

RESPONSE BY UKCCSC

**CARBON CAPTURE AND STORAGE: A CONSULTATION ON BARRIERS TO COMMERCIAL
DEPLOYMENT, HM TREASURY, MARCH 2006**

RESPONSE BY THE UK CARBON CAPTURE AND STORAGE CONSORTIUM

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1. What are the barriers to commercial development of CCS?

Response to 1: The main barriers are:

- a) novelty: higher project risks because of new, undemonstrated technologies and business models and lack of staff with actual experience of CCS etc.
- b) bankability: a lack of confidence that a CCS project would be able to recover its additional costs given the short-term nature of current EU ETS and the relatively weak caps; uncertainty about those costs and concerns that they are going to be 'unaffordable',
- c) legality: currently uncertain regulations and legislation surrounding CO₂ injection into offshore geological structures (with the exception of use for EOR, and the relevant London and OSPAR conventions are being reviewed),
- d) liability: concerns about long term liability for stored CO₂, with no framework defined, and
- e) acceptability: CCS must be seen as part of an aggressive, multi-pronged emissions reduction strategy to reduce possible opposition to siting and development; long term leakage of stored CO₂ is a concern; there is a need to communicate the environmental reasons why CCS is being considered (local risks vs. climate change and ocean acidification) or public opinion could be a barrier.

- 2. What CO₂ savings could be delivered by CCS, and how do these savings vary between different options for deployment, different fuels, and different kinds of technology at each stage of the CCS process? Can the life-cycle CO₂ savings be estimated comparably with those of other technologies?**
- 3. How do the potential CO₂ savings compare with other options for reducing carbon emissions?**

Response to 2 and 3: CCS can reduce emissions from all fossil fuels used in capture plant to produce decarbonised energy vectors (electricity or hydrogen) by at least 80% of compared to direct combustion, including additional energy for CO₂ capture and storage ('capture and storage' is understood here and elsewhere also to include any necessary transport). Life cycle emissions can be estimated as reliably as for other technologies, including the CO₂ emissions associated with extracting and transporting the fossil fuel.

The limits to CO₂ savings that could be achieved by CCS thus depend on the extent to which decarbonised energy vectors can be used in applications which currently use fossil energy vectors, principally housing and transport. In principle, electricity use in housing, combined with heat pumps and other optimising strategies, appears feasible even without any further advances in technology. Using electricity or hydrogen for ground transport would require technology improvements in storage and substantial infrastructure changes, but such developments are currently the subject of considerable research activity.

CCS cannot be applied to air transport directly, but the use of biomass in CCS combustion or gasification plants could offer the possibility of net negative emissions, which would then provide a valid offset to emissions from other sectors such as transport. Approximately 80% of the energy in the biomass would still be available for use (i.e. not be required to power the CO₂ capture process). RCEP estimates for maximum UK biomass production by 2050 are about 60 Mt per year¹, equivalent to perhaps 24 Mt of carbon (88 Mt CO₂) so the offset capability is limited (since obviously not all of this biomass would be available for use in CCS plants), but still comparable to the quantities of carbon dioxide emissions from such high-value, difficult-to-displace applications for carbon based fuels. Costs also appear to be reasonable. Capture and storage costs for biomass carbon of an estimated \$50/tonne CO₂ are equivalent to an extra \$22/barrel of oil, a cost increase that the aviation industry has sustained over the last year with minimal adverse effect.

Finally, CCS has a fundamentally different characteristic to all other options for reducing carbon emissions; the carbon that is not emitted to atmosphere is left in the ground as unusable carbon dioxide instead of usable fossil fuel. Whether or not this is significant for long term CO₂ emission reductions depends on the perceived feasibility of indefinitely avoiding the use of accessible fossil fuels, by political means or by providing cheaper and better non-fossil alternatives. IPCC estimates (Figure 1) show that available global fossil fuel reserves and resources, particularly for coal, appear to be much too high to allow unrestricted unabated use, even at reduced rates, if current expectations for 'safe' CO₂ stabilisation levels (possibly less than 550 ppm and certainly less than 1000 ppm)² that will give a reasonable chance of avoiding dangerous climate change are to be achieved. It must also be recognised that coal can be converted to oil equivalent fuel at perhaps \$50-100/barrel, so it can be transformed into a fuel that would be quite desirable in a 'post peak oil' world. Both the US and China have started to devote more attention to coal-to-liquids production and without capture and storage on the CO₂ formed during the conversion process, such high-carbon energy sources would impose a significant additional atmospheric burden compared to conventional oil.

¹ (Royal Commission on Environmental Pollution, *Biomass as a renewable energy source*, May 2004, <http://www.rcep.org.uk/bioreport.htm>)

² "Avoiding Dangerous Climate Change", Ed. Schellnhuber, H.J., Cambridge University Press, 2006. (<http://www.defra.gov.uk/environment/climatechange/internat/pdf/avoid-dangercc.pdf>)

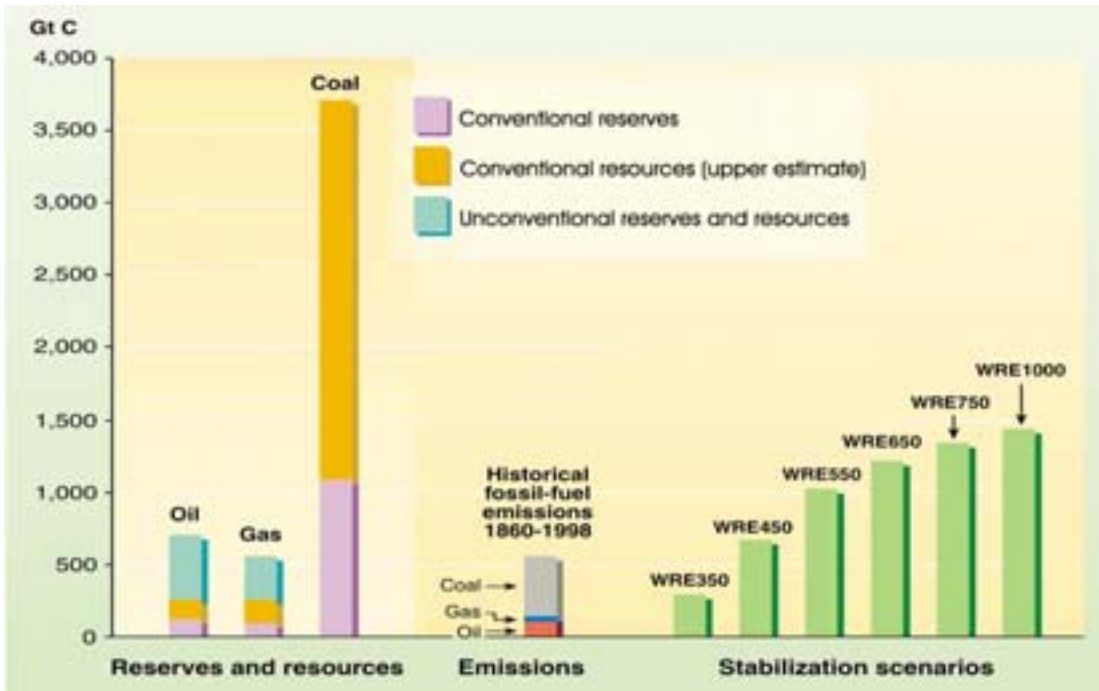


Figure 1 Carbon in remaining fossil fuel reserves and resources is much larger than 'safe' emissions to atmosphere up to the year 2100.

'Unconventional oil' includes oil sands and oil shales but not coal-to-liquid potential. 'Unconventional gas' includes coal bed methane, deep geopressed gas etc. but not gas from coal and a possible 12,000 GtC from gas hydrates. (Based on IPCC CCS, Climate Change 2001: Synthesis Report, www.ipcc.ch/pub/un/syrenq/q1to9.pdf)

- 4. What are the different technological options currently available and in development for each stage of the CCS process - and what are the costs of these options?*
- 5. What scope is there for applying these technological options to different forms of power generation (particularly gas and coal) and other large-scale sources of CO₂ emissions, and can they be installed on the basis of both new-build and retrofitting?*
- 6. At what level of market readiness are these various technological options?*
- 7. What limitations exist when it comes to selecting from the options at each stage to form a full CCS process?*
- 8. What would be the costs and benefits of early adoption of this technology in the UK?*

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Response to 4-8: Details of available technologies and publicly announced initial full-scale deployment projects are given in Tables 1 and 2 below.

Table 1 CCS technologies that might be considered for deployment for electricity generation in the UK over the next 10-20 years

Fuel	Capture technology name	Electricity generation technology	Fuel processing technology	Capture technology	New build /retrofit	Deployment and availability
Natural gas	Natural gas combined cycle (NGCC) with post combustion capture	Gas turbine combined cycle (GTCC)	None	Post combustion	Both	Small scale only, but similar larger capture plant in chemical industry. Clean combustion products so minimal difficulties, available now to at least 200 Mwe per absorber unit.
Natural gas	Natural gas combined cycle (NGCC) with precombustion capture	GTCC	Conversion to H ₂ and CO ₂ (reforming and shift)	Pre-combustion	Both	None, but similar fuel processing and capture plant in chemical industry, available now at full.
Coal (optionally plus biomass)	Pulverised coal (PC) with post combustion capture	Conventional steam turbine (boiler and turbine may be upgraded before capture)	None	Post combustion	Likely to be retrofit	Small scale only, test plants for coal combustion products just started in Europe and Japan. Near-commercial available versions up to at least 400 MWe from 2007/8, but likely to see extensive development.
Coal (optionally plus biomass and/or petroleum coke)	Integrated gasifier combined cycle (IGCC) with capture	GTCC	Conversion to mainly H ₂ and CO (gasification)	a) Shift: CO + H ₂ O to CO ₂ + H ₂ b) Pre-combustion capture	All new build, or could use existing GTCC	4 working IGCC plants without capture (2 US, 2 Europe), more planned. 100's of gasifiers, capture technology similar to chemical industry. Incremental development except for new oxygen plant (Ion transfer membrane - ITM) . Available now.
Natural gas	Natural gas oxyfuel turbines	Steam/CO ₂ turbine	None	Combustion in high purity oxygen. Drying and cleaning only	New build	Small test plants, a number of variants, might be commercial option by 2020
Coal (optionally plus biomass)	Pulverised coal oxyfuel	Conventional steam turbine	None	Combustion in high purity oxygen. Drying and cleaning only	Likely to be new build, but possibly retrofit	Base plant very widely used but significant changes for oxyfuel operation, might be commercial option from 2012-2015.

Table 2 Global initial full-scale (~300 MWe and above) CCS projects

Information in the table below is based on media reports, press releases and personal communication and should be regarded as indicative only

Company/ Project Name	Fuel	Plant output/cost	Capture technology	Commissioning date*
Progressive Energy Teeside, UK	Coal (petcoke)	800 MW (or less with H2 to local grid) (\$1.5bn)	IGCC + shift + precombustion	2009
BP/SSE DF1 Peterhead/Miller UK	Natural gas	350 MW (\$600M)	Autothermal reformer, precombustion, H2 rich gas to GTCC*	2010
Powerfuel Kuzbassrazrezugol Hatfield Colliery, UK	Bituminous coal	~900 MW	IGCC + shift + precombustion	2010
BP DF2 Carson USA	Petcoke	500 MW (\$1bn)	IGCC + shift + precombustion	2011
Statoil/Shell Draugen Norway	Natural gas	860 MW	NGCC+ Post-combustion Amine	2011
SaskPower Saskatchewan Canada	Lignite coal	300 MW	PC+ Post-combustion or oxyfuel (to be determined Q3 2006)	2011
E.ON Killingholme Lincolnshire coast UK	Bituminous coal (+petcoke?)	450 MW (£1bn)	IGCC + shift + precombustion?	2011
Stanwell Queensland Australia	Bituminous coal	N/A	IGCC + shift + precombustion (Shell gasifier)	2012
Futuregen USA	Bituminous coal	275 MW	IGCC + shift + precombustion	2012
RWE Germany	Coal	450 MW (€1bn)	?	2014
RWE Tilbury UK	Bituminous coal	~500 MW (£800m)	PC (supercritical retrofit) + post-combustion	2016 (with capture), supercritical retrofit could be earlier

* Start date assuming that appropriate means are put in place in time by market regulators/government to allow the additional costs of CCS to be recovered

Early adoption of CCS by the UK is envisaged as falling into two phases:

Phase 1 - initial deployment of a limited number of full-scale projects to open up the CCS option for the UK, starting as soon as possible to achieve commissioning dates between 2010 and 2012.

Phase 2 - more widespread deployment starting around 2015-2020, when significant new electricity generation capacity will be required to replace closed coal and nuclear plants and a trajectory leading to the 60% reduction target by 2050 would mandate that low emission technologies be used. Possible scenarios for UK electricity generation by source in 2020 are shown in Table 3 below. Actual deployment in Phase 2 will depend on a range of factors, including fuel and carbon emission

* Gas Turbine Combined Cycle

prices and, critically, the extent to which different CCS technologies are proven for fully commercial projects.

Phase 1 is required to give the necessary experience and utility and investor confidence for widespread deployment of CCS to help meet 2020 emission and generation gaps. It is envisaged that this could involve full-scale deployment using plants of the order of 500 MW output, with perhaps a total of four units (i.e. order 2GW in aggregate) being built to cover different technology options and give experience to a range of industry and other stakeholders. Investment decisions on these plants would be required in 2006 or 2007 to achieve commissioning dates of 2010-2012. A typical project schedule for an actual project (the SaskPower CCS plant) is shown in Figure 2; the investment commitment decision is made in mid 2007 for a 2011 start.

Table 3 UEP electricity generation mix and illustrative alternative scenarios for 2020³.

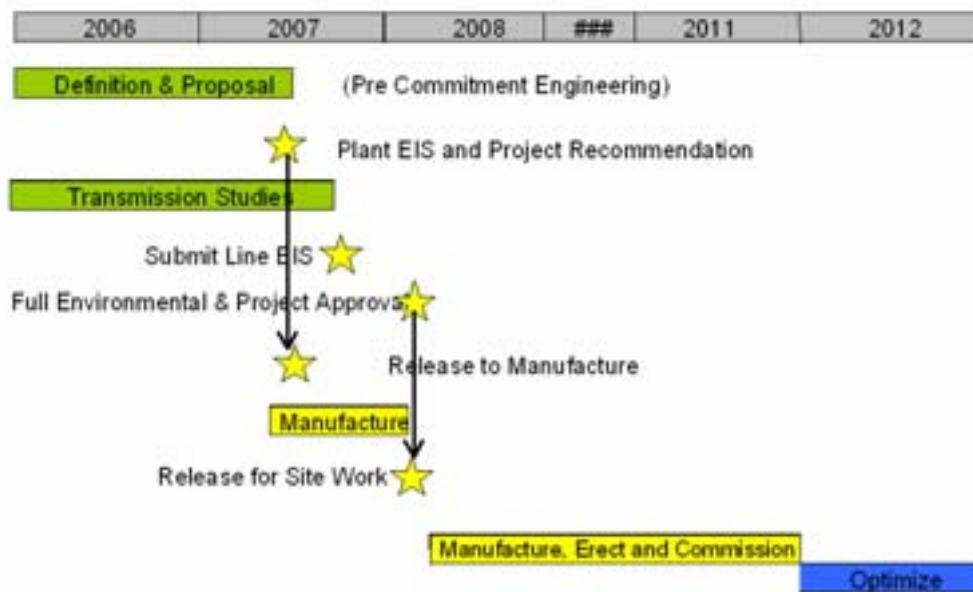
Fuel	Original UEP values					2020 scenarios		
	Electricity Generation, TWh/yr					A	B	C
	2000	2005	2010	2015	2020	No coal, 20% renewables	9GW CCS, 2GW new nuclear	Less coal, 13GW gas CCS
Coal	111.9	113	106	89	57	0	7	20
Coal + CCS						0	50	0
Oil	2.1	2	2	2	2	2	2	2
Gas	127	116	132	159	225	264	174	144
Gas + CCS						0	17	100
Nuclear	78.3	84	61	41	27	27	43	27
Renewables	10.1	15	39	58	58	76	76	76
Imports	14.3	9	10	10	10	10	10	10
Pumped storage	2.6	3	3	3	3	3	3	3
Total	346.3	344	353	362	382	382	382	382
MtCO ₂ /yr	153.7	147.1	138.9	134.0	126.9	88.1	71.3	72.2
Mean kgCO ₂ /kWh including 8% transmission losses	0.479	0.462	0.425	0.400	0.359	0.249	0.201	0.204
MtCO ₂ to storage						0	54	31
Low emission power	30%	32%	32%	31%	26%	30%	52%	57%
% gas	37%	34%	37%	44%	59%	69%	50%	64%

Assumptions:			
	Coal	Oil	Gas
2020 plant kg CO ₂ /kWh generated	0.903*	0.660	0.329
... with CCS	0.108	–	0.054
Fraction of CO ₂ captured	90%	–	85%
Additional fuel for CCS plant	20%	–	10%

* The same UEP value has been used for all coal plants for consistency, although this would be pessimistic for new or upgraded coal plant with CCS.

³ Jon Gibbins, Stuart Haszeldine, Sam Holloway and Jonathan Pearce, John Oakey, Simon Shackley and Carol Turley, "Scope for Future CO₂ Emission Reductions from Electricity Generation through the Deployment of Carbon Capture and Storage Technologies", Ch. 40 in "Avoiding Dangerous Climate Change", Ed. Schellnhuber, H.J., Cambridge University Press, 2006, (<http://www.defra.gov.uk/environment/climatechange/internet/pdf/avoid-dangerccc.pdf>)

Figure 2 Master schedule for SaskPower 300MW lignite CCS plant ⁴



9. Are there skills gaps that could create barriers to the development of CCS in the UK?

Response to 9: There are essentially no previous generations of CCS-aware professional engineers and scientists for a future expansion in UK CCS deployment to draw on. Young scientists and engineers are, however, generally very enthusiastic about a career in this field and rapid progress could be made if more resources were available. Both the Research Councils and Government Departments such as the DTI are already funding a limited number of academic projects on CCS, but additional funding is required for academic R&D projects and postgraduate courses that train the next generation of CCS experts and build up centres of UK expertise for all elements in the CCS capture, transport and storage chain as well as produce immediate research results.

10. What scope is there to develop and use CCS within the current regulatory framework?

11. What regulatory framework would need to be put in place to support the development of CCS technology while also ensuring protection of human health and the environment?

12. What additional costs and considerations are created by the long-term liability implications attached to CCS, and how can these be best managed?

13. What issues arise concerning (short-term) liability for CO₂ at particular points in the CCS process? Are there costs attached to these and what are they?

Response to 10-13: There are essentially five major categories of short- to medium-term risk bearing on carbon dioxide storage liability: toxicological effects, environmental effects, induced seismicity, subsurface trespass, and climate effects⁵. Toxicological effects of CO₂ depend on the concentration and duration of exposure. Catastrophic release of CO₂ from a geological formation is highly unlikely, but accumulation of carbon dioxide in a topographically sensitive area could be a source of concern, although in virtually all cases the released carbon dioxide would be expected to dissipate quickly. Environmental effects include the possibility of groundwater contamination and the effects of carbon dioxide exposure on the ecosystem. Groundwater liability is associated with acidification due to carbon dioxide coming into contact with groundwater, displacement of brine and brine coming into contact with groundwater, or the mobilisation of metals that enter the groundwater supply. With respect to terrestrial ecosystem effects, although moderately elevated concentrations of carbon dioxide can be beneficial to plant life, exposure to high concentrations will be detrimental. Marine ecosystems are more sensitive to increases in CO₂ as it reacts with seawater to form carbonic acid and reduces pH and carbonate ion concentration. The latter is used by many marine organisms to make their calcium carbonate shells. Should sub sea bed leakage reach the biologically active

⁴ Max Ball et al, SaskPower Clean Coal Project, Proc. Fifth Annual Conference on Carbon Capture & Sequestration, Alexandria, VA, May 2006.

⁵ M.A. de Figueiredo, D.M. Reiner, H.J. Herzog, K.A. Oye, *The Liability of Carbon Dioxide Storage*, GHGT-8, Trondheim, Norway, 2006.

sediments and overlying seawater there could be local impacts but this will depend on the local hydrological mixing. These potential local impacts needed to be balanced against the global acidification of surface waters already occurring through the uptake of CO₂ from the elevated atmospheric CO₂^{6 7}. Induced seismicity, or the potential for carbon dioxide injection and storage to induce stresses or increase pore pressure sufficient to produce seismic activity has not been observed in connection with CCS, but has been seen in other subsurface injection activities, generally in the form of micro-seismic events in already seismically active areas. Subsurface trespass would take place if the relevant property interests have not been acquired, and the stored carbon dioxide either wrongfully commingled with native substances or took up storage space which could have been used by the rightful property owner. Finally, there is the potential that carbon dioxide leakage could harm the climate. Although leakage undercuts the benefits of CO₂ storage, studies have shown that storage might still have economic value even if it is only temporary. The liability related to the climate risk is essentially a contractual liability for non-performance.

The risk to climate change and global ocean acidification of continuing business as usual needs to be assessed against the risks outlined above and should take into account the substantial difference in scales of potential impact.

Leakage from sub-sea storage in UKCS reservoirs is a particular concern in the present debate - "Will it leak?" is the question everybody asks. We are of necessity relying on predictive modelling for assurance about what will happen in the long term. This is a robust approach for the natural system in some situations, e.g. storage in depleted oil and gas fields, where, providing the pore fluid pressure is kept within sensible bounds, the main concern would be whether the seal could have been damaged by changes in stress during the production process. But less is known about the long term prospects for wells. If it could be shown that wells will not leak in the long term or that leaks (to take the most difficult case from plugged and abandoned exploration and appraisal wells offshore) could be remediated to re-seal them, then it would be easier to define long-term liability for CO₂ stored in our offshore oil and gas fields. Techniques do already exist for working over and remediating wells onshore relatively easily in most cases, although the costs may be significant. This is an area that has not yet received much attention in the oil and gas industry, where abandoned wells usually connect to de-pressurised reservoirs which are more likely to exhibit inward leakage. Monitoring and possible remediation of UKCS wells is greatly facilitated, however, because the sea bed location of all North Sea wells is known (at least to within a few metres) and held by the DTI in their well index.

At present there are no specific national regulations that address CO₂ storage. A regulatory regime for geological CO₂ storage could include predefined performance criteria to ensure geological storage could become an accepted method of earning allowance credits in the European emission trading scheme (EU ETS).

An outline scheme⁸, which highlights some of the key issues that the regulatory process should address, could comprise a series of staged licence applications, made by the operator to the national regulatory authority. Receipt of a licence would allow a storage operator to move to the next stage of the process. Key stages are:

- Licence issued to explore for potential storage sites.
- Licence issued to construct infrastructure and inject CO₂, subject to:
 - comprehensive site characterisation (including baseline surveys)
 - risk assessments (appropriate environmental impact assessments)
 - monitoring programmes
 - remediation contingency plans

⁶ Raven, J., K. Caldeira, H. Elderfield, O. Hoegh-Guldberg, P. Liss, U. Riebesell, J. Shepherd, C. Turley, and A. Watson, 2005: *Ocean acidification due to increasing atmospheric carbon dioxide*. Policy document 12/05, The Royal Society The Clyvedon Press Ltd, Cardiff, UK, 68pp.

⁷ Turley, C., J. Blackford, S. Widdicombe, D. Lowe, and P. Nightingale, 2006: *Reviewing the impact of increased atmospheric CO₂ on oceanic pH and the marine ecosystem. Avoiding dangerous climate change*. Schellnhuber, H.J.p.C.W., N. Nakicenovic, T. Wigley, and G. Yohe. Cambridge University Press, Cambridge, UK, pp. 65-70.

⁸ Pearce, J.M., Chadwick, R.A., Bentham, M., Holloway, S. and Kirby, G.A. Monitoring technologies for the geological storage of CO₂. UK Department of Trade and Industry Technology Status Review Report, 2005; No DTI/Pub URN 05/1033: 98 pages. <http://www.dti.gov.uk/energy/coal/cfft/cct/pub/reports.shtml>

This licence could be time-limited to coincide with ETS accounting intervals. The storage licence could stipulate that permission to finally close the site must be obtained from the regulator.

The regulator would grant permission to the operator to close the site subject to an appropriate risk assessment. This assessment would be accompanied by documented evidence that the long-term behaviour of the site will meet the performance criteria as defined by the regulator. This evidence will largely be based on the site characterisation, baseline surveys and subsequent monitoring surveys, all of which will help to provide confidence in the results of modelled predictions of likely future system behaviour.

At this point the regulator may assume liability. However, it is recognised that current practice regarding oil and gas decommissioning is that any residual liability rests with the operator. The required storage times of several thousand years or more creates significant obstacles to this however, and it is recommended that this important issue be explored further. Indeed, by analogy this has long been recognised in the nuclear waste industry where special arrangements are made by industry, and underwritten by the state, to ensure long-term liability is sufficiently funded.

At two key points regulators may wish to subject the project to an independent expert review. These key points are following an operator application for a licence to inject and following an operator application for site closure. The independent expert review will assess the appropriateness of the monitoring program and subsequent interpretation (such as the system model) to support the regulator's decisions on these applications.

Since the responsibility for long-term monitoring and stewardship of stored CO₂ will inevitably devolve to the Government, because private companies cannot be expected to have the necessary longevity (i.e. centuries), establishing a UK Carbon Dioxide Capture and Storage Authority might be the most appropriate way to manage this regulatory process, if it becomes apparent that a significant industrial demand is developing (i.e. if the larger Phase 2 of CCS activity occurs, but not for a limited Phase 1 of initial full scale CCS deployments). The Authority would take overall responsibility for the regulation of CO₂ storage and eventually provide long-term stewardship for the CO₂ stored underground. The Authority would be expected to be largely self-supporting, with fees charged for authorisation studies, per tonne of CO₂ stored and a variable fee (depending on likely future risks) for accepting long-term responsibility for authorised storage sites that have been properly closed down (possibly after a 'quarantine' period in industrial ownership to establish integrity).

14. What might be the likely public reaction to concerns about CCS, and how could concerns be addressed?

Response to 14: It is difficult to speak of a possible public reaction to CCS in the abstract. Current levels of awareness of CCS across the UK and most other advanced countries are very low⁹. With little information, views are sceptical or negative¹⁰ although few have an informed view on the subject. Once informed, support for CCS is moderately positive, although still substantially below renewable sources. It will not be until the first projects have taken place that one might expect growing awareness of CCS. The most immediate threat of public opposition is associated with NIMBY concerns over local siting, although concerns from local residents are likely to be largely removed if the early focus is on subseabed storage rather than onshore storage. Many environmental groups also have significant qualms about the potential for CCS to divert funds away from renewables and efficiency and discourage a decentralised electricity system. Addressing these concerns will help allay such fears. In the absence of broader public awareness, environmental groups will have an important role in shaping the views of the public.

⁹ D.M. Reiner, T.E. Curry, M.A. de Figueiredo, H.J. Herzog, S.D. Ansolabehere, K. Itaoka, M. Akai, F. Johnsson, M. Odenberger, *An international comparison of public attitudes towards carbon capture and storage technologies*, GHGT-8, Trondheim, Norway, 2006.

¹⁰ Shackley, S., McLachlan, C. and Gough, C., *The public perception of carbon dioxide capture and storage in the UK: results from focus groups and a survey*, Climate Policy 4, 2005, 377-398. http://www.tyndall.ac.uk/publications/working_papers/wp44.pdf

15. What are the costs currently associated with the development of different potential CCS technologies and forms of deployment? (It will be important for the Government to have a good, current evidence base and understanding of the costs on a commercial scale so that decisions

about the viability and cost-effectiveness of CCS can be established.)

Response to 15: Indicative costs for CCS are available in the literature and have been supplied in Table 4, (see Response to 17) but it must be recognised that a real evidence base for costs of commercial CCS in the UK can only be provided by data from a series of actual plants. The first full-scale CCS plants planned for a 'Phase 1' roll-out in 2010-2012 in the UK and elsewhere are useful to establish technical feasibility, but these initial projects will of necessity involve conservative design methods and are likely to incur higher costs than later schemes that will have benefited from learning by doing.

The first real information about the cost-effectiveness of CCS is likely to be available when the detailed FEED (front end engineering design) studies for a second phase of CCS projects are completed in perhaps 2010-2012, prior to investment decisions for a programme of capacity replacement timed around the 2016 EU Large Combustion Plant Directive deadline and existing UK nuclear plant closures. This presumes, however, that there has been a first phase of full scale CCS plant deployment in the UK starting as soon as possible (i.e. investment decisions in 2006 and 2007). The limited number of full-scale CCS projects under consideration elsewhere in the world (see Table 2) is unlikely to be sufficient to give UK utilities and investors sufficient information on relevant technologies and specific UK market requirements, nor to develop an adequate skills and experience base in the UK. Without a Phase 1 deployment of full-scale CCS projects, a good evidence base for Government and industry decisions on CCS deployment to help meet the 2020 generation and emissions gaps cannot be developed.

16. How might these costs change over time and what is the evidence for any estimates of this?

Response to 16: The International Energy Agency Greenhouse Gas Programme (IEA GHG) has recently published a report by Prof. Ed Rubin at Carnegie Mellon on learning curves for selected CO₂ capture plant types¹¹. This work has been undertaken on the basis of incremental technology development, assuming that amine post-combustion, pre-combustion and oxyfuel capture systems are not replaced by more radical changes from currently-anticipated technologies. Based on historical learning curves for similar technologies it was estimated that the following reductions in cost of electricity (COE) and final COE would be obtained after 100 GW of new CCS plant of that type had been built worldwide.

Technologies that have a reasonable prospect of giving a step change to a lower cost reduction curve include alternative solvents to amines for post-combustion capture and ion transfer membranes (ITM) to reduce oxygen production costs for IGCC and oxyfuel plants.

It must also be recognised that project financing costs, and hence actual commercial plant prices, may additionally be reduced significantly as CCS technologies become more proven through experience with full scale deployment.

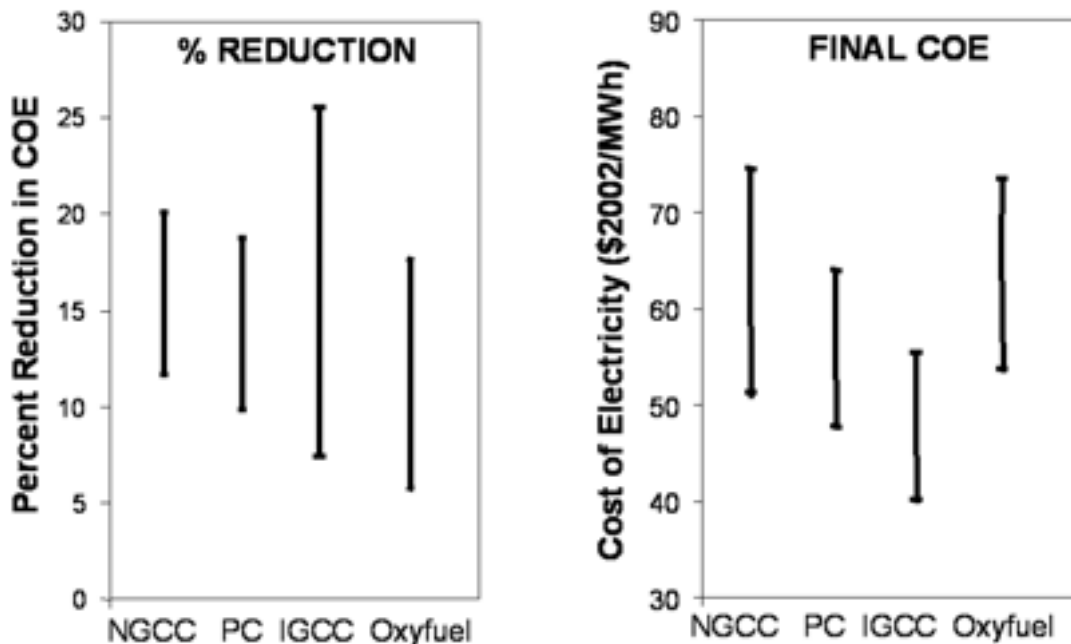


Figure 3. Rubin et al / IEA GHG study estimates for cost of electricity reductions for 100 GW build of that type of CCS plant world wide¹²

(NGCC and PC both with post-combustion amine capture, IGCC with shift and precombustion capture, oxyfuel is PC with cryogenic air separation. Main assumptions: Coal \$1.5/GJ, Gas \$6/GJ, 85% load factor, 11% annual capital charges, excludes cost of CO₂ transport and storage)

17. How might changes in the relative prices of coal and gas in the framework governing emissions of CO₂ and other pollutants affect the costs and profitability of CCS?

Response to 17: Electricity generation costs for the UK market have been estimated using the assumptions below. All cost data is, however, intrinsically variable and it is important to note that, with a proper uncertainty analysis, there would be some differences in the conclusions from the simple deterministic approach presented here.

- Discount rate of 10% and investment lifetime of 25 years

¹¹ IEA GHG Report 2006/6, Estimating the future trends in the cost of CO₂ capture technologies, Feb. 2006.

¹² E. Rubin., *Estimating Future Costs of Power Plants with CO₂ Capture*, Proc. 5th Annual Conference on Carbon Capture & Sequestration, Alexandria, Virginia, May 10, 2006

- 8000 hours operation per year
- Coal prices of £1.4/GJ (net) and gas prices of £4/GJ (net) (and £3/GJ and £5/GJ)
- CO₂ delivery pressure of 110 bar (and pipeline quality)
- Transport to offshore aquifer storage, total cost £5.50 per tonne CO₂ stored

Capital costs estimates used in the electricity cost calculations are taken as the total expenditure (i.e. including interest during construction, commissioning fuel etc., less any income from generation during trials) that would have been made for a new plant up to the end of its commissioning period. From this point on it can be assumed that the plant will be capable of achieving the design availability for the remainder of its investment lifetime. The plants here are assumed to be based on technology that is well-developed at the time they are built, so that build times are not extended while novel equipment is commissioned. Typical build times are assumed to be approximately 3 years for pulverised coal (PC) plants and 2.5 years for natural gas combined cycle (NGCC) plants.

In practice, capital costs can be expected to vary significantly between sites and over time. It is very likely that many new power plants in the UK will use existing sites; the extent to which the infrastructure in place will help to reduce overall plant capital costs will vary significantly. Factors such as currency exchange rates, whether manufacturers' order books are full or empty, metal prices etc. will also affect actual costs significantly for all types of power plant.

In addition, there is obviously no market experience for new coal plant in the UK, and relatively little in Europe as a whole (and much of that is for German brown coals (lignites), so not directly relevant). So while a single 'reasonable' estimate has been made for capital plant costs for pulverised coal plant in the UK, a typical variability of at least +/-20% is estimated for the quoted capital costs, leading to roughly +/- 10% variability in costs of generation for coal plants. This is a real variability, which generators will perceive and have to include in their own pre-feasibility study cost assessments.

Supercritical pulverised coal plant equipment costs for a 750MW plant are given as 1222 \$/kW in a recent IEA study¹³, and this is also a reasonable typical value from the literature. Based on build times and expenditures it is estimated that this would be increased by approximately 15% to give the initial plant capital costs that have to be recovered over the life of a plant. With an estimated exchange rate (for the date of the IEA study) of \$1.6/£ this gives a value of 880 £/kW.

Integrated gasifier combined cycle (IGCC) capital costs without capture are even more uncertain than for PC plant, since there is very limited experience. It has been assumed, based on current US market expectations, that IGCC specific capital costs without capture would be 10% higher than for PC without capture (with no benefit in efficiency, so costs for IGCC without capture have not been presented). Based on recent IEA GHG studies¹⁴, it has been estimated that IGCC plant with capture would require an increase of 30% in the specific capital costs compared to IGCC without capture, for a low-cost/low-efficiency wet-quench gasifier system suited to CO₂ capture.

NGCC (natural gas combined cycle) costs were estimated from costs in [4] of 499 \$/kW equipment costs for a 776 MW plant. With an estimated increase of 10% to the end of the commissioning period (vs 15% for PC, reflecting the shorter construction period for NGCC) and an exchange rate of \$1.6/£ this gives a rounded initial project capital value of £340/kW. For post combustion capture, the specific capital cost is estimated to increase by 75%, in line with estimates from the same IEA GHG study. No values have been supplied for pre-combustion capture with NGCC, since whether or not this technology option is competitive with post combustion capture is expected to depend on local site-specific factors (e.g. space availability)¹⁵.

To assess the value of achieving capital cost reductions through effective use of existing infrastructure and technical developments, some cost results are also presented for 20% lower capital cost estimates. Cost estimates 20% higher than central values are also used, indicating possible cost levels for early plants which have higher financing costs as well as much less benefit from experience.

A wide range of O&M costs are reported in the literature, possibly reflecting the scope of the costs that are included (e.g. taxes) and the different manning levels in publicly owned and private utilities. IEA GHG study

¹³ IEA GHG PH4/33, *Improvements in Power Generation with Post Combustion Capture of CO₂*, Nov 2004.

¹⁴ IEA GHG PH4/19, *Potential for Improvement in Gasification Combined Cycle Power Generation with CO₂ Capture*, May 2003.

¹⁵ IEA GHG 2005/1, *Retrofit of CO₂ Capture to Natural Gas Combined Cycle Power Plants*, Jan 2005.

values appear high compared to a survey of other studies^{16 17 18}. Tentatively, estimated annual O&M costs of £30/kW have been used for supercritical PC plant, £35/kW for IGCC plant, £15/kW for NGCC and £30/kW for NGCC plant with capture.

An efficiency without capture of 44% LHV is assumed for advanced supercritical steam plant (600/620°C single reheat). A capture penalty of 6.5 percentage points from an initial efficiency of 40% is assumed for IGCC. A non-capture efficiency of 56% and a capture penalty of 6 percentage points is assumed for the NGCC plant (based on two GE 9FA turbines with a single steam turbine). For the NGCC capture case it is assumed that post combustion capture is being used. Pre-combustion capture with natural gas does not appear to give a better performance although it might be used under certain circumstances (e.g. limited space).

Electricity generation costs estimated on the basis described are presented in Table 4. It must be recognised, however, that, while it is useful to have discrete values, the tables and trend diagrams presented are still only generalised and approximate costs (as are nearly all of the generation cost estimates presented in the UK energy debate) and should not be over-interpreted. There is no substitute for site-specific and time-specific project costs, and these will vary from each other and from the estimates presented. It is also worth noting that no mechanism exists in the current UK market explicitly to relate electricity price to total generation costs. Electricity wholesale prices are generally set by marginal operating costs.

Table 4 Electricity cost estimates under a range of assumptions for UK power plants,

¹⁶ Royal Academy of Engineering, *The Costs of Generating Electricity*, March 2004. (<http://www.raeng.org.uk/policy/reports/electricityreports.htm>)

¹⁷ S. Dalton, *Cost Comparison IGCC and Advanced Coal*, EPRI Roundtable on Deploying Advanced Clean Coal Plants, July 29, 2004 (http://www.climatevision.gov/pdfs/coal_roundtable/dalton.pdf)

¹⁸ IEA, *Projected costs of generating electricity, 2005 update*. (<http://www.iea.org/w/bookshop/add.aspx?id=196>)

RESPONSE BY UKCCSC

with and without CCS

Plant name (net electrical output approx. 800MW)		Supercrit Pulverised Coal	IGCC + precom	NGCC £4/GJ		NGCC £3/GJ	NGCC £5/GJ	NGCC £4/GJ + postcom	NGCC £3/GJ + postcom	NGCC £5/GJ + postcom
Total plant cost at end of commissioning	£/kW	880	1258	340		340	340	595	595	595
Efficiency (LHV)	% LHV	44.0%	33.5%	56.0%		56.0%	56.0%	50.0%	50.0%	50.0%
% CO2 captured		0%	85%	0%		0%	0%	85%	85%	85%
Fuel cost (LHV)	£/GJ	1.4	1.4	4		3	5	4	3	5
	p/kWh heat	0.50	0.50	1.44		1.08	1.80	1.44	1.08	1.80
CO2 emissions on LHV heat basis	gCO2/kWh heat	325	325	210		210	210	210	210	210
CO2 emissions	gCO2/kWh elec.	739	146	375		375	375	63	63	63
CO2 captured	gCO2/kWh elec.	0	825	0		0	0	357	357	357
Operating hours	hrs/yr	8000	8000	8000		8000	8000	8000	8000	8000
Load factor		91.3%	91.3%	91.3%		91.3%	91.3%	91.3%	91.3%	91.3%
Discount rate	%	10%	10%	10%		10%	10%	10%	10%	10%
Plant life	years	25	25	25		25	25	25	25	25
Capital recovery factor	%/yr	11.02%	11.02%	11.02%		11.02%	11.02%	11.02%	11.02%	11.02%
Annual capital charges	£/kW/yr	96.95	138.64	37.46		37.46	37.46	65.55	65.55	65.55
Operation & maintenance	£/kW/yr	30	35	15		15	15	30	30	30
CO2 storage cost (part of 10MtCO2/yr aquifer/gas field storage system)	£/tonne CO2	5.5	5.5	5.5		5.5	5.5	5.5	5.5	5.5
EU ETS CO2 Emission Allowance cost	£/tonne CO2	15	15	15		15	15	15	15	15
Cost of electricity										
Capital	p/kWh	1.21	1.73	0.47		0.47	0.47	0.82	0.82	0.82
Operating expenditure	p/kWh	0.38	0.44	0.19		0.19	0.19	0.38	0.38	0.38
Fuel	p/kWh	1.15	1.50	2.57		1.93	3.21	2.88	2.16	3.60
CO2 storage costs	p/kWh	0.00	0.45	0.00		0.00	0.00	0.20	0.20	0.20
Cost of electricity ex. EU ETS	p/kWh	2.73	4.13	3.23		2.58	3.87	4.27	3.55	4.99
Low capital (-20%)	p/kWh	2.49	3.78	3.13		2.49	3.78	4.11	3.39	4.83
High capital (+20%)	p/kWh	2.97	4.48	3.32		2.68	3.96	4.43	3.71	5.15
Emission allowance costs	p/kWh	1.11	0.22	0.56		0.56	0.56	0.09	0.09	0.09
Cost of electricity inc. EU ETS	p/kWh	3.84	4.35	3.79		3.15	4.43	4.37	3.65	5.09
Low capital (-20%)	p/kWh	3.60	4.00	3.70		3.05	4.34	4.20	3.48	4.92
High capital (+20%)	p/kWh	4.08	4.69	3.88		3.24	4.53	4.53	3.81	5.25
Break-even carbon price for CCS rel. to central PC cost	£/tonne CO2	0.00	23.54	13.61		-4.07	31.29	22.77	12.11	33.43
Low capital (-20%)	£/tonne CO2		17.70							
High capital (+20%)	£/tonne CO2		29.38							
Marginal cost of generation (i.e. minimum electricity price at which plant will be operated once built)										
Fuel	p/kWh	1.15	1.50	2.57		1.93	3.21	2.88	2.16	3.60
CO2 storage costs	p/kWh	0.00	0.45	0.00		0.00	0.00	0.20	0.20	0.20
Emission allowance costs	p/kWh	1.11	0.22	0.56		0.56	0.56	0.09	0.09	0.09
Marginal cost of generation	p/kWh	2.25	2.18	3.13		2.49	3.78	3.17	2.45	3.89

Technology options for minimum cost of electricity with assumed constant coal price and varying gas and carbon (CO₂) prices are shown in Figure 4. Since gas and carbon prices tend to be correlated, it may be that lowest cost plant goes directly from being unabated gas to coal with capture as carbon constraints increase.

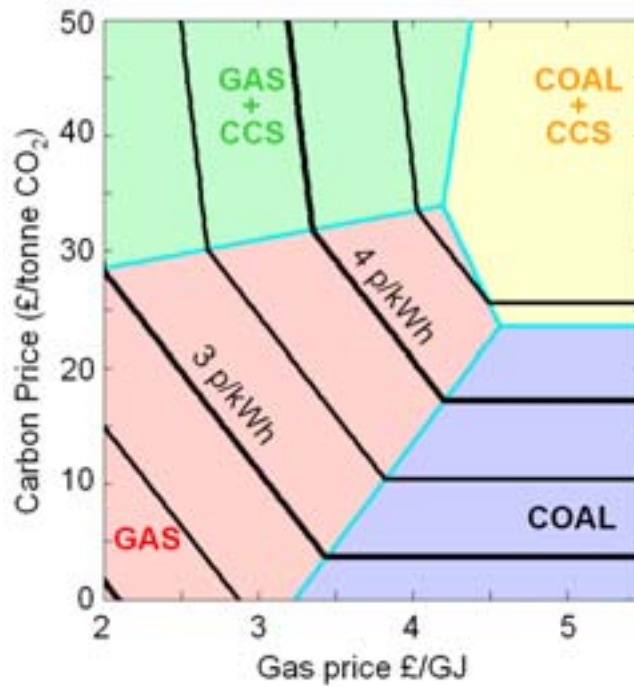


Figure 4 Estimates for lowest cost generation option as a function of gas and carbon prices (Coal price: £1.4/GJ, 25 year plant life, 10% IRR)

18. To what extent does EOR reduce costs and increase the commercial viability of CCS?

Response to 18: CCS EOR can, in principle, be very effective especially at current oil prices. Existing studies (on other countries) indicate that the effect of the incremental revenues could be to significantly reduce the net costs of the CCS chain. Typical efficiencies are 1 extra barrel of oil (worth around \$70) for every 150-600 kg CO₂ injected. In practice, however, the EOR activity has its own costs and revenues. The EOR activity generates revenues whose value depends on the responsiveness of the reservoirs to CO₂ injection (volume effect) and the unit value of the oil/gas (price effect). The EOR costs include all those relating to the injection for EOR activity and those related to the extension of field life. The latter include all the production related activities such as wages/salaries, maintenance and refurbishment costs, and insurance costs. A noteworthy reduction in costs is the benefit of the postponement of decommissioning costs. For a discussion of the classification all of the costs through the CCS chain see the new paper by Kemp and Kasim¹⁹ (copy supplied).

19. How does EOR using CO₂ compare in cost terms to EOR using other means?

Response to 19: CO₂ injection may be defined as a tertiary recovery technique (as distinct from primary and secondary recovery techniques). Tertiary recovery techniques are not yet extensively employed in the UKCS, but the potential additional output from these techniques is felt to be substantial (see the paper by Kemp and Stephen²⁰ attached). The tertiary recovery techniques that are felt to be promising in the context of the UKCS are as follows: (1) advanced chemical flood (surfactants/polymers), (2) air injection, (3) microbial EOR, (4) low salinity waterflood, (5) CO₂ injection, and (6) miscible gas injection. Other possibilities are hot water/thermal flooding. Because of the lack of experience of using these techniques in the UKCS it is not yet clear which are likely to be the most productive and cost-effective. For example, CO₂ injection equipment costs tend to be slightly higher than using hydrocarbon gas injection, since the CO₂ has to be supplied to the oilfield and corrosion-resistant piping needs to be used, but the cost of the working fluid may differ significantly. Because all tertiary recovery techniques are promising, it is felt that they deserve tax incentives at least on the R and D aspects to kick-start the activities. Development of EOR in the Permian Basin in Texas was intertwined with the availability of federal tax credits.

□

20. Is the use of CO₂ for EOR appropriate on the UK continental shelf and at what stage in the life of a specific field is it appropriate to use EOR?

Response to 20: The use of CO₂ for EOR is appropriate for the UKCS because it offers the additional advantage of large storage facilities for CO₂. The reduction in emissions of CO₂ is a national goal and the fields in the UKCS constitute the most important storage prospects. The optimal stage in the life of a field for instigating EOR schemes depends on the characteristics of the reservoir, the particular EOR schemes being considered, and their expected productivity. It can be used in both relatively new fields and those that are mature waterfloods, but it is difficult to apply very late in the field life if the reservoir pressure has been allowed to decline significantly as the final stage before conventional abandonment. So in some cases EOR schemes can optimally commence in mid-field life or even earlier, and it will certainly not always be the case that EOR starting in late-field life is optimal. A further relevant consideration is the extent of the continued availability of infrastructure in the UKCS. This is necessary to ensure the viability of EOR schemes. Some of the main platforms used for processing will be coming to the end of their economic lives in the next few years and substantial EOR schemes could extend the life of this infrastructure. The same issue applies to pipelines.

¹⁹ Professor Alexander G. Kemp and Dr. Sola Kasim, University of Aberdeen, North Sea Study Occasional Paper No. 102, *Developing a Supply Curve for CO₂ Capture, Sequestration and EOR in the UKCS: an Optimised Least-Cost Analytical Framework*, May 2006

²⁰ Professor Alexander G. Kemp and Linda Stephen, University of Aberdeen, North Sea Study Occasional Paper No. 101, *Prospects for Activity Levels in the UKCS to 2035 after the 2006 Budget*, April 2006

21. What are the costs associated with building capture-ready plant and how do they differ from the cost of constructing fully operational CCS facilities? (The cost of building capture-ready plant (a plant intended for the later retrofitting of CCS technologies) is a further issue on which the evidence base needs to be developed. There is a lack of clarity as to whether the cost would be the same, similar or very different to the cost associated with developing a fully operational CCS facility.)

22. To what extent can any additional costs be mitigated by decisions on design, location etc?

Response to 21 and 22: The costs for a capture ready plant should be close to those of an industry standard plant built without CCS. The ideal capture ready power plant, or other plant using fossil fuel, would have the following characteristics²¹:

1. prior to capture, requires no additional expenditure and has no performance penalties compared to the standard industry plant options;
2. can be converted to capture with no more than normal maintenance outages, taking the maximum possible advantage of the then available best technology, and with minimal additional expenditure beyond the cost of the capture equipment itself;
3. after conversion to capture, operates with same performance as if the base plant and the capture equipment had been designed and built as a single unit;
4. is sited with ready access to suitable CO₂ storage.

General principles for making plant capture ready, and to closely approach the capture ready ideals, can be broken down into fundamental requirements:

- a) Sufficient space on site and in critical access locations to add CO₂ capture plant and necessary interconnections.
- b) Design study for adding CO₂ capture, to assess technical feasibility and cost-effectiveness.

Plus:

- c) Optional pre-investments to reduce future costs/improve performance etc., depending on economic justification (based on NPV and probability of benefiting from the investment). Plant siting to reduce storage costs could also be viewed as a pre-investment.

Items (a) and (b) above probably should be implemented by regulation, and these will generally ensure that CO₂ can be captured from that plant in the future, at some feasible cost. Pre-investment decisions under item (c) are probably best left to those responsible for power plant lifetime economics (i.e. plant owners, other investors and possibly also regulators for regulated utilities), as is currently the case for similar trade-offs associated with fuel prices, competing generation technologies etc. Obviously long-term certainty with respect to timing and stringency of carbon regulations would be desirable for such pre-investment decisions.

Fossil fuel plants that might be made capture ready include:

- Gasifier-based polygeneration plants (e.g. electricity + hydrogen, liquid fuels)
- Natural gas combined cycle plant (NGCC) – both capture ready and gasifier ready
- IGCC
- Pulverised coal (PC) plant (and other combustion technologies)

In some cases plant owners may have no choice with respect to the technology to adopt. Polygeneration (or just gasification for chemical synthesis) is one such case, and many of these plants already produce CO₂-rich streams or can be easily modified to do so.

²¹ Jon Gibbins, Jia Li and Xi Liang, Capture ready fossil fuel plants: a critical stage in tackling climate change, Proc. 7th European Gasification Conference, Barcelona, April 25-27, 2006. http://www.icheme.org/gasification2006/CR_IGCC.pdf

For electricity production, however, the owner will need to choose between natural gas and coal, and then, if the latter option is taken, between gasification and combustion for coal plants. The ability to be made capture ready and subsequently to capture carbon dioxide from the plant is not a clear differentiating factor between coal and gas. Coal gasification plants, with or without CCS, could in principle also be retrofitted to NGCC plants. Thus it could be considered that, with suitable preparation, an NGCC plant is a capture ready IGCC plant. Space for the gasification and ancillary plants and provision for coal and CO₂ transport are obvious requirements. Whether or not any compromises might need to be made with regard to gas turbine selection and steam plant sizing is more debatable; a balance between up-front penalties and subsequent cost-saving would have to be made. As discussed below, up-front costs will inevitably dominate. There is also the need for detailed discussions with gas turbine vendors on their specific development plans for the use of H₂-rich gases at the time that final procurement decisions are made.

For markets currently with high gas prices and low carbon prices, coal plants without CCS would be the natural market choice for new build. Higher carbon prices in the future are, however, a risk in any market and making a plant capture ready is one way of managing this risk. In the absence of technology-specific subsidies the choice between IGCC and PC as capture ready plant would depend on project-specific economic performance without capture, taking into account perceptions of risk for the base plant and the capture technology. Plant economics without capture are probably better for PC, but capture technologies involve a greater additional cost and are technically unproven at scale. But while IGCC plants are less well proven and probably currently more expensive than PC for applications without capture, adding capture involves a smaller economic penalty and uses better-proven technologies that are already deployed at large scale in the chemical/refining industries. This state of affairs is obviously subject to changes, however. IGCC costs and experience are likely to be improved by a number of new commercial-scale projects. Post-combustion and oxyfuel capture for pulverised coal plants are both also likely to be demonstrated at large scale over the next few years.

PC and NGCC can be made optimally capture ready with little more than space provisions and suitable siting, but in addition to the basic space requirement, the scope for pre-investment to reduce the costs of adding capture to IGCC needs to be considered. The fundamental problem in making IGCC plants capture ready is that adding a shift stage will, in general, reduce the chemical energy available in the product gas and increase the heat available as steam. Designing to accommodate this will require equipment to be oversized, with an additional capital cost of perhaps 5%²². The alternative, operating at a reduced output after capture is added, also increases capital costs with capture by approximately 5%. If any significant time elapses before capture is fitted this trade-off therefore obviously does not represent a satisfactory return on initial pre-investment expenditure. An alternative approach, developed by Jacobs²³, is to incorporate a shift stage from the outset, with losses minimised by some heat recovery as chemical energy and additional shift/gasifier thermal integration. In this case efficiency is reduced slightly before capture but capital costs before and after capture are not significantly affected. Whether the resulting increased fuel consumption (~5%) will offset the saving in capital cost for adding capture will depend on local fuel costs and the period of time before capture is added.

An IEA study on capture ready, commissioned in response to the Gleneagles G8 communiqué, will be completed in the latter part of 2006.

23. Is the use of CCS currently a profitable option for businesses in the electricity supply sector and other sectors and, if not, what is the shortfall?

Response to 23: No. The shortfall is variable, since it depends on fuel prices, carbon prices, and commodity prices (or rather their expectations at plant construction time) as well as on CCS technology characteristics and project specific factors. Capital costs cannot be determined until contracts are signed, or

²² Rutkowski, M., Schoff, R., Holt, N. and Booras, G., 2003, *Pre-Investment of IGCC for CO₂ Capture with the Potential for Hydrogen Co-Production*, Gasification Technologies 2003, San Francisco, CA, October 12-15, 2003. (http://www.gasification.org/Docs/2003_Papers/29RUTK_paper.pdf)

²³ Griffiths, J. and Scott, S., 2003, *Evaluation of Options for Adding CO₂ Capture to ChevronTexaco IGCC*, Gasification Technologies 2003, San Francisco, CA, October 12-15, 2003. (http://www.gasification.org/Docs/2003_Papers/28GRIF.pdf)

even until the plant is successfully commissioned, even for relatively standard plant. Operating costs, including extra fuels, cannot be predicted with any reliability.

Indicative shortfall values are probably 2-4p kWh for initial full-scale deployment plants. It is recommended that the shortfall for these first-deployment 'Phase 1' CCS projects is met through a project-specific support scheme, since a flat-rate approach would tend to encourage multiple installations of similar technologies rather than the more diverse range required for demonstration. A flat rate of support would also not be able to take advantage of site-specific features that give reduced, or increased, costs. It should be recognised that the main objective for Phase 1 is not to achieve CO₂ emission reductions at the minimum cost, but to help open up a viable CCS option, for the UK and globally.

Project developers would be invited to bid for support, on either on a p/kWh basis or a tonne of CO₂ abated (stored) basis, for a limited number (approx. 4) of projects to meet a suggested total of about 2GW of CCS generation. Bids would be assessed on relevance for likely future UK and global needs and the need to achieve diversity as well as cost. Support terms would have to extend for at least 15 years from project commissioning date to ensure 'bankability'. This is out to perhaps 2025-2030, so it is quite likely that the price of carbon would be high enough over this period to cover CCS costs, provided the EU ETS legislation and national allocation procedures allow it to be applied to Phase 1 plants. In this case, the support contracts should allow for the support payments to be suspended and even for a fraction of any excess plant revenue from carbon abatement to be paid back. It may also be desirable to include a support cancellation option that would allow projects to be terminated before the original time limit, with the plant converting (relatively easily) to operation without CCS.

Support payments for Phase 1 CCS plants should be financed on a similar basis to ROCs, effectively by imposing a general levy on electricity generation.

24. Under what conditions might it become profitable?

Response to 24: The use of CCS might, in principle, achieve adequate profit margins from 2013, if caps in EU ETS phase 3 are sufficiently tight to give sustained higher carbon prices and global oil and gas prices do not collapse. Expected electricity plant closures around 2015 would also help to make new CCS plant more competitive. Even then, however, some longer term indications that there will be continued pressure to reduce carbon dioxide emissions, with clarity on how CCS plants will be treated under the emissions trading scheme, will be required to give a bankable assurance that the investment and operating costs of CCS could be recovered.

25. What is the impact of the current policy framework on the development of CCS?

26. Are there any particular issues that need to be taken into account with regard to CCS when considering the use of policy mechanisms to reduce CO₂ emissions in the UK economy?

Response to 25 and 26: The current policy framework will need a number of modifications, many of which are already being developed, such as modifications to the London Protocol and OSPAR Convention, as well as the Petroleum Act 1998.

UK CO₂ policy is also directed at achieving global CO₂ emission reductions. CCS is particularly important in this context for use in key coal burning economies such as China, India and the USA. Because the UK is leading on achieving actual CO₂ reductions (and not just undertaking research) it is feasible for initial full scale CCS deployment for power generation in the UK to lead most of the rest of the world by perhaps 5 years. Early full-scale plants would both demonstrate the technologies and provide a positive confirmation of the UK's support for this technology and the principle of achieving the large and rapid cuts in CO₂ emissions that CCS enables.