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Carbon Dioxide Capture and Storage

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I. INTRODUCTION

Carbon dioxide capture and storage (CCS) is the capture and secure storage of carbon dioxide (CO_2) that would otherwise be emitted to the atmosphere. Currently, the major CCS efforts focus on the removal of carbon dioxide directly from industrial or utility plants and subsequently storing it in secure geologic reservoirs. The rationale for CCS is to enable the use of fossil fuels while reducing the emissions of CO_2 into the atmosphere, and thereby mitigating global climate change.

At present, fossil fuels are the dominant source of the global primary energy supply, and will likely remain so for the rest of the century. Fossil fuels supply over 85 per cent of all primary energy; the rest is made up of nuclear, hydro-electricity, and renewable energy (commercial biomass, geothermal, wind, and solar energy).

While great efforts and investments are made by many nations to increase the share of renewable energy in the primary energy supply and to foster conservation and efficiency improvements of fossil-fuel usage, addressing climate-change concerns during the coming decades will likely require significant contributions from CCS. In his keynote address at the 9th International Conference on Greenhouse Gas Control Technologies (GHGT-9, November 2008), Jae Edmonds[1] reported that 'preparations for the IPCC 5th Assessment Report have indicated that meeting low carbon stabilization limits is only possible with CCS'.

The goals of this paper are to describe the fundamentals of CCS technology, to discuss the current status and costs of the technology, and to explore the policy context required for CCS to become a significant climate-change mitigation option. The paper is divided into sections as follows. Section II describes the major components of a CCS system and their commercial use today, while section III describes the CO_2 sources that are compatible with CCS. Sections IV (capture) and V (geologic storage) review the technological basis for CCS. Section VI looks at CCS costs. Section VII comments on China and CCS, while section VIII

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discusses the future of CCS in the context of climate policy. Some concluding comments and presented in section IX.

II. COMPONENTS OF A CCS SYSTEM

While there is no unique way to break down a CCS system into its component parts, typical components include the following.

- *Capture*. The separation of CO_2 from an effluent stream and its compression to a liquid or supercritical[2] state. In most cases today, the resulting CO_2 concentration is >99 per cent, though lower concentrations may be acceptable. Capture is generally required to be able to transport and store the CO_2 economically.
- *Transport*. The movement of the CO_2 from its source to the storage reservoir. While transport by truck, train, and ship are all possible, transporting large quantities is most economically achieved with a pipeline.
- *Injection*. Depositing CO_2 into the storage reservoir. Since the main storage reservoirs under consideration today are geological formations, these are the focus in this paper. Other potential reservoirs include the deep ocean, ocean sediments, or mineralization (conversion of CO_2 to minerals). While some commercial use of CO_2 may be possible, the amount that can be used compared to the amount of CO_2 that is emitted from power plants will be very small.
- *Monitoring*. Once the CO_2 is in the ground, it must be monitored. Since CO_2 is neither toxic nor flammable, it poses only a minimal environmental and health and safety risk. The main purpose of monitoring is to make sure that the sequestration operation is effective, meaning that almost all the CO_2 stays out of the atmosphere for centuries or longer.

It should be noted that all components of a CCS system are commercial today. The challenge for CCS to be considered commercial is to integrate and scale up these components. Below is a brief summary of the commercial use of each of the above components. Later sections discuss the technical aspects of both capture and storage.

(i) Capture

The idea of separating and capturing CO_2 from the flue gas of power plants did not originate out of concern about climate change. Rather, it gained attention as a pos-

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[2] This means compression of CO_2 to above its critical pressure of 73.9 bar. At these pressures, CO_2 properties (e.g. density) are more like those of a liquid than of a gas.

sible economic source of CO_2, especially for use in enhanced oil recovery (EOR) operations, where CO_2 is injected into oil reservoirs to increase the mobility of the oil and, thereby, the productivity of the reservoir. Several commercial CO_2-capture plants were constructed in the late 1970s and early 1980s in the USA. When the price of oil dropped in the mid-1980s, the recovered CO_2 was too expensive for EOR operations, forcing the closure of these capture facilities. However, the North American Chemical Plant in Trona, California, which uses this process to produce CO_2 for carbonation of brine, started operations in 1978 and is still operating today. Several more CO_2-capture plants have subsequently been built to produce CO_2 for commercial applications and markets.

All the above plants used post-combustion capture technology (discussed below). The amount of CO_2 captured ranged from a few hundred tons of CO_2 a day to just over a thousand tons a day. Deployment of post-combustion capture technologies for climate-change purposes will entail very substantial increases in scale, since a 500 MW coal-fired plant produces about 10,000 tons/day of CO_2.

(ii) Transport

There exist over 3,400 miles of CO_2 pipelines in the United States[3] (see Figure 13.1). Their main function is to transport CO_2 from naturally occurring reservoirs to the oil fields of West Texas and the Gulf Coast for enhanced oil recovery. The Wyoming/Colorado pipelines are fed by the LaBarge natural gas processing plant, where large quantities of CO_2 need to be separated from natural gas in order for the natural gas to meet commercial specifications, such as heating value. The North Dakota pipeline is fed by the Great Plains Synfuels Plant, which produces synthetic natural gas from coal, with large amounts of CO_2 as a by-product.

(iii) Injection

Though a relatively new idea in the context of climate-change mitigation, injecting CO_2 into geological formations has been practised for many years.

Acid-gas Injection

The major purpose of these injections is to dispose of ‘acid gases’, a mixture consisting primarily of H_2S (hydrogen sulphide) and CO_2 that is a by-product of oil and gas production. Acid-gas injection projects remove CO_2 and H_2S from the produced oil or gas stream, and compress and transport the gases via pipeline to an injection well, where they are injected into geological formations. In 2001, nearly 200m cubic metres of acid gas were injected into formations across Alberta and British Columbia at more than 30 different locations. In most of these

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[3] From the *Chemical Economics Handbook* (SRI Consulting).

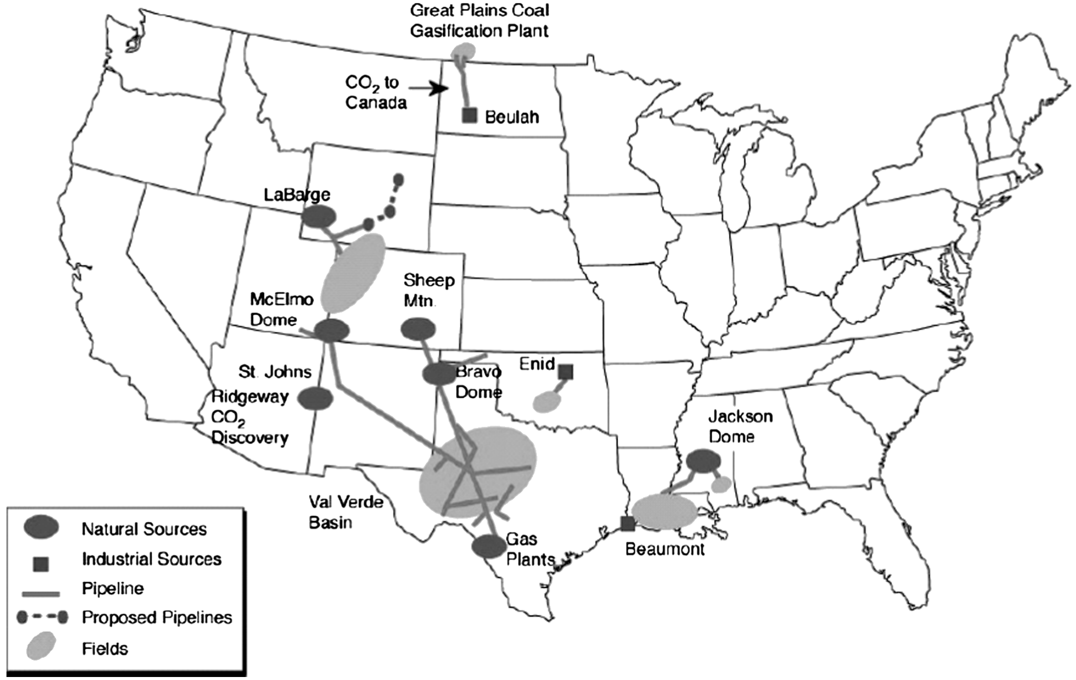

Figure 13.1. Existing CO_2 pipelines in the USA

Source: SRI Consulting, *Chemical Economics Handbook*, Carbon Dioxide Market Research Report, January 2007.

projects, CO_2 represents the largest component of the acid gas, consisting of up to 90 per cent of the total volume injected for some projects.

EOR

CO_2 injection into geological formations for enhanced oil recovery is a mature technology, having begun in 1972. In 2000, 84 commercial or research-level CO_2-EOR projects were operational worldwide. The United States, the technology leader, accounts for 72 of the 84 projects, most of which are located in the Permian Basin. Combined, these projects inject over 30m tons of CO_2 per year. Outside the United States and Canada, CO_2-EOR projects have been implemented in Hungary, Turkey, and Trinidad.

In addition to acid-gas injection and EOR, natural-gas storage is also a commercial activity. Natural gas, like CO_2, is a buoyant fluid when injected into a geological formation, so their behaviour is similar. Natural gas was first injected and stored in a partially depleted gas reservoir in 1915. Since then, underground natural-gas storage has become a relatively safe and increasingly practised process to help meet seasonal as well as short-term peaks in demand. Because depleted oil and gas reservoirs were not readily available in the Midwest, saline aquifers were tested and developed for storage in the 1950s. Between 1955 and 1985 underground storage capacity grew from about 2.1 trillion cubic feet (Tcf) to 8 Tcf. Since CO_2 stored underground will be much denser than natural gas, 8 Tcf of natural gas capacity is roughly equivalent to the storage space needed to hold the CO_2 emitted annually from all the power plants in the United States.

(iv) Monitoring

Many tools and techniques used in oil and gas exploration and production are directly applicable to CO_2 storage.[4] Chief among these are several seismic techniques, including time-lapse 3D seismic monitoring, passive seismic monitoring, and crosswell seismic imaging. There are also many other methods, such as using tracers, sampling the reservoir brines, and soil gas sampling, illustrating the large variety of monitoring tools in use today that can be applied to CO_2 storage.

III. CARBON SOURCES

By far the largest potential sources today are fossil-fuelled power plants. Power plants are responsible for more than one-third of the CO_2 emissions worldwide. Power plants are usually built in large centralized units, typically delivering

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[4] See section 5.6 of the IPCC Special Report, *Carbon Dioxide Capture and Storage* (IPCC, 2005), for a more detailed discussion on monitoring.

500–1,000 MW of electrical power. A 1,000 MW pulverized-coal-fired power plant emits 6–8 megatonnes (Mt)/year of CO_2, while a 1,000 MW natural-gas combined-cycle power plant will emit about half that amount. Coal-fired power plants represent by far the largest set of CO_2 sources that are compatible with CCS.

Several industrial processes produce highly concentrated streams of CO_2 as a byproduct. Although limited in quantity, they make a good capture target, because the CO_2 capture is integral to the total production process, resulting in relatively low incremental capture costs. For example, natural gas produced from the wells often contains a significant fraction of CO_2 that could be captured and stored. Other industrial processes that lend themselves to carbon capture are ammonia manufacturing, fermentation, and hydrogen production (e.g. in oil refining).

Fuel-conversion processes also offer opportunities for CO_2 capture. For example, producing oil from the oil sands in Canada is currently very carbon intensive. Adding CCS to parts of the production process can reduce the carbon intensity. Another example arises if we move towards a hydrogen economy. Opportunities for CO_2 capture will arise from producing hydrogen fuels from carbon-rich feedstocks, such as natural gas, coal, and biomass. The CO_2 by-product would be highly concentrated (in many cases, >99 per cent CO_2) and the incremental costs of carbon capture would be relatively low compared to capture from a power plant (usually just requiring compression).

Finally, coupling CCS with biomass feedstocks offers the potential for *negative net emissions*. Biomass contains carbon taken from the atmosphere and, in theory, we can capture and store the carbon in the biomass, resulting in a lowering of carbon concentrations in the atmosphere (i.e. negative emissions). Of course, one must account for the life-cycle emissions due to growing, harvesting, and processing the biomass. But if these emissions are kept low, net negative emissions can result.

IV. CAPTURE PROCESSES

CO_2 capture processes from power production fall into three general categories: (i) post-combustion capture; (ii) oxy-combustion capture; and (iii) pre-combustion capture. The first two categories are compatible with the existing pulverized coal (PC) power plant infrastructure that relies on combustion of fossil fuels. The last category is generally reserved for incorporation into an integrated gasification combined-cycle (IGCC) power plant.

(i) Post-Combustion Capture

Post-combustion capture can be considered a form of flue-gas clean-up. The process is added to the back end of the power plant, after the other pollutant

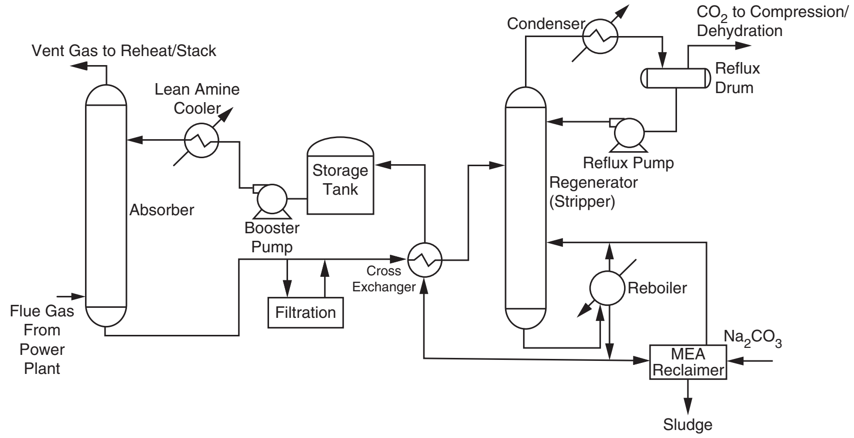

Figure 13.2. Process flow diagram for a typical amine separation process

control systems (to control for particulates, sulphur dioxide (SO_2), and nitrous oxides (NO_x)). To be cost-effective, heat integration with the power plant is required.

To date, all commercial post-combustion CO_2-capture plants use chemical absorption processes with monoethanolamine (MEA)-based solvents. MEA was developed over 70 years ago as a general, non-selective solvent to remove acid gases, such as CO_2 and H_2S, from natural-gas streams. The process was modified to incorporate inhibitors that reduce solvent degradation and equipment corrosion when applied to CO_2 capture from flue gas. Considerations for degradation and corrosion also kept the solvent strength relatively low, resulting in relatively large equipment sizes and solvent regeneration costs.

As shown in Figure 13.2, which depicts a typical process flowsheet, flue gas contacts the MEA solution in an absorber. The MEA selectively absorbs the CO_2 and is then sent to a stripper. In the stripper, the CO_2-rich MEA solution is heated to release almost pure CO_2. The CO_2-lean MEA solution is then recycled to the absorber.

A later section discusses representative costs of a supercritical pulverized coal (SCPC) power plant, with and without capture, based on a modern amine system. A big part of the cost of post-combustion capture is the parasitic energy load. For capture of 90 per cent of the CO_2, the parasitic load for capture and compression will reduce the power plant output by about 25 per cent.

Research into new post-combustion capture technology is under way. The primary goal of these new processes is to reduce costs. This can be achieved by reducing the parasitic load, as well as reducing equipment sizes. Some approaches under way are:

- *Developing new solvents*. For example, two new processes based on ammonia as a solvent are currently being tested in pilot plants.

- *Using alternative separation processes*. These include adsorption and membrane-based processes. While theoretically possible, it is a difficult task due to the low CO_2 concentrations and pressures in the flue gas.
- *Developing new separation materials*. This is a new line of research that is still in the early stages of development. However, materials such as ionic liquids or metal organic frameworks (MOFs) are being applied to the CO_2-capture problem. They offer the possibility of significant cost reductions but not enough research has been carried out yet to judge whether they can be applied at the required scale and in the harsh flue-gas environment.

(ii) Oxy-Combustion Capture

Because nitrogen is the major component of flue gas in power plants that burn coal in air (which nearly all existing plants do), post-combustion capture is essentially a nitrogen–carbon dioxide separation. If there were no nitrogen, CO_2 capture from flue gas would be greatly simplified. This is the thinking behind oxy-combustion capture: instead of air, the power plant is fed oxygen that is produced on site in an air separation plant. The resulting flue gas will be mostly CO_2 and H_2O, which are easily separable (the water condenses out in the compression process).

A few items about this process should be noted.

- The primary separation process has now shifted from the flue gas to the intake air, where oxygen is separated from nitrogen. This is done in a standard air separation unit (ASU), but it will have a large parasitic load of about 15 per cent of a power plant's electric output.
- A standard power boiler can be used for this process (making retrofits of this technology to standard PC plants possible), but a portion of the flue gas needs to be recycled into the combustion chamber in order to control the flame temperature.
- Once the water is separated out, the flue gas will be over 90 per cent CO_2. However, there will be minor impurities in the effluent, including SO_2, NO_x, and non-condensables such as oxygen and nitrogen. In general, these impurities will need to be cleaned up before the CO_2 is ready for transport and injection.

Studies show that oxy-combustion capture can be competitive with post-combustion capture. However, experience with oxy-combustion is limited. In September 2008, Vattenfall began operation of a 30 megawatt thermal (MWth) oxy-combustion pilot plant at its Schwarze Pumpe site in Germany. The cost of this facility was about $100m and it is expected to provide critical operating data for the oxy-combustion process. Vattenfall projects that for full-scale operations, the cost of oxy-combustion capture will be 40 euros/tonne CO_2 or less.

Future improvements in oxy-combustion can come from:

- specially designed boilers that increase efficiency and eliminate the need for the external recycle of flue gas;
- use of ionic transport membranes for oxygen production.

Other oxy-combustion technologies are:

- Chemical looping combustion, where solids flow between two fluidized bed reactors. In one reactor, the solid reacts with air (picking up oxygen). In the second reactor, it reacts with fuel (losing its oxygen). If successful, this process can essentially eliminate the cost of oxygen production.
- Clean Energy Systems has a process based on an 'oxygen turbine' (as opposed to oxygen boilers in the systems above). A pilot plant is currently under construction in California as part of the US Regional Partnership Program.

(iii) Pre-Combustion Capture

Pre-combustion capture is usually applied in IGCC power plants. This process includes gasifying the coal to produce a synthesis gas composed of carbon monoxide (CO) and hydrogen (H_2); reacting the CO with water (in a water-gas shift reaction) to produce CO_2 and H_2; capturing the CO_2; and sending the H_2 to a turbine to produce electricity. Since the primary fuel sent to the gas turbine is now hydrogen, some can be bled off as a fuel for separate use, such as in hydrogen fuel cells to be used in transportation vehicles.

Capturing CO_2 before combustion offers some advantages. First, CO_2 is not yet diluted by the combustion air. Second, the CO_2-containing stream is usually at elevated pressure. Therefore, more efficient separation methods can be applied, for example using pressure-swing-absorption in physical solvents, such as methanol or polyethylene glycol (commercial brands are Rectisol and Selexol). One of the biggest barriers to this pathway is that currently electricity generation is cheaper in PC power plants than in IGCC plants. The pre-combustion process could also be used when natural gas is the primary fuel. Here, a synthesis gas is formed by reacting natural gas with steam to produce CO_2 and H_2. However, for the natural gas case, it is unproven whether pre-combustion capture is preferable to the standard post-combustion capture.

Worldwide, gasification facilities exist today that do not produce electricity, but synthesis gas and various other byproducts of coal gasification. In these facilities, CO_2 is separated after the gasification stage from the other gases, such as methane, hydrogen, or a mix of CO and hydrogen. The synthesis gas or hydrogen is used as a fuel or as a chemical raw material, e.g. for liquid fuel manufacturing or ammonia synthesis. The CO_2 can also be used as a chemical raw material, for dry-ice manufacturing, carbonated beverages, and EOR. For example, the Great Plains Synfuel Plant, near Beulah, North Dakota, gasifies 16,326 tonnes per day of lignite coal into 3.5m standard cubic metres per day of combustible syngas, and close to 7m standard cubic metres of CO_2. A part of the CO_2 is captured by a physical solvent based on methanol. The captured CO_2 is compressed and 2.7 m million standard cubic metres per day are piped over a 325 km distance to the Weyburn, Saskatchewan, oil field, where the CO_2 is used for enhanced oil recovery.

V. GEOLOGICAL STORAGE

(i) Types of Formations

Geological sinks for CO_2 include oil and gas reservoirs, deep saline formations, and unminable coal seams. Together, these can hold hundreds to thousands of gigatons of carbon (GtC), and the technology to inject CO_2 into the ground is well established. CO_2 is stored in geologic formations by a number of different trapping mechanisms that depend on the formation type.

Oil and Gas Reservoirs

Depleted oil and gas reservoirs have proven that they can hold hydrocarbons for millions of years. This gives confidence that they can store CO_2 for a long time. Also, these reservoirs are relatively well characterized. However, some questions arise about whether the wells drilled into the reservoirs and the removal of the hydrocarbons have compromised their integrity. Active oil reservoirs have become a high priority target, since CO_2 storage can be combined with EOR.

Unmineable Coal Seams

Abandoned or uneconomic coal seams are another potential storage site. CO_2 diffuses through the pore structure of coal and is physically adsorbed to it. This process is similar to the way in which activated carbon removes impurities from air or water. The exposed coal surface has a preferential affinity for adsorption of CO_2 than for methane with a ratio of 2:1.

Deep Saline Formations

Deep saline formations, both subterranean and sub-seabed, may have the greatest CO_2 storage potential. These reservoirs are the most widespread and have the largest volumes. The density of CO_2 depends on the depth of injection, which determines the ambient temperature and pressure. The CO_2 must be injected below 800 metres so that it is in a dense phase (either liquid or supercritical). When injected at these depths, the specific gravity of CO_2 ranges from 0.5 to 0.9, which is lower than that of the ambient aquifer brine. Therefore, CO_2 is buoyant and will naturally try to rise to the top of the reservoir.

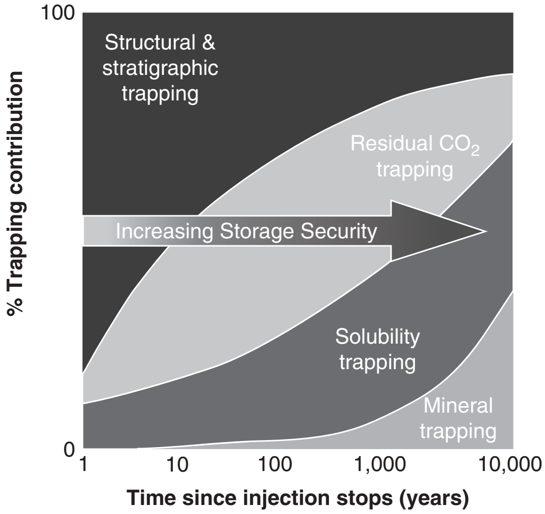

Figure 13.3. Schematic of the influence of different trapping mechanisms over time

Source: IPCC Special Report (2005), *Carbon Dioxide Capture and Storage*, Figure 5.9, p. 208.

(ii) Trapping Mechanisms for Saline Formations

Unlike oil and gas reservoirs, deep saline formations have a limited history of use for storage, primarily from acid-gas injections or natural-gas storage. However, research has shown that there are a number of mechanisms that work to trap the CO_2. These mechanisms work on different time scales, but they work in such a way that the longer CO_2 stays in the ground, the smaller the chance of any leakage. This is shown schematically in Figure 13.3.

The four trapping mechanisms are described further below.

- *Structural and stratigraphic trapping*. The CO_2 is injected into a permeable reservoir, initially displacing the brine that is in the pores. The injection will generally cause a rise in pressure. This needs to be monitored to make sure it stays below the pressure at which the rock starts to fracture. The CO_2 will be buoyant in this environment, causing it to rise to the top of the reservoir. It is here that an impermeable caprock of the formation will trap the CO_2.
- *Residual CO_2 trapping*. As the CO_2 flows through the reservoir, some of it gets incorporated into the soil matrix. This is called residual CO_2 trapping. The CO_2 trapped in such a manner becomes immobile, and its storage can be considered permanent.
- *Solubility trapping*. Over timescales of decades to centuries, some of the CO_2 will dissolve in the brine. This is called solubility trapping. The timing and amount of CO_2 trapped in such a manner is very reservoir-dependent. This trapping removes the buoyancy from the CO_2, thus reducing the likelihood

of leakage. If the brine ever leaves the reservoir, the CO_2 will be released. However, this usually occurs on very long timescales.

- *Mineral trapping*. Over centuries to millennia, the injected CO_2 may react with the minerals in the reservoir. Essentially, CO_2 can get incorporated into the solid rocks and minerals in the reservoir. This is called mineral trapping and can be considered permanent storage.

(iii) Capacity

The IPCC Special Report, *Carbon Dioxide Capture and Storage*, concluded that 'available evidence suggests that, it is likely that there is a technical potential of at least about 2,000 $GtCO_2$ of storage capacity in geological formations'. This is a large number (about two orders of magnitude greater than total annual worldwide CO_2 emissions), indicating the potential of CCS to be a significant CO_2 mitigation strategy. It should be pointed out that some countries have an abundance of storage capacity (e.g. USA, Australia), while others have limited options (e.g. Japan).

The reservoirs with the largest potential capacity are the deep saline formations. At present, capacity estimates for CO_2 storage in deep saline formations are highly uncertain. This is because the data required to do rigorous capacity calculations are very sparse. Data are typically obtained through drilling wells. Unlike oil and gas reservoirs, deep saline formations have no commercial value, so the number of wells drilled into these formations is limited.

On the other hand, much more data exist for storage estimates in oil and gas reservoirs. However, owing to a current lack of field data needed to confirm the methodology used to calculate storage capacities, there is still uncertainty in these numbers.

Calculating storage capacities in coal seams is very difficult, in part because the feasibility of large-scale storage in coal seams has not been demonstrated. Any capacity estimates for these formations must be taken as very highly uncertain.

The US Department of Energy (DOE) has just completed a *Carbon Sequestration Atlas of the United States and Canada*.[5] It gives capacity estimates for oil and gas reservoirs as 82 $GtCO_2$. For saline formations, it gives a range of 920–3,400 $GtCO_2$. The high end of this range is greater than the worldwide capacity reported by the IPCC. It should be noted that the IPCC was being conservative in its estimates (saying 'at least'), but this does highlight the uncertainty in making these estimates.

In summary:

- At present, capacity estimates are highly uncertain;
- however, there is a broad consensus that the capacity will be large enough for CCS to be a significant CO_2 mitigation strategy;

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[5] Available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/

Table 13.1. Existing large-scale storage operations

Project	Leader	Location	CO_2 source	CO_2 sink
Sleipner (1996)	Statoil	North Sea, Norway	Gas processing	Saline formation
Weyburn (2000)	Pan Canadian	Saskatchewan, Canada	Coal gasification	EOR
In Salah (2004)	BP	Algeria	Gas processing	Depleted gas reservoir
Snovit (2008)	Statoil	Barents Sea, Norway	Gas processing	Saline formation

- while potential storage reservoirs exist around the world, some countries will have better CCS opportunities than others.

(iv) Large-Scale Projects

At present, four large-scale CO_2 storage projects are in operation (see Table 13.1). All of these projects are injecting in the order of 1m tonnes per year CO_2. Also, the source of CO_2 for all of these projects is an industrial by-product, so the cost of capture is relatively small. The number in parentheses next to the project is the year it started CO_2 injections.

The first commercial-scale project dedicated to geologic CO_2 storage is in operation at the Sleipner West gas field, operated by Statoil, located in the North Sea about 250 km off the coast of Norway. The natural gas produced at the field has a CO_2 content of about 9 per cent. In order to meet commercial specifications, the CO_2 content must be reduced to 2.5 per cent. At Sleipner, the separated CO_2 is compressed and injected via a single well into the Utsira Formation, a 250 metre thick aquifer located at a depth of 800 metres below the seabed. About 1 Mt of CO_2 have been stored annually at Sleipner since October 1996, equivalent to about 3 per cent of Norway's total annual CO_2 emissions. A total of 20 Mt of CO_2 is expected to be stored over the lifetime of the project. Over the years, the injected CO_2 has been monitored via time-lapse 3D seismic techniques. This has allowed researchers to get a better understanding of the behaviour of CO_2 in the reservoir. The seismic monitoring strongly suggests that the CO_2 is safely stored and not escaping the reservoir. However, the resolution of the seismic data is not great enough to definitively say that 100 per cent of the CO_2 has remained in the reservoir. Experiences at the other three sites are similar to that at Sleipner, in that they provide learning opportunities and demonstrate that CO_2 can be safely stored in geological formations.

(v) Regulatory and Legal Issues

While there is no comprehensive legal and regulatory framework for CO_2 storage *per se*, the US Environmental Protection Agency (EPA) has a regulatory framework governing most types of underground injection, the Underground Injection Control (UIC) Program. The UIC Program was created under the Safe Drinking Water Act of 1974 (SDWA) and establishes requirements to assure that underground injection activities will not endanger drinking-water sources. The UIC Program regulates underground injection under five different classes of injection wells, depending on the type of fluid being injected, the purpose of injection, and the subsurface location where the fluid is to remain. States are allowed to assume primary responsibility for implementing the UIC requirements in their borders as long as the state programme is consistent with EPA regulations and has received EPA approval. Injection operators are required to provide financial assurance in case they cease operations, with the level of assurance a function of the estimated cost of plugging and abandoning the injection well.

Recently, the EPA released a proposed rule for federal requirements under the UIC Program for CO_2 geologic sequestration (GS) wells.[6] Below is an excerpt from the EPA's fact sheet[7] on the new rules.

> EPA's proposed rule would establish a new class of injection well—Class VI—and technical criteria for geologic site characterization; area of review and corrective action; well construction and operation; mechanical integrity testing and monitoring; well plugging; post-injection site care; and site closure for the purposes of protecting underground sources of drinking water.
>
> The elements of today's proposal build upon the existing UIC regulatory framework, with modifications based on the unique nature of CO_2 injection for GS, including:
>
> - Geologic site characterization to ensure that GS wells are appropriately sited;
> - Requirements to construct wells with injectate-compatible materials and in a manner that prevents fluid movement into unintended zones;
> - Periodic re-evaluation of the area of review around the injection well to incorporate monitoring and operational data and verify that the CO_2 is moving as predicted within the subsurface;
> - Testing of the mechanical integrity of the injection well, ground water monitoring, and tracking of the location of the injected CO_2 to ensure protection of underground sources of drinking water;
> - Extended post-injection monitoring and site care to track the location of the injected CO_2 and monitor subsurface pressures; and
> - Financial responsibility requirements to assure that funds will be available for well plugging, site care, closure, and emergency and remedial response.

Beyond incorporation into existing regulations, CCS contains some items that go beyond the scope of the UIC Program. One item is legal access to the geologic formation. In most of the world, the pore space is owned by the state, so this is not a major problem. However, in the United States, this is not the case. While there may be some differences between the states, people that own mineral rights and/or

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[6] See http://www.epa.gov/safewater/uic/wells_sequestration.html

[7] See http://www.epa.gov/safewater/uic/pdfs/fs_uic_co2_proposedrule.pdf

surface rights will have claim to ownership of the pore space. Under current law, the right to use the sub-surface would need to be acquired from every owner where the CO_2 plume migrates. This could become impractical in many situations, so new legislation may be needed to ease this process.

How to deal with the long-term stewardship and liability of the CO_2 is still an open issue. By long term, we mean centuries or longer. Questions on how to monitor the reservoir once it is closed and for how long need to be resolved. Liability would arise if CO_2 leaked out and caused environmental or health problems, but it is a highly unlikely that leaking CO_2 is a significant health or environmental risk. Of more concern, a leaking CO_2 reservoir becomes a CO_2 emissions source. We assume that there will be a charge for CO_2 emissions (through either a tax or cap-and-trade system), and someone would be liable for that charge. It has been suggested that a number of years after closure (in the order of 10 years) and assuming no significant leakage or operational problems, the long-term stewardship and liability would be taken over by the government. To help pay for this, companies injecting CO_2 into the ground would pay into a liability fund.

VI. COSTS[8]

In MIT's *The Future of Coal* report (MIT, 2007), detailed cost estimates were developed for all three of the CO_2-capture categories discussed in section IV. However, in the report, costs were based on analyses done in the 2000–4 timeframe, with costs given in 2005 US dollars. Since then, commodity and fuel costs have risen significantly, resulting in significant increases in costs. For example, CERA (Cambridge Energy Research Associates) reports that capital costs for coal-fired power plants have risen about 80 per cent over this timeframe.

Recently, we updated the cost estimates from *The Future of Coal* study. We only published the costs for supercritical pulverized coal (SCPC), since the recent literature and discussion with industry experts support these new estimates. We decided not to publish new cost estimates for IGCC and oxy-fuel combustion technology for two reasons. The first reason is the tremendous uncertainty regarding the true costs and performance characteristics of such new technologies. The second reason is that our discussion with industry experts indicates that any current IGCC cost estimate is highly uncertain since costs for IGCC may have doubled or tripled since 2004. To present a new estimate under such high uncertainty would be detrimental to the discussion about new-generation technology. This situation underscores the importance for new comprehensive design and cost studies reflecting the new technical knowledge about IGCC in this transient cost environment.

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[8] This section is based on Hamilton *et al.* (2008). See http://sequestration.mit.edu/pdf/GHGT9_Hamilton_Herzog_Parsons.pdf for more details.

Table 13.2. Updated costs for Nth plant SCPC generation

Reference plant	Units	SCPC
Total plant cost	\$/kWe	1,910
CO_2 emitted	kg/kWh	0.830
Heat rate (HHV)	Btu/kWh	8,868
Thermal efficiency (HHV)		38.5%
LCOE		
Capital	\$/MWh	38.8
Fuel	\$/MWh	15.9
O&M	\$/MWh	8.0
Total	\$/MWh	62.6
CO_2 capture plant		
Total plant cost	\$/kWe	3,080
CO_2 emitted @ 90% capture	kg/kWh	0.109
Heat rate (HHV)	Btu/kWh	11,652
Thermal efficiency (HHV)		29.3%
LCOE		
Capital	\$/MWh	62.4
Fuel	\$/MWh	20.9
O&M	\$/MWh	17.0
Total	\$/MWh	100.3
\$/tonne CO_2 avoided		
	\$/tonne	52.2

Estimates of costs for SCPC have been updated to a 2007 US dollar basis according to estimates of recent escalation in capital, operating, and fuel costs (see Table 13.2). These costs are for an Nth plant (N may be in the range of 5–10). The first several CCS plants built will probably be more expensive, as typically happens with the introduction of new technologies. It should also be recognized that we are currently in a highly volatile market and costs are constantly changing.

In summarizing CCS costs for the SCPC case, the following should be noted.

- The mitigation cost for capture and compression is about \$52/tonne CO_2. This does not include transport and storage costs, which are very site specific. However, we can estimate a typical range of \$5–15/tonne CO_2. This implies a carbon price of about \$60–65/tonne CO_2 is needed to make these plants economical in the marketplace.
- Adding capture to a power plant raises the cost of electricity by about 4¢/kWh. This represents an increase in the delivered price of electricity in the 25–50 per cent range.

It should be noted, that the cost of CCS from other sources (as discussed in section III) may be significantly less expensive than from coal-fired power plants and they may be good initial targets. However, their CO_2 emissions are much smaller than those from coal-fired power.

VII. CHINA

China has abundant coal reserves. Inexpensive coal has been crucial in powering China's rapid growth; on average, a new coal plant starts up every week in China. Since this trend is likely to continue (at perhaps a reduced rate), the question of whether CCS can be deployed in China is important.

Some specific points can be made about China and CCS.

- The CCS technology used in China will be essentially the same as is used in the USA and Europe.
- No authoritative studies have been conducted on potential geologic storage reservoirs in China. However, initial assessments suggest that, while not as abundant as in, say, the United States, there are significant resources available.
- China has shown a willingness to host CCS demonstration projects. China seems to have an easier time in developing infrastructure than the USA or Europe.

CCS, like most mitigation technologies, is very dependent on what China decides to do about climate policy in general. The MIT coal study (MIT, 2007) looked at China and concluded that it will probably lag the West in adoption of climate policies. How to integrate China and the rest of the developing world into an international climate regime is a difficult and critical issue, but beyond the scope of this paper.

The cost of CCS may also significantly slow its adoption by China, even after China implements a climate policy. Therefore, reducing costs for CCS becomes even more important in the China context.

VIII. THE POLICY CONTEXT AND THE FUTURE OF CCS

There are many roads CCS can take as we move forward. What path it takes depends not only on how the technology evolves, but also on how climate-change technology evolves. In this concluding section, CCS is discussed in this policy context.

First, it may be instructive to look at example scenarios for the growth of CCS. MIT (2007) presented simulations performed with its emissions predictions policy analysis (EPPA) model, a computable general equilibrium (CGE) model of the world economy. One set of simulations in the report contrast a business-as-usual (BAU) scenario, with two policy cases, one with a high global carbon price and one with a low price, implemented either through cap-and-trade or a carbon tax. The low carbon price is modelled as beginning in 2010 at \$7/ton CO_2, increasing at a real rate of 5 per cent annually, and the high carbon price begins at \$25/ton CO_2 in 2015, increasing at an annual rate of 4 per cent thereafter. Table 13.3 from the report shows the resulting coal CO_2 emissions, the coal consumption, and

Table 13.3. Implications for global coal consumption under alternative CO_2 price assumptions (from MIT, 2007)

	2000	**BAU 2050**	**Low CO_2 price 2050**	**High CO_2 price 2050**
Coal CO_2 emissions ($GtCO_2$/year)	9	32	15	5
Coal consumption (Exajoules (EJ)/year)	100	448	200	161
% Coal with CCS	0	0	4	60

the proportion of coal technologies that use CCS under the three scenarios. The simulations assume limited expansion of nuclear technologies and a reference gas price with no breakthroughs in liquefied natural gas (LNG) transport.

The model predicts that, under the BAU scenario, global CO_2 emissions from coal will reach $32GtCO_2$/year by 2050. Under both CO_2 price scenarios, coal use grows from current levels, but not as much as under the BAU case. However, thanks to CCS, under a high CO_2 price, coal consumption still grows by over 60 per cent, but its emissions are almost cut in half.

The above simulation assumes that CCS has achieved both technological readiness and that policies are in place to create a market for CCS. Today, neither of these assumptions is valid. Below is an outline of the actions and policies necessary for CCS to move forward.

In the MIT study (MIT, 2007), conducting large-scale CCS demonstrations was identified as the key to achieving technological readiness:

> The central message of our study is that demonstration of technical, economic, and institutional features of carbon capture and sequestration at commercial scale coal combustion and conversion plants, will (1) give policymakers and the public confidence that a practical carbon mitigation control option exists, (2) shorten the deployment time and reduce the cost for carbon capture and sequestration should a carbon emission control policy be adopted, and (3) maintain opportunities for the lowest cost and most widely available energy form to be used to meet the world's pressing energy needs in an environmentally acceptable manner.

MIT called for 3–5 demonstration projects in the US in the next 8–10 years. More recently, at their 2008 meeting in Japan, the G-8 called for 20 demonstrations worldwide by 2020. The demonstration projects, coupled with a strong R&D programme, would help address the two biggest challenges for CCS:

- reducing or eliminating first-mover costs;
- reducing uncertainties primarily associated with storage at scale:
  - capacity
  - long-term integrity
  - regulatory framework
  - liability
  - public acceptance.

Assuming a successful demonstration programme, by 2020 CCS could be ready for large-scale deployment. However, an additional three key ingredients are necessary for CCS to be considered truly commercial.

(i) *Creating a market through climate policy*
As stated in section VI, a carbon price of about \$60–65/tonne CO_2 is needed to make CCS from power production economical in the marketplace. While a cap-and-trade system (or carbon tax) can create a carbon price, it is highly unlikely that climate policy will result in a carbon price greater than \$60/tonne CO_2 by 2020. Therefore, there will be a gap between the cost of CCS and the carbon price. Over time, the carbon price will rise and the cost of CCS may fall, giving hope that the gap will eventually disappear. However, for a decade or two, additional policy measures will be needed to promote CCS. These can take many forms—direct subsidies, production credits, bonus allowances, portfolio standards, etc.

(ii) *Providing a regulatory environment*
Companies will not enter a business with a high degree of regulatory uncertainty. As discussed in section V, there are three primary concerns that must be addressed:

- ownership of the pore space;
- regulations for site selection, injection operations, and site closure;
- resolution of the long-term liability issue.

(iii) *Development of a business structure*
While the two items above are primarily government tasks, this item is up to the private sector. It is the private sector that will build and operate CCS systems. It is the private sector that will make choices about technology and will spur future improvements. It is highly unlikely that one company will offer services for all parts of the CCS value chain. Today, quite a few companies are actively working to provide capture technology. Also, CO_2 transport companies exist. However, no companies exist to provide storage services or long-term stewardship. In addition, rules for how these companies interact still need to be developed.

IX. CONCLUSIONS

To summarize some of the key messages from this paper:

- there is a growing consensus that it will be impossible to achieve significant cuts in greenhouse-gas emissions (50–80 per cent below today's levels) without CCS. So while CCS may not be a silver bullet, it can be considered a 'keystone' technology;

- all components of a CCS system are commercially available and in operation today;
- the key technical challenge for CCS is the integration and scaling-up of the system components. This is a significant task that relies on major investments in the technology, but no technological breakthroughs are required.

The steps moving CCS to commercialization rely on making the necessary investments in the technology and involve both the private and public sectors. The four essential elements include:

- private–public partnerships are needed to build and operate approximately ten demonstration plants worldwide over the next decade;
- governments (with advice from the private sector) must create a market for CCS through climate policy. The policy should be technologically-neutral (i.e. avoid picking winners and losers);
- governments (with advice from the private sector) must provide a suitable regulatory environment for CCS. These regulations must be stringent enough to protect the public interests, but not overly stringent so as to stifle CCS development;
- the private sector must develop a business organization to address all components of the CCS value chain. The implementation of CCS, including decisions on the appropriate technologies, needs to be left up to the private sector.

BACKGROUND READING

Most of the material in this paper has been based on publications produced by the MIT Carbon Capture and Sequestration Program. These publications can be found at http://sequestration.mit.edu/
Several publications in particular were heavily relied upon:

de Figueiredo, M.A., Herzog, H. J., Joskow, P. L., Oye, K. A., and Reiner, D. M. (2007), ‘Regulating Carbon Dioxide Capture and Storage’, CEEPR WP-2007-003, April.

Hamilton, M., Herzog, H. J., and Parsons, J. (2008), ‘Cost and US Public Policy for New Coal Power Plants with Carbon Capture and Sequestration’, presented at the 9th International Conference on Greenhouse Gas Control Technologies, Washington, DC, November.

Herzog, H. J., and Golomb, D. (2004), ‘Carbon Capture and Storage from Fossil Fuel Use’, in C. J. Cleveland (ed.), *Encyclopedia of Energy*, New York, Elsevier Science, 277–87.

MIT (2007), *The Future of Coal: Options for a Carbon Constrained World*, Massachusetts Institute of Technology, available at http://mit.edu/coal/

In addition, two sources of additional reading are recommended for those who want to explore more deeply some of the topics discussed in this paper:

IPCC (2005), *Carbon Dioxide Capture and Storage*, Intergovernmental Panel on Climate Change, Special Report, New York, Cambridge University Press, available at http://www.ipcc.ch/ipccreports/srccs.htm

Proceedings of the 9th International Conference on Greenhouse Gas Control Technologies, Washington, DC, November 2008 (forthcoming). This will be made available through Science Direct in February 2009.