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Author: Marius Log	
Programme coordinator: Supervisor(s): Pål Østebø Andersen Raoof Gholami	
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Carbon dioxide storage in saline formations

Introduction

Since the industrial revolution there has been an major increase in the atmospheric concentration of carbon dioxide and other Green House Gases. This increase of carbon dioxide in the atmosphere has caused a rise in the average global temperature. The scientists have been looking for methods to reduce the carbon dioxide emissions and to reduce the amount of Green House Gases and carbon dioxide in the atmosphere. The three main options for controlling the carbon dioxide emissions are: Using less carbon rich fossil fuels, improving energy efficiency and carbon sequestration.

Underground geological storage

The subsurface is the largest "reservoir" to store carbon dioxide on the Earth. The Earth already stores CO_2 in the upper crust by itself as a natural process which has been ongoing in hundreds of million years. Carbon dioxide derived from igneous activity, biological activity and chemical reactions between rocks and fluids accumulates in the natural subsurface environment as carbonate minerals, in solution or in a gaseous form, either as a gas mixture or as pure carbon dioxide. There are many ways to store carbon dioxide underground, and the main ways are in oil and gas reservoirs, possibly coal formations and particularly saline formations. Very few sedimentary basins are suitable for carbon dioxide storage because some are too shallow and others are dominated by rocks with low permeability or poor confining characteristics. Basins suitable for Co_2 storage have characteristics such as thick accumulations of sediments, permeable rock formations saturated with saline water (saline)formations, extensive covers of low porosity rocks. CO_2 can be trapped under caprock, reacting with minerals, trapped in pore spaces, dissolution in fluids, adsorption onto organic matter and shale. The global capacity to store carbon dioxide is very large, because it is possible to store carbon dioxide onshore as well as offshore. The cost of geological storage of carbon dioxide is highly site specific, and depends on the underground, the reservoir temperature and pressure conditions, how deep the reservoir is placed etc. Scientists believe that 99% of injected carbon dioxide will be retained for 1000 years, one reason is that carbon dioxide becomes less mobile over time. Leakage of CO2 could degrade the quality of groundwater, damage some hydrocarbon or mineral resources, and have lethal effect on plants. Therefore careful site election is important. To geologically store CO2, it must be compressed, to dense the supercritical fluid state. Depending on the rate of temperature increasing with depth, the density of CO2 will increase with depth. Geological formations underground are mostly composed of transported and deposited rock grains. The pore space between the rock grains in the rock is occupied by fluid, mostly water but could also be oil and gas. When we inject carbon dioxide into the pore space of the permeable rock, than the carbon dioxide will displace the fluid, or mix with the fluid. [1]

The first ideas of capturing and store carbon dioxide as a greenhouse gas mitigation were first proposed in 1970, but few people believed in the ideas, and there was not done much research before 1990, when the ideas gained more credibility. In 1966 the worlds first large scale storage was initiated by Statoil at the Sleipner Gas Field in the North Sea. [1]

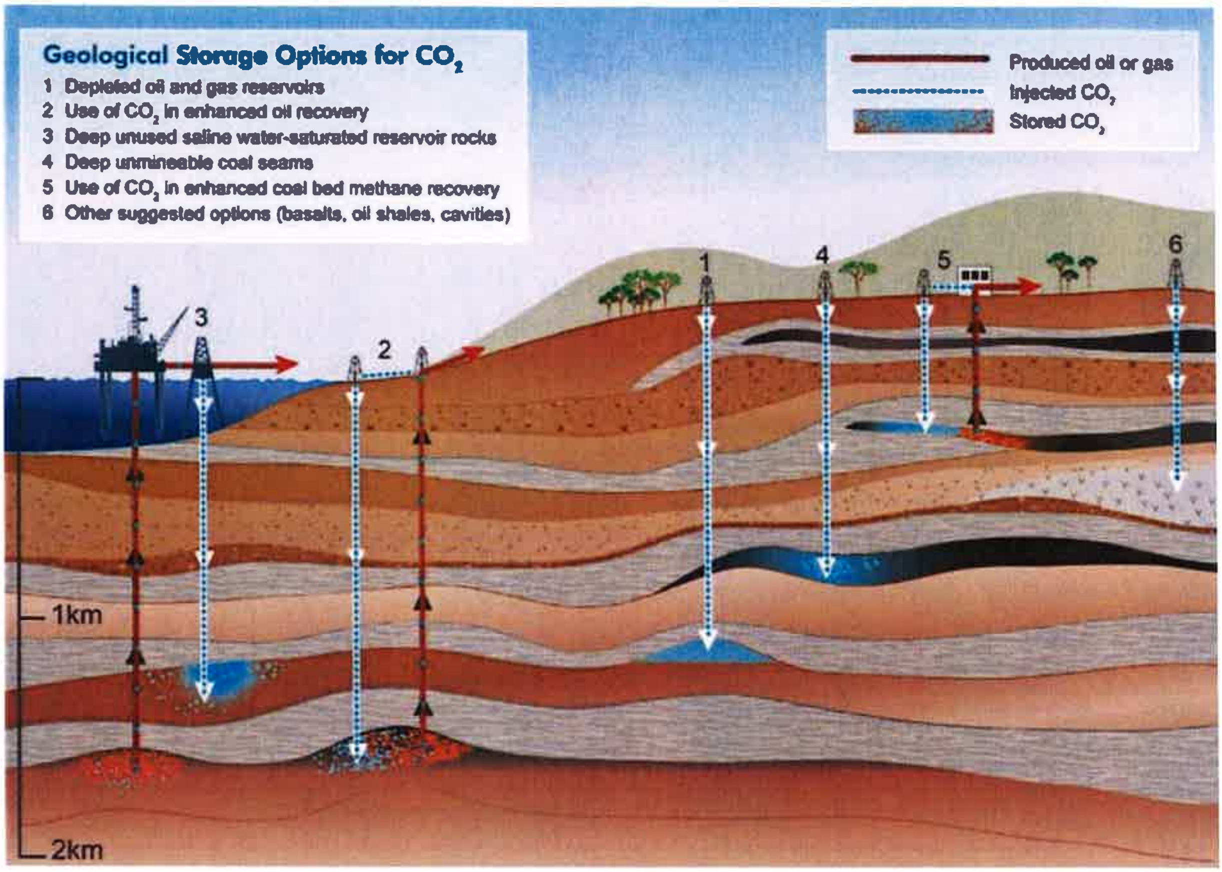


Photo taken from "IPCC Special Report on Carbon Dioxide Capture and Storage" [1]

Saline formations

Saline formations are deep underground porous reservoir rocks saturated with brackish water or brine, containing high concentrations of dissolved salts. Deep saline formations are believed to have by far the largest capacity for CO2 storage and are much more widespread than other options. They are usually very big and have an enormous storage potential, and are more extensive than coal seams and oil and gas fields. Saline formations occur in sedimentary basins throughout the world, both onshore and on the continental shelves and are not limited to hydrocarbon provinces or coal basins. In saline formations, the comparatively large density difference (30– 50%) between CO2 and formation water creates strong buoyancy forces that drive CO2 upwards.

Also, in saline formations and oil reservoirs, the buoyant plume of injected CO2 migrates upwards, but not evenly. This is because a lower permeability layer acts as a barrier and causes the CO2 to migrate laterally, filling any stratigraphic or structural trap it encounters. However, estimating the CO2 storage capacity of deep saline formations is presently a challenge for the following reasons:

• There are multiple mechanisms for storage, including physical trapping beneath low permeability caprock, dissolution and mineralization;

• These mechanisms operate both simultaneously and on different time scales, such that the time frame of CO2 storage affects the capacity estimate; volumetric storage is important initially, but later CO2 dissolves and reacts with minerals;

• Relations and interactions between these various mechanisms are very complex, evolve with time and are highly dependent on local conditions

• There is no single, consistent, broadly available methodology for estimating CO2 storage capacity.

• Only limited seismic and well data are normally available
[8] [1]

Types of trapping

The best way to trap carbon dioxide in saline aquifers is to have a good combination of physical and geochemical trapping mechanisms. The most effective and best storage sites are those where the carbon dioxide is immobile because it is trapped under a thick, low-permeability seal, or when it is converted to solid minerals in a chemical reaction.

Physical trapping

The principal means of physical trapping of carbon dioxide below low-permeability caprock in geological formations are for example very-low-permeability shale or salt beds. Shallow gas hydrates may conceivably act as a seal in high latitude areas. Normally in sedimentary basins there are many closed physically bond traps which are mainly occupied by saline brines, oil or gas. In some circumstances, faults in the formation can act as permeability barriers for trapping carbon dioxide, but those faults can also be useful as good pathways for fluid flow. To main types of physical traps are structural traps and stratigraphic traps, which both are suitable for carbon dioxide storage. Structural traps are those traps which are formed by folded or fractured rocks, for example by faults in the formation. Stratigraphic traps are formed by changes in rock types during the deposition of rocks in the reservoir. It is very important to control the pressure when storing carbon dioxide in physical traps, to not exceed the maximum overpressure and then accidently fracture the caprock or re-activating the faults.

Another type of physical trapping is called hydrodynamic trapping. This type of trapping occurs in saline formations where fluids migrate very slowly over long distances, and there is no completely closed trap. Carbon dioxide is less dense than saline water, so when carbon dioxide is injected into a formation it displaces the present saline formation water and then migrates upwards because of the buoyancy forces. The carbon dioxide continues to migrate upwards in the formation, and when it reaches the top of the formation, it will in the end be trapped under local structural or stratigraphic traps, or as a residual carbon dioxide saturation. As time goes by, significant quantities of carbon dioxide dissolve into the formation water and then slowly migrate with the groundwater. The distance from the deep injection site to the overlying permeable formation could be hundreds of kilometers, and then it can take million of years for the carbon dioxide to reach the top.

Geochemical trapping

Over time carbon dioxide will react geochemically with the rock or the formation water which will further increase the storage capacity and the storage effectiveness, this is called geochemical trapping. Solubility trapping is a common process which normally occurs when carbon dioxide dissolves into formation water. After solubility trapping the carbon dioxide is no longer a single phase, which means that the buoyancy upwards migration will stop. When the rock also dissolves into the formation water, the carbon dioxide will react with the minerals and then form carbonated minerals, which is called mineral trapping, the most permanent form of geochemical trapping. Mineral trapping could take thousand years, and it is a very slow process. It is one of the most favorable methods of trapping carbon dioxide over long time. The process when carbon dioxide dissolves into the formation water is called dissolution. [1] [4] [8]

Dissolution

One of the primary mechanisms for stable long-term geological storage of carbon dioxide is the dissolution of injected carbon dioxide within ambient brine. Dissolution of carbon dioxide into the formation water, resulting in stable stratification, increases storage security, and decreases the potential risk of leakage. The dissolution rate is determined by convection in the formation water driven by the increase of water density with carbon dioxide saturation. [1][4]

This chemical reaction represents the dissolution of carbon dioxide in formation waters:

$CO_2 (g) + H_2O \leftrightarrow H_2 CO_3 \leftrightarrow HCO_3^{\,-} + H^+ \leftrightarrow CO_3^{\,2-} + 2H^+$

The carbon dioxide solubility in formation water decreases as temperature and salinity increase. Dissolution is normally very rapid when the formation water and carbon dioxide share the same pore space, but once the formation fluid is saturated with carbon dioxide, the rate slows and is controlled by diffusion and convection rates. Carbon dioxide dissolved in water produces a weak acid, which reacts with the sodium and potassium basic silicate or calcium, magnesium and iron carbonate or silicate minerals in the reservoir or formation to form bicarbonate ions by chemical reactions. This chemical reaction represents this process:

3 K-feldspar + $2H_2O$ + $2CO_2 \leftrightarrow$ Muscovite + 6 Quartz + 2K+ + $2HCO_3$

Reaction of the dissolved carbon dioxide with minerals can be rapid (days) in the case of some carbonate minerals, but slow (hundreds to thousands of years) in the case of silicate minerals. Carbon dioxide dissolution is significant for leakage risk, because once carbon dioxide is dissolved, it is unavailable for leakage as a discrete phase. [1] [8] [4]

Carbon dioxide storage estimation in saline aquifers

The Carbon Sequestration Leadership Forum (CSLF) has developed an equation for storage of carbon dioxide in structural and stratigraphic traps as static trapping. The boundary conditions are considered to be open in saline aquifers. Here is the equation:

“$MCO_{2e} = V_{trap}\varphi(1 - S_{wirr})\rho CO_2C_c = Ah\varphi(1 - S_{wirr})\rho\, CO_2C_c$ [9]

Where MCO_{2e} is the effective storage capacity, V_{trap} is geometric volume of the structural or stratigraphic trap down to the spill point, φ is the porosity, S_{wirr} is the irreducible water saturation, ρCO_2 is the carbon dioxide density at the temperature and pressure of the aquifer, C_c is the capacity coefficient that incorporates the cumulative effects of trap heterogeneity, carbon dioxide buoyancy and sweep effiency, and A and h are the trap area and average gross thickness, respectiviely" [8]

The US department of Energy also developed a method and equation to calculate the carbon dioxide storage resource mass estimate (G_{CO2}) for geological storage in saline formations. Here is the equation:

$$G_{CO2} = A_t h_g \varphi_{tot} \rho E_{saline}$$

Where A_t is the total geographical area that defines the basin or region being assessed for carbon dioxide storage, h_g is the gross thickness of the saline formation for which carbon dioxide storage is assessed within the basin or region defined by A_t, φ_{tot} is the total porosity in volume defined by the net thickness, ρ is the density of carbon dioxide evaluated at the pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over h_g and A_t. [1] [8]

Convective mixing

In fluid dynamics, convective mixing is the vertical transport of a fluid and its properties, and the action of mixing two groups of particles so they are dispersed with each other. When carbon dioxide is injected in saline aquifers, dissolution causes a local increase in brine density that can cause Rayleigh-Taylor-type gravitational instabilities. The Rayleigh-Taylor instability is an instability of an interface between two fluids of different densities which occurs when the lighter fluid is pushing the heavier fluid. Trapping of carbon dioxide can be enhanced when gravitational instabilities are triggered by a local increase in brine density as carbon dioxide dissolves into brine in the top of an aquifer. This Rayleigh-Taylor-type instability is sometimes referred to as gravito-convective mixing and involves both diffusive and advective motion of dissolved carbon dioxide, with advection being the dominant driving force. Whether the interface between carbon dioxide-bearing brine and fresh brine becomes gravitationally unstable depends on the ratio of advection to molecular diffusion. When a fingering instability is triggered, dissolved carbon dioxide is mixed throughout the aquifer at advective time-scales, which can be much faster than diffusive transport. This improves the storage capacity of a given aquifer and decreases the leakage risk in case of cap rock failure. [2] [3]

Injectivity

Injection of carbon dioxide was first done in the early 1970s in Texas, USA as a part of EOR projects. Complex fluid-rock interactions can occur during the injection of carbon dioxide into saline aquifers for sequestration, which may affect carbon dioxide injectivity and storage capacity. Well injectivity issues are of importance for carbon capture and storage because the gas injection rate must be maintained at a high level. Injection of dry gas in deep saline aquifers might lead to near wellbore drying and salt precipitation. The solid salt might then reduce the rock permeability by clogging pores or by pore throat restriction. [5]

Caprock integrity

The caprock and its location is important to keep the carbon dioxide trapped in a supercritical state, and to prevent leakage. Some leakage related risks are:

- Reactivation of the faults in the caprock: local pressure near a fault during injection reduces effective normal stress and thus reduces the shear strength of the fault
- Induced shear failure of caprock.

- Hydraulic fracturing (Prior to injection and during injection)
- Leakage via the injection well.

The caprock should be at a desired depth to keep the carbon dioxide in supercritical state and at the same time it should be away from any major anthropomorphic penetrations like faults or wells to avoid leakage. The caprock mass should be dense and intact, and should possess low permeability so as to keep the injected carbon dioxide from seeping through it over a long period. Also, the caprock must have high strength under both compression and tension to be able to bear the change in stress fields during and after injection. Leakage through cap rock may occur due to fracturing of the cap rock under pore fluid pressure or due to the upward pressure exerted by the carbon dioxide accumulated just beneath the cap rock. Reopening of pre-existing faults or joints in the caprock may occur under the influence of external forces like seismic activity or due to the stress changes inside the geological formation. There is also a possibility of carbon dioxide leakage through capillaries in the caprock when the pressure differences of the fluid phase, and the water phase, in the pores adjacent to the cap rock is higher than the capillary entry pressure of the caprock. [6]

Supercritical state carbon dioxide

At low temperatures (below -78 °C) carbon dioxide is a solid, at a temperature ranging between -56.5 and 31.1 °C, carbon dioxide is a gas and at temperatures higher than 31.1 °C and pressures greater than 7.38 MPa (critical point), carbon dioxide is in the supercritical state. This property of carbon dioxide is important in terms of its sequestration since carbon dioxide is preferably injected in the supercritical state, as supercritical carbon dioxide has a higher density than gaseous carbon dioxide.

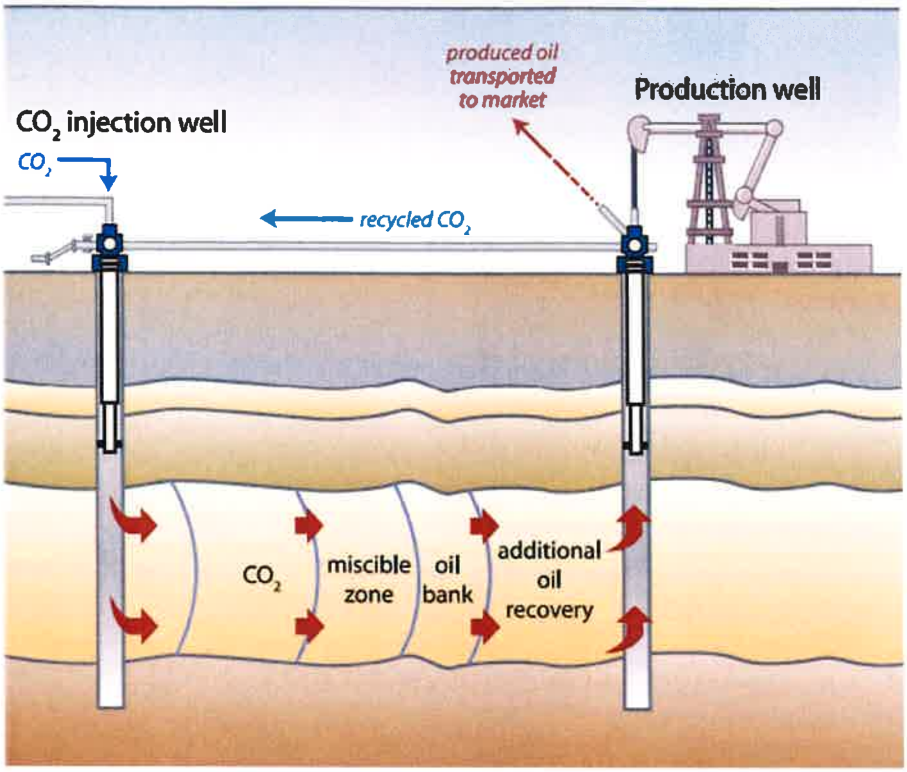
To geologically store carbon dioxide, it must first be compressed, usually to the dense fluid supercritical state. Depending on the rate that temperature increases with depth (the geothermal gradient), the density of carbon dioxide will increase with depth, until at about 800 m or greater, the injected carbon dioxide will be in a dense supercritical state. At depths below about 800–1000 m, supercritical carbon dioxide has a liquid-like density that provides the potential for efficient utilization of underground storage space in the pores of sedimentary rocks. Because supercritical carbon dioxide is much less viscous than water and oil (by an order of magnitude or more), migration is controlled by the contrast in mobility of carbon dioxide and the in site formation fluids. [1] [4] [8]

Carbon dioxide miscibility

Miscible flooding with carbon dioxide or hydrocarbon solvents are considered to be one of the most effective enhanced oil recovery (EOR) processes applicable to light and medium oil reservoirs. The injection of carbon dioxide for secondary and tertiary oil recovery has received considerable attention in the industry because of its high displacement efficiency and relatively low cost. Miscible recovery of a reservoir oil can be achieved by carbon dioxide displacement at a pressure level greater than a certain minimum. This minimum pressure is hereafter defined as the carbon dioxide minimum miscibility pressure (MMP). The carbon dioxide MMP is an important parameter for screening and selecting reservoirs for carbon dioxide injection projects. For the highest recovery, a candidate reservoir must be capable of withstanding an average reservoir pressure greater than the carbon dioxide MMP. Crude oil reservoirs have different temperatures, compositions, and pressures, therefore oil recovery performance by carbon dioxide injection varies from one case to another. Furthermore, it is predicted that lower interfacial, the presence of several different phases may decrease the permeability and slow the rate of migration. tension between injected carbon dioxide and reservoir fluid results in more oil recovery. When carbon dioxide is injected into a deep saline formation in a liquid or liquid-like supercritical dense phase, it is immiscible in water. [7]

EOR

Enhanced oil recovery (EOR) through CO2 flooding (by injection) offers potential economic gain from incremental oil production. Of the original oil in place, 5–40% is usually recovered by conventional primary production. An additional 10–20% of oil in place is produced by secondary recovery that uses water flooding. Various miscible agents, among them CO2, have been used for enhanced oil recovery or EOR, with an incremental oil recovery of 7–23% of the original oil in place. Oil displacement by CO2 injection relies on the phase behaviour of CO2 and crude oil mixtures that are strongly dependent on reservoir temperature, pressure and crude oil composition. These mechanisms range from oil swelling and viscosity reduction for injection of immiscible fluids (at low pressures) to completely miscible displacement in high-pressure applications. In these applications, more than 50% and up to 67% of the injected CO2 returns with the produced oil, and is usually separated and re-injected into the reservoir to minimize operating costs. The remainder is trapped in the oil reservoir by various means, such as irreducible saturation and dissolution in reservoir oil that it is not produced and in pore space that is not connected to the flow path for the producing wells. [1]



Picture showing EOR. Photo taken from "IPCC Special Report on Carbon Dioxide Capture and Storage" [1]

Security and duration of carbon dioxide storage in geological formations

Research done by scientists show that hydrocarbons, oil and gas, and also gases like carbon dioxide can be trapped for million of years in the subsurface. Estimations for oil and gas in different world-class petroleum provinces can be up to 1400 million years in some minor petroleum accumulations. But, even if the estimations say million of years, there will always be a risk for leakage, so therefore careful site selection and safe injection practices are important. To be a good storage cite for carbon dioxide the site must follow at least three important criterias:

- Adequate capacity and injectivity
- A satisfactory sealing caprock
- A sufficiently stable geological environment to avoid compromising the integrity of the storage site

Bad and poor geological storage sites for carbon dioxide are usually:

- Thin (less than 1000m)
- Poor relationship between reservoir and seal
- Highly faulted or fractured
- Located within fold belts
- Have strongly discordant sequences
- Have undergone significant diagenesis
- Have overpressured reservoirs

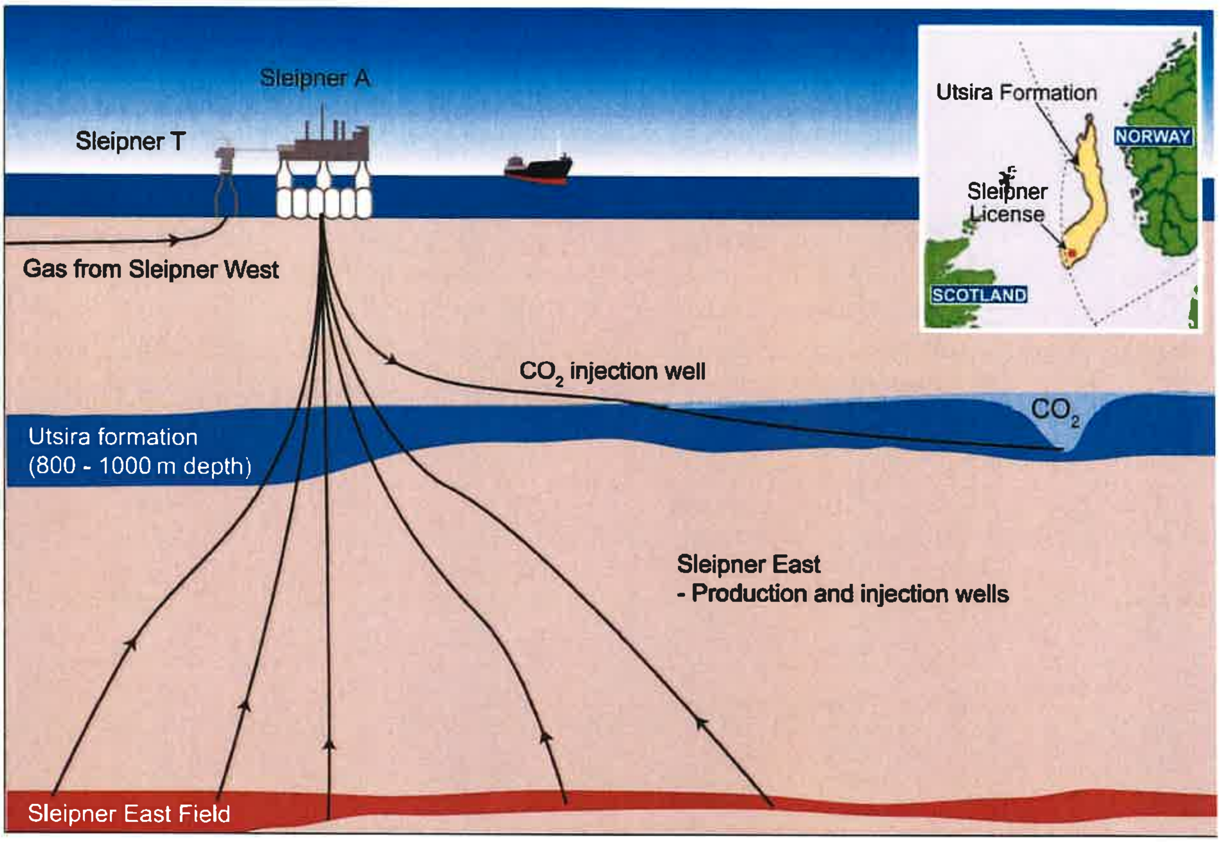
The safety of the storage increases with increasing carbon dioxide density, because, as said before, of the buoyancy force that drives the upward migration, which gets stronger when the carbon dioxide is lighter. Carbon dioxide have higher density in cold, shallow sedimentary basins, than in warm, deep sedimentary basins, which makes sedimentary basins at shallower depth, 100-1000m, more favorable for carbon dioxide storage. Normally, when choosing storing site, sites which ate already used for hydrocarbon exploration are the best sites for carbon dioxide storage. This is for many reasons, but some are because such basins:

- Have well-known characteristics
- Hydrocarbon pool or coal beds have already been discovered and produced
- Some petroleum reservoirs may already be abandoned as uneconomic
- The infrastructure needed for carbon dioxide transport and injection may already be in place

If there are already many producing wells in the storage site, then there will be a greater risk for carbon dioxide leakage. [1]

The Sleipner project

The Sleipner Project, operated by Statoil in the North Sea about 250 km off the coast of Norway, is the first commercial scale project dedicated to geological carbon dioxide storage in a saline formation. The carbon dioxide from Sleipner West Gas Field is separated, then injected into a large, deep, saline formation 800 m below the seabed of the North Sea. The Saline Aquifer CO2 Storage project was established to monitor and research the storage of carbon dioxide. Approximately 1 MtCO2 is removed from the produced natural gas and injected underground annually in the field. The CO2 injection operation started in October 1996 and, by early 2005, more than 7 MtCO2 had been injected at a rate of approximately 2700 t/day. Over the lifetime of the project, a total of 20 MtCO2 is expected to be stored. The saline formation into which the CO2 is injected is a brine-saturated unconsolidated sandstone about 800–1000 m below the sea floor. The formation also contains secondary thin shale layers, which influence the internal movement of injected CO2. The saline formation has a very large storage capacity, on the order of 1–10 GtCO2. The top of the formation is fairly flat on a regional scale, although it contains numerous small, low-amplitude closures. The overlying primary seal is an extensive, thick, shale layer. The fate and transport of the carbon dioxide plume in the storage formation has been monitored successfully by seismic time-lapse surveys. The surveys also show that the caprock is an effective seal that prevents carbon dioxide migration out of the storage formation. Today, the footprint of the plume at Sleipner extends over an area of approximately 5 km^2. Reservoir studies and simulations have shown that the carbon dioxide-saturated brine will eventually become denser and sink, eliminating the potential for long-term leakage [1]

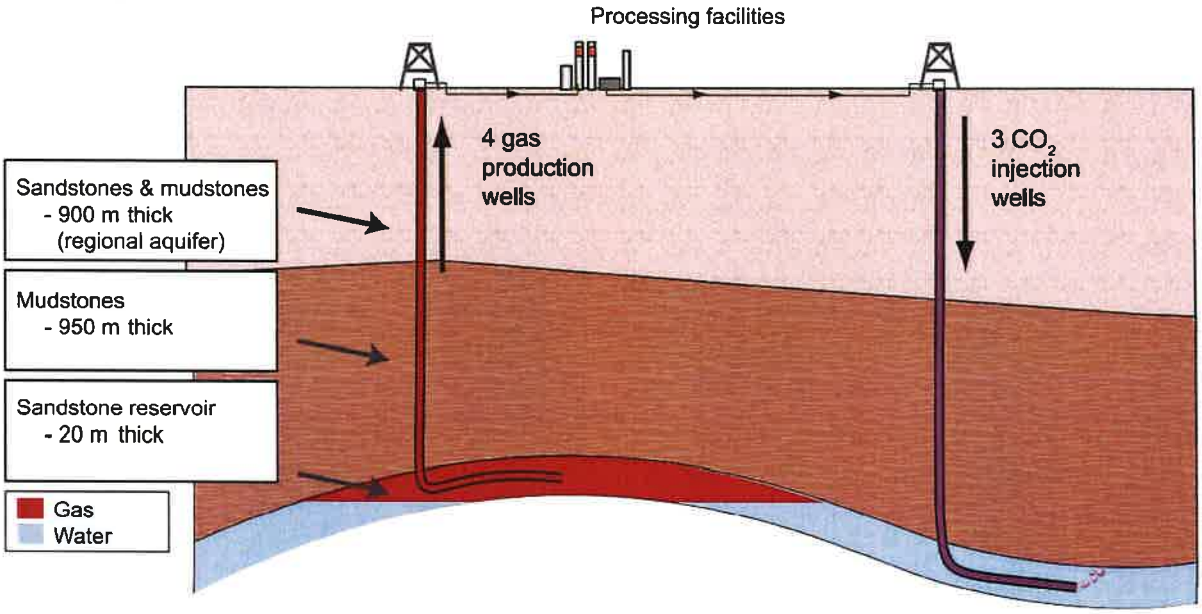


The Sleipner Project. Photo taken from “IPCC Special Report on Carbon Dioxide Capture and Storage” [1]

In-Salah project

The In Salah Gas Project is the world’s first large-scale carbon dioxide storage project in a gas reservoir. The Krechba Field at In Salah produces natural gas containing up to 10% carbon dioxide from several geological reservoirs, and the carbon dioxide is removed from the gas production and then it is compressed, transported and re-injected the into a 1,9km deep sandstone reservoir called Carboniferous, at a depth of 1800 m and storing up to 1.2 Mt of carbon dioxide.

After that, the facility delivers the carbon dioxide to markets in Europe. The project involves re-injecting the carbon dioxide into a sandstone reservoir at a depth of 1800 m and storing up to 1.2 $MtCO_2$. Carbon dioxide injection started in April 2004 and, over the life of the project, it is estimated that 17 $MtCO_2$ will be geologically stored. The project consists of four production and three injection wells. [1] [10]



Schematic of the In Salah Gas project. Photo taken from "IPCC Special Report on Carbon Dioxide Capture and Storage" [1]

Weyburn project

The Weyburn project is an enhanced oil recovery project (EOR-project) located in a geological structure extending from south-central Canada into north-central United States, called the Williston Basin. The goal of the project is to store all of injected carbon dioxide by eliminating the carbon dioxide that would normally be released during the end of the field life. The Dakota Gasification Facility is the source for the Weyburn project, which is located 325km south of Weyburn in Beulah, North Dakota. At this facility, coal is gasified to make synthetic methane, and as a by-product you get a very pure stream of carbon dioxide. The pure stream of carbon dioxide is then compressed, dehydrated and piped in a pipeline deigned to transfer 5000t carbon dioxide a day in about15 years. The Weyburn field is a very large field, expanding over an area of 180 cubic kilometers. There is about 222 million cubic meters of original oil in place, and in 20-25 years the project is expected to have stored about 20Mt of carbon dioxide in the field. To optimize the sweep efficiency of the carbon dioxide, the field has been designed with both vertical and horizontal wells. The reservoir in the Weyburn oil field is about 20 to 27m thick, and a thick, flat shale forms a good barrier to leakage from the reservoir. As said before, already existing wells could increase the risk of leakage, but at Weyburn, there is a presence of many hundreds already existing wells, and even after four years of carbon dioxide injection there has been no measurable leakage. The EOR project produces about 1600 cubic meters of incremental oil from the field every day, which is way more than first expected. All of the carbon dioxide emissions, approximately 1000t carbon dioxide a day, from the oil production are captured and re-compressed for reinjection into the production zone. [1] [11]

How will the future be?

As you can see, there are many carbon dioxide storage projects which has already been started, and for example in the Weyburn project, it looks like it is possible to inject carbon dioxide into subsurface, safely without a big leakage. There is still much research to do on how to store more carbon dioxide, how to store it safely over many years, and how do make it economically and environmentally beneficial. Saline sedimentary basins have a large potential for carbon dioxide storage in the future. The goal with carbon dioxide storage is to save the planet from global warming and heating, to capture the greenhouse gases and store them underground. There is always a risk of leakage, and the processes have to be monitored and controlled to minimize this risk. How can we capture and store carbon dioxide to save the earth? Will it be economically beneficial? How big are the consequences for the surroundings, the nature, animals and humanity in case of leakage? How can we know for sure that capturing carbon dioxide actually will prevent the earth from heating up? How can we save the future for the next generations?

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