key assumption in assessing the cost of gas-fired generation is the base price within the long term gas supply contract and the adjustments to which it is susceptible as energy prices fluctuate. Not surprisingly, details of individual gas contracts are commercially very sensitive, so full figures are not generally available.

Figure 11: EdF's comparative generation costs (2005)

Data	Coal	Coal	Gas (CCGT)	Gas (CCGT)	Nuclear
Cost (MWh)	€50-€66	€54-€70	€47-€55	€67-€75	€46
Assumptions	Coal at $50 per tonne	Coal at $65 per tonne	Brent Oil $40/ barrel in 2015	Brent Oil $70/ barrel in 2015	1,600 MW
	CO_2 at €8 to €24 per tonne	CO_2 at €8 to €24 per tonne	CO_2 at €4 to €12 per tonne	CO_2 at €4 to €12 per tonne	60 Years' Life
	New Greenfield Site	New Greenfield Site	New Greenfield Site	New Greenfield Site	91% Capability Factor
	No Free CO_2	No Free CO_2	No Free CO_2	No Free CO_2	€3.3bn Investment
					FOAK Financing

Source: EdF

Nevertheless, claims that the cost of generating power from a CCGT plant is comparatively cheap need to be set alongside the gas input assumptions. Any forecasts of the wholesale price of gas in 20 years' time are bound to be very wide-ranging.

As Figure 11 (above) indicates, based on 2005 data, EdF has calculated that a new greenfield CCGT, assuming an oil price of $40 per barrel and with a carbon emission cost of just €8 per tonne, would produce power at a cost of around €51 per MWh.

At the current exchange rate, this would equate to £45 per MWh – a figure boosted by the recent comparative strength of the €. This projected cost is below the €64 per MWh, equivalent to £56 per MWh, quoted recently by E.On, on the basis of a carbon emission cost of €20 per tonne.

The RWE figure for gas-fired generation, again based on 5,700 full hours per year, is £64 per MWh: a €16 carbon emission cost per tonne has been assumed.

At face value, these fossil-fuel generation cost figures compare rather poorly with those for new nuclear build, many of which are close to £40 per MWh. However, any cost projections for new nuclear build are subject to wide deviation. Indeed, EdF's new third generation nuclear plant, Flamanville 3, which is currently under construction, is already materially exceeding its projected costs.

A crucial component, especially for a discounted cash flow (DCF) valuation model, is the assumed lifetime of the nuclear plant. A modest 20 years' assumption is likely to produce a poor return whilst the more optimistic 60 years' assumption – now becoming the US norm – will give rise to a much enhanced financial return.

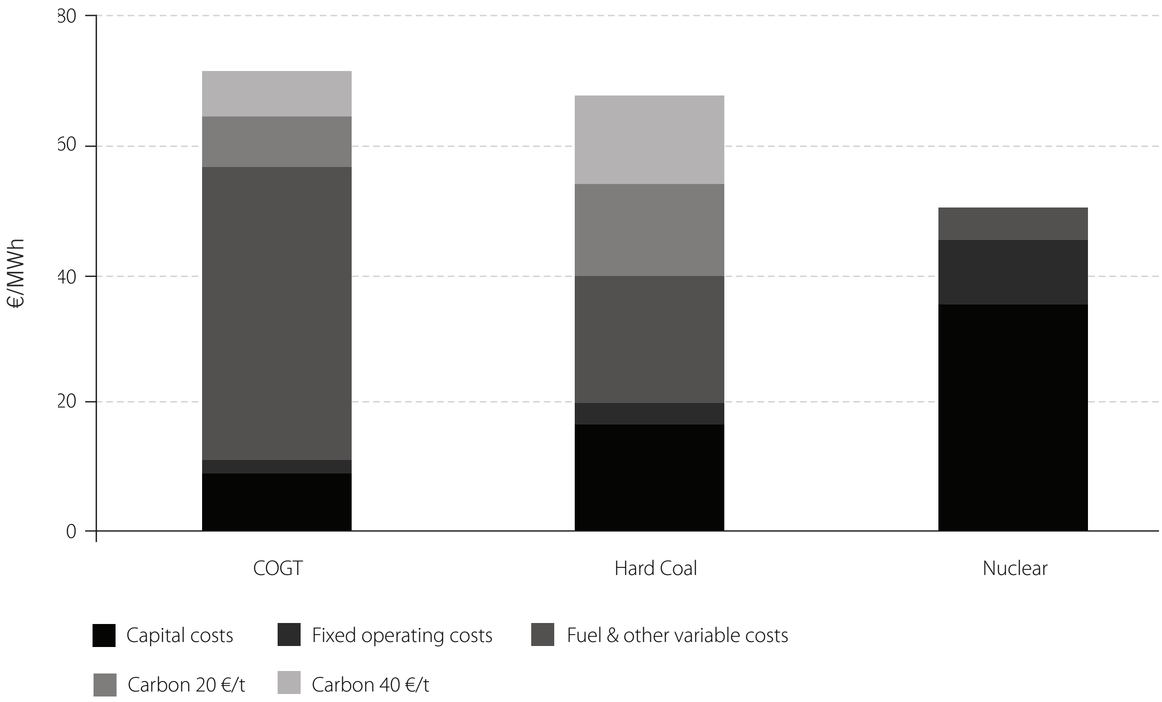
But the most important factor for calculating the projected return is the WACC. Given the long lead-time for new nuclear build, the heavy fixed cost component and the extended life-time, the WACC calculation is crucial.

The WACC itself is derived from the cost of equity, the cost of debt and the mix between these two financing sources. With assured revenues through the proposed LCO, a 35% equity to 65% debt ratio and a Treasury indemnity, it may be possible to secure a WACC of about 7.5%, which should make new nuclear build very profitable if selling prices materially exceed £45 per MWh.

Some allowance would need to be made for FOAK costs, along with higher specialised steel prices. In BERR's 2008 Nuclear White Paper, its mid-range capital cost projection for new nuclear build was £1.25 million per MW, whilst its WACC assumption was 10%.

In fact, the overnight capital cost for new nuclear build has risen appreciably over the last 18 months. First, the £/€ exchange rate is now much weaker. Secondly, the pronounced over-runs at Olkiluoto 3 and, less seriously, at Flamenville 3 provide further

Figure 12: E.On's comparative generation costs (2008)



Source: E.On

Figure 13: Projected new nuclear build generation costs (£ per MWh)

Capital Cost per MW	WACC of 6.5%	WACC of 7.5%	WACC of 8.5%
£1.5m	31	35	38
£2.0m	35	38	41
£2.5m	38	41	45

Source: Nigel Hawkins Associates

evidence that the relatively low costs quoted in recent years, both by nuclear vendors and academics, are far too optimistic.

Based on a 60 year plant life, EdF's 2005 figures show nuclear generating costs of €46 per MWh, equivalent to £40 per MWh. These figures look very competitive, especially since FOAK costs are included. E.On's more recent figures for nuclear generation costs are, not surprisingly, above those published by EdF. E.On's new nuclear build projections are about €50 per MWh, equivalent to £44 per MWh.

Clearly, much depends upon the capital cost assumptions and the WACC. Figure 13 (above) shows the projected cost per MWh, based on varying capital costs and WACC scenarios. They assume LCO off-take contracts, a Treasury indemnity and a 35% equity to 65% debt ratio.

In terms of renewable generation, BERR has published data compiled by Ernst & Young in 2007, which reveals a very pronounced cost differential between the various renewable sources.

For the onshore wind sector, BERR shows a range of between £54 per MWh and £106 per MWh. For offshore wind plants, most experts believe that the generating costs are at least double that figure. BERR's figures are lower, with a range of between £82 per MWh and £102 per MWh.

However, over the last two years, turbine-related costs have risen appreciably, although the current recession is now reversing this upward trend. Since they account for roughly 80% of the capital expenditure of a wind plant project, this trend is clearly having a marked impact upon the economics of wind generation.

The data for other renewable sources is very variable, especially as there is a large one-off capital investment element to many of them – something that is especially true of new hydro-power plants.

Significantly, whilst there has been considerable overseas investment in solar stocks, BERR's figures conclude that the cost per MWh for solar photovoltaic generation is close to £500 per MWh and probably higher.

The calculations published by BERR in the 2007 Energy White Paper are set out in Figure 14.

Figure 14: Renewable generation costs

Source	£ per MWh
Sewage Gas	28-53
Landfill Gas	32-63
Co-firing	51-75
Onshore wind	54-106
Energy with waste with CHP	75-83
Hydro-electric	46-97
Offshore wind	82-102
Dedicated biomass (regular)	77-114
Dedicated biomass* & Biomass CHP	119-180
Wave & tidal stream	121-282
Anaerobic digestion/gasification/pyrolysis	103-202
Solar PV	488-717

** Energy Crops. Source: BERR, Reform of the Renewables Obligation 2007.*

The comparative generation data published by EdF and E.On for coal, gas and nuclear generation has been recalibrated to reflect current coal and gas input costs; similar adjustments have been made to the RWE fossil-fuel figures, which are based on much lower annual output.

In terms of nuclear power, an allowance has been made for a higher WACC arising from the current financial crisis. Also included in Figure 15 below, which compares generation costs in £ per MWh, is the Ernst & Young mid-range estimate for onshore wind generation.

Figure 15: Summary of comparative generation costs (£ per MWh)

Source	EdF	E.On	RWE	Ernst & Young
Coal	49	45	55*	n/a
Gas	56	55	60*	n/a
Nuclear	43	46	n/a	n/a
On-shore wind	n/a	n/a	n/a	80

** Based on mid-merit output levels. Source: Companies, BERR & Nigel Hawkins Associates.*

9 Networks

Transmission

Curiously, the role of National Grid in the privatization of the electricity supply industry almost 20 years ago was very much that of a bit player. Today, it is the EU's most valuable electricity transmission business.

Whilst the two fossil-fuel generators, National Power and PowerGen, the 12 RECs and the two integrated Scottish companies – ScottishPower and the then Scottish Hydro-Electric – attracted many investors, National Grid's ownership was spread amongst the 12 RECs.

In the mid 1990s, National Grid was demerged. Currently, its £13.0 billion market capitalisation exceeds that of all other privatised electricity companies in the UK, most of which have now been subsumed into larger international organisations.

Previously, National Grid was simply the monopoly operator of the English and Welsh high voltage electricity transmission system. Today, its UK activities embrace electricity and gas – a core business that has been broadly replicated on the Eastern seaboard of the US. Recently, investors have focussed on its acquisition of KeySpan, a major US energy delivery company located in the same area.

At the heart of National Grid's core business is its UK electricity transmission division, which regulators have treated generously over the years. With its substantial investment programme, this UK business benefits from secure returns derived from Ofgem's WACC assumption – 4.4% after tax at the last periodic review.

In expanding its UK operations, National Grid acquired the Transco division of the privatised British Gas. The long-distance gas transportation business remains a substantial profit contributor, although the ongoing returns from the original eight gas distribution businesses have been scaled back. Not only did National Grid sell four of these gas distribution networks but also the regulatory regime has reduced allowable returns.

National Grid's UK electricity transmission investment, a central part of its overall capital expenditure programme, is very much driven by plant margin concerns. Historically, for the UK grid network, a minimal plant margin of around 17% has been assumed.

This plant margin figure allows for unexpected station outages and sudden surges in demand. In effect, this margin, based on many years of operating experience, is the defined allowable minimum to ensure that demand on the generation system can be met. But, with lower base-load plant investment in recent years and with more intermittent renewables plant coming onto the system, there is real concern as to whether this plant margin is sufficient.

In order to protect the plant margin, it is essential that the larger peak plants are kept available. They will only be called up irregularly but they materially enhance security of supply. As such, there is a strong argument for providing capacity payments, either directly or indirectly via National Grid, to operators of these plants as a financial incentive to ensure their continued availability.

National Grid Finances

National Grid's low-risk business characteristics have been instrumental in enabling it to operate with a high net debt structure, which minimises its tax liabilities. At March 2009, National Grid's net debt stood at £22.7 billion, a figure that would – in today's depressed markets – normally disconcert investors, even for a heavily capitalised utility. Indeed, there is some stock market speculation that National Grid may need to launch a large rights issue over the coming months.

Between 2006 and 2012, National Grid plans to have invested around £12 billion, part of which is earmarked for the upgrading of the UK electricity transmission system. However, given the ongoing credit crisis, it will surely review some of its more marginal schemes. Within this category would lie some of the proposed transmission links to remote sites in Scotland and to some offshore wind plants, whose costs are looking increasingly uncompetitive.

Of course, other transmission businesses, on the basis of Ofgem's competitive build-out policy, may bid to undertake at least some of the necessary offshore connections. DECC anticipates that up to 33 GW of offshore wind plant could be constructed in the UK, which would give rise to an estimated £12 billion of investment in transmission infrastructure. To what extent Ofgem's competitive tendering process will achieve its aims remains doubtful.

Other Networks Investment

Since much of the electricity distribution system was built in the 1960s, widespread upgrades are now needed. But because it is largely owned by four of the six integrated energy companies, it is unlikely that there will be serious difficulties in raising the necessary funds to refurbish it. Significantly though, there have been reports that EdF – the owner of three major electricity distribution companies – is seeking to sell some of its network assets.

Figure 16 shows the current owners of the 12 electricity distribution businesses in England and Wales, the two in Scotland and the monopoly business in Northern Ireland.

Of the eight regional gas distribution businesses, National Grid retains ownership of four networks. SSE is the leading investor in Scotia Gas, which owns the networks in Scotland and in the South of England. The remaining network operators – Wales and West Utilities, and Northern Gas – are owned primarily by the Macquarie European Infrastructure Fund and by Hong Kong infrastructure companies respectively.

Currently, Ofgem is conducting a review – its RPI-X@20 project - of utility distribution networks and how they are price regulated.

Figure 16: Electricity distribution ownership

Distribution Company	Owner
Eastern	EdF
East Midlands	E.On
London	EdF
Manweb	Iberdrola
Midlands	Aquila
Northern	Mid American
Norweb	Private Equity*
Seeboard	EdF
Southern	SSE
Swalec	Western Power
Sweb	Western Power
Yorkshire	Mid American
Scottish Hydro-Electric	SSE
Scottish Power	Iberdrola
Northern Ireland	Arcapita

**JP Morgan Infrastructure and Commonwealth Bank of Australi's Colonial First State. Source: Utility Week.*

10 Consumer Prices

Rising energy prices – both at the wholesale and retail levels – remain an abiding political concern. Over the last three years, prices have risen appreciably on the back of higher oil prices, to which gas prices are closely linked.

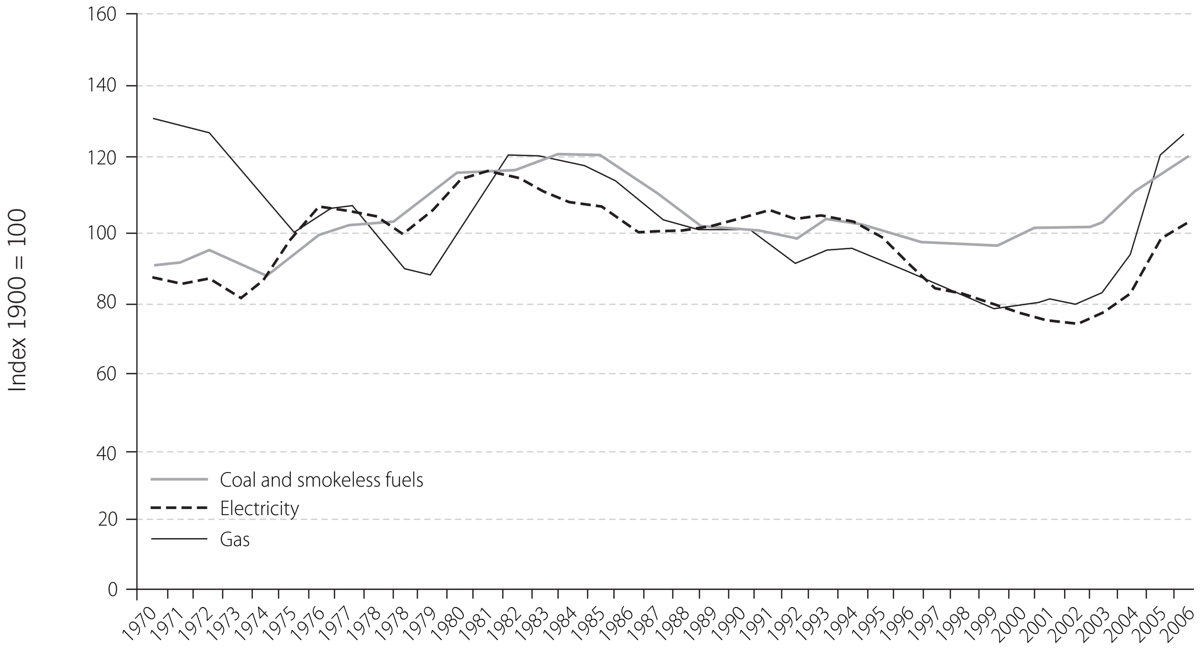
More recently, the six integrated energy companies have been slow to reduce their domestic energy prices as the oil price has plunged, although the gas price generally lags the oil price by up to a year.

Figure 17 shows how domestic gas and electricity prices have fluctuated in real terms since 1970.

For elderly people in particular, the price of gas, which provides most space heating, is particularly crucial. On the back of rising wholesale gas prices, average domestic gas bills have risen sharply since 2006. But price cuts have recently been announced with the average annual retail gas bill for Centrica, which has a domestic gas market share of roughly 46%, falling from £882 to £799.

Figure 18, (over) which reproduces data compiled by Consumer Focus on the basis of a standard credit tariff, shows the relevant price movements in recent years

Figure 17: Movements in UK domestic gas & electricity prices



Source: Office for National Statistics

Figure 18: Average annual gas bill (£)

Supplier	1/2006	1/2009
British Gas/Centrica	515	882
EdF	470	793
Npower/RWE	466	797
PowerGen/E.On	493	809
ScottishPower/Iberdola	463	912
SSE	453	801
Averages	**477**	**832**

Source: Consumer Focus

The Six Integrated Energy Companies

Following the acquisition of PowerGen and National Power in the late 1990s, the two leading integrated German companies, E.On and RWE, secured a strong position in the English and Welsh electricity supply market. As part of the vertical integration strategy, the electricity supply businesses of the 12 RECs were carved out, with the largest players now being E.On, RWE and EdF. Beyond this European trio, three other integrated players have emerged.

First, Centrica, which was demerged from British Gas, has used its domestic gas franchise to build up a sizeable share of the UK electricity market: its dual fuel strategy has been popular. To supply its customer base effectively and to reduce its risk exposure, Centrica has felt compelled to participate in the UK generation market.

Secondly, Iberdrola has entered the UK electricity sector via its acquisition of ScottishPower, which also owns Manweb. Iberdrola's priority remains the renewables sector, where it is the world leader through its majority stake in Iberdrola Renovables.

Thirdly, SSE has expanded substantially from its two bases, the North of Scotland and the South of England. It owns large coal-fired plants, including Ferrybridge and Fiddlers Ferry. On the supply side, SSE has been aggressive in successfully expanding its market share; on various measurements, its prices are the cheapest nationwide.

Figure 19 below lists the UK electricity supply market shares held by each integrated energy company; it also shows the financial markets data, including that for National Grid, based on prices as at June 15 2009.

Whilst several independent suppliers have emerged over the years, none has been successful in challenging the six integrated energy companies. Bizz Energy, which built up a reasonable share in the SME market, was recently sold very cheaply, for a reputed £3.5 million, to Centrica.

The dominance of the six integrated energy companies has, not surprisingly, raised concerns about a lack of effective competition. In fact, in many other sectors – including high street banking, groceries and mobile telephony – there is also market dominance by between four and six companies.

In the electricity sector, this situation is partly due to the compelling advantages of vertical integration, all the more so since the introduction of NETA in 2001. Some organisations, including Consumer Focus, have called for the electricity supply industry to be referred to the Competition Commission. It is very doubtful that such a move would bring about any marked and long-lasting improvement in the structure of the UK electricity industry.

An alternative is to re-introduce price controls for both electricity and gas supply, especially at the retail level. But given that they

Figure 19: Share of UK supply market and valuations

Company	UK Supply Market Share (%)	Market Cap. (£bn)	Net Debt (12/2008)* (£bn)	Enterprise Value
EdF	14	56.8	-21.5	78.3
E.On	19	44.5	-39.3	83.8
RWE	16	27.1	-16.4~	43.5
Iberdrola	12	26.5	-24.9"	51.4
National Grid	n/a	13.0	-22.7	35.7
Centrica	21	12.0	-0.5	12.5
SSE	18	10.8	-4.8	15.6

** March 2009 data has been used for National Grid &SSE. ~Pre Essent acquisition."Including tariff deficit. Source: Ofgem, Financial Times and Companies.*

were abolished some years ago, on the basis that competition would be the most effective way to provide consumers with the best deals, many would regard this as a retrograde step.

In order to promote greater transparency about the profits of UK-based generators, the Government, through Ofgem, should require the six integrated energy companies to provide an annual – and externally audited – profit and loss account for each major power station that they own.

These figures would replicate those published annually by the Drax Group for its eponymous plant; they would provide valuable data about fuel input costs and profit margins. Similar disclosure requirements should also be applied to Centrica, with regard to its British Gas WACOG (Weighted Average Cost of Gas) figure that it no longer publishes.

To avoid the well-worn commercial confidentiality excuse, all these figures could be published on the same day each year – a new National Energy Day.

11 Financial Developments

Like other sectors, the electricity and gas industries have been impacted by the unprecedented turmoil in the financial markets as the global banking system imploded and the long years of debt expansion came to a rapid end. Banks in the US, Europe and the UK have all been grievously affected. Most of them are prime lenders to the electricity and gas companies.

During 2008, the US-based Lehman Brothers collapsed, whilst other major financial institutions, including the world's leading insurance company, AIG, needed massive injections of government money to maintain their financial viability. The Bank of America, the new owner of Merrill Lynch, and JP Morgan Chase, which acquired Morgan Stanley, were major recipients of federal support, along with Citigroup, in which the US Government is now taking a large minority stake.

The UK situation has been equally grave, with every leading retail bank, except HSBC, experiencing massive share price falls and, in some cases, being subject to cash injections from the Government. In Barclays' case, it decided to accept higher priced Middle East loans rather than UK Government finance.

But the Royal Bank of Scotland (RBS), a major utility investor and lender over the last decade, was forced to undertake a second rights issue, which was almost exclusively taken up the Government. More recently, RBS's share price has collapsed – the Government's ownership is now set to exceed 80%.

Britain's leading mortgage lender in recent years, Halifax Bank of Scotland (HBOS) – now controversially merged with Lloyds – saw its shares crash by over 90% during 2008. Following large cash injections, the Government's stake in the new group may exceed 60%.

In total, Government has budgeted for a liability of c£50 billion as the cost of its financial intervention in the banking system; other institutions, including the International Monetary Fund (IMF), have projected a far higher figure. Most of this liability is associated with saving RBS and Lloyds, including HBOS, mainly through the injection of £37 billion of equity capital. The expected losses from the Government-insured Asset Protection Scheme (APS), which covers £325 billion of RBS assets and £260 million of Lloyds' assets, account for much of the remainder.

Figure 20: Bank shares data

Bank	Share Price (1/1/2008) (p)	Share Price (1/1/2009) (p)	Share Price (15/6/2009) (p)	Share Price Fall between 1/1/2008 & 1/1/2009 (%)
Alliance & Leicester	648	n/a	n/a	Owned by Santander
Barclays	504	153	292	-69.6
Bradford & Bingley	268	n/a	n/a	Owned by Santander & Northern Rock
HBOS	735	69	n/a	-90.6; now part of Lloyds
HSBC	842	662	547	-21.4
Lloyds	472	126	65	-73.3
RBS	444	49	40	-88.9

Source: Financial Times and Daily Telegraph

During 2008, the valuations of UK banks plunged. As Figure 20 shows, the share price falls – in just one year – of every bank, except HSBC, have been quite unprecedented. They reveal starkly both the depth of the financial crisis that the UK is currently facing and, more specifically, the immense shareholder value destruction by the banks involved. It is the case though that bank shares, notably Barclays, have rallied strongly in recent weeks.

The recent traumatic events for the UK banking sector have direct implications for the electricity industry. Despite the massive injections of Government funds, especially into RBS, lending levels remain low as banks have understandably adopted a policy of conserving cash. Moreover, many overseas lenders have re-focussed on their domestic markets. To that extent, it remains difficult for any company, except prime borrowers, to secure substantial funds at reasonable interest rate levels.

Bond Costs

Not surprisingly, the credit crisis is having a major effect on borrowing costs and the resulting WACCs. E.On has confirmed that it is now paying around 40 basis points more than it had previously. For less well-financed companies, this increase will be far more pronounced.

Since the impact of the credit crisis became clear during last autumn, there were relatively few new medium or long-term bond issues by UK utilities. By contrast, EdF and E.On have continued to issue bonds over the last six months.

More recently, though, UK utility borrowers, such as SSE and National Grid, have returned to the debt market. Figure 21 lists the major UK utility bond issues since the start of 2009.

In addition, last December, Centrica undertook a £2.2 billion rights issue, which gave rise to a 91% take-up by investors. The funds have been used by Centrica to finance a 20% minority stake in the EdF-owned British Energy.

The reality is that prime borrowers should continue to access debt markets successfully, although on less beneficial terms than previously. For smaller businesses, borrowing is now increasingly difficult as banks either withdraw or limit credit lines.

Figure 21: Recent utility bond issues

Company	Value	Maturity	Interest Cost	Spread
National Grid	£400m	5.25 years	6.125%	335 bp over Gilts
National Grid	€500m	5.25 years	6.5%	365 bp over Mid Swaps
National Grid	£350m	22 years	7.375%	320 bp over Gilts
Severn Trent	£400m	9 years	6.0%	285 bp over Gilts
SSE	£700m	5 years	5.75%	290 bp over Gilts
Thames Water	€500m	4 years	6.175%	330 bp over Mid Swaps

Source: Companies

12 Other Issues

Three other issues relating to the UK energy sector warrant comment – fuel poverty, smart meters and windfall taxes.

Fuel Poverty

Fuel poverty is defined as existing in a household that spends more than 10% of its income on fuel to maintain a satisfactory heating regime. As part of its strategy to combat fuel poverty, the Government has recently raised winter fuel payments for both the over 60s – from £200 to £250 – and for the over 80s – from £300 to £400.

Furthermore, the Government and Ofgem have placed requirements on the six integrated energy companies to divert some financial resources to combat fuel poverty. In the 2008 Budget, annual expenditure on social tariffs was raised from £50 million to £150 million.

With a much lower oil price, electricity and gas prices are now beginning to fall. If this momentum is sustained, the fuel poverty issue will be less acute. Nonetheless, whilst fuel poverty has fallen notably from the 6.5 million households defined as such in 1996, it has recently begun to climb again on the back of the substantial energy price increases in 2007 and 2008: Consumer Focus recently claimed that 5 million households suffered from fuel poverty.

Smart Meters

Smart meters allow energy suppliers to communicate directly with their customers, thereby removing the need for meter readings and ensuring accurate bills – without the need for estimates.

Moreover, the widespread introduction of smart meters would bring various benefits in terms of energy savings and lower bills, depending upon how the installation of these meters were financed. Smart meters can also make a positive contribution to balancing micro-generation output and in monitoring a feed-in tariff regime.

For some years, there have been discussions about smart meters and their potential benefits. There is a strong case, once the technology is totally reliable, for Ofgem to give the go-ahead for the installation of smart meters, initially in pilot areas with a mix of electricity consumers. The process of switching to water meters in recent years should also provide some valuable administrative lessons.

The Government has recently published its proposals for the installation of smart meters, which are the subject of consultation. Its preferred approach is a model under which gas and electricity supply companies will be responsible for the provision of smart meters, whilst a single provider will be appointed centrally to provide communication services to and from meters. Whether the Government's proposals will prove successful is questionable.

However, to provide incentives to the six integrated energy companies, who are likely to sell less electricity through the installation of smart meters, Ofgem should commit to allowing the cost to be part of the Regulatory Asset Base (RAB) of the relevant distribution company, on which the latter will earn a specified regulated return. With the intention of promoting meter competition, Ofgem removed meter costs from the RAB in 2005.

Windfall Taxes

With the six integrated energy companies reporting sharply higher profits on the back of marked price increases over the last three years, notwithstanding soaring public borrowing levels, it is hardly surprising that there have been calls for the imposition of a Windfall Tax. There is a utility precedent since the incoming Labour Government in 1997 did impose a Windfall Tax, although this was targeted more at the under-pricing of the original utility privatizations rather than on the profits that the companies were earning at the time.

With four of the integrated energy companies being international businesses with operations throughout much of Europe, there would be obvious negative investment implications of introducing such a tax. To what extent Finland, which has recently announced a Windfall Tax on energy companies, suffers from this tendency remains to be seen.

The investment programmes of international energy companies, such as E.On – which is constructing 20 power plants in Europe and four in Russia with a combined capacity of over 20,000 MW – are mobile: some of the funds earmarked for planned UK capital expenditure could readily be re-directed overseas. Such a scenario would be particularly damaging for the prospects of new nuclear build in the UK.

13 Conclusion

This report has analysed many of the key issues surrounding the UK energy sector. Most of the challenges are generation-related, whether it is the compelling need to build more base-load plant, to promote new nuclear build or to safeguard future gas supplies. If the generation-related issues can be satisfactorily resolved, many of the other shortcomings in the UK electricity and gas sectors will be less pronounced.

Since maintaining security of supply – in the short, medium and long terms – remains the prime challenge, it is incumbent upon the Government not only to draw up policy documents, of which there have been many, but also to participate pro-actively with the six integrated energy companies to ensure that their capital projects are actually delivered.

After all, it is these six companies who – through their investment decisions – will decide the UK's energy fate beyond 2014.

It is now the time for less words and more action.

Appendix I – A Chronology of Energy

The chronology below lists the main energy events since the Industrial Revolution, which began in England during the 18th century. It focuses disproportionately on major UK energy events, especially over the last 50 years.

Pre 1800 – Many windmills were constructed, especially in the Low Countries; some geothermal sources were also exploited. As the Industrial Revolution took root in England, hydro-power was a key factor, especially in the textile industry.

1859 – First on-shore oil is produced in Titusville, Pennsylvania.

1882 – Thomas Edison builds the world's first electricity generating plant in Pearl Street, New York.

1890/1940 – Various hydro-power sources are exploited, notably in Norway and Sweden.

c1920 – 1 million coal miners work in 1,000 UK pits

1930s – Building of the Tennessee Valley New Deal Scheme.

1942 – Enrico Fermi, the Italian physicist, generates the world's first nuclear power in a Chicago squash court.

1950 – Denmark leads the development of modern wind-power generation.

1950/80 – The US space programme provides a boost to research into solar/photovoltaic cells for energy generation purposes, notably in the US and Japan.

1956 – The world's first nuclear power plant is opened at Calder Hall, Cumbria.

1960/71 – The Nile/Aswan Dam scheme is constructed in Egypt.

1966 – The 240 MW Rance tidal power generation plant near St Malo, France, is completed.

1967/77 – The nation-wide conversion in the UK of town gas to piped gas is implemented.

1972/74 – Major strikes break out at UK pits.

1973/74 – The first global oil crisis takes place, with oil prices quadrupling.

1974 – The first units of the Drax plant are commissioned; the second units were completed in 1986.

1975 – A major nuclear build programme is started in France.

1975 – The first North Sea oil is produced from the Argyll field.

1977 – The first North Sea gas is piped ashore from the Frigg field in Norway to the St Fergus landfall terminal in Scotland.

1979 – The Three Mile Island nuclear accident in Harrisburg, Pennsylvania, takes place.

1979/80 – The second global oil crisis develops, with further upward pressure on oil prices.

1984 – The UK coal miners' strike lasts for one year.

1986 – The Chernobyl nuclear disaster occurs in Ukraine.

1989/1991 – Most of the UK electricity industry is privatised – a policy that is subsequently replicated throughout much of Western Europe.

1990/2000 – The 'dash for gas' takes place in the UK – a trend that is emulated in Spain several years later.

1992 – The closure of 31 of the UK's 50 pits is announced.

1992 – Under the auspices of the United Nations' body, UNCED, the world's first Earth Summit was held at Rio de Janeiro, where a Convention on Climate Change was signed.

1992 – The Maastricht Treaty, which promotes sustainable development, is ratified by members of the EU.

1994/2009 – The controversial Three Gorges Project in China is constructed.

1997 – Terms of the Kyoto Treaty, which prescribes major reductions in greenhouse gas emissions, are agreed. However, the US, China and India – all major carbon polluters – do not ratify this Treaty.

2001 – The agreement for the phase-out of German nuclear power stations by around 2020 was signed by the Government and the nuclear-power generators.

2001 – Introduction of the New Electricity Trading Arrangements (NETA) in the UK.

2004 – The EU holds the Renewable Energy Conference in Berlin, which sets out various goals, notably that – by 2020 – the EU would seek to obtain 20% of its energy requirements from renewable energy sources.

2005 – The EU's Emission Trading Scheme (ETS) starts up; permits to emit carbon dioxide become tradable.

2006 – Over the New Year, gas supplies to Ukraine are cut off by Russia's Gazprom – they are restored after international pressure.

2007 – In the UK, the Energy White Paper is published, which proposes new nuclear build.

Appendix II – Glossary

AGR – Advanced Gas-cooled Reactor, the UK's second generation design.

AP1000 – Westinghouse's latest nuclear design, marketed by Japan's Toshiba.

APS – Asset Protection Scheme, set up to insure the banks' toxic debts.

Bcm – Billions of cubic metres.

BERR – Department of Business, Enterprise and Regulatory Reform.

BG – British Gas, a leading UK gas exploration and production company.

Bp – Basis point, which refers to the premium paid over Government bonds.

BWR – Boiling Water Reactor, a nuclear design sold widely by GE.

CCGT – Combined Cycle Gas Turbine plant, the leading gas generation design.

CCS – Carbon Capture and Storage plants, which are under development.

CEGB – Central Electricity Generating Board.

CHP – Combined Heat and Power.

CIF – Cost, Insurance and Freight.

CoRWM – Committee on Radio-active Waste Management in the UK.

Co2 – Carbon Dioxide, the major emissions gas from fossil-fuel plant.

DCF – Discounted Cash Flow.

DECC – Department of Energy and Climate Change.

DTI – Department of Trade and Industry, recently renamed BERR. (see above)

EdF – Electricite de France, France's leading electricity company.

E.On – Germany's largest energy company.

EPR – Evolutionary Power Reactor, a nuclear design marketed by Areva.

ETS – Emissions Trading Scheme, set up by the EU in 2005.

EU – European Union.

FGD – Flue Gas Desulphurisation equipment, which minimises pollution.

FOAK – First-of-a-Kind, the cost of building the first plant of a new design.

GdF – Gaz de France, now part of the GdF Suez group.

GE – General Electric, the world's leading conglomerate.

GW – Gigawatt, equivalent to 1,000 Megawatts.

HBOS – Halifax Bank of Scotland, now owned by Lloyds.

HSBC – Hong Kong and Shanghai Bank, the UK's largest financial institution.

HSE – Health and Safety Executive, UK.

IGCC – Integrated Gasification Combined Cycle plants.

IMF – International Monetary Fund

IPC – Infrastructure Planning Commission, as set up by the Planning Act 2008.

IPP – Independent Power Project.

KWh – Kilowatt hour, a unit of power.

LCO - Low Carbon Obligation, as proposed in this report.

LCPD – Large Combustion Plant Directive, issued by the EU.

LNG – Liquefied Natural Gas.

MAGNOX – Magnesium Oxide plants, the UK's first generation nuclear design.

MtC – Millions of tonnes of Carbon emissions.

MW – Megawatt, equivalent to 1,000 Kilowatts.

NDA – Nuclear Decommissioning Authority, a UK Quango.

NETA – New Electricity Trading Arrangements for the UK, introduced in 2001.

NFFO – Non-Fossil Fuel Order, a renewable price support mechanism.

NII – Nuclear Installations Inspectorate, part of the HSE.

NRC – Nuclear Regulatory Commission, US.

O & M – Operation and Maintenance Costs.

OPEC – Organisation of the Petroleum Exporting Countries, formed in 1960.

PV – Photo-voltaic cells, as used in the solar sector.

PWR – Pressurised Water Reactor, the most widely used nuclear plant design.

RBS – Royal Bank of Scotland, now almost entirely owned by the Government.

REC – Regional Electricity Company, 12 of which were privatised in 1990.

RO – Renewables Obligation, a requirement placed on UK electricity companies.

ROC – Renewables Obligation Certificate, which underpins green subsidies.

RWE – Germany's second largest energy company.

SME – Small and Medium-sized Enterprises.

SSE – Scottish and Southern Energy, a vertically integrated energy company.

WACC – Weighted Average Cost of Capital, a blend of debt and equity finance.

WACOG – Weighted Average Cost of Gas, as published formerly by Centrica.

About the Author

Nigel Hawkins is an investment analyst, who specialises primarily in the electricity, gas, water and telecoms sectors; he also covers several other sectors. He has been employed in the City since 1988 and has worked for Hoare Govett (now owned by RBS), Yamaichi and Williams de Broe (now Evolution).

He is a regular feature writer for *Utility Week* and *Cleantech* magazines and frequently contributes to the financial media. In addition, he undertakes various research projects on energy, water, health and economics policies for Westminster-based Think Tanks and other organisations. Last year, he wrote *Privatization – Reviving the Momentum* for the Adam Smith Institute, where he is a Senior Fellow.

Prior to joining the City, he worked for six years in politics, including three years as Political Correspondence Secretary to Lady Thatcher at 10 Downing Street. In 1987, he stood in the General Election as Conservative Party candidate in Sedgefield against Tony Blair.

He was awarded a 2.1 degree in Law, Economics and Politics from Buckingham University and subsequently qualified as an Associate of the Institute of Chartered Secretaries and Administrators (AICS), whilst working as Export Sales Manager at Marlow Ropes, Hailsham, East Sussex.