

Carbon Capture, Utilization, and Storage: An Update

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Summary

Recent progress in carbon capture, utilization, and storage (CCUS) is reviewed. Considerable research effort has gone into carbon dioxide (CO₂) capture, with many promising separation processes in various stages of development, but only a few have been tested at commercial scale, and considerable additional development will be required to determine competitiveness of new technologies. Processes for direct capture of CO₂ from the air are also under development and are starting to be tested at pilot scale. Transportation of CO₂ to storage sites by pipeline is well-established, though substantially more pipeline capacity will be required if CCUS is to be undertaken at a large scale. Considerable experience has now been built up in enhanced-oil-recovery (EOR) operations, which have been under way since the 1970s. Storage in deep saline aquifers has also been achieved at scale. Recent large-scale projects that capture and store CO₂ are described, as are current and potential future markets for CO₂. Potential effects of changes in the US tax code Section 45Q on those markets are summarized. Future deployment of CCUS will depend more on cost reductions for CO₂ separations, development of new markets for CO₂, and the complexities of project finance than on technical issues associated with storage of CO₂ in the subsurface.

Introduction

The challenge of making deep reductions in greenhouse gas (GHG) emissions in this century is a daunting one given the scale of the use of energy by humans and our current dependence on fossil fuels, which provide essential energy services at low cost to modern societies. In broad strokes, human activities that contribute to CO₂ emissions and, therefore, to climate change, include combustion of fossil fuels; industrial activities such as the production of iron and steel, cement, and fertilizer; and agriculture and land-use changes. **Fig. 1** shows estimates of the magnitudes of the anthropogenic CO₂ emissions from these broad sectors (Le Quéré et al. 2016), reported as average annual flows of CO₂ in billions of metric tons of CO₂ per year (GtCO₂/yr) for the decade 2006–2015. Of the 38 GtCO₂/yr of emissions associated with fossil fuel use, industrial emissions, and land-use change, approximately one-quarter of the CO₂ was taken up by the ocean (reducing ocean pH), almost a third was incorporated in terrestrial plants, and the remainder (approximately 44%) remained in the atmosphere. The concentration of CO₂ in the atmosphere is currently increasing approximately 2 ppm per year, with 2016 the first full year in which the concentration was greater than 400 ppm (Le Quéré et al. 2016). Methane (CH₄) is also an important GHG that has contributed approximately 20% of the anthropogenic radiative forcing of the atmosphere so far (Saunio et al. 2016).

Meeting the challenge of reducing GHG emissions will require a fully diversified portfolio of approaches, such as much more energy-efficient end-use technologies (e.g., cars, home and business heating and air conditioning, lighting); electrification of energy services coupled with reduced GHG emissions from electric power generation; fuel switching in transportation and electric power generation; deployment of additional renewable power generation; land-use changes toward lower-emission agriculture; emission reductions of short-term forcers such as black carbon, CH₄, and hydrofluorocarbons (HFCs); and capture and use or storage of CO₂ (CCUS), among many others.

Integrated assessments of the various pathways indicate that portfolios that include significant deployment of CCUS have lower estimated costs than those without CCUS (Clarke et al. 2014; Krey et al. 2014).

Any CCUS project requires capturing the CO₂ from some emissions stream, transporting it to a storage or utilization site, and then storing it in the subsurface or using it directly as a feedstock. Considerable research has been performed worldwide since the 1970s to develop EOR methods based on high-pressure CO₂ injection, along with the required pipeline transportation of the CO₂ from sources to oil fields; to examine the potential capacity of a variety of subsurface porous rock formations (primarily those containing oil and gas or salt water) to store CO₂; to develop efficient ways to capture CO₂ from combustion product gases, and examine in detail the physical mechanisms that could act to retain CO₂ in the subsurface, as well as the risks associated with large-scale CCUS and potential for leakage, and in a much more limited way; and to consider the potential large-scale uses of CO₂ in addition to EOR.

Results of all that research have been summarized in numerous reviews. In 2005, the Intergovernmental Panel on Climate Change (IPCC) issued a detailed special report (SRCCS) on many aspects of carbon capture and storage (CCS) (Metz et al. 2005). Technical aspects of geologic storage of CO₂ were reviewed by Orr (2009a, 2009b). de Coninck and Benson (2014) offered a broader review of capture and storage technologies as well as legal, policy, and public perception issues. Wilcox (2012) provided detailed descriptions of specific capture technologies and their energy requirements, as did Boot-Handford et al. (2014), who gave additional commentary on pipeline transportation issues, subsurface storage issues, and a European policy perspective. Rubin et al. (2015) examined the costs of CCUS technologies, comparing them with SRCCS cost estimates (Metz et al. 2005). Databases of CCS projects are available as well (MIT 2016; Global CCS Institute 2018), and information concerning projects sponsored by the US Department of Energy (US DOE) and its Regional Carbon Sequestration Partnerships is available in Carbon Storage Atlas V (Department of Energy 2015).

While considerable progress has been made in the technical aspects of CCUS, and a variety of pilot-scale demonstration projects have been performed, deployment at full commercial scale has been much more limited. Reasons for the slow deployment and recent experience in new commercial projects are discussed below. The sections that follow review the state of play and the potential for future deployment of CCUS to contribute to reductions in GHG emissions at a scale of approximately 1 GtCO₂/yr or more.

CO₂ Sources and Capture From Concentrated Streams

The first step (and usually the most costly, typically 60 to 85% of total costs) in any CCUS project is to separate the CO₂ from the gas stream in which it is present. As **Fig. 2** illustrates, there are many options (SEAB 2016). A recent report by the Secretary of

Energy’s Advisory Board (SEAB 2016; Majumdar and Deutch 2018) assessed the potential for deployment of these pathways both to reduce CO₂ emissions directly and to achieve what are known as negative emissions, activities that actively remove CO₂ from the atmosphere. A more-detailed discussion of ways to achieve negative emissions with estimates of costs is given by the National Academies of Sciences, Engineering, and Medicine (2018).

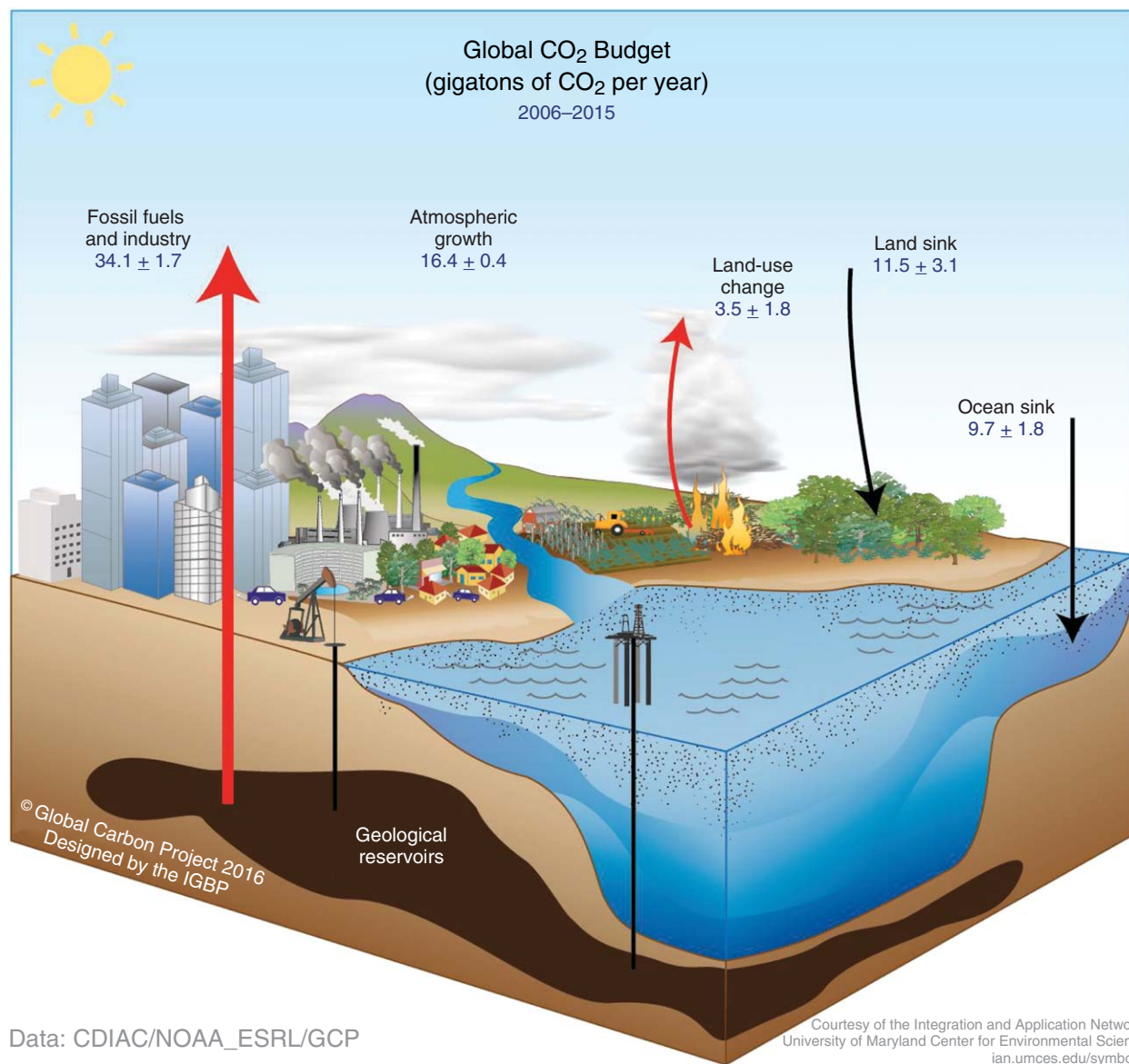
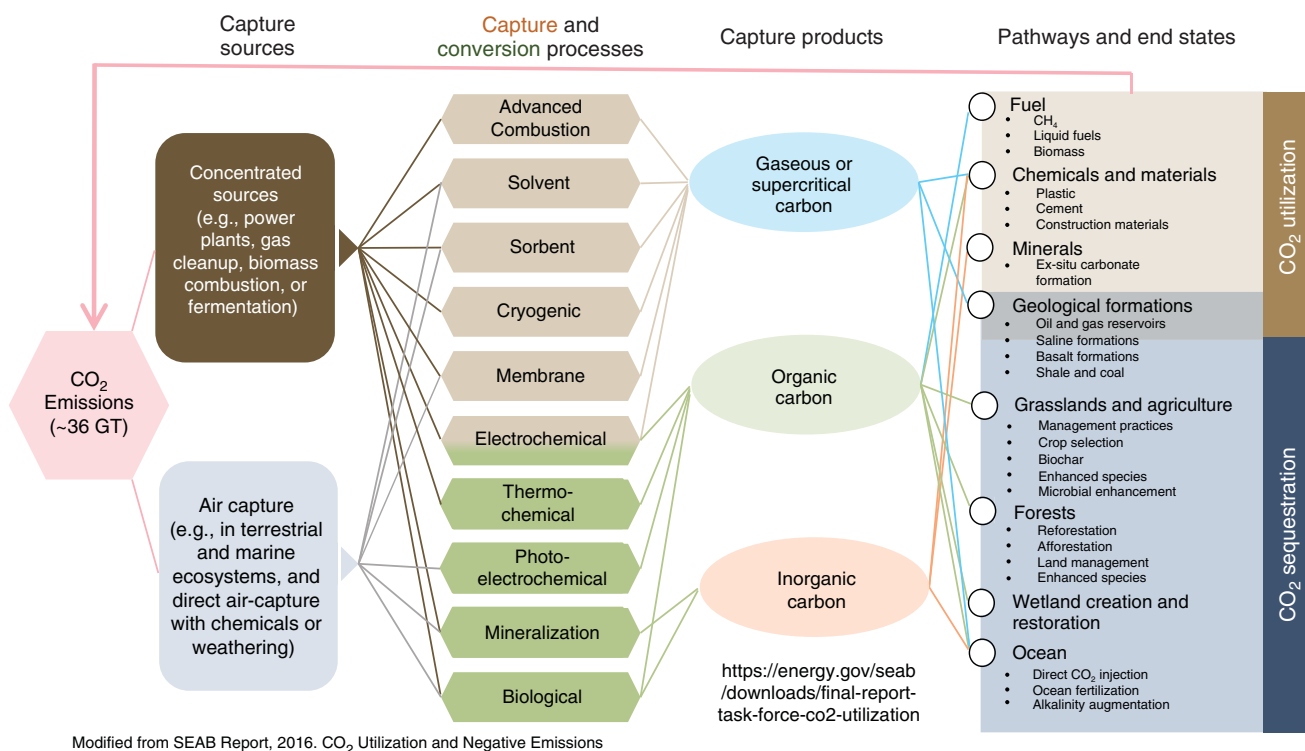


Fig. 1—Perturbation of the global carbon cycle caused by anthropogenic activities, averaged globally for the decade 2006–2015 (GtCO₂/yr) (Le Quéré et al. 2016).

These pathways involve two groups of CO₂ sources. One group includes sources (for example, power plants, refineries, or some natural-gas production streams that contain relatively concentrated CO₂ (4% to nearly 100%). The other pathway seeks to capture CO₂ from the atmosphere, where the concentration is much lower (≈400 ppm or 0.04%). Either pathway, of course, could provide CO₂ that could be stored or put to use in some way.

Combustion product gases have CO₂ concentrations typically in the 4 to 15% range with coal-fired power plants at the high end of the range and gas turbines at the low end. The concentration of CO₂ in produced natural gas varies widely. For example, CO₂ is 9% of the gas stream at Sleipner (Global CCS Institute 2014), 15% at Gorgon (Chevron Australia 2005), and 65% at La Barge (Parker et al. 2011). Iron and steel making produces gases that contain 15 to 30% CO₂ from burning of fuel and calcining, which is removal of CO₂ from CaCO₃ (Romano et al. 2013). CO₂ emissions in cement manufacturing stem from combustion of fuels for calcining along with the CO₂ removed from the CaCO₃. Fertilizer and ethanol production yield nearly pure streams of CO₂.

CO₂ is produced in large quantities by fossil fuel combustion associated with electric power generation and transportation, though capture efforts have generally focused on electric power generation given the challenges of collecting CO₂ from distributed sources in transportation settings. Industrial processes for which CO₂ separations are already performed at commercial scale are also potential CO₂ sources: natural-gas processing, hydrogen production in petroleum refining, and ammonia, ethanol, cement, and steel production, for example. While much of the discussion of CCS technologies has been in the context of coal-fired power generation, much of the CO₂ currently being stored as part of pilot and demonstration projects comes from natural-gas processing, where the CO₂ must be separated in order to sell the natural gas (Orr 2009b; de Connick and Benson 2014). There are also examples of projects where the CO₂ is emitted during ethanol or ammonia production (Rubin et al. 2015; MIT 2016; Global CCS Institute 2018).



Modified from SEAB Report, 2016. CO₂ Utilization and Negative Emissions

Fig. 2—Options for reducing CO₂ emissions or capturing previously emitted CO₂ from the atmosphere (SEAB 2016).

CO₂ capture in combustion settings such as electric power generation is usually divided into precombustion or post-combustion processes. In post-combustion capture, CO₂ is separated from combustion product gases that are predominantly nitrogen and water, though contaminants such as particulates or sulfur and nitrogen oxides could also be present. Post-combustion capture has been tested at scale for pulverized-coal plants, but could also be applied to natural-gas-fired plants. In precombustion capture, an air separation plant provides pure oxygen that can then be used directly for oxyfuel combustion or for integrated gasification and combined cycle (IGCC) power generation. Oxyfuel combustion produces a CO₂/water mixture that is easily separated by cooling the combustion product gas. IGCC makes use of partial oxidation of a fuel such as coal or coke to gasify the solid fuel, producing a syngas mixture of CO₂, carbon monoxide, hydrogen, and water. A water/gas shift reaction is typically used to produce more hydrogen and eliminate carbon monoxide, and CO₂ is separated from the hydrogen, which is then burned in a combined cycle plant.

Technologies for separation of CO₂ from a gas stream include absorption in a liquid solvent, adsorption on a solid sorbent, membrane separations, cryogenic separation, and chemical reactions including mineralization (de Connick and Benson 2014; Wilcox 2012; Boot-Handford et al. 2014). de Connick and Benson (2014) compare the characteristics, advantages, and technical challenges of the various separation technologies (see their Table 1). The most widely deployed separation technology is absorption of CO₂ from natural gas in a liquid amine solution (typically monoethanolamine) (Rochelle 2009; Rochelle 2012). The CO₂-rich solution is then physically separated from the gas and regenerated by heating the liquid to recover the CO₂. Compression of the CO₂ and transportation by pipeline to the storage site, typically an EOR project or a deep saline aquifer, complete the process. The solvent regeneration step requires substantial energy to heat the solvent mixture to strip the CO₂ and regenerate the solvent. Considerable research has been performed to improve solvents and optimize thermal energy management (de Connick and Benson 2014; Wilcox 2012; Boot-Handford et al. 2014; Rochelle 2009, 2012).

While various amines are the most widely used, other solvents are also available, including chilled ammonia (Mathia et al. 2010), and mixed solvents such as rectisol, selexol, or sulfinol have been used in settings where sulfur removal is important (Department of Energy 2018). More recently, ionic liquids have been investigated as potential solvents for CO₂ capture (de Connick and Benson 2014; Boot-Handford et al. 2014; Brennecke and Gurkan 2010). Ionic liquids are salts that remain liquid at relatively low temperatures. A wide variety of chemical structures can be made by choosing the anion and cation portions of the salt to seek useful attributes such as high solubility of CO₂, low volatility, good thermal stability, and low energy of regeneration (Boot-Handford et al. 2014). These solvents have not yet been tested at pilot or demonstration scale, however. This is an active area of research, with the potential to yield significant benefits, though the cost of such materials as the ionic liquids will have to be reduced if they are to be deployed widely.

Solid adsorbents such as activated carbon or zeolites have also been used to capture CO₂ (de Connick and Benson 2014; Wilcox 2012; Boot-Handford et al. 2014; Sumida et al. 2012). Metal organic frameworks have been identified as potential sorbents. These materials are hybrid organic-inorganic networks of metal ligands that allow selection of the metals and organics to adjust sorption properties (Boot-Handford et al. 2014; Sumida et al. 2012) and energy requirements for regeneration. Solid adsorbents are typically regenerated by a pressure swing rather than the temperature swing typically used for liquid solvents. If vacuum extraction of the CO₂ is used, the energy requirement for compression of the CO₂ to pipeline pressure is typically higher than that of solvent separations. These separations have not yet been applied at pilot or demonstration scale for storage.

Membrane gas separations are sometimes used for natural-gas cleanup. They can also be used to separate CO₂ (de Connick and Benson 2014; Du et al. 2011; Yang et al. 2008). Both polymer membranes and inorganic membranes have been investigated. Membrane separations have not seen widespread application in field projects (de Connick and Benson 2014) so far.

A cryogenic separation of CO₂ and H₂S from a produced-gas stream containing 65% CO₂ and 5% H₂S has been demonstrated at the Shute Creek facility that processes gas from the La Barge Field in Wyoming (Parker et al. 2011). Cryogenic distillation has long been

used to separate gases (O_2 from N_2 , or CH_4 from heavier hydrocarbons, for example). However, if the concentration of CO_2 is high, a solid phase forms if the temperature is sufficiently low. Chilled feed gas is introduced into the middle of a column that includes a conventional cryogenic distillation section above that sprays liquid downward to encounter the feed gas. As CO_2 and H_2S partition into the liquid and CH_4 and N_2 evaporate from the liquid, the concentration of CO_2 rises in the liquid until a CO_2 -rich solid phase forms. As that solid phase descends further through the column, it warms and melts into a liquid containing the CO_2 and sulfur compounds. That liquid is then compressed to pipeline pressure for transportation to a storage site. The obvious advantage of a process such as this is that solvents or sorbents are not required, and the recovered liquid CO_2/H_2S mixture can be more easily compressed than can a gas phase.

Another version of a cryogenic CO_2 separation using solid formation for application to a flue gas stream from a coal-fired power plant has been tested at pilot scale by Jensen et al. (2015). It is based on formation of a solid CO_2 phase (desublimation) from flue gas cooled to 154 K. The solid phase is transported in a hydrocarbon contacting liquid, physically separated, and then warmed to melt it into a liquid that can be compressed. Jensen et al. (2015) note that a similar process could be applied to separate CO_2 flue gas containing 4% CO_2 , a typical concentration for a natural-gas-fired power plant. The design of this process allows recovery of most of the energy required to cool the flue gas as exiting cold fluids cool feed gas in heat exchangers.

If precombustion capture is to be used, a conventional cryogenic air separation unit is one way to provide the O_2 required (de Connick and Benson 2014; Wilcox 2012; Boot-Handford et al. 2014). That O_2 can then be used directly for oxyfuel combustion or for IGCC power generation. In direct oxyfuel combustion, a recycle stream of CO_2 is blended with the stream of O_2 to limit maximum combustion temperature. Boot-Handford et al. (2014) provide a detailed discussion of design variations and list a number of demonstration projects.

An alternative way to separate O_2 from air is to use chemical looping (Boot-Handford et al. 2014). In this approach, O_2 in air reacts with metal particles, which are transferred to a separate reactor to contact with fuel, leaving the N_2 behind to exit the metal-particle reactor. In the fuel reactor, the metal oxide is reduced when the oxygen reacts with the fuel. The metal particles are then circulated back to contact air and oxidize, completing the loop. In both oxyfuel combustion and chemical looping, a separation of O_2 substitutes for a CO_2 separation at the back end of the combustion process. Testing of these processes is further along for oxyfuel combustion than it is for chemical looping (Boot-Handford et al. 2014).

Thus, as Fig. 2 indicates, there are many options for capture of CO_2 from relatively high-concentration sources. Of them, conventional amine separations have been most common in demonstrations at medium to large scales, but pilot and demonstration-scale testing of other methods are currently under way. Which method turns out to be most promising will depend on a combination of costs, energy penalties, and the rate of progress in reducing elements of both capital cost and operating cost. Given the cost of currently deployed separation technologies, the variety of separation settings, gas compositions (including contaminants), temperatures, sources of energy for regeneration, and opportunities for integration with other plant operations, investing across a wide-ranging research and development (R&D) portfolio of separation materials and processes with the explicit aim to reduce separation costs would lower a primary barrier to future deployment of CO_2 capture. As the range of processes described in this section indicates, there are many opportunities for progress.

New Options for Power Generation and CO_2 Capture

It is possible to combine CO_2 capture with electric power generation in ways that facilitate capture. An example is the combination of oxyfuel combustion of natural gas with a turbine using supercritical CO_2 as the working fluid (Service 2017). Combustion of the CH_4 with pure O_2 in a stream of recycled CO_2 yields a mixture of CO_2 and H_2O . That mixture drives a turbine that can be much smaller than a conventional steam turbine because the supercritical CO_2 is much denser than steam. The exhaust stream is cooled to condense and remove H_2O . The amount of CO_2 added by combustion is removed for disposal at relatively high pressure after recompression of the cooled CO_2 as part of the recycle of the working fluid upstream of the combustion chamber. The elimination of condensation of steam with a cooling tower reduces energy losses, which gives relatively high-efficiency power generation, and fresh water is produced rather than consumed (in a cooling tower). A demonstration plant has recently been completed by Net Power near Houston (Service 2017). If the plant performs as planned, and credits are given for sales of liquid nitrogen, argon, and oxygen, the cost of electric power would be similar to that of a conventional single-cycle gas turbine. In that case, the incremental cost of the CO_2 capture and compression would be quite small.

A second example of a combination of technologies is being tested at the scale of a small pilot by Fuel Cell Technology and ExxonMobil (2016). In this design, conventional electric power generation with a gas turbine produces a product stream that contains approximately 4% CO_2 . That gas is mixed with more CH_4 as the feed to a molten carbonate fuel cell that produces additional electric power and concentrates the CO_2 to 70 to 80% purity. Proponents note that a similar system could be used to capture CO_2 and produce H_2 in combination with electric power generation with a gas turbine.

Whether these approaches will find their way into the market place will depend on whether they can compete on cost of electric power and at the same time reduce the cost of CO_2 capture significantly. Both approaches have the potential to offer ways to capture CO_2 from natural-gas power generation that are more efficient and less costly than conventional amine separations. Approaches such as these that combine technologies to increase efficiency and reduce cost should continue to be investigated.

Capture From Low-Concentration Streams: Direct Air Capture

Fig. 2 also indicates that various schemes for capture of previously emitted CO_2 directly from the atmosphere are also being considered. Researchers in this area argue that the pace of deployment of technologies that reduce GHG emissions, even if the Paris Accords goals are met, will be insufficient to meet the goal of limiting global warming to $2^\circ C$, let alone the more ambitious goal of $1.5^\circ C$, and, therefore, that CO_2 concentrations in the atmosphere will overshoot. Capturing CO_2 from the air followed by storage in the subsurface or conversion for use in some way would allow reductions in the CO_2 concentration in the atmosphere—so-called negative emissions (Keith 2009; Majumdar and Deutch 2018; National Academies of Sciences, Engineering, and Medicine 2018; Rosen 2018). Advocates for research in this area note, of course, that capture from air will always be more expensive than capture from more-concentrated sources, which should be done at scale as a first step (Keith 2009; SEAB 2016) even as R&D on air capture proceeds. Improvements in capture materials would help in either application, of course. As the SEAB report (SEAB 2016, page 73) indicates, “if R&D yields sorbents that satisfy the condition for direct air capture, CO_2 capture from point sources would be solved as well.”

Direct air capture is much less well-established, at least partly because of the thermodynamic challenge of separations with a relatively small concentration driving force, in which very large volumes of air must be handled to recover the CO_2 . Estimated costs of direct-air-capture processes are typically at least an order of magnitude larger than those for conventional capture processes—a 2011

study estimated a capture cost of USD 600/t, for example (Socolow 2011). Even so, several processes are being developed by start-up companies, including the examples discussed next (Rathi 2017). Climeworks uses an amine-based solid absorbent with temperature swing using low-temperature waste heat to capture CO₂ from the air. A small demonstration plant (50 t/a) captures CO₂ that is then dissolved in water and injected into reactive basalts in Iceland. A second installation in Zurich sells 1000 t/a of captured CO₂ to a greenhouse. The cost of capture is consistent with the USD 600/t estimates reported by Socolow (2011), though the company estimates that reductions to below USD 100/t are possible.

Carbon Engineering is making fuels from CO₂ captured from the air. The capture process combines a calcium oxide-based capture process with hydrogen generated by hydrolysis of water to create a drop-in hydrocarbon fuel. The design calls for the energy required for the separation, hydrolysis, and synthesis reactions to be obtained from renewal resources, which would make the fuel carbon neutral. A small pilot plant is operating in Squamish, British Columbia, at the scale of 1 t/d of CO₂ capture and 1 B/D of fuel (Carbon Engineering 2017). Keith et al. (2018) describe material and energy balances for the separation process and report results of independent cost analyses that indicate CO₂ could be supplied at pressure at a cost of USD 94 to USD 232/t CO₂ for a plant at the scale of 1 MtCO₂/yr, depending on energy and financing cost assumptions.

Global Thermostat uses a ceramic-supported amine to capture CO₂ from the air and low-temperature waste heat to release the CO₂. A small pilot plant is operating in Menlo Park, CA (Rathi 2017).

Whether any of the cost estimates mentioned will be realized in actual operations remains to be seen, of course. The time frame for deployment of these technologies at scale will clearly be much longer than for more-concentrated CO₂ streams.

It is worth noting that direct air capture occurs at very large scale around the planet in natural biological systems (see Fig. 1). Roughly 21 net GtCO₂/yr is captured by the terrestrial biosphere and the ocean, as part of cycles of carbon that are an order of magnitude larger (SEAB 2016, Appendix 5). Thus, one possibility is to use plants to capture CO₂, and then burn the resulting biomass in power plants with CCS to create negative emissions (known as BECCS) (National Academies of Sciences, Engineering, and Medicine 2018). Some researchers envision large-scale growth of energy crops, while others note that increasing soil carbon by amending soils with biochar or improving growth of root stocks could have multiple benefits including storing carbon and improving soils. Forestation or reforestation would store CO₂ as long as the trees remain unharvested, are not burned in a forest fire, or do not die and decompose. Questions also remain as to whether planting of energy crops could be achieved at very large scale without adverse effects on food production, water use, and competition for land use in general. Even so, this is an area that has the potential to yield CO₂ capture at the GtCO₂/yr scale if research is successful (SEAB 2016, Appendix 5; National Academies of Sciences, Engineering, and Medicine 2018).

Transportation of CO₂

Pipeline transportation of CO₂ is well-established with approximately 6000 km of pipelines operating, mostly in the US. See Boot-Handford et al. (2014, pages 157–161) for a detailed review of the issues associated with transporting CO₂ by pipeline. Truck transportation of liquid CO₂ can be used for small quantities, such as food grade CO₂ used for carbonated drinks and other food uses. Ship transportation has been used in a limited way in Europe, and a relatively large project that would capture CO₂ from industrial sources and then would use ship transport of liquid CO₂ has been proposed for the North Sea by Statoil, Shell, and Total (Statoil 2017). Thus, while transportation adds cost to CCS, the technology issues associated with transportation have largely been solved, and there is considerable industrial scale experience on which to build.

Pipelines are by far the most widely used transportation method—essentially all of those pipelines have been purpose built for specific projects, and most have been built for EOR applications. More-widespread deployment of subsurface storage will clearly require additional pipeline capacity. For example, a network of pipelines that gathers CO₂ from multiple sources and distributes it to multiple injection sites would allow subsurface storage of gas from midsize industrial sources that already separate CO₂ or that have high-concentration CO₂ streams. Such a network was constructed over time in the Permian Basin, west Texas, where multiple pipelines deliver CO₂ to a number of EOR projects in the region. Areas that have many sources (such as the US Gulf Coast) would be obvious possibilities, though the present market for CO₂ is insufficient to support the investment required (see below for a discussion of the market).

How much pipeline capacity would be required to support 1 GtCO₂/yr of CCUS? Thirty-one projects that are listed in the Global CCS Institute Database as currently active or being planned (Global CCS Institute 2018) list pipeline lengths. They have an average of 166 km of pipeline per project, though the range is from 0 to 460 km. If that average is applied to 1,000 projects injecting 1 MtCO₂/yr, something like 166 000 km of pipelines would be required to support 1 GtCO₂/yr of injection, a 28-fold increase over the 6000 km of pipeline infrastructure currently in place (Boot-Handford et al. 2014). That is obviously a significant increase, and it would need to be built over an extended period, but it is not beyond the capacity of the industry.

Subsurface Storage of CO₂

Oil and gas reservoirs have low-permeability layers (seals) that can retain buoyant fluids indefinitely (provided they are not damaged by operations that activate a fault, or fracture through the seal), and there are large volumes of pore space in deep formations that contain saline water. There is clearly no shortage of pore space—the IPCC SRCCS reported it is likely that at least 2000 GtCO₂ of potential storage locations could be available in sedimentary basins (Metz et al. 2005). Not all of that pore space will meet essential criteria for the existence of appropriate seals, distance from CO₂ sources, being in nonurban areas, pressure management, acceptable injection rates, and so on, but the number is large enough to indicate that geologic storage could be undertaken at large scale if other barriers can be overcome. A survey of storage capacity that considers injection rate and pressure constraints on storage capacity for 11 deep aquifers in the US is reported by Szulczewski et al. (2012). They found that for a growth rate of 45 MtCO₂/yr of injection, the US has sufficient capacity for at least 100 years of storage in deep aquifers. Kearns et al. (2017) compared methods for estimating storage capacity, noting the limitations in data availability, and compiled estimates for sedimentary basins in 18 regions around the world. The global estimate for onshore storage ranged from 6000 to 42 200 GtCO₂, and the estimate of practical offshore storage ranged from 1900 to 13 400 GtCO₂. In both estimates, the lower end of the range resulted from an assumption of pressure limitations from closed reservoirs, while the upper end assumed formations with no pressure limitation. Kearns et al. (2017) judged that the lower estimate would be sufficient to meet demand for pore space for the rest of the century even if policy and cost reductions because of technology development lead to extensive deployment of CCS. Thus, while estimates of available storage volume vary widely, they are all large enough and widely distributed enough that sites sufficient for storage at the GtCO₂/yr scale should be available.

The physical mechanisms that can lead to essentially permanent storage of the CO₂ are well-documented in other reviews (Metz et al. 2005; Orr 2009a, 2009b; de Connick and Benson 2014; Boot-Handford et al. 2014). CO₂ is buoyant in most subsurface settings, so suitable storage sites will need low-permeability seals (preferably multiple layers) above the storage zone to retain the CO₂ while

other physical mechanisms act to immobilize the CO₂ (Ide et al. 2007). Those mechanisms include dissolution in brine. CO₂-saturated brine is slightly denser than brine alone, and, hence, the driving force for upward migration of CO₂ is replaced by a small downward driving force (Riaz et al. 2006). Also important is capillary trapping, in which invading brine snaps off isolated bubbles of CO₂ that are akin to residual oil and, therefore, are very difficult to move (Metz et al. 2005; Ide et al. 2007). In water-wet systems, as a separate CO₂ phase dissolves in brine or remaining oil, the volume of dissolved CO₂ will be replaced by mobile brine, which will trap additional CO₂, a mechanism that can limit the travel of CO₂ migrating updip in a sloping aquifer (Hesse et al. 2008) or at the base of a dissolving CO₂ cap. Adsorption on solid surfaces in coal or organic-rich shales, for example, can also immobilize CO₂ (as long as adequate pressure is maintained) and can mobilize adsorbed CH₄ (Zhu et al. 2003), though at current natural-gas prices, enhanced gas recovery from coal is unlikely to be economic.

Chemical reaction of injected CO₂ to form carbonate minerals is also a possible mechanism for immobilization. Most assessments of mineralization in sedimentary rocks have concluded that the limited amounts of calcium, magnesium, and iron-rich silicate minerals that react to form carbonate minerals will limit both the amount and rate of mineralization in those settings [see Romanov et al. (2015) for a detailed review of mineralization in the subsurface as well as above ground]. Mineralization rates could be higher in basalts. In the CarbFix pilot test in Iceland (Matter et al. 2016), 175 tons of CO₂ and then 73 tons of a mixture of CO₂ and H₂S were dissolved in water and injected into a fractured shallow basalt formation. Tracer tests indicated that more than 95% of the injected CO₂ had reacted during a 2-year period. Dissolving the CO₂ in water eliminates the need for a seal to retain a buoyant fluid, but requires handling large quantities of water. If future tests of this process confirm the reaction rates for longer periods, basalts could offer another large set of potential storage locations.

An area of research that has received more attention in recent years is the interplay of geomechanics with large-scale CO₂ injection. Fig. 3 from the review provided by Rutqvist (2012) describes the issues, including the potential for induced seismicity in large-scale CO₂-injection projects. Injection of CO₂ will occur at some downhole pressure higher than the surrounding formation pressure, and the corresponding pressure rise as injection proceeds will extend farther into the injection and adjacent formations than the CO₂ itself will invade. The stress changes that result will cause deformation and possibly microseismic events. In some locations and with large enough injection overpressure, well damage, fracturing, or fault activation could result. For example, Zoback and Gorelick (2012) argued that the pressure increases associated with large-scale CO₂ injection could initiate slip on critically stressed pre-existing faults and trigger earthquakes that might damage impermeable seals above the storage zone. Vilarassa and Carrera (2015), on the other hand, argued that in sedimentary formations in the 1- to 3-km depth range, faults are unlikely to be critically stressed. Either way, managing overpressure during CO₂ injection will be an important operational task. For example, the design of the Gorgon Project in Australia calls for drilling eight injection wells and four water-production wells to reduce formation pressure (Flett et al. 2008). Techniques such as those suggested by Snee and Zoback (2018) to reduce the potential for earthquakes resulting from oil and gas operations can be deployed to limit those risks for CO₂ injection.

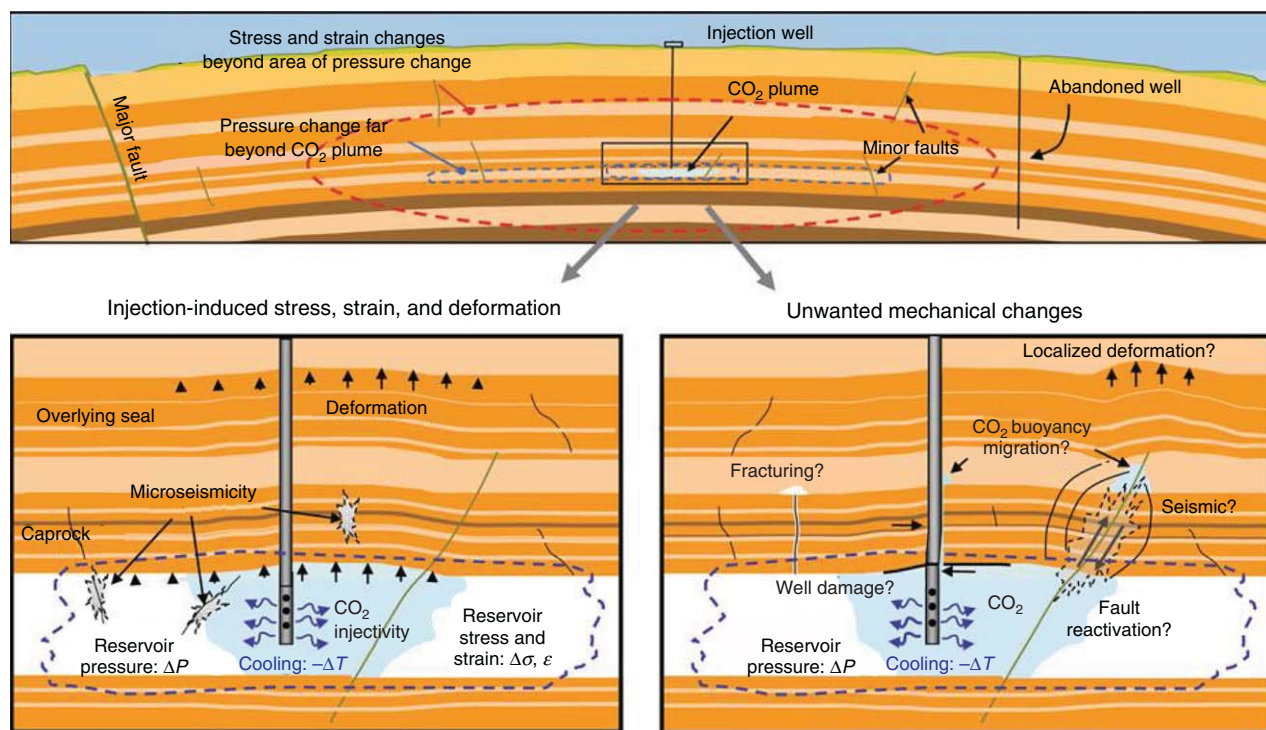


Fig. 3—Geomechanical processes active during CO₂ injection into deep sedimentary formations. [Reprinted by permission from Springer Nature: Springer Nature, *Geotechnical and Geological Engineering* 30 (3), The Geomechanics of CO₂ Storage in Deep Sedimentary Formations, J. Rutqvist, 2012.]

Well damage and potential for leakage along wellbores is also a possibility that should be considered (Rutqvist 2012; Gasda et al. 2004; Nordbotten et al. 2009). Risks of leakage can arise from wellbore instability during drilling, deformation of the well assembly during injection, degradation of rock/cement barriers, or from the existence of abandoned wells. Current state-of-the-art wells for which appropriate monitoring is conducted are unlikely to leak (Rutqvist 2012), but wells abandoned earlier might not meet those standards. See Nordbotten et al. (2009) for an analysis of potential wellbore leakage that highlights the value of multiple caprock layers to limit adverse vertical migration.

Thus, there are many technical issues to be considered in designing and operating a CO₂ storage project, and research to improve our ability to predict where the CO₂ will go and how fast it will be immobilized should continue as projects are developed. But it is clear from the long history of injection of CO₂ in EOR settings that CO₂ can be injected safely, that recycling of produced CO₂ throughout project life can store the CO₂ in the long term, and that physical mechanisms that immobilize the CO₂ are well-enough understood that deployment of subsurface CCS can proceed. Injection of CO₂ into deep saline formations has also been under way long enough now that considerable experience in the characterization of storage sites and the reservoir engineering required for such projects has accumulated. Eiken et al. (2011) reviewed lessons learned from storage operations at Sleipner, In Salah, and Snohvit. Those geologic settings have widely varying porosities, permeabilities, temperatures, and pressures. In those projects, a variety of monitoring methods were applied, including time-lapse seismic monitoring, gravity surveys, and satellite radar interferometry, in addition to wellhead pressures, temperatures, and flow rates. They concluded that careful monitoring was very useful in reservoir management and confirmation of the absence of leakage, as well as efficient use of pore space. Developing monitoring methods and reducing their cost will continue to be an important part of acceptance of large-scale projects.

Current and Potential Markets for CO₂

A large majority of the CO₂ captured to date that has been injected into the subsurface has been for the purpose of EOR. That is currently the only large market for CO₂—approximately 88% of the anthropogenic CO₂ currently being injected into the subsurface worldwide is used for EOR. In the US, experience with CO₂ EOR began in the early 1970s in the Permian Basin in a time of high global oil prices, and expanded to include floods in Louisiana and Mississippi, and in Colorado and Wyoming (MIT 2016; Global CCS Institute 2018; Department of Energy 2015). A number of projects outside the US have also been undertaken. For example, CO₂ captured from the Dakota Gasification synfuels project was and still is used for EOR in southern Saskatchewan, and there are several other projects operating or under construction in Canada and Australia. Of the 17 large-scale projects listed as operating in the Global CCS Institute database (Global CCS Institute 2018), 13 provide approximately 31 MtCO₂/yr for EOR, with the remaining four storing approximately 4 MtCO₂/yr in deep saline formations. That wealth of experience provides a basis for operating CO₂ storage projects in the future.

An important question is whether CO₂ EOR actually reduces overall CO₂ emissions. Combustion of any oil produced by EOR obviously generates CO₂ emissions, and the various activities of separating CO₂ from produced gas, compressing it, and reinjecting it emit CO₂ associated with the energy required for those activities. An assessment of life-cycle emissions for enhanced oil and gas recovery was reported by the International Energy Agency (Heidug et al. 2015). The following are key assumptions: how much CO₂ is emitted by combustion of a barrel (bbl) of oil (assumed to be on average 0.51 t CO₂/bbl), how much CO₂ is ultimately stored at the end of the EOR process (assumed to be 0.3 t CO₂/bbl for conventional CO₂ EOR), and what fraction of the oil recovered offsets conventional oil production in the global oil market (0.84 bbl of conventional oil offset per barrel of oil recovered by CO₂ EOR)

With these assumptions, the study indicated a 63% reduction in CO₂ emissions per bbl of EOR oil when compared with emissions of a barrel of conventionally produced oil. The study noted that there is considerable variability in the carbon content of oils that could be offset (with reduction values ranging from 47 to 150% depending on the oil) and that there is additional potential for modifying EOR process operations to optimize a combination of storage and EOR if there is a carbon price or tax credit (Kovscek and Cakici 2005). In effect, making the EOR process less efficient, by injecting CO₂ in the capillary transition zone at the base of a reservoir, for example, (Jessen et al. 2005) and, therefore, storing more CO₂ per bbl of oil produced, could improve costs by taking advantage of revenue from carbon storage in addition to that from oil production. For example, Godec et al. (2016) cite proposed next-generation operations of CO₂ floods that are expected to have CO₂ utilization values of 0.45 to 0.5 t CO₂/bbl. They also estimated life-cycle CO₂ emissions for oil recovered by CO₂ EOR (using coal-fired power generation for the electricity required for CO₂ compression) would be 0.42 to 0.43 t CO₂/bbl of EOR oil. If both sets of values are achieved, the combustion of the oil recovered would be balanced by the CO₂ stored. Thus, while estimates of the reductions vary widely depending on the assumptions made in the analyses, substantial reductions in CO₂ emissions from EOR oil compared with conventional oil appear possible.

The global market for CO₂ from any source, anthropogenic or natural, is approximately 80 MtCO₂/yr, with approximately 50 MtCO₂/yr used for EOR, nearly all of that in North America (Global CCS Institute 2011). The remaining 30 MtCO₂/yr is used for beverage carbonation and other food industry applications and in small amounts for various industry uses. The current global CO₂ market is small, approximately 2% of annual CO₂ emissions—a 12-fold increase in the market would be required to reach the 1-GtCO₂/yr scale.

There are only a few markets for commodities that rival the magnitude of CO₂ emissions. Fuels, of course, are one, though it is clear that reducing CO₂ to make a fuel would require more energy than would be released by combustion of the fuel, and the energy resources to make that fuel would need to have very low CO₂ emissions and very low cost. For example, if solar or other carbon-free electricity were available at 2 to 3 cents/kWh, then it might be possible to produce liquid hydrocarbon fuels at competitive cost (SEAB 2016, Appendix 6). Given the value of energy-dense liquid fuels, especially for aircraft and long-haul surface transportation, there is research under way on electrochemical reduction of CO₂ and CO to make liquid fuel precursors [see Li et al. (2014) for an example]. Building materials offer another area where the quantities in use are large and where it might be possible to use CO₂ productively in the form of carbonate minerals.

Prospects for growth in demand in existing and emerging markets for CO₂ were evaluated by the Global CCS Institute (2011). The report argues that emerging uses for CO₂ with the largest potential for growth are EOR, carbonate mineralization, using CO₂ for curing concrete, enhanced coalbed-methane recovery, boosting yield in urea production, and renewable methanol. Most of these technologies are at an early stage of development, so considerable work will be required to improve cost performance, even if a carbon price comes into play.

Recent Experience at Scale

Fig. 3 shows locations of large-scale CCUS projects actively injecting CO₂ now as well as those for which planning activities are under way. There are currently 17 projects operating at the 0.7- to 1-MtCO₂/yr scale. A number of projects have been implemented in the last few years, building experience at commercial scale, with CO₂ capture from a variety of industrial processes.

The Boundary Dam project (MIT 2016; Global CCS Institute 2018) in Saskatchewan is the first full-scale CCS project at a coal-fired power plant. It uses an amine solvent to capture CO₂ from a rebuilt 110-MW lignite coal power unit that is part of a large generating station. CO₂ capture began in 2014, with a planned injection of 1 MtCO₂/yr. Most of the captured CO₂ is transported by a 66-km pipeline to the Weyburn field, where it is injected at a depth of 1.5 km. A smaller test in a nearby deep saline formation (3.4-km depth) began in 2015. Operating problems were encountered during startup, and critics argue that less-expensive ways to reduce carbon emissions are available (Seale 2017), but those problems have been resolved, and the cumulative injection of CO₂ now exceeds 2 MtCO₂.

The Quest project in Alberta captures approximately 35% (up to 1.2 MtCO₂/yr) of the CO₂ from hydrogen production by methane steam reforming (MIT 2016; Global CCS Institute 2018). The hydrogen is used to upgrade bitumen. The captured CO₂ is transported by a 64-km pipeline and injected into a saline formation at a depth of 2 km. The project was completed on schedule, with CO₂ injection starting in 2015, and the total CO₂ injection now exceeds 2 MtCO₂.

Two new projects are operating in the Middle East (MIT 2016; Global CCS Institute 2018). CO₂ separated from natural gas (0.8 MtCO₂/yr) at the Uthmaniyah Gas Plant has been used since 2015 for EOR in the giant Gawar Field in Saudi Arabia. It is transported by an 85-km pipeline to the field and injected at depths between 1.8 and 2.1 km (Saini 2017). CO₂ capture from iron and steel production in Abu Dhabi at the scale of 0.8 MtCO₂/yr began in 2016. That CO₂ is transported by a 43-km pipeline and is also used for EOR.

Difficulties were encountered at the Kemper plant in Mississippi. This plant was designed to gasify lignite, burn the resulting syngas to generate electric power, and capture 3 MtCO₂/yr. The project required significant scaleup of the gasifier, and a combination of construction delays and startup operating problems in the gasifier led to large cost overruns, with the original \$2.9 billion estimate ballooning to \$7.5 billion. Declining natural-gas prices during the 8-year period of project development also played a role. During the period in which startup problems with the gasification portion of the plant were encountered, natural gas was used to power the combined cycle electric power generation section. An Economic Viability Analysis performed by Mississippi Power indicated that operation of the IGCC plant would be more expensive than continuing to use the natural gas to power the combined-cycle generation in low and medium natural-gas price scenarios (Mississippi Public Service Commission 2017; New York Times 2017), an option that the company adopted and regulators approved. The CO₂ capture from syngas in the IGCC design that would have occurred upstream of the combined-cycle power generation was eliminated. The evolution of this project over an extended period is an example of the difficulties that gasification projects have in competing with low-cost natural gas (Herzog 2016).

Experience with post-combustion capture was better at the Petra Nova Parish power plant near Houston (MIT 2016; Global CCS Institute 2018). The project captures 1.4 MtCO₂/yr, 90% of the CO₂ from a 240-MW slipstream from a 610-MW unit, which is part of a 3700-MW plant. The project supplies CO₂ by pipeline to an oil field for EOR. It was completed on time and on budget and is said to be operating at a profit (Schwartz 2017).

An ethanol production plant is the source of CO₂ for the Illinois Industrial CCS project near Decatur, Illinois (Global CCS Institute 2018). The fermentation process that produces the ethanol generates a nearly pure CO₂ stream (approximately 1 MtCO₂/yr). This project made use of results of the Illinois Basin Decatur Project completed in 2014 that included detailed characterization of the site geology, risk assessment and reservoir modeling, and engineering design including a monitoring system (McDonald 2017). The addition of compression and a 1.6-km pipeline facility was required for storage in a deep saline formation, and injection into a saline aquifer at a depth of 2.1 km began in 2017.

An important question is whether the 13 projects shown as being in the early or advanced stages of development now (see Fig. 4) will actually survive all the way to implementation. Experience indicates that a complex set of factors must come together to allow a project to proceed: a capture process that provides CO₂ at low enough cost, a potential storage site, a business reason to undertake the project, regulatory approval, public acceptance, and financing, which might include government support (Herzog 2016). Many more projects have been proposed than have been developed all the way to operations. Herzog (2016) provides a detailed discussion of the complexity of project planning and financing and analyzes reasons that projects have succeeded to operations or have been cancelled. There are many variations around the world in project drivers (regulatory and business), the availability of government subsidies, the complexity of the capture setting (from natural-gas separation or ethanol production at the simple end to coal gasification at the complex end), and particularly in financing arrangements, which can be complex as well. Any project that proceeds will have to satisfy the constraints at the project location. At this point, it is likely that the complexity of projects and financing barriers will provide more challenges to project development than the technical issues of the project design.

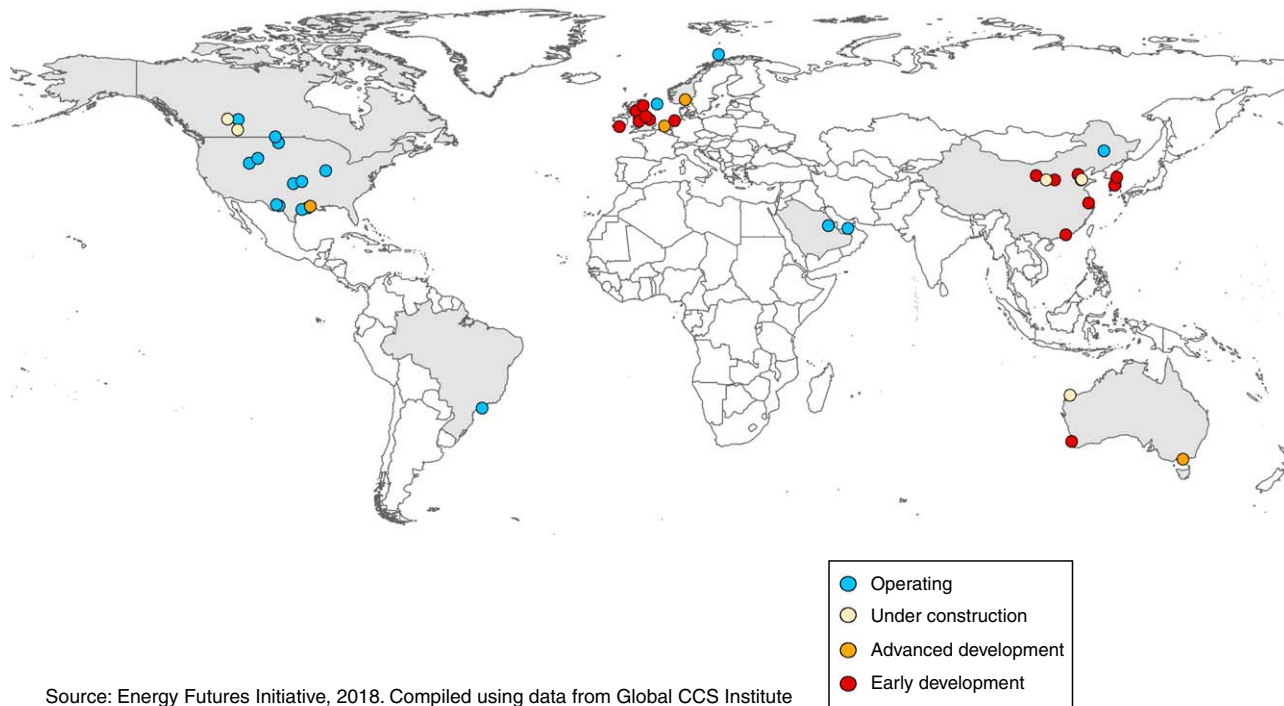


Fig. 4—Large-scale CCUS projects worldwide (Bushman et al. 2018).

Prospects for Future Deployment (45Q)

Given the length of time during which CCUS has been investigated, it is reasonable to ask why deployment has not moved faster. A primary reason is market size given the current cost of supplying CO₂, so R&D that reduces capture costs has the potential to expand markets. In a world that does not price carbon emissions, pilot and demonstration projects can be undertaken with R&D support, typically by governments and large companies, but deployment at scale is unlikely unless there is a market large enough to support it. There is such a market for CO₂ EOR, of course, but not in general for storage in deep saline formations or other forms of storage or use. The Sleipner project in the North Sea offshore Norway (Global CCS Institute 2014) illustrates the point. It began injection of CO₂ into the Utsira formation as a way to avoid payment of a carbon tax applicable to offshore operations. While various experiments with carbon markets are under way, the financial incentives for storing carbon have so far been too low to support deployment.

A recent change in the US tax law could alter that picture (in the US, at least). The Bipartisan Budget Act of 2018 extended an existing tax credit program and increased the size of the credits substantially. Under the new system, EOR projects can earn a tax credit up to USD 35/ton over 12 years from start of operation for new projects that begin construction by 2024 (Schwartz 2017; Bushman et al. 2018; Learn 2018). The tax credit ramps from USD 10/ton to USD 35/ton in 2026, so the size of the credit depends on when the projects start. The credit for deep-saline-formation storage increases from USD 20/ton to USD 50/ton in 2026. Also, the previous 75-MtCO₂ cap on credits was eliminated. Power generation facilities that capture at least 0.5 MtCO₂/yr would qualify for the credit, as would industrial and direct-air-capture plants that capture 0.1 MtCO₂/yr. The legislation allows the tax credit to be transferred from capture equipment owners to entities that sequester or use the carbon, and it might be possible for project developers to make use of US DOE loan guarantees in addition to the tax credit (Bushman et al. 2018; Learn 2018).

The extent to which these credits will enable financing of CCUS projects remains to be seen. For projects in which the cost of separation is lower than the amount of the tax credit (typically where CO₂ is separated already), there will be a financial incentive for CCUS. The requirement that projects start by 2024 favors projects for which storage-site characterization is at least already under way. Bennett and Stanley (2018) argue that the tax credit could increase global capture capacity by two-thirds, with additions of 10 to 30 MtCO₂/yr by 2024. They anticipate that most of the applications would be for EOR and most of the CO₂ would be captured from natural-gas processing, ammonia production, ethanol fermentation, and hydrogen production. Whether demand for CO₂ for EOR or other uses will be sufficient to absorb that additional capture capacity will depend on oil price and on whether projects can be put together quickly enough to take advantage of the credit. The increase in capture capacity envisioned by Bennett and Stanley would be a significant step toward storage at the scale of a GtCO₂/yr, but the tax credit would have to be extended to permit steady deployment in the longer term.

Outside the US, the rate of deployment will depend on local conditions. Because these vary widely around the world and are continuing to evolve, it is not yet possible to project how fast the worldwide scale of CCUS activities will grow. In the absence of some sort of regulatory or carbon price driver at more locations in the world, which could also modify markets for CO₂, growth in the scale of CCUS is likely to continue to be modest.

An indication of potential role of EOR in setting the scale of worldwide CCUS deployment is given by Kolster et al. (2017). They examined the impact of future oil price, cost reductions in separation technology, and/or a carbon price on deployment of CCUS under five scenarios (an optimistic base case with a low carbon price and low oil price, a climate-action world with a high carbon price, a high-oil-price world, a depleting-oil-resource world with oil-supply constraints, and a fast-learning world with rapid reductions in the cost of CO₂ capture from an initial cost of USD 86.7/tCO₂). They found that with a low initial carbon price (USD 25/tCO₂ increasing by USD 1/yr), oil prices in the neighborhood of USD 50/bbl, and an assumed rate of technological learning (10% reduction for each doubling in capacity), cumulative deployment for EOR (not including potential aquifer storage) by 2050 reaches approximately 1/2 GtCO₂/yr. Increasing the initial CO₂ price to USD 40/tCO₂ (reaching USD 75/tCO₂ by 2050), an oil price above USD 85/bbl, or a technology learning rate greater than 14% with each doubling would be required to support EOR deployment at the GtCO₂ scale. Combinations of higher oil prices, a higher CO₂ price, and faster learning could also support GtCO₂/yr deployment. Thus, there is a need for continued reductions in capture cost as well as policy support if CCUS is to contribute CO₂ emission reductions at the GtCO₂ scale by midcentury.

Conclusions

Review of the large and steadily growing literature on CCUS leads to the following conclusions: A portfolio of CCUS technologies is sufficiently developed, so that deployment at the scale of a GtCO₂/yr is technically feasible. Business drivers and models, overall costs, and project financing remain as barriers to the scaleup required. Many capture technologies have been demonstrated, but only a few have been deployed at commercial scale, and the cost of capture is still a primary barrier to wide deployment of CCUS. Continued R&D on new materials (solvents and sorbents) and new processes to reduce the cost of capture is an essential element of support for future growth of CCUS; which capture processes are deployed will depend on competitive operating cost and operating performance of the materials and processes. Combinations of technologies such as the oxyfuel combustion of CH₄ combined with a supercritical CO₂ turbine, or the combination of a molten carbonate fuel cell with a conventional natural-gas combustion turbine, have the potential to reduce capture costs. Other combinations of technologies like this should be investigated as a way to increase efficiency and offer new options that could have widespread application. Capture of CO₂ directly from the atmosphere is possible but costly, with the possible exception of capture by biological systems (plants and algae). BECCS offers the possibility of negative emissions. Progress in dealing with capture from dilute sources will benefit capture from more-concentrated sources. Transportation technologies for compressed CO₂, pipelines and ships at large scale and trucks for small scale, are well in hand. Large-scale deployment of CCUS will require significant expansion of existing infrastructure for transporting CO₂. Physical mechanisms that can immobilize CO₂ in the subsurface are sufficient to retain CO₂ indefinitely, though seals are required in most settings to allow time for that to happen. Continued research to improve the ability to predict where injected CO₂ will go and how long it will take to immobilize it will aid acceptance of subsurface storage projects. Careful attention to geomechanical issues will continue to be required in the design of subsurface storage projects to limit adverse effects on caprock and wellbore integrity. With careful management of injection pressures and overall pressure rise, it should be possible to manage induced seismicity in CCS projects. Current markets for CO₂ are small compared with emissions. EOR and food-industry applications are the largest current markets. Much larger markets will require a carbon price or other regulatory limits on emissions. In the long term, conversion of CO₂ to products such as chemicals or fuels will require access to very low cost zero-carbon electricity, improved catalysis, and better process efficiency. Recent changes to tax credits (45Q) in the US have the potential to stimulate CCS projects for EOR and storage in deep saline formations, though time limits on the availability of the credits will require swift project development. Projects that store CO₂ that has to be separated anyway (natural-gas processing, ethanol plants, hydrogen production, for example) will be favored, given their relatively low capture costs. Recent experience with large-scale CCUS projects

indicates coal gasification projects have difficulty competing in a world of low natural-gas prices. EOR will continue to be an important component of CCUS deployment because it provides project income that can support project financing. Mechanisms such as a carbon price or tax credit, in combination with higher oil prices and cost reductions in CO₂ capture, will be needed for CCUS to reach deployment at the scale of a GtCO₂/yr.

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