Climate Technology Sheet #6: Storage in Saline Aquifers

Carbon dioxide captured from fossil fuels can be stored in geological formations like saline aquifers, oil or gas fields and coal seams. Of these, saline aquifers may offer the highest storage volumes. They could potentially store injected CO_2 for thousands of years, helping avoid atmospheric emissions that enhance the greenhouse effect. There are issues of concern however, which include the site-specific nature of acceptable geology, the potential ecological impact, guarding against large CO_2 releases, leakage levels given large-scale use, and an overall question about the impact of relying on carbon capture and storage to the possible exclusion of other low-carbon energy paths, like renewable energy.

What this document covers:

Figure 1: The Sleipner natural gas drilling platform. CO2 is separated from the gas and reinjected to a saline aquifer. (www.statoil.com)

Overview of aquifer storage

Storage of carbon dioxide in saline aquifers[1] is one method proposed to handle CO_2 captured from power plants, as a way of avoiding emissions that are damaging to the global climate. An injection well, as commonly used in the oil industry, would pump CO_2 into formations below 800m in depth, where CO_2 can be stored in its compressed supercritical state[2]. Covered by a nearly a kilometre of rock (the less permeable the better), and either sealed by faults or so extensive as to contain any potential spread of the CO_2, the aquifers are predicted to sequester the CO_2 for thousands of years.

Compared to enhanced oil recovery as a storage method (tech sheet #4), aquifer storage offers four main advantages: potential storage volumes are larger, they are not limited to hydrocarbon-bearing areas, they are largely unused so rights should be available, and they are rarely penetrated by wells, which may become sources of leakage. The main disadvantage is that they

[1] Also known as saline-, salty water-, or brine-filled sedimentary rock formations. Extensive basins are distributed worldwide as in figure 3.

[2] Gases enter supercritical state when the temperature is too high for the vapours to form liquids, but the pressure compresses them to the density of the liquid state. They retain the viscosity of a gas. CO2's supercritical point is 74 times atmospheric pressure at 31 degrees C. Density is on the order of 600-800 kg/m^3

have never been commercially exploited and geologic information about specific sites is therefore far more limited than in oil and gas fields.

Current state of development

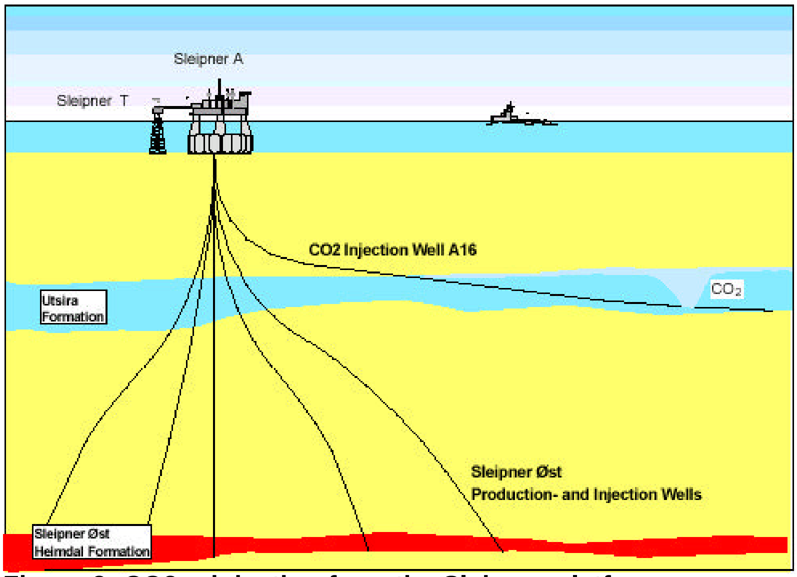

Figure 2: CO2 reinjection from the Sleipner platform (Kaarstadt, IPCC).

The petroleum industry has extensive experience injecting CO2 into oil and gas fields for enhanced oil recovery, but there is only one project currently doing aquifer storage of CO_2, which is responsible for most of the real-world information. This is the Sleipner offshore gas platform in the North Sea between Norway and Scotland, and is run by the Norwegian energy company Statoil (figs.1 and 3). They began re-injecting CO_2 separated from natural gas to the Utsira sand formation 1000 m below the sea in 1996, at a rate of 1MT per year. The Saline Aquifer CO_2 storage (SACS) project has carried out studies including seismic monitoring to track the progression of CO2 movement in the formation.

Statoil is planning a second reinjection at a new development in the Snøhvit field in the Barents Sea, off the Northwest coast of Norway. The gas will be piped for separation onshore and the removed CO_2 will be sent back to an aquifer under the gas field. Norwegian environmental organisations have opposed development of Snøhvit overall as an unnecessary intrusion into a nature area.

For several years Exxon and the Indonesian state oil company Pertamina have been considering a similar reinjection project on a larger scale in the Natuna gas field under the South China Sea. Up to 100MT annually would be stored. Other projects being prepared include injection on the site of a power plant in the Ohio River Valley and a small injection into the Frio Brine formation near Houston, Texas. While the amounts of CO_2 are small, the geological information to be gathered, and modelling of predicted behaviour, is significant.

In Alberta, Canada, acid gas (CO_2 and H_2S together, in varying proportions) has been injected into sedimentary basins at over 40 sites for the last 13 years. This was in response to sulphur emissions controls rather than an attempt to sequester CO_2. Monitoring has been limited and therefore lessons are just now being gleaned from the experience (see also Tech Sheet #7).

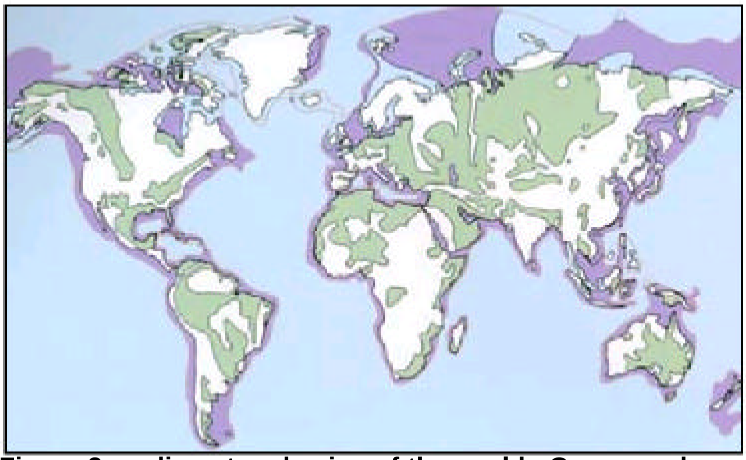

Figure 3: sedimentary basins of the world. Green onshore, purple offshore. Not all are suitable for sequestration. (Kaarstadt, IPCC/ Schlumberger).

Storage mechanisms and volumes

The total volume of saline aquifers potentially appropriate for storage is very large, but estimates vary wildly. The IEA places it at anywhere from 400-10,000GT of CO_2, which corresponds to between 20 and 500 times the total amount of fossil fuel CO_2 likely to be emitted between now and 2050. The porosity and permeability of a formation roughly describe the capacity limits and ease of injection in a formation. The lowest suitable porosities (the gaps in and between the rocks) are on the order of 2% by volume, and some formations have been found to be nearly 35% porous: the more space, the more storage. Permeability is related to porosity but varies by rock type: levels of 10-100mD[3] is acceptable but 100-1000mD allows easier injection and circulation into the formation.

There are essentially four mechanisms retaining CO_2 in the formation: hydrodynamic trapping is simply the containment of the supercritical CO_2 by the caprock, preventing it from rising out of the formation. Second, residual gas saturation describes the amount of CO_2 trapped in rock crevices, and is influenced by the qualities of the rock itself[4]. Third, CO_2 is soluble in the water present in the formation, which will tend to keep it trapped. Finally, CO_2 can react with minerals in the formation to create carbonates of calcium, iron or magnesium and thereby remain immobilised (although this tends to reduce permeability).

Overall the ideal situation is to have a high permeability formation allowing easy injection but with high residual saturation tending to keep the CO_2 trapped. Over time, dissolution into formation water and mineralisation will further immobilise it.

Leakage pathways

Leakage from CO_2 storage sites is a problem because it can be dangerous or at least damaging, and because it defeats the purpose of the effort in the first place. Therefore a great deal of emphasis needs to be placed on determining how it might happen and how to avoid or at least reduce it.

Leakage can be expected in two forms: a failure of the injection well, which could lead to large quantities being emitted quickly, and seepage through migration pathways: faster if they're unidentified large ones, or slower if it's through minor cracks. The petroleum engineering community is quick to assert that well failures and any potentially dangerous CO_2 leakage from their operation is very unlikely. There is significant experience in this field and following technical standards should reduce risks substantially. Nevertheless, because there are potentially serious consequences, preventing large leaks deserves careful thought. What is more difficult to determine and control is what will happen once CO_2 leaves engineered systems and is free in the subsurface environment. Proper siting can reduce the likelihood of leakage, but there are many possible avenues for CO_2 to eventually find its way to the surface.

Aside from their potential for failure and large releases, wells are also the main leakage risk in other ways. They are breaches into a previously geologically stable field that form the most direct route to the surface. While the injection well(s) of a project would be monitored carefully, abandoned wells may not be. Their integrity is primarily an issue of the stability of the cement used to fill them. The older and less well documented an area, the higher the risk that old and degraded wells will go unidentified. This may be less of a risk in saline aquifers than in oil and gas fields, however, as they have not been exploited commercially.

[3] The mD is the "millidarcy," the standard unit of intrinsic permeability in formations like petroleum reservoirs. The size and arrangement of the grains of rock affect permeability; this number captures these qualities.
[4] Previous estimates suggested some 2-6% of the filled pore volume would be trapped in this way, but new research suggests it could be 5-10 times higher, increasing capacity estimates for any given area.

Another obvious but slow leakage pathway is upward through the caprock. CO_2 is more buoyant than water, so there will be upward pressure on caprock. If it is relatively impermeable then there will be a very slow process of movement through the pores, where it can take thousands of years for CO_2 to reach the surface. The presence of faults and fractures would naturally tend to provide a faster route to the surface, so studying a site to identify these features is a central task. A formation may be bounded by impermeable rock on the sides or below, or may not be. If not, there is the possibility that CO_2 will spread laterally as it rises. Again, good understanding of the site is essential. Data from Sleipner and simulations at other sites show lateral movement to be much smaller than the overall size of the containing formation.

As mentioned above, CO_2 will react with minerals in the formation to form carbonates. These may block pores and inhibit permeability, as well as possibly compromise the mechanical integrity of the reservoir. An area of weakened rock that blocks injected CO_2 and therefore faces increased pressure could crack or shift, with the possibility of providing a leakage pathway.

Main environmental issues

There are three main environmental issues of concern with geological storage: The first are potential local impacts of a project, addressed here. The second is the climate change aspect, i.e., whether CO_2 will leak and impact the climate, undermining the original intent of the effort; this is addressed in Tech Sheet #8. The third kind of environmental impact is indirect, relating to the wider implications of carbon capture and storage generally, that is, that it extends the use of fossil fuels and the various environmental impacts throughout the cycle of extraction, transport and use, while shifting emphasis from alternative technologies that may be better overall for the environment.

Local environmental, safety and health impacts of a geological storage project break down to four categories: surface releases (asphyxiation by CO_2, impacts of increased CO_2 levels in soil), subsurface effects of CO_2 (mobilization of metals and other contaminants; impacts on habitats of extremophile species); physical impacts due to the quantities of CO_2 injected (ground heave, induced seismic activity, and displacement of groundwater), and landscape impacts due to the placement of wells and pipelines.

With all of these impacts there is a significant wildcard at the moment: the purity of injected CO_2. Almost all research into the subject assumes pure CO2 injection, but the reality is that, due to the high cost of obtaining pure CO_2 through the capture process, the CO_2 stream can in fact be up to 10% hydrogen sulfide (H_2S), sulphur dioxide (SO2) and nitrogen oxides (NOx). H_2S in particular is much more dangerous to humans in low concentration than CO_2, and is far more corrosive in the presence of water. Assessment of the likelihood and impact of leakage may shift as more research is done into these impurities.

Surface releases

Leakage from CO2 storage could have impacts on humans, plants and animals. The atmosphere is normally 0.035% CO2; flora and fauna can withstand somewhat higher levels briefly, but beyond a few percent it quickly becomes a dangerous asphyxiant and narcotic (fig. 4). Because it is heavier than air, it doesn't disperse like leaking natural gas does, making it much more hazardous. Examples from the natural world are few, but in some cases dramatic. In 1986, 1700 people around Lake Nyos, Cameroon were killed by a large CO_2 cloud that emerged from the lake. Experts speculate that CO_2 of volcanic

Normal level of CO2 in atmosphere: 0.035% (and rising)	
Enhanced level	**Exposure impact @ 15 minutes**
<2%	No effects
3 - 5%	Stimulated breathing
7.5%	Trouble breathing, increased pulse, headaches, dizziness
>10%	Loss of consciousness
20%	Fatal

Figure 4: human health effects of increased CO_2 level. (www.ccohs.ca)

origin had accumulated on the bottom of the lake, and been released suddenly as the waters overturned. A similar event killed 37 people at Lake Monoun, Cameroon in 1984. In 1979, 142 people were killed while fleeing a cloud of CO_2 released from a volcanic vent near the Dieng Volcano on Java.

Figure 5: A tree killed by high CO2 levels in the soil in Northern Hungary. (Nascent Programme)

Aside from these massive releases with dramatic impacts, there are also locations with more diffuse emissions. On Mammoth Mountain, California, large areas of trees are dying due to underground seepage of CO2 from deep magma. Confined areas in buildings on the mountain have CO_2 levels over 1%; measurements in a basement and a storage room showed 25% and 89% CO2. Relatively short exposure at these locations would be fatal, indicating that even small releases can build up to dangerous levels in low-lying, confined spaces.

In Europe, carbogaseous regions are responsible for some if its more famous products: naturally effervescent waters like Vichy and Perrier[5]. CO_2 has been present underground for millions of years, but there are upwelling points. Bubbling streams and well water are locally present in various parts of Europe, and residents have long been aware of the hazard of CO_2 in confined spaces. Impacts due to high CO_2 concentrations in soil are also evident (figure 5).

Subsurface effects of CO2

The most important subsurface risk is that the CO_2 will displace salty water towards potable water sources. This may be particularly true of formations without natural caps or traps that prohibit the migration of water, such as extensive sandy brine formations. Prevention of just such an eventuality is the centrepiece of regulation of underground waste injection of other types, such as the water pumped from oil and gas wells. There is therefore quite some experience in this area. Remoteness of injection from water sources and accurate prediction of flow are the most important factors in isolating potable water from contamination.

CO_2 may also dissolve heavy metals in the subsurface and mobilize them; if this should then come in contact with topsoil or drinking water there would be cause for concern. How important this effect is does not seem to be well studied, but the risk from it naturally hinges on the mobility of the CO_2.

Although the deep surface seems an unlikely place to find life, there are species adapted to these and other extreme environments, known as “extremophiles.” The significance of their ecological niche is essentially unknown; they are in any case likely to be significant in number given their large areas of habitat, which could be affected by CO_2 injection.

Ground heave and induced seismicity

Drilling wells, injecting and extracting materials to and from the geological formations can all affect the mechanical integrity of the subsurface. Avoiding any possible impacts will tend to limit the physical volume of CO2 that can be safely injected.

[5] Currently these products no longer use these naturally effervescent waters

Well-drilling could change the structural integrity of the formation. Emptying or filling a reservoir will cause a respective decrease or increase in pressure that can raise stress. Filling a reservoir beyond its capacity to absorb CO_2 within the existing pores, or dissolved into fluids, will cause pressure that may cause the surface to buckle. CO_2 also exerts a different kind of pressure than water for example, due to its lower density, which would tend to push upwards on the caprock, and due to its lower viscosity, which helps it find its way into smaller pores.

Good knowledge of the pre-existing stress conditions and the mechanical properties of the rocks, with simulations prior to injection, could alleviate concerns more fully. Areas with higher tectonic activity (such as Japan) may be at risk.

Environmental impacts of Additional infrastructure (pipelines, wells, etc.)

Not directly related to the properties of CO_2 or geological formations is the inescapable fact that any storage project will involve construction: pipelines, wells, support buildings, roads, etc. These should not be overlooked in the process. Barrow Island, a class A nature preserve in northwestern Australia, is the proposed site of a reinjection project where 300 hectares would be cleared for development. Opposition to the project from green groups has been largely on the basis of these local impacts.

Monitoring and verification

Monitoring and verification of sequestered CO2 is important at all stages of the project cycle:

- There has to be good characterization of the site to see if it is suitable
- There has to be verification that injection is proceeding as claimed, establishing legal and procedural credibility
- The injection process should be monitored to ensure safety, to check for signs of risks in the subsurface like increasing pressure, and for signs of impacts nearer the surface, like displaced saline water reaching wells
- Ecological monitoring is necessary to check for possible ecosystem impacts'
- CO2 leakage should be monitored in the long term to determine the effectiveness of the storage. Just how long the long-term is (Decades? Centuries? Millennia?) is subject to debate.

The issue of monitoring and verification is covered in more depth in Tech Sheet #7.

Costs

While CO_2 capture is costly and involves considerable technical effort at the power plant, storing it means essentially just pumping CO_2 into the ground, a relatively common practice in the oil industry. The IEA estimates transport and injection cost between \$5 and \$21/t CO_2, depending on transport distance and storage method. Transport on its own is estimated to cost between \$1 and \$3 / t CO_2 per 100 km of distance covered. Data from the Sleipner projects show costs are estimated to be around \$80m for the CO_2 compression and injection well, which as an offshore operation and retrofit to an existing platform will be many times more expensive than onshore operations designed into the system.

What is still uncertain are the costs of monitoring and verification – how much is necessary and which techniques to use will be important to determine in establishing the legitimacy and effectiveness of CO_2 storage overall, and costs could vary widely. Extensive geological research must be done first to identify a suitable site, characterize it, then monitor injection throughout the lifetime of the project, monitor the subsurface for effects the CO_2 might have, and to monitor surface leakage, perhaps for hundreds of years.

Pro and con attitudes

There is a high degree of confidence among CO_2 storage proponents that aquifer sequestration can be done safely and result in long-term CO_2 storage. As evidence they point to, among other things, the experience of the petroleum industry in performing related activities safely on a large scale, and the containment of natural gas over geological time. Proponents of all types of sequestration projects are clearly worried by the reaction to the International ocean injection field experiment that was cancelled off the coast off Hawaii due to public opposition, and then stopped in Norway, in 2002. Protecting the oceans from becoming the dumping ground of the world has been an important concern of the environmental movement and it is clear why adding another industrial waste burden would not be well received. Geological storage may be less controversial insofar as the location of storage—underground rock formations—is less ecologically important.

Public acceptance will be important at two opposite scales: local acceptance of the risks near the project area, and acceptance by policy-minded groups about CO_2 capture as an approach to climate change mitigation.

Pilot geological sequestration projects have until now had three characteristics mitigating negative public responses: they have either been away from population centres (Sleipner), executed in and among current operations that are well accepted locally (Weyburn), or are very small scale (Frio brine). But CO_2 is a hazardous substance in large quantities and the public's view could easily shift when siting of a substantial project nears. What is unclear is whether projects under the sea floor (far from populations (which is good for safety) but far from public scrutiny) will be more or less popular than projects on land (close to populations but easier for the public to keep an eye on).

Risk characterisation and communication of that risk to the public are gaining in importance to project developers, who are aware that public opposition at an early stage could prevent the whole CO_2 sequestration from getting off the ground. Emphasis is being put on being prepared to convince the public of why there is nothing to worry about ("information" and "communication"), and less on how project developers can work with the public from an early stage to build their ideas into project design ("public participation").

A separate problem with sequestration projects is that they are clearly being used to "green" petroleum projects that are in other ways unacceptable. Justification of the proposed Snøhvit oil and gas field is done partially on the basis of CO_2 reinjection. However, Snøhvit is in one of the most pristine and fragile areas of ocean left in the world, and home to many species of importance. CO_2 reinjection does nothing to overcome the spills and routine destruction that will result from this project.

Main references:

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