

CARBON CAPTURE AND STORAGE

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While the Office of Science and Innovation commissioned this review, the views are those of the authors, are independent of Government and do not constitute Government policy.

Abstract

CCS is currently considered to be technically feasible at a commercial scale using a range of technologies. A number of electricity generation projects with CCS have been proposed and, if implemented, should allow the learning-by-doing that is required for these technologies to be developed. A key research objective will be capital and operating cost reduction, particularly for CO₂ capture processes.

The three main technologies currently proposed for CO₂ capture are post-combustion capture from conventional flue gases, pre-combustion capture after shifting carbon monoxide to carbon dioxide and hydrogen and oxyfuel combustion, in which the fuel is burned in oxygen to give CO₂-rich combustion products. Performance and costs are currently predicted to be similar for all three techniques. A wider range of other methods, such as chemical looping or high-temperature membranes, could be applied to CO₂ capture from natural gas but it remains to be seen whether future gas prices are low enough to make capture attractive.

The critical factors in geological storage are site potential for CO₂ injection, the design of EOR projects offshore, the displacement of ambient porefluids and monitoring and assurance on leakage. Rapid leakage paths, the most likely of which are failed wells, present an obvious re-emission problem but as such are likely to be identified and remediated quickly. These technical issues will contribute to developing appropriate legal and regulatory frameworks and public understanding and acceptance.

Current status and barriers

Carbon capture and storage (CCS) is currently considered to be technically feasible at commercial scale using a range of technologies. In addition to existing CO₂ injection activities in the oil and gas industry,¹ 11 technically feasible electricity-generation projects with CCS producing 275 megawatts (MW) or more and proposed to start between 2009 and 2016 are listed in Table 1. None of these projects is considered to require any scientific breakthroughs. Given the lead-time required for design and construction, they must be based on existing technology. But none of these projects has yet been confirmed either. The principal barriers to deployment are the lack of:

- a market mechanism that is sufficiently large and long-term enough to reward carbon abatement using CCS
- a legal framework for transport and geological storage of CO₂ (particularly for offshore storage²).

A number of research and development activities to develop technologies which would contribute to CCS implementation can be identified, including actions to reduce costs (particularly for CO₂ capture) and to assure identification, performance and monitoring of appropriate storage sites. However, these barriers cannot be overcome solely by 'enabling' technological improvements. CCS, however advanced, will always incur additional costs beyond unabated use of fossil fuels and will only be implemented if these costs can be justified for the lifetime of the project by the large CO₂ emission reductions that can be achieved. Similarly, irrespective of the scientific confidence associated with injection of CO₂ into appropriate geological formations, the extent to which it is a financially viable emission reduction activity is governed by the legal and regulatory framework for emissions accounting and trading that is in place.³

Technological advances can complement policy developments to overcome these barriers, principally by reducing the costs and risks involved. The main element of CCS cost is the cost of capture, and therefore this will receive the most attention in this paper. But, since many advances can be realised only through 'learning by

¹ For example, Statoil's Sleipner and Snohvit projects; BP's In Salah project, all aquifer injection of CO₂ that has to be separated from natural gas to allow export of that gas. Also, CO₂ injection for EOR (but not storage) has been standard practice in the Permian Basin in Texas for decades.

² Although progress is being made on including sub-sea geological storage in the London and OSPAR regulatory regimes negotiations are still ongoing. It is expected that a proposal to amend London Convention Protocol will be placed in autumn 2006.

³ For example, under current laws the Norwegian Sleipner project is legal and gains exemption from national carbon taxes and also reduces Norway's national inventory of CO₂ emissions, but it would not be eligible for consideration as a JI project under Kyoto since CCS is currently not recognised. Similarly, the Peterhead/Miller project would be legal, since the CO₂ is sent offshore for EOR and could reduce the UK inventory total but would not currently be eligible for inclusion in the EU Emission Trading Scheme (EU ETS), nor could any of the CO₂ be sent offshore simply for storage under the current rulings of the OSPAR and London Conventions.

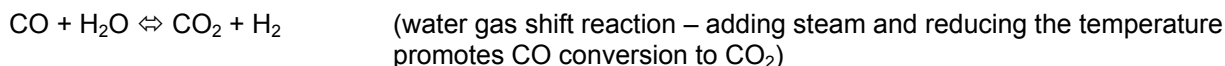
doing', some early deployment will have to take place while the barriers are still relatively high. Complying with proposed CCS regulations will also be easier with improved monitoring technology.

A comprehensive review of carbon dioxide capture and storage was recently prepared (Metz et al. 2005) for the Intergovernmental Panel on Climate Change (IPCC). This is an extremely valuable and detailed reference document but, because it was based on a consensus of peer-reviewed literature, it reflects the understanding of perhaps an average of three years ago. Particularly in the field of CO₂ capture, however, technology concepts and their evaluation have been moving rapidly, so some detailed conclusions have already been superseded (for example, IEA GHG 2006a).

CO₂ capture technologies

Operating principles for the three main technologies currently proposed for CO₂ capture are shown in Figure 1. In post-combustion capture, a new final processing stage is applied to remove most of the carbon dioxide from the combustion products just before they are vented to atmosphere. The most commercially advanced methods use wet scrubbing with aqueous amine solutions. CO₂ is removed from the waste gas by the amine solvent at relatively low temperatures (order 50°C). The solvent is then regenerated for re-use by heating (to around 120°C), before being cooled and recycled continuously. The CO₂ removed from the solvent in the regeneration process is dried, compressed and transported to safe geological storage.

Pre-combustion capture of CO₂, the second method, is in some ways an oxymoron because CO₂ is obviously not normally available for capture prior to combustion. All types of fossil fuels can, however, be gasified (partially combusted, or reformed) with sub-stoichiometric amounts of oxygen (and usually some steam) at elevated pressures (typically 30 to 70 atmospheres) to give a 'synthesis gas' mixture of predominantly CO and H₂. Additional water (steam) is then added and the mixture is passed through a series of catalyst beds for the 'water gas shift' reaction to approach equilibrium.



The CO₂ can be separated to leave a hydrogen-rich fuel gas. The separation process will typically use a physical solvent; CO₂ is dissolved at higher pressure and then released as the pressure is reduced. Because no heat is required to regenerate the solvent and because the CO₂ can be released at above atmospheric pressure, the energy requirements for CO₂ capture and compression in pre-combustion capture systems may be of the order of half that required post-combustion capture. But pre-combustion capture systems also have to pay an efficiency penalty for the shift reaction and for the lost mass of CO₂ that does not pass through the turbine and generate power, whereas the CO (combusted to CO₂) would do so in the equivalent plant without capture. The efficiency of hydrogen-burning gas turbines is also lower than conventional natural gas or syngas units; heat transfer coefficients are higher for combustion products from hydrogen-rich fuels and turbine inlet temperatures must therefore be lower to achieve the same metal temperatures. For solid and liquid fuels, additional efficiency losses are incurred during gasification, particularly for the most cost-effective gasifier designs in which the hot products are cooled by a simple water spray (which saves the cost of a very high-temperature heat exchanger and also adds additional water for the shift).

As a consequence, post-combustion capture on coal using best current commercial technologies (e.g Fluor Econamine Plus or Mitsubishi Heavy Industries KS1 on advanced supercritical steam plants) are currently predicted to have higher thermal efficiencies for conversion to electricity than pre-combustion integrated gasification combined cycle (IGCC) designs (Table 2). Post-combustion capture also appears likely to give lower total electricity costs than pre-combustion capture for natural gas plants (Figure 2). In contrast, pre-combustion capture from IGCC plants is currently predicted to produce low-carbon electricity slightly more cheaply from coal, due to the high capital costs for current atmospheric pressure post-combustion absorber designs and the cost of replacing degraded solvent. It is important, however, to realise that all costs are estimates that can be expected to change as experience is gained with real plants. It is also likely that rates of learning, and hence cost reductions, will differ between technologies (IEA GHG 2006b).

Oxyfuel combustion options for gas and coal are also shown in Table 2 and Figure 1. In these plants, the main separation step is oxygen from nitrogen. The fuel is then burnt in a mixture of oxygen and recycled flue gases (the latter to replace the nitrogen in air and thus moderate peak flame temperatures to take account of materials

and ash slagging constraints in boiler design etc.). This gives a mixture of mainly CO₂ and condensable water vapour, which can be separated and cleaned relatively easily during the compression process. For coal, oxides of nitrogen and sulphur (NO_x, SO_x) and other pollutants must be removed from the product gas before or during the CO₂ compression process. In addition, SO_x may also have to be removed from the recycle stream (to prevent high-temperature corrosion in the boiler furnace). Oxyfuel combustion options for natural gas combined cycles using current cryogenic distillation technology for oxygen production appear to be uncompetitive, even without allowing for the development costs for a completely new gas turbine design (see Table 2). New designs must also be developed for pulverised coal oxyfuel combustion boilers (although the steam turbine and alternator would be essentially unchanged). In contrast to gas-fired plant, these appear to have the potential to give efficiencies and costs that are competitive with amine-based post-combustion plant and a number of boiler manufacturers and utilities are already working in this area (e.g. Mitsui Babcock, E.On, Vattenfall).

CO₂ geological storage

Geological storage of CO₂ relies on injection at depths of more than 1 km. Temperatures will be above the critical value for CO₂ (31°C) but pressures are high enough (order 100 atmospheres and above) to give densities of the order of 500 kg/m³. CO₂ may be placed into oil reservoirs, where it can also give enhanced oil recovery (EOR), into abandoned gas fields, or into deep saline aquifers. Total UK offshore storage capacity for regions assessed to date is at least 20 GtCO₂ in depleted oil and gas fields and saline aquifers, representing approximately 40 years of total UK emissions at current rates (Gibbins et al. 2006). Storage capacity in all accessible saline aquifers is expected to be equivalent to several centuries of current total UK CO₂ emissions.

The critical factors in geological storage are the potential for CO₂ injection, the design of offshore EOR projects, the displacement of ambient porefluids, monitoring to EU standards and assurance on leakage. Rapid leakage paths, the most likely of which are failed wells, present an obvious re-emission problem but as such are likely to be identified and remediated relatively quickly. Lower rates of seepage, through unforeseen permeable faults, for example, may cause local damage in the terrestrial or marine environment. Additionally, even at low rates (order 0.1% of stored volume per year) such seepage may ultimately lead to increases in atmospheric CO₂ concentrations compared to schemes where this does not occur. Key enabling technologies for geological storage are:

- directional and horizontal drilling to give cost-effective injection of CO₂, even into relatively impermeable strata, from a limited number of central facilities (particularly for offshore storage)
- modelling techniques to
 - predict deep groundwater displacement
 - provide fundamental identification and quantification to predict CO₂ migration and dispersion
 - describe geochemical processes to predict CO₂ distribution and eventual immobilisation, in a wide range of geological rock formations and structural settings
- seismic and other imaging techniques to monitor CO₂ location underground
- borehole logging and smart monitoring techniques to give early warning of seepage.

A comprehensive review of monitoring technologies for the geological storage of CO₂ has recently been published by the DTI (Department of Trade and Industry 2006). Many techniques developed for the oil and gas industry can be applied to modelling and monitoring CO₂ storage, although it was concluded that 'a key requirement is to test these technologies in combination at a variety of storage sites so that their strengths and weaknesses can be evaluated in real situations, and optimal strategies developed'; another example of the need for 'learning by doing' to progress CCS. New developments for monitoring reflect a requirement for low-cost, long-term observations by instruments that can be left in place for a number of decades and operate semi-autonomously, including borehole and sub-sea CO₂ sensors and pH sensors. There is also a need to develop passive seismic monitoring using multiple long-term sensors, such as resistivity or gravimetric monitoring. These may be able to give enhanced resolution of CO₂ dissolved in groundwater, which is difficult to resolve seismically. The response of sea-bed marine and terrestrial biological communities to slow leakage of CO₂ also needs to be assessed; this could aid in the early detection of leaks.

Once further practical experience from CO₂ storage projects is available, it is likely that the basic additional requirements for modelling and monitoring will be developed into useable forms relatively quickly. In line with oil and gas industry experience, however, and helped by progress in other areas (e.g. electronics, materials, computing, oil and gas extraction) continuous improvements can be expected through to 2050 and beyond,

reducing costs and giving more detailed information on CO₂ movements and interactions with the geological and, occasionally, surface environments. Different geological contexts will also require the development of specialised approaches through experience.

Future advances in CO₂ capture technology to 2050 and beyond

The key advances for CO₂ capture technology over the next 50 years are likely to arise from an adoption of CCS as standard practice for all large stationary fossil-fuel installations, as is now the case for other pollutants. A parallel transition to the use of decarbonised energy vectors (electricity and hydrogen) in applications such as domestic heating (e.g. fuel cells, heat pumps) and ground transport (e.g. fuel cell or plug-in hybrids) that now use hydrocarbon gases and liquids will have to take place to achieve large reductions in CO₂ emissions. Decarbonised energy vectors can be produced by a variety of means but, for an extended transition period, fossil fuels, and particularly coal, could be a relatively low-cost and environmentally sustainable source in locations with access to suitable CO₂ storage. CCS will also be applied, starting in the short to medium term, to minimise CO₂ from fossil-fuel industries (e.g. LNG production, oil sand processing and coal-to-liquid plants), but these applications are at best only a transition, and perhaps a learning, measure. Even with CCS to reduce emissions during production, long-term reliance on such carbon-based energy vectors for all but 'essential' uses (e.g. air travel, emergency and military vehicles) is clearly inconsistent with stabilising atmospheric CO₂ at safe levels.

Biomass may also be used increasingly in CCS plants, probably mostly in conjunction with fossil fuels where co-firing or co-gasification of biomass can give economies of scale and even out natural supply fluctuations. This can both convert the energy content of the biomass into a more useable form (at an improved conversion efficiency vs. most stand-alone utilisation, because of the scale) and removes most of the carbon in the biomass from the atmosphere. The latter benefit can, for example, be used to offset the use of liquid fuels in the premium applications noted above.

Hydrogen will tend to be made by gasifying lower-value fuels, probably coals and heavy (or residual) oils and bitumens (i.e. not natural gas and other clean, hydrogen-rich hydrocarbons), and biomass. Gasification and associated shift, gas cleaning and CO₂ capture technologies will be improved incrementally to give much greater reliability and reduced costs, but no major breakthroughs are expected. Hydrogen could be converted to electricity on the spot, or be transported for direct use elsewhere; this depends on developments in end-use applications (e.g. hydrogen storage vs. batteries for road vehicles). It is likely, however, that hydrogen production would always most advantageously be combined with some electricity production (plants where this occurs are often called polygeneration plants, although examples that produce mainly environmentally benign decarbonised energy vectors should not be confused with polygeneration plants producing carbon-rich products such as synthetic liquids – these are better described as coal-to-liquid plants etc.).

Where only electricity is required from a gasifier-based system, an IGCC would be used. The US National Energy Technology Laboratory (NETL) has commissioned a study of possible improvements in IGCC technology, with and without CO₂ capture (Gray et al. 2004). These changes were stated to be taking place up to 2020, but a longer period (e.g. to 2030) is possible. Beyond that, cost improvements could be expected but little further scope exists for efficiency or availability improvements. Absolute changes are shown in Table 3, relative changes in Figure 3. The best cost reductions arise from incremental improvements: in gasifier load factor, instrumentation, materials and methods of construction. Historically well-understood changes, to two-stage gasification and dry feed, also achieve some improvement, as does the use of the latest gas-turbine technologies (through incremental combustor and cooling developments for the use of syngas). 'Breakthrough' ion transfer membrane (ITM) technology for oxygen production could achieve fairly large cost reductions but, despite giving a large improvement in efficiency, the move to a solid oxide fuel cell/gas turbine hybrid does little to improve operating costs.

Equivalent performance with CO₂ capture at three stages in gasifier development is shown in Table 3 (Cases 12–14). In Case 12, a 'conventional' shift process is assumed with about 85% CO₂ capture. In Cases 13 and 14, a special oxyfuel combustion system for the syngas gives 100% CO₂ capture. Interestingly, although absolute costs of electricity with capture fall, the efficiency penalty stays constant at 6–7 percentage points and the relative increase in the cost of electricity with capture stays in the range 20–30%, highlighting that CCS will always result in additional cost, despite technical progress. Further cost reductions might, however, be achieved by using the very compact high-temperature 'rocket-burner' oxyfuel 'steam' turbine system being developed by

Clean Energy Systems in place of the fuel cell/turbine hybrid, although this could not readily be integrated with an ITM oxygen unit.

Pulverised coal (PC) systems will be built in significant numbers for at least the next 10 years and these new plants are likely to remain in use until 2050 for electricity production from coal, because of their flexibility and general RAMO (reliability, availability, maintainability and operability) advantages. In the future, PC units (especially if built as 'capture-ready') may be retrofitted with capture equipment rather than being retired early or used only for peaking capacity, once appropriate developments in technology and market incentives for CCS have been established. For new build beyond 10 years, although the basic PC technology has been in use for nearly a century, the change from ferritic steel to nickel alloys for high temperature components and consequent change in peak cycle temperatures from ~600°C to 700–750°C would allow significant further increases in power plant efficiencies (~45% to ~50% LHV) without capture. Thus, if capital costs for oxyfuel or post-combustion capture systems fall, these plants could be competitive for some time. Improved solvent systems for multi-component removal (SO_x, NO_x, Hg, CO₂) are also being considered (e.g. Alstom chilled ammonia, CANSOLV amine) and these may have the potential to give significantly reduced capital costs as well as somewhat lower energy penalties. An important external factor determining the relative competitiveness of PC and gasification-based systems could be the emergence of a demand for hydrogen, which would clearly favour the latter.

A wider range of technologies, including chemical looping or high-temperature membranes, could be applied to CO₂ capture from natural gas, because of its clean-burning properties (Metz et al. 2005), but it remains to be seen whether future gas prices are low enough to make capture from gas power plants attractive before 2050.

Conclusions

CCS is currently considered to be technically feasible on a commercial scale using a range of technologies. A number of technically feasible electricity-generation projects have been proposed and, if implemented, should allow the 'learning by doing' that is required for technology to be developed so as to reduce the costs and risks currently associated with large-scale CCS schemes.

The three main technologies currently proposed for CO₂ capture are shown in Figure 1. A wider range of other technologies, such as chemical looping or high-temperature membranes, could be applied to CO₂ capture from natural gas, but future gas prices may not be low enough to make capture from gas power plants attractive before 2050.

Critical aspects of CO₂ geological storage activities have also been identified and discussed. Many other aspects of CCS project development have not been considered in detail in this paper, but are vitally important in ensuring that the technology available to allow CCS can be implemented. Particular challenges include the development of an appropriate legal and regulatory framework and developing public understanding and acceptance. The infrastructure for CO₂ transport from the capture plant to storage site also needs to be considered.

It is expected that most of the improvements in CCS technology will be incremental, initially based on problem solving at first-of-kind plants and related research and development activity. A key research objective will be cost reduction, particularly for CO₂ capture processes. However, it should be noted that plants operating with CO₂ capture will always have a higher cost of electricity generation than equivalent plants without capture. Thus, CCS will only be a commercially viable option in situations where the CO₂ emission reductions associated with this process are given an appropriate value.

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Table 1 Proposed full-scale (275 MWe and above) CCS power plant projects
(based on media reports, press releases and personal communication, therefore indicative only)

Company/ Project Name	Fuel	Plant output/cost	Capture technology	Start
Progressive Energy, Teeside, UK	Coal (petcoke)	800 MW (+ H2 to grid) (\$1.5bn)	IGCC + shift + precombustion	2009
BP/SSE DF1, Peterhead/Miller, Scotland	Natural gas	475 MW, (>\$600M)	Autothermal reformer + precombustion	2010
Powerfuel/Kuzbassrazrezugol Hatfield Colliery, UK	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	Coal (+petcoke?)	450 MW (£1bn)	IGCC + shift + precombustion? (may be capture ready)	2011
Stanwell, Queensland, Australia	Coal	275 MW	IGCC + shift + precombustion	2012
Futuregen, USA	Coal	275 MW	IGCC + shift + precombustion	2012
RWE, Germany Germany	Coal	450 MW (€1bn)	IGCC + shift + precombustion	2014
RWE, Tilbury, UK	Coal	~500 MW (£800m)	PC (supercritical retrofit) + post-combustion (may be capture ready)	2016

Table 2: Comparison of power stations with and without CO₂ capture (IEA GHG 2006a)

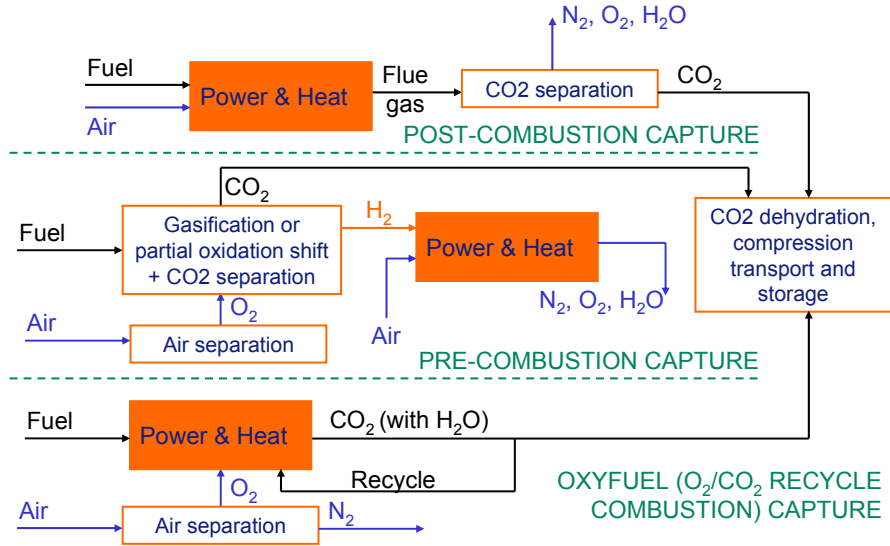
Technology	Thermal efficiency % LHV	Capital cost \$/kW	Electricity cost c/kWh	Cost of CO ₂ avoided \$/t CO ₂
Gas fired plants				
No capture	55.6	500	6.2	-
Post-combustion capture	47.4	870	8.0	58
Pre-combustion capture	41.5	1180	9.7	112
Oxy-combustion	44.7	1530	10.0	102
Coal fired plants				
No capture	44.0	1410	5.4	-
Post-combustion capture	34.8	1980	7.5	34
Pre-combustion capture	31.5	1820	6.9	23
Oxy-combustion	35.4	2210	7.8	36

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Table 3: Effect of technical developments on cost of electricity (COE), efficiency (LHV basis) and specific capital cost for IGCC plants with (Cases 1–11) and without (Cases 12–13) CO₂ capture (Gray et al. 2004)

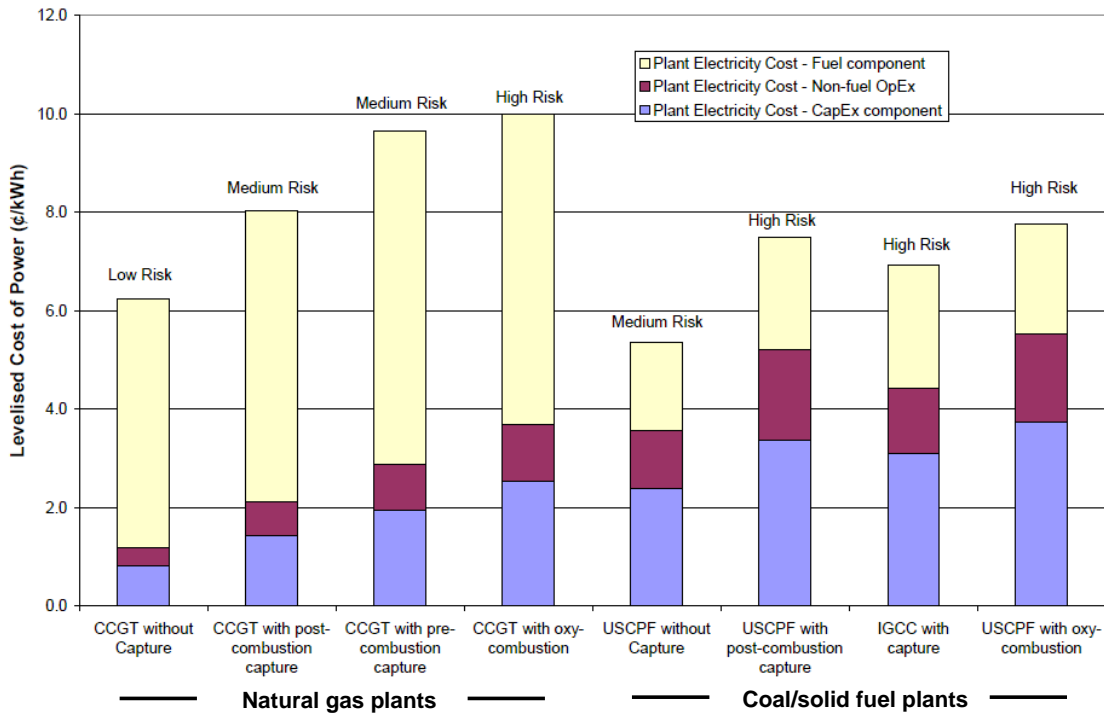
Case		COE (\$/MWh)	Efficiency (%LHV)	Capital (\$/kW)
1	Current technology	45.2	41.9	1,294
2	75% to 85% load factor	41.2	41.9	1,294
3	95% to 98% fuel conversion	40.6	43.1	1,279
4	Two stage gasification	39.4	44.8	1,241
5	Wet to dry feed	38.3	47.3	1,217
6	FB advanced gas turbine (vs F)	36.4	49.0	1,149
7	Advanced gas cleaning	34.6	50.2	1,086
8	Ion Transfer Membrane vs Cryogenic Oxygen Plant	32.7	50.6	1,027
9	85% to 90% load factor	31.5	50.6	1,027
10	H ultra-advanced gas turbine (vs. FB)	29.6	52.9	953
11	SOFC+turbine hybrid cycle	29.2	68.0	1,002
12	Case 1 with pre-combustion capture	56.99	35.9	1,656
13	Case 8 with oxyfuel turbine capture	43.04	43.7	1,377
14	Case 11 with oxyfuel turbine capture	35.42	62.6	1,242

Figure 1: Principles of three main CO₂ capture options



After Jordal, K. et. al. (2004) *Oxyfuel combustion for coal-fired power generation with CO₂ capture – opportunities and challenges* Proceedings of 7th International Conference on Greenhouse Gas Control Technologies, to be published, available online at www.ghgt7.ca

Figure 2: Costs of electricity for gas and coal power plants with and without CCS (IEA GHG, 2006a)



IEA GHG (2006), CO₂ capture as a factor in power station investment decisions, Report No. 2006/8, May 2006

Costs include compression to 110 bar but not storage and transport costs. These are very site-specific, but indicative aquifer storage costs of \$10/tonne CO₂ would increase electricity costs for natural gas plants by about 0.4 c/kWh and for coal plants by about 0.8 c/kWh.

Figure 3: Relative improvements in IGCC efficiency and cost of electricity from technical developments (Gray et al. 2004)

