2. ELECTRICITY AND POWER GENERATION

2.1 Recent Trends and Short-Term Outlook

Electricity

In the MDM-E3 fuel type classification, Electricity (8) is defined as electricity consumed as final demand, including losses in pumped hydro-electric power and net trade with France. For a profile of fuel type (8) see table: Profile of Fuel Types in MDM_E3 Classification in 2007.

Electricity generation in the UK has changed from being predominantly coal-based in the 1990s to a much more even generation mix

In 1990 coal accounted for two-thirds of power generation in the UK and nuclear power accounted for one-fifth. The remaining 14% was provided by oil, renewables and imports. Gas accounted for approximately 0.1% of generation. In stark contrast, in 2007, gas accounted for almost 42% of generation. Coal, on the other hand, provided only about 35% of total generation in the UK. Nuclear power now provides less than one-fifth of total generation in the UK, and it is expected that nuclear power generation will decline further as stations are decommissioned. However, at the start of 2008, the government announced that it would support the construction of a new fleet of nuclear power stations. It therefore looks as though nuclear power may become important again in the UK from around 2020 onwards.

Only a small proportion of generation comes from renewables, despite efforts by the government to promote it. In 2007 renewables accounted for around 4-5% of total generation compared to less than 2% in 1990.

Net imports fell from between 3 and 4% in 2000 to just over 1% in 2007. Total supply increased from 330 TWh in 1990 to 391 TWh in 2000 and in 2007 total power generation was over 400 TWh.

The UK's total electricity supply fell by 4.5% between 2008Q1 and 2009Q1 as demand contracted

According to DECC's *Energy Trends*, the total supply of electricity in the UK in 2009Q1 was down 4.5% from 2008Q1, highlighting the effect of the recession on UK

PROFILE OF FUEL TYPES IN MDM03 CLASSIFICATION IN 2007

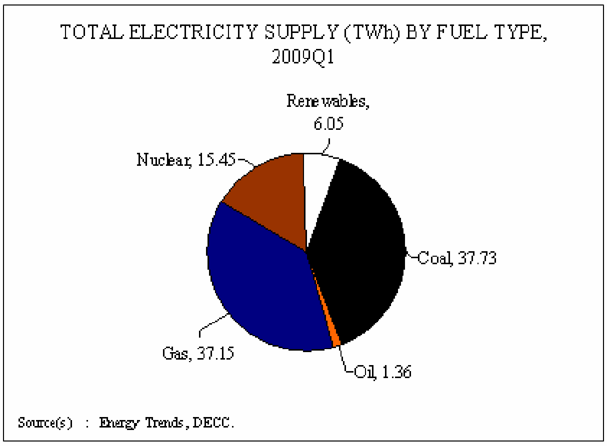
No.	Fuel Type	Share of final energy demand (%) in 2007[9,10]	Share of total electricity generation (%) in 2006	Carbon emissions (mt carbon) in 2006	Sulphur emissions ('000 t SO_2) in 2006
1	Coal[1]	1.6	37.1	40.8	480.3
2	Motor Spirit[2]	12.7	-	15.5	1.2
3	Derv[3]	14.6	-	17.4	0.8
4	Gas Oil	4.5	-	5.7	42.4
5	Fuel Oil[4]	1.2	0.3	2.6	82.6
6	Other Refined Oil[5]	11.9	-	8.4	8.9
7	Natural Gas[6]	33.5	35.5	56.4	11.1
8	Electricity[7]	18.7	-	0.0	0.0
9	Nuclear Fuel	0.0	16.0	0.0	0.0
10	Steam	0.7	-	0.1	0.0
11	Other Fuel[8]	0.6	5.5	5.1	47.4

Note(s) : 1 Includes Hard coal, Lignite/Brown Coal/Sub-Bituminous Coal, Coking Coal, Other Bituminous Coal & Anthracite, Peat, Patent Fuel, Coke Oven Coke and Lignite Coke, BKB and Charcoal.
2 Includes Motor Gasoline, Other Kerosene and Other Petroleum.
3 Diesel.
4 Includes Heavy Fuel Oil, Naphtha, Other Petroleum Products, Crude/NGL/Non-Crude and Crude Oil.
5 Includes Refinery Gas, Ethane, Liquefied Petroleum Gases, Additives/Blending Components, Inputs other than Crude or NGL, Aviation Gasoline, Gasoline type Jet Fuel and Kerosene type Jet Fuel.
6 Includes Natural Gas, Gas Coke, and Natural Gas Liquids.
7 Electricity consumed as final demand, including losses in pumped hydro-electric power and net trade with France.
8 Includes Primary Solid Biomass and Liquid Biomass, Biogas, Industrial Wastes, Municipal Wastes Renewables, Municipal Wastes Non-Renewables, and Non-specified Primary Biomass and Wastes.
9 Total final energy demand includes steam and other fuels.
10 Total final energy demand excludes power generation, energy industries' own use of energy and non-energy use.

Source(s) : Cambridge Econometrics.

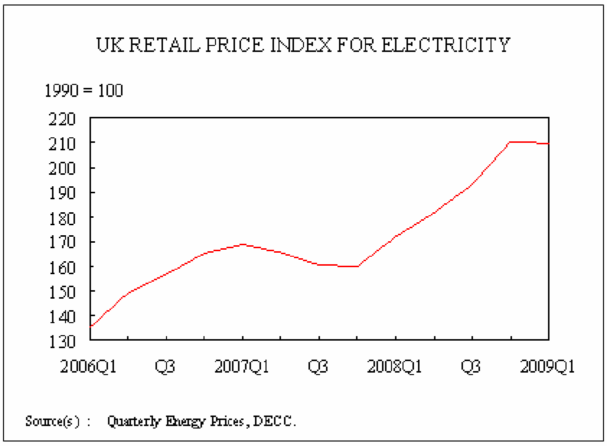
electricity demand. However, indigenous production only fell by 2.9%, whereas net imports, which are typically used to meet expected excess peak demand, fell by nearly 50% to just 1.4 TWh, so that only 1.4% of total electricity supply was imported in 2009Q1 compared to 3.1% for 2008. The UK's import capacity is due to increase at the end of 2010 when the BritNed interconnector between the UK and the Netherlands is completed (currently, the UK can only trade electricity with France).

The use of fuels in the production of electricity saw a large shift away from gas. The use of gas fell by 20.8% in the year to 2009Q1, while coal use increased by 10.0% and nuclear by 17.6%. This reflects the falling price of coal relative to gas, as the large increases in price witnessed in 2008H2 fell back slightly and then levelled off. This shift to coal also highlights the relatively low EU ETS permit price caused principally by the effect of the recession on industrial output. The use of nuclear sources increased by 17.6% as two of British Energy's reactors which were closed due to safety concerns were reopened in 2009Q1. The share of electricity generated by gas fired power stations in UK electricity supply was at a record high of 50.3% in 2008Q1 but has since fallen back and in 2009Q1 electricity generated by coal was equal to that of gas at around 37-38 TWh (see chart: Total Electricity Supply by Fuel Type). Total fuel use fell by 1.1% in the same period.



Following record price rises in 2008, major energy suppliers have reduced their prices to domestic customers in 2009

Throughout 2008, the UK's major energy suppliers announced substantial increases in gas and electricity prices for their domestic customers. Following an initial round of price increases in the first half of the year, EdF raised them again in 2008Q3 by introducing rises of 22% in gas prices and 18% in electricity prices with immediate effect from July. The rest of the 'big six' energy suppliers soon followed: British Gas (owned by Centrica) introduced price rises in July of 35% for gas and 9% for electricity; Scottish and Southern Energy and EON followed in August and npower and Scottish Power in September. According to DECC's *Quarterly Energy Prices*, domestic electricity prices overall rose by 17% in the year to 2008Q3. In addition, industrial users saw a price increase of 27.6% in the same period (see chart: UK Retail Price Index for Electricity). The near simultaneous price rises prompted an investigation by Ofgeminto the state of competition in the retail energy market.



These price rises were in large part due to large rises in the wholesale prices of fuels, including gas. Prices surged in the first half of 2008: between 2007Q3 and 2008Q3 the UK's major power producers saw coal prices rise by 78.3% and natural gas prices by 53.5%. These rises were connected to the rise in the international oil price, which hit a record level of $147 a barrel in July. Further upward pressure on retail prices has come from carbon reduction policies, such as the Renewables Obligation (RO) and the EU Emissions Trading Scheme (ETS). Phase II of the EU ETS was launched in 2008, and initially had higher allowance prices than in Phase 1, although they have now fallen due to the recession. For the most part the additional costs of carbon reduction policies are borne by final consumers as they can be passed on, in full, by energy suppliers.

The Brent crude oil price stabilised at around $70 per barrel over the summer months and wholesale gas prices, which are typically closely linked to the international oil price, also seem to have fallen off a little since peaking after the oil price in late 2008. The carbon price on the EU ETS has also fallen because of the fall off in industrial activity in the EU. While in January 2009, wholesale gas prices remained relatively high, due in part to a cold winter and the drawn-out dispute between Ukraine and state-owned Russian gas producer Gazprom, which led to all gas supplies through Ukraine being cut off for a period (Russia produces around 25% of EU gas, about 80% of which comes through Ukraine), there is now evidence that gas prices have fallen slightly in 2009H1. Accordingly, some UK energy suppliers have begun to reduce their domestic prices: Scottish and Southern, Scottish Power, Edf UK and EON announced price cuts in February 2009, and Npower followed in March all offering modest cuts in domestic energy prices of about 10%. In January 2009, Centrica announced price cuts for gas and in May 2009 followed this with a 10% cut in its electricity prices.

In the longer term, prices are expected to rise as a result of government policies aimed at reducing carbon emissions. The Renewable Energy Strategy (RES) estimates that its proposals will increase electricity bills by 10-13% for domestic customers and 11-15% for industrial customers by 2020, approximately 1% pa.

In the short term, UK electricity demand is projected to decline sharply in 2009 and 2010

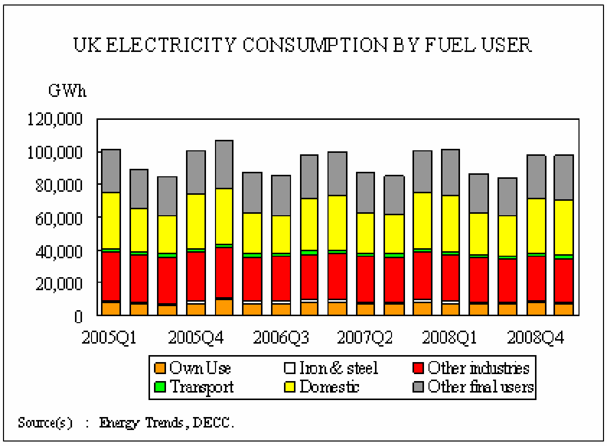
Total electricity demand is estimated to have fallen for most fuel users in 2008, in response to increased prices due to the EU ETS, estimated rises in the price of fossil fuels and the recession (see table: Short-Term Indicators: Electricity). However, overall demand remained unchanged due to increased consumption from households.

SHORT-TERM INDICATORS: ELECTRICITY

	2008	2009	2010
Consumption (TWh):			
Energy-Intensive Inds	40.8	34.3	32.1
Other Industry	71.0	67.5	64.8
Transport	2.7	2.7	2.6
Households	118.2	116.5	115.5
Commerce etc	107.3	103.0	102.9
TOTAL*	400.2	382.0	376.0
Consumption (% pa):			
Energy-Intensive Inds	-3.3	-15.9	-6.6
Other Industry	-3.9	-5.0	-3.9
Transport	0.6	-2.1	-2.7
Households	2.7	-1.5	-0.8
Commerce etc	-0.7	-4.0	-0.1
TOTAL*	0.0	-4.6	-1.6

Note(s) : * Total includes energy industries' own use of energy.
Source(s) : DUKES, Cambridge Econometrics.
Ref : C92F4E August 2009.

Demand from households, who are the largest consumers of electricity, is estimated to have increased by 2¾% in 2008. This is partly caused by a cold winter at the end of 2008. In the short term, households are generally far more sensitive to temperatures and seasons than to prices, even for electricity, and historically their consumption has fluctuated far more than that of other sectors (see chart: UK Electricity Consumption by Fuel User).



A sharp fall in electricity demand is expected across the board in 2009 because of the recession, even though prices are expected to fall. Overall, demand is forecast to fall by 4½%. Particularly steep falls are expected in industries and commerce, because these sectors are most sensitive to economic activity. The contraction in demand is expected to continue less severely in 2010, with a fall of 1½%. All fuel users will continue to reduce their demand for electricity in 2010.

2.2 Factors Affecting Prices and Production

The structure of the UK electricity industry: the supply chain

The supply chain that brings electricity to the retail market is divided into three parts: the British Electricity Trading and Transmission Arrangements (BETTA), under which electricity generators sell electricity to National Grid plc (NG) and directly to large users; transmission of electricity through the grid operated by NG; and the electricity distribution businesses who sell the electricity to end-use suppliers.

Continuous, or 'baseload', electricity is generated from power sources that take a long time to start up and have cheap operating costs but high capital costs. These include large coal-fired, nuclear-powered and some renewable-based facilities; and their output levels cannot be easily altered. To complement the baseload in times of peak demand, 'peakload' power stations are required to handle the additional demand for short periods of time.

These stations can be started rapidly and usually have low capital costs but high operating costs. Gas, oil and small coal-fired stations are examples of peak-load power stations. The differing nature of the two sources means that the prices can move very differently. Peak prices are higher than baseload prices.

BETTA is a wholesale market comprising generators, suppliers, traders, large customers and NG, who buy and sell electricity generated from power stations. This trade is negotiated through bilateral contracts. The market also provides forward prices for up to three years ahead to give generators an idea about the future demand for generation capacity: increases in the forward price send a signal to firms to build more generation or to reduce their future demand. As electricity cannot be economically stored, supply must be exactly balanced with demand at any point in time. Also, there must exist enough electricity capacity to meet the highest expected level of demand, known as the 'peak demand'.

Wholesale markets are in approximate balance, and NG fine-tunes these markets on a second-by-second basis. NG does this by buying or selling a margin of 2-5% of the electricity produced in the market. NG's role is to provide information about the amount of power required to satisfy market demand and to encourage greater production by generators or reductions in consumption by direct users if generation margins are small. NG also buys an operating margin of available generation to deal with unexpected changes in demand or with generator problems. Further, should a generator be unable to provide the amount of electricity it is contracted for, it will have to buy electricity from the market. In times of peak demand, this price can be very high; and this gives a strong incentive to firms to maintain their plants and to rectify breakdowns quickly.

Electricity that is traded on the wholesale market and not sold directly to large users is then sold to NG. Because distribution and transmission of electricity are natural monopolies, the prices are regulated by Ofgem, the regulatory body for the gas and electricity markets in the UK. Ofgem's objectives include the promotion of effective competition and regulation of the monopoly companies who provide gas and electricity infrastructure; helping to secure the UK's energy supplies and assisting efficient environmental improvements in the gas and electricity markets.

From the National Grid, electricity is distributed to the Distribution Network Operator (DNO) companies who operate the low-voltage regional electricity networks. From here, electricity supply companies can buy electricity to fulfil bilateral contracts and sell it on to business and domestic customers. The DNOs are often suppliers and generators themselves. Whereas previously, under the regional structure, consumers only had the choice of a single provider, consumers can now choose from a range of suppliers, including a number of smaller companies who mainly supply green electricity. This has led to improved conditions for consumers, who can now make decisions based not only on lowest price but also on a number of qualitative judgements (eg customer service and environmental considerations).

BETTA applies in England, Wales and Scotland. It was introduced in 2005 to replace the similar NETA, which only covered England and Wales. NETA was introduced in 2001 to replace the Electricity Pool, which had been in operation since the privatisation of the market. The Pool compelled generators to sell all of their output into the Pool at the same price; NETA was introduced to add more flexibility by allowing generators to negotiate prices directly with suppliers in bilateral trades. However, this has given an additional competitive advantage to vertically-integrated energy companies that comprise both generators and suppliers, as these companies can arrange bilateral trades across their organisation. Accordingly, the market has become increasingly concentrated in vertically-integrated firms in recent years.

The structure of the UK electricity industry: generators and end-user suppliers

In the UK there are more than 2,000 power-generating stations, providing around 83GW of electricity capacity and 350TWh of electrical generation a year to the UK electricity market. In addition, there is an electricity interconnector with France with capacity for the import or export of up to 2.5GW. Electricity from autogeneration is also provided for industrial use. Power generation firms typically own different types of generating stations to allow them to diversify supply in response to changing gas, coal and carbon prices. British Energy, now a subsidary of the 85% state-owned French company EdF, owns the nuclear advanced gas-cooled reactors (AGR) sites, which provide around 10GW of electrical capacity, and a single large coal-fired site, Eggborough, which provides 2GW. As a condition of the EdF takeover, the Eggborough site will have to be sold. The Nuclear Decommissioning Authority (NDA), a non-departmental body of the UK government, is responsible for the older Magnox nuclear sites, all of which are due to be decommissioned by 2010, but currently provide 2.3GW of capacity to the National Grid. Their management is contracted out. Centrica predominantly operates combined-cycle gas turbine (CCGT) generators but has also invested in offshore wind. EON the German multinational, owns a variety of power generators via its subsidary EON UK: CCGT, coal, offshore wind, onshore wind and biomass. Together these provide approximately 10GW of capacity in the UK. RWE npower provides nearly 9GW of electrical capacity in the UK from coal, CCGT and open-cycle gas turbine (OCGT) plant.

Slightly smaller firms include Scottish Power, which owns a mix of CCGT, hydro, coal and pumped storage, and Scottish and Southern Electric, whose capacity of 3GW comprises just one CCGT plant (approximately 1.5GW) and a number of smaller renewable generators including wind, hydro and pumped storage.

In the 1990s the supply of electricity was liberalised and transferred from state-owned regional suppliers to privately-owned utilities firms. While generators were initially separate from suppliers, there has been an increasing trend towards vertical-integration, helped by the structure of the BETTA wholesale market. Most of the major suppliers in the UK now also operate a generation business or are subsidiaries of larger energy companies that also include generation plants. In 2009, major suppliers include British Gas (owned by Centrica), npower (owned by RWE), Edf UK (which owns London Energy and is itself a subsidary of EdF), EON UK (formerly Powergen), Scottish Power (owned by Iberdrola, the Spanish utilities firm), and Scottish and Southern Energy.

Ofgem has found no evidence of collusion in UK retail energy markets, but will take action to prevent 'unfair' differential pricing strategies

The almost simultaneous price rises introduced by UK major energy suppliers in 2008 gave rise to concerns about competition in the industry. Together with the large profits being reported by many suppliers in 2008 (in part due to the grandfathering of EU ETS permits) and growing worries about fuel poverty, this prompted the industry regulator Ofgem to launch a probe into the competition in the UK retail gas and electricity markets. The initial report(see http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=4&refer=Markets/RetMkts/ensuppro)of the Energy Supply Probe was published in October 2008, and found no evidence of industry collusion; prices are being set independently and without improper information exchange. Rather, the spate of price rises occurred because of wholesale price rises and because the major suppliers use each other's price announcements as benchmarks.

However, while Ofgem was broadly positive about the industry's transition from a monopoly to a competitive market with several suppliers, it did raise a number of concerns and made proposals for raising the level of competition. In particular, it was worried about the existence of differential pricing strategies, whereby, for example, suppliers charge less to those outside their former regional monopoly market than those in it, and customers using Pre-Payment Meters (PPM) are charged a premium well above the cost differential. These pricing strategies tend to fall on more vulnerable consumers, including the fuel-poor. In addition, it was disappointed at the lack of a major 'competitive fringe' of smaller companies to compete with the big six suppliers. Actions suggested by Ofgem to tackle these issues include:

- promoting customer engagement by forcing suppliers to provide more and clearer information,
- reducing barriers to entry and removing regulations that act as undue deterrents to newcomers,
- tackling price differentials through new licence requirements for suppliers, under which undue price discrimination would be prohibited.

Although some suppliers had already reduced price differentials on PPM in reaction to the probe, Ofgem signalled its determination to tackle this issue in December 2008 by scheduling a consultation on the above licence proposals to begin in January 2009. In March 2009, Ofgem announced its proposed new rules to eliminate unfair price differentials. These included:

- an outright ban on price differentials between payment methods that do not reflect cost differentials
- bills must include an 'at-a-glance' scorecard on tariffs that can easily be compared with other tariffs
- suppliers must issue an annual statement to their customers, with details including their tariff, their consumption, and a reminder of their right to switch

In addition, the government has asked Ofgem to publish quarterly reports during 2009 showing the relationship between wholesale prices, estimated hedged wholesale costs and average retail prices for gas and electricity.

The UK government has given its support for the construction of a new generation of nuclear power stations

Britain's existing nuclear generation capacity is set to decline rapidly in the 2010s and to disappear entirely by 2035. Of the ten nuclear power stations currently operating in the UK, the two remaining Magnox plants, Oldbury-on-Severn and Wylfa on Anglesey, are due to be closed in 2010 (Oldbury had been due to close in 2008, but one reactor has been kept operating), and most of the others are due to be decommissioned by 2020. From 2023 onwards, only Sizewell B in Suffolk is due to remain operational (it will do so until 2035). Furthermore, Britain's ageing nuclear power stations seem to be increasingly unreliable. In 2008 British Energy had to close reactors at Hartlepool and Heysham temporarily on safety grounds.

In response to this planned ending of nuclear capacity as well as the expected loss in capacity from the closure of coal-fired plants due to the EU's Large Combustion Plants Directive, the UK government announced in January 2008 in a White Paper on nuclear power(see http://www.berr.gov.uk/whatwedo/energy/whitepaper/consultations/nuclearpower2007/page39554.html/)that it would support the construction and operation of a new generation of nuclear power stations. This marked a shift from the 2003 Energy White Paper, in which the government was unpersuaded by the economics of nuclear power, but had decided to keep the nuclear option open. This uncertainty over political support had done much to deter private investment.

The government has shown its commitment to its new position by launching the Office for Nuclear Development in September 2008. The brief of this office is to facilitate new nuclear investment in the UK and to advise the government on its policies towards nuclear power. In January 2009, the government announced that the Nuclear Decommissioning Authority expects to nominate Sellafield, Wylfa, Oldbury and Bradwell as potential sites for new nuclear power stations.

The government is to take steps to encourage private operators to build new stations but it will not build any itself. The plans outlined by ministers in January 2008 propose that energy companies must meet the entire bill for construction and a capped bill for waste disposal and decommissioning. Waste disposal and decommissioning only constitute 3% of the lifetime cost of a reactor; thus, the cap is intended to provide only 'modest financial support'. Waste disposal and decommissioning are to be overseen by an independent advisory body, the Nuclear Liabilities Financing Assurances Board, which will liaise with the government and operators. No other support, such as a subsidy, is to be provided unless there is an emergency. In a subsequent announcement in February 2008, the government stated that companies would have to produce a detailed 'funded decommissioning programme' before they could receive approval to build a nuclear power station. Firms will also have to commit to paying money into an independently-managed fund to cover the costs of closing a plant as well as for waste-disposal. Some of the details that have yet to be finalised include the location of a new site for a national repository for nuclear waste.

The shift in government policy seems to have done much to encourage new nuclear build. The most notable sign of this to date is EdF's purchase of British Energyfor $12.5bn (the government announced that it would sell its stake in March 2008) and its proposal to build four new reactors after 2012. However, some uncertainty remains over the economic viability of nuclear generation, given the high capital and start-up costs involved. The UK government's preferred reactor design is thought to be the new European Pressurised Reactor (EPR) built by Areva, the French nuclear group, which has a generation capacity of 1,600 MW and a construction cost of about £2.8bn. Construction is by far the greatest cost in the lifetime of such a plant. The relative competitiveness of nuclear power depends on the price of alternative fuels and on policies about the price of carbon, including the future of the EU ETS. The large falls in the price of oil in 2008H2 following record highs in 2008H1 have raised some concerns, but current discussions on the third stage of EU ETS indicate that it will have a greater coverage and tighter emissions limits, which would favour nuclear power. Opponents of nuclear power cite the high cost, the 'legacy of waste' that can remain harmful for thousands of years and the risk that nuclear plants may be targets for terrorism. Opponents normally advocate renewable energy.

EdF has completed a takeover of the UK's nuclear power generator British Energy

In March 2008 the UK government announced that it was willing to sell its 36% stake in British Energy, the purchase of which would automatically trigger takeover proceedings for the whole company. British Energy owns most of Britain's existing fleet of nuclear power plants, including the AGR sites that will continue generation for some time after the older Magnox sites (which it does not own) have closed. The announcement was part of the government's newly confirmed policy to replace and increase nuclear power generation in the UK.

A number of bidders expressed interest, but EdF soon emerged as the front runner and the government's preferred bidder due to its size and expertise (the firm runs France's 58 nuclear reactors). More valuable than the generation capacity was the land owned by British Energy, on which it is expected to be fairly easy to obtain planning permission for new capacity. By the informal May deadline only EdF had made an offer, and, although an initial bid was rejected at the last minute in August, a takeover deal worth £12.5bn along with some contingency value rights was agreed in September 2008. The move received the approval of the European Commission in December 2008 and the takeover was formally completed in January 2009. EdF is already committed to the construction of four new reactors in the UK, which will be European Pressurised Reactors (EPRs), with the first due to be operational by 2017 and all four by 2025. These are likely to be built at Hinkley Point in Somerset and Sizewell in Suffolk. British Energy has been holding consultations on which of its other sites would be suitable for redevelopment.

EdF will probably not be the only player in the future of British nuclear power generation. Centrica, which at one time considered bidding for British Energy itself as a 'national champion', obtained an understanding with EdF in September that it would purchase a 25% stake in British Energy at the same share price as EdF paid, once regulatory approval had been achieved. Centrica raised the necessary funds in a rights issue in November 2008, and now that the European Commission has approved EdF's takeover, Centrica is expected to press for this deal to be completed soon. In addition, EdF has agreed with the UK government that it will sell off some of British Energy's sites to other companies interested in building new nuclear plants in Britain, such as RWE and EON. Furthermore, the Nuclear Decommissioning Authority is looking for buyers for some of its nuclear sites, including Wylfa on Anglesey.

Despite concerns over profitability, investment in UK wind power generation seems set to continue

The rapid expansion of wind power generation since the 1990s has put pressure on the supply chain for turbine components, leading to lengthening delays and rising prices. This is particularly the case for offshore wind projects, which also face problems in finding staff able and willing to work in difficult offshore conditions. These problems have led to concerns about the profitability of wind power generation. In May 2008 Centrica issued a warning about the rising costs of wind power projects and said that it would be reviewing its investments in the area. In the same month, Shell pulled out of the London Array project to build what will be the world's largest offshore wind farm, citing cost rises and better renewable incentives in the US (the project has survived thanks to the existing partners EON and Denmark's Dong Energy taking an increased share and selling a stake to Masdar of Abu Dhabi). Since then, the financial crisis and falling cost of fossil fuels has made raising capital for wind power generation even more unattractive. In November 2008 Centrica reiterated its warning on the cost of offshore projects, saying that it had risen to £3m per megawatt compared to £2m earlier in the year, and in January 2009 EON warned that falling fossil fuel prices had put the viability of the London Array project 'on a knife edge'.

The economic viability of wind power generation will depend to a large extent on the expected strength of carbon reduction policies. The UK's current flagship policy for renewables generation is the Renewables Obligation(RO), under which electricity suppliers are forced to source an increasing percentage of their electricity sales from renewables or pay a buy-out price. From 2009 onwards, the introduction of banding in the RO will mean that each megawatt hour of electricity sourced from offshore wind will be worth 1½ times that of each megawatt hour sourced from onshore wind farms. Despite this, the British Wind Energy Association (BWEA) has said that the RO in its current form is insufficient to meet EU targets and DECC's target for the UK to have an offshore capacity of 14GW by 2020. However, the Renewable Energy Strategy published in June 2009 considers extending and strengthening the RO in order to increase renewables' share in electricity generation to a third by 2020.

In spite of these concerns and partly because of a continuted commitment to wind powered electricity generation from the UK government, statistics from the BWEA show that growth in the UK's wind power generation capacity continues apace, with offshore wind growing fast. As of August 2009, there was:

- 2,118 MW of onshore and offshore wind electricity capacity under construction
- 6,892 MW of onshore and offshore wind electricity capacity that has had planning permission approved
- 9,402 MW of offshore wind electricity capacity awaiting planning permission.

The capacity of UK wind power generation in 2008 was around 2.8 GW of onshore wind and around 600 MW of offshore. New projects announced in 2008 include a 133 MW joint venture between UK Coal and Peel Power to convert 14 former collieries into wind farms and plans for a 300 MW offshore wind farm off the coast of Kent to be built by Vattenfall, Europe's fifth-largest electricity generator.

The UK Renewable Energy Strategy sets out plans for a major expansion of wind power and other renewables generation but there are still a number of obstacles to overcome

In June 2009, the Department for Energy and Climate Change (DECC) launched *The UK Low Carbon Transition Plan*and alongside it the *Renewable Energy Strategy (RES)* was also published. The policies and strategies outlined within the two documents build on previous policy initiativesrelating to energy efficiency, power generation, transport and over-arching policies such as the EU ETS. Of particular relevance to electricity generation was the ambition to source 30% of UK electricity from renewable sources, including 2% from small scale electricity decentralised supply. To achieve this the RES outlines potential policies to create financial incentives for both centralised and decentralised electricity production. In order to encourage centralised production the government will consult on a number of measures to improve and extend the RO;

- to extend the RO beyond 2027 to 2037
- to introduce a limit to the support to 20 years per project
- to remove the maximum obligation level of 20%
- to review the banding support

The UK is aiming to achieve some 27 GW of electricity capacity in the form of onshore and offshore wind and a further 11 GW of capacity from bioenergy, wave and tidal, hydro and small scale measures by 2020. If this extended renewables ambition can be realised, it will go a long way to meeting the EU target for 15% of final energy demand to be met by renewables.

There are various programmes and policies being introduced to enable the UK to cope with an expansion of wind power and other renewable energies. The Carbon Trust, in partnership with five European energy firms, has launched a technology initiative called the Offshore Wind Accelerator (OWA) with the aim of improving and lowering the cost of offshore wind technology. This will be a five-year project comprising research and development with large-scale demonstrations due to begin in 2010. The Department of Energy and Climate Change's (DECC's) Energy Markets Outlook(see http://www.berr.gov.uk/whatwedo/energy/energymarketsoutlook/page41839.html/)of December 2008 considers several obstacles to growth and highlights measures to remove them. The Planning Act 2008, which received royal assent in November 2008, is intended to streamline the planning permission process for major projects, for example by creating an Infrastructure Planning Committee (IPC) that will take planning decisions on projects of national importance. Obtaining planning permission is often lengthy and uncertain for major wind power projects, particularly those that are onshore and face objections from local communities.

Grid access is a further problem for renewables generation; the UK's current transmission infrastructure is limited in areas that are suited for wind power and other renewables generation, such as the Scottish Highlands. In addition, the manufacture of new infrastructure is hampered by capacity constraints in the supply chain. The government and industry regulator Ofgem published the *Transmission Access Review*in June 2008, which considers possible reforms to how generators obtain Grid access, including firmer connection dates and access rights and a trading scheme for access rights. In the meantime, it implements a 'connect and manage' policy, whereby derogations from the usual network standards will be tolerated in the short term in order to connect new generators more quickly. In addition, in 2009 Ofgem is consulting on a new regulatory regime(see http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/offtrans/pdc/cdr/cons2009)that will give network operators incentives to take on risks in expanding the transmission network to offshore sites before generation projects are completed or confirmed.

The UK government is not ruling out the construction of new coal-fired power stations while clean-coal technologies are being developed

No new coal-fired power stations have been built in the UK since 1984, and the decline of its existing fleet will be accelerated by the introduction of the EU's Large Combustion Plant Directive (LCPD), which forces large combustion-fired electricity generators to conform to air quality standards or else close either after 20,000 hours of operation from 1 January 2008 or by 2015 in any case. However, a number of planning applications for new coal-burning power stations have forced the issue of coal-based electricity generation back onto the agenda, raising some controversy as coal is one of the dirtiest forms of generation. In January 2008 Medway Council endorsed EON UK's bid to build a new coal-fired power station to replace its existing one at Kingsnorth on the Hoo Peninsula. Although planning permission can only be granted by the UK government, the council's action sparked a series of protests from environmental pressure groups such as Greenpeace. Criticism also came from the Environment Agency, which said in September 2008 that new coal stations should not be approved until Carbon Capture and Storage (CCS) technology has been proven on a commercial scale (see below). Another coal-based project is being considered for Hunterston on the Firth of Forth, where Dong Energy of Denmark has applied to build two new plants of 800MW each.

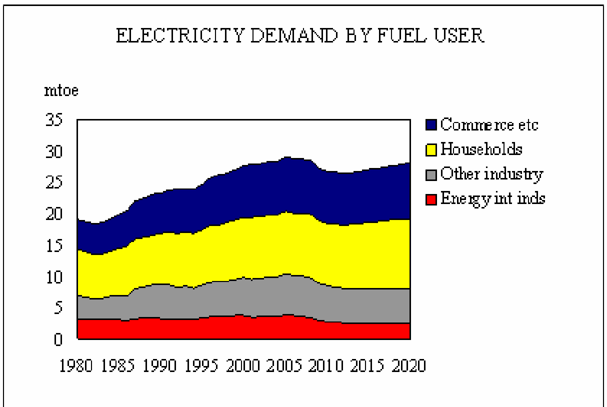
Despite concerns over the environmental impact of coal, the UK government is, for the sake of security of supply, reluctant to see coal disappear from the country's generation mix. Unlike many renewable technologies, coal-based generation is not intermittent, and the UK has substantial coal reserves of its own should securing fuel imports become a problem. The government is therefore pinning its hopes on emerging CCS technologies, which aim to capture the carbon dioxide emitted from fuel-burning and store it away from the atmosphere, possibly in emptying oil wells. However, the 'capture' technology has not yet been proven to work on an industrial scale or to be commercially viable, and there are also serious doubts about storage. The government is attempting to promote the development of this technology and in June 2008 launched a consultation entitled *Towards Carbon Capture and Storage(see http://www.berr.gov.uk/consultations/page46811.html)*to consider how it can support the development, demonstration and deployment of CCS technology. It also launched a competition(see http://www.berr.gov.uk/energy/sources/sustainable/ccs/ccs-demo/page40961.html)in November 2007 to support the construction by 2014 of a commercial-scale plant that captures 90% of its carbon emissions. The short-list currently consists of EON UK, Peel Power (now owned by RWE npower), and Scottish Power, after BP pulled out in November 2008.

In the meantime, the energy secretary Ed Miliband said in December 2008 that the government would not block the construction of new coal-fired power plants while CCS is still being developed and that a ban on coal plants without CCS may not be introduced within the next 20 years. He cited concerns over security of supply. In taking this position, the government is running against the advice of the Climate Change Committee (CCC) to introduce a ban by the early 2020s, and that from the House of Commons Environmental Audit Committee's July 2008 report(see http://www.publications.parliament.uk/pa/cm200708/cmselect/cmenvaud/654/654.pdf), which said that 'the possibility of CCS should not be used as a fig-leaf to give unabated coal-fired power stations the appearance of environmental acceptability'.

2.3 Long-Term Prospects

Demand from households will drive limited long-term growth in UK electricity demand

In 2009 and 2010, electricity demand is expected to decline each year across all types of fuel user in line with falling economic activity and by as much as 4½% in 2009 and 1½% in 2010. Particularly sharp falls are expected for energy-intensive industry and other industry. In the longer term, however, electricity demand is expected to increase, albeit fairly modestly, across most fuel users driving overall growth of ½% pa over 2010-15 and 1% over 2015-20 (see table: Long-Term Projections Electricity and chart: Electricity Demand by Fuel User). The exceptions are 'other industry' and energy-intensive industry where the decline in consumption is projected to continue at a slower rate over 2010-15 and still to be falling, albeit modestly, towards the end of the forecast period. These consumers are becoming more energy efficient in response to various low-carbon policies.



Source(s) : Cambridge Econometrics, DUKES.

Demand from households, the largest consumer of electricity, is expected to recover after the economic slowdown and grow faster than that from any other fuel user, with annual growth between 1¼% and 1½%. This will be driven by the take-up of new technologies and the slow pace of efficiency improvement in the housing stock. Although it is expected that household demand will be tempered a little by temperature rises, it is thought that this might be compensated for by the increased use of air-conditioning in the summer months.

Energy-intensive industry demand is projected to decline more slowly after its initial sharp fall in 2009 and 2010, helped by a shift from fossil fuels to electricity due to the EU ETS carbon price. Transport demand (rail transport) is expected to turn to growth at the end of the forecast period, albeit slowly and from a low base. Consumption growth from commerce, the second-largest user, is expected to pick up towards the end of the forecast period to reach 1¼% pa.

LONG-TERM PROJECTIONS ELECTRICITY

	1990	2005	2010	2015	2020	** 1995-00	** 2000-05	** 2005-10	** 2010-15	** 2015-20
Consumption (TWh)										
Energy-Intensive Inds	40.7	44.8	32.1	29.4	28.2	1.0	0.2	-6.5	-1.7	-0.8
Other Industry	59.4	73.8	64.8	63.1	63.1	3.3	1.6	-2.6	-0.5	0.0
Transport	2.5	2.7	2.6	2.4	2.5	0.1	0.0	-0.9	-1.5	0.7
Households	98.7	116.8	115.5	122.9	131.3	0.8	0.9	-0.2	1.3	1.3
Commerce etc	79.0	108.4	102.9	104.3	111.5	2.4	1.1	-1.0	0.3	1.3
TOTAL*	335.7	404.3	376.0	385.9	405.8	1.8	0.7	-1.4	0.5	1.0

Note(s) :
1 * Total includes energy industries' own use of energy.
2 ** denotes average growth rates % pa.
Source(s) : DUKES, Cambridge Econometrics.
Ref : C92F4E August 2009.

The UK's generation mix is projected to change in favour of renewables and CCGT, but the government will miss its 2020 renewables target

The UK's total electricity capacity is expected to increase to 92.6 GW by 2010 and then to nearly 94 GW by 2020, compared to 84½ GW in 2005 (see table: Electricity Generation and Capacity by Station Type). The forecast for electricity capacity is based on off-model adjustments of known projects and the result of the Energy Technology sub-model. A major growth area in capacity will be renewable technologies, which are projected to account for about 19¼% of total capacity in 2020 compared to just 5¼% in 2005. There will also be modest growth in CHP, particularly in the non-renewable category.

ELECTRICITY GENERATION AND CAPACITY BY STATION TYPE

	2000	2005	2010	2015	2020
Capacity (GW):					
Conventional Coal, non-FGD, MPP	19.1	12.8	3.9	1.9	0.0
Conventional Coal, FGD, MPP	5.8	9.8	19.2	19.5	19.1
CCGT(excluding CHP)	19.3	23.6	28.2	33.1	36.0
Nuclear	12.5	11.9	10.4	6.9	3.9
CHP(non-renewables)	4.6	5.4	5.6	6.8	7.8
CHP(renewables)	0.1	0.1	0.2	0.2	0.3
Renewables(non-CHP incl. nfh)	2.8	4.4	7.1	11.9	19.3
Other(oil, mixed)	14.8	14.5	16.0	10.4	4.5
Net imports	2.0	2.0	2.0	3.0	3.0
TOTAL	80.9	84.5	92.6	93.6	93.9
Memo: CHP	4.3	4.4	4.5	5.4	6.5
Memo: Renewables (RO basis)	2.0	3.6	6.2	11.0	18.4
Generation (TWh):					
Conventional Coal, non-FGD, MPP	62.5	60.9	19.7	8.6	0.0
Conventional Coal, FGD, MPP	33.3	49.3	94.3	105.2	97.0
CCGT(excluding CHP)	117.1	128.7	120.7	131.2	156.2
Nuclear	85.1	81.6	48.2	30.1	18.6
CHP(non-renewables)	26.1	28.3	24.7	30.8	39.6
CHP(renewables)	0.4	0.5	0.5	0.6	0.8
Renewables(non-CHP incl. nfh)	9.5	16.4	26.6	39.6	59.1
Other(oil, mixed)	37.9	33.1	24.3	15.1	9.2
Net imports	14.2	8.3	17.4	24.7	24.7
TOTAL	386.1	407.2	376.5	385.8	405.1
Memo: CHP	25.7	26.9	23.8	29.7	38.6
Memo: Renewables (RO basis)	6.6	13.2	22.7	35.6	54.8
Memo: RO Generation (% of UK electricity sales)	1.9	3.5	6.6	10.2	15.2

Note(s) :
1 Total includes own generation.
2 nfh is natural flow hydo.
3 MPP is major power producers.
Source(s) : DUKES, Cambridge Econometrics.
Ref : C92F4E August 2009.

Amongst conventional and fossil fuels, the only growth area is expected to be in CCGT (gas), which is expected to easily maintain its status as the largest power station type, as is it currently the cheapest form of electricity production, although sharply increasing gas prices are starting to affect this position. It is projected to rise steadily from a capacity of 23½ GW in 2005 to a capacity of 36 GW in 2020 - around 39% of projected total UK capacity. Overall coal capacity is set to fall moderately over the forecast period, with all non-FGD stations operated by major power producers either going off-line by 2015 or being fitted with FGD technology in order to comply with the EU's LCPD (Large Combustion Plant Directive). Although nuclear is an important component of the UK's generation capacity today, it will rapidly decline to just 4 GW of capacity by 2020 due to the decommissioning of most of Britain's ageing reactors. Depending on the success of the government's drive to encourage new nuclear power stations, nuclear may become important once more but, as there are few concrete plans as yet, this does not show in the forecast. In any case, there will be little new build before 2020. If nuclear build is planned and completed before 2020, then it is likely to replace the projected growth in CCGT.

The share of electricity generated by renewables is well below their share of capacity because of the intermittency of some renewable technologies. Furthermore, fossil fuel prices are projected to be quite low and as such, fossil fuel generation looks relatively cheaper. Consequently, total generation of renewable electricity in 2020 is expected to be 54¾ TWh in 2020, or 15¼% of all UK consumption, according to the RO basis. Although this is a sizeable rise from 5.1% in 2008, this would be well short of the government's target of 20% of final electricity sold in the UK to be met by renewables. We therefore project that the government will not meet its 2020 target on current trends, policies and planned projects, let alone the 30% outlined in the Renewable Energy Strategy.

Carbon emissions from power generation in the UK are expected to decline sharply over the short term, and to decline more slowly to the end of the forecast period

Carbon emissions from power generation are expected to decrease further by around 1¾% pa over 2005-10 for two reasons: first, the rise in allowance prices under the EU Emissions Trading Scheme by 2010 is expected to bring about a significant shift away from coal-fired and towards gas-fired generation over the next two years; and secondly, falling electricity demand due to the impact of the recession is expected to lead to lower generation. A further decline of around ¾% pa is forecast over 2010-15, as the rise in emissions from gas-fired generation is more than offset by falling carbon emissions from coal-fired plant (see table: Long-Term Projections by Fuel User).

The sharper decline of around 1¼% pa after 2015 reflects the progressive elimination of non-FGD coal-fired generation (accompanied by a further decline in FGD generation). This will more than offset the continued growth in emissions from gas-fired generation. The fall in carbon emissions from power generation during the 1990s, when gas-fired generation replaced a substantial portion of coal-fired generation, helped the UK to meet its target for carbon emissions in 2000. However, the scale of reduction in carbon emissions from power generation beyond 2015 is likely to be moderated, in part because of the projected reduction in capacity and generation from nuclear plant, even though the contribution from renewable energy is increasing markedly and is accompanied by a moderate expansion in CHP. It is assumed that the EU ETS allowance price will continue to rise 2% pa in the long term to reach €27.6/tCO2 by 2020, as the UK participates in Phase 3 of

LONG-TERM PROJECTIONS BY FUEL USER

	1990	2005	2010	2015	2020	1995-00*	2000-05*	2005-10*	2010-15*	2015-20*
Final Energy Demand (ttoe):										
Energy-Intensive Inds	18045.5	14145.5	10306.6	8980.0	7954.1	-1.6	-2.8	-6.1	-2.7	-2.4
Other Industry	19415.5	21517.2	17558.0	16649.1	15742.1	3.8	0.2	-4.0	-1.1	-1.1
Rail Transport	1125.0	1465.4	1377.4	1342.2	1350.3	1.4	1.2	-1.2	-0.5	0.1
Road Transport	38816.0	42389.6	40073.4	38670.9	38334.4	0.9	0.6	-1.1	-0.7	-0.2
Water Transport	1363.0	1371.8	1590.7	1522.4	1519.2	-2.8	5.8	3.0	-0.9	-0.0
Air Transport	7332.0	13856.3	12893.1	14203.2	17073.3	7.1	3.0	-1.4	2.0	3.7
Households	40747.6	47244.7	44573.2	44082.1	43698.4	1.9	0.2	-1.2	-0.2	-0.2
Commerce etc	18954.0	20240.7	18361.0	18607.7	18955.7	0.7	-1.2	-1.9	0.3	0.4
TOTAL**	145799.0	162231.0	146733.0	144058.0	144628.0	1.6	0.1	-2.0	-0.4	0.1
CO2 Emissions (MtCO2):										
Power Generation	208.8	185.6	170.3	163.4	153.8	-0.4	1.8	-1.7	-0.8	-1.2
Energy-Intensive Inds	44.5	33.3	27.3	25.5	23.7	-2.3	-2.2	-3.9	-1.4	-1.4
Other Industry	57.4	44.8	33.3	30.8	28.4	0.9	-2.1	-5.7	-1.6	-1.6
Rail Transport	2.2	2.2	2.1	2.2	2.1	1.6	-0.9	-0.5	0.4	-0.4
Road Transport	109.7	120.1	109.9	104.5	103.5	0.9	0.7	-1.8	-1.0	-0.2
Water Transport	5.5	4.9	5.4	5.2	5.2	-3.3	3.9	2.0	-0.9	-0.0
Air Transport	5.1	4.5	4.0	4.4	5.3	-0.8	2.9	-2.1	2.0	3.7
Households	79.8	84.6	79.2	77.2	75.3	1.4	-0.5	-1.3	-0.5	-0.5
Commerce etc	39.4	36.3	30.9	30.2	28.8	-0.8	-1.4	-3.2	-0.4	-1.0
TOTAL	590.6	558.6	497.0	478.7	462.8	0.0	0.3	-2.3	-0.7	-0.7
SO2 Emissions ('000 t S02):										
Power Generation	2769.3	415.6	132.7	48.5	3.8	-12.2	-13.4	-20.4	-18.2	-39.9
Energy-Intensive Inds	128.4	64.1	54.2	50.3	47.1	-7.7	-5.8	-3.3	-1.5	-1.3
Other Industry	296.6	36.8	34.2	31.5	27.0	-22.3	-6.7	-1.5	-1.6	-3.0
Rail Transport	2.4	1.9	1.9	1.9	1.9	1.1	5.1	-0.5	0.4	-0.4
Road Transport	63.8	2.9	2.4	2.3	2.2	-33.9	-15.1	-3.7	-0.9	-0.2
Water Transport	36.2	41.9	52.0	49.8	49.7	-6.4	9.9	4.4	-0.9	-0.0
Air Transport	1.0	1.3	1.2	1.4	1.6	-3.1	7.7	-0.4	2.0	3.7
Households	142.5	20.4	28.3	30.4	33.0	-10.5	-19.0	6.8	1.4	1.7
Commerce etc	105.4	17.4	12.3	11.6	10.5	-18.4	-7.2	-6.7	-1.2	-1.8
TOTAL	3716.9	687.6	408.4	315.8	265.4	-12.6	-10.5	-9.9	-5.0	-3.4

Note(s) :
1 * denotes average growth rates % pa.
2 Final energy demand excludes power generation, energy industries' own use of energy and non-energy use.
3 ** Total final energy demand includes steam and other fuels.
4 Commerce etc. emissions includes emissions from energy intensive industries' own use of energy
Source(s) : DUKES, NAEI, Cambridge Econometrics.
Ref : C92F4E August 2009.

the EU Emissions Trading Scheme (see: The price of EU ETS allowances is assumed to fall sharply in 2009, to rebound over 2011-13, and then to grow moderately in the long run.).