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After the Coal Rush:

Assessing policy options for coal-fired electricity generation

by Matthew Lockwood

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Contents

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Abbreviations and acronyms

ASC	advanced supercritical coal
BAT	best available technology
BERR	Department for Business, Enterprise and Regulatory Reform
CBI	Confederation of British Industry
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CDM	Clean Development Mechanism
CEA	coal emissions allowance
CHP	combined heat and power
CO_2	carbon dioxide
DEFRA	Department for Environment, Food and Rural Affairs
EC	European Commission
EOR	enhanced oil recovery
EPS	emissions performance standard
ETS	emissions trading scheme
EU	European Union
EUAs	EU allowances
FGD	flue gas desulphurisation
GW	gigawatt
GWe	gigawatt electrical
GWh	gigawatt hour
IGCC	integrated gasification combined cycle
JI	Joint Implementation
kWh	kilowatt hour
LCPD	Large Combustion Plant Directive
LNG	liquefied natural gas
MEP	Member of the European Parliament
$MtCO_2$	million tonnes of carbon dioxide
$MtCO_2e$	million tonnes of carbon dioxide equivalent
Mtoe	million tonnes of oil equivalent
MW	megawatt
MWe	megawatt electrical
MWh	megawatt hour
NERP	National Emissions Reduction Plan
NPV	net present value
RO	Renewables Obligation
SRMC	short-run marginal cost
tCO_2	tonne of carbon dioxide
TUC	Trades Union Congress
TWh	terrawatt hour
UKERC	UK Energy Research Centre

Executive summary

In early January 2008, Medway Council gave approval to a planning application from energy company E.ON to build a new coal-fired power station on the site of an existing plant at Kingsnorth. This would be the first major coal-fired power station built in the UK since the 1970s.

The Kingsnorth application has provoked a major new debate on coal, energy policy and climate policy in the UK. This is, in part, because it is the first real test of both the Climate Change Bill passing through Parliament, and the wider consensus across Government, business and civil society that more radical action must be taken to reduce carbon emissions.

In this report, we provide a comprehensive examination of the issues at stake. To decide what should be done about Kingsnorth and other proposed new plants, we argue that it is essential to understand the wider context of energy markets and energy policy, both within the UK and at European level.

Much of the argument about new coal is characterised by a high degree of uncertainty, as are future electricity generation and investment.

Achieving the Government's ambitious renewable energy targets also has implications for coal – the more electricity we get from wind and other renewable sources, the less we will need from coal.

If we could apply the emerging technology of carbon capture and storage (CCS) to coal, then much of the problem would be solved. However, both the timing and economics of CCS are uncertain, with little prospect that it will make a difference before 2020.

Thus, under the current policy framework for coal as a fuel in electricity generation, there are no guarantees on future emissions, and, as a result, there is a risk that the Climate Change Bill targets for domestic emissions reduction will not be met. This is a serious concern, and has led to a number of proposals to close down this risk, for example new regulations on plant-level emissions, adopted recently in California, or a moratorium on new coal build until CCS has been fully developed.

The Government and energy companies are resistant to such ideas. This is partly because they see them as raising risks in other areas – that security of supply will be made more vulnerable, and that energy prices may rise to politically unsustainable levels. These are real concerns among the public, and any policy to reduce emissions must address them convincingly to establish credibility with investors.

There is also resistance because proposals for additional measures are argued to undermine and cut across the policy at the heart of the current framework – the European Union emissions trading scheme (ETS). The credibility of the EU ETS as a mechanism to guide investment is just being established, and its proponents see further measures as a threat.

However, major decisions on power sector investment across Europe have to be taken in the next three years. With companies and traders discounting the carbon price because of uncertainty about the future of the scheme, there is a danger that a large amount of investment in new coal plants will go ahead, which would not have happened in a fully credible market.

In such a scenario there is a risk that it will not be politically feasible to keep the cap on emissions in the scheme, especially from 2015 when many of the new plants would come on stream. Maintaining the cap in such circumstances would mean large-scale deployment of carbon capture, with major concomitant increases in the price of electricity. Some form of temporary limitation of new coal build across Europe would, therefore, help to strengthen the credibility of the EU ETS.

The context

Debate on the future of coal has been sparked by the application for a new power station at Kingsnorth. However, several other energy companies have indicated that they will also put forward planning proposals for new coal plants.

Coal burning for power generation matters for climate policy because it is the single most important source of carbon dioxide. In 2006, emissions from power stations were estimated to have been responsible for 32 per cent of total UK carbon emissions. Over the 1990s, emissions fell sharply as energy companies built gas-fired power stations. However, since 1999 the trend has reversed and UK carbon emissions have drifted upwards, with the result that the Government's own targets for carbon reduction by 2010 will not be met.

Concerns about new coal have been expressed by a wide range of organisations and individuals, including Greenpeace, Oxfam, the Royal Society and the world-renowned climate scientist Jim Hansen, who has written to the Prime Minister pleading for a ban on new coal plants.

The fear is that an expanded future for coal-fired power generation is completely incompatible with a move to a low-carbon world. New coal in the UK is seen as threatening the 2020 emissions reduction target in the draft Climate Change Bill, and undermining UK claims to international climate leadership, at a time when moves to prevent the building of new coal power stations are taking place in other countries, including New Zealand, Denmark and Canada, and in the American state of California.

Why companies want to build new coal plants

The decision to invest in new coal plants currently lies with companies, rather than government. The major energy suppliers are all expecting a shortfall in generating capacity in the next decade, and, therefore, higher electricity prices. This is driving a general interest in investing in new capacity.

Interest in new coal plants has been sparked by relatively low coal prices over the last five years, making them more profitable than gas plants. However, the strongest driver for new coal is the desire by companies to maintain a portfolio of generating capacity that includes a range of fuels, to hedge against market, security of supply or policy risk. As some companies are losing a significant amount of coal capacity from 2015 onwards, they are very keen to replace it.

The role of carbon pricing

Along with the prices of coal and gas, the price of carbon is becoming a relevant factor in energy investments. A price for carbon emissions has been created by the European Union's emissions trading scheme (EU ETS). Because coal-fired power generation is more carbon intensive than gas-fired generation, carbon pricing makes it less attractive commercially.

In January 2008, the European Commission made proposals for a stronger EU ETS, with a tighter, single, EU-wide cap, and longer time frames. Market analysts predict that, on the basis of such an approach, carbon prices would reach around €40 per tonne of carbon dioxide by 2020, in today's prices. Analysts expect that over the period to 2020, this carbon price will drive companies to close down coal-fired plants and switch to gas on a major scale, since this is the cheapest way of reducing emissions on a large scale and, thereby, of staying under the cap.

However, some uncertainty still hangs over the future of the ETS. The final shape of Phase 3 of the EU ETS is yet to be determined by political negotiations, with heavy lobbying from industry for a looser scheme. Agreement may not come until mid-2009, or possibly even later. But even then, energy companies may not be convinced that a strong carbon policy is politically sustainable until a global deal involving the USA and China is reached. This means that they discount carbon prices when planning investments, and are more likely to decide to build new coal.

The role of the EU renewable energy target

The European Commission has also proposed new ambitious targets for renewable energy. The implications are that up to 40 per cent of UK electricity demand would have to come from renewable sources by 2020 (mostly expected to be large-scale wind). This would be a massive increase on our current renewable output.

If the new proposed EU target were to be met, there may be little or no need to build new fossil fuel power stations for conventional baseload generation, although some new plants will probably be needed for balancing the intermittent supply of power from wind.

However, this scale of expansion of renewable electricity capacity in the UK faces several technical and political problems, and there are doubts among energy companies about whether the target can be reached. Decisive action by government is needed to address these doubts, and allow an expansion of renewable electricity to play a role in limiting the need for new coal.

Implications for carbon emissions

Under the current policy framework, there is great uncertainty about how much new coal capacity may be built in the UK, due to uncertainty about fuel prices, about the development of the EU ETS, and about future policy on renewable electricity.

In this report we assess the implications of this uncertainty by exploring a range of new-build scenarios of between four and 11.6 GW. These scenarios give estimates of additional emissions (as against new gas capacity) of between 11 and 32 $MtCO_2$.

However, future emissions from new plants are only part of the picture. Overall emissions from coal-fired power generation will depend not only on how much new capacity is built, but also on how much it is run, whether it replaces or adds to existing capacity, and how much that existing capacity is run.

The key factors in determining total emissions are fuel prices, and carbon policy. These factors are reflected in modelling commissioned by the Government, which suggests that, if carbon policy is not sufficiently strong or credible, up to 9 GW of new coal-fired power could be built, and UK power sector emissions could be higher in 2020 than they are today.

The current framework for coal-fired power generation does, therefore, potentially pose a problem for the Climate Change Bill target for 2020.

Prospects for carbon capture and storage

Coal would not pose a problem to climate policy if the emerging technology of CCS were available today at an affordable price. CCS involves capturing the carbon dioxide produced by coal-fired power stations, transporting it by pipeline, and sequestering it in depleted oil- and gas-fields.

There are two competing technologies for capturing carbon from coal-fired power generation: pre-combustion and post-combustion. The Government has shown leadership in deciding to support a demonstration project on post-combustion carbon capture. However, there is a strong case for the UK running a second demonstration project, involving a pre-combustion technology.

There is also an urgent need to start planning for the transportation infrastructure for carrying carbon dioxide captured in power stations and other installations to storage sites.

Overall, it is unlikely that widespread deployment of CCS to coal-fired generation will occur much before 2020.

Assessing the UK debate on coal

The risk that higher emissions from new coal (as well as the new plants themselves) may undermine the leadership that the Climate Change Bill gives the UK has led some groups to propose new measures to prevent new coal build.

These measures are inspired by various moves to rule out new coal plants in other countries, including an emissions performance standard that would apply at the level of each new plant, and immediate or future bans on new coal build.

These proposals tend to focus on preventing new coal power stations being built. However, the relation between new coal build and total emissions for burning coal is not straightforward. Under certain conditions, banning new coal might even increase total coal emissions, as older, less efficient plants are kept open. An alternative approach might, therefore, be to cap emissions from UK coal-fired power generation as a whole.

The Government and energy companies firmly oppose such proposals, mainly on the grounds that they are inconsistent with, and would politically undermine, the EU ETS, just at the time that its credibility is beginning to be established.

In turn, critics argue that since the EU ETS is not currently effective in shaping investment, the use of more effective measures should not be sacrificed on the EU ETS altar.

A wider perspective on coal and the EU emissions trading scheme

At the heart of this debate lie divergent views of the EU ETS. However, the one issue that both sides agree on is that confidence in the ETS is still not fully established.

Companies and carbon market traders are discounting the carbon price, because there are still uncertainties about the future of the EU ETS. This is not so much about its existence, but more about how rigorously it will be enforced in the future.

There is still some lack of clarity about the final Phase 3 deal that member states will sign up to, but the bigger source of uncertainty is whether a global deal involving China, the USA and other big emitters will be reached. If it is, then the future of the EU ETS as the core of a new global carbon market is assured. If it is not, then the future is less certain.

While uncertainty will remain for the next two to three years, decisions on a large amount of new power sector investment have to be taken over precisely this period if the lights are to be kept on from 2015 onwards. This is not only the case in the UK, but also in Germany and other countries.

With present uncertainty, more coal-fired plants will be built than would be the case if investment decisions reflected full confidence in the Phase 3 cap. However, starting to build new coal plants now itself risks the future breakdown of the ETS. It makes a huge gamble on being able to bring forward the widespread deployment of carbon capture and storage to the period 2015-2020. Investment in new coal would thus weaken the current credibility of the EU ETS still further.

There is a strong case for a temporary moratorium on new coal investments at the EU level. The UK should pre-commit itself to such an investment pause as way of engaging with Germany and other member states with large energy markets.

Policy credibility: addressing concerns about cost, security of supply and planning

Less coal will mean greater dependence on gas, at least temporarily. One concern about gas is short-run interruptions of physical supply. While such episodes are not unknown, it is also important to remember that the UK gas system is fairly robust. The main issues are likely to be domestic resilience to incidents like fires, and problems with free flow of gas through European pipelines. Both of these can be addressed through appropriate policies, and much has already been done to improve the situation.

On cost, the biggest demand for gas is in space and water heating, so end-use efficiency measures will have the biggest impact on containing gas demand. More combined heat and power (CHP) generation, which uses gas more efficiently, would also help.

Another policy that will reduce gas prices would be the major expansion of renewables envisaged by the European Commission in its proposals for 2020 targets. However, this policy, along with a strong EU ETS policy, an expanded demonstration programme for CCS, and a support programme for CHP, all imply a higher cost for electricity. Companies fear that the UK (and wider European) public will not be willing to pay that cost, which undermines the credibility of these policies. To address this problem it will be necessary to produce authoritative estimates of the costs involved, and make the case for the investments, partly by also developing estimates of benefits in terms of jobs and export earnings.

Finally, the expansion of renewables, but also, potentially, city-centre CHP and the establishment of a CCS infrastructure, also face opposition through the planning system. The new Planning Bill may streamline planning for such investments, but this will not be clear for a year or two whether it works on the ground. Making the political case for investments remains necessary. Ensuring that local people can have a stake in onshore wind farms in particular would help.

Summary of recommendations

Strengthening the EU emissions trading scheme

- An EU-wide moratorium on investment in new coal-fired power stations should be introduced, lasting at least until mid-2010.
- The UK Government should pre-commit itself to such an approach (which would include the proposed plant at Kingsnorth), and use this pre-commitment to bind in other member states with large energy markets, such as Germany.
- The UK Government should work as hard as possible to ensure that the proposals for Phase 3 of the scheme by the European Commission are not weakened in areas such as the auctioning of credits, and tighter limits on the use of Clean Development Mechanism (CDM) credits.

Carbon capture and storage

- A new CCS Directive specifying a process for 12 demonstration plants, should be adopted into the energy and climate package.
- The UK Government should extend the demonstration programme to include a second, pre-combustion demonstration, and immediately start planning a framework for the carbon dioxide transport infrastructure that will be needed.

The 2020 renewable energy target

- Stronger policies are needed to radically increase the conservation of electricity use.
- The support policy for renewable electricity generation will have to be revisited. Stronger incentives for off-shore wind are likely to be needed. This includes the possibility of some form of production or export tariff for micro-renewables. New guidance for Ofgem to ensure that it plays a suitable role will also be necessary.
- Strategic planning for new transmission and distribution capacity (especially for offshore wind) and guaranteed access to that capacity for renewables is essential. This is an area where incremental reform will not be enough – the national grid needs to be rebuilt for the age of renewables.
- All approaches to managing the penetration of intermittent renewables of above 30 per cent need to be explored, including the use of 'dynamic demand' appliances and 'vehicle-to-grid' technologies.
- To persuade voters and business of the feasibility and affordability of this goal, government should produce an authoritative and transparent cost estimate for reaching the electricity component of the proposed renewable energy target, steer through new planning arrangements that are accepted on the ground, and undertake genuine and wide consultation.

Addressing cost and security of supply concerns

- Efforts to improve energy efficiency in domestic heating need to be radically expanded to reduce gas demand. A more effective programme of support for combined heat and power that makes more efficient use of gas in power production should be part of these efforts.
- The Government should also develop strategic gas storage in the UK, and work at the EU level both to improve the framework for energy negotiations with Russia and to prevent European energy companies using their control of gas pipelines to divert gas supplies to their own customers.
- The Government needs to provide authoritative and widely accepted estimates of what the costs of energy to 2020 are actually likely to be. Effective policies are urgently needed to reduce the impact of costs on potentially vulnerable groups, especially the fuel poor.
- If the UK takes bilateral actions, consideration of the situation of energy-intensive industries exposed to competition will also be needed.
- Finally, the Government needs to make the benefits of decarbonisation, in terms of technological opportunities and jobs in renewable energy, CCS and other areas, much clearer.

Introduction

In early January 2008, Medway Council, Kent, gave approval to a planning application from energy company E.ON to build a new coal-fired power station on the site of an existing plant at Kingsnorth. This would be the first major coal-fired power station built in the UK since the 1970s. Several other energy companies have indicated that they will also put forward planning proposals for new coal plants.

These proposals for a new generation of coal-fired power stations in the UK are highly controversial. While other issues, such as aviation, have tended to occupy much of the debate on climate policy, burning coal to produce electricity is, in reality, the single most significant source of carbon emissions in the UK (as it is around the world). The policy framework for investment in electricity generation is, therefore, at the heart of climate policy.

The Government's position is that such investments are allowable within the liberalised framework of the energy market, and that environmental considerations should be addressed by the EU emissions trading scheme (EU ETS).

However, environmental and international development campaign groups are strongly opposed to any new coal power stations going ahead at all, unless they have working carbon capture and storage (CCS) technology.

In October 2007, E.ON's Kingsnorth plant was scaled by Greenpeace protestors, and, more recently, in January 2008, activists from the Stop Kingsnorth campaign set up by the World Development Movement targeted E.ON's London office (World Development Movement 2008a). These groups have the support of a wider range of civil society organisations, including the RSPB, Oxfam, WWF and the National Federation of Women's Institutes.

The world-renowned US climate scientist Jim Hansen wrote to the UK's Prime Minister, in December 2007, calling on him to halt the building of new coal plants that do not have CCS (Connor 2007), as has the President of the Royal Society (Adam 2008). Hansen has subsequently argued that the phasing out of coal globally is necessary to avert dangerous climate change. The Conservatives and Liberal Democrats are also opposed to new coal build without CCS.

Critics of the Government's framework point to the fact that other countries in the Organisation for Economic Cooperation and Development (OECD) are taking more direct measures on new coal build. The US state of California has introduced an emissions performance standard for all new power stations, set at a level that rules out coal in the absence of CCS or combined heat and power (CHP). New Zealand is introducing a 10-year moratorium on new fossil fuel power stations, while Denmark brought in a ban on new coal plants as early as 1990. Even within the G8, Canada is now introducing a requirement for new coal-fired power stations to have CCS from 2018.

This report explores the nature of the problem, and assesses the different approaches to policy. It is based on a series of interviews with some of the key actors, including government, environmental organisations, energy companies, the Trades Union Congress, the Confederation of British Industry and academic experts. In total, we conducted 26 interviews over the period December 2007 to March 2008 (see Annex A).

Structure of the report

In Chapter 1, the importance of emissions from coal-fired power generation is established, and details of energy company proposals for new coal investments are given.

The following three chapters, which are mainly descriptive, then examine the current framework for investment decisions: Chapter 2 investigates the key drivers for new coal from the perspective of the energy companies; Chapter 3 looks at the role of carbon pricing through the EU ETS; and Chapter 4 considers how new targets for the expansion of renewable energy may affect investment decisions.

There is, in fact, a great deal of uncertainty about how many of the energy company proposals will be realised, and how much new coal-fired power capacity will be built. Investigating the emissions implications of new coal plants, therefore, involves looking at a range of scenarios. This is explored in Chapter 5, which looks, in particular, at the implications for emissions reductions targets for 2020 and 2050 in the Climate Change Bill currently before Parliament.

A range of organisations, from the Intergovernmental Panel on Climate Change to the TUC, and including the Government and the energy industry, anticipate that emissions from coal-fired power generation can be reduced through CCS technologies. The prospects for CCS are reviewed in Chapter 6.

It is clear that although there is uncertainty about new coal investment, there is a potential emissions problem and that CCS cannot address much before 2020 at the earliest. Much hinges on the strength of the climate and energy package currently being debated by the European Parliament and Council. Chapter 7 assess the debate on options for further action within the UK.

However, to get a complete picture of the policy problem with coal, we also need to look at the issue at the European level, and in particular how potential new coal build and the European Union emissions trading scheme interact. Chapter 8 provides an analysis of this dynamic, along with policy recommendations.

All proposals to contain risks of high emissions from coal-fired power generation have to address concerns about security of supply (especially in relation to gas), the costs of electricity generation, and planning. The problem of establishing credible policy is tackled in Chapter 8.

A final section concludes and summarises the recommendations of the report.

1. Coal-fired power generation in the UK: an overview

Until the 1980s, most electricity generated in the UK came from burning coal, and coal mining and power generation were closely related as strategic industries, both under nationalised control.

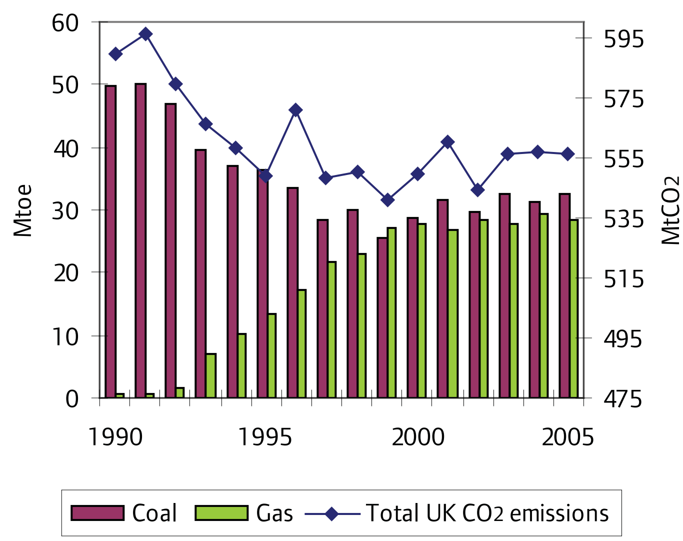
This picture has since changed dramatically. The electricity industry was privatised in 1989, and cheap gas prices led to a wave of investment in combined cycle gas turbines (CCGT), known as the 'dash for gas'. This marked a major shift away from coal (Figure 1.1), and, along with nuclear power, led to a diversification of fuels for electricity generation. At the same time, following the miners' strike of 1984-85 and subsequent privatisation, the UK mining industry continued its decline in production and employment. Imports of coal now make up around 70 per cent of supply.

The importance of coal-fired power generation for historical emissions

The dash for gas had implications for carbon emissions. Because electricity from gas is around 2.4 times less carbon-intensive than that from coal, the fuel shift of the 1990s led to a major reduction in emissions through to the end of that decade, falling from around 240 million tonnes of carbon dioxide ($MtCO_2$) per year down to around 180 million tonnes per year by 1999 (Figure 1.1).

Figure 1.1. Coal and gas use in, and carbon dioxide emissions from, electricity generation

Source: BERR 2007a, DEFRA 2007



However, since 2000, oil and gas prices have increased significantly (see Figure 2.1 below). This has led to a resurgence of the use of coal for power generation, and power sector emissions have increased to over 180 $MtCO_2$ per year again (see also IPA 2006).

Emissions from electricity generation in general are much larger than those from any other source, including road transport. In 2006, emissions from power stations were estimated to have been responsible for 32 per cent of total UK carbon emissions (BERR 2007a). The dominance of emissions from electricity generation can be illustrated by the fact that total UK carbon emissions have tracked emissions from electricity closely since 1990 (Figure 1.2, next page). The rise in total UK carbon emissions since 1999 is largely attributable to greater coal burning for power generation.

A new wave of coal-fired power stations?

Energy companies in the UK are now considering building a number of new coal-fired power stations (see Table 1.1). The first of these is 1.6 GW[1] of new capacity proposed by E.ON for the site of an

1. A gigawatt of power is 1,000 megawatts (MW). A megawatt is, in turn, 1,000 kilowatts (kW). The full capacity of most fossil fuel power stations is in the range 800-2,400 MW.

existing plant at Kingsnorth, in Medway, Kent. This would be the first major new coal-fired power station to be built in the UK for 33 years.

Plans for other applications, including at Tilbury in East London, Ferrybridge in Yorkshire, and Blyth in Northumbria, are at an advanced stage. It is not necessarily the case that all these plants will be built. However, if they are, then 11.5 GW of new coal-fired power plants will be added to UK generating capacity.

At the same time, 8.2 GW of existing coal-fired power plants will have to close by the end of 2015, under the EU Large Combustion Plant Directive (LCPD) (legislation aimed at cutting sulphur and other local pollution) (BERR 2007b). It is also possible that some additional coal-fired plants will also close by 2020, or be running on a restricted basis because of further LCPD requirements.

The new plants being proposed will all be 'supercritical' coal power stations, so called because of the high operating pressures in the steam turbines. A supercritical coal plant has a higher efficiency than previous designs (around 45 per cent rather than 35 per cent), and so produces slightly lower carbon emissions per unit of electricity generated (around 15-20 per cent lower). However, electricity generated by such plants will still produce emissions at a rate of around 0.7-0.75 kg/kWh, almost

Figure 1.2. Carbon dioxide emissions from energy industries, and total UK carbon dioxide emissions ($MtCO_2$)

Source: DEFRA 2007

Note that both axes cover the same range (80 $MtCO_2$)

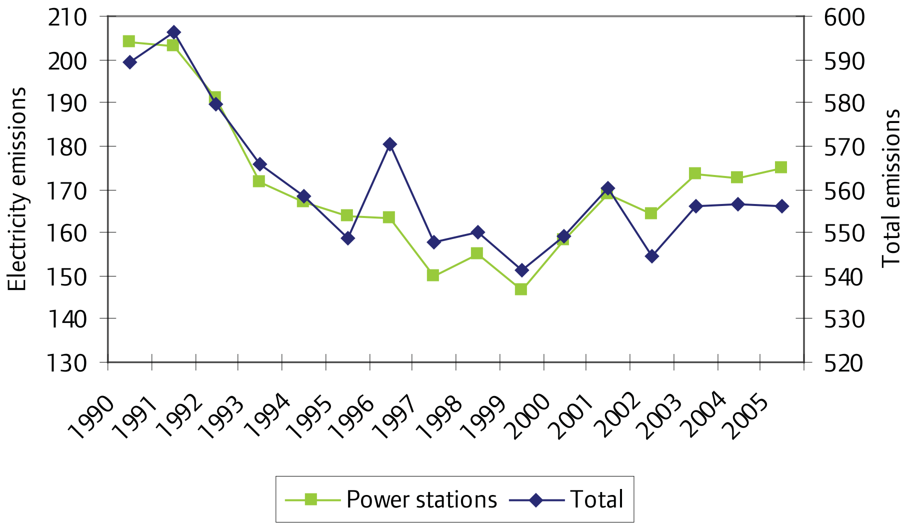


Table 1.1. Potential new UK coal plants

Location	Company	Capacity	Status at January 2008
Kingsnorth	E.ON	1.6 GW	Approved by Medway Council, with BERR for Section 36* approval
High Marnham	E.ON	1.6 GW	n/a
Tilbury	RWE npower	1.6 GW	Scoping report submitted. S36 application imminent
Blyth	RWE npower	2.4 GW	Scoping report submitted. S36 application imminent
Ferrybridge	Scottish and Southern Energy	800 MW	Scoping studies underway. S36 application shortly
Longannet	Scottish Power	2.3 GW	Feasibility study announced
Cockenzie	Scottish Power	1.15 GW	Feasibility study announced

* Section 36 refers to approval required for all large power plants from the Secretary of State

Source: *ENDS Report* 396 (January 2008), and interviews with energy companies twice that of a modern combined-cycle gas turbine (CCGT) plant, which is seen in the industry as the default technology.

Some energy companies also have plans for integrated gasification combined cycle (IGCC) coal-fired plants to demonstrate pre-combustion carbon capture and storage. However, since the Government has decided not to support this technology (see Chapter 3), these plants will probably not be constructed, as IGCC is not currently competitive with supercritical coal.

These investment plans obviously pose major potential challenges to UK emissions targets, including the mid-term 2020 targets in the draft Climate Change Bill.

To understand what proposed new coal build might mean for emissions to 2020 and beyond, and for renewables, it is first necessary to look at how investment and operational decisions in the electricity sector work.

2. Why energy companies want to build new coal-fired power stations

In this chapter we examine the key drivers for new coal plants from the perspective of the energy companies, given the current policy framework. It is important to understand why companies might want to build new coal plants, both in order to assess what the environmental implications are, and also to assess the potential effects of proposed policies.

Investing in a new coal-fired power station, with capital costs typically well in excess of £1 billion, is a major financial undertaking. For example, in early 2008, E.ON's estimate for the capital costs of the new Kingsnorth plant was £1.7 billion. For companies considering such an investment, there is always a risk that electricity prices may fall once it is built, or that gas prices may fall, leaving coal exposed in cost terms. Since the capital costs of coal plants are significantly higher than those of new gas plants, coal is a riskier proposition. Nevertheless, as noted in Chapter 1, applications to build new coal plants are beginning to come through the planning system.

Like all private sector investments, the decision to invest in a coal-fired power station can be seen in terms of a trade-off between risk and expected return on the project. Both revenue and risk will be judged against alternative uses of the capital. Understanding why several energy companies currently want to invest in new coal, therefore involves looking at all of these elements.

In this chapter we look at some of the current main drivers for building coal plants in the UK. These include the recent movement of gas and coal prices, an anticipated shortfall in electricity generating capacity expected in the middle of the next decade, and strategic considerations.

However, the policy landscape for investment decisions is changing rapidly, and both the future of the EU ETS and the proposed 2020 renewable energy targets have implications for potential new coal build. These are examined in Chapters 3 and 4 respectively.

The UK electricity market

Since the privatisation of the electricity industry in 1989, decisions about investment in new power stations have been taken not by the Government but by the private sector. Over time, the industry has become vertically integrated, so that the companies that supply electricity to homes and businesses also own power stations. The market is now dominated by six large, vertically integrated companies. Having their own generation portfolio protects suppliers, to some extent, against risk, as they would otherwise have to source all the electricity they sell from other companies.

The idea of the liberalised market is that all kinds of generation compete on price to provide the cheapest possible electricity prices (one of the Government's energy policy objectives [HM Government 2007]). However, within this framework, some sources of electricity receive special treatment.

The Renewables Obligation (RO) supports investment in renewable electricity by requiring electricity suppliers to source a growing proportion of the power they sell from renewable generators (or pay a penalty buy-out fee). This creates an artificial demand for renewable electricity, and raises its price. So far, this mechanism has mainly supported onshore wind projects, but the RO will shortly be reformed to give more support to other technologies, with offshore wind and biomass expected to gain the most.

Within a wider liberalised market, the RO has the effect of partitioning electricity generation. The RO has been criticised for being both expensive and ineffective compared with alternative policies adopted widely elsewhere in Europe (Greenpeace 2008b, Friends of the Earth 2007, Ofgem 2006, Gross *et al* 2007, Department of Trade and Industry 2004), and actual renewable generation has lagged behind targets. However, the RO has succeeded in 'forcing' a certain amount of renewable electricity into the market, with the proportion of electricity generated by renewables growing every year. This portion of the market is, effectively, partially protected from competition by other sources of generation.[2]

2. The existence of the penalty buy-out means that actual build lags behind targets, so that renewables are only partly guaranteed a share of the market (see Chapter 4). However, this lag is mainly ascribed to planning barriers, rather than a lack of project proposals.

Existing nuclear power generation has also been protected, by subsidy from the Non-Fossil Fuel Obligation up to 1998, and, since then, by financial aid packages for British Energy. New nuclear build is now supposed to compete directly with coal and gas, but will almost certainly not be operational until after 2020, so is ignored here.

This leaves the rest of the 'mainstream' market, where coal and gas have to compete with one another.[3] Companies investing in new coal plants will, therefore, look first at expected renewables build under the RO, and then compare the economics of coal-fired generation with that of gas-fired generation.

A final point to note about the UK electricity policy framework is that it has evolved in the absence of a heat policy. This is important because coal- and gas-fired power stations (along with nuclear plants) produce huge amounts of heat, which is not utilised. The consequent low levels of efficiency of conversion of primary energy into electricity is often contrasted with countries like Denmark and Finland, where most electricity is generated in CHP plants, in which waste heat from power generation is used in homes or industry.

The reasons why major energy suppliers do not invest more in CHP plants are discussed in more detail in Chapter 8 below, but they are essentially a combination of the absence of a heat policy, and limited opportunities for a sufficient return on capital within the companies' current business model.

The economics of the electricity market

Electricity is a system, rather than a fuel, and so, at any one time, the amount used in homes and businesses must be balanced by the amount generated in power stations. Generators make offers to supply electricity at half-hourly periods through the day and night. They make the decision to offer power in light of the expected price of electricity, as against the cost of operating their plant over the period of time they run it. This cost (called the short-run marginal cost, or SRMC) is heavily affected by the price of fuel used to generate the electricity.

Thus, for determining what kind of power stations actually run at any one point in time, a key variable is the difference between wholesale electricity prices and the prices of the relevant fuels – in other words, gas or coal – paid by generators. Up until around 2000, coal and gas prices were close together, and both were low (see Figure 2.1).

Other costs, including the cost of capital, meant that gas-fired power stations had the edge over coal, so, in any given period of time, owners of CCGT power stations would be the first to offer power supply to the National Grid Company, which is responsible for keeping the system running. Newer plants tend to be more efficient, and so power output from these is offered first. This means that, through the 1990s, all the available CCGT plants would be running at full capacity for most of the time. This arrangement is known as *baseload* operation.

Only once all the gas plants had put in their low-cost offers would owners of coal plants start to bid in, at higher prices. Some of the least efficient, and therefore highest cost, coal plants (along with the few oil-fired power stations) might only offer to run in times of peak demand (known as *peakload* operation). One important consequence of this is that the price of wholesale electricity in the spot market (which changes every half an hour) at any one time reflects the costs of the marginal, most expensive plant in operation.

However, since 2001, changes to electricity trading arrangements mean that the spot wholesale market only handles a small part of electricity traded. Most generating companies sell their electricity directly to their supply arms via bilateral contracts. Competition for customers on price is, therefore, related directly to the efficiency and fuel costs of each company's generating portfolio.

3. In the past, coal has also received special treatment, most notably helped by a moratorium on new gas-fired plants at the end of the 1990s (Helm 2003). However, coal-fired electricity generation does not now receive any direct subsidy.

Drivers of costs

Coal versus gas prices

One important factor driving a resurgence of interest in coal-fired power generation is that, in contrast to the 1990s, over the last few years it has, at times, been highly competitive with gas-fired generation. From 2000, rising gas prices began to change the cost relationship between coal- and gas-fired power generation. Especially in winter, coal-fired plants started to look cheap, and began to run baseload, while gas moved towards more periodic use.

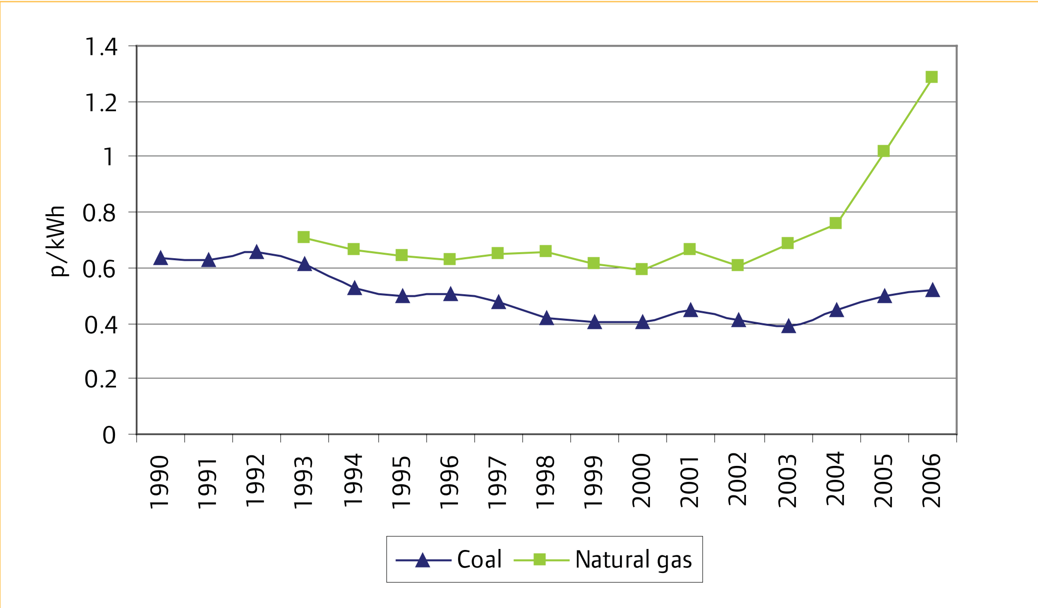
In theory, investment decisions should be based on a long-term and comprehensive view of costs, including not just fuel costs, but also operating and maintenance costs and the cost of capital. These are known as 'levelised' cost estimates, expressed in relation to the amount of electricity expected to be produced by a plant over its lifetime. Estimates can vary appreciably due to differing methodologies (see Gross *et al* 2007 for further details), but historically the levelised costs of generating electricity from coal and gas lie very close together. In a recent review of 1,200 cost estimates, the median cost of coal was £31.90/MWh compared with £30.50/MWh for gas (Gross *et al* 2007).

However, in practice, it is possible that investment sentiment may be swayed by more current price movements. Over the 1990s, gas prices were relatively low and stable (Figure 2.1), and the lower capital costs of gas plants made it the build of choice. But starting around 2002, gas prices for electricity generators started to rise sharply, especially in winter periods, when the demand for gas for heating also goes up. For the UK, this rise coincided with the shift from being a net exporter of natural gas from the North Sea, to beginning to import gas.

The UK will become increasingly exposed to the regional European gas market. Companies express concerns both about the flow of gas through Continental pipelines, and about gas supply, which is dominated by Russia (Helm 2007, Stern 2006). The nature of gas security of supply issues is assessed in detail in Chapter 8.

Figure 2.1. Gas and coal prices for UK electricity producers

Source: BERR 2007b



The rise in gas prices has shifted gas from being mainly a baseload fuel to a peakload one. In the UK market, wholesale electricity prices are set by the short-run operating costs of the marginal plant (see above). Since the early 2000s, the marginal fuel has often been gas, especially in winter, so average electricity prices have moved up with gas prices, from around 3p/kWh in 2004 to over 5p/kWh in 2006. Coal prices have, by contrast, been relatively stable until 2007, meaning that generating electricity from coal has been a very profitable activity over much of the decade.

This situation is now changing. In the last six months, coal prices have also moved up sharply, from about US$70/tonne to a peak of US$140/tonne in December 2007 (Lekander *et al* 2008b). With high demand from Asia set to continue, and some supply problems, coal prices are expected to remain high for the next two to three years. However, gas prices, which are tied to oil prices in European markets, are also rising sharply.

Fuel prices and modelling of investment

In modelling of future expected investment in new coal plants, fuel prices usually play an important role. For example, scenarios developed by the Government for the 2007 Energy White Paper are based on a range of gas and coal price projections (Table 2.1). They also assume an EU ETS carbon price of €20/tCO_2 from 2010 and €25/tCO_2 from 2015-2020 (see Chapter 3).

Table 2.1. Energy White Paper 2007, gas and coal price projections

	Gas (pence/therm, 2006 prices)			Coal (£/tonne, 2006 prices)		
	Low	Central	High	Low	Central	High
2010	32	42	50	28	30	38
2015	18	38	53	20	31	41
2020	21	40	53	20	32	45

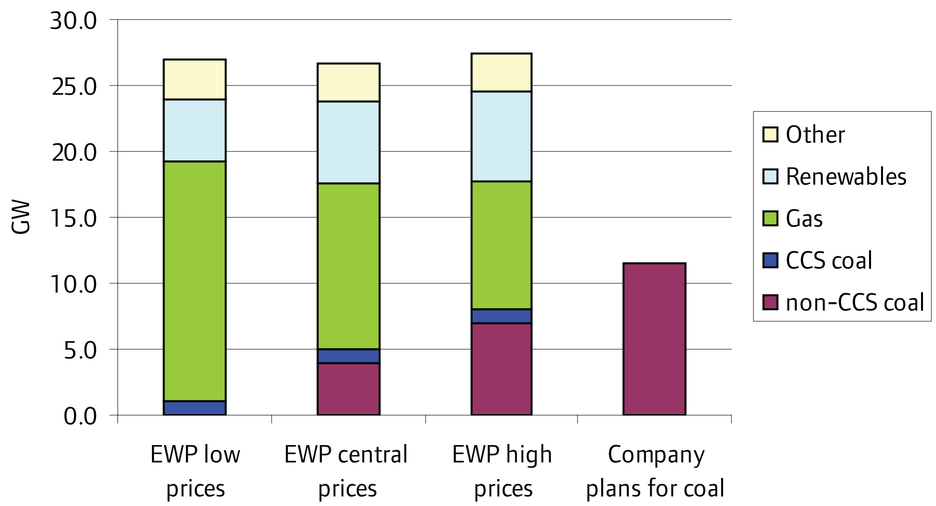
Note: These projections are, of course, dependent on the full range of assumptions underlying the modelling, and are presented here for illustrative purposes only.

Source: BERR 2007e

These fuel prices are the main factor in determining the profile of new coal build in the Energy White Paper (EWP) modelling (Figure 2.2). In the 'low' fuel price scenario, coal is not competitive with gas, which, along with renewables, dominates projected new build. However, with higher price scenarios, coal becomes more competitive. The central fuel price projections would lead to around 4 GW of new coal build. If prices are high in the period to 2020, the Government anticipates that around 7 GW more coal-fired capacity would be built by 2020.

Figure 2.2. Additions to capacity by 2020 under different scenarios

Source: Blyth 2008



Note: Energy White Paper projections are all for central policy impact scenario

Note that higher coal prices do not work against building new coal, as long as gas prices also hold up. This is because when new coal plants are built they have to compete not only against gas-fired plants, but also against existing coal plants. These are all at least 30 years old, and have long since amortized their capital. By contrast, to be worth building, new coal-fired plants do have to pay off their capital costs, which are considerable.

The reason why new supercritical coal power stations might be able to do this is that, as noted in Chapter 1, they are considerably more efficient than coal plants built in the past. However, this efficiency advantage is greatest when coal prices are high. If coal prices fall very low, then the efficiency gain is worth less, and new coal would be a riskier proposition.[4]

The role of new nuclear build

A final factor to note is the role of possible new nuclear build. As noted above, unlike in the past, nuclear power should now be seen as part of the competitive electricity market. The Government has recently signalled that it now wishes to see new nuclear plants built in the UK. Some energy companies are showing some interest in pursuing new nuclear build. RWE and EDF are considering takeover bids for nuclear generator British Energy, which would give these companies options on likely nuclear sites (Pagnamenta and Kennedy 2008).

It is too early to say whether, and how soon, applications will come forward, as companies are also waiting for further government action on pre-licensing arrangements, and the passage of the Planning Bill, both of which are seen as requirements by industry for investing in nuclear. However, given that the Government has repeatedly maintained that there will be no repeat of past subsidies for nuclear,[5] the most important factor is cost and competitiveness. Cost estimates of nuclear power vary substantially according to methodology, and it is possible that no applications will be forthcoming unless there is some form of support (the most likely being a floor price for carbon).

Planning and building new nuclear power plants, even with streamlined procedures, will take a long time, and even the most optimistic estimates are that there will be no capacity operating before 2018. If it happens, new nuclear capacity will start to enter the UK electricity market in a major way only from the early 2020s onwards.

However, since all power plants are long-lived, expectations about nuclear new build influence both coal and gas plans, and vice versa. At the same time, since gas-fired plants remain the default investment, and gas prices tend to determine electricity prices, both coal and nuclear remain the riskier investments: not only more capital-intensive than gas, but also exposed both to market price and policy risks (see Annex B for more details).

The generation gap

Costs and cost risk do matter for investment decisions, but, as Gross *et al* (2007) have recently pointed out, while policy on electricity generation has tended to be informed by cost estimates, actual investment decisions are probably driven more by expected revenue and risks associated with revenue.

Looking ahead over the next 10-15 years, expectations about future electricity revenues are dominated by the anticipation of a 'generation gap' in the latter part of the next decade. The UK currently has about 76 GW of generation capacity, and a winter peak demand of around 63 GW, giving a 'capacity margin' of around 21 per cent of peak demand. A capacity margin of more than 15 per cent is considered desirable in order to maintain the resilience of the electricity system to shocks, such as several normally operating plants going down at the same time.

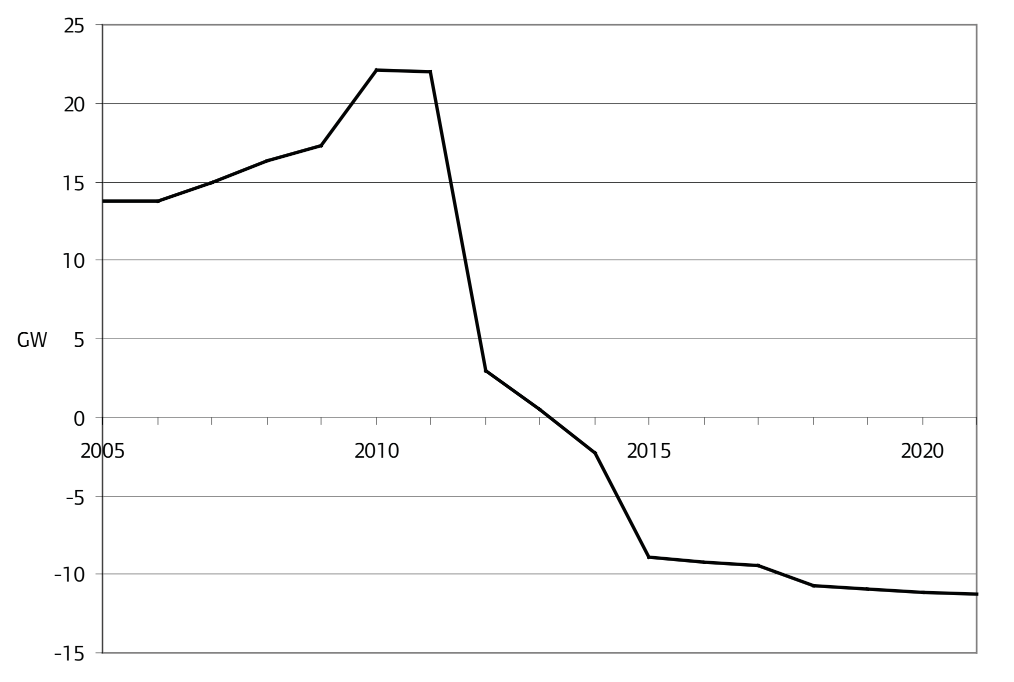
4. The author is grateful to Will Blyth for this observation. The efficiency gain would also be less (or non-existent) if new plant were built with CCS, as this involves an energy penalty (see Chapter 6).
5. There is a level, if implicit, subsidy in limits to the insurance liability that nuclear operating companies have to take on.

However, some nuclear and coal plants are certain to close down over the period to 2020, and further plants may well do so. The Government predicts that 22.5 GW of capacity – almost 30 per cent – will be lost by 2020 (HM Government 2007).

Figure 2.3 shows an indicative projection of the capacity margin in GW, taking into account only current capacity, planned retirements and new projects with planning approval. It shows a steep fall off in capacity from around 2012 as nuclear plants close down, and then another fall from 2016 as coal plants are phased out under the Large Combustion Plant Directive. The Government takes the view that 20-25 GW of new capacity will be needed by 2020, with possibly another 10 GW by 2030 (HM Government 2007).

Figure 2.3. Capacity margin without new investment

Source: BERR 2007c



Projections of capacity margins and generation gaps depend heavily on assumptions. The projection in Figure 2.3 is very conservative, in that it ignores capacity in the planning pipeline and the impact of possible future policies. In fact, not only are some new gas-fired plants already being built, but also more are at application stage, with some 16 GW in the pipeline. There is also 9 GW of wind-power awaiting approval (BWEA 2008).[6]

The Government also expects there to be some new nuclear capacity by 2020, and potentially a lot more after that date, and the European Commission's proposed targets for renewable energy will also have significant implications for the generation gap if adopted (see Chapter 4).

Projections of margins also make assumptions about the demand for electricity. Figure 2.3 is based on the Government's forward analysis of markets, which assumes an increase in peak demand over the period by about eight per cent. If future electricity demand is lower, due to conservation measures and the smoothing of demand, then the generation gap would also be smaller, although, even on optimistic views of the potential for reducing demand, a gap will still exist.

The major generating companies, which all have their own similar versions of this generation gap analysis, expect that there will be a significant generation gap, and consequently that electricity prices could start to rise from early in the next decade (Blyth 2005). All the major companies are now

6. Note that effective capacity from these sources will be less than the headline figures, especially in the case of wind where the capacity factor is in the region of 0.3, because the wind does not always blow at the speed required for the rated capacity.

proposing or considering a wave of new investments on the basis of the market becoming increasingly tight.

The dynamics of price movements and investment timing are also important. As White (2005) points out, in a competitive arena like the UK wholesale electricity market, the price spikes associated with a shortage of capacity can be short-lived, and companies have to time their investments just right. If they are slightly behind other market players, they risk bringing new capacity on stream just as the generation gap disappears, and prices drop to levels where they find it hard recover their capital costs. This is particularly a problem for coal, as coal-fired power stations take longer to build and are more expensive than gas-fired plants.

Strategic considerations

Given their expectation of electricity revenues, based on their analysis of the generation gap, and of costs, companies will make decisions about developing proposals for investment in new coal, gas, wind or other generation accordingly. Future revenues and costs are discounted at a given rate, and then summed to give a net present value (NPV) for the project. Companies appraise investments on the basis of the spread of NPVs of projects under different price assumptions, and the project risks involved (see Annex B for a fuller explanation of NPV and an estimate of spreads for gas and coal projects).

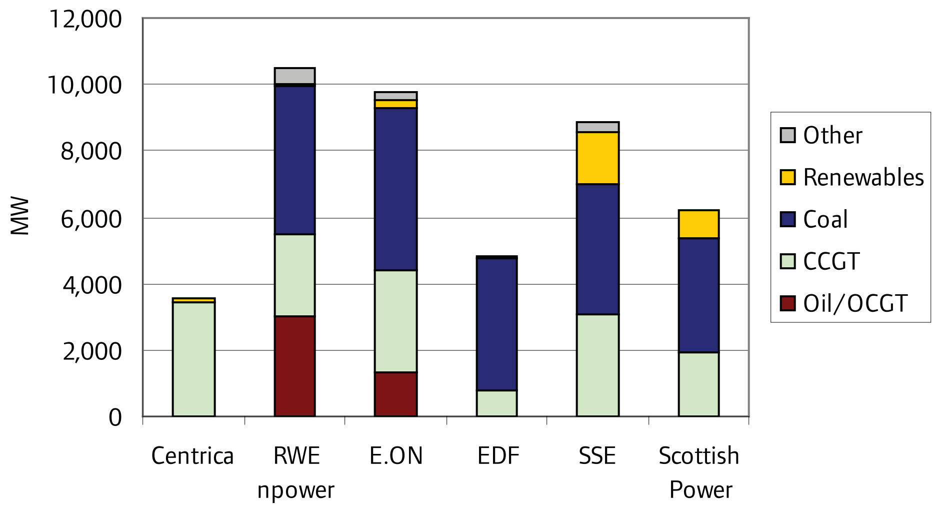
On a conventional NPV basis, under a range of cost assumptions, gas still looks like the lowest risk investment, and, therefore, the default investment choice. This is because, while gas is at the margin, electricity prices will tend to move with gas prices, thereby reducing revenue risk for gas, but not for coal. Coal can bring big rewards, but is more of a risk.

However, in addition to calculations made purely on the basis of plant economics, investment decisions will also be affected by strategic considerations. One of these is having a diverse generation portfolio, to hedge against the risk that any one fuel or technology may become very expensive because of market, security of supply or policy factors (Gross *et al* 2007).

Five out of six of the major energy companies currently have coal capacity in their portfolios (Figure 2.4), often along with gas and some renewables. However, under the LCPD, E.ON will have to close 3 GW of coal plants by 2016, RWE npower will have to close 3.2 GW, and Scottish Power 1.2 GW. More coal capacity may close subsequently, or have to run at reduced load under further LCPD provisions.

Figure 2.4. Portfolio of the major suppliers in 2007

Source: BERR 2007a



It is important to realise that the phase-out of coal plants can have an even bigger impact on the generating capacity of individual companies than on the country as a whole. By 2015, E.ON, for example, will have lost around 45 per cent of its total capacity, and 60 per cent of its coal plants, while RWE will lose 80 per cent of its existing coal capacity. Because the loss of coal capacity under the LCPD all happens by 2016, and the planning and building of a new coal plant takes five to six years, all the major companies that have opted-out coal plants are thinking about new coal now.

Thus, plans for investment in new coal are being driven, at least partly if not mainly, by a desire to hold on to a portfolio that will be large enough to maintain (or, for some, increase) market share, and which also includes a significant amount of coal. Companies regard having too large a proportion of gas capacity in their generation mix as exposing themselves to a cost risk. They talk in terms of 're-planting', in other words replacing capacity that is coming to the end of its life with new plants that use the same fuel.[7]

An implication of this is that new coal plant investments are seen as giving an additional risk reduction benefit, above and beyond the conventional investment appraisal. This premium makes it more likely that they will be built. Against this is the carbon price risk to which coal is particularly exposed, and which is discussed in the next chapter.

A final point to note is that energy companies are also proposing or seriously considering new coal build elsewhere in the EU (Table 2.2). According to an analysis by Greenpeace International in 2007, based on information from the energy data firm Platts, a total of 68 new coal-fired or lignite-fired[8] power stations are being considered across the EU27, with a total capacity of 64 GW (Greenpeace International 2007). The largest number of projects is being proposed in Germany.

Some companies in the UK market – specifically E.ON and RWE – operate across the EU, with headquarters in Germany. For these companies, the planning of new coal capacity in the UK might therefore also be seen as part of a wider European portfolio diversification strategy. However, it should be noted that the future of these proposals depends, in part, on the final shape of Phase 3 of the EU ETS. This is discussed further in the next chapter.

Table 2.2. Planned coal power plants in Europe

Country	Proposed new capacity (MW)	Number of projects
Germany	33,435	33
Italy	5,890	6
Poland	3,526	6
Netherlands	6,200	5
Hungary	1,600	2
Bulgaria	750	1
France	700	1
Greece	600	1
Austria	800	1
Slovenia	885	1
Spain	1,200	1
Total	64,026	68

Source: Greenpeace International (2007)

7. Centrica is the only energy major not to own coal-fired capacity, but has said that it will not invest in non-CCS coal plant, on grounds of corporate environmental responsibility and carbon policy risk.
8. Lignite, also known as brown coal, is a soft coal with a high moisture content used extensively in Germany, but not in the UK. It has a higher carbon dioxide content than hard coal.

Summary

Under the current liberalised electricity policy framework, the decision to invest in new coal lies with companies rather than government. Companies will invest in new coal if they think it will be more profitable than alternatives, and given the requirements imposed by the Renewables Obligation.

The major energy suppliers are all expecting a shortfall in generating capacity in the next decade, and, therefore, higher electricity prices, and this is driving a general interest in investing in new capacity.

Interest in new coal in particular has been sparked by relatively low coal prices over the last five years.

However, it is perhaps most strongly driven by the desire to maintain a portfolio of generating capacity that includes a range of fuels, to hedge against market, security of supply or policy risk. As some companies are losing a significant amount of coal capacity from 2015 onwards, they are interested in replacing it.

3. The role of carbon pricing

Cost, revenue expectations and strategic considerations are all factors driving the new interest in coal. However, since 2005, a new development has come into the investment equation in the form of carbon pricing through the EU emissions trading scheme (EU ETS).

Carbon pricing works against new coal investment because burning coal emits at least twice as much carbon per kWh generated than burning gas. The additional costs from carbon pricing will, thus, be higher for coal-fired generating plants than for gas-fired plants.

The EU emissions trading scheme

The EU ETS covers both the power sector and heavy industry. Under Phases 1 and 2 of the EU ETS, covering 2005 to 2012, most emissions allocations are determined at the level of installation (for example, power station, factory), based on the installation's emissions over the previous five years ('grandfathering'). This process was handled under national allocation plans (NAPs) developed by each member state, which were then assembled into a total EU carbon market. Installation owners can also, up to a certain limit (for example, seven per cent for power stations) meet their obligations by buying credits from projects created under the Clean Development Mechanism (CDM) and the Joint Implementation (JI) scheme of the Kyoto Protocol.

In Phase 1, NAPs were overgenerous, and, in April 2006, when it became clear that allowances were larger than actual emissions, the carbon price collapsed. Only with a tighter cap in Phase 2 from January 2008 has carbon started to be effectively priced (in the range €20-25/tCO_2 in March 2008) (see www.pointcarbon.com).

In January 2008, the European Commission put forward proposals for Phase 3 (to run from 2013 to 2020). These proposals represent a further tightening of the cap, and are discussed in more detail below.

Carbon prices, fuel switching and banking

In theory, the price of carbon on the EU ETS is ultimately determined by the total cap on emissions set by European governments, relative to the emissions that would otherwise be created by electricity generation and heavy industry, taking into account the amount of CDM and JI credit that can be used.

The price of carbon in future phases of the EU ETS will depend on how far and fast governments want to push emissions reductions, which is, in turn, ultimately a political decision. The carbon market, therefore, exposes electricity generators to *policy risk*, in addition to the commercial risks they face because of volatile coal and gas prices (although gas prices in fact have a certain element of political risk also contained within them).

The view of carbon market analysts is that, once a cap is biting, then the price of carbon should tend towards the cheapest way of reducing emissions at that level of the cap. As the cap is tightened over time, the carbon price can be expected to increase, as the cheapest ways of reducing emissions are exhausted and more expensive technologies have to be applied. This is referred to as the marginal abatement cost curve.

The cheapest form of large-scale abatement available to installations is to buy in credits from CDM/JI schemes. This is an important issue for future phases of the scheme because the more scheme participants are allowed to buy in CDM/JI credits, the greater the downward pressure on carbon prices.

Once this avenue is exhausted, the next cheapest thing to do is to switch from more to less carbon-intensive fuels in electricity generation (White 2006, Lekander *et al* 2008a, Lewis 2008, Lewis and Curien 2008). If carbon prices exceed the cost of switching fuels, it is more profitable for the electricity plant at the margin to reduce output and sell their carbon allowances. If carbon prices are lower than this level, it is more profitable for the marginal plant to buy allowances and produce electricity.

The most carbon-intensive fuel used in European power generation is lignite, or brown coal, with a carbon factor of 0.9-1.3kgCO_2/kWh, compared to conventional, hard coal, with a carbon factor of 0.7-0.95kg CO_2/kWh. The ranges relate to how efficient the plant is, with more modern supercritical power stations having higher efficiencies and lower carbon factors. Thus, one would expect the first power stations to reduce output or close down to be old, inefficient lignite-fired plants in Germany or central and eastern Europe.

There is some scope for fuel switching from lignite to hard coal or gas. There is some 60 GW of lignite-fired capacity and 130 GW of hard coal capacity in the EU (RWE 2007). In Germany, one quarter of power generation is from lignite, representing around 130 TWh a year. Although their markets are smaller than Germany's, the proportion in some of the new member states in the east of Europe is much higher. Furthermore, some of the hard coal plants in Europe are older and more inefficient than those in the UK.

Fuel switching driven by carbon pricing is, therefore, unlikely to happen directly in the UK for a while. (A decline in output from coal-fired generation is more likely to be driven by closures under the Large Combustion Plant Directive.) Lewis and Curien (2008) estimate that the carbon price will have to reach €55/tCO_2 for large-scale fuel-switching from coal to gas in the UK. This may happen later in Phase 3 (2013-2020) if the European Commission's proposals are accepted (see below).

This relationship between the carbon price and fuel switching means two things: first, the carbon price will tend to move, so as to keep the short-run marginal costs (SRMC) of generation of the two fuels the same. Initially, this will be lignite and hard coal, or lignite and gas. However, in the longer run, the carbon price should equalise the SRMCs of hard coal- and gas-fired power generation. A consequence of this is that the 'merit order' of plants in the UK would then be dictated more by efficiency than by fuel costs. More efficient newer plants (for example, supercritical coal) would run baseload, while older plants would be pushed to peakload or reserve.

A second consequence of this relationship is that the carbon price will move in step with the price of the less carbon-intensive fuel. Consider the case of coal and gas again. Suppose the price of gas falls, while the cost of coal stays the same. This makes the cost of switching from coal to gas lower, and so the price of carbon can fall to accommodate this shift. The reverse happens if the cost of gas rises relative to coal.

A final point about point about carbon prices relates to the introduction of 'banking'. In the move from Phase 1 to Phase 2 of the EU ETS, one important change is that participants are allowed to 'bank' allowances. This means that they can buy them in one year, say 2008, and then surrender or sell them in a later year, say 2012. The proposals for Phase 3 are that participants will be able to bank allowances between Phases 2 and 3, that is, forward all the way to 2020.

The implication of this is that the carbon price, in theory, should start to rise quickly to the cost of abatement expected at the end of the period (2020) (Lewis 2008, Lewis and Curien 2008). If a participant buys an allocation in 2020 to cover emissions, then, on the analysis above, the price they will pay will reflect the cost of abatement in 2020. Since the cap will be tighter then, this cost will be higher up the marginal cost curve than the cost of abatement in, say, 2008. It would, therefore, make sense for participants to start buying allowances in 2008, bank them, and surrender them in 2020. This creates a demand for 2008 allowances that drives up their price to the 2020 abatement cost level, discounted for inflation.

Carbon prices and investment in coal

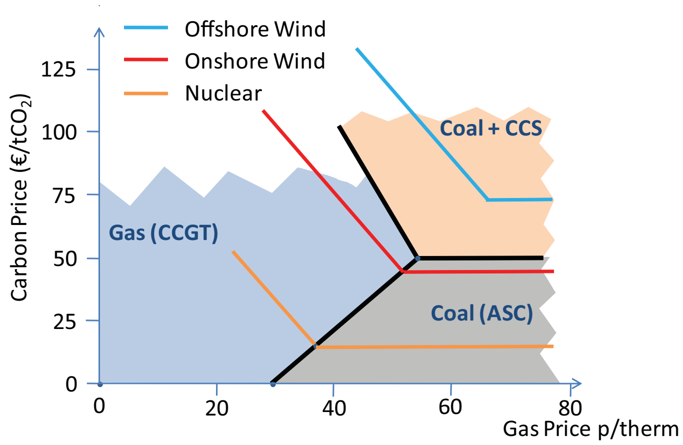
Carbon prices will have a bearing on the decision on whether or not to invest in new coal-fired power stations in the UK, although how much they matter depends on how much certainty companies ascribe to the future shape of the EU ETS. We examine this in more detail below.

For investment decisions, what matters is the difference that carbon prices make to *expected future costs*, over the lifetime of the investment. The precise relationship depends on estimates of those costs, which do vary between sources, and also over time. Figure 3.1 gives one illustration, based on underlying technology costs taken from background analysis commissioned for the 2007 Energy White

Paper (Redpoint Energy Strategies 2007). The exact location of the lines may vary with different cost estimates, but the basic shape of the diagram remains common.

Figure 3.1. Preferred technology for investment, based on central Energy White Paper coal prices

Source: Blyth 2008



The diagram illustrates how technology choice is related to gas and carbon prices, for a given coal price (in this example, around £30/tonne – the central projection for coal prices in the 2007 Energy White Paper). A higher coal price would shift the lines on the phase diagram to the right.

In this case, with a zero price for carbon, gas-fired plant is the investment of choice for gas prices of less than 30p/therm. In the 1990s, gas prices for electricity generators were as low as 18p/therm, and there was no carbon price, a situation that clearly explains the 'dash for gas'. In recent years, however, gas prices have moved up into the 30-50p/therm range. In the absence of a carbon price, this makes coal plants (or, rather, advanced supercritical coal plants) a lot more attractive.

However, a carbon price works against coal, in favour of gas. If gas prices are at, say, 40p/therm, then at low carbon prices up to about €20/tCO_2, coal would still be the preferred investment. But, at a higher carbon price, the additional penalty paid by coal starts to take effect. So, even with a gas price of 50p/therm, if carbon prices start to exceed about €40/tCO_2, gas may be the more cost-effective technology.[9]

However, as discussed above, the carbon price is expected to be related to fuel prices via the fuel switching relationship. In the early phases of a properly working EU ETS (which really only dates from early 2008), the fuel switch is between lignite and hard coal or gas. However, as the cap comes down and fuel switching moves to hard coal to gas, the carbon price will tend towards equalising the SRMCs of gas and coal, moving up and down with the relative price of gas. This suggests, for example, at BERR's central coal price projection for 2020 (£23/tonne), and the high gas price projection of 42p/therm, the carbon price would be around €40/tCO_2. This is consistent with projections of carbon prices in 2020 under the Phase 3 proposals for the EU ETS (see below).

Since SRMCs are lower than levelised costs, this relationship will tend to favour gas as an investment. Essentially, effective carbon pricing will act in such a way as to prevent the returns to new coal investment covering fixed costs, and especially the cost of capital.

9. Note that the attractiveness of investment in other technologies, including nuclear, onshore and offshore wind, and coal with carbon capture and storage (CCS), is also influenced by gas and carbon prices.

The EU ETS so far

The effect of carbon pricing on investment decisions in the real world will depend both on the strength of carbon policy (that is, the tightness of the cap, whether allocation is by auctioning or grandfathering, and so on), and on how confident companies are that the market will be there over the long term, and that governments have the political support for carrying out a strong policy.

So far, the EU ETS has been too weak a mechanism to really influence decisions about investment in electricity generation, on both counts. Indeed, a major concern of environmental organisations is that, if companies are now seriously considering building new coal-fired power stations, something is very wrong with policies that are supposed to deliver a transition to a low-carbon economy.

Thus, the time frames of the scheme have been far too short-term, creating uncertainty about the future. For example, in 2005, Vincent de Rivaz, chief executive officer of EDF Energy, commented that: 'the long term price of tradable emissions allowances is too uncertain to be a driver of systematic technological change in an industry whose generating capacity investments must be planned over 30-year periods' (de Rivaz 2005; similar views were expressed by Sarwjit Sambi of Centrica at an ippr seminar in January 2008).

Another problem is that Phase 1 caps were set too generously, a situation that led to the carbon price collapsing in the spring of 2006.

A further criticism is that companies are allowed to use credits from Kyoto Protocol mechanisms – the Clean Development Mechanism (CDM) and the Joint Implementation (JI) scheme – to meet a large part of their emissions reduction requirements. There is evidence that some of these credits do not guarantee additionality in terms of emissions reduction (see, for example, Schneider 2007, Wara and Victor 2008), and so weaken the environmental effectiveness of the EU ETS. These credits tend to be cheaper than the cost of abatement within the EU, so also depress the price when caps are insufficiently tight.

These issues are a problem for the credibility of the EU ETS, since, while driving short-term abatement at the margin is useful, the really important achievement of an emissions trading scheme will be to drive investment in lower-carbon technologies over time. Certainly the most basic step one would expect from such a scheme would be to make investment in the most carbon-intensive activities unattractive – of which burning coal to make electricity is one.

There are signs that EU ETS policy is now tightening up. In Phase 2 of the scheme, running from now until the end of 2012, caps are tighter than in Phase 1. It is expected that this will mean more demand for credits. For example, the German energy company Vattenfall has predicted a shortfall of 35.8 million allowances per year for Phase 2 (www.pointcarbon.com). However, CDM or JI credits still play a major role, as up to two-thirds of the emissions reduction can be met through buying such credits.

Proposals for Phase 3 of the EU ETS

In January 2008, the European Commission made formal proposals for Phase 3 of the ETS (EC 2008a), which imply a stronger carbon policy regime. This package includes:

- A single EU-wide cap on emissions from sectors covered by the EU ETS
- A longer phase, running for eight years from 2013 to 2020
- An annual cap, declining linearly, with an indication of future decline for Phase 4 (2021-2028) (this cap is based on overall EU greenhouse gas reduction targets, rather than previous performance of installations)
- 60 per cent of total allowances to be auctioned, with 100 per cent in the power sector[10]
- More limited use of CDM/JI credits to meet required emissions reductions.

10. Note that auctioning is relatively more costly for coal, compared with grandfathering, because, while grandfathering accommodates the higher carbon content of coal, under auctioning, coal plants will have to pay more than gas plants.

There are two possibilities or scenarios for the cap in Phase 3. One applies in the absence of a 'satisfactory' international agreement on climate change and emissions reduction. The cap in this case is based on a target of a 21 per cent reduction in greenhouse gases from 2005 levels by 2020. Under this scenario, unused CDM/JI credit limits from Phase 2 can be carried over into Phase 3. For this version of Phase 3, the Swiss bank UBS predicts an annual average shortfall in allowances of 440 million (Lekander *et al* 2008a).

However, most observers expect that the more relevant scenario for Phase 3 is one in which a 'satisfactory' international agreement is deemed to have been reached. The cap under this scenario involves a 31 per cent emissions reduction from 2005 levels. However, in this version of Phase 3, more CDM and JI credits will be allowed, up to 50 per cent of the additional emissions reduction effort involved.

Under both scenarios, early predictions for the carbon price are of the order of €20-25/tCO_2 in 2013, rising to €35-40/tCO_2 by 2020 (see, for example, Buchan 2008, Lekander *et al* 2008a). Lewis and Curien (2008) offer a more comprehensive analysis that includes banking, and offer a prediction of €40/tCO_2 for 2008 allowances, rising to a 2020 price of €67/tCO_2.

With carbon pricing driving fuel switching away from coal to gas from Phase 2, continuing to higher levels in Phase 3 and beyond, investment in new coal-fired power stations would become less attractive. Indeed, there are signs that companies are beginning to rethink investment plans in light of the January 2008 EU package. For example, in a speech following the European Commission package, Ulrich Jobs, a board member of German utility RWE, said that planned investments would not go ahead if the package were to be agreed by member states (Forbes 2008).

UBS estimates that the tightening of the proposed cap under Phase 3[11] and the subsequent doubling of the expected emissions shortfall from Phase 2, along with limits on use of CDM and JI credits, will mean that around 430 TWh of coal-fired power generation – 43 per cent of output from coal (including lignite) in 2005 in the 27 countries of the EU – will have to be switched to gas by 2020 (Lekander *et al* 2008b).

This order of fuel switching would begin to affect coal-fired power stations in the UK. In 2005, the UK produced more electricity from hard coal than any other EU country (the other large coal users are Germany, Poland and Spain). Lewis and Curien (2008) argue that, given the relative carbon intensity of fuels used and the relative efficiency of plants across Europe, the UK will see abatement of around 10 MtCO_2 per year from fuel-switching, only after Spain and Germany, and at carbon prices in the range of €36-40/tCO_2.

Recent analysis by Lewis and Curien (2008) implies, however, that the options for fuel-switching across the EU based on the current generation portfolio are limited, and will not be sufficient to allow the cap proposed for Phase 3 to be met. They argue that the most likely outcome is that the carbon price will rise to the point that makes gas-fired generation competitive with coal (around €40/tCO_2 in today's prices), to induce a major wave of investment in gas-fired plants of up to 60 GW. They also estimate (along with some energy industry analysts) this to be the carbon price at which coal with CCS becomes commercially viable.

Carbon prices, banking and expectations

As explained above, the more sophisticated estimates of the price for carbon that we should expect to see in the EU ETS, with banking of allowances, are around €40/tCO_2 (Lewis and Curien 2008). Currently, however, the carbon price is in the range of €20-25. With banking now in place, why are prices not moving up to the higher range?

The reason is that participants in the market (energy companies, but also carbon market traders) are discounting future prices because of uncertainties about the future of the scheme.

11. The UBS analysis takes the 21 per cent reduction scenario as its reference point, but it would broadly apply to the 31 per cent reduction.

The first issue is that the final shape of Phase 3 of the EU ETS is not yet determined, and the final outcome will be the result of political negotiations between member states and MEPs, heavily lobbied by their own industries and energy companies (some of which have a presence in several EU countries). Agreement may not come until mid-2009, or possibly even later. While the overall cap in Phase 3 is already agreed in principle, it is not clear that the proposals on limits to the use of CDM/JI credits and on auctioning will go through, both of which will have an impact on the carbon price.

Within this context, statements about cancelling coal investments can also be seen as lobbying against a strong EU ETS policy. For example, Johannes Teyssen of E.ON has said that plans for auctioning emissions allocations in the EC climate and energy package are creating uncertainty and the cancellation of projects, which will, in turn, lead to an energy crisis (Gow and Woodward 2008).

This will change to some degree when final agreement on Phase 3 is reached in the European Parliament and Council. However, there may still be remaining questions about the overall credibility of EU carbon policy, because this is, in turn, tied to the development of a global agreement on climate change, and the spread of carbon markets beyond the EU ETS. This issue is discussed further in Chapter 8 below.

Effects of policy uncertainty on new coal investment

More complex models of electricity investment introduce policy uncertainty as a factor shaping decisions about building new plants. An example of how the potential effects of uncertainty about carbon prices on decisions about investment in new coal build might work can be seen in detailed modelling of the mainland UK electricity system out to 2031, commissioned by the Government as a background study for the 2007 Energy White Paper (Redpoint Energy Strategies 2007).

This study incorporated a sophisticated representation of investment decisions, and compared two scenarios that demonstrate the potential influence of carbon policy on coal new-build. In both scenarios, the analysis uses the Government's central price projections, as in Table 2.2 above.

In the first scenario, markets were assumed to work well, with investors taking a view 15 years ahead, and anticipating capacity shortages in the late 2010s, liquidity in wholesale electricity markets, and a facilitative planning system. Crucially, this scenario also assumes certainty about the future existence of a carbon price. In the base case this rises from €22/tCO_2 in 2008 to €25/tCO_2 in 2013, and then to around €32/tCO_2 in 2020, and continues rising thereafter. All allowances are assumed to be auctioned from 2013.

In this scenario, around 35 GW of new capacity is brought on stream by 2020. The majority is gas and renewables. There is, however, about 6 GW of new coal plants built as well.

In the second scenario, investors take a shorter-term view (meaning, for example, that final decisions on whether to replace plants closing under the LCPD are not made until 2010/11), and lack of liquidity means considerable vertical integration in the market. And, although expected carbon prices are almost the same as those in the first scenario, there is uncertainty about the commitment of policymakers to future carbon policy, and, therefore, the existence of the carbon price. This uncertainty reduces the risk for coal, and influences what is predicted for new build.

In this second scenario, less total new capacity is built, about 30 GW in total. But more coal plants are built from 2015 onwards, with around 9 GW in place by 2020.

Summary

The EU emissions trading scheme (EU ETS) creates a price for carbon dioxide emissions, and, because the cap for the scheme is set through a political process, it introduces a policy risk for energy companies.

Because coal-fired power generation is more carbon intensive than gas-fired generation, carbon pricing makes it less attractive commercially. Once a steady and significant price for carbon is established in the market, analysts expect that it will drive fuel switching from coal (and lignite) to gas, since this is the cheapest way of reducing emissions on a large scale and, thereby, staying under the cap.

In theory, carbon pricing should deter investment in new coal plants. However, so far the EU ETS has not been effective in driving down emissions, let alone influencing investment decisions. This is mainly because allowances have been too generous, and the time frame of each phase of the scheme has been too short.

In January 2008, the European Commission made proposals for a stronger ETS, with a tighter, single, EU-wide cap and longer time frames. Market analysts predict that, on the basis of such an approach, carbon prices would reach around €40/tCO_2 by 2020, and that over 40 per cent of EU27 coal-fired power generation would have to switch to gas.

The final shape of Phase 3 of the EU ETS is not yet determined, and the final outcome will be the result of political negotiations between member states and MEPs, heavily lobbied by their own industries and energy companies. Agreement may not come until mid-2009, or possibly even later. Even then, energy companies may not be convinced that a strong carbon policy is politically sustainable, meaning that they may tend to discount carbon prices when planning investments.

4. The role of the 2020 renewable energy target

The European Commission's proposals for Phase 3 of the EU ETS, put forward in January 2008, were part of a wider package on climate and energy. This package also included ambitious new targets for the development of renewable energy (EC 2008c). The targets have implications for investment in both coal and gas.

Current policy on renewable electricity

Currently the Government has a target of achieving 10 per cent of electricity generation from renewable sources by 2010, with an aspiration of reaching 20 per cent by 2020, from current levels of 4.4 per cent (HM Government 2007). The main instrument for achieving these increases is the Renewables Obligation (RO), which requires energy suppliers to source a certain proportion of power supplied each year from renewable sources, or pay a penalty.

The level of the RO in 2007/08 was 7.9 per cent, and this will rise to 15.4 per cent by 2015, where it will stay until the mechanism ends in 2027. However, the existence of the penalty buy-out, along with projects becoming stuck in the planning process, has meant that actual renewables build has not fully kept pace with targets.

To tackle this problem, along with the fact that the RO has favoured a single renewable technology – onshore wind – the Government is introducing a Planning Bill to speed up projects, and a reformed RO that will give greater benefit to other technologies.

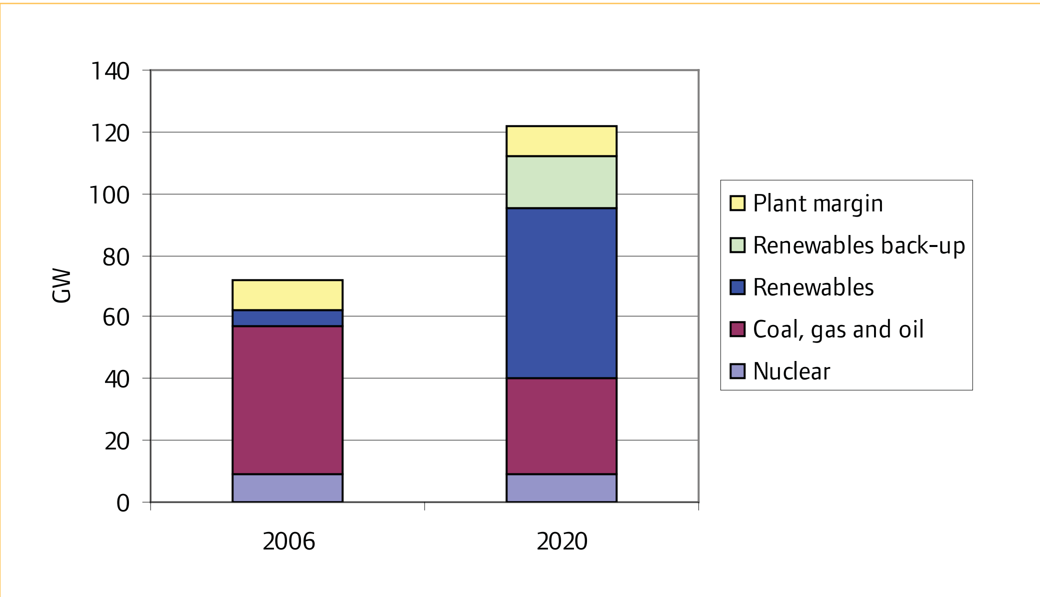
As noted in Chapter 2 above, the result of the Renewables Obligation is that the electricity market is effectively partitioned, and the growth of renewable electricity generation is somewhat protected from competition from other sources.

The 2008 draft European Renewable Energy Directive

The proposed new EU-wide target for renewable energy (including electricity, heat and transport) is 20 per cent by 2020. The UK's target for renewable energy would be 15 per cent. Exactly what this means for electricity generation has yet to be determined, but it is broadly agreed that this target is consistent with approximately 35-40 per cent of electricity demand being met from renewable sources by 2020. Given the projection of total electricity demand of around 370 TWh a year for 2020 in the Energy White Paper, this means 130-150 TWh a year of renewable electricity being generated by that date.

Figure 4.1. UK electricity capacity requirements under the draft EU 2020 target for renewable energy

Source: Business Council for Sustainable Energy 2008



If this target were to be met, a lot of renewable electricity capacity would be introduced into the UK wholesale market, through an expanded RO or other means yet to be determined.[12] An indicative picture of what this market might look like can be seen from an analysis from the UK Business Council for Sustainable Energy (BCSE 2008). The BCSE analysis assumes that 37 per cent of electricity demand will be met from renewable sources in order to meet the 2020 target. Of this, 43 per cent will be from offshore wind, and 24 per cent from onshore wind. Total system capacity requirements are shown in Figure 4.1, previous page.

Aside from the very much larger amount of renewable capacity in 2020, the two striking differences between the current requirements and the 2020 picture are: first, a significant new requirement for back-up to handle the intermittency of wind, and second, a sharply reduced requirement for conventionally run (that is, non-back-up) coal and gas capacity, down from 48 GW in 2006 to 31 GW in 2020.

The new requirement for stand-by raises quite fundamental questions about future investment in electricity generating capacity, since most investment is made on the basis that the new asset will be run as much as possible in its first years to generate a return on investment. Building a new power station on the basis that it will be available for occasional use is an entirely different proposition. Since this type of investment is more about system stability than about generation, and has a public goods characteristic because it supports low carbon generation, a new policy framework for such investment may be called for.

The second message of Figure 4.1 is equally radical. Total thermal (gas, coal and oil) plant capacity in the UK in 2006-07 was 58.5 GW, while nuclear capacity was around 12 GW (BERR 2007c). According to the BCSE analysis, by 2020 only around 30 GW of thermal capacity – little more than half – will be needed. Some of the current capacity will certainly be retired by 2020. However, even if this is as much as 20 GW, there will still be ample gas and coal capacity to meet conventional generating demand. In other words, the lights could be kept on without the need for any new fossil fuel plants.

Thus, the overall implication of the 2020 target is that, compared with previous thinking about the generation gap and the shape of the electricity market in 2020, a huge expansion of renewables will impact on the mainstream fossil fuel part of the market. If the renewables targets were to be met, a large amount of fossil fuel investment now would mean a glut in the market by 2020. Depending on renewables policy and carbon pricing after 2020, this oversupply problem would also apply to new nuclear build.

There is still a possibility that companies may build new coal plants, in order to compete within the non-renewables part of the market. Whether this happens depends on expected fuel carbon prices, and, if it did, new coal plants would tend to displace old coal plants.

Finally, it should be noted that the European Commission's January 2008 proposals for the EU ETS and for renewable energy have been determined jointly, with each based on the assumption that the other will be met. This means that, if the 2020 renewable energy target is not actually met at the EU level, the carbon reductions associated with that target will have to be met from elsewhere. This will drive up the EU ETS carbon price, which will tend to deter investment in new coal. Conversely, if generation from renewable sources of electricity exceeds the target, the carbon price may collapse.

The politics of the 2020 renewable energy target

The proposed renewable energy target is intended to show strong leadership through action, by the EU to the rest of the world. The Commission also presents the target as improving Europe's energy security and developing its renewables industry, all at a manageable cost.

12. Under the draft Directive, it is technically possible for the UK to meet its target through credits generated by renewable energy in other EU countries, once they have met their own targets, but it is expected that this opportunity will be limited. UK ministers are now suggesting that investments in renewables by the UK outside of the EU should count towards the target (see below).

From an environmental point of view, therefore, achieving the targets is very important. A major concern of critics of new coal build is that it will be, at best, a distraction from, and, at worst, a threat to, the expansion of electricity generation from renewable sources. A Stop Kingsnorth Campaign briefing, for example, argues that:

> '…the huge potential for renewable energy (wind, marine and solar power) in the UK is being largely overlooked, and risks being squeezed out by new coal-fired power stations' (World Development Movement 2008b)

All the major energy companies are currently seeking to invest in renewables, especially wind, which is highly profitable under the RO. Many see the Government's existing targets for 2020 as challenging, but possibly achievable. If companies believed that the 2020 renewable energy target were attainable and would be enforced, they would not invest in any new coal, or, indeed, in any new fossil fuel plant, up to 2020. (A greater coal-related threat to the renewables target would come from coal with CCS; see below.) However, the target currently has a huge credibility problem with the electricity industry, which is sceptical that the more ambitious EC proposals of January 2008 can be realised.

Certainly, meeting the UK target will be challenging. To put the scale of change required into perspective, Germany increased its share of renewable electricity from 4.8 per cent in 1999 to approximately 14 per cent in 2007 (mostly wind and biomass, with some solar photovoltaics) (German Federal Ministry for the Environment 2007. If this rate of growth could be sustained, Germany could reach 35 per cent of electricity from renewable sources by 2020. However, the UK has only now reached a four to five per cent share of renewables, so would have to have a much more rapid expansion of renewables over the next 12 years than Germany has seen over the last eight years.

Nevertheless, a major expansion of renewable electricity is technically possible. For example, the British Wind Energy Association forecasts that, by 2020, 13 GW of onshore wind and 20GW of offshore wind could be in place, with another 10-13 GW of wave and tidal, hydro and biomass (BWEA 2008b).

The Government is taking steps to reinforce confidence in its commitment to the target. In November 2007, the Prime Minister gave a clear statement of intent:

> '…at the European Council this year Britain led the way to an agreement that by 2020 one-fifth of all Europe's energy should come from renewables, a near threefold increase. The UK worked hard to get agreement to this target, *and let me make it absolutely clear, we are completely committed to meeting our share*.' (Brown 2007, emphasis added)

Shortly afterwards, the Secretary of State for Business announced proposals for a major expansion of offshore wind of up to 33 GW by 2020, and the renewables team at BERR is being expanded (Hutton 2007).

In late June 2008, the Government launched a substantial and detailed strategy for meeting the target (BERR 2008), now open for consultation, which included proposals in a range of areas, discussed in the next section.

However, this strategy does argue that getting all the way to the target will be prohibitively expensive and calls for an element of trade-off, such as investment in renewable energy by the UK abroad counting towards the target. These ideas were floated earlier in the year by the Business Minister, Lady Vadera (Vidal 2008), and reflect reported concerns within BERR that the targets face 'severe practical difficulties' and would be too expensive (Vidal 2007).

Improving the credibility of commitment to the renewable energy target

If the Government wants to improve the credibility of its commitment to the renewable energy target with potential investors, then, other than being more consistent in its statements, it will have to take decisive action in a number of areas, all of which will be explored during a Government consultation on the future of renewable electricity to be held in the summer of 2008.

The first is to develop stronger policies to radically increase the conservation of electricity use, since the lower the total demand, the easier it will be to meet the target on the supply side.

As well as reducing overall demand, measures to match demand to intermittent renewable generation will be particularly useful. In the short term, such measures could include interruptible supply contracts with large industrial consumers. In the longer term, there may be potential for developing and deploying 'dynamic demand' appliances that can switch themselves off at times of reduced output (BERR 2007f), as well as the use of 'vehicle-to-grid' technologies that would allow electric vehicles to be used as balancing and storage capacity (see, for example, Kempton and Tomić 2005).

Second, the UK's support policy for renewables will have to be revisited. The Renewables Obligation is to be rebanded, but the whole deployment support framework for renewables will need to be reexamined in light of the target. This includes the possibility of some form of production or export tariff for micro-renewables, if smaller scale investment by households and communities is to play a role in reaching the target. Such a form of support is more likely to induce widespread household investment in renewables than the RO, as the higher risk associated with the RO can be much better managed by companies than households (Gross *et al* 2007).

Third, Government will have to tackle a number of technical issues that could form a significant barrier to a rapid and large expansion of renewable electricity capacity, including supply chain problems, transmission and distribution capacity (especially for offshore wind) and access. The Business Council for Sustainable Energy estimates that around 34 GW of additional transmission capacity will be needed to meet the target (BCSE 2008). This is an area where incremental reform will not be enough – the national grid needs to be rebuilt for the age of renewables.

The Government is taking some steps on these technical issues, but will have to take more, and very soon. The 2007 Energy White Paper laid out proposals for improved grid investment and access for renewable generation, which are crucial for the successful expansion of wind, and these plans will need to be updated and expanded in light of the new draft renewable targets. The Energy Bill currently before Parliament provides the legislative framework for new offshore transmission capacity to be put in place.

There is some understanding of the challenges of managing penetrations of intermittent renewables at up to 20-30 per cent of electricity generation (for example ILEX and Strbac 2002, Gross *et al* 2006), but not at higher levels, and more work should be commissioned in this area. In theory, a renewables mix that included significant amounts of solar PV, biomass and biogas as well as wind could help handle intermittency issues. Experiments at the University of Kassel, with virtual baseload generation using combinations of renewables, are interesting here.[13]

Government will also have to engage with bottlenecks and shortages in the supply chain for renewables such as solar and wind, which some energy companies are concerned about. In some other European countries, governments are intervening quite actively to address these supply chain problems for renewables. It should be noted, however, that all major potential energy investment, including not only CCS and nuclear, but also conventional gas and coal projects, all currently face shortages of skilled labour and high materials costs.

Fourth, and, perhaps, most importantly, to establish the credibility of an effort to reach the renewables targets, the Government will have to engage with the fact that some potential investors are not yet convinced that a commitment to reach the targets is politically sustainable (Helm *et al* 2003). They fear that the cost and planning implications of very ambitious renewable electricity targets mean that voters may not support governments that pursue them, and that business may also oppose them. Any support mechanism that the Government puts in place now may not be maintained in future, which would leave companies with investments that cannot compete commercially (called 'stranded' assets).

13. See: www.kombikraftwerk.de/fileadmin/downloads/Technik_Kombikraftwerk_EN.pdf

These fears are not without basis. For example, although the Corporate Leaders Group on Climate Change backs the proposed EU goal (EU Corporate Leaders Group on Climate Change 2008), the CBI does not. Almost immediately after it was announced, the CBI's director-general Richard Lambert said that there was no chance of Britain meeting its share, mainly on grounds of cost (Traynor 2008).

If companies continue to believe there is a risk that a commitment to the EU renewable energy target may be reneged on, they will not build the amount of renewable capacity required by the target. This, in turn, will mean that the need for fossil fuel capacity will be greater, at least into the early 2020s, and this may include new coal. This issue is discussed further in Chapter 8.

Summary

The European Commission has proposed ambitious new targets for renewable energy. The implications are that up to 40 per cent of electricity demand would have to be come from renewable sources by 2020 (mostly expected to be large-scale wind).

This target represents a considerable expansion of the current UK Government aspiration for renewable electricity, which, at present, is that 20 per cent of electricity should come from renewable sources by 2020.

If the new EC target were to be met, there may be little or no need to build new fossil fuel power stations in the UK, subject to the requirements for balancing the intermittent supply of power from wind.

However, this scale of expansion of renewable electricity capacity in the UK faces several technical and political problems. Probably the most serious is that the large energy companies, as potential investors in renewables, have doubts about the wider credibility of the target with voters and business. They are particularly concerned about whether the costs of a large-scale and rapid expansion of renewables are politically sustainable. To establish the credibility of the targets, this uncertainty will have to be reduced.

5. Implications of new coal plants for the Climate Change Bill emissions targets

The previous three chapters provide the foundations for understanding the framework and drivers for investment in new coal-fired power stations, and coal-fired power generation in the UK more generally. In this chapter, we assess what the implications are for carbon dioxide emissions in the period up to 2020, in the context of the targets in the Climate Change Bill currently before Parliament. The impact of new coal-fired power stations on the achievability of the Climate Change Bill targets is one of the main concerns of environmental organisations.

This assessment is made in a series of steps. First, we review the conclusions of the previous three chapters, emphasising that there is considerable uncertainty about the prospects for new coal build in the UK. Second, we explore the implications of a range of new build scenarios for the Climate Change Bill targets, assuming that all plants are run baseload, and are additional to existing capacity. Third, we assess the conditions under which new coal build might be expected to add to, or replace, existing coal-fired capacity, and draw out the implications for emissions. Lastly, we give some quantitative illustrations, based on modelling commissioned by Government.

Uncertainty about new coal build

No one, including the energy companies themselves, knows how many new coal-fired power stations may be built in the UK.

There are some factors working in favour of new coal build. Both gas and coal prices are set to remain high for some time, which will work in favour of coal new build. Perhaps even more importantly, some companies are losing existing coal plants and want to replace them to maintain a diverse portfolio to match their customer base. This gives companies strategic reasons for wanting to invest in new coal plan above and beyond pure return on investment criteria (see Chapter 2).

At the same time, companies will take their expectation of future carbon prices and carbon policy into account (see Chapter 3). Faced with the certainty of a tight and declining cap on emissions, with high carbon prices into the future, they will not build new coal plants, as such policy will favour the less carbon-intensive gas. However, future carbon policy and prices are still uncertain, even after the January 2008 proposals from the European Commission. Even when the final EU ETS caps and rules are agreed, they will not necessarily have full credibility with companies. This means companies may discount expectations of future carbon prices (see Chapter 8 for a further discussion of the credibility problem).

The same factors apply to the proposed EU 2020 target for renewable energy (see Chapter 4 above). If the implied new capacity of renewable electricity were to be agreed and delivered, then there would be little incentive for investment in new fossil fuel capacity, let alone coal. However, many companies have doubts that such an increase in renewables capacity can be achieved technically, or that it would be politically sustainable.

Modelling estimates for new coal build by 2020, even under quite a narrow range of assumptions about fuel prices, carbon prices and electricity market conditions, range from none to around 9 GW.

At the same time, uncertainty also means that there is value in maintaining an option to build (Blyth 2005, Trigeorgis 1996, Dixit and Pindyck 1994). Investors will tend to delay investment decisions, especially if there are particular developments, either in commercial markets or in policy, that will clarify the movement of future prices. The value of keeping options open means that proposals (either formal Section 36 applications or just scoping studies) for new coal build will not necessarily come to fruition.

The value of having an option to build is particularly important in the case of coal, because there are few sites in the UK suitable for coal-fired power generation, combining good access for coal (often by rivers) and transmission grid access. Many companies want to keep these sites in play for as long as possible, but options cannot be kept open indefinitely, or at zero cost. Maintaining an option on grid access, for example, becomes increasingly expensive as the date approaches by which that option has to be taken up.

However, the value of having an option is limited in competitive markets (Blyth 2005), which does apply to UK energy supply markets. Since the large energy companies are vertically integrated, with generation businesses closely linked to and covering their customer base, if they wait too long they risk losing sufficient capacity to supply their customers. This in turn opens up the risk of losing customers to competitors, or having to rely on electricity supply contracts with independent power producers, at potentially greater cost, again undesirable in a competitive market.

An alternative to delaying investment is to favour smaller, more flexible power stations (Blyth 2008). The latter tend to be gas-fired, which reinforces the factors working for CCGT investment explained above.

Emissions from new coal build

Given this degree of uncertainty about new coal build, it is useful to look at the emissions implications of a range of possible scenarios. For illustrative purposes, we consider the following three cases:

- 4 GW of new coal-fired capacity, representing the Government's projection in the 2007 Energy White Paper (see Chapter 2).
- 9 GW of new coal-fired capacity. This represents a scenario in background modelling commissioned by the Government for the Energy White Paper, where carbon prices are discounted due to uncertainty.
- 11.6 GW of new coal-fired capacity, representing all the projects currently being proposed or scoped by companies. This scenario may be realised in a situation in which both gas and coal prices are high, and both carbon and renewable energy policies are weak.

Assuming a capacity factor[14] of 0.9, and a carbon factor of 0.75 kgCO_2/kWh for supercritical coal, then if these plants ran at full load, the emissions produced would be 24, 53 and 69 MtCO_2 a year respectively (Table 5.1).

Table 5.1. Annual output and emissions from new coal

Scenario	4 GW	9 GW	11.6 GW
Annual electricity generated (TWh)	31.5	71.0	91.5
Annual emissions (MtCO_2)	23.6	53.2	68.6
Net additional emissions			
(as against gas) (MtCO_2)	11.0	24.9	32.0
Net additional emissions as a percentage of 1990 emissions	1.9	4.2	5.4

Source: Author's calculations

However, the *net* addition to annual emissions these plants would make depends on what is built instead. If renewable generation, say wind power, were built instead of coal plants, then net additional annual emissions would simply be the total emissions produced by the coal plants. If, as is more likely, gas-fired plants were built instead of coal, then net additional annual emissions would be equal to emissions from coal less those from gas – between 11 and 32 MtCO_2 (Table 5.1).

14. The capacity factor is the proportion of time in a year that a power plant is typically available for generation, outside the time needed for maintenance or repair. Greenpeace, using a capacity factor of 0.9, and a lower carbon factor of 0.65 kgCO_2/kWh, predicts emissions of 56 MtCO_2/year.

These net additional emissions range from approximately two per cent of 1990 emissions up to about 5.5 per cent. If new coal build is at or towards the top of the range of cases considered here, if the plants operate at baseload, and if they are additional to existing plants, then investment in new coal would present a major problem for reducing emissions in the UK in the future.

Emissions from new coal build versus existing coal capacity

However, the future trajectories of emissions from coal-burning, from the power sector and from the UK as a whole, will depend not only on the potential net contribution of new coal build, but also on what will be happening to emissions from existing coal plants. In particular, if new coal plants displace existing ones, then total emissions from coal-fired power generation could actually be lower in the period to 2020 than would otherwise be the case.

Therefore, two key questions are: (i) how much of the existing coal capacity would still potentially be operating to 2020?; and (ii), how much will it actually run?

Total UK coal capacity now stands at just over 27 GW (taking into account reduced load at Eggborough under the National Emissions Reduction Plan). A key question is whether more existing coal capacity will close than the 8.2 GW that must close because of sulphur emissions reduction targets under the Large Combustion Plant Directive from 2015. Coal plants will also have to fit further equipment to reduce nitrogen emissions or purchase nitrogen emissions credits, under the National Emissions Reduction Plan, if they are to continue running up to full load, but it is not yet clear how many will do so. Estimates of further closures differ from none through to a further 6 GW by 2020 in the Energy White Paper scenarios (HM Government 2007), and 7.5 GW in the detailed modelling by Redpoint Energy Strategies (2007). In the Redpoint analysis, Eggborough (1.9 GW), Fiddler's Ferry (1.96 GW), Ferrybridge (1 GW), Longannet (2.3 GW), and Uskmouth (0.36 GW) would close after 2015.

These estimates would leave between 12.3 GW and 19.1 GW of existing coal plants in operation by 2020. With the range of new build possibilities, total coal capacity could, therefore, be anywhere between 16.3 GW – a little over half current capacity – and 30.7 GW – more than current capacity.

The other question is how much coal capacity will actually be run in total. The key issue is whether new coal plants will simply *substitute* for existing plants, or whether it will be run additionally to old plants that can be run after 2015.

New coal-fired plants would be more efficient, and hence cheaper than old plants. As a result the new plants will be dispatched first. It is also the case that companies will be keen to get a return on their investment as soon as possible. Broadly, a strong EU ETS carbon policy will drive older, more inefficient plants off the system first through fuel switching, so any new coal plants that are built will displace existing coal plants (see Chapter 3 above). At the same time, high coal prices will also favour new coal build over old, as explained in Chapter 2 above.

The possible combinations to 2020 are summarised in Table 5.2. High and low coal prices are in relation to gas prices.

If companies anticipate a strong and credible carbon policy, together with low coal and gas prices, they will not invest in new coal. Actual emissions then depend on how strong carbon policy turns out to be, and how high coal prices are.

With a credible and strong carbon policy expected, but also very high coal prices, it is possible that there might be some investment in new coal on efficiency grounds, but this would depend on how long the window on burning coal would be left open within the EU ETS. The worst case for emissions in this case is if actual outcomes are the opposite of expectations – in other words, if carbon policy turns out to be weak, and coal prices low. In these circumstances, new coal-fired power stations will operate alongside existing stations rather than displacing them.

If companies expect carbon policy to be weak, they are more likely to proceed with new coal build plans. New coal will be more attractive if coal prices as well as gas prices are anticipated to be high. However, if carbon policy turns out, in fact, to be strong, then old coal plants will tend to be phased out through fuel switching, with new coal build taking its place.

Table 5.2. New coal build and emissions possibilities

Expected		Actual		Implication for coal		Implication for emissions
Carbon policy	Coal prices	Carbon policy	Coal prices	New coal build	Displacing/adding	
Strong	High	Strong	High	Low	New displaces old	Low
Strong	High	Strong	Low	Low	New displaces old	Low
Strong	High	Weak	High	Low	New displaces old	Low
Strong	High	Weak	Low	Low	New adds to old	Medium
Strong	Low	Strong	High	No new build	Old coal phased out	Low
Strong	Low	Strong	Low	No new build	Some old coal remains	Low
Strong	Low	Weak	High	No new build	Some old coal remains	Low
Strong	Low	Weak	Low	No new build	More old coal remains	Low
Weak	High	Strong	High	High	New displaces old	Low
Weak	High	Strong	Low	High	New displaces old	Low
Weak	High	Weak	High	High	New displaces old	Low
Weak	High	Weak	Low	High	New adds to old	High
Weak	Low	Strong	High	Low	New displaces old	Low
Weak	Low	Strong	Low	Low	New displaces old	Low
Weak	Low	Weak	High	Low	New displaces old	Low
Weak	Low	Weak	Low	Low	New adds to old	Medium

The worst-case scenario from the point of view of emissions overall is if expectations of weak carbon policy and high coal prices encourage new build, but in the event carbon policy is weak but coal prices are low enough in relation to gas prices to allow old coal to continue burning alongside new.

Modelling of emissions from coal

There are few quantitative estimates of future emissions from coal-fired power generation. However, those available – from studies commissioned by the Government – do illustrate these influences of fuel prices and carbon policy.

As discussed above in Chapter 2, modelling of different scenarios for the 2007 Energy White Paper assume a common carbon price of €25 from 2015, but different fossil fuel prices (see Table 5.2). This leads to a range of predictions for new coal build from none, to 4 GW and 7 GW for low, central and high fossil fuel price projections respectively.

At the two extremes, and using the central policy impact assumptions from the White Paper, electricity generation from coal under the low fossil fuel price projection is 63 TWh by 2020, corresponding to around 57 $MtCO_2$. Under the high fossil fuel price projection, generation is 121 TWh, corresponding to around 100 $MtCO_2$ (BERR 2007e).[15] This is, effectively, because a high gas price encourages more coal burning. It is clear – comparing these figures with the estimates above – that, in these models, new coal capacity is largely displacing existing coal capacity.

The importance of carbon policy expectations is illustrated by detailed modelling commissioned from Redpoint Energy Strategies (2007) as background for the 2007 Energy White Paper (see Chapter 3). The Redpoint study contrasted two scenarios, both of which see carbon prices rising from €25 to €32/tCO_2 over Phase 3 of the EU ETS. However, while one scenario has well-functioning investment markets and a credible carbon policy, the other is characterised by a short-term investment horizon

15. However, it should be noted that, under both the low and high fossil fuel price projections, total emissions for the UK are about the same. This is partly because higher fossil fuel prices, while leading to more coal-fired electricity generation, also mean higher electricity prices, and, therefore, more conservation of energy in final demand.

and a much more uncertain carbon policy. In the first scenario, new coal build was 6 GW; in the second it was 9 GW.

There is a considerable difference in total electricity sector emissions between the two scenarios (emissions from coal-fired power generation are not available separately). In the first, emissions fall from around 185 $MtCO_2$ in 2010 to 160 $MtCO_2$ by 2020. However, in the second, electricity emissions rise over the period and end up at 195 $MtCO_2$, higher than the 184 $MtCO_2$ emitted in 2006.

Finally, the UK Coal Forum recently produced a range of scenarios for the future of coal-fired power generation (Harris *et al* 2008). The Forum considered a range of new build scenarios, from no new build up to 15 GW of new build, and assumes CCS is progressively fitted to all new coal build by 2025. Nuclear plants, and plants with CCS, are assumed to run at baseload, but the Coal Forum modelling appears to consider no expansion of renewables.

In the 'medium' new coal build scenario (10 GW), emissions from coal-fired power generation fall from just under 130 $MtCO_2$ in 2006/7 to around 80 $MtCO_2$ in 2020/21, with total emissions from the power sector at around 135 $MtCO_2$. The 'low' new coal build scenario (5 GW) gives total power sector emissions of around 130 $MtCO_2$ in 2020, with coal contributing a little over 70 $MtCO_2$.

Coal-fired power generation and the Climate Change Bill targets

The analysis in this chapter should be seen within the context of the targets in the draft Climate Change Bill, especially the near term target for 2020. The 2020 target in the Bill is to reduce carbon dioxide emissions in total by between 26 and 32 per cent from 1990 levels. This means a fall from 592 $MtCO_2$ in 1990 to between 436 and 402.5 $MtCO_2$ by 2020.

The Climate Change Bill represents the Government's central ambitions for reducing emissions, and a major part of its purpose is to demonstrate international leadership. While it is proposed that the Climate Change Committee (included within the Bill) determines exactly how much of the target is met through domestic activity, for purposes of demonstrating leadership, this will have to be a high proportion.

Total UK emissions in 2006 were 554 $MtCO_2$. Thus, to reach the Climate Change Bill 2020 target band through domestic effort, a reduction of between 116 and 151.5 $MtCO_2$ will be needed. This is equivalent to a reduction of between 21 and 27 per cent from 2006 levels.

In most scenarios of future decarbonisation (for example, Lockwood *et al* 2007, Bows *et al* 2006), the electricity sector is expected to lead the way, reducing emissions the quickest and most deeply. This is also the case in the modelling for the Energy White Paper.

The Government estimates that, if all the policy measures in the 2007 Energy White Paper have a high impact, then emissions will be reduced to 437 $MtCO_2$, just reaching the upper end of the Climate Change Bill target emissions range (HM Government 2007). However, within this, the Government assumes that emissions from the power sector will fall more quickly than emissions overall (Table 5.3).

Table 5.3. Emissions reductions assumed in the 'high' policy impact scenario, 2007 Energy White Paper ($MtCO_2$)

	Power sector	Total
2005 (actual)	175	556
2010	157	496
2015	139	469
2020	121	437
Reduction as % of 2006	30.8	21.8

Note: Central fossil fuel price scenario. Assumes a carbon factor of 0.85 for coal-fired power generation.

Source: BERR 2007e

In the central fossil fuel price scenario, the Government assumes that 4 GW of new coal plants are built (see above Chapter 2), but that it replaces rather than adds to existing capacity, allowing a 31 per cent fall in emissions from the power sector by 2020. Emissions from coal-fired power generation could fall by almost half. This is, in part, due to the carbon price of €25/tCO_2 that the Government assumes in this case. A higher carbon price would expect to work against coal burning even more.[16]

However, as discussed above, and illustrated in the Government's own modelling and commissioned work, higher gas prices or more uncertainty about carbon pricing could lead to more coal investment and more coal burning, and, therefore, higher emissions. In the worst of these scenarios, emissions from the power sector in 2020 are higher than they are currently, meaning that it would be impossible to reach the Climate Change Bill targets through domestic effort.

Summary

There is great uncertainty about how much new coal capacity may be built in the UK under the current policy framework. This is due to uncertainty about fuel prices, about future carbon prices under the EU ETS, and about future policy on renewable electricity.

Assuming a range of new build scenarios between 4 and 11.6 GW gives estimates of additional emissions (as against new gas-fired capacity) of between 11 and 32 MtCO_2, if the new plants run at baseload.

However, future emissions from new plants are only part of the picture. Overall emissions from coal-fired power generation will depend not only on how much new capacity is built, but also on how much it is run, whether it replaces or adds to existing capacity, and how much that existing capacity is run.

These outcomes depend largely on expected and actual fuel prices and carbon policy. The best-case scenario for emissions is where a strong carbon policy (that is, a tight cap) is expected, along with low coal prices relative to gas and then where a strong carbon policy does actually apply, but where coal prices rise relative to gas, meaning that coal burning is largely pushed to peakload.

The worst-case scenario is where expectations of a weak carbon policy (that is, a loose cap) and high coal prices drive new investment, and those expectations are then met, meaning coal is run at baseload.

These factors of carbon pricing and fuel prices are reflected in modelling commissioned by Government, which gives quantitative estimates of power sector emissions for various scenarios. This modelling suggests that, if carbon policy is not sufficiently strong or credible, up to 9 GW of new coal could be built, and power sector emissions could be higher in 2020 than they are today. The current framework for coal-fired power generation, therefore, does potentially pose a problem for the Climate Change Bill target for 2020.

16. In such a scenario, the path of total UK emissions is unclear. On the one hand, high gas prices would mean higher electricity prices, and more conservation of energy in final demand. However, on the other hand, the cost of carbon (which would be passed on to consumers) would be lower.

6. The prospects for carbon capture and storage

So far in this report, we have looked only at existing coal-fired power generation technology. Incremental innovations in coal-fired power generation, such as supercritical boilers, offer the prospect of some reduction in carbon dioxide emissions. However, these changes are relatively small. The technology that currently offers the only hope of genuinely low-carbon coal-fired power generation is carbon capture and storage (CCS). CCS is, therefore, a key potential technology, not just in the UK, but also in places such as the USA, China and India, where coal is plentiful and cheap. CCS can also be applied to gas-fired electricity generation and industrial processes.

Discovering whether CCS can be made to work at power station scale, at an affordable cost, is, therefore, crucial for the future of coal-fired power generation in a carbon-constrained world. There is considerable confidence in some parts of government and industry that CCS will eventually work technically. The TUC argues that, given the need for CCS in China, it will *have* to be made to work, at whatever cost required (Clean Coal Task Group 2006). However, a prime concern for environmentalists is that the discovery will take too long. For example, Greenpeace quotes journalist George Monbiot's concerns that: 'We could be stuck with a new generation of coal-burning power stations, approved on the basis of a promise that never materialises, which commit us to massive emissions for 40 years' (Greenpeace 2008a).

Much of the current debate over the future of coal-fired power generation in the UK centres on CCS, and, in particular, on proposals to make new plants 'CCS-ready'. If CCS can be introduced quickly and cheaply, then the potential emissions problem with coal-fired power generation identified in the previous chapter does not matter. However, if this is not the case, then, in WWF's words: 'A promise of carbon capture and storage readiness simply isn't good enough – [the proposed plant at Kingsnorth] could still claim to be "CCS ready" in 30 years' time, while merrily belching out carbon in the interim' (WWF 2008).

In this chapter, we briefly review the technology involved in CCS, and estimates of cost, and assess the UK policy framework and likely timetable for its implementation.

CCS technology

The Intergovernmental Panel on Climate Change defines CCS as: '…a process consisting of the separation of CO_2 from industrial; and energy-related sources, transport to a storage location and long-term isolation from the atmosphere.' (IPCC 2005: 3)

CCS would make coal-fired power generation low-carbon rather than zero-carbon, with between 85 and 95 per cent of carbon dioxide captured with available technology. This would mean coal-fired generation with CCS will emit in the region of 50-100 gCO_2/kWh.

Capture

There are three types of capture technology, all of which will require further development and demonstration before they can be deployed at scale:

- **'Post-combustion'**: capturing carbon dioxide from the flue gases produced by burning coal in air.
- **'Oxyfuel'**: capture of carbon dioxide from combustion of coal in pure oxygen.
- **'Pre-combustion'**: gasifying coal (heating coal in the presence of small amounts of oxygen, rather than combustion), which produces a mixture of hydrogen and carbon monoxide (called syngas). The carbon monoxide is then separated from the hydrogen (which is burned to produce electricity) and converted to carbon dioxide.

To retrofit existing coal plants, or apply CCS to proposed new supercritical plants, post-combustion technology would have to be used. The main technical issues to be resolved in post-combustion capture from coal-fired power generation relate largely to the choice and efficacy of processes and solvents for removing the carbon dioxide from flue gases (with attendant impurities and dust), at the scale of a large power generation plant, requiring scaling up by a factor of 20 to 50 times from existing applications in the natural gas processing industry (Metz *et al* 2005).

Pre-combustion CCS would apply to large-scale integrated gasification combined cycle (IGCC) power plants. There are a number of different technical options for conversion of carbon monoxide to carbon dioxide (Metz *et al* 2005). Pre-combustion capture of carbon dioxide is easier and cheaper than post-combustion, and is quite widely used in various industrial applications, including fertilizer manufacture and hydrogen production.

However, for the pre-combustion approach, the problems lie more with the underlying power generation plant. Whereas supercritical coal plants are well-established as a commercial technology, IGCC is still developing. There are only a handful of coal IGCC plants operating around the world, and all were subsidised (Metz *et al* 2005). IGCC plants use gas turbines, which are more efficient than the steam turbines used in conventional coal plants, but they can be less stable and flexible in operation than supercritical coal and gas. Because CCS reduces flexibility in operation for all technologies, so CCS plants are likely to run baseload. This would not matter if IGCC were competing in a purely CCS market, but it is a disadvantage in current markets.

Oxyfuel technology is much less well-developed than either post-combustion or pre-combustion technologies, and is still at the demonstration phase.

Transport

Captured carbon dioxide would be compressed, and transported by pipeline or ship. Pipeline transport of carbon dioxide already operates on a commercial basis, with over 2,500 km of pipelines in the USA carrying carbon dioxide from natural sources for enhanced oil recovery in western Texas and elsewhere. The main challenge in a UK context is the laying of pipeline along the seabed out to storage sites in the North Sea.

Storage

There are a number of options for storing the carbon dioxide captured, including depleted oil and gas reservoirs, and deep saline formations both onshore and offshore (IPCC 2005). Injecting carbon dioxide into oilfields can also be used for enhanced oil recovery (EOR). There are three industrial-scale (around 1 $MtCO_2$/year) projects involving such storage locations: in Norway, Canada and Algeria.

Estimates of the potential storage capacity in gas- and oilfields and offshore saline formations available to the UK range considerably, from 20,000 up to 260,000 $MtCO_2$ (POST 2005). However, even at the bottom end of this range, these sites could accommodate hundreds of years of emissions from coal-fired power generation.

The IPCC report on CCS gives a relatively high degree of confidence to the view that the vast majority of stored carbon dioxide will not leak from 'well-selected, designed and managed geological storage sites' (IPCC 2005: 14).

Costs of CCS

Because it is still at the pre-demonstration phase, the real costs of CCS for coal-fired power stations (in terms of electricity produced) are not yet known with certainty.

The costs of the first projects are likely to be very high indeed. The EU's Zero Emissions Platform (ZEP) project estimated that a carbon price of €103/tCO_2 would be necessary to support a pre-combustion demonstration project, while a carbon price of €129 would be needed for a post-combustion demo (Climate Change Capital 2007).

For subsequent plants, a range of cost estimates are available, including those from the 2005 IPCC report on CCS (Metz *et al* 2005), the EU's ZEP project (Climate Change Capital 2007), and a background study for the 2007 Energy White Paper (Redpoint Energy Strategies 2007). Although cost estimates change somewhat over time (partly because construction costs have gone up in the last few years), the main cost messages apply across all sources.

Figure 6.1. Costs of advanced supercritical and IGCC coal plants with and without CCS (p/kWh)

Source: Blyth (2008)

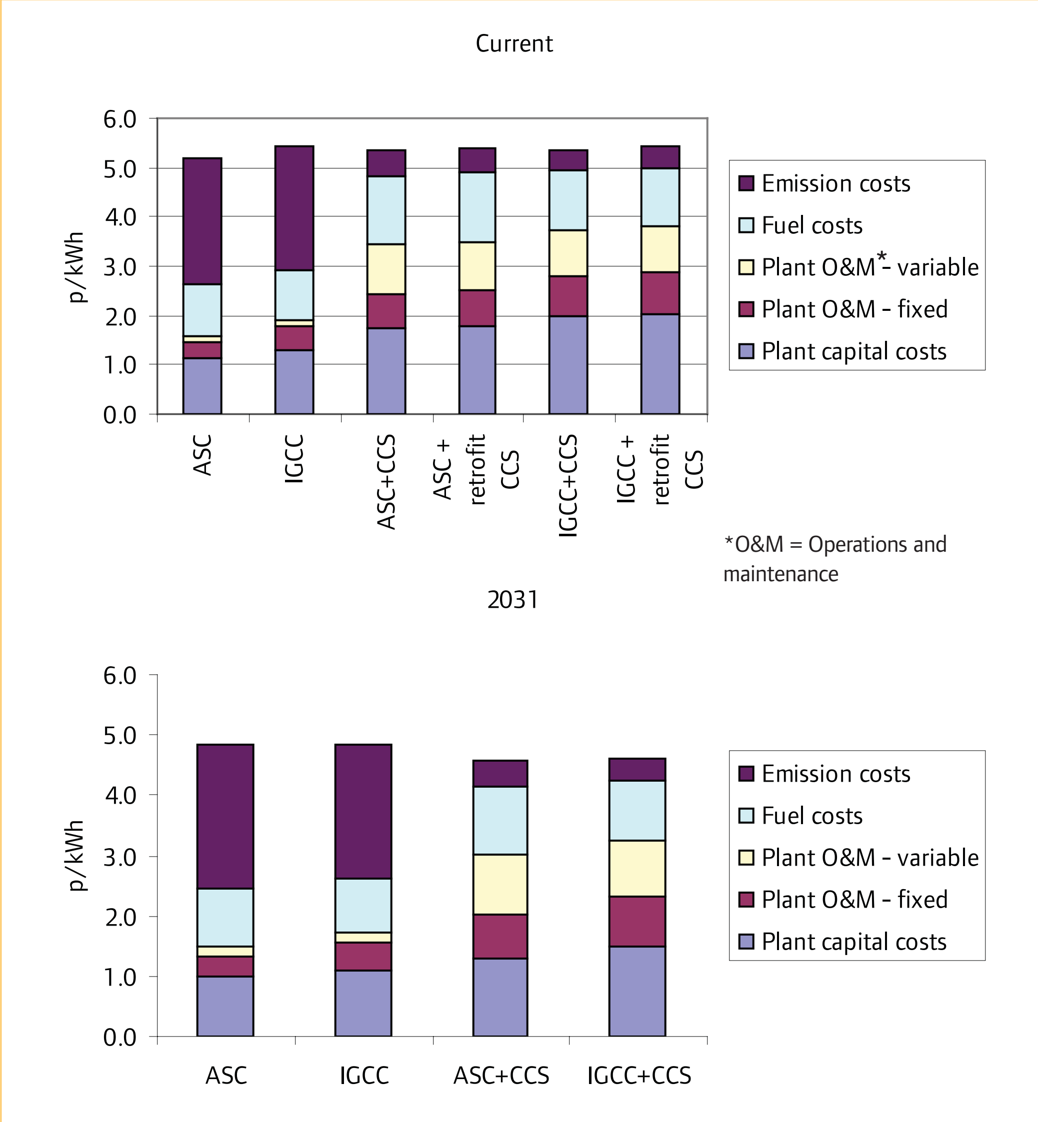


Figure 6.1 is based on the Redpoint estimates, and gives levelised costs in pence per kWh for advanced supercritical coal (ASC) and integrated gasification combined cycle (IGCC) plants, based on the central Energy White Paper coal price scenario (see Table 2.1 above) and with a carbon price of €50/tCO_2 as the basis for emissions costs.

There are several important points to note about estimates of CCS costs.

The first is that a supercritical pulverised coal plant without CCS has lower capital and operating costs than IGCC without CCS, but only slightly. However, as noted above, it is a more mature and flexible technology.

A second key point is that cost estimates for coal plants with CCS are much higher under current market conditions than the costs of coal plants without CCS, whether post-combustion or pre-combustion. No companies will currently build a coal plant with CCS on a commercial basis (see also Climate Change Capital 2007). Some form of support, whether capital grants or carbon pricing, will be required to make CCS commercially viable. The additional costs of CCS lie both in higher capital costs and in higher operating costs. This is because of the extra equipment involved, but also because CCS plants are less energy efficient than non-CCS plants. A significant amount of energy is used up in the carbon dioxide capture processes (which dominate costs over transport and storage).

A third key point is that, if the costs of plants with CCS are compared, the cost difference between supercritical coal plants and IGCC plants disappears. Under the Redpoint assumptions, the levelised costs including CCS are very similar for the two technologies, at just over 5.3p/kWh. Other estimates of cost, incuding the IPCC and the ZEP reviews, give a with-CCS cost advantage to pre-combustion IGCC capture over post-combustion capture. This is because of the greater efficiency of IGCC plants.

A fourth point is that costs are expected to decline over time, with levelised costs for both technologies coming down to about 4.5p/kWh by 2030 (in current prices).

Finally, a last point is that retrofitting CCS at a later date is no more costly than fitting at the time of the new build, and that this is the case for both conventional supercritical and IGCC technologies. This means that there is no penalty for companies building a coal generation plant without carbon capture now (while carbon prices are below the breakeven price for CCS) with a view to retrofitting the capture and storage plant should carbon prices rise sufficiently in the future. In this sense, the expectation of a viable CCS technology provides an important hedge against the risk of high future carbon prices, essentially reducing the risk of building coal plants. Therefore, new build decisions for coal without CCS could be accelerated as a result of the option to retrofit CCS at a later date (Blyth and Yang 2007).

The UK demonstration competition

All the elements of the three phases of CCS – capture, transport and storage – do exist in locations around the world, but not yet at the scale of a conventional coal plant, or joined up in a single system.

There are many capture and storage demonstration projects being investigated by companies and governments around the world. The Carbon Sequestration Leadership Forum lists 19 registered projects (CSLF 2008), and the European Commission cites 20 potential demonstration projects signalled by industry in 2006-07 (EC 2008b). However, any projects at scale at this early stage will need support, so many company proposals will not come to fruition. Demonstrations of the full range of elements – capture, transport and storage – are also very rare.

The Government has now set up a framework for a supported demonstration project with just such an end-to-end approach (BERR 2007d). Britain is well placed to demonstrate and develop CCS, as it has a strong science and engineering base and good storage site in the North Sea.

The Government has chosen to invite bids to demonstrate a particular technology – post-combustion capture from coal-fired power generation, initially at a scale of 50-100 MW by 2014, and then at 300-400 MW as soon as possible thereafter. This decision was based on a number of arguments:

- It would not be possible to evaluate and choose between bids from companies for demonstration projects across technologies in a fair way.
- The development of CCS has most significance for tackling climate change through its deployment in India and China, which have a large number of conventional (non-IGCC) coal plants. Only post-combustion technology can be retrofitted to such plants. At the same time, those countries are looking to richer countries to demonstrate that CCS technology works and is cost-effective.
- Capture from gas-fired power generation is being demonstrated in other countries, most notably in Norway.
- Pre-combustion technology is also being demonstrated in other countries, notably the FutureGen project in the USA.

This decision has been strongly criticised by a number of companies, environmental organisations, the TUC, the CCS Association and others. Criticism is based, in turn, on a number of arguments.

The first is that, while there are some real technological uncertainties to be resolved in the post-combustion approach, the pre-combustion approach is much nearer potential large-scale deployment, with cost discovery rather than technological development being the main purpose of a pre-combustion demonstration. Companies with plans to build IGCC plants with pre-combustion CCS say they could have full-scale operation (that is, at 800 MW) in place by 2014. By ruling out a pre-combustion demonstration, the Government is delaying the introduction of CCS in the UK.

The Government's argument that post-combustion CCS needs to be demonstrated for China is disputed, partly on the grounds that China is quite capable of developing CCS technology itself. Interestingly, China is indeed developing its own 250 MW pre-combustion IGCC demonstration plant, through the GreenGen project in Tianjin.

At the same time, the US FutureGen IGCC project recently collapsed when the US Government withdrew funding (Cleantech 2008). While other pre-combustion demonstrations may still go ahead in the USA, they are likely to be delayed until 2015 at the earliest. The demise of FutureGen points up the problem that there is, as yet, no effective international mechanism for coordinating CCS demonstration projects in a way that means that any one country can be assured that its own efforts will be complemented by others in a predictable way (Stern 2007). The Carbon Sequestration Leadership Forum is the most likely candidate, but critics argue that it lacks the funding and authority to play this role effectively at present. The EU's Zero Emissions Platform also suffers from a lack of resources or power to coordinate member states' efforts.

Likewise, the ambition to have 12 demonstration plants up and running across the EU has not been converted into action. Within the energy and climate package, the only major issue not to go forward as a Directive is the development of CCS. Many countries in the EU are unenthusiastic about the technology, in part because they see their options for storage as too limited.

In the absence of such a strong coordination framework, even within the EU, proponents of a further pre-combustion demonstration argue that the Government should remain an international player on the pre-combustion front, not least for reasons of commercial positioning as the CCS market takes off. The UK is already ahead in terms of sorting out regulatory and legal aspects of CCS, and has proposals for IGCC new build from several companies, as well as good storage sites. If there were to be agreement on the 12 demonstration plants across the EU, it is very likely that the UK would be involved in more than one, given its comparative advantages.

Pre-combustion proponents do not argue against a post-combustion demonstration as such, because of the evident need to retrofit capture to the many subcritical and supercritical plants that already exist, or are being built around the world. However, they do argue that post-combustion technology should be demonstrated on an existing power station. If any technology is to be tested on a new build coal plant, it should be pre-combustion, as this is cheaper and nearer deployment.

Another demonstration project would, of course, mean more money. The level of support to the post-combustion demonstration will only be determined through the process of selecting the preferred bidder, but will be at least several hundred million pounds, and could be of the order of £1 billion. Support for a pre-combustion demonstration could be expected to be of the same order. Within the wider context of a tight fiscal position in the UK over the next few years, this is quite a lot of money to find.

However, proponents argue that revenue raised from auctioning of EU ETS credits in the power sector should be used for this purpose, as suggested by the European Commission in its proposals in January 2008 (EC 2008a). A report by Point Carbon for WWF estimates that auction revenues in the UK will be worth €6-15 billion over Phase 2 of the EU ETS, or €1.5-4 billion a year (Point Carbon Advisory Services 2008). This need not involve formal hypothecation.

An alternative approach, proposed by Climate Change Capital for CCS demonstration at the EU level, is to avoid capital grant support and instead ring-fence some 60 million allowances, and give three allowances for each tonne of carbon dioxide stored through CCS (Climate Change Capital 2007). This would provide a sufficient incentive to cover demonstration costs.

The timetable for CCS in the UK

A final, and crucial, issue is timing. A preferred bidder for the post-combustion demonstration project will not be announced until the middle of 2009, with actual operation of capture, transport and storage being required by 2014 at the latest.

Capture operation for the demonstration plant will be at 50-100 MW initially, and as soon as possible thereafter (say 2015) at 300-400 MW. With two to three years of operation for learning, planning for deployment of CCS at full unit scale (that is, 500-800 MW) could then follow only from 2017-2018, with operation starting at some point in the early 2020s. Others argue that there is the need for two research cycles, and put the earliest date for *widespread deployment* at no earlier than 2025.

Proponents of a pre-combustion demonstration argue that, since there is more experience with pre-combustion capture technology, and sites and plans of companies proposing IGCC plants in the UK are more advanced, there would not be the same need for a full research cycle before widespread deployment could begin. Assuming this argument is true, and a support mechanism is in place, a number of IGCC plants with CCS could be in operation by the second part of the next decade.

In addition, there is the question of the infrastructure for carbon dioxide transport, which the Government has not yet begun to address.

There are likely to be several regional networks for power stations and industrial sites: on the Thames, on the Humber (where Yorkshire Forward has been coordinating a CCS consortium) and in southern Scotland or north-east England. An integrated and cost-effective carbon dioxide transport infrastructure will require planning at a national level, along with a framework for financing a major infrastructure project, on a similar scale to the construction of the National Grid. Major investment in such an infrastructure cannot begin until capture and storage have been shown to work at some scale, but if work is started only after the technology has been fully demonstrated, then widespread deployment could be pushed back even further.

Finally, because it will involve energy companies, engineering companies and oil companies in a new kind of partnership, making CCS work requires a new business model, which will also take time to develop successfully (although the demonstration competition should help in this respect).

Taking into account all these elements, even an accelerated timetable could not see large-scale deployment of CCS in the UK much before 2020. This is consistent with other projections at the EU level (Gibbins 2007).

A support framework for CCS

Even if CCS for coal works technologically, it is clear from Figure 6.1 that it will not be competitive with ordinary coal or gas without some support. It is fairly widely expected in industry that this support will come in the form of carbon pricing through the EU ETS. Carbon pricing is probably the most appropriate form of support, since the additional costs of CCS arise mainly because the capture process involves an energy penalty, which reduces the net output of the power station (Climate Change Capital 2007).

Figure 3.1 suggests that coal plants with CCS only become competitive when the carbon price is around €50/tCO_2. This estimate coincides with views in industry, although companies tend to distinguish between the carbon price required for the first-of-a-kind plant and for subsequent plants, which would be lower, possibly around €40/tCO_2, which is the price level being predicted for Phase 3 of the EU ETS under current proposals from the European Commission (see Chapter 3). Estimates developed for the EU's Zero Emissions Platform vary more widely (at €25-67/tCO_2), but cover the same range (Climate Change Capital 2007).

However, there is no certainty that a carbon price at the right level will be in place at the time that a viable technology is proven. Climate Change Capital (2007) argues for supporting CCS demonstration plants by ring-fencing a certain number of EU ETS allowances and giving CCS additional support by awarding a multiple number of allowances (three, for example) for each tonne of carbon dioxide captured and sequestered.

If carbon prices are still too low to support CCS once the technology has been proven past the demonstration phase, then this approach could be extended for some time, or some other deployment mechanism (such as portfolio standard) might be used. However, if carbon pricing does fail to support CCS sufficiently over a long period, the case for a ban on coal without CCS becomes very strong. This is explored further in the next chapter.

Summary

Developing and deploying carbon capture and storage is of huge importance, not only within the UK, but also, more importantly, in the rest of the EU, China, India, the USA and elsewhere. It provides the only means by which coal-fired power generation might have a long-term future.

While there are technological questions to be settled, especially in relation to post-combustion capture of carbon dioxide from power stations, the uncertainties about CCS are more about how quickly the technology can be deployed, and how much it will cost.

The Government has shown leadership in deciding to support a demonstration project with post-combustion carbon capture. However, there is a strong case for the UK running a second demonstration project, involving a different technology.

Although there would be extra costs involved, such a demonstration would be widely supported, since an acceleration of CCS is being called for by a large range of sectors of society, including many of the energy companies, trades unions, and most environmental groups. As an example of concrete activity within the UK (as opposed to paying a carbon premium to support investment elsewhere) it is also likely to be popular with the wider public (see Downing and Ballantyne 2007).

As it holds out the prospect of moving more quickly towards deployment of CCS in the UK, the development of pre-combustion CCS is also important for the objective of international leadership.

If the Government wishes to demonstrate the feasibility of a particular technology that will have to be widely deployed in coal plants in the USA, India and China in order for dangerous climate change to be avoided, then a post-combustion demonstration makes sense. (Although, it should be noted that some of these countries are capable of exploring post-combustion technologies themselves.)

However, it makes more sense for the UK (and more widely, Europe) to be demonstrating – especially to China and India – how a country or region with a high energy demand can achieve *widespread deployment* of coal-fired generation with CCS quickly and affordably. For this objective, a pre-combustion route makes sense, as this is the more likely way to demonstrate such a transition.

At the same time, the UK should not stop actively pursuing a fully funded and empowered international coordination framework for CCS, to ensure the rapid development of full-scale CCS demonstration plants covering all technologies by other countries.

Within the UK, other important tasks are beginning preparations for the planning and financing of a national carbon dioxide transport infrastructure, leading to construction timed to allow rapid movement from final demonstration phase into large-scale deployment.

In any event, even with the development of the pre-combustion option, it is unlikely that widespread deployment of CCS to coal-fired generation will occur much before the end of the next decade. This deployment will be dependent on a strong EU ETS policy (with a carbon price of at least €40/tCO_2), or, in the event that this does not happen, will require some other form of support.

A final point relates to the debate over what constitutes a coal-fired power station being 'CCS ready'. The timetable and cost factors laid out above mean that a new coal plant proposed now can be 'CCS-ready' only in a very limited sense. On this view, a 'CCS-ready' supercritical plant – such as is proposed for Kingsnorth – built in the next few years will have the same emissions as existing supercritical plants.

Some engineering changes from standard design, to enable easier retrofit at a later date, can be specified, and space for chemical plant can be set aside. But any further investments that would involve major costs will not be made outside of the context of a supported demonstration plant. Thus, 'CCS-readiness' is somewhat of a red herring – either largely meaningless on the one hand, or too expensive to be realised on the other.

7. Assessing the UK policy debate on coal

In the previous chapters we have examined the economics of coal-fired power generation, the implications for carbon emissions, and the prospects for carbon capture and storage (CCS). In so doing we have shown that, within the current policy framework, there is considerable uncertainty about future new coal build, coal-fired power generation more widely, carbon capture, and carbon emissions.

Over the next three chapters, we examine the implications for emissions and energy policy in the light of the above analysis.

Much of the current debate focuses on UK leadership, the implications of new coal-fired power stations for the Climate Change Bill targets, and the risk that a large part of the effort will have to be made through purchasing credits from overseas. We start by considering the arguments made for proposals for new measures to rule out new coal build or limit emissions, with the aim of eliminating that risk. However, both the Government and energy companies are against further measures of this type. At the heart of this opposition is the argument is that these measures will cut across and undermine the development of the EU emissions trading scheme (ETS), which is at the centre of the Government's approach to tackling climate change.

This impasse leads to a consideration of the dynamics of coal and the EU ETS at the European level, where the issue looks somewhat different. The EU ETS is still developing, and carbon prices are unlikely to fully reflect the cap set by the EU until there is certainty about the future of a global post-2012 agreement. Before then, the EU ETS will not shape investment decisions in a way fully consistent with the cap. This has serious implications for UK and EU leadership in movement towards a successful post-2012 international agreement.

The strongest case for considering further measures to support the investment framework by constraining coal new build, therefore, applies within this EU ETS context, which is examined in the next chapter.

The policy debate also makes clear that, over the next 10 years, such a framework for transition towards a low-carbon electricity system, involving an ambitious expansion of renewables, constraints on new coal, and almost certainly an increased dependence on gas, means facing up to problems of affordability and security of supply. These crucial issues are addressed in Chapter 9.

New coal build and UK emissions risk

We start by considering the implications of the analysis in this report for the UK coal debate. As already discussed, the future of coal-fired power generation in the UK is shrouded in uncertainty: it is not yet clear how many new coal plants might in fact be built or how many existing plants opted-in under the EU Large Combustion Plant Directive (LCPD) will actually run to 2020 and beyond. Nor is it yet clear how credible EU ETS policy will be in Phase 3 or how far the Government's commitment to the 2020 renewable energy target can be realised. And it is not clear whether CCS will work (or at least by when it can be made to work) or at what cost.

However, what can be said is that this uncertainty means that there is some risk that the UK may not meet its Climate Change Bill targets for emissions reductions without major recourse to buying credits from abroad. Some 11.6 GW of new coal-fired capacity is being considered by the major energy suppliers and, although it is not certain that all will get consent, and it is probably unlikely that all will be built, the quite powerful strategic driver of maintaining portfolio diversity means there is a good chance that some will.

New coal plants may tend to replace existing coal plants in operational terms, in which case emissions from coal-fired power generation may fall, even if new plants are built. However, in a world with low coal prices and a weak carbon policy, old coal plants may run alongside new coal plants, creating a serious shortfall in emissions reductions against 2020 Climate Change Bill targets.

The significance of UK emissions

It is important to be clear about the nature of what is at risk here. Reducing UK emissions will not, on its own, directly influence atmospheric processes sufficiently to avoid dangerous climate change. Rather, the environmental objective of energy policy should be seen as mediated through political action, and, specifically, through international leadership. A major intention behind the Climate Change Bill was to provide international leadership on climate change, as much as to reduce emissions *per se*. Ensuring that the UK's environmental performance is not undermined by high emissions from coal is, therefore, about acting in a way that is consistent with the drafting of the Climate Change Bill and leadership on international negotiations, which will ultimately lead to reductions in global emissions.

However, although this type of risk is not directly environmental, it still matters if the Climate Change Bill is to have served any purpose. If the Bill becomes law, but a large proportion of the 2020 target is met through buying credits from abroad, while at the same time a large amount of new coal-fired power generation capacity is built in the UK in the next few years, then the UK's flagship climate initiative will have no credibility. As shown in Chapter 1, coal-fired power generation plays a dominant role in emissions, meaning that, if emissions from coal do not decline towards 2020, it will be impossible to make up for this through emissions reductions in other sectors.

Beyond the details of emissions, the building of new coal plants in the UK, which are beginning to have an iconic status in climate change discourse internationally, will be hard to square with the UK's image and role as an international leader on climate policy. The future of coal is, therefore, at the heart of the UK's international credibility.

A counter-argument is that what matters in terms of international leadership is not what the UK does, but rather what the whole of the EU does, especially through reducing emissions under a cap. Countries including China do not care what the UK does on its own, and are not particularly interested in the Climate Change Bill.

This latter argument is not fully convincing. What the UK does domestically does have significance, not least because it is viewed closely by other member states in the EU. The UK cannot expect to approve several new coal-fired plants and increase power sector emissions while expecting others in the EU not to do so. More broadly, in the words of the Climate Change Minister Phil Woolas: 'The point that the United Kingdom's credibility overseas in [the post-Kyoto] negotiations must be matched by a credible performance domestically is of extreme importance' (Woolas 2008).

The EU ETS and the Climate Change Bill targets

The Government's tool for managing the emissions risk from coal, and, therefore, the risk to the Climate Change Bill targets, is the EU emissions trading scheme. As explored in Chapter 3, the new targets for emissions reductions to 2020 should, in theory, lead to a substantial reduction in coal-fired power generation across Europe.

The view from Government and energy companies is that new coal plants may well be built in the UK under the EU ETS, but, as long as the EU-wide cap is not breached, then this is not a problem in itself. If they are built, new coal power stations will come on stream only from around 2015, and, with the possibility of retrofitting CCS from the early 2020s, the period during which emissions may be higher than they otherwise would have been is relatively brief.

However, there are several reasons why the EU ETS alone may not be sufficient to prevent emissions from coal driving progress towards the Climate Change Bill targets off course.

The first is that the UK is in a position where it is adopting ambitious *national* targets for emissions reduction, while, at the same time, is dependent in large part on a *European-wide* policy instrument (which has to be agreed across 27 member states and the European Parliament) in meeting those targets.[17]

17. In the Energy White Paper, it is assumed that the EU ETS will be responsible for between 41 and 58 per cent of total UK emissions reductions by 2020 (HM Government 2007). This issue is recognised in the Office of Climate Change's recent analytical overview of climate policies (OCC 2007).

Currently the Climate Change Bill and the EU ETS aim for different 2020 goals. The Bill's target for 2020 is currently to reduce UK carbon emissions by between 26 and 32 per cent from 1990 levels. The proposed cap for the EU ETS is based on the EU's commitment to reduce overall greenhouse gas emissions in 2020 by 20 per cent from 1990 levels. Only if there is a 'satisfactory' international agreement will this be increased to a 30 per cent emissions reduction target.

A second issue is that much of the actual emissions reduction generated by the EU ETS may take place elsewhere in the EU, rather than in the UK (as explained in Chapter 3). Again, if, in practice, the UK power sector relies heavily on credits bought from elsewhere in the EU, the international credibility of the Bill will be undermined (especially in Europe). The Government currently has no estimate of the impacts of the proposals for Phase 3 on fuel switching in the UK power sector.

In this context, the case for further measures additional to the EU ETS is based on the argument that these are needed to remove the risk that a large part of the Climate Change Bill target for emissions reductions by 2020 will be met by international trading. Some proponents of this approach would want to see the target met through domestic activity alone.

A third factor is that, while the overall cap for Phase 3 is now unlikely to be changed, the scheme could be weakened in terms of its influence on investment decision in the EU by increasing the use of CDM credits.

Finally, energy companies still do not have full confidence that the caps in Phase 3 and subsequent phases of the EU ETS will be rigorously implemented (see Chapters 3 and 8).

For these reasons, there has been considerable debate on additional measures to stop new investment in coal.

A plant-level emissions performance standard

In the UK, most of the debate has focused on a plant-level standard for carbon emissions, informed and influenced by the experience of California.

A range of environmental groups in the UK – including WWF, Greenpeace, and Friends of the Earth – are calling for a mandatory plant-level emissions performance standard (EPS) for all new power stations in the UK. This policy has been adopted by both the Liberal Democrats and the Conservative Party. WWF is also calling for such an approach at the EU level.

The EPS follows the model of the California Public Utilities Commission, which has introduced a performance standard of 500 $kgCO_2$/MWh for all new baseload capacity. The law is being extended to capacity that supplies California but lies outside the state borders (CPUC 2008a). Some proponents of this approach make an analogy between the EPS and minimum product standards, when certain options (in this case, coal-fired power stations) are removed.

Inspired by this approach, an amendment to the UK's Energy Bill was tabled in the House of Lords, proposing a mandatory standard at 400 gCO_2/MWh. At this level, a standard would rule out coal-fired power generation, unless CCS were fitted or a combined heat and power (CHP) approach were adopted.

Were such a measure to be introduced without any other policies, energy companies say they would build the least risky and lowest cost alternative instead, which is gas-fired plant. However, the proposal for an EPS usually comes in a package together with other proposals aimed at channelling investment into alternative areas of energy investment, including energy efficiency, renewables, CHP and CCS. In the case of California, the EPS has been adopted within a 2003 energy action plan that prioritises conservation and energy efficiency first, then new renewables and distributed generation capacity, and only then 'clean and efficient fossil fuel generation' (State of California 2003).

A central attraction of the EPS approach, which now has considerable political momentum, is that it is very clear, and offers apparent certainty for investors. However, as discussed in Chapter 9 below, an EPS would still have to tackle credibility questions that arise from cost and security of supply concerns, so a key question is whether investors believe it may be reversed or abandoned in the future.

Another issue with the EPS proposal is that there are some circumstances in which such a policy might, perversely, lead to higher emissions than if new coal build were allowed and no other action were taken. If a new wave of coal plants were to be built and run from around 2014-15, then because they would be significantly more efficient than existing coal plants (many of which date back to the 1970s), these new plants would be run at baseload before existing coal plants are brought into the generation running order.

There are some circumstances in which new coal plants would displace, rather than add to, existing coal-fired power stations (see Table 5.2 above). The main case in which this might arise is when carbon policy is weak, and a combination of high coal prices and low gas prices tends to drive the least efficient coal plant off the system.

If new coal plants were banned in such circumstances, the only coal available would be old coal plants, with their higher attendant emissions.

A moratorium on new coal-fired power stations without CCS

As long ago as 1990, Denmark introduced a moratorium on new coal-fired plants, which was reaffirmed in 1997, along with a requirement for CHP (Danish Energy Authority 1998). New Zealand is currently introducing a climate change bill that would introduce a 10-year legislative moratorium on all fossil fuel baseload plants, both coal and gas, requiring new investment to focus entirely on renewable sources (Ministry of Economic Development 2007).

With the widespread deployment of CCS still some way off, even on optimistic views, an immediate moratorium on new coal-fired capacity without CCS would have a similar impact on investment decisions and emissions to a plant-level emissions performance standard, as above.

Canada, meanwhile, is introducing a requirement that any coal-fired plants built from 2012 onwards will have to meet emissions standards at levels based on CCS from 2018 onwards (Government of Canada 2008). This is based in part on the model of 'stretch targets' that have been applied to vehicle emissions in California and other places. Such targets are ambitious, but allow manufacturers time to work towards them.

A moratorium on coal without CCS from a future date would make CCS compulsory if the technology works and is of a reasonable cost. If CCS doesn't work or is prohibitively expensive, then coal-fired power generation will be environmentally unacceptable and will have to end anyway. In a speech on climate change last year, the Prime Minister referred to retaining this option (Brown 2007).

This requirement for CCS could, in principle, work in a similar way to the requirement for lower sulphur emissions under the EU Large Combustion Plant Directive (LCPD), which offers plant operators a choice, by a certain date, between fitting flue gas desulphurisation (FGD) or limited running hours followed by closure.

Crucially, the key to the credibility of the LCPD has been that the technology needed was both well-established and sufficiently cheap to allow continued commercial operation.

The current framework for CCS is proceeding slowly, both internationally and within the UK, and a best available technology (BAT)[18] (or its impossibility) may not be identified until well after 2025. One approach would be to align a requirement for CCS or closure with the EU ETS, and apply it from 2028 (the end of Phase 4, with caps on coal emissions applying until that date).

However, this is very late from an emissions point of view. A more ambitious approach would be to force the pace of CCS development, so that a BAT would be identified earlier, and then be required for all new coal plants and retrofitted to all coal plants built after 2008. In January 2007, the European Commission proposed such an approach, with a CCS required from 2020 (Europa 2007). As noted above, Canada is now proposing a requirement from 2018. If applied, this should help force the pace

18. 'Best available technology' is a term used in environmental regulation meaning state-of-the-art processes, facilities or methods known to be effective in reducing pollution.

of CCS development internationally, so such a target date should be possible for other countries and regions, including the UK. Finally, the introduction of a requirement for CCS would eventually have to apply not only to coal, but also gas.

The main problem for the future moratorium approach is that, if it involves a serious threat to the stability of the electricity system, and the prospect of the lights going out, then it will be politically impossible to carry through. The more gradual a phase-out, the easier it is to follow through on. If a large amount of coal-fired capacity is built now, plant owners have a strong incentive to lobby for a delay on the moratorium, or its cancellation.

Emissions versus investment – a mandatory limit on carbon emissions from UK coal-fired generation

An emissions performance standard and moratoria are aimed at influencing the decision to invest in new coal power stations. However, as discussed in Chapter 5, the number of new coal plants built does not convert in any direct way into future emissions from coal, since this depends on coal prices, carbon prices and existing coal plants.

If the real target of concern is *emissions* from coal, within the context of the risk to the Climate Change Bill targets, an alternative approach would be to directly introduce a limit on carbon emissions from coal burning in the UK power sector.

There are probably several ways to introduce such a limit. One might be a limit on the number of hours a particular plant could run over a specified period. This would be feasible, as the amount of carbon emitted per kWh of power generated by each power station is monitored by the Environment Agency. This approach has been used for limiting sulphur emissions under the LCPD. Coal plants that have opted out of the Directive can run for a maximum of 20,000 hours over the period 2008-2015.

A more flexible approach would be to have a tradable permit scheme (see Annex 3 for a numerical example), which is one of the options for limiting nitrogen oxide (NOx) emitted from coal plants in the National Emissions Reduction Plan (NERP).

In either case, a strict cap on carbon emissions from coal-fired power generation would be effective in limiting emissions, although there would be pressure to include a buy-out price, which might affect this. A cap approach would also allow the Government to set a particular level of emissions. In the period up to 2020, a declining cap could be set in relation to the Climate Change Bill targets. A cap could also be extended beyond 2020, and progressively reduced to phase out coal burning without CCS.

This approach would not rule out investment in new coal build *per se*, since it would be aimed at total coal emissions. However, with a tight and declining cap on emissions from coal, it is, in practice, unlikely that any investors would build new coal plants, as long as the policy were credible.

Coal policy and the EU ETS

When the above measures are proposed within the UK context, at the heart of the response from the Government and energy companies is the argument that domestic measures such as these are not compatible with the EU ETS.

There are three commonly expressed parts to this argument. The first, especially applied against an EPS or moratorium, is that a market-based mechanism like the EU ETS fits best with the UK's liberalised energy markets.

For example, this argument was made by the Energy Minister Malcolm Wicks in a recent parliamentary debate on the amendment to the Energy Bill proposing an emissions performance standard (EPS). Although an EPS has more of an explicitly environmental basis than a moratorium, the Minister still emphasises the clash with the liberalised market framework:

> 'The Government do not believe that prescribing emission limits in that way is the most effective route to low-carbon power generation. Such an approach goes against the Government's fundamental approach to energy policy, as set

> out in the 2007 White Paper. In the UK's competitive market framework, the choice of fuel and technology for a new power station is a matter for the energy company. The Government's role is to set the right framework to incentivise private sector investment, consistent with meeting our energy goals of tackling climate change and providing energy security.' (Debate on new clause on carbon dioxide emissions performance standard power, Energy Bill Committee, House of Commons, Tuesday 26 February 2008)

A second issue arises in how domestic measures interact with the EU ETS technically. Consider the case of an EPS that rules out new coal-fired power stations in the UK. This might cut future emissions from the power sector. However, because the UK power sector is included in the EU ETS, such a cut would mean UK power producers would then bid for fewer allowances, leaving more allowances for the power sectors of other member states elsewhere in the EU, and for heavy industry. This is known as producing 'hot air', and means that the domestic measure has the effect of moving emissions from one place in Europe to another, rather than reducing them in total.

It is worth noting that this problem does not arise in the case of California, because the EPS predates proposals for a cap-and-trade scheme like the EU ETS (CPUC 2008b). Indeed, the Public Utilities Commission views the EPS as a bridge to a possible cap-and-trade scheme, and an insurance measure against financial risk exposure to any potential US federal-level cap-and-trade scheme (CPUC 2007).

Total emissions under the EU cap would reduce as a result of an EPS only if there were also a downward adjustment to the cap, to match this cut in emissions from UK coal-fired power stations. However, the problem lies in knowing what this adjustment should be, since it is not known how many coal plants would otherwise be built in the absence of an EPS, and how much they would run.

There are already UK domestic policies that overlap with the EU ETS, including the Renewables Obligation, the Carbon Emissions Reduction Target for the domestic sector, and the Carbon Reduction Commitment for the commercial and public sectors. However, for these policies, so far, the overlap is relatively small, whereas for measures that would affect large amounts of coal capacity or generation, the overlap would be much more significant.

The third response to proposals for domestic measures to constrain coal is the most important. This is that the proposals undermine the EU ETS politically, just as its credibility is becoming established after several years of political effort. They are effectively a statement of no confidence in the EU ETS, because they replace the carbon markets as the main force driving the decarbonisation of electricity. Emissions from coal-fired power generation make up over a third of the total emissions covered by the EU ETS. Equally, since investment in coal-fired power generation is the form of investment with the highest carbon intensity covered by the ETS, governing new coal by an EPS sends a strong signal that the ETS will not be expected to play any significant role in shaping investment.

However, the force of these arguments depends on the view one takes on the prospects for the EU ETS to be an effective driver of low-carbon investment in the future. Some commentators believe that the EU ETS has become an end in itself, rather than being the means to an end, and that the emphasis should shift to other mechanisms for delivering emissions reductions. Indeed, the whole point of considering further measures at the UK level is because of concerns that the EU ETS is not going to be effective in delivering emissions reductions sufficient for the Climate Change Bill targets.

Summary

New coal investment creates a risk that the 2020 Climate Change Bill targets may not be achievable without the purchasing of a large amount of credits from abroad. New coal investment without carbon capture would also seriously undermine the UK's credibility as a climate leader in a broader sense.

Critics of the EU ETS argue that it is failing to prevent new coal build, to provide assurance that the Climate Change Bill targets can be met mainly through domestic activity, and that the UK's credibility on climate is at risk. This is the basis for new and more direct measures, such as an emission performance standard.

A major challenge for a plant-level emissions performance standard is that although it offers clarity, it is nevertheless open to the problems of credibility that face any proposal that may involve higher costs or gas security of supply problems, especially in the longer term. These are discussed in more detail in Chapter 9.

However, the EPS approach does also cut across the EU emissions trading scheme (into which the UK and some other member states have put considerable political investment) in certain ways. Thus the EPS proposal draws the response that they are incompatible with the market approach, that they move emissions around within the EU rather than reducing them, and, most importantly, that they undermine the EU ETS politically, just at the time that its credibility is beginning to be established. In turn, this response is met with the argument that, since the EU ETS is not delivering on shaping investment, so the use of more effective measures should not be sacrificed on the EU ETS altar.

One clear conclusion that can be drawn from this debate is that the EU ETS – and differing views of it – lie at its heart. The eventual role that the EU ETS comes to play in shaping investment cannot be predicted in any simple sense, since it will be the outcome of complex political processes.

However, a second conclusion that can be reached is that the one issue that both sides in the debate agree on is that confidence in the EU ETS is still not fully established. This lack of full credibility in the EU ETS is important not only for the UK debate, but also at the European level. The way that it influences investment decisions points to a further and separate rationale for additional policy interventions on coal. This is explored in the next chapter.

8. A wider perspective on coal and the EU emissions trading scheme

The examination of the UK debate on coal in Chapter 7 made clear that the EU emissions trading scheme lies at the heart of disputes about what should be done. In this chapter, we look at coal and the EU ETS in a different context – that of the whole of the EU, rather than the UK alone.

This change of perspective leads to a different way of framing the problem, and to the conclusion that a regulatory intervention to limit new coal investment will *strengthen* the credibility of the EU ETS, not weaken it.

The EU ETS as a bridge to a global deal

A starting point is to consider why the EU ETS is given such a central place in UK Government thinking. As discussed in the previous chapter, it is partly because the EU ETS, as a carbon market, fits with the liberalised energy market in the UK.

However, the Government's position is that the EU ETS matters not just because of emissions reductions in Europe, although these are important, but because of its larger purpose to provide a platform for the EU in global climate negotiations, and a bridge to global carbon markets. These will form an essential part of a new international deal to combat climate change.

In the words of Grubb (2007: 4), 'The EU ETS is backbone of implementation and compliance, and focal point of global attention', being the principal tool of EU decarbonisation, dominating international carbon-related financial flows to developing countries such as India and China, and energising international negotiations.

Clearly, carbon markets are not sufficient on their own to deliver successful global action to limit climate change. Technology policy and a host of other policies, from regulation to providing information, will also be needed (Stern 2007). However, it is true that the ETS plays a central role for Europe in the current international context (Gibbs and Retallack 2006).

Against this incredibly important ambition, the EU ETS has got off to a rocky start. By common consent, Phase 1 had virtually no effect on emissions, let alone investment. The overgenerous, free allocations may have been needed to get companies on board, but the experience of Phase 1 has undermined the confidence of many observers (including some environmental organisations that should have been supporters of the approach) that the EU ETS can ever be made to work.

Also problematic is the link to CDM/JI credits. Although the link allows the transfer of finance to countries like China and India, demonstrating how future global markets might work, the existence of projects that do not guarantee genuinely additional emissions reductions has strengthened the view that the EU ETS is leaky – and the carbon price is lower – as a result.

Uncertainty, credibility and discounting in the EU ETS

However, the EU ETS is evolving. The proposals for Phase 3 are particularly important, since they begin to answer many of the criticisms made of the scheme in Phases 1 and 2, including the need for a centrally set, declining cap, and limits on the use of CDM/JI credits, as long as these proposals are not diluted through lobbying.

As a result, independent analyses agree that the Phase 3 proposals from the European Commission should have a major influence on coal burning, with coal-fired generation declining by over 40 per cent by 2020 (for example, Lekander *et al* 2008b). This is an enormous effect, quite unprecedented on the European scale.

Furthermore, as explained in Chapter 3, analysis of the carbon price, taking into banking of allowances between Phases 2 and 3, a price of around €40/tCO_2 should already be emerging in the market (Lewis 2008, Lewis and Curien 2008). However, carbon prices are, at the moment, significantly lower than this, in the range €20-25/tCO_2. This is because the market is discounting the carbon price in the face of remaining uncertainties about the future of the EU ETS (for example, Grubb 2007, Fankhauser 2008). (See White 2006 for an analysis of how the carbon market similarly discounted carbon prices against uncertainties in Phase 1 of the EU ETS.)

One uncertainty is what the final agreement on the shape of Phase 3 will be. While the overall cap will not change, views differ between member states on the limits on the use of CDM credits, and the degree of auctioning. Industry groups are actively lobbying on these points. This uncertainty will not be resolved until the European Council and Parliament reach agreement. This is expected in March 2009, although it may be delayed until after the Copenhagen meeting of the UN Framework Convention on Climate Change at the end of 2009.

However, there is a wider credibility question relating to the commitment of the USA and China, as the largest emitters, to a global deal.[19] If this is clear (in early 2010 if things go well), then the future of the EU ETS (and, beyond that, the global carbon market) will be assured, and the carbon price should move to reflect that. However, if a global deal involving the major emitters is not forthcoming, then the future of the EU ETS is less clear, since how far member state governments will want to continue unilateral carbon pricing in these circumstances is not known.

As the Stern Review notes, uncertainty creates a lack of credibility, which is a key element for effective carbon policy (Stern 2007). The current situation is recognised by the Government in its recent consultation document on Phase 3 of the EU ETS: 'Markets and investors need to have confidence in the continued rigour of future cap setting in the EU ETS in order to take low-carbon investment decisions (for example investment in renewables) and we need to look at how we can reinforce that confidence' (Defra 2008: 22).

Uncertainty leads to discounted prices because traders and companies believe that there is still a possibility that the EU ETS may be not be rigorously applied at some point after 2010, and, consequently, the carbon price in the future may go very low or fall to zero. The current price, therefore, reflects an adjustment to take account of this possibility.

In the time frame in which several companies in the UK are seeking to make decisions on substantial new investments – that is, the next one to two years – the uncertainties about the future of the EU ETS are not likely to be resolved. However, this also applies much more widely across the EU, with something in the region of 140 GW of new capacity required by 2015 (RWE 2007).

The risk of high-carbon lock-in

Why does this matter? The danger is that different choices are made from those that would have been made under a more established EU ETS; choices that drive a lock-in to higher-carbon generation. The risk of such a lock-in for markets that are not yet well-established enough to correctly shape investment is highlighted in follow-up work to the Stern Review (Stern Review 2007).

At the level of an individual company, regulatory uncertainty gives a value to the option of waiting until the uncertainty is resolved before making a decision on an investment (Blyth 2005, Dixit and Pindyck 1994). We might therefore expect energy companies across Europe to wait for the outcome of both the EU energy and climate package, and the post-Kyoto negotiations. Price rises caused by a tightening of capacity margins from 2015 would not necessarily be a bad thing, seen at the level of the individual firm.

However, as Blyth (2005) points out, the option to wait is much less valuable when the company is part of a competitive market, since if a company defers investment in a favourable market, it risks losing market share. This is a very real issue for vertically integrated energy companies that face losing a significant part of their generating capacity under the Large Combustion Plant Directive or for other reasons. It is also the reason why some energy companies are so keen to invest over the next few years even in a climate of great uncertainty.

But although they may not want to wait to make investments, uncertainty will still make energy companies discount future carbon prices, which is what in turn will determine whether or not they will build new coal plants. Effectively, uncertainty about the future of the carbon market makes building coal plants less risky.

19. I am grateful to Tim Pyke for pointing out this aspect of uncertainty about the EU ETS.

With the current uncertainties about the future of the EU ETS, a substantial number of new coal plants may be started in the next two to three years. It will be very costly and politically difficult to reverse investment decisions once construction has started. As noted in Chapter 2, in 2007 there were proposals for 64 GW of new coal and lignite power stations. Once built, these new coal-fired power stations will have an operational life of 40 years or more.

The most frequently expressed concern about this situation in the UK context is that, if CCS turns out to be unworkable, or very expensive, then the UK will be locked into coal burning to 2050 or beyond. However, if this is the case, a few coal-fired power stations in the UK will be minor problem, compared with the scale of the coal problem in China, for example.

A more important problem is the implication for the ETS itself. Once new coal plants are built, plant operators will want to run the new plants at baseload over this period to maximise the return on capital. If a lot of new coal plants are built, then, compared with a situation in which less carbon-intensive generating capacity is built (say gas), emissions will be higher from around 2015 onwards (given the five- to six-year build time for coal plants). This will tend to be the case, especially in circumstances where new coal does not displace old, but, rather, adds to it; for example, if gas prices are relatively high (see Table 5.2 above).

The scale of the problem can be seen by considering the proposals for new coal- and lignite-fired power stations. RWE (2007) estimates that about 25 GW of new coal and lignite plants will be built by 2012. Table 2.2, taken together with UK proposals, implies around 75 GW of new coal-fired power stations are being considered across the EU over a longer time scale. Compare these scenarios with Lewis and Curien's prediction that 60 GW of new *gas*-fired capacity will be needed for fuel-switching away from coal to meet the proposed Phase 3 cap (Lewis and Curien 2008).

If 75 GW of new coal and lignite power stations were to be built and run at baseload, they would emit more than 200 $MtCO_2$ more than an equivalent amount of gas-fired capacity per year. For comparison, under the basic Phase 3 proposals, the target for reductions in annual emissions by 2020 is 254 $MtCO_2e$. In other words, if all new EU coal proposals were to be realised, this would come close to doubling the emissions reductions requirement in Phase 3. Since power sector emissions make up about two-thirds of those covered by the ETS, this would be impossible to achieve. While not all the plants listed in Table 2.2 are likely to be built, the driver to replace closing coal power stations and maintain a diverse portfolio is a very strong one, and many may be built.

A large amount of new European coal build, combined with high gas prices, will put huge upward pressure on the carbon price in the latter part of Phase 3. With a high demand for carbon allowances because of a lot of coal burn, carbon capture then becomes a critical technology for Phase 3, because it is the only way in which large amounts of coal can be made consistent with the cap. It is possible that up to 12 demonstration plants may be operating in the EU towards 2020 at the end of Phase 3, but these would not be operating commercially.

Analysis by Deutsche Bank implies that even if the ETS carbon market were operating with full credibility, the carbon price will need to rise to the level needed to make carbon capture and storage commercially competitive (Lewis and Curien 2008). While this could be no higher than €40 in today's prices in the 2020s, in the period 2015-2020 it is likely to be significantly higher than this, since the technology will only just have been demonstrated at scale. The more new coal plants are built, the more will have to be fitted with carbon capture to avoid a breaching of the cap. Thus a consequence of building a lot of new coal plants now may be to accelerate the deployment of CCS across the EU.

But the consequences of this will be felt in the electricity price. Coal without CCS remains cheaper than gas as a way of producing electricity, but coal with CCS is likely to be much more expensive. As can be seen from Figure 6.1 above, the price of electricity from coal with CCS could easily be double that from coal without CCS. In the early stages of the technology, the price differential could be even more. With a large amount of new coal build, if electricity prices will rise to politically unsustainable levels, the consequence will be a breaching of the cap and a collapse of the scheme.

The other, quite likely, possibility is simply that CCS on a large scale is not feasible before the end of Phase 3, in which case the cap will be breached in any event. Some of those working directly on the development of CCS within the energy industry take the view that widespread deployment will not be possible until the later half of the 2020s.

The dynamics of investment and expectations also suggest that the current situation is unstable and may lead to a rush of new coal investment. This is because the more that other companies invest in new coal plants, the lower the credibility of the Phase 3 targets, and so the more likely it is for each company to seek to realise any coal plans it may have.

This is an entirely new challenge for the EU ETS, since the major issue so far has been the opposite problem: a lack of scarcity in the market. However, the combination of a tighter, declining cap and lots of new coal plants could dramatically reverse this picture.

Thus, at the heart of the problem is the danger of a self-fulfilling prophecy – allowing a large number of new coal-fired power stations to be built at this stage, before the credibility of the EU ETS is fully established, will actually weaken its credibility further, by introducing new uncertainties about what will happen beyond 2015.

Beyond these impacts on the EU ETS itself, the prospect of a large, new wave of coal plants undermines the wider image of the EU as the key leader on global climate change.

In these circumstances an intervention to strengthen the market makes sense. As Blyth (2005: 4) points out, 'Although risk in general does not require policy intervention, a possible exception is risks created by government policy itself.'

A European Carbon Bank?

The conventional approach to the credibility problem is to delegate powers over control of a market to an independent agency (Helm *et al* 2003). In the monetary policy field, this takes the form of giving the power to set interest rates to an independent central bank. The idea is that such an agency is insulated from the political pressures that bear on governments, and is therefore able to take the right decisions based on the long-term objectives it has been set.

Concerned to bolster confidence in the EU ETS, Prime Minister Gordon Brown floated the idea of an independent European Carbon Bank in February this year. As the Government's recent consultation paper on the EU ETS puts it:

> 'The Commission's proposals for a revised EU ETS take a big step in the right direction, by recommending a clear trajectory for future caps. The Government wants to consider how giving responsibility to an independent institution could underpin that confidence, and remove the risk of short-term political pressures interfering with the long-term commitment to a low-carbon future.' (Defra 2008: 22)

In the longer term, such a proposal makes sense as a means of strengthening confidence in the market. However, the UK proposal has not been taken up by the Commission at this point.

There is also the question of how such an institution would act to deal with the danger of lock-in to high-carbon electricity generation through a wave of new coal investment in the next three years.

The existence of the Bank might give investors some greater confidence that the cap might not slip in the face of very high prices. However, if actors conclude that a lot of new coal build produces a significant risk that the cap cannot be attained, then the creation of a new institution would not, on its own, prevent a collapse in credibility of the market.

A floor price for carbon?

Another approach to uncertainty or a lack of credibility in pollution markets, explored in the Stern Review and elsewhere (for example, White 2006), is for the Government to provide a floor to the price. This could be achieved via a levy on carbon emissions, if the EU ETS price fell below the floor, or by the Government guaranteeing to buy credits at that price.

A variant would be for the Government to offer a 'contract for difference' on the carbon price. This would mean that if the price of carbon in the EU ETS fell below a certain level, the Government would make up the shortfall, but if it rose above that level, companies would have to pay the difference to Government. This is the approach, for example, currently proposed for fixing a price of carbon as a form of support in the UK CCS demonstration competition (BERR 2007d).

One problem with this approach is the scale of the gap between the current carbon price in the market and estimates of the price that would be obtained in a fully credible market. At €15-20/tCO_2, this gap would involve a massive public financial liability on any approach that involved member state governments buying credits at the floor price.

A levy on carbon allowances at the point of purchase provides an alternative approach. However, if the lack of full credibility in the market is due to uncertainty about what happens after 2011, then this uncertainty also applies to the levy itself. There is every reason to extend the uncertainty about future carbon policy to the future of such a levy, since member state commitment to the levy would surely be questionable if a global deal was not forthcoming. As the Stern Review notes, 'people would … have to believe that [the floor itself] will not be changed' (Stern 2007: 330).

Without full credibility, it is likely that market actors will adjust the underlying price so that the new price including the levy reflects this. For example, if the current carbon price is €25/tCO_2, and a levy of €15/tCO_2 is introduced, the underlying price will fall to €10/tCO_2 to offset the levy.

Overall, while a floor mechanism may credibly work to stabilise carbon prices at a level within the range in which they are already fluctuating, or move them slightly higher, it is a less attractive option for inducing a major shift to a new level.

A pause in investment in new coal?

In such circumstances, there is a strong case for some form of temporary measure ruling out new investment on coal-fired power stations across Europe, to support the EU ETS through an initial period while credibility is not fully established. If a global agreement is reached, and the future of the EU ETS assured, then the measure could be ended. In a context of considerable uncertainty for investors in the medium term, the aim would be to reduce uncertainty about decisions that have to be taken in the short term.

Given the timetable for international negotiations, it would make sense for such an investment pause to run at least until early-to-mid 2010 and possibly later. Markets will be looking for bankable commitments to the expansion and integration of carbon markets in developed countries (especially the USA), which are unlikely to be in place in terms of a formal agreement until the Conference of the Parties in Copenhagen, due in late 2009. However, given the timing of the US elections, it is also possible that this will be pushed back until early 2010. Market actors will also want to observe how any new agreement is received by public opinion in large countries like the USA.

However, to function as a bridge to a more effective ETS, such a freeze should be time-limited. Otherwise, like the emissions performance standard, it will effectively be a replacement for the ETS. A time-limited and relatively short freeze will also suffer a lot less from credibility problems.

One important effect of a temporary moratorium on this timetable is that it would push back the possibility of any new coal-fired power stations coming on line to around 2016-17 at the earliest, given typical build times. While several EU countries, including Germany, the Czech Republic, Hungary and Poland, face the need for some new generation capacity by 2015 (RWE 2007), this issue is probably the most pressing for the UK, because of the phase out of existing coal plants under the Large Plant Combustion Plant Directive (LCPD).

The LCPD will mean that some 12 GW of old coal plants will have to be closed by January 2016. This situation, together with the closure of Magnox nuclear reactors, is presented by some energy companies as meaning that the UK electricity system faces a 'cliff edge' in generating capacity at some point between 2012 and 2015.

However, these analyses tend to play down the considerable amounts of new gas-fired capacity in the pipeline, along with increasing amounts of offshore wind. In 2007, 4.5 GW of new gas capacity was near to or under construction, and another 9.5 is in the formal planning process. According to the Government's latest forecast, which excludes any potential expanded renewables investment or further gas-fired proposals, the effective capacity margin[20] will only fall below the level it was in 2005/06 (5 per cent) by around 2017 or 2018 (BERR 2007c).

In reality, and as discussed in Chapter 2 above, the 'cliff-edge' problem applies much more to individual companies in the UK, rather than to the country or the EU as a whole. In particular, RWE will lose all, and E.ON almost all, their coal capacity, and a large chunk of their total corporate generating capacity, by 2015, because they consist of coal-fired plants opted out under the LCPD. Scottish Power will also lose around 1 GW of capacity. With a moratorium on new coal in place until early-to-mid 2010, these companies face a choice between investing in new gas capacity, and waiting to see if they still want to build new coal from 2010, with the likelihood that they will have to rely on independent power producers in the wholesale electricity market for a brief period around 2015-2017 if they choose the latter option.

The other question is how a temporary moratorium would work in practice. In the UK, there is a precedent for a moratorium on a particular fuel within the energy sector, ironically one intended to protect the coal industry. In October 1998, Peter Mandelson, the then Secretary of State for Trade and Industry, introduced a temporary ban on new gas power plants (Helm 2003). The moratorium was lifted in November 2000.

The gas moratorium worked in practice simply by the Government withholding licences for new power plants. Under the very broad powers governing permission to build new power stations granted to the Secretary of State under section 36 of the 1989 Electricity Act, a temporary moratorium on new coal plants could be introduced without new legislation.

UK or EU action?

If the basis for a limit on new coal build is to support the EU ETS through a period in which credibility is not fully established, then it makes sense to do this at an EU-wide level. A further advantage of acting at the EU-wide level is that this approach allows a burden-sharing of any problems arising from higher costs of power that might result from ruling out coal. If a moratorium is applied within any one country, then all the costs are borne by a single country, which would pose intra-EU competitiveness problems for some industries. The evidence is that intra-EU competitiveness problems from higher energy prices are greater than competitiveness problems between the EU and the rest of the world (Sato *et al* 2007).

However, while the UK Government could introduce a national-level moratorium quickly, action at the EU level may be more difficult politically. If EU-level action is not politically feasible, is it still worth it for the UK to act unilaterally?

A temporary ban on new coal build in the UK alone will have much less of an impact on expectations about the future of the ETS than action at the EU level.[21] Such action would also mean the UK exposing itself unilaterally to cost and competitiveness problems.

At the same time, new coal build plans in the UK are the second highest in the EU, behind Germany. Indeed, if a bilateral agreement could be reached between Germany and the UK to introduce an investment pause on coal, this would cover around two thirds of new build plans in Europe, and would have a major impact on the ETS credibility problem. It would therefore perhaps be best for the UK to use a proposal for a temporary moratorium on coal as a way to engage other member states (especially Germany) on the issue.

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20. The excess of electricity supply over peak demand, adjusted to take account of the fact that generating plants are not available all the time.
21. It is interesting to note that, since the objective of limiting new coal build would be to ease upward pressure on the EU-wide cap, the 'problem' that this may create 'hot air' elsewhere, seen from within the context of the UK debate, turns out to be precisely the point of the measure, when seen in the wider context of the EU ETS lock-in problem.

Summary

The pace of new investment in power generation across the EU is running ahead of the establishment of full credibility in the EU ETS, and there is a danger that a new wave of coal-fired power stations will further undermine confidence in the future of the scheme, given the timetable for CCS.

Lock-in to a high-carbon power system, with consequent pressures on the EU ETS cap (and wider EU emissions reductions targets), is a real danger. Under such circumstances, it will be hard for Europe to continue its leading role in movement towards a post-2012 international agreement.

It seems counterintuitive that a non-market intervention, such as a moratorium on new coal build, could strengthen a market mechanism like the EU ETS. However, it is precisely because this is a direct form of regulation, whose role is relatively short-lived, that it can play such a role.

9. Policy credibility: addressing concerns about cost, security of supply and planning

In Chapters 7 and 8, various policy options for preventing investment in new coal-fired power stations in the UK or limiting emissions from coal-fired power generation were discussed.

Such measures are aimed at political objectives – hitting the Climate Change Bill targets, and avoiding high-carbon lock-in and reduced credibility of the EU ETS – that are, in turn, part of a global effort to mitigate dangerous climate change.

The ultimate environmental imperative is very clear, and from this flows a political imperative for the UK and Europe to limit new coal investments and reduce emissions, if we want to play a serious role in helping to tackle climate change at a global level. However, reducing emissions is not the only objective of energy policy, and, more importantly, is not the only concern of the wider society, including voters, consumers and businesses. Security of supply and the cost of electricity matter, too, especially to certain politically sensitive groups such as the fuel poor, and energy-intensive industries.[22] There is also a set of issues to do with planning permission, and perceptions about the effect of energy infrastructure on landscape and local quality of life, that are politically important.

Thus, while environmental organisations want to eliminate risks of high emissions from coal, others place a greater focus on risks that fuel supplies may be interrupted, that costs will rise excessively, or that the local environment will suffer. The current debate about coal can be seen in terms of where different parties want the risk to be distributed.

The political importance of the issues of security of supply and cost for the Government should not be underestimated. Retail electricity prices have risen twice due to winter gas market problems in the last three years. These price hikes are unpopular with consumers (who are, of course, also voters), and with businesses. In the winter of 2006, high gas prices led to production at several paper mills, glassworks and chemical plants being interrupted (CBI 2007). They have also sharply increased the numbers of households estimated to be living in fuel poverty (see, for example, HM Government 2007).

In a longer-term context of rising oil and gas prices, there is also some nervousness in parts of government about adding further to electricity costs through ambitious EU ETS and renewables policies. The expansion of wind energy has also faced considerable opposition through the planning system.

Coal is seen by both government and energy companies as helping with these issues, and the case for new coal is often made in these terms. Thus, proponents of all policies that ban or limit coal new build or generation – including a strong EU ETS policy – have to engage with these issues of cost, security of supply and planning. This chapter addresses these issues.

The policy credibility problem

The existence of multiple policy objectives and underlying societal concerns means that, although the Government is beginning to set frameworks for emissions reductions and the promotion of renewable power, its commitment can suffer from a *credibility* problem, which will have an important impact on the success or failure of those frameworks (Helm *et al* 2003).

22. The other political issue associated with coal is the future of mining in the UK. The British coalmining industry is a shadow of its former self, with only around 8,000 people now employed in deep-mine and open-cast production. The mining unions and the TUC have serious concerns about the survival of the industry, and UK coal as a strategic national asset (although it should be noted that the TUC is committed to a future for the use of coal in electricity generation only on the basis of carbon capture and storage) (Clean Coal Task Group 2006).

Such policies are designed to shift investment from conventional, high-carbon technologies (for example, coal) into lower-carbon technologies (for example, gas or wind). If governments cared only about reducing emissions, then commitment to such policies would be quite credible. But in the case of the UK, the Government also has security of supply and low prices as part of its goal. Behind these objectives lies the political incentive of re-election, since no government that lets the lights go out, or energy bills to rise excessively, is likely to be re-elected.

It is this fact, that Government has an incentive to renege on commitments to reduce emissions, that may make companies back away from investments in low-carbon technologies that they would otherwise be willing to make. The response to policies by companies in terms of actual investments will depend on whether they think governments will stand by their promises. If companies make long-lived investments on the basis of environmentally ambitious policies that turn out to be politically unsustainable, and are subsequently reversed, they risk ending up with stranded assets on their hands. This lack of credibility can seriously undermine the investment response.

Thus, while companies prefer certainty and clarity in policy, they will always assess clear statements of intent within this wider context of credibility. At the moment, some of those in energy companies making investment decisions are expressing considerable uncertainty about how society wants to balance environment, security and affordability. In the words of one senior strategy manager: 'Are people really prepared to pay the real costs of tackling climate change? Is there any hard evidence that they are?' The low take-up of green tariffs, and the opposition to planning consents for onshore wind is cited as evidence of a lack of willingness to embrace strong climate policy.

If companies doubt that the Government can sustain a strong carbon policy and impose the proposed EC renewable targets, and believe that the Climate Change Bill targets will be met mainly by purchase of credits from abroad, rather than through domestic effort, then they are much less likely to invest heavily in renewables, and more likely to take the risk of building new coal power stations.

The credibility issue applies equally to measures such as a direct moratorium on new coal build, a plant-level emissions performance standard, or a limit on coal emissions. While these would prevent investment in new coal in the short term, if they are not credible then companies will take the view that they will be overturned at some point, and keep coal plans ready at hand for rapid deployment in that event.

Below we note the two main issues underlying the policy credibility problem: security of supply and cost.

Security of supply

Note that we refer here to the security of supply of the fuels used to generate electricity, not the functioning of the transmission and distribution system (which we refer to as 'resilience').

Maintaining reliable energy supplies is one of the objectives of the Government's energy policy. Within a longer-term goal to conserve and decarbonise energy, this objective makes sense, since modern economies and societies are heavily energy-dependent, and loss of energy supplies can be highly disruptive.

Since storing electricity is currently expensive, with limited options, secure supplies of fuel for generating electricity are a major concern. When physical supplies of fuel are threatened, even indirectly, costs tend to rise, leading to higher prices for industry and customers. The CBI, for example, says that its members are concerned about security of supply.

This concern applies to other countries as well. For example, while New Zealand is currently introducing a moratorium on new fossil fuel baseload generation, the legislation does provide exemptions for circumstances in which there are concerns over security of supply (Ministry of Economic Development 2007).

Concerns over gas

The main security of fuel supply concerns in the context of the UK relate to natural gas. Britain has been largely self-sufficient in natural gas since the late 1970s, but this situation is set to change. By 2020, we could depend on imports for 80-90 per cent of our gas use (Bird 2007). This development has coincided with a sharp rise in wholesale gas prices, especially compared with coal (see Figure 2.1 above).

The two trends are related, in that a shift from self-reliance to imports will increasingly expose the UK to price risks (and possibly even physical supply risks) associated with the European regional gas market (Helm 2007, Stern 2006). Although the UK is supplied by a number of countries, including Norway and, increasingly, Algeria, these countries will sell gas at prices set by the conditions of exports from Russia. An expansion of liquefied natural gas (LNG) supply will only partially offset this dominance (Helm 2007).

Russia has pursued a strategy of increasing control over pipelines to, and increasingly within, Europe, maintaining close links with other suppliers, and attempting to block the development of alternative supplies, for example from the Caucasus. At the same time, the UK is at the end of physical pipelines that run through continental Europe, and which are controlled by supply companies that have an interest in prioritising their own physical security of supply over that of UK companies. Unlike many continental companies (especially in Germany), which have negotiated long-term contracts with Russian supplier Gazprom, UK companies tend to rely heavily on spot markets for imports, leading to greater price instability.

There are two particular concerns in this situation. The first is the threat that gas pressure may be lost, as was the case in parts of Europe during a dispute between Russia and Ukraine in January 2006. In this event, industrial users would be asked to cut use first, to protect domestic customers, but the political damage could well exceed the economic cost of lost production. The second concern is that gas prices can soar if such an event is even threatened, let alone if it happens, and electricity prices follow.

By comparison with gas, coal is abundant and supplied competitively in a global market. Currently that market is tight, but, in the longer run, the prospects are that the price of coal will be lower and more stable than that of gas. In addition, while 70 per cent of demand is met from imports, the UK also has large coal reserves (Bird 2007).

Coal capacity can help more to ease any short-term *physical interruptions* to UK gas supply that might arise. While a number of gas-fired plants in the UK do have oil-fired backup available, being able to bring in more coal to replace gas over short periods gives the system stronger resilience. Switching fuel in power generation is also the most cost-effective way of avoiding gas outages, according to work commissioned by the Government for the Energy White Paper (Oxera 2007).

Coal is, therefore, seen as a buffer against risks associated with gas supplies. For example, the Energy Minister Malcolm Wicks recently argued the need to work to ensure: 'that coal … can maintain its present niche in UK energy portfolio, producing reliable, affordable power, and so helping to deliver security of supply through diversity of supply' (Wicks 2008).

Given the value of coal-fired capacity in this context, the credibility of any proposal to limit the role of coal will be increased by policies that reduce the likelihood of physical interruptions to gas supply.

Increased efficiency of gas use

The plentiful availability of natural gas from the North Sea has allowed the UK to be lazy in its thinking about the resource. On the Continent, where countries have been reliant on imports from other countries for a long time, cost and security of supply concerns have driven investment in a much more efficient use of gas, including greater strategic security than in the UK, and a wider use of CHP in countries such as Germany, Holland, Denmark and Finland. With North Sea supplies running out, the UK needs to catch up, and start thinking about gas supplies in a new way.

Power generation makes up only about 30 per cent of natural gas use in the UK. Use of gas for space and water heating in homes and businesses, along with industrial uses, is far more important. Improving energy efficiency in these areas would, therefore, help to improve security of gas supply by reducing demand. It would also save money.

There are a number of existing policies in place aimed at achieving such objectives, including the Carbon Emissions Reduction Target for homes and the Carbon Reduction Commitment for businesses, as well as building regulations that require more efficient domestic boilers and double-glazing. However, these measures have so far tended to constrain growth rather than lead to major reductions in demand, so there is a strong case for further action on heat.

The wider use of CHP production, which uses gas more efficiently than centralised power plus boilers, would also improve security of supply for gas through reduced demand. For example, in an application of its model to the UK in a study produced for Greenpeace, the World Alliance for Decentralised Energy estimates that investing heavily in decentralised energy capacity could lead to a 14 per cent fall in gas use by 2023, as against a centralised new build scenario (WADE 2006).

However, CHP currently represents little more than seven per cent of Britain's generating capacity (5.5 GW, including industrial plants, which have the majority of capacity), and growth in schemes and capacity is still low (BERR 2007a). While the market for CHP in new developments is now beginning to be driven somewhat by planning rules, the scale of investments is still very small.

The gap between current investment levels and aspirations can be seen by considering the case of London. In 2006, Greenpeace and the Greater London Authority published a study of the potential for decentralised energy in the capital, based partly on the density of commercial and residential heat loads. This potential was identified as between 2.5 and 3.7 GWe by 2025 (Greenpeace and Mayor of London 2006). By contrast, current installed capacity of CHP is around 175 MWe (Mayor of London 2004). Achieving the potential would mean installing around 250-350 MWe of CHP capacity every year between now and 2025. Total capital costs would be in the region of £3 billion and £4.4 billion, implying an annual investment requirement of the order of £300-440 million (Mayor of London 2006).

Greenpeace and other organisations have called for much wider use of CHP as part of a decentralised approach to energy (see, for example, Greenpeace 2005). The example of the town of Woking, Surrey, where a creative approach using CHP combined with renewable electricity in a new business model, is frequently cited as an inspiration. There are various barriers to more investment in community-scale CHP, which include regulatory burdens on small power producers (LCCA 2007). However, major energy companies also take the view that opportunities to get a good rate of return on capital in community-scale CHP are limited, that costs (especially management overheads and capital costs) are high in relation to revenue streams, and that it is difficult to persuade potential commercial customers to agree to long-term (10-15 year) contracts for heat, which are necessary to repay the investment on the heat network.

Similar commercial difficulties exist for the capture and use of heat from large power stations. Currently the Government does require companies proposing large thermal plant to consider possibilities for CHP, and has published a map of heat loads to help this process (www.industrialheatmap.com). E.ON, for example, says that it is examining the options for a new coal-fired power station at Kingsnorth to serve a heat network in the Thames Gateway. This idea has also been proposed for heat from an extension of Barking power station. However, in practice, such heat capture and use is rare in the UK, only being used at scale by Conoco for its refinery at Immingham on the Humber estuary.

This is mainly because large power stations generate an enormous quantity of heat throughout the year, and generating companies consider it both difficult and costly to align many potential users of that heat in the right configuration and with the right timing to produce a viable commercial deal. This is difficult enough when the potential customers are one or two large industrial companies, but virtually impossible where there are a number of developers working to different timescales, and with miles of heat network to be constructed to serve residential loads.

While the major energy companies do have some interest in decentralised renewable energy, such as biomass CHP and especially in new developments, it is clear that on a commercial basis, this will remain a niche activity for these companies. This is despite a package of support for CHP offered by Government, which includes measures such as exemption from the Climate Change Levy on power produced by CHP, and higher Enhanced Capital Allowances (BERR 2007a) (to qualify for Levy Exemption Certificates and ECAs, CHP has to be of 'good quality', in other words, high efficiency).

An effective policy to encourage more community-scale CHP is likely to involve a greater role for local authorities in schemes, with an appropriate financial and technical support package. Investment in CHP for large power plants may only happen as the result of legal requirement, as has been the case in Denmark.

Measures to increase domestic gas system resilience

While a lot of attention is focused on concerns about problems arising from the source of gas (Russia) and transit (continental Europe), in recent years more serious threats to UK gas pressure have come from incidents – mainly fires – at facilities within the UK, including most recently at Bacton, Norfolk, in February 2008. According to Stern:

> 'Summarising the security incidents which have occurred over the past 25 years in Europe, there have not been very many …[and]… facility incidents appear to have increased over recent years. In particular, as far as the UK is concerned, the risk of facility incidents became increasingly problematic in the mid-2000s due to the tightness of the supply/demand balance and the lack of storage capacity. Despite references by the EU to problems of importing gas from "regions threatened by insecurity" it is difficult to think of any historical incident [up to 2001] involving political instability which has prevented gas from being delivered to Europe.' (Stern 2006)

Cost-effective measures to increase the resilience of the UK gas system would, therefore, make an important contribution to policy credibility. Such measures would include improved demand-side management through smart metering, but also improved networks and strategic gas storage (Oxera 2007, Helm 2007).

The private sector is currently building new pipelines from Norwegian and Dutch gas-fields and new LNG terminals. There are also plans to increase gas storage capacity to allow for at least two months supply (CBI 2005). The Energy Bill currently before Parliament also contains measures to facilitate the development of offshore gas storage. According to a recent speech by the Secretary of State for Business John Hutton, between 2005 and 2010, the UK market will deliver around £10 billion in new gas import, storage and pipeline capacity (Hutton 2008b). As a result, the Government's assessment of the gas market outlook takes the view that:

> 'In the short term … the UK's gas supply capacity appears robust against most credible scenarios and events. For the medium to long term, investments over the next five years are critical; if they come forward as expected, the capacity margin will be large enough to provide a buffer against most large single interruptions.' (BERR 2007c)

Measures to improve regional market conditions

As noted above, while the UK receives gas imports from a range of sources, Russia determines the price in the regional market, and has been highly strategic in its domination of that market. At the same time, the UK is at the end of a continental delivery system over which other national energy companies have control.

There are, thus, a number of policy changes that the UK could usefully pursue at the European level. These include (Helm 2007):

- Planning of and investment in European gas networks
- Unbundling to create a European gas infrastructure, rather than a series of national ones

- Strategic gas storage to protect against geo-political risk
- Developing a centralised European framework for energy negotiations with Russia, rather than a series of bilateral relationships
- Establishing reciprocity with Gazprom on ownership to protect European networks
- Creating a European Energy Agency to drive this agenda through.

Renewables

It is also quite widely argued that security of supply concerns can be addressed through the greater use of renewable energy. This argument is made, for example, by the European Commission, in favour of the 2020 renewable energy target.

As with coal, more renewable energy at the EU level over the long term will help to reduce demand for gas for power generation, and so should bear down on prices in the regional market. Unlike coal, some renewables (including wind, the UK's current main option) cannot be dispatched on demand, which may limit its use in addressing short-term interruptions to the physical supply of gas. The other important issue with a major expansion of renewables is cost. This is discussed below.

Cost

Whatever the particular combination of policies adopted to decarbonise electricity and shift away from the use of coal, there will be additional costs involved. This is true of a carbon price in the EU ETS, but it also applies to a rapid and large expansion of renewable electricity, grant-supported demonstrations of CCS, and an effective support package for community-scale CHP.

Costs of alternatives to coal

Although the price of coal has risen in recent months, the price of gas remains even higher, with little sign of this situation changing in the next few years. However, other alternatives to coal for the period 2015-2020 are potentially even more expensive, in particular renewable energy.

Accelerated renewables investment to meet the 2020 target discussed in Chapter 4 will need either an expanded Renewables Obligation or some new instrument (both environmental organisations and the Conservative Party have proposed feed-in tariffs[23] for micro-renewables, for example). Both will probably be financed by raising prices. For the UK, the cheapest and most abundant renewable power source is wind, but this is a relatively mature technology, in which economies of scale from turbine sizes have now been largely realised. Wind power is also suffering from rising materials costs, problems that may persist into the next decade (see, for example, ODE 2007). Deployment support to other technologies can also be expensive.

Rising costs for wind because of shortages of material are, of course, shared by other power sector investments. In 2007, RWE reported that shortages of steel, equipment shortages and rising subcontractor costs, driven by the worldwide boom in construction, have also pushed up the costs of building new fossil fuel plants by 15-20 per cent in the last two years (RWE 2007). This means that, regardless of the fuel or type of generation, in the near term electricity will cost more. But the issue here is whether the relative costs of coal and renewables – especially offshore wind – have changed. There is no evidence that this is the case.

There are also uncertainties about the costs of dealing with the intermittency of electricity produced by wind, which is likely to be the dominant renewable in the UK. There are estimates of system capacity and balancing costs for penetration of wind of up to 20 per cent, which are quite small at £2-3/MWh (0.2-0.3 p/kWh) (Gross *et al* 2006). ILEX and Strbac (2002) put the cost per additional unit

23. Feed-in tariffs are guaranteed rates for electricity exported from a generation site and fed in to the electricity distribution system. The 2006 Climate Change and Energy Act called on UK electricity supply companies to offer tariffs for generation or export from micro-renewables, and several now do so.

of renewable generation at 20 per cent penetration somewhat higher, at £3-9/MWh, rising to £4-11/MWh at 30 per cent penetration. At the upper end of the range of estimates for 30 per cent penetration, this implies annualised costs of around £1 billion a year.

In Germany, which has seen the largest expansion of renewable energy in Europe, fees paid to exporters of renewable electricity amounted to €5.5 billion in 2006 (German Federal Ministry for the Environment 2007). About half of this goes to wind projects, and 15 per cent to solar PV output. Of this cost, just over €3 billion was passed to electricity consumers. For domestic customers, these passed-on costs represented 0.72 cents per kWh, or just under four per cent of household electricity costs.

The European Commission estimates that achieving the 2020 renewable energy target will cost €13-18 billion a year across the EU. In initial work on the UK commissioned by the Government, Pöyry Energy (2008) estimates that the cost will be of the order of £5-7 billion per year, or £200-300 extra on electricity bills.

An accelerated and enlarged programme for CCS would also add to costs. As discussed in Chapter 6, an effective CCS package would probably need to involve support for pre-combustion CCS, in addition to the current post-combustion demonstration competition, which could cost several hundred million pounds a year. Additionally, there are the costs of constructing a carbon dioxide transportation pipeline network. This could be financed through private investment, but costs would again be passed on to customers.

CHP is often argued to be a cost-effective technology, with higher capital costs being offset by savings on fuel use and avoided transmission and distribution investments. However, cost estimates usually omit development and project management costs, which can be relatively high. As a result, the major energy companies regard community-scale CHP as, at best, a niche investment (see above).

An effective package for community-scale CHP would, therefore, probably need to include a major support programme and financing for local authorities as lead agents in public-private partnerships, as has been the case in a number of towns and cities, including Woking, but also Southampton, Aberdeen, Leicester, and, most recently, Birmingham. It is not currently possible to say what the costs of a support package sufficient to get investment on a scale significant enough to help with the security of supply of gas would be.

The total cost of all of these elements will add several hundred pounds per year to electricity bills. This order of magnitude is well within recent rises in electricity costs for consumers and businesses. This underlines the fact that the high cost of gas, driven by record highs in oil prices, works in favour of all the approaches outlined above (although not enough to make them competitive without support). However, a high cost of gas also works in favour of coal, and, although coal prices have risen in recent months, the structural factors behind those rises are not as deeply entrenched as those in oil and gas markets.

Meeting additional costs

Cost is a particular concern at a time when both consumers and Government are bearing relatively high debt burdens, and concerns about cost have already been used by the CBI as a basis for opposition to the EC's climate and energy package (Traynor 2008). This situation is not confined to the UK or EU. In the case of New Zealand, which is bringing in a moratorium on new fossil fuel power stations, media coverage has focused on the likely costs to businesses and households (Espiner 2007).

Decarbonising electricity through supply-side measures will involve extra costs. Within this context, the biggest credibility problem for new initiatives involving renewables, CHP and CCS probably lies in the uncertainty about costs, and about the willingness of business and voters to accept further rises in costs over the medium term.

Probably the most effective way to reduce this uncertainty, and, therefore, the credibility of policies, is for government to develop authoritative cost estimates, and explore the political acceptability of measures, in terms of the balance between cost and emissions reduction (and other benefits). This should be done as a matter of urgency.

In addition, policy credibility will be strengthened by emphasising that there will be economic benefits, which means developing authoritative estimates of the resultant employment and exports.

Some organisations argue that additional costs should be met through, or set against, revenues from auctioned EU ETS allowances. These are expected to be of the order of €50 billion across the EU by 2020 (European Union 2008),[24] and could be €4.5 billion a year in the UK alone in Phase 3 (Point Carbon Advisory Services 2008). Although this is unlikely to be enough to cover all the costs discussed above, it could make a serious contribution. The challenge with this approach is that most costs, in practice, would be met via price rises to consumers, rather than through public spending, so a mechanism would have to be developed to redistribute revenue to consumers in a fair and cost-efficient way.

A final point is that in addition to reducing carbon, measures such as a large expansion of renewables will have other long-run benefits for consumers, such as energy independence, and protection from fuel price volatility (such as is currently being driven by speculation in oil markets). It is essential that this message reach the public.

Planning

The expansion of renewables, CCS and CHP also potentially opens up direct political risks for government in the form of local opposition to the siting of onshore and offshore wind farms, new overhead transmission lines, CCS pipelines and town centre CHP.

Planning has been the major constraint on the expansion of wind power – especially onshore wind – in the UK to date, with an approval rate of only 56 per cent for projects in Scotland in 2007 (Chamberlain 2008). The recent rejection of an application to build a 650 MW wind farm on the island of Lewis underlines this point.

Although it is less obvious, planning may also be an issue for setting up a CCS transport infrastructure. According to some of those interviewed, such an infrastructure project will be of the order of magnitude of planning and building the national grid, and there will be major issues of how the pipelines will be routed, and how local planning will be obtained.

The Government has introduced a new Planning Bill to make energy investments easier to get through the planning system. However, the British Wind Energy Association argues that the Bill will not help wind projects as much as might be expected, because they are either too small to be covered by the Bill, or are in Scotland, where the Bill will not apply. It estimates that only 300 MW of the 8 GW currently held up in the planning system would be fast-tracked under the Bill's provisions.

Moreover, it is clear that companies still have concerns that the legislation may not be effective on the ground, if local feeling is very strong. They will only be convinced if they see a couple of years of effective implementation.

While offshore wind projects often do face challenges from the Ministry of Defence and wildlife charities, it is onshore projects that face the strongest local opposition. One factor in this opposition is that ownership is usually divorced from location – almost all UK wind farms are developed and owned by large corporations. This contrasts with Germany, where the vast majority of wind farms are owned by farmers or private individuals, and where planning has not been such a major issue (Szarka and Blühdorn 2006). Encouraging more local ownership of wind farms could help increase the credibility of wind expansion.

24. Note, however, that a moratorium on new coal, or measures to reduce emissions from coal, would also reduce the number of allowances bid for, and hence the revenue available.

Summary

Limiting coal-fired power generation and investment raises real challenges relating to the security of supply of natural gas, cost and planning. These challenges undermine the credibility of policies with investors, and, therefore, the effectiveness of policy. However, there are measures that can help address these challenges and increase the credibility of a range of policies, from frameworks for renewable energy through to carbon markets and regulatory limits on new coal build.

Having coal-fired capacity will be effective in helping address security of supply problems, mainly in the form of short-run interruptions of physical supply, rather than high prices.

While such episodes are not unknown, it is also important to remember that the UK gas system is fairly robust (BERR 2007c). Gas has played a substantial role in the UK power sector for over 15 years now without any large-scale problems. While North Sea supplies are now beginning to run out, which means that the UK will have to import more gas, most analysts note that this does not necessarily mean that gas supply will become less secure. While Russian supply dominates the European market, there are strong incentives for Russia to maintain secure supply to that market (Stern 2006).

The more significant issues are likely to be domestic resilience to incidents like fires, and problems with free flow of gas through European pipelines. Both of these can be addressed through appropriate policies, and much has already been done to improve the situation. Additional policies to reduce (or at least contain) demand for gas would also be important. The other policy that could be effective in reducing gas prices would be the major expansion of renewables envisaged by the European Commission in its proposals for 2020 targets.

However, this policy, along with a strong EU ETS policy, an expanded demonstration programme for CCS, and a support programme for CHP, all have cost implications, and, therefore, credibility problems.

The biggest challenge to overcoming these problems is to produce authoritative estimates of the costs involved, and make the case for investment, partly by also developing estimates of benefits in terms of jobs and export earnings.

Finally, the expansion of renewables, but also, potentially, city-centre CHP, and the establishment of a CCS infrastructure, face a credibility problem in terms of opposition through the planning system. The new Planning Bill may have some impact, but this Bill itself is open to a credibility question, the outcome of which may not be clear for a year or two. Making the political case for investments remains necessary. In relation to onshore wind in particular, encouraging more local ownership would help.

Conclusion and recommendations

The planning application for a new coal-fired power station at Kingsnorth has kick-started a major debate about coal-fired power generation in the UK. In this report, we have argued that, in order to know what to do about Kingsnorth and any future cases, we need to look at the broad context, including energy policy more widely, the future of renewable energy, the prospects for carbon capture and storage (CCS), and, above all, the EU emissions trading scheme (EU ETS).

The future of coal-fired power generation matters because it is at the heart of the climate change challenge. Historically, emissions from coal-fired power stations have dominated the UK's total emissions. Proposals for new coal plants will be the first real test of the Government's ambitions for a transition to a low-carbon economy, expressed through the Climate Change Bill targets for 2020 and 2050.

For energy companies seeking a portfolio of generation from diverse fuels, coal has significant attractions. In recent years, it has been highly competitive on cost grounds. Coal is also available on a world market from a range of different countries, in contrast with gas, where the UK is becoming increasingly exposed to a regional market dominated by Russia.

However, it is far from clear how many of the coal plants currently being looked at will actually get built. Companies currently face risks not only from volatile coal prices, but also from uncertainty about future carbon prices in the EU ETS, both of which are important for potential returns on investment in new coal plants.

This uncertainty also extends beyond decisions about investment in new coal plants to the wider running of all coal power stations – new and existing – and, hence, to total future carbon emissions from the power sector.

A further new factor in the equation is the new renewable energy target for 2020. If this were to be achieved, the commercial case for new coal capacity would be much weaker, because of the huge increase in renewable electricity capacity that the target implies. However, it is clear that there is uncertainty in the energy industry about whether the target can and will be met.

Carbon capture and storage has the potential to dramatically reduce emissions from coal-fired power generation. However, technological and cost uncertainties remain, and the demonstration of successful CCS will take time. Even if the Government significantly extends its framework for CCS, it will not be widely deployed much before 2020.

The first conclusion from this analysis is that the uncertainties surrounding coal mean that there is a real risk that meeting the Climate Change Bill 2020 target largely through domestic emissions reductions will become very difficult, if not impossible, within the current policy framework.

Much of the UK debate focuses on the Climate Change Bill and UK leadership. Having to meet a significant part of the target through buying credits from abroad, while at the same time seeing an increase in emissions from new coal-fired power stations, would, indeed, be a serious blow to the UK's credibility as a leader on climate change, and would call into question the point of having a Climate Change Bill in the first place.

The UK debate hinges ultimately on divergent views on the role of the EU ETS. For one side, the EU ETS lies at the centre of the framework to guide investment and emissions reduction, and any attempts to displace the EU ETS by domestic intervention is to be resisted. On the other side, critics of the EU ETS argue that it is failing to prevent new coal build, and to provide assurance that the Climate Change Bill targets can be met mainly through domestic activity. They propose new measures, such as an emission performance standard or a ban on new coal, which imply a downgrading of the importance of the EU ETS in guiding investment.

However, at the EU level, there is a separate and further concern, based on the fact that the EU ETS does not yet have full credibility with companies and traders, which is a key reason why it is failing to guide investment consistently with the tighter cap set for 2020. This will not change until a new climate deal is agreed and the future of global carbon markets is secured. Because of this credibility problem, carbon prices in the EU ETS are currently lower than would be consistent with the EU cap for 2020.

Unfortunately, it is not possible to delay decisions on investments in new generating capacity until after 2010, when uncertainty about a global deal should have declined. Both the UK and many other countries in the EU have to make decisions in the next two to three years.

In many of these countries, companies are planning to build new coal plants. But a major new wave of coal plants, coming on stream around 2015, may well place huge upward pressure on prices, leading to politically unsustainable electricity prices, or a breaching of the cap. This prospect, in turn, threatens to further weaken the credibility of the scheme at a crucial time.

Thus a temporary moratorium on new coal investment at the European level would serve not to weaken, but to strengthen the emissions trading scheme, and help ensure that it acts as a bridge to a new global agreement on climate policy.

Recommendations

Because the coal issue sits within the wider frame of energy and climate policy, a coherent approach to addressing it requires action across a number of areas.

Carbon capture and storage

The only way to make coal-burning consistent with tackling climate change is through the emerging technology of carbon capture and storage. Both at the European and the global level, it is essential that CCS technology be developed and demonstrated as a matter of urgency. All governments are moving too slowly in this area.

The European Union has so far failed to follow through earlier plans for 12 demonstration plants, which should immediately be fast-tracked. A new CCS Directive specifying a process for this programme, along with associated resources for the demonstration plants, should be adopted into the energy and climate package.

The UK Government has started a process to demonstrate post-combustion CCS, but given the UK's size and its carbon storage options, it could and should do more, extending the programme to include a second, pre-combustion demonstration. Such a move would have the support of key groups, including environmental organisations, trades unions and energy companies, as well as the wider public.

At the same time, the UK Government should immediately start planning a framework for the carbon dioxide transport infrastructure that will be needed.

The 2020 renewable energy target

In order to tackle climate change, it is also essential that renewable energy be developed, deployed and brought down in price. At the same time, if the UK can achieve the ambitious renewable energy target adopted for 2020, the need for new coal for conventional generation is much less.

Reaching the target means putting the UK on an entirely new energy path, and requires a public policy effort of the order not seen in the energy sector since the construction of the national grid. Decisive and speedy action from Government will be essential and necessitates five steps:

- The first step is to develop stronger policies to radically increase the conservation of electricity use, since the lower the total demand, the easier it will be to meet the target on the supply side.
- Second, the UK's support policy for renewables will then have to be revisited. Stronger incentives for off-shore wind are likely to be needed. This includes the possibility of some form of production or export tariff for micro-renewables, if smaller scale investment by households and communities is to play a role in reaching the target, which will help build political support. New guidance for Ofgem to ensure that it plays a suitable role will also be needed.
- Third, government will have to tackle a number of technical issues that could form a significant

barrier to a rapid and large expansion of renewable electricity capacity. Strategic planning for new transmission and distribution capacity (especially for offshore wind) and guaranteeing access to that capacity is particularly important. This is an area where incremental reform will not be enough – the national grid needs to be rebuilt for the age of renewables.

- Fourth, approaches to managing the penetration of intermittent renewables of above 30 per cent need to be explored. The Government should ensure that it looks at all possible options, including the use of 'dynamic demand' appliances and 'vehicle-to-grid' technologies.
- Fifth, and, perhaps most importantly, to establish the credibility of an effort to reach the renewables targets, the Government will have to make a major effort to persuade voters and business of the feasibility and affordability of this goal. Key elements of this will include: highlighting the benefits in terms of future protection from energy price volatility, and energy security; a detailed, authoritative and transparent cost estimate for reaching the electricity component of the proposed renewable energy target; steering through new planning arrangements that are accepted on the ground; and genuine and wide consultation.

Strengthening the EU emissions trading scheme

Carbon markets will not on their own deliver effective international action to limit climate change. But the EU emissions trading scheme remains a key element in the building of a global climate agreement, and it is important that it functions effectively as part of a framework for decarbonising the EU.

In a number of areas, including the auctioning of credits, and tighter limits on the use of Clean Development Mechanism (CDM) credits, it is important that the proposals for Phase 3 of the scheme by the European Commission are not weakened. The UK Government should work as hard as possible to ensure that this is the case.

At the same time, the operation of the CDM itself should be reformed to improve the credibility of projects and to better ensure additionality of projects.

As outlined above, the ETS is still evolving and does not yet have full credibility with companies and market traders, because of uncertainty about its future implementation, much of which is related to the outcome of negotiations for a post-2012 international agreement on climate policy. This situation is unlikely to be resolved until early-to-mid 2010 at the earliest.

The discounting of carbon markets make coal investment more likely, and at the same time competitive pressures are driving energy companies to make investments in the next few years, precisely over the period of uncertainty. However, major new coal investments coming on stream across the EU from 2015 present grave problems for the emissions trading scheme cap, and place too great a reliance on the possibility of widespread deployment of CCS in the period 2015-2020.

To address this situation, an EU-wide moratorium on investment in new coal-fired power stations should be introduced, lasting until mid-2010.

The UK Government should pre-commit itself to such an approach, and use this pre-commitment to bind in other member states with large energy markets, such as Germany. This moratorium would include the application for a new coal-fired plant at Kingsnorth.

Addressing cost and security of supply concerns

Some measures that reduce emissions from coal (including a strong EU energy and climate package), and expand renewable energy, raise potential risks for the other objectives of energy policy – that is, cost and security of supply. They are also likely to face problems of policy credibility, if companies are not convinced that they are politically sustainable.

If the Government is serious about reducing emissions and reaching the 2020 renewable energy target, then it has to clarify, and where possible reduce, the security of supply and cost risks.

The most effective approach to improve energy security and contain the costs of renewables expansion would be to radically increase efforts to improve energy efficiency. A more effective programme of support for combined heat and power that makes more efficient use of gas in power production should be part of these efforts.

However if coal-fired electricity generating capacity is to be phased out, and dependence on gas increases, then alternative measures to strengthen physical security of supply in particular will also be needed. The priorities are to develop strategic gas storage in the UK, and work at the EU level both to improve the framework for energy negotiations with Russia and to prevent European energy companies from using their control of gas pipelines to divert gas supplies to their own customers.

In the short run, it is inevitable that the decarbonisation of electricity supply will have costs. Given this, three steps are key for increasing the credibility of policy aimed at such a transition:

- First, the Government needs to provide authoritative and widely accepted estimates of what the costs to 2020 are actually likely to be.
- Second, effective policies are urgently needed to reduce the impact of costs on potentially vulnerable groups, especially the fuel poor. If the UK takes bilateral actions, consideration of the situation of energy-intensive industries exposed to competition will also be needed.
- Finally, Government needs to make the benefits of decarbonisation, in terms of technological opportunities and employment in renewable energy, CCS and other areas, much clearer.

Summing up

The potential new coal rush is the first real test of the UK's and Europe's desire to help lead the world towards a solution to climate change. In the long term, the solutions are clear – carbon capture and storage and vastly expanded renewable energy can offer us energy security and low carbon electricity at an affordable price. The real challenge is in the short-term transition to that future over the next two decades, during which time much of Europe's electricity generation capacity will have to be replaced.

The investment decisions we make over the next few years are absolutely critical to whether we can make that transition successfully or not. The current policy framework has worked well in certain ways in the past, and does contain some of the elements that will be needed. But it is not currently sufficient on its own to manage the trade-offs between the challenge of climate change, energy security and affordability that are inevitable. Further steps are needed.

Annex A. List of interviewees

Keith Allott, Head of Climate Change, WWF

Dr Robert Clay, Assistant Director, BERR

Kirsty Clough, Climate Change Policy Officer, WWF

Rachel Crisp, Deputy Director, Carbon Abatement Technologies, BERR

Nigel Downes, Business Development Manager, Centrica

Matthew Farrow, Head of Environment, CBI

Joss Garman, Climate Campaigner, Greenpeace

Simon Goodwin, Head of Clean Coal, Centrica

Dieter Helm, Professor of Energy Policy, University of Oxford

Edmund Hosker, Head of Energy Markets Unit, BERR

Michael Jacobs, Special Adviser to the Prime Minister, Prime Minister's Office

Judith Konigshofer, Carbon Capture and Storage Association

Charlie Kronick, Senior Climate Adviser, Greenpeace

Andrew Lever, Generation Strategy Manager, E.ON UK

Russell Marsh, Head of Policy, Green Alliance

Steven Marshall, Technology Strategy Manager, Scottish Power

Nick Mabey, Director, E3G

Chris Morritt, Public Affairs Manager, E.ON UK

Sam Peacock, Public Affairs Manager, Scottish and Southern Energy

Philip Pearson, Economic and Social Affairs Department, Trades Union Congress

Lisa Poole, Public Affairs Manager, Centrica

Tim Pyke, Head of Climate Change, E.ON UK

Andy Read, Business Development Manager, Clean Coal Development, E.ON

Brian Seabourne, Head of Regulation and Government Affairs, E.ON UK

Alex Tindall, Head of Portfolio Development and Strategy, RWE npower

Robin Webster, Head of Climate and Energy, Friends of the Earth

Dr Anthony White, Managing Director of Market Development, Climate Change Capital

Bryony Worthington, Sustainable Development Manager, Scottish and Southern Energy

Annex B. Net present value and risk

When considering an investment, a company will put together expected revenue and costs in each year of the project. However, rather than then simply adding these up, the company then discounts future net revenue (or costs) at a certain rate. This is essentially because uncertainty increases over time, and revenue next year matters a lot more than revenue 20 years hence. The sum of the discounted revenues over the lifetime of the project is known as its net present value (NPV). Of course, since there are also uncertainties about future costs and revenues, investment appraisal will typically involve a range of net present values rather than a single estimate.

NPV is a basic tool in appraising investments, and is more relevant than costs *per se*. This matters because the two are rather different, especially in relation to risk, as can be seen in Figures B1 and B2. Figure B1 shows a range of levelised costs for combined-cycle gas turbine (CCGT) plants, supercritical coal, and an emerging coal technology called integrated gasification combined cycle (IGCC), all in £/MWh. The black lines show the range of costs for each technology, based on different future fuel price scenarios from the 2007 Energy White Paper, and for carbon price scenarios ranging from €0/tCO_2 to €25/tCO_2 (see Chapter 4). The red bar gives the average costs.

Figure B1. Levelised costs for different technologies

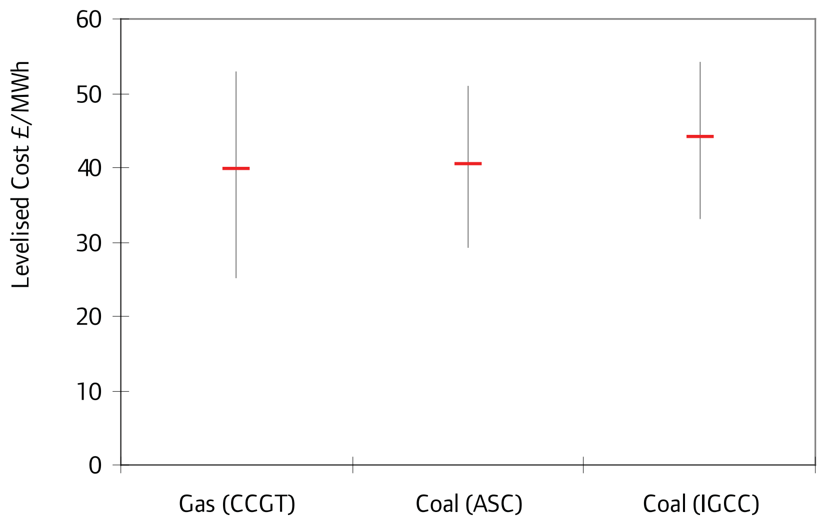
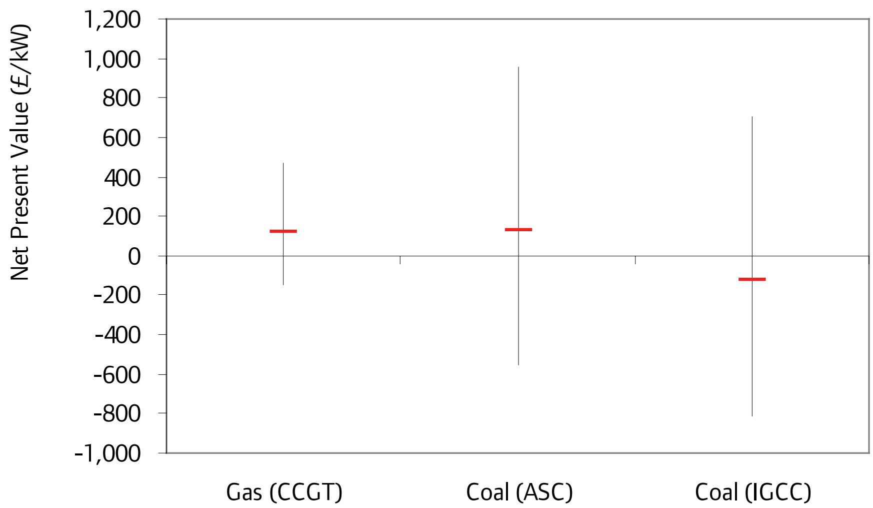


Figure B2. Net present values for different technologies

Source: Blyth 2008



As noted above, average expected costs for CCGT and supercritical coal are very close, with IGCC a little higher. However, in terms of the range of possible costs, and, therefore, the risks, it is the cost of CCGT that is the most uncertain. This is because there is more uncertainty about future gas prices than about future coal prices, and the carbon price range is not enough to offset this.

Figure B2 is based on the same cost information, but shows the range of NPVs in £/kW of new capacity for the same technologies, having factored in expected revenues. Again, average CCGT and supercritical coal NPVs are very close together, and exceed that for IGCC (which is negative, showing why no companies currently have plans to build IGCC on a commercial basis). However, the important point to note is that, while CCGT has a larger cost range, and therefore higher risk, it is supercritical coal that has a much larger NPV range, and therefore risk.

This is because, with gas prices expected to be high relative to coal, coal will tend to be run as baseload, with gas coming in to meet peak demand. As explained above, the price of electricity will reflect the costs of the marginal plant, which will be gas. This means that, even if the cost of gas increases, the price of electricity will tend to rise with it, so that gas-fired plants will still be able to recover their costs. By contrast, coal operators will get a price that bears little relationship to their costs of operation. As a result, coal appears to be a significantly more risky investment prospect. As such, it may also be more expensive to raise capital to pay for the investment, since, as a rule, the cost of capital reflects risk (Gross *et al* 2007).

This pattern of NPV risk may explain why a number of CCGT plants are currently being built in the UK, despite gas prices being high.

A final point about risks associated with investment is that the existence of uncertainty gives a certain value to keeping options open and waiting, until more information becomes available. It takes about four to five years to plan and build a coal-fired power station, and two to three to do the same for a CCGT one. If companies anticipate that electricity prices will start to rise in the run-up to a generation gap opening up early in the next decade, they will not want to wait until the last minute to invest. However, if there are particular developments either in commercial markets or in policy that will clarify the movement of future prices, these developments will reduce uncertainty, and, therefore, investment risk.

Annex C. Coal emissions allowances: a numerical example

It is possible to construct a tradable scheme that is technically consistent with the EU ETS and does not simply move emissions elsewhere within the EU.

One way to do this in Phase 3 would be to use the Government's role in auctioning EU ETS credits. The Government could ring-fence a certain number of credits, equivalent to the target for emissions from coal-fired power generation. These credits would not be auctioned, but, rather, removed and held by Government.

In their place, the Government would auction an equivalent number of new emissions credits. These new credits, called coal emissions allowances (CEAs), could be used only for coal-fired power generation. Generators would be required to hold sufficient CEAs to cover their emissions exactly. CEAs could be associated with coal supply, or, alternatively, with power output, since the carbon factor for each coal-fired power station is known. Once auctioned off, CEAs would be entirely tradable between coal generators, allowing least cost abatement within the sub-sector. Since generators would be legally required to present EU ETS credits at the end of the period, they would present their CEAs to Government, which would then convert them back again to EU ETS credits for this purpose.

EU ETS credits would not be acceptable to cover emissions from coal-fired power generation, but, if coal operators held more CEAs than their emissions at the end of the period, they could convert them through a one-way valve to EU ETS credits.

Since the number of CEAs issued is exactly the same as the number of EU ETS credits withdrawn from auction, this approach would mean that the overall EU cap would remain the same (see below for a numerical example). Overall UK demand for EU ETS credits would not be reduced, although it would be switched away from coal generation to gas generation. The only circumstances in which emissions might be moved to the rest of the EU would be if the cap on emissions from UK coal-fired power generation were set at a level higher than would be the case otherwise. The cap would have to be set with this in mind, and take into account the retirement of plants and reduced running under the Large Combustion Plant Directive (LCPD). However, it should be possible to construct a coal emissions cap that meets these requirements.

This approach, thus mirrors the way that the EU ETS works, but *guarantees* that a certain level of emissions reduction is located in the UK. The main compatibility problem it poses is, therefore, not technical but political, in that it would effectively be replacing the EU ETS in a key sector. However, it would be introduced in the event of a weak Phase 3 agreement, and, if EU carbon policy subsequently strengthened again, the CEA approach could be phased out.

Finally, any policy that guarantees a certain level of emissions for a particular sector or sub-sector is likely to raise the overall cost of abatement (as indeed a floor price would), and could, therefore, pose a credibility problem (see Chapter 8). However, achieving emissions reduction in the UK in this way, through inducing a certain level of fuel switching, is the least-cost method of abatement within the sectors covered by the EU ETS.

A numerical example

Under the Commission's proposals for Phase 3, the EU-wide cap on emissions would be 1,974 $MtCO_2$, with an equal number of EU allowances (EUAs) issued. The UK Government will be given about 10.5 per cent of this (Lekander *et al* 2008a), that is 207 million EUAs, of which about half will be auctioned to the power sector (say 100 million EUAs).

We do not know what UK power sector emissions will be in 2013, but based on projections from the 2007 Energy White Paper, they could be around 140 $MtCO_2$. Thus, the UK power sector would be around 40 million EUAs short. Up to seven per cent of this shortfall (that is, 2.8 million) can be covered by buying in credits through the Clean Development Mechanism or Joint Implementation, leaving a demand for EUAs of 37.2 million.

Currently, over 70 per cent of power sector emissions come from coal, but this could be lower by

2013, as LCPD slow running comes into operation. If the proportion of power sector emissions in 2013 is, say, 60 per cent, this means coal-fired power generation would be responsible for something of the order of 84 $MtCO_2$.

The proposed scheme would involve the Government retiring, say, 75 million EUAs from the allocation intended for power sector auctioning. This leaves 25 million behind, which are auctioned to the power sector to cover non-coal generation (that is, 56 $MtCO_2$). Assuming all allowances are bought at auction, this non-coal sub-sector is then 31 million short, and would have to buy credits on the market.

Government then creates 75 million coal emissions allowances (CEAs), which are auctioned to coal generators, and traded among them. Coal generators are thus nine million allowances short. However, unlike the non-coal sub-sector, they have to abate by running less (or buying less coal), reducing their emissions by nine $MtCO_2$, with the least efficient plants being the first to reduce output.

Combined cycle gas turbine (CCGT) power generation would increase output to cover the shortfall, which also increases the demand for EUAs among CCGT operators (which will, in many cases, be the same companies as are running coal plants). However, because gas is less carbon intensive than coal, their demand will go up by nine million EUAs scaled down by the ratio of gas to coal carbon factors: that is, around four million. This means that the non-coal sub-sector is now 35 million allowances short in total.

In total, emissions from the UK power sector (assuming that the non-coal sub-sector buys rather than abates) is nine (from lower coal emissions) less four (from higher CCGT emissions) = 5 $MtCO_2$. In each year, the cap on coal emissions would be reduced further (for example, 70 $MtCO_2$ in 2014, etc.).

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