

Carbon capture technology: future fossil fuel use and mitigating climate change

DR N FLORIN AND DR P FENNELL

Executive summary

What is carbon capture and storage?

Carbon Capture and Storage (CCS) refers to the set of technologies developed to capture carbon dioxide (CO₂) gas from the exhausts of power stations and from other industrial sources, the infrastructure for handling and transporting CO₂, and the technologies for injecting and storing the CO₂ in deep geological formations. All the individual elements operate today in the oil, gas and chemical processing sectors; however, their integration and scale-up for CO₂ capture from power plants in the next two decades is a major challenge, and the storage of giga-tonnes of CO₂ deep underground raises new issues of liability and risk. The focus of this Briefing Paper is on carbon capture; a companion paper addresses the challenges of storage.

Capture is the first and most expensive element in the CCS chain, imposing a significant parasitic energy penalty on the process, requiring about 20% more fuel to be burned for the same power output. For power plants, the capture step involves separating dilute CO₂ (3–15% by volume) from a gas stream, with nitrogen, water vapour and minor impurities comprising the balance. The near pure CO₂ is then compressed to high pressure (around 10 MPa) for transport to a storage site where it is injected into geological formations either deep underground or under the seafloor.

Why are we interested in CCS?

CCS is a transitional technology offering a near-term way of mitigating climate change, as progress towards a truly sustainable low-carbon energy system is likely to take many decades. Since we have to use fossil fuels while achieving large-scale global CO₂ emissions reductions in the next 30–40 years, CCS is an essential technology. Substantial additional investment is needed to deploy any low-carbon energy technology while meeting the projected growing demand for energy^{1,2}. These costs are expected to be considerably higher if CCS is not included in the low-carbon energy technol-

Contents

Introduction	2
Technology review	5
Research agenda	8
Reducing the efficiency penalty and the cost of capture	11
Capture technology specific RD&D programmes.....	12
From pilot to commercial-scale deployment	13
Policy issues and international context.....	15
Conclusions	16

Grantham Briefing Papers analyse climate change research linked to work at Imperial, setting it in the context of national and international policy and the future research agenda. This paper and other Grantham publications are available from www.imperial.ac.uk/climatechange/publications.

ogy portfolio¹⁻³. For energy security, the deployment of CCS in countries with very large indigenous fossil fuel reserves is important; equally, decoupling the use of coal from CO₂ emissions is attractive in terms of allowing a more diverse range of energy sources for countries heavily reliant on imported fuels⁴.

Why CCS is not just a synonym for ‘clean coal’?

CCS technology is most frequently discussed in the context of capturing CO₂ from coal-fired power stations; however, CO₂ capture from gas and biomass power stations is also possible. Biomass CCS could potentially result in negative CO₂ emissions—that is the net removal of CO₂ from the atmosphere. CCS is also a key strategy for “decarbonising” energy intensive industries, including: cement, oil refineries, iron and steel, gas processing, chemicals, and pulp and paper. These industries represent large sources of CO₂ emissions and are frequently difficult, or impossible, to decarbonise without fundamental changes to the processes.

CCS technology can potentially contribute to reductions from single source emitters; for example, in the building and transport sectors by increasing the use of decarbonised electricity or heat produced in power stations with CCS⁵. For, example, a decarbonised electricity supply could contribute to significant emission reductions in the transport sector with a shift from internal combustion engine vehicles to electric vehicles or hybrids².

The current state of CCS technology

The enormous challenge of achieving widespread commercial deployment of CCS cannot be overstated. The IEA CCS technology roadmap identifies the need for a hundred “large-scale integrated projects” (LSIPs) by 2020 to allow commercial deployment of CCS; forty of these would be in the power sector, and about half deployed in emerging economies⁶. Eighty LSIPs have been identified, which are at various stages of development, from preliminary scoping and screening to operating⁷. Nine out of the eighty are currently operating, two more are under construction. The majority of these projects inject the captured CO₂ for enhanced hydrocarbon recovery, which enables additional oil and gas to be recovered from depleted reservoirs. These applications may not achieve net CO₂ storage assuming the hydrocarbons recovered are burned and that it is not viable to capture the associated emissions⁸. Thus, it is important that life cycle assessment is used to determine the mitigation potential of these and other CCS projects. CO₂ injection for enhanced hydrocarbon recovery is discussed in a separate Grantham Institute Briefing Paper on storage. In terms of the application of CCS in the power sector – where it is possible to avoid more than 90 % of the CO₂ emissions – forty four projects are planned with major efforts in North America, the European Union, Australia and a few projects in emerging economies, including in China^{7,9}.

Non-technical challenges

Credible policy and regulatory frameworks are needed to manage the economic, health and environmental risks associated with full-scale demonstration and deployment phases if CCS is to gain public acceptance across the globe. Public perceptions will likely be formed based on the performance of the demonstrators, and early failures may have serious implications for the credibility and estimated cost of CCS as a major mitigation option¹⁰.

Forty four projects are planned in the power sector, with major efforts in North America, the European Union and Australia

Cost reduction is the major challenge for carbon capture technology because more fuel must be burned (about 20%) to produce the same amount of electricity, and thus, there are significant implications for fuel security which must be considered alongside emission mitigation strategies. A price for carbon emissions that is high enough to drive deployment is needed as well as more support for deployment in emerging economies.

The risks associated with carbon capture are generally considered less important than those associated with storage; however, inadequate consultation related to the location of capture and compression plants and transport infrastructure could potentially delay, or lead to a failure to deploy CCS at a sufficient rate to gain learning benefits from early demonstration.

Introduction

The global challenge of achieving the significant CO₂ emissions reductions necessary to mitigate climate change cannot be overstated. Far-reaching strategies must be deployed to achieve reductions in every sector, including: improving the efficiency of energy transformation, improving end-use energy efficiency, increased use of renewable energy sources, increased use of nuclear power, behavioural and lifestyle changes to reduce demand, as well as carbon capture and storage applied to power generation and industry (CCS)—the focus of this Briefing Paper.

The energy sector accounts for the biggest share of anthropogenic GHG emissions, mostly CO₂ as a by-product of fossil fuel combustion¹¹. Coal, which has the highest emission intensity of conventional fossil fuels, is also the fuel whose rate of utilisation is increasing the greatest. The relationship between energy demand and CO₂ emissions is reflected in the increasing trend in CO₂ emissions from fossil fuel combustion (including coal, gas and liquid fuels), as shown in Figure 1. The exponential increase in CO₂ emissions is a consequence of rapid industrialisation, ignited by the industrial revolution in the “west”, sustained by its spread to the rest of the world – especially India and China – and with additional demand owing to the electronic revolution and globalisation of the late 20th Century.

The deployment of CCS technology in the power and industrial sector is therefore important to help mitigate climate change in the near-term (2020s) and to provide energy security, by decoupling CO₂ emissions from fossil fuel usage, and allowing a more diverse range of fuels and energy supply lines to meet a demand that cannot be met on this timescale by renewable and nuclear energy. In the longer-term, CCS can support a transition to a sustainable energy future recognising that at any rate of improvement in energy efficiency and increase in the use of renewable energy sources, CCS will be critical in curtailing emissions from the necessary continued and extensive use of fossil fuels in the next few decades at least.

Substantial investment is needed to deploy any low-carbon energy technology while meeting a growing demand for energy: the IEA estimate the total investment required between 2010 and 2050 to be about USD 316 trillion, which is 17% more investment compared to their Baseline reference scenario whereby CO₂ emissions double². According to the IEA ‘Blue Map scenario’, to achieve a 50% global CO₂ reduction by 2050 at lowest cost, about one fifth of the total reductions in CO₂ emissions (projected total for 2050 – 43 Gt) is required from the application of CCS to power generation, industry and fuel transformation (Figure 2).

With the exception of enhanced hydrocarbon recovery, there is currently no significant market for CO₂ relative to the quantity generated from fossil fuel usage. In the longer term, as an alternative to CCS, there is interest in using CO₂ as a renewable feedstock, displacing petrochemicals, e.g. CO₂ can in principle be used for production of chemicals such as plastics and fuels such as methanol¹³. For the production of fuels from CO₂, to be a viable mitigation option, it is important that the overall energy balance is considered, as well as the downstream emissions when the fuels are used. Such a route is currently only at the stage of research feasibility and decades behind CCS in terms of proven technology.

To have a meaningful effect on global CO₂ concentrations, most CO₂ will need to be stored in safe geological structures, such as saline aquifers, where no revenue can be generated by the recovery of hydrocarbons. The capital investment for new plant and operating costs for separating, compressing, transporting and storing the CO₂ will impose a considerable economic burden on the power sector or industrial processes. Thus, CCS deployment in these sectors will only occur with policy and regulatory frameworks designed to provide an incentive for investment, or which introduce a penalty associated with emitting CO₂ (CCS policy issues are discussed below.)

All the key technical elements for CCS are available now, and in a few cases CCS is commercially viable, albeit for niche applications where revenue can be generated from enhanced hydrocarbon recovery (in the oil and gas sectors), or where unique taxes apply, e.g., Norway.

The range of important CCS applications are shown in Figure 3,

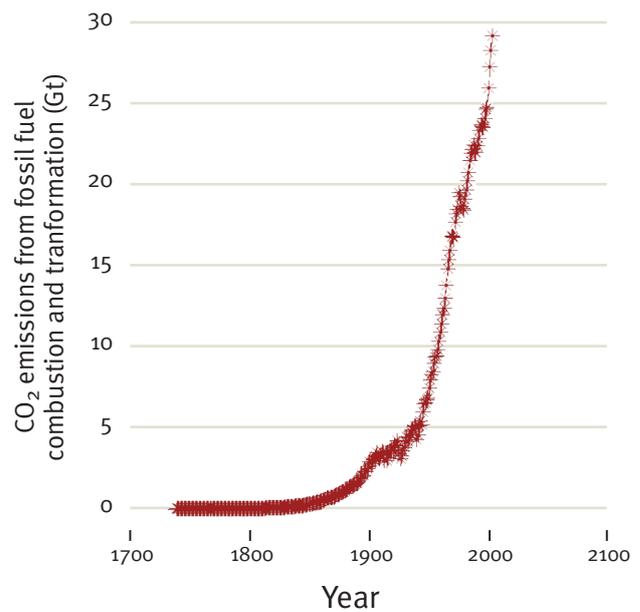
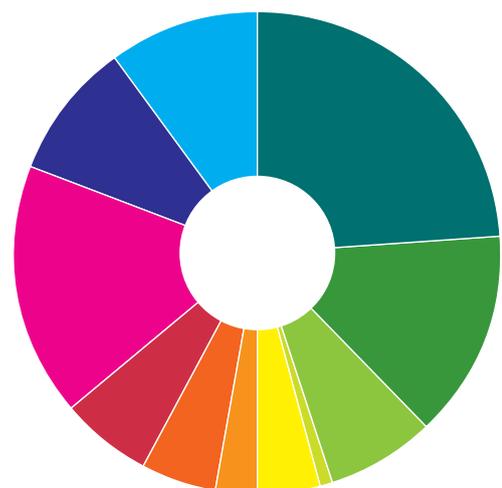


Figure 1. CO₂ emissions from fossil fuel combustion, and fuel transformation¹²



- End-use fuel efficiency 24%
- End-use electricity efficiency 14%
- Electric vehicles 7%
- Other electrification 1%
- Fuel cell vehicles 4%
- Other end-use fuel switching 3%
- Power generation efficiency & fuel switching 5%
- Nuclear 6%
- Renewables 17%
- CCS industry & transformation 9%
- CCS power generation 10%

Figure 2. CCS applied to power generation, industry and fuel transformation provides about one-fifth of the lowest-cost GHG reduction in 2050 according to the IEA Energy Technology Perspectives 2010².

Carbon Capture and Storage

- CO₂
- Electricity
- Gas
- Coal and Biomass

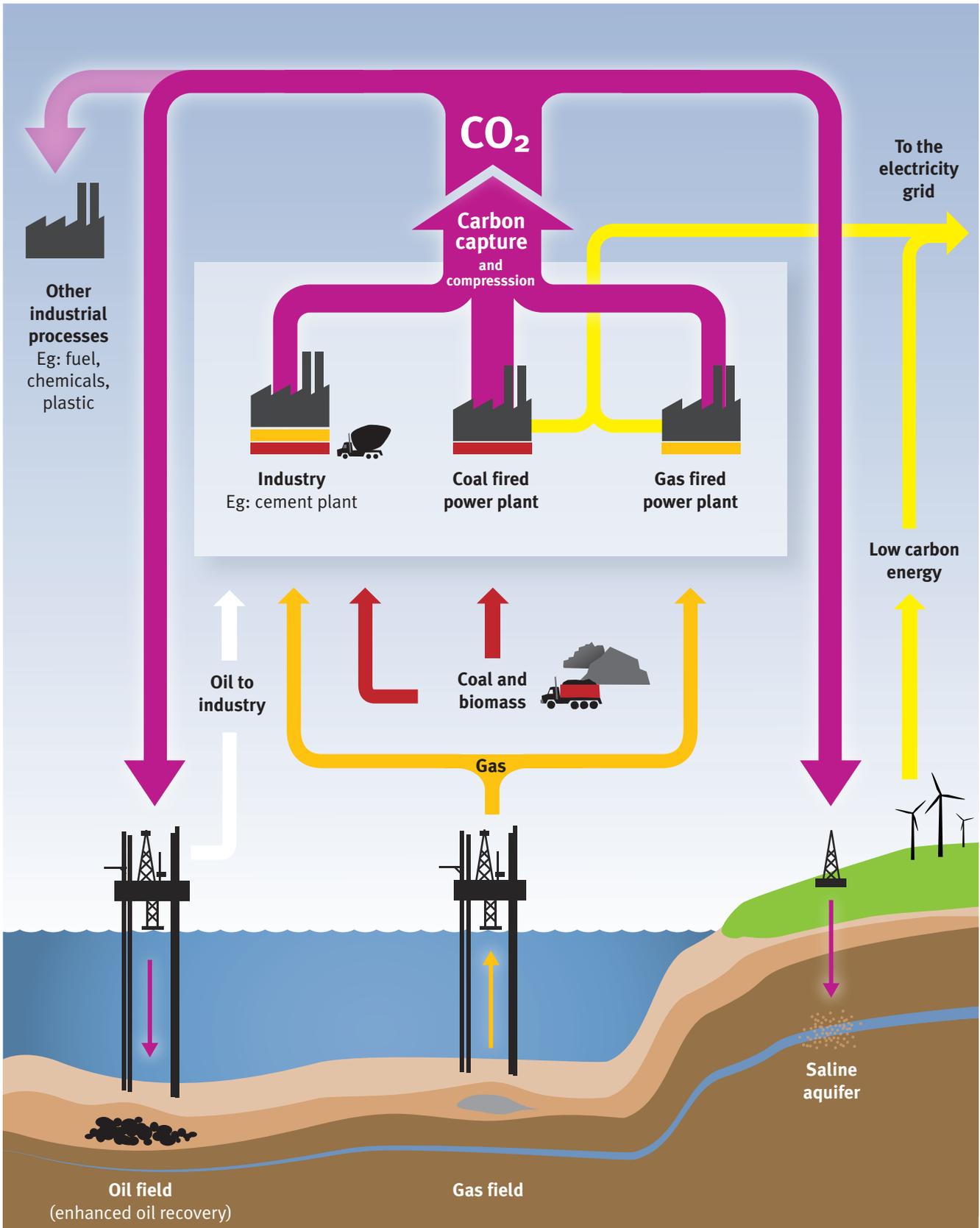


Figure 3. Diagram of CCS chain from capture to storage

including CO₂ sourced from the use of coal, gas and biomass for power and industry; and storage in geological forms, such as saline aquifers and depleted oil and gas fields. Industry specific issues are discussed below in the context of cement plants and oil refineries, which after the power sector, are ranked 2nd and 3rd highest in terms of CO₂ emissions from stationary sources (Box 1). Other major industrial contributors to global CO₂ emissions include the iron and steel, aluminium, and pulp and paper sectors. Thus, there is significant potential for CCS to contribute to emissions reduction outside of the power sector; for example, according to the IEA Technologies Perspectives 2010, CCS applied to industrial emitters could represent 20% of the total amount of CO₂ captured using CCS technology in 2050².

The different applications of CCS have various emission reduction outcomes. For example, a coal-based synthetic liquid fuel production plant with CCS will still result in CO₂ emissions to the atmosphere if the fuel is burnt in the transport sector where capture may not be economically viable. On the other hand, a coal-fired plant with CCS that substitutes some coal with biomass could potentially result in negative emissions assuming

the emissions associated with cultivating and transporting the biomass is less than the amount absorbed from the atmosphere during its growth. Life cycle assessment is important to benchmark the different technology options in terms of cost, efficiency and emission mitigation potential.

Technology Review

The CO₂ capture technologies are categorised according to three main types: (i) post-combustion, (ii) pre-combustion and (iii) oxy-combustion.

Post combustion

Post combustion capture is an “end of pipe” technology which involves separating CO₂ from a flue gas consisting mainly of nitrogen, water, CO₂ and other impurities (sulphur oxides - SO_x, nitrous oxides - NO_x and dust). The inherent advantage of such a technology is that it is potentially suitable for retrofit without drastically affecting process operations, other than reducing the power output which is discussed below. The minimal impact on process operations may be particularly important in

Box 1. Some examples of CO₂ capture in non-power applications

Cement plants

Cement production is energy and resource intensive, a typical cement plant produces 1–3 Mt CO₂ per year compared to about 5 Mt from a modern 1000 MW coal-fired power plant²¹. The cement industry accounts for about 5 % of the global stationary emissions⁵. A large fraction of the CO₂ emissions (up to 40%) are from the combustion of fuel (e.g., coal, petroleum coke, waste oil, refuse-derived-fuel, sewage sludge) to heat the raw materials to the temperature at which they react to form cement; another 50% results from CO₂ bound in the raw materials (mainly from the production of CO₂ from the decomposition of limestone to leave calcium oxide), with the remainder of the emissions from electricity use in the plant and from transport²². As large CO₂ sources with typically high concentrations of CO₂ in the flue gas (15–30%), cement plants are prime candidates for CCS.

Post-combustion and oxy-combustion CCS technologies are most viable here, since pre-combustion only results in a 50% emission reduction, failing to address the CO₂ released from the raw materials. A number of alternative options for reducing emissions also fail to capture CO₂ from the raw materials, including: energy efficiency improvements and fuel switching (e.g., using refuse-derived-fuel to displace fossil fuel use). Furthermore, modern cement plants tend to have high energy efficiencies so thermal efficiency improvements will be small²¹.

A promising approach for capturing CO₂ from a cement plant utilises a CO₂ separation process known as carbonate looping

(discussed in detail in the Technology Research Agenda section)²³. The use of exhausted limestone-derived sorbent as a input for cement manufacture offers significant potential for synergy between a power station with CCS and the cement industry²⁴.

Refineries

CO₂ emissions from refineries account for about 4% of the global stationary emissions⁵, with a typical large refinery producing 1–4 Mt CO₂ per year²⁵. The main sources of emissions include: combustion of fuel in the furnaces and boilers used to produce heat for separation processes and for reforming and cracking of heavy hydrocarbons; the production of electricity and steam used at the refinery; and CO₂ emissions associated with hydrogen production. While the adoption of more energy efficient processes can result in some reductions, the nature of the refinery process, which is very energy intensive, means that inevitably considerable amounts of energy are consumed and large amounts of CO₂ are produced. A recent study by Shell Global Solutions International, based on a generic refinery, concluded that emissions from H₂ production processes (where the stream of CO₂ is highly concentrated and at high pressure suitable for pre-combustion technology) and post-combustion capture from the flue gases, together representing about 50% of the total emissions from a refinery, offer the ‘least-cost’ reduction potential. The remaining 50% of emissions, associated with many small sources with low CO₂ concentrations, and widely distributed around the refinery site, may be prohibitively expensive without technological breakthrough²⁵.

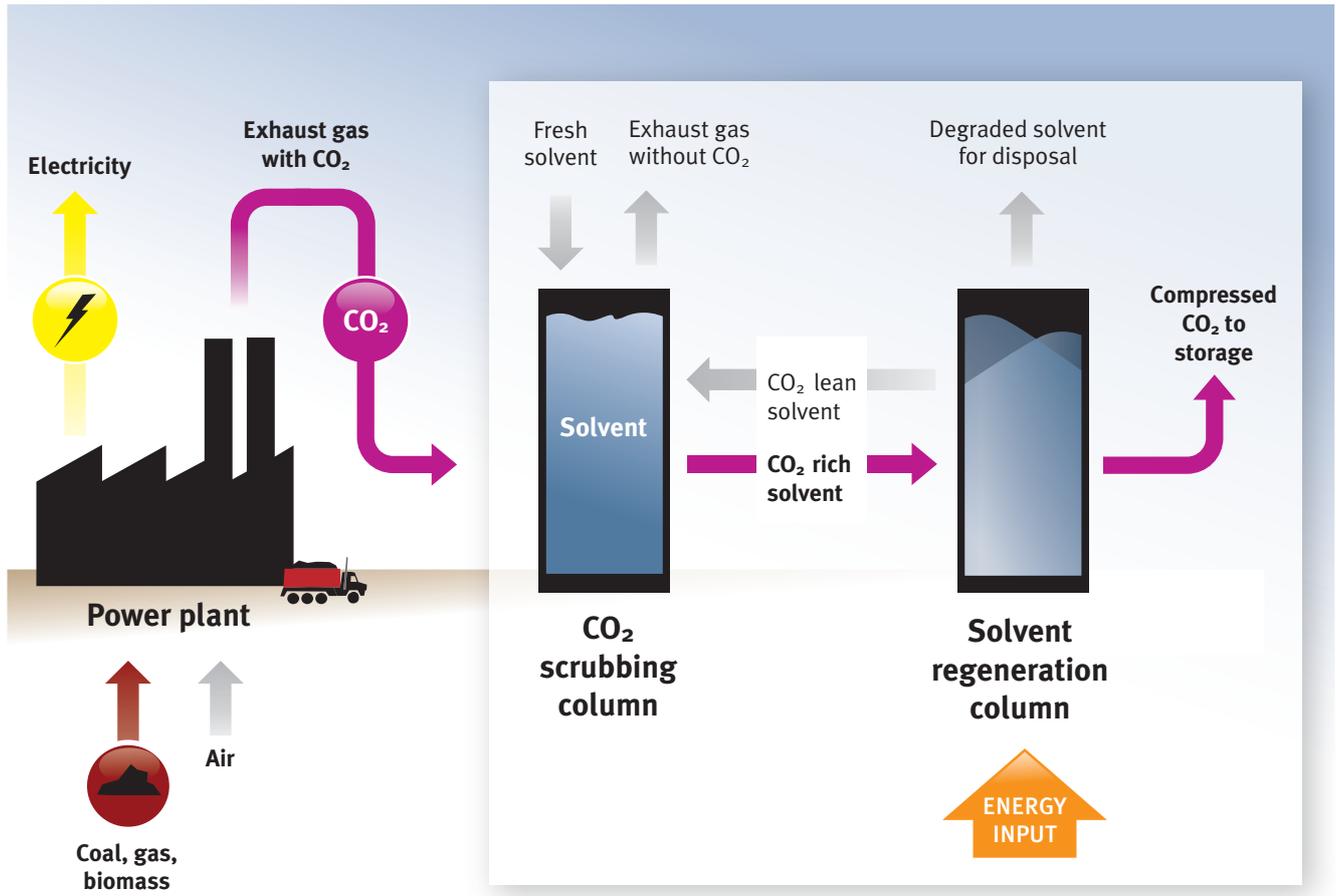


Figure 4. Post combustion capture process using amine-based solvents

the future with greater penetration of intermittent renewable power sources and new challenges in demand forecasting with the increased use of decarbonised electricity in the transport sector¹⁴. There is some concern about the degree of coupling between power and capture plants and there may be a trade-off in terms of flexibility and the amount of CO₂ captured in periods of high demand.

Solvent-based scrubbing, as applied to a power plant, is shown in Figure 4. First, the flue gas is cooled and cleaned of dust and other impurities, before contacting with a solvent in a “CO₂ scrubbing column” (kept at about 80°C, 0.1 MPa), which removes more than 90% of the CO₂ through absorption. Next, the solvent, now rich in CO₂, is passed to a “solvent regeneration column” (kept at about 120°C, 0.2 MPa) where heat transfer with hot steam, diverted from the power cycle, releases CO₂ from the solvent, resulting in solvent regeneration through the desorption process. In this way a nearly pure stream of CO₂ (over 99% of pure CO₂) is produced and the regenerated solvent is recycled. The CO₂ release and solvent regeneration process requires energy (otherwise used to produce electricity) and thus imposes an efficiency penalty on the process and results in a “de-rating” of the thermal efficiency of a generic modern power plant from about 45% to 35%^{5,16}, creating approximately a 20% reduction in the electricity generated. This

means more fuel must be burned and more CO₂ is released (although not emitted) in order to maintain the same power output.

Pre-combustion

Pre-combustion capture (Figure 5) involves a process called gasification whereby the fuel is reacted with insufficient oxygen (O₂) for complete combustion, producing a mixture known as synthetic gas or “syngas”, consisting mainly of carbon monoxide, methane, hydrogen and CO₂. Next, a series of reactions converts these gases to a mixture of CO₂ and hydrogen (H₂). After separating from the CO₂, the H₂-rich fuel gas can be used to fire a gas turbine or run a fuel cell. Operating flexibility is limited by the large capital cost of the gasifier meaning that it should be run at full load, constantly producing syngas. However, options such as gas storage (either H₂ or syngas), or potentially the production of liquid fuel from the syngas (taking into account the CO₂ emissions associated with the combustion of the fuel), may allow operation even during periods of low electricity demand. The conditions for CO₂ capture here are very different compared with post-combustion capture because the gas is already at elevated pressure (2–7 MPa) and the CO₂ concentration is significantly higher (15–60% by volume)¹⁷. Because of these conditions, a different range of solvents are used, known as physical solvents. Generally, physical solvents combine less strongly with

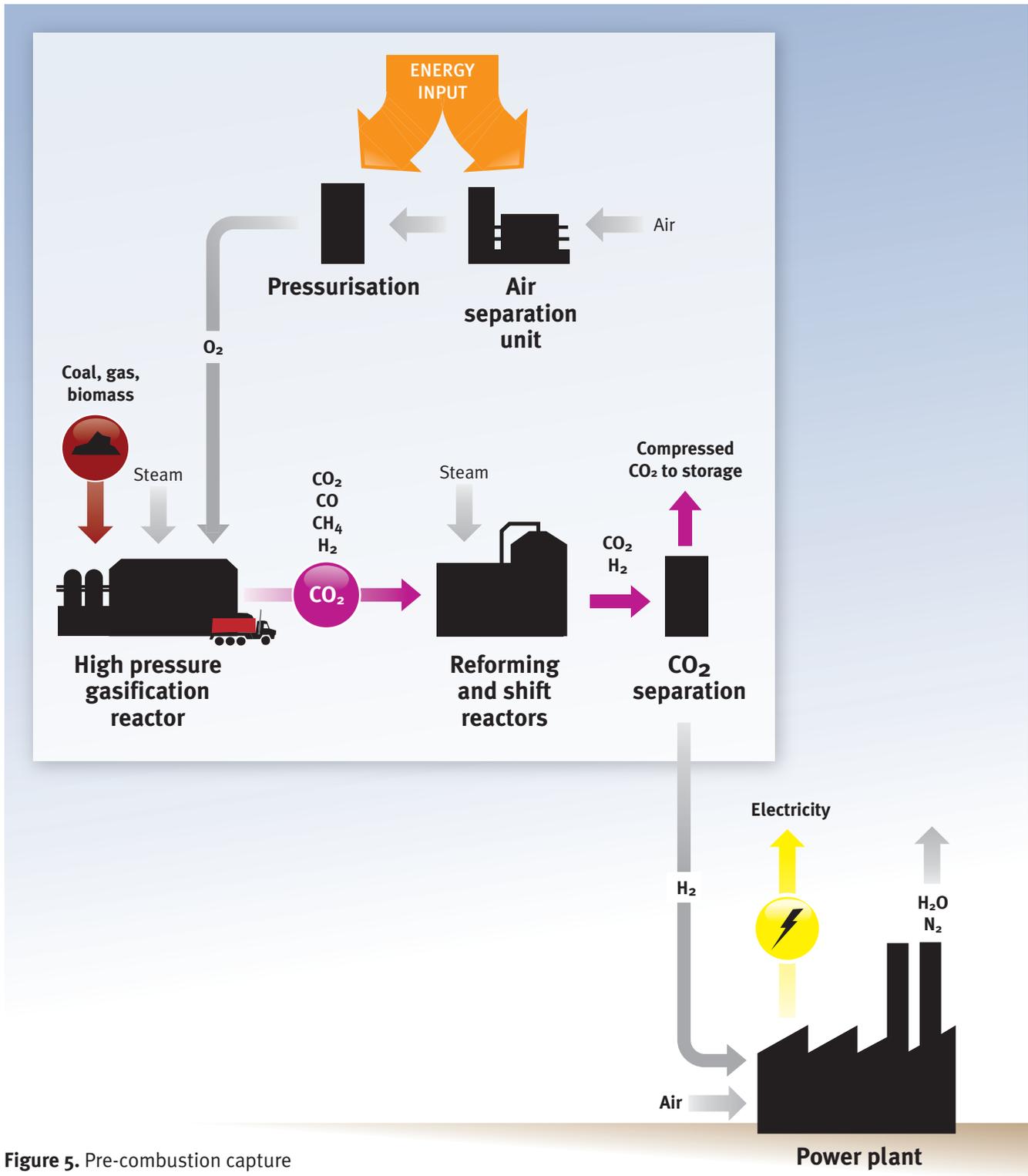


Figure 5. Pre-combustion capture

the CO₂ resulting in a lower energy penalty for desorption. The status of demonstration of this option is discussed in detail in the following section on the Technology Research Agenda.

Oxy-combustion

Oxy-combustion (Figure 6) involves burning fuel in a mixture of recycled CO₂ and pure O₂ instead of air and results in a flue gas that is composed mainly of CO₂ and water vapour, which is easily separated at low cost by the condensation process. Re-

cycling CO₂ produced by this process moderates the otherwise extremely high flame temperature in the boiler. The major cost and energy penalty owing to CO₂ separation in post- and pre-combustion processes is traded here for the costly and energy intensive oxygen production, typically by cryogenic air separation. The key advantages of this process are the potential for high CO₂ separation efficiencies and the relative simplicity of the method, which potentially allows for retrofit¹⁸. Flexible operation for oxy-combustion is limited by the rate of the air separation

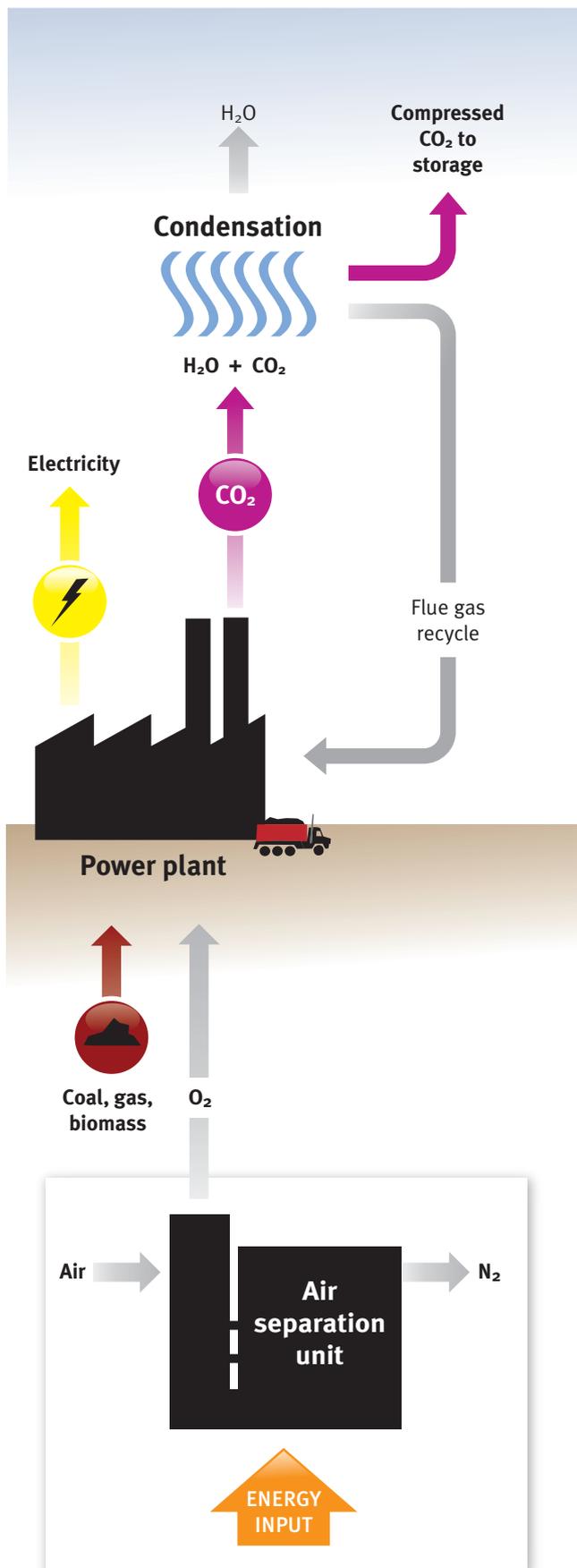


Figure 6. Oxy-fired capture

stage, making the possibility of intermittently switching to air firing desirable, though at the cost of stopping the CO₂ capture for this time period. One key challenge is the potential risk of ingress of ambient air into the boiler, typically operated at sub-atmospheric pressure, so reducing the concentration of CO₂¹⁹. Oxy-firing is also important for gasification technologies and a range of other advanced technologies (see below for more details)²⁰. On this basis, a breakthrough in terms of efficient oxygen separation is likely to represent a step-change in terms of process efficiency and a range of potential technologies have been identified, e.g. using polymeric membranes, high-temperature ceramic membranes, or O₂ production by chemical air separation¹⁹.

Technological Research Agenda

The CO₂ capture technologies discussed in this section are summarised in Table 1, including the main advantages and technical challenges. Technology readiness levels (TRLs) rank technologies between 1 (basic principles observed and reported), through intermediate levels (5 – technology or part of technology validated in a working environment), to a maximum of 9 (technology deployed). Technology levels in this Briefing Paper are based on an up-to-date assessment of peer-reviewed literature and major demonstrations of the technologies. Further details about TRLs are available²⁶.

Much research in basic **amine scrubbing** is focused on the design of new solvent molecules and/or blends of existing solvents, together with the mitigation of problems such as corrosion. These blends are of interest because it is possible to exploit the desirable characteristics of different solvents; for example, the high capture rate for primary and secondary solvents with the high ultimate CO₂ uptake for tertiary solvents¹³.

Alstom is developing the **chilled ammonia process**²⁷, which reportedly uses only 15% of the amount of steam consumed by monoethanolamine (MEA) for regeneration. However, electricity is required for refrigeration, such that the overall efficiency represents only a marginal improvement compared to amine scrubbing. The process operates at 0–10°C, meaning that it will be more efficient where cold cooling water is available and can also capture SO_x and NO_x, reducing system complexity. Furthermore this process allows regeneration of CO₂ at elevated pressure, reducing the energy penalty for CO₂ compression²⁷.

Amine impregnated solid sorbents are sometimes seen as the “next generation” of amine-based sorbents for CO₂ capture. Eliminating water from the system greatly reduces the amount of energy required for regeneration. Today there are commercially available solid amine sorbents which are used to remove CO₂ in closed environments such as submarines and space shuttles²⁸. Amines have been incorporated onto a wide range of substrates^{29–31}; however, this work has not progressed to testing in reactors capable of simulating realistic conditions

	Technology	Technical challenges
Post combustion	Solvent scrubbing, e.g. MEA, KS-1, MDEA, chilled ammonia (TRL = 6)	High energy requirements, high degradation rates, environmentally hazardous solvent degradation products, potential problems due to equipment corrosion, requires very large equipment
	Low-temperature solid sorbents, e.g. supported amines (TRL = 2–3)	Relatively low capture capacity, no experience under realistic conditions
	Ionic liquids (TRL = 2–3)	Very expensive, complicated manufacturing process
	Biological capture using algae ponds or bioreactors (TRL = 2)	Scale-up challenges due to growth rate of algae populations – may be overcome with genetically engineered species
	High-temperature solid sorbents, e.g. post-combustion carbonate looping (TRL = 4–5)	Drop-off in CO ₂ capture capacity of sorbent derived from natural limestone associated with exposure to impurities and physical decay
	Membrane separation technology for CO ₂ separation from flue gas (i.e. N ₂) (TRL = 2–3)	High cost of materials, life-time and reliability issues with to exposure to impurities, demonstration of large-scale pressure/vacuum equipment, efficient integration with power scheme
Pre combustion	Integrated gasification combined cycle with pre-combustion capture, e.g. Rectisol, Selexol and Fluor processes (TRL = 6)	Integration of CO ₂ capture system with power generation scheme
	Sorbent enhanced reforming using carbonate looping, incl. ZEC concept (TRL = 1–2)	Drop-off in CO ₂ capture capacity of sorbents, complexity due to high level of process integration
	Membrane separation technology for H ₂ separation from synthesis gas (TRL = 2–3)	High cost of materials, life-time and reliability issues with to exposure to impurities, demonstration of large-scale pressure/vacuum equipment, efficient integration with power scheme
Oxy combustion	Oxy-fuel boiler with O ₂ separation from N ₂ by cryogenic air separation (TRL = 5)	Costly and energy intensive air-separation, temperature moderation due to high flame-temperature when fuel is combusted in concentrated O ₂
	Chemical-looping-combustion using solid metal oxygen carriers (TRL = 4)	Degradation of oxygen carriers during long-term cycling, most significant when using coal or biomass
	Membrane separation for O ₂ separation from N ₂ with ion-exchange membrane (TRL = 2–3)	High cost of materials, life-time and reliability issues with to exposure to impurities

Table 1. Summary of the main CO₂ capture technologies

and the capture capacity of CO₂ currently demonstrated with supported-amines is low in comparison to alternative solid sorbents, e.g. calcium oxide (CaO).

Post-combustion capture using **high-temperature solid sorbents** is a promising technology and the leading candidate is **post-combustion carbonate looping** using calcium oxide

derived from natural limestone. Carbonate looping technology offers four key advantages³²: (i) low energy penalty; (ii) synergy with cement manufacturing; (iii) use of mature large-scale equipment, which reduces scale-up risk; and (iv) cheap sorbent (natural limestone). Overall, utilisation of this process could reduce the thermal efficiency de-rating associated with CO₂ capture, to about 6–8 %³³ compared to 8–10% for

MEA-scrubbing, representing a significant fuel and cost saving over the lifetime of a typical power station. Degradation of the sorbent over repeated cycles, particularly in the presence of ash and sulphur, is a potential problem³². However, owing to the low cost of the sorbent (crushed limestone), this is a minor concern^{34–36}, and the economics and CO₂ balance are particularly favourable if exhausted sorbent is used as a feedstock for cement manufacturing (Box 1)²⁴. Significant research efforts are focussed on improving the long-term capacity of CaO-based sorbents^{34–36}. Looking further into the future, Ca-looping technology underpins a range of advanced power schemes for the production of electricity and/or hydrogen, including: combined shift-carbonation sorbent enhanced reforming (SER)³⁷, and the zero-emission coal concept (ZECA)^{38,39}. These processes offer significant potential for efficiency and economic improvements but are complicated².

Ionic liquids (ILs) are materials with low melting points and high boiling points (usually liquids at room temperature), composed entirely of ions. They have been described as “designer solvents” because of the ability to tailor the solvent’s properties by appropriate combinations of cations and anions of different size and chemistry. The major advantage of ILs is that they are non volatile at ambient conditions, minimising the risk of fugitive solvent losses; they have a wide liquid range and thermal stability up to 300°C, offering flexibility in terms of process optimisation⁴³ and can also integrate sulphur removal into one stage⁴⁰. However, currently, ILs are prohibitively expensive, and their manufacture is very complicated, hence significant cost reductions and process simplifications for large-scale production are required for economic viability. Future potential may arise from the possibility of combining ILs and amines⁴².

The use of **biological capture** systems such as algae to remove CO₂ from industrial flue gas is also an active area of research, one which has received significant commercial interest. The general concept involves using the waste heat and exhausted CO₂ from combustion, plus water and sunlight, in order to cultivate algae populations. A range of methods have been considered including open ponds or tanks, and closed bioreactor systems; the latter characterised by better process control, higher productivity, but a significant increase in capital cost. The large-scale cultivation of algae represents a valuable source of biomass, which may be used to produce additional energy, including liquid fuels such as bio-oil and bio-diesel⁴³. For example, Solix (a start-up company established with funds from the US Department of Energy) assert that bio-oil would be competitive with an oil price of more than \$USD 75 per barrel⁴⁴. However, it is important to note that the re-use of CO₂ as a liquid bio-fuel only displaces the use of fossil fuels, hence limiting the CO₂ mitigation potential. Decarbonisation of the transport sector by electrification of vehicles, utilising electricity from power plants with CCS would result in considerably lower emissions. Biological capture processes suffer from inherent scale-up issues because of the limited rate at which algae can grow, and challenges associated with bioreactor design. Future advances in this field are anticipated using highly-productive genetically engineered algal strains.

Chemical-looping-combustion eliminates direct contact between the fuel and air by using a metal oxygen carrier (MeO), such as the oxides of iron, nickel or copper, to transfer the oxygen needed to combust the fuel. Unfortunately, the oxygen carriers tend to degrade during long-term cycling, a limitation that must be overcome to realise the potential for high overall efficiencies of greater than 50%⁴⁵. Chemical-looping-combustion has been investigated for combusting gaseous and solid fuels, as well as advanced H₂ production processes^{45–48}. Chemical-looping-combustion with natural gas (NG) for electricity production is limited by the efficiency of the steam cycle and therefore, in general, has a lower overall efficiency compared to a NG CCGT with CO₂ capture unless the system is pressurised.

Membrane separation technology involves the selective permeation of gases through porous materials, and is driven by a pressure difference that is achieved by either compressing the gas upstream, or creating a vacuum downstream. The type of material—including: polymeric, metallic and ceramic membranes—is strongly dependent on the application, and there is a range of applications relevant to CO₂ capture systems, e.g. for separating CO₂ from N₂ in flue gas, O₂ separation from N₂ in air, and H₂ separation from coal-derived synthesis gas. In the case of CO₂ separation from flue gas, which involves very large volumes of gas, a recent study by Membrane Technology and Research, Inc. highlighted the critical importance of increasing membrane permeability to reduce the efficiency penalty associated with achieving the pressure gradient across the membrane⁴⁹. For the application of O₂ separation from N₂ for oxy-combustion, or gasification plants, the development of the ion transport membranes by Air Products is described as a break-through technology⁴⁰. Major challenges which must be overcome include: the cost of membrane materials, the life-time of membrane and reliability issues due to exposure to particulates SO_x, NO_x and trace metals, demonstration of large-scale compression or vacuum equipment and efficient integration with power systems⁴⁹.

Cryogenic separation is an alternative approach for gas-gas separation exploiting the different boiling temperatures and partial pressures of the gases in a mixture which can be easily separated into distinct phases by cooling or pressurisation. Currently, cryogenic air separation is the main method used for the separation of O₂ from N₂ by cooling the air to about –196°C at which point N₂ becomes a liquid. For CO₂ separation, CO₂ can be frozen at –75°C and atmospheric pressure, or condensed to liquid when pressurised past its critical point at about 31°C and 7.4 MPa. The major problem for cryogenic separation is the high-energy consumption and cost associated with compression and cooling. For CO₂ separation, where CO₂ may be less than 15% of the total gas stream, then a lot of energy is consumed in the compression and cooling of the remaining 85% of the gas stream. Another challenge is the removal of the water which is necessary before cooling to avoid the formation of ice⁵⁰. Owing to the considerable energy penalty there is significant scope for fundamental research.

Reducing the efficiency penalty and the cost of capture

The application of CCS, using closest-to-market technology, would currently de-rate the thermal efficiency of a power plant by about 8–10%, equivalent to a reduction in power output of 20%. To achieve the same power output more fuel must be consumed, more CO₂ is produced (though not emitted), more waste is generated, and the potential for adverse environmental impacts is increased. This efficiency penalty correlates directly with the long-term cost of capture, shown in Figure 7, which illustrates a likely trajectory towards cost reduction arising from improved overall efficiency and increased process integration. Thus, capture systems deployed in 2030 and beyond may look very different to those deployed in the first raft of full-scale demonstration projects. It is therefore prudent to support R&D of more advanced technologies to avoid lock-in to sub-optimal technologies.

CO₂ abatement cost estimates (including capture, transport and storage) range from about 30–90 USD/t CO₂

avoided for coal and gas power stations^{5,6,51,52} and a much broader range is estimated from about 20–130 USD/t CO₂ for the different industrial applications¹⁴. Overall, cost estimates between the main technology categories are not vastly different given the margins of uncertainty. Cost-efficiency data is very limited for next generation technologies, such as carbonate looping; however, preliminary analysis suggest that these may be extremely competitive^{53, 54}.

The IEA¹ published efficiency targets for current plants (i.e., for a new plant constructed today) compared with targets for efficiency penalties in 2020. These targets have also been adopted by the Advanced Power Generation Technology Forum, which is an industrial forum including RWE, E.ON and Doosan-Babcock. The summary adopted by the Forum is reproduced in Table 2. The omission of efficiency targets for the more advanced technologies, such as post-combustion carbonate looping and chemical looping, conveys the general view of the power sector that technology readiness levels are too low for these options to be seriously considered for power station retrofit before 2020.

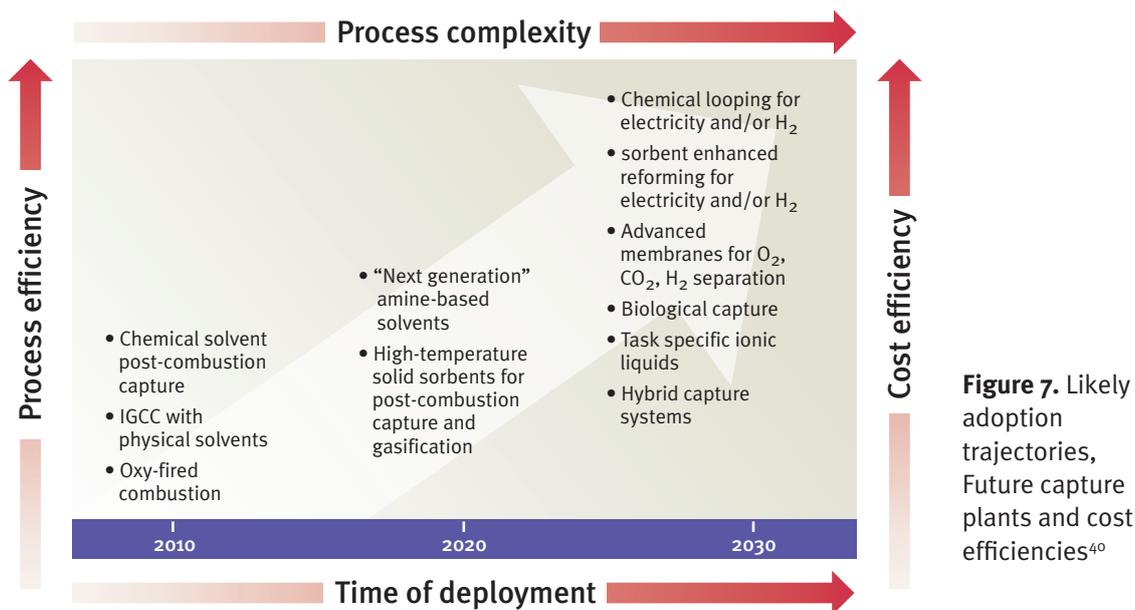


Figure 7. Likely adoption trajectories, Future capture plants and cost efficiencies⁴⁰

Technology	Current state-of-the-art efficiency	Target efficiency
Steam Cycle	Efficiency (LCV) ~ 45 %	~ 50 - 55 %
	de-rating	de-rating for 2020
CCS – post combustion	– 10 % points	– 8 % points
CCS – oxy fuel	– 10 % points	– 8 % points
CCS – pre combustion	– 7 - 9 % point	– 5 - 6 % point
CCS gas – post combustion	– 8 % points	– 7 % points
CCS gas – oxyfuel	– 11 % points	– 8 % points

Table 2. Efficiency penalty estimates for capture and compression (targets published by IEA and adopted by the UK Advanced Power Generation Technology Forum)

Capture technology specific RD&D programmes

This section provides a snapshot of some of the important technology specific demonstrations—it is not intended to be an exhaustive list.

The **closest to market technology** is **amine-based solvent scrubbing**, with a number of pilot plants around the world. Examples from the UK include a 0.5 MWth test facility at RWE npower Didcot power station⁵⁵ (also operable as an oxy-fuel test rig), with plans for a 3 MWe pilot plant at Aberthaw on a slipstream (i.e., a small stream diverted from the main flue gas stream) of the existing coal-fired power plant (with planned delivery in 2011). Longannet power station (ScottishPower)⁵⁶ also has a pilot test facility (1 MWe) which has been in operation since 2009. Under the UK CCS competition (discussed below), it was announced on 12 March 2010 that ScottishPower was awarded a feasibility and front-end engineering design study (FEED) contract for a 30 MWe post-combustion capture plant with plans to scale-up to a 300 MWe, including transport and storage under the North Sea by 2014. A second FEED contract was awarded to E.On (Kingsnorth power station) towards the development of a 300–400 MWe post-combustion plant⁵⁷. E.On however announced in November 2010 that it is not proceeding with its plans for the Kingsnorth demonstration plant, leaving ScottishPower's plans for a CCS retrofit project as the likely beneficiary of government CCS funding.

Siemens Energy⁵⁸ and The Netherlands Organisation for Applied Scientific Research have signed a cooperation agreement to develop a “second-generation” solvent based on a proprietary amino-acid-salt. A pilot plant for this technology is in operation at the Staudinger coal-fired power plant in Germany (E. On), this takes a slipstream from the existing power plant flue gas. In China, the China Huaneng Group use amine-based solvents to capture CO₂ from a slipstream from the 845 MWe Gaobeidian coal-fired power plant in Beijing. This pilot, which has been in operation since July 2008 has the capacity to capture about 3000 tonnes of CO₂ per year and produces food-grade CO₂ (more than 99.5% pure) that is sold to soft drink manufacturers. A scaled-up version was commissioned earlier this year at Shidongkou Power Plant in Shanghai with a design capacity to capture 10,000 tonnes of CO₂ per year⁵⁹.

Alstom⁶⁰ is investing in **chilled ammonia technology**, and have plans to commercialise it in collaboration with EPRI, E.ON and Statoil. AEP's 1,300 MWe coal-fired powered plant at Mountaineer in the USA has been fitted with chilled-ammonia technology on a 20 MWe slipstream. Phase II involves capture from 235 MWe by 2016. Sargas have developed a post-combustion technology based on **wet potassium carbonate scrubbing**, which is available in 100 MW modules for capturing SO_x, NO_x and CO₂. A reported CO₂ capture efficiency of more than 95% was reported based on results from pilot trials at the pres-

surised coal-fired Värtan combined heat and power plant, Stockholm⁶¹. A 400 MW plant at Husnes⁶², Norway is planned with the captured CO₂ (2.6 Mtpa) to be used for enhanced oil recovery (EOR) in North Sea Oil fields.

IGCC plants with CCS which are in early stages of development include the Texas Clean Energy Project⁶³ led by Summit Power Inc. This project is developing a 400 MW (245 MWe) IGCC plant in Texas, USA, which is expected to be in operation by 2014, with the captured CO₂ used for EOR. In the UK, construction of a 900 MW IGCC plant at Hatfield⁶⁴ is underway. This project, excluded from the UK CCS competition for using pre-combustion technology, was awarded €180 million from the European Commission (discussed in detail below). In China, the GreenGen Project is looking to be the first commercial-scale IGCC power plant (400 MW) with CCS with construction currently underway in Tianjin using technology developed by the Thermal Power Research Institute⁷. In Australia a 400 MW IGCC plant, the ZeroGen project⁶⁵ with technology provided by Mitsubishi heavy Industries, is working towards planned commercial deployment by 2015. The location of the IGCC plant and CO₂ storage site is expected to be announced with completion of the feasibility studies and construction is expected to commence in 2012. The Norwegian flagship project to capture CO₂ from a combined cycle gas turbine facility in Møngstad⁶⁶ (350 MWth, 280 MWe), has received significant publicity recently because the Norwegian Government has delayed the final investment decision till 2014.

Vattenfall's 30 MWth oxyfuel pilot plant at Schwartze Pumpe,⁶⁷ Germany has been in operation for over a year and a capture rate of more than 90% has been demonstrated. Experience obtained from this work is expected to support the scale-up to a planned 250 MWe demonstration in Jämschwalde aimed for 2015 and listed for European Commission funding. In the UK, Doosan Babcock has equipped a 40 MWth burner test facility for oxy-combustion demonstration at their plant in Renfrew, Scotland⁶⁸. In the US, the Futurgen project, which originally proposed a new-build IGCC plant with CCS, has been redeveloped and will now involve the retrofit of an existing coal plant with an oxyfuel boiler funded in part with stimulus money⁶⁹. In Australia, construction is underway on the Callide Oxyfuel Project which involves the retrofit of oxyfuel technology to an existing 30 MWe boiler at Callide A Power Station, Queensland⁷⁰.

Post-combustion carbonate looping is currently being tested at the pilot scale up to about 120 kWth scale in Spain⁷¹, Canada⁷², and Germany⁷³. Larger pilot facilities are planned including a 2 MWth plant on a slip stream from a 50 MWe coal power plant at La Pereda, Spain operated by Hunosa (recently funded by the European Commission under the 7th Framework Programme) and a 1 MWth test facility, funded by the German government and industry at Technical University Darmstadt, Germany⁵⁴. With regards to integration with cement manufacturing, Cemex has a pilot plant in Monterrey, Mexico⁷⁴.

From pilot to commercial-scale deployment

CCS technology is most cost-efficient for large point source CO₂ emitters. Suitable sources are shown on the map in Figure 8a as red dots. Figure 8b shows the nine operating large-scale

integrated projects (LSIPs) according to the definition adopted in the recent GCCSI CCS Project Status Report (These projects are listed in Table 3). In addition, there are many more projects, proposed or potential, that are at various stages of development (Figure 8c). The GCCSI identify eighty LSIPs in a recent survey of CCS projects⁷.

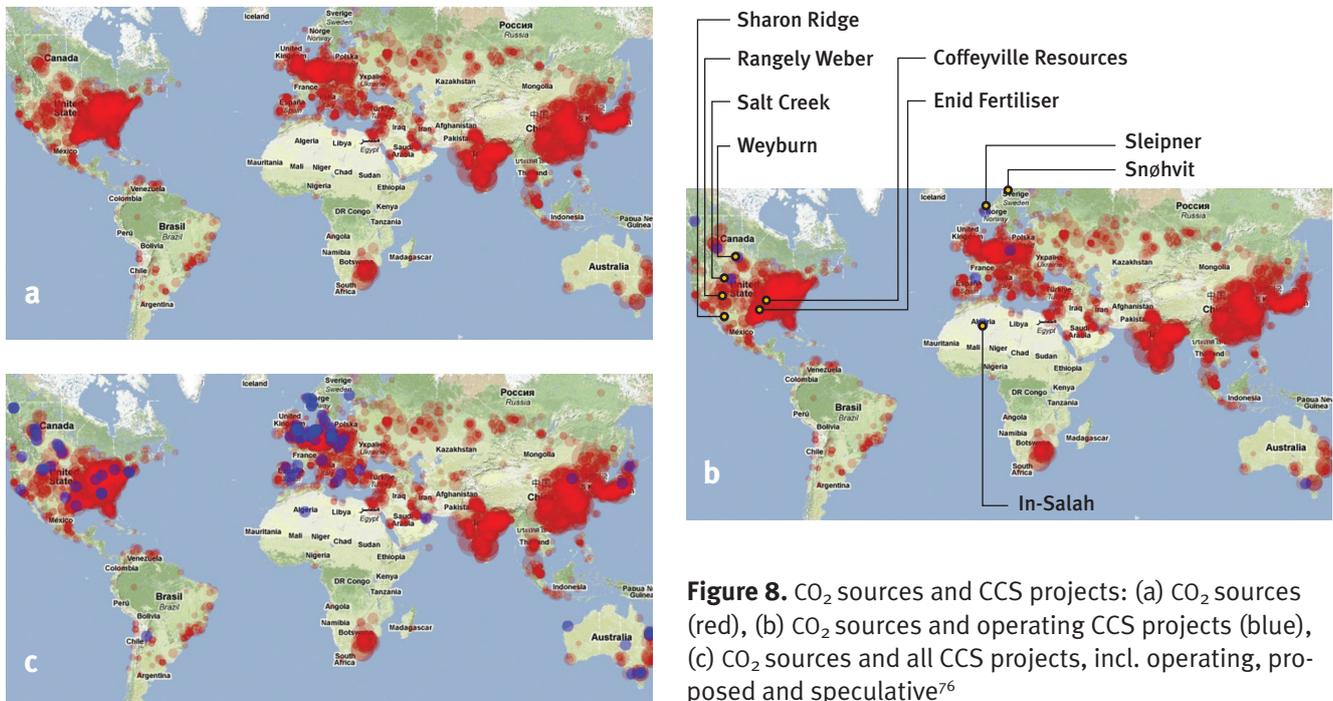


Figure 8. CO₂ sources and CCS projects: (a) CO₂ sources (red), (b) CO₂ sources and operating CCS projects (blue), (c) CO₂ sources and all CCS projects, incl. operating, proposed and speculative⁷⁶

Project name and location	Capture technology	Storage	In operation
Sleipner, Norway	natural gas processing	saline formation	1996
Snøhvit, Norway	natural gas processing	saline formation	2008
Weyburn operations US/ Canada	syn-fuels plant with pre-combustion capture	EOR	2000
In-Salah, Algeria	natural gas processing	EOR	2004
Rangely Weber Project, USA	natural gas processing	EOR	1986
Salt Creek, USA	natural gas processing	EOR	2004
Sharon Ridge, USA	natural gas processing	EOR	1999
Enid Fertilizer, USA	fertilizer plant with pre-combustion capture	EOR	2003
Coffeyville Resources Nitrogen Fertilizer Plant, USA	gasification plant with pre-combustion capture	EOR	2000

Table 3. Large-scale integrated CCS projects in operation today^{7,9}

Currently the lack of a defined cost for CO₂ emissions means that the commercial deployment of CCS is dependent on policy and regulatory frameworks—ultimately someone has to pay. Presently, all of the operating and many of the possible and speculative projects are related to enhanced oil and gas recovery (EOR and EGR), enhanced coal-bed methane (ECBM) and natural gas (NG) processing because the only way to make CCS projects economical is to use the CO₂ for producing more hydrocarbons, with the notable exception of projects in Norway, where a CO₂ emission tax has led to the Sleipner and Snøhvit projects. Nonetheless, the eighty LSIPs (Figure 8c) reflect the efforts of some governments offering financial support for the first commercial CCS projects. For example, the IEA, Carbon Sequestration Leadership Forum report to the Muskoka 2010

G8 Summit⁹ estimate over 26 billion USD in funding has been committed to date, including government support for the launch of between nineteen and forty three LSIPs by 2020⁷. The majority of the commitments are from governments in developed countries, notably United States, Canada, the European Union, Norway, Japan, Korea and Australia⁹.

Despite the significant contribution to global CO₂ emissions, energy intensive industries such as the cement and refinery sectors (see Box 1) have received significantly less research and government policy attention compared to the application of CCS in the power sector. For example, in the UK, direct industrial emissions represent about one quarter of total emissions (2008 data) and a recent analysis for the Committee on Climate

Country	Coal		Natural gas		CO ₂ emissions from fossil fuel for electricity and heat, g CO ₂ /kWh ^d	CCS policy highlights
	Proven reserves at end of 2009, Mt (share of total, %) ^a	Consumed 2009, share of total, % ^b	Proven reserves at end of 2009, trillion m ³ (share of total, %)	Consumed 2009, share of total, % ^c		
UK	155 (<0.05);	0.9	0.29 (0.2)	2.9	500	Government commitment to fund up to 4 coal CCS plants
Norway	–	< 0.05	2.05 (1.1)	0.1	7	Offshore CO ₂ tax since 1991, CO ₂ separation and re-injection from two sour NG producers, go ahead postponed for gas CCS project
US	238308 (28.8)	15.2	6.93 (3.7)	22.2	549	Government committed economic recovery funds, currently three large-scale EOR projects
Canada	6578 (0.8)	0.8	1.75 (0.9)	3.2	205	Federal and provincial governments committed funds, three operating projects for sour NG, EOR and ECBM
Australia	76200 (9.2)	1.6	3.08 (1.6)	0.9	907	Government committed funding for large-scale demonstration, CO ₂ injection currently operating
China	114500 (13.9)	46.9	2.46 (1.3)	3.0	758	A number of national initiatives and international collaborations with focus on EOR

Table 4. Conventional fossil fuel reserves, amount consumed and CCS policy highlights^{80, 81}

^a including anthracite, bituminous, sub-bituminous and lignite; ^b world total consumed in million tonnes oil equivalent, 3278.3; ^c world total consumed in billion cubic metres, 2940.4; ^d Data for 2007, CO₂ emissions from fossil fuels combustion for electricity, combined heat and power and main activity heat plants divided by the output of electricity and heat generated from fossil fuels, nuclear, hydro (excluding pumped storage), geothermal, solar and biomass

Change estimated that it would be technically and economically viable to apply CCS to address about 30% of these emissions (38 Mt in 2030)¹⁴. According to the recent GCCSI status report on CCS projects only three industrial projects are classified as LSIPs, one project in the cement sector (CEMEX), one in the iron and steel sector (ULCOS Florange), and one in pulp and paper (Battelle Memorial Institute project). The US Department of Energy has recently announced one billion USD stimulus funding (including private funds) for three commercial scale projects targeting chemicals production (methanol and ethanol) coupled with EOR⁷⁵. Industry-specific policy and regulations will be necessary to encourage more projects, taking into account the specific features of each industry. Current policy, whereby emission constraints are limited to developed countries, is problematic in terms of the potential for carbon leakage² with the transference of heavy emitting industries from these countries to jurisdictions where constraints may be lax.

Policy issues and international context

Since CCS will increase the cost of electricity and/or heat, the only reason for deploying it is to mitigate climate change. Legal and regulatory frameworks are crucial to provide incentive for investment. To this end, a number of governments, including the UK, are developing CCS policies. The key CCS policy issues for countries around the world are summarised in Table 4, which also compares relative dependence on conventional coal and gas reserves for electricity and heat generation.

United Kingdom

The UK has committed to reducing GHG emissions in the UK by 80% by 2050. To this end, the UK Climate Change Committee (CCC) have suggested as an interim target that the UK energy fleet to aim for an average emission intensity of less than 100 g CO₂/kWh by 2030, down from the current average of

about 500 g CO₂/kWh (a new coal-fired power plant has an emission intensity of about 750 g CO₂/kWh compared to about 400 g CO₂/kWh for combined cycle gas turbine plant). Responding to this (and in addition to the EU ETS discussed below), the new Energy Act 2010 prioritises the early application of CCS to coal-fired power stations using post-combustion or oxy-fuel technology, with the government committed to providing funding towards up to four CCS demonstrators. Furthermore, any new coal power stations approved must have CCS applied at the commercial-scale when it is judged to be a “proven” technology. ScottishPower’s Longannet power station is the first project likely to be funded via the UK CCS competition, with the government promising one billion GBP towards capital costs to the recipient that must demonstrate 90% CO₂ capture and storage off-shore from the equivalent of 300 MWe of generation capacity⁷⁷.

In addition, new planning consent requirements of the Department of Energy and Climate Change require all new combustion plants (coal, gas and biomass) greater than 300 MWe to assess practicability for combined heat and power and to be carbon capture ready (CCR). While the definition of CCR remains ambiguous, the Department of Energy and Climate Change requires that proposed power plants must demonstrate that there is sufficient space to accommodate capture plants in the future, that the retrofit is technically feasible, and that there is a feasible transport route to deliver CO₂ to an identifiable geological storage location offshore⁷⁸. In response to this requirement, Drax Power in partnership with Siemens Venture Projects, have announced plans to build three 290 MWe biomass power plants⁷⁹. Some progress has been made towards providing the regulatory framework for CO₂ transport by pipeline and offshore storage, including amendments to the London Marine Dumping Convention and OSPAR Marine Convention to enable sub-seabed storage and transportation across international borders⁵⁷. However, there remains an urgent need for investment in the infrastruc-

Proposal	Applicant	Demonstration technology	Funding under EEPR (Millions of EUR)
Jaenschwalde, Germany	Vattenfall Europe Generation*	Oxycombustion/post-combustion	180
Hatfield, UK	Powerfuel Power Limited*	IGCC with physical sorbent	180
Porto Tolle, Italy	Enel Ingegneria e prod.*	Post-combustion	100
Rotterdam, Netherlands	Maasvlakte CCS Pjt CV	–	180
Belchatow, Poland	PGE Elektrownia Belchatow	Post-combustion	180
Compostilla, Spain	ENDESA Generacion sa	oxycombustion	180

* Grant agreements signed as of May 2010

Table 5. Summary of EU funding allocations for CCS demonstration⁸³

ture and the establishment of legal and regulatory frameworks for CCS (for coal, gas and biomass), which might include the introduction of a CO₂ emission performance standard to meet the targets recommended by the UK CCC.

The UK CCC have recommended that to meet the UK emission reduction target of 80% by 2050, the commitment to CCS should include gas-CCS, with at least one gas-CCS demonstration plant making up the four⁸².

This recommendation is made acknowledging the importance of gas plants as part of the future generation mix, in part because of new stricter pollutant restrictions (SO_x, NO_x) placed on coal plants (according to the EU Large Combustion Plant Directive), and the relatively low gas prices effecting the economics of gas CCS¹⁴. The future dominance of gas is also clearly reflected by the fact that there are about ten current UK planning applications for combined cycle gas turbine power plants compared only to one for coal-fired plant.

Other European Union Countries

Within the EU, the EU ETS will raise revenue from auctioning 300 million credits to support CCS and innovative renewables (a maximum of three projects in each technology category), with the first funding decisions expected in early 2011⁸³. There is an additional 1.05 billion EUR for CCS demonstration from the European Energy Program for Recovery (EEPR), with the UK securing €180 million. A summary of the allocation of EU funding from the EEPR is given in Table 5. Additionally, the European Technology platform for Zero Emission Fossil Fuel Power Plants has been asked to investigate the development of up to 12 demonstration plants, and to co-ordinate European CCS research⁸⁴.

Other Countries

In **Australia**, there is 2 billion AUD available for “flagship” projects demonstrating large-scale CCS. The most high profile is the Gorgon liquefied natural gas project in Western Australia expected to inject and store 3.4 Mtpa starting in 2014. The Australia Government has also committed an additional 100 million AUD per year for four years for the formation of the Global CCS Institute (GCCSI)⁸⁵, which administers a *Funding and Support Program providing about AUD \$50 million per annum* to support CCS projects around the world.

The **Canadian** federal government has offered 1.3 billion CAD for research, development and demonstration (RD&D), and in addition to federal funding the Province of Alberta has committed 2 billion CAD to support CCS deployment.

In **China** CCS is starting to be recognised as an important issue and some general policies are in place supporting CCS R&D.

There are a number of demonstration activities, including the pilot demonstrations operated by the China Huaneng Group, and international collaborations. For example, Shenhua Corporation is looking at options to capture CO₂ from its direct coal liquefaction demonstration plant in Inner Mongolia, which may be used for EOR or stored in a saline aquifer. International collaborations include Near Zero Emissions Coal project, and Cooperation Action with CCS China-EU⁸⁶.

Norway has had a tax on offshore CO₂ emissions for oil and gas operations since 1991 and the government has also allocated 1.2 billion NOK for CCS projects. The postponed Møngstad project, which will capture CO₂ from a combined cycle gas turbine plant (350 MWth, 280 MWe), remains in the planning stage with final investment decisions expected in 2014⁶⁶.

The **USA** has committed support for CCS demonstration by announcing a 3.4 billion USD in the American Recovery and Reinvestment Act⁸⁷ for clean coal and CCS technology development. The specific breakdown of funding includes 1 billion USD for testing novel energy production methods from coal, 1.52 billion USD for industrial CO₂ capture

projects, and 800 million USD to add to CO₂ capture projects under the Clean Coal Power Initiative⁶.

CCS is a potentially critical transitional technology, offering a near-term way of mitigating climate change

Conclusions

CCS is a potentially critical transitional technology, offering a near-term way of mitigating climate change consistent with continued extensive fossil fuel use, while progress is made towards establishing a truly sustainable low-carbon energy system in the medium to longer term. The costs of mitigation are expected to be considerably higher if CCS is not included in future low-carbon energy technology portfolios. The deployment of CCS in countries with very large indigenous fossil fuel reserves could also reinforce energy security, while not compromising climate mitigation goals.

It is therefore extremely important to have early demonstration and deployment of this technology to test the system on a large scale and to iron out problems prior to its projected global roll-out post 2020. Legislative and policy clarity and consistency, such as that exemplified by the Norwegian carbon tax, are also crucial, otherwise the large capital costs of the technology and long payback time will hold back investment in CCS. The general public are justifiably concerned about the potential risks of CO₂ storage, particularly near to populated areas. Research, consultation and dialogue will all be needed to help make clear the potential risks and how these will be managed to address concerns.

Currently available carbon capture technologies involve a significant energy penalty. Sustained investment in RD&D will therefore be necessary into more advanced, less costly second generation capture technologies to avoid lock-in to sub-optimal solutions.

Development of international—perhaps sector specific—policy frameworks for dealing with CO₂ emissions from key industrial sectors will be important to avoid problems of competitiveness and the potential risk of carbon leakage in jurisdictions where less strict emission requirements may apply.

Abbreviations and acronyms

CCCP Combined Cycle Cogeneration Plant

CCR Carbon Capture Ready is a set of principles/requirements that ensure that a plant can be retrofit with CO₂ capture plant at some time in the future

CCS Carbon Capture and Storage

CO₂ Carbon Dioxide

ECBM Enhanced Coal-Bed Methane

EGR Enhanced Gas Recovery

EOR Enhanced Oil Recovery

FEED Feasibility and Front-end Engineering Design study

GCCSI Global Carbon Capture and Storage Institute

GHG GreenHouse Gas including CO₂ also CH₄

IEA International Energy Agency

IGCC Integrated Gasification Combined Cycle

LSIPs Large-Scale Integrated Projects, defined by the Global CCS Institute to be over 0.8 million tonnes per annum (Mtpa) of CO₂ captured and stored from coal-fired power stations and over 0.4 Mtpa from gas-fired plant and energy intensive industrial point sources

MWe Mega-Watt of Electrical power

MWth Mega-Watt of Thermal power

NG Natural Gas

About the authors

DR N. FLORIN
n.florin@imperial.ac.uk

Dr Florin is an Imperial College Junior Research Fellow working on “next-generation” CO₂ capture technology development, and he is an Energy Engineering Group and Grantham Institute Researcher. He has provided advice to the UK Department for Energy and Climate Change (DECC) and the Environment Agency (EA) on CCS technology and policy issues and was invited to be on an International Panel of Experts to review CCS R&D project proposals. He has published more than 20 papers on CO₂ capture technology, and biomass and waste utilisation for the production of electricity and hydrogen.

DR P. FENNELL
p.fennell@imperial.ac.uk

Dr P Fennell heads the Energy Engineering group at Imperial College Chemical Engineering and has published widely on the subject of calcium-looping technology and in the wider field of chemical engineering. He sits on the Institution of Chemical Engineers Energy Conversion subject panel, the International Energy Authority High-Temperature Solid Looping Cycles Network Executive, and has written reports for the UK Department for Energy and Climate Change (DECC) on future technologies for Carbon Capture and Storage (CCS) and carbon capture readiness. He is also a deputy director of Imperial College’s Centre for Carbon Capture and Storage. He has published more than 25 papers since 2005.

About the Grantham Institute

The Grantham Institute is committed to driving research on climate change, and translating it into real world impact. Established in February 2007 with a £12.8 million donation over ten years from the Grantham Foundation for the Protection of the Environment, the Institute's researchers are developing both the fundamental scientific understanding of climate change, and the mitigation and adaptation responses to it. The research, policy and outreach work that the Institute carries out is based on, and backed up by, the world-leading research by academic staff at Imperial.

www.imperial.ac.uk/climatechange

About Imperial College London

Consistently rated amongst the world's best universities, Imperial College London is a science-based institution with a reputation for excellence in teaching and research that attracts 13,000 students and 6,000 staff of the highest international quality.

Innovative research at the College explores the interface between science, medicine, engineering and business, delivering practical solutions that improve quality of life and the environment - underpinned by a dynamic enterprise culture. Since its foundation in 1907, Imperial's contributions to society have included the discovery of penicillin, the development of holography and the foundations of fibre optics.

This commitment to the application of research for the benefit of all continues today, with current focuses including interdisciplinary collaborations to improve health in the UK and globally, tackle climate change and develop clean and sustainable sources of energy.

www.imperial.ac.uk

References

1. IEA, Energy Technology Perspectives. IEA, Paris, France, 2008
2. IEA, Energy Technology Perspectives. Executive Summary. IEA, Paris, France, 2010
3. The Stern Review, 2007 available from: http://www.hm-treasury.gov.uk/stern_review_report.htm
4. Bosetti V, Carraro C, Massetti E, Alessandra S, Tavoni M. *Optimal energy investment and R&D strategies to stabilize atmospheric greenhouse gas concentrations*. Resource and Energy Economics 2009, 31, 123–137
5. Intergovernmental Panel on Climate Change Special Report on Carbon Capture and Storage (IPCC SRCCS), 2005, available from <http://www.ipcc.ch/ipccreports/special-reports.htm>
6. IEA, Technology Road Map, *Carbon Capture and Storage*, 2009, available from http://www.iea.org/papers/2009/CCS_Roadmap.pdf
7. Global Carbon Capture and Storage Institute: *The Status of CCS Projects Interim Report 2010*
8. McGarry A. *CO₂ storage and EOR: Does it add up?* Msc Thesis Imperial College London, September 2009
9. IEA/CSLF Report to the Muskoka 2010 G8 Summit, *Carbon Capture and Storage: Progress and Next Steps*, 2010
10. DOE/NETL-2009/1391, *Public Outreach and Education for Carbon Storage Projects*, December 2009
11. United Nations Framework Convention on Climate Change (UNFCCC), National greenhouse gas inventory data for the period 1990-2007. Note by the secretariat. FCCC/SBI/2009/12, Available from <http://unfccc.int/2860.php>
12. Carbon Dioxide Information Analysis Centre (CDIAC) Available from: http://cdiac.ornl.gov/ftp/ndp030/global.1751_2006.ems
13. Mac Dowell N., Florin n, Buchard A, Hallet J, Galindo A, Jackson G, Adjiman C, Williams C, Shah N, Fennell P. 2010 *An overview of CO₂ capture technologies*. Phys. Chem. Chem. Phys., 2010, 12, 1–29
14. Element Energy, *Potential for the application of CCS to UK Industry and natural gas power generation for Committee on Climate Change*. Final Report Issue 3 28/06/2010
15. Kohl AL and Nielsen RB. *Gas Purification*, 5th Edition, 1997 Gulf Publishing Company Houston, Texas
16. Holt N. (EPRI) Lecture titled: *Coal Usage in a Carbon Constrained World, BCURA Coal Science Lecture*, October 12 2009 available from <http://www.bcura.org/>
17. Davison and Thambimuthu K. Special Issue Paper: Proc. IMechE 2009, 223 Part A: J. Power and Energy, 201–212
18. Strömberg L, Lindgren G, Jacoby J, Giering R, Anheden M, Burchhardt U, Altmann H, Kluger F, Stamatelopoulos G-N *Update on Vattenfall's 30 MWth Oxyfuel Pilot Plant in Schwarze Pumpe*. Energy Procedia 1 2009: 581-589
19. Beysel G. 1st IEA International Conference on Oxyfuel Combustion, 2009 Ch. *Enhanced Cryogenic Air Separation – a proven process applied to Oxyfuel*
20. Shimizu T, Hiramata T, Hosoda H, Kitano K, Inagaki M, Tejima K. *A twin fluid-bed reactor for removal of CO₂ from combustion processes*. Transactions of the Institute of Chemical Engineers 1999; 77A: 62
21. Barker DJ, Turner SA, Napier-Moore PA, Clark M, Davison JE. *CO₂ capture in the cement industry*. Energy procedia 1 2009: 87-94
22. Bosaga A, Masek O, Oakey JE. *CO₂ capture technologies for cement industry*. Energy Procedia 1 2009:133–140
23. C. Dean, J. Blamey, N. H. Florin, M. J. Al-Jeboori, and P. Fennell. *The Calcium Looping Cycle for*

- CO₂ Capture from Power Generation, Cement Manufacture and Hydrogen Production*. CHERD, submitted
24. Rodriguez N, Alonso M, Abanades JC, Grassa G, Murillo R. *Analysis of a process to capture the CO₂ resulting from pre-calcination of the limestone feed to a cement plant*. Energy Procedia 1 2009
 25. van Straelen J, Geuzebroek F, Goodchild N, Protopapas G, Mahony L. *CO₂ capture for refineries, a practical approach*. Energy Procedia 1 2009: 179–185
 26. A technology strategy for carbon capture and storage. *UK Advanced Power Generation*. Technology Forum 2009:21
 27. Rhudy R and Black S. *Chilled ammonia process update*. In 10th International Network for CO₂ Capture, Lyon, France, 24-25 May 2007, available from www.co2captureandstorage.info/docs/capture/2007-810thCaptureMtg_FinalReport.pdf
 28. Lin A, Smith F, Sweterlitsch J, Graf J, Nalette T, Papale, W, Campbell M, and Lu, S-D. NASA technical report (ID 20070020003): *Testing of an Amine-Based Pressure-Swing System for Carbon Dioxide and Humidity Control*, July 2007, available from <http://ntrs.nasa.gov/search.jsp?R=358593&id=3&as=false&or=false&q=Ns%3DHarvestDate%257c1%26N%3D4294656038>
 29. Drage TC, Blackman JM, Pevida C, Snape CE. *Evaluation of activated carbon adsorbents for CO₂ capture from gasification*. Energy and Fuels 2009; 23(5):2790–2796
 30. Gray ML, Champagne KJ, Fauth D, Baltrus JP, Pennline H. *Performance of immobilized tertiary amine solid sorbents for the capture of carbon dioxide*. International Journal of Greenhouse Gas Control 2008; 2(1):3-8
 31. Chuang S. *Metal Monolithic Amine-Grafted Zeolites for CO₂ Capture from Power Plants*. Proceedings of the Annual NETL CO₂ Capture Technology for Existing Plants R&D Meeting, March 24–26, 2009
 32. Blamey J, Anthony EJ, Wang J, and Fennell PS. *The Carbonate Looping Cycle for Large-Scale CO₂ Capture*. Progress in Energy and Combustion Science; 2010
 33. Abanades JC, Anthony EJ, Wang J, and Oakey JE. *Fluidized bed combustion systems integrating CO₂ capture with CaO*. Environmental Science & Technology 2005; 39(8): 2861–2866
 34. Manovic V. and Anthony EJ. *Thermal Activation of CaO-Based Sorbent and Self-Reactivation during CO₂ Capture Looping Cycles*. Environmental Science Technology 2008; 42(11):4170-4174
 35. Manovic V. and Anthony EJ. *Steam reactivation of spent CaO-based sorbent for multiple CO₂ capture cycles*. Environmental science & technology 2007; 41(4):1420-1425
 36. Florin N, Blamey J, Fennell P. *Synthetic CaO-based sorbent for CO₂ capture from large-point sources*. Energy and Fuels 2010, accepted
 37. Harrison D. *Sorption-enhance hydrogen production: A review*. Industrial and Engineering Chemistry Research 2008; 47: 6486–6501
 38. Gao L, Paterson N, Dugwell D, Kandiyoti R. *Zero-emission carbon concept (ZECA): Equipment commissioning and extents of the reaction with hydrogen and steam*. Energy & Fuels 2008; 22(1):463-470
 39. Gao, L., Paterson, N., Fennell, P., Dugwell, D., and Kandiyoti, R., *The zero emission carbon concept (ZECA): Extents of reaction with different coals in steam/hydrogen, tar formation and residual char reactivity*. Energy & Fuels, 2008. 22(4): p. 2504-2511.
 40. Figueroa JD, Fout T, Plasynski S, Mcllvried H. And Srivastava RD. *Advances in CO₂ capture technology—The U.S. Department of Energy’s Carbon Sequestration Program International Journal of Greenhouse Gas Control* 2 (2008) 9–20
 41. Siemens Energy website, 2009. Available from http://w1.siemens.com/innovation/en/highlights/energy/update_o2_carbondioxide-capture.htm
 42. Bara JE, Carlisle TK, Gabriel CJ, Camper D, Finotello A, Gin DL, Noble RD. *Guide to CO₂ separations in imidazolium-based room-temperature ionic liquids*. Ind Eng. Chem. Res. 2009;48:2739–2751
 43. Rasmussen M. *Carbon dioxide capture with algae*, August 2008. Available from <http://www.sartec.com/co2capture.pdf>
 44. National Renewable Energy Laboratory Technical Report (NREL TP-580-24-190). *A look back at the US DOE’s Aquatic Species Program: Biodiesel from Algae*. Available from <http://www.nrel.gov/docs/legosti/fy98/24190.pdf>
 45. Lyngfelt A, Leckner B. and Mattisson T. Chem. Eng. Sci. 2001; 56:3101-3113
 46. Dennis JS, Scott SA. and Hayhurst AN. J. Energy Inst. 2006; 79:187 - 190
 47. Scott SA, Dennis JS, Hayhurst AN. and Brown T. AIChEJ. 2006(52):3325-3328
 48. Ryden M, Lyngfelt A. and Mattisson T. Fuel 2006; 85:1631-1641
 49. Merkel TC, Lin H, Wei X, and Baker R. *Power Plant Post-Combustion Carbon Dioxide Capture: An Opportunity for Membranes*. Journal of Membrane Science. Accepted Manuscript 23rd October 2009
 50. Stanford University Global Climate & Energy Project: an assessment of Carbon Capture Technology and Research Opportunities, 2005
 51. McKinsey, 2008. *Carbon Capture and Storage: Assessing the Economics*. McKinsey & Company
 52. Rubin ES, Chen C, Rao AB. *Cost and Performance of fossil fuel power plants with CO₂ capture and storage*. Energy Policy 2007, 35, 4444–4454
 53. Mackenzie A, Granatstein DL, Anthony EJ, Abanades JC. *Economics of CO₂ Capture Using the Calcium Cycle with a Pressurised Fluidised Bed Combustor*. Energy Fuels 2007; 21(2): 920–926
 54. Ströhle J, Galloy A. and Epple B. *Feasibility study on the carbonate looping process for post-combustion CO₂ capture from coal-fired power plants*. Energy Procedia 2009; 1(1):1313-1320
 55. UK RWE NPower website: http://www.npower.com/rwenpowercr/5_responsible_business/5_2_low_carbon_economy/5_2_3_3_ccs_debate_research.html
 56. Scottish Power Press Release. 2009 available from http://www.scottishpower.com/PressReleases_1876.htm
 57. Northmore B. DECC Carbon Abatement Technologies – Review of policies and measures in the UK, UK APGTF workshop 16 March 2010
 58. Siemens Energy website, 2009. Available from <http://www.energy.siemens.com/hq/en/power-generation/power-plants/carbon-capture-solutions/post-combustion-carbon-capture/pilot-demonstration-plants/pilot-demonstration-plants.htm>
 59. IEA, GHG R D &Ds projects database: http://www.co2captureandstorage.info/project_specific

60. Chilled ammonia demo info available from : <http://www.carboncapturejournal.com/displaynews.php?NewsID=475> and http://sequestration.mit.edu/tools/projects/aep_alstom_mountaineer.html
61. Bryngelsson M. and Westermark M. *CO₂ capture pilot test at a pressurized coal fired CHP plant*. Energy Procedia 2009; 1(1):1403-1410
62. Husnes project information available from: <http://www.sargas.no/Operations/husnes.html>
63. Texas Clean Energy Project (TCE) available from: <http://sequestration.mit.edu/tools/projects/tcep.html>; <http://texascleanenergyproject.com/about-tcep>
64. Hatfield information available from: http://powerassetmodelling.co.uk/html/hatfield_igcc_.html
65. ZeroGen project information available from: <http://www.zerogen.com.au/project/overview.aspx>
66. Demonstration at Mångstad available from: <http://www.reuters.com/article/idUSTRE6410YM20100502>
67. Vattenfall Newsletter on Carbon Capture and Storage at Vattenfall, Bridging to the Future. No. 14 December 2009
68. Farley M. BCURA Coal Science lecture. 2008, available from <http://www.bcura.org/cslo8.pdf>
69. FuturGen information available from: <http://www.scientificamerican.com/article.cfm?id=back-to-the-future-with-futuregen-coal-plant>
70. Callide Oxyfuel Project website: <http://www.callideoxyfuel.com>
71. Gonzalez, B., Alonso, M., Abanades, J. C. *Sorbent attrition in a carbonation/calcination pilot plant for capturing CO₂ from flue gases*. Fuel, In Press
72. Hughes, R. W., Lu, D. Y., Anthony, E. J., Macchi, A., 2005. *Design, process simulation and construction of an atmospheric dual fluidized bed combustion system for in situ CO₂ capture using high-temperature sorbents*. Fuel Processing Technology 86(14-15): 1523-1531
73. Charitos, A., Hawthorne, C., Bidwe, A.R., Holz, H., Pfeifer, T., Schulze, A., Schlegel, D., Schuster, A., Scheffknecht, G., 2009. *Parametric study on the CO₂ capture efficiency of the carbonate looping process in a 10 kW dual fluidized bed*. 20th International Conference on Fluidized Bed Combustion. Xi'an, China
74. Röder A. CEMEX– Climate Change Strategy and CCS. Available from <http://www3.imperial.ac.uk/pls/portallive/docs/1/50227751.PDF>. In *Innovation and Investment Opportunities in Carbon Capture and Storage*. Imperial College, London, UK. 2008
75. <http://green.venturebeat.com/2010/06/10energy-dept-does-out-massive-sums-to-carbon-capture-geothermal-projects>
76. Bellona interactive CCS tool website available from: <http://www.bellona.org/ccs/> accessed June 2010
77. HM Treasury Spending Review 2010 , available from: http://cdn.hm-treasury.gov.uk/sr2010_completereport.pdf
78. Department of Energy and Climate Change, November 2009, *Carbon Capture Readiness (CCR): A guidance note for Section 36 Electricity Act 1989 consent applications*
79. Drax Power press available from: http://www.draxpower.com/biomass/renewables_energy_plants
80. BP, June 2010, *Statistical review of world Energy*
81. IEA, 2009, *CO₂ Emissions from Fuel Combustion 2009 –Highlights*
82. Committee on Climate Change, Letter to Rt Hon Chris Huhns, Secretary of State for Energy and Climate Change, *CCC advice on the approach to investment in fossil fuel power generation*, 17th June 2010
83. Bennett S. (European Commission, DG Energy Unit B3) *CCS-European Overview*, presented at APGTF Workshop on Carbon Abatement Technologies 16 March 2010
84. Rowe M. *Europe's race for CCS*. Energy World (Magazine of the Institute of Energy, U.K.) 2009; 372:12–13
85. http://www.globalccsinstitute.com/work_plan/gccsi_work_plan.html
86. Near Zero Emission Coal (NZE) information available from: <http://www.nzec.info/en/>
87. American Recovery and Reinvestment Act of 2009. 2009, available from: <http://www.gpo.gov/fdsys/pkg/PLAW-111publ5/html/PLAW-111publ5.htm>