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PERSPECTIVE

Onshore Geologic Storage of CO₂

Franklin M. Orr Jr.

The possibility that substantial quantities of CO₂ can be injected into subsurface porous rock formations has been investigated sufficiently to show that pore space available to contain the CO₂ is abundant. Multiple rock types and physical mechanisms can be used to trap the CO₂ indefinitely. With careful site selection and operations, leakage to the near-surface region can be avoided. The next step is to test these injection processes at the scale of a large power plant.

One option for reducing CO₂ emissions from fossil fuel combustion to the atmosphere is to capture and store the CO₂ in porous rocks in the deep subsurface. Large volumes of pore space that might be used to contain CO₂ exist in sedimentary rocks distributed widely around the world, especially in the U.S. Estimates of worldwide potential storage capacity range from 1700 to almost 11,000 gigatons of CO₂ (GtCO₂) (1, 2), and more recent estimates for the U.S. alone show potential storage capacity of 2020 to 14,220 GtCO₂ (3, 4). The wide ranges of the estimates reflect differing assessment methodologies and assumptions about the types and locations of geologic formations included in the assessments (5). Not all potential storage resources will turn out to be suitable, but even so, the potential capacity is large enough that storage of sizable quantities of CO₂ can be contemplated. About 95% of large point sources of CO₂ in the U.S. are within 80 km of a potential storage formation (2).

What rock formations might be suitable for storage? The best choices will be at depths below ~800 to 1000 m, where the CO₂ density is high enough (~500 to 700 kg/m³) to limit the storage volume required. An essential feature is the presence of low-permeability formations above the storage zone (known as seals or caprocks, often shales or evaporites) that prevent vertical flow of CO₂ to the near-surface region. Suitable formations will be large enough that tens of millions of metric tons of CO₂ can be stored in a project lasting the multidecade lifetime of a power plant, and they will

be permeable enough that the CO₂ can be injected at reasonable rates through a modest number of injection wells. Suitable sites will avoid leak hazards of nonsealing faults or wells that have not been properly plugged and

decades of experience transporting large quantities of CO₂ through 5600 km of pipelines and injecting it into the subsurface has been accumulated in this location (6). CO₂ is used for EOR because at high pressure, transfer of components from oil to supercritical CO₂ creates mixtures that can displace oil efficiently in the portion of the formation swept by CO₂. Several of the tests of CO₂ storage worldwide involve EOR (7). CO₂ EOR has always been limited by availability of CO₂ at a cost low enough to allow economic projects: Abundantly available CO₂ with a high price of emissions would make more oil reservoirs candidates for CO₂ EOR, though other constraints, such as field size and availability of infrastructure for delivery and distribution of CO₂, will also limit potential applications.

Oil and gas reservoirs are present in some locations near large sources of CO₂ (in the Gulf

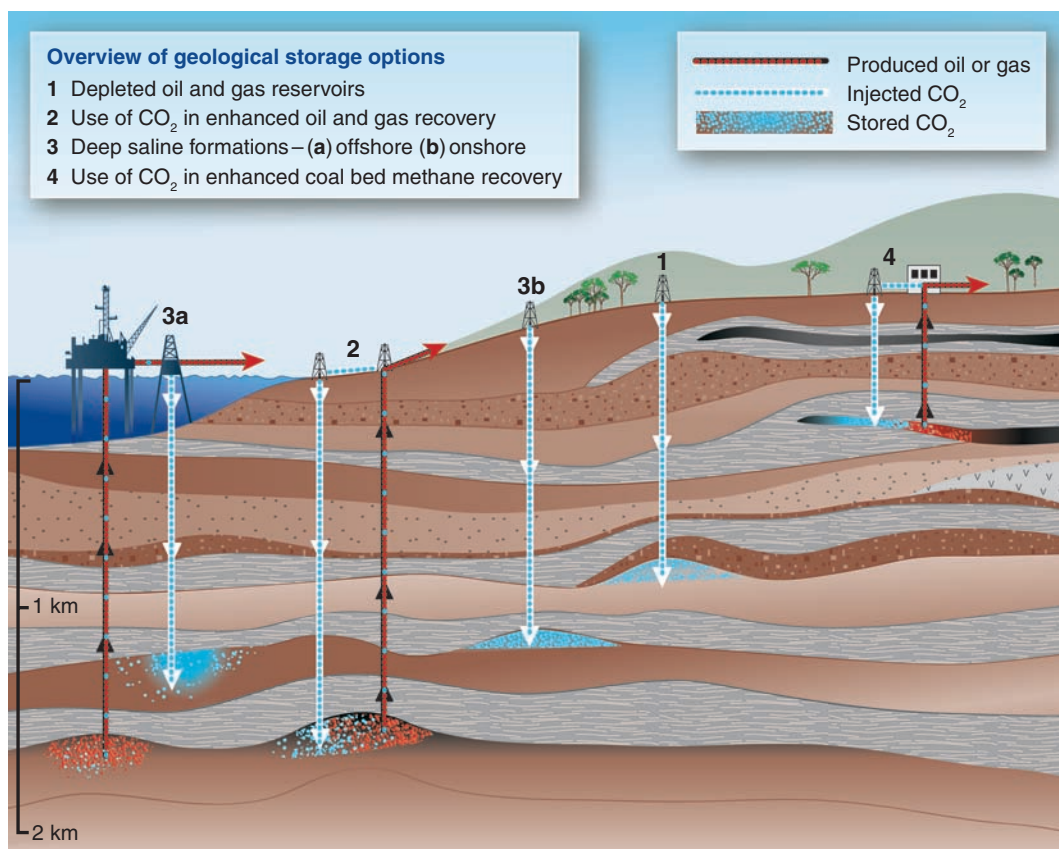


Fig. 1. CO₂ storage options. Options include oil and gas reservoirs, deep formations that contain salt water, and deep coal beds. [Source: Fig. TS-7, IPCC Special Report on Carbon Capture and Storage]

abandoned and will have sufficient surface area available for the required facilities.

Oil and gas reservoirs are obvious potential choices (Fig. 1). The fact that buoyant oil and gas have been retained in them for geologic periods of time is a direct indication that a seal exists. About 30 megatons of CO₂ (MtCO₂) are injected into oil reservoirs in west Texas each year for the purpose of enhanced oil recovery (EOR). Three

Coast region of the U.S., for example), but their overall capacity is expected to be modest (47 to 138 GtCO₂ in the U.S.) (2–4). In other locales, deep formations that contain nonpotable salt water are the candidate storage settings. 1800 to 13,910 GtCO₂ of the estimated onshore capacity for CO₂ storage in the U.S. is contained in these deep saline formations (2–4). Injection of CO₂ into deep saline formations is being tested at the commer-



cial scale (~1 MtCO₂ per year) with the use of CO₂ that is separated from natural gas at the Sleipner field in the North Sea, the In Salah field in Algeria, and the Snohvit field off the northern coast of Norway (7). These projects inject CO₂ at a scale of about one-quarter to one-third of that required for a large coal-fired power plant.

What happens when the CO₂ is injected in those settings? At the subsurface temperature and pressure, the CO₂ is typically a supercritical phase that is less dense than brine or oil, but more dense than natural gas. In liquid-filled formations, the CO₂ will flow away from the injection well under the imposed pressure gradient in a relatively thin gravity tongue just beneath the caprock, though heterogeneities in the permeability of the rocks will also influence where the CO₂ flows. The injected CO₂ will then interact with the fluids and minerals present. The pressure will rise in the formation as injection proceeds, and an important determinant of the total capacity of a deep formation will be the maximum pressure rise that can be tolerated without breaching the seal rocks or activating faults that might conduct flow (8, 9).

What physical mechanisms act to prevent escape of the CO₂ from the storage formation and on what time scales? Seals prevent vertical flow immediately. CO₂ is relatively soluble in brine, and the resulting brine mixture is slightly more dense than brine alone. At typical subsurface conditions, about 20 volumes of brine are required to dissolve 1 volume of CO₂. Low-viscosity CO₂ displaces brine relatively inefficiently, however, so that sufficient brine to dissolve the CO₂ will remain in the pore space. Dissolution begins immediately when CO₂ contacts brine, creating a small driving force for downward unstable flow of the denser brine mixture (10). Once all of the CO₂ is dissolved, the driving force for upward migration of CO₂ is eliminated, though transport due to brine migration is still possible (11). When brine invades zones that are filled with CO₂, as will happen after CO₂ injection has ceased because of gravity relaxation or if brine is injected after the CO₂, capillary forces create a pore scale instability that snaps off isolated bubbles of CO₂. Once these bubbles are created, they cannot move unless very high pressure gradients are applied, and hence, the CO₂ is immobilized while it continues to dissolve slowly. Estimates of the time scales for trapping and dissolution suggest that whatever trapping is going to happen will do so in a few injection time periods (typically 30 to 40 years), and dissolution will also be completed on a time scale of centuries (12). These immobilization mechanisms act in parallel over the life of a storage project to increase storage security with time (1).

Deep, unmineable coal beds are also possible storage locations, with potential U.S. capacity of 30 to 173 GtCO₂ (2–4). Flow of injected CO₂ takes place in naturally occurring fractures, and adsorption of CO₂ in the coal matrix begins immediately as diffusion delivers CO₂ to adsorption

sites. Potential vertical flow of CO₂ through the fractures means that a seal must be present in this setting as well. When CO₂ adsorbs, it replaces CH₄, and the desorbed CH₄ can migrate to the fractures and be recovered. The use of CO₂ for enhanced gas recovery has been demonstrated at the laboratory scale (13) and tested in a limited way in the field (7). However, adsorption of CO₂ reduces permeability, and that considerably reduces the rate at which CO₂ can be injected, a problem that has been observed in field tests.

Shales that are rich in organic material may also have potential for CO₂ storage (14). Recent growth in natural gas production has come from wells drilled in these shales, where horizontal wells and fracturing technologies have been used to increase gas flows. Limited experimental evidence suggests that, whereas the amount of CO₂ that adsorbs in shales is lower than in coals (14), the shale deposits are large enough that one study estimated potential capacity as 107 GtCO₂ (4). As in coals, the challenge will be to establish flow paths that can deliver the CO₂ in quantity to adsorption sites and collect any desorbed CH₄ (15).

On still longer time scales, thousands of years in many settings, chemical reactions can take place that immobilize the CO₂ in the form of minerals (16). Which reactions take place and what minerals form depend strongly on the chemistry of the brine and the minerals and cements present in the porous rock. Dissolved CO₂ in brine reduces pH and forms carbonate and bicarbonate ions that can react to dissolve calcium carbonate or silicate minerals (17) or mobilize other trace metals such as manganese (18). Dissolution of silicates can raise the pH enough to precipitate calcium, iron, or magnesium carbonates and other minerals. A version of these mineralization reactions has been proposed for basalts, which are widely distributed on Earth and contain more of the reactive elements than do typical sedimentary rocks (17). Whether CO₂ could be injected and contained in basalts for the times required to react the CO₂ is still under investigation.

Careful characterization of the subsurface, good design of the injection project, and careful field operations will be required for safe conduct of large-scale carbon capture and sequestration (CCS) projects. At low concentrations, CO₂ is not dangerous. For example, a large coal-fired power plant (for instance, 500 MW) emits ~3 MtCO₂ per year to the atmosphere, and mixing of the N₂/CO₂ effluent with the atmosphere quickly reduces the local concentration near the stack. At high concentrations, however, CO₂ is an asphyxiant and is toxic. A concentration of 4% CO₂ in air is immediately dangerous to human health, and the National Institute for Occupational Safety and Health and Occupational Safety and Health Administration limit for exposure is 5000 parts per million. Thus, leakage to the surface, where dense CO₂ could collect in a depression at times of zero or low wind (19), or to the near-surface region, where water supplies could be affected,

must be avoided. Wells are the most likely leak paths because they must penetrate the storage zone (19). Well pressures and pressures in formations above the storage zone are easily monitored, however, and well problems are corrected routinely in oil and gas operations.

Migration of CO₂ in the subsurface can also be monitored (1). Seismic methods (both surface reflections and tomography) have been used in field tests to detect the movement of CO₂ in the subsurface and should also be able to detect leaks out of zone. Gravity methods and deformation measurements (synthetic aperture radar, tiltmeters) can provide somewhat lower-resolution indications of migration. Tracers, fluid composition measurements, electromagnetic methods that detect changes in fluid conductivity, soil gas, and eddy covariance methods for air sampling also can be used where appropriate. Because the probability of leakage will decline after injection ceases, as the pressure gradient in the storage zone decays and trapping, dissolution, and reaction immobilize CO₂, storage security will increase with time, and the need for active monitoring will decline (1).

Experience with CO₂ injection in EOR and aquifer settings is accumulating at sites around the world, and many more tests are in various stages of planning (7). The component technologies for CCS have been demonstrated at the commercial scale, though integration at the scale of a large power plant (500 MW or more) has not yet been demonstrated. An important next step will be to test geologic storage in a larger variety of geologic settings with CO₂ from power plants and other sources, such as refineries, chemical, cement, ethanol, or natural gas processing plants, that release relatively pure CO₂ now.

It is important to recognize that the infrastructure that will be required to substantially reduce emissions is very large: Subsurface injection of 1 GtCO₂ per year, about one-sixth of the U.S. CO₂ emissions from energy use, is the equivalent in subsurface volumes of 25 to 35 million barrels per day of injection—about 50% more than the volume of U.S. daily petroleum use. The many tests of CCS now being planned for a variety of CO₂ separation schemes and geologic settings are an essential next step to determine whether CCS can be one element in the portfolio of ways to reduce CO₂ emissions.

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PERSPECTIVE

Storage of Carbon Dioxide in Offshore Sediments

Daniel P. Schrag

The battle to reduce greenhouse gas emissions and prevent the most dangerous consequences of climate change will be waged across multiple fronts, including efforts to increase energy efficiency; efforts to deploy nonfossil fuel sources, including renewable and nuclear energy; and investment in adaptation to reduce the impacts of the climate change that will occur regardless of the actions we take. But with more than 80% of the world's energy coming from fossil fuel, winning the battle also requires capturing CO₂ from large stationary sources and storing that CO₂ in geologic repositories. Offshore geological repositories have received relatively little attention as potential CO₂ storage sites, despite their having a number of important advantages over onshore sites, and should be considered more closely.

There are some good reasons why carbon capture and storage (CCS) is attractive as a climate change mitigation strategy: A large fraction of CO₂ emissions comes from relatively few sources. In 2007, there were 2211 power plants that emitted at least 1 million metric tons of CO₂ per year: 1068 were in Asia (559 in China), 567 in North America (520 in the United States), 375 in Europe, and 157 in Africa (1). Together, these power plants released 10 billion metric tons of CO₂, or one-third of global emissions. If these plants could be retrofitted or rebuilt with capture technology, and if appropriate storage locations could be identified, then CCS would allow the world to reduce emissions while still using its fossil fuel reserves, at least until long-term substitutes can be developed. Widespread adoption of CCS in the United States and Europe over the next few decades would make it more likely that similar systems will be deployed in other countries, especially in rapidly growing economies with high present and future CO₂ emissions.

For the past 13 years, a Norwegian oil company has been running an experiment that leads

the world in showing how CCS can play an important role in a broad portfolio of climate-mitigation strategies. Since 1996, in the North Sea, halfway between Scotland and Norway and far out of sight of land, StatoilHydro has been quietly injecting 1 million metric tons of CO₂ per year into a sandstone reservoir that lies 1000 m below the sea surface (Fig. 1). The CO₂ comes from a natural gas deposit called the Sleipner field. Extracting the gas for transport back to land requires separating the CO₂ anyway, so, faced with a carbon tax from the Norwegian government, StatoilHydro decided to turn a liability into an opportunity. As the longest-running, commercial-scale carbon-injection site, Sleipner serves as a demonstration for those who believe that this approach can help decarbonize our energy economy and serves as a laboratory for understanding how CO₂ migrates through the subsurface after injection, using techniques such as time-lapse seismic surveys (2).

One million metric tons of CO₂ per year is a start, but the demand for CCS is much more, perhaps as much as 10 billion metric tons of CO₂ per year or more. Finding storage locations for all that carbon will not be easy. Such amounts far exceed the capacity of old oil and gas fields, which will be among the first targets for sequestration projects because of additional revenues earned from enhanced oil recovery

(EOR). Safe storage of CO₂ in a geologic formation requires a good reservoir with adequate porosity and permeability and thick, impermeable cap rocks that will prevent the CO₂ from escaping. Luckily, geologic storage does not have to last forever—only long enough to allow carbon sinks in the natural carbon cycle to reduce atmospheric CO₂ to near preindustrial levels [roughly 4000 years (3)].

Most investigations of CO₂ storage in the U.S. focus on terrestrial geologic formations, in particular, deep saline aquifers. Another approach to CO₂ storage is injection offshore into marine sediments, similar to what is done at Sleipner. Both approaches will ultimately be needed to accommodate all the large stationary sources of CO₂ in the United States, but there are several reasons why storing CO₂ in geologic formations offshore may be easier, safer, and less expensive than storing it in geologic formations on land, at least during the early days of commercialization.

CO₂ storage in offshore geologic formations is not ocean storage. The CO₂ injected into ocean sediments is stored deep beneath the ocean, avoiding the hazards of direct ocean injection, including effects on ocean ecology. Furthermore, marine sediments offer enormous storage potential. For example, a series of Cretaceous sandstones off New Jersey (4), which were drilled extensively in the 1970s as part of the oil and gas exploration program, appear to have the capacity to store at least several hundred billion tons of CO₂: enough to dispose of all the CO₂ from power plants within 250 km of the coast from Maryland to Massachusetts for the next century. Like on land, offshore storage sites require reservoirs with high permeability (typically sandstones), and thick, low-permeability cap rocks to prevent CO₂ from escaping (typically mudstone and shale). However, if one could find reservoirs with adequate permeability in deep water (that is, below 3000 m), the high pressure and low temperature would render the CO₂ denser than seawater, making the cap rock less important (5), although high-permeability sandstones are uncommon in deeper water environments. In many marine settings, the upper 1000 m of sediment, if it is dominated by clay, is unconsolidated, which means that faults and fractures do not persist as high-permeability pathways for CO₂ escape.

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