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Characteristics of CO_2 sequestration in saline aquifers

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Abstract: Storage of CO_2 in saline aquifers is a viable option for reducing the amount of CO_2 released to the atmosphere. This paper provides an overall review of CO_2 sequestration in saline aquifers. First, the principles of CO_2 sequestration are presented, including CO_2 phase behavior, CO_2-water-rock interaction, and CO_2 trapping mechanisms. Then storage capacity and CO_2 injectivity are discussed as the main determinants of the storage potential of saline aquifers. Next, a site section process is addressed considering basin characteristics, reservoir characteristics, and economic and social concerns. Three main procedures are then presented to investigate the suitability of a site for CO_2 sequestration, including site screening, detailed site characterization, and pilot field-scale test. The methods for these procedures are also presented, such as traditional site characterization methods, laboratory experiments, and numerical simulation. Finally, some operational aspects of sequestration are discussed, including well type, injection rate, CO_2 purity, and injection strategy.

Key words: CO_2 sequestration, saline aquifer, site selection, screening criteria, geological storage, storage capacity

1 Introduction

Due to human activities, especially the tremendous worldwide consumption of fossil fuels such as oil, natural gas, and coal, the concentration of CO_2 in the atmosphere has increased from about 280 ppm to more than 380 ppm over the last 250 years, and is now rising at a rate of about 1 ppm per year, leading to measurable global warming (Sprunt, 2006; IEA, 2008; USGS, 2008). Climate modeling shows that a rise of 0.3-0.6 °C in the near-earth-surface temperature could result from the increase in atmospheric CO_2 concentration during the last 150 years (Pruess et al, 2003). Growing concerns about global warming and the challenge of CO_2 emissions regulation highlight the need to develop effective and economical means to sequester CO_2 (Bryant, 2007; Gibson-Poole et al, 2007; Sengul, 2006).

Carbon sequestration refers to the long-term storage of carbon in the terrestrial biosphere, underground or in the oceans to reduce or slow the buildup of CO_2 concentration in the atmosphere (Reichle, 1999). Many groups, such as the International Energy Agency (IEA), consider underground storage (or geological sequestration) as a viable option (IEA, 2002). Three main underground storage alternatives have been identified: saline aquifers, depleted oil and gas reservoirs, and coal beds (IPCC, 2005; Sprunt, 2006). Among these, saline aquifers, defined as porous and permeable reservoir rocks containing saline fluid, are most promising because of their large capacity and broad distribution (IPCC, 2005; Hesse et al, 2006). The storage of CO_2 in saline aquifers has been discussed since the early 1990s (Pruess et al, 2003). Currently, many industrial projects have been carried out and have demonstrated the viability of CO_2 sequestration in saline aquifers. The first field test was in the Sleipner West Field, North Sea. CO_2 has been injected into the Utsira Formation- a saline sandstone aquifer since 1996. About 1 million metric tons of CO_2 have been sequestered per year, which is approximately 3% of Norway's annual CO_2 emissions (Sengul, 2006; Jikich et al, 2003).

Reducing carbon emissions in a safe, effective, and economical manner requires an understanding of CO_2 sequestration mechanisms and considerations for potential storage sites (Bryant, 2007). This paper presents a general review of current status of CO_2 sequestration in saline aquifers. It mainly explains how CO_2 can be stored in saline aquifers and how a potential CO_2 storage site should be selected.

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2 CO_2 sequestration principles

2.1 CO_2 phase behavior

Geological sequestration of CO_2 in saline aquifers would preferentially occur at supercritical conditions (Bachu, 2000; Kaldi and Gibson-Poole, 2008). The critical point is 31.1 ˚C and 7.38 MPa, at which CO_2 becomes a supercritical fluid (Fig. 1). Supercritical CO_2 has a high density like a liquid, but moves like a gas, which means it can be stored in great amounts and easily occupy an entire available space. Under standard atmospheric conditions, CO_2 is a stable gas with a density of 1.872 kg/m^3. At temperatures greater than 31.1 ˚C and pressures greater than 7.38 MPa, CO_2 is supercritical with a density ranging from 150 kg/m^3 to over 800 kg/m^3 (Bachu, 2003). The density of CO_2 stored underground depends on the pressure and temperature regime. Considering normal conditions with a surface temperature of 15 ˚C and a geothermal gradient of 30 ˚C/km, CO_2 density increases rapidly with depth and then remains stable (Fig. 2).

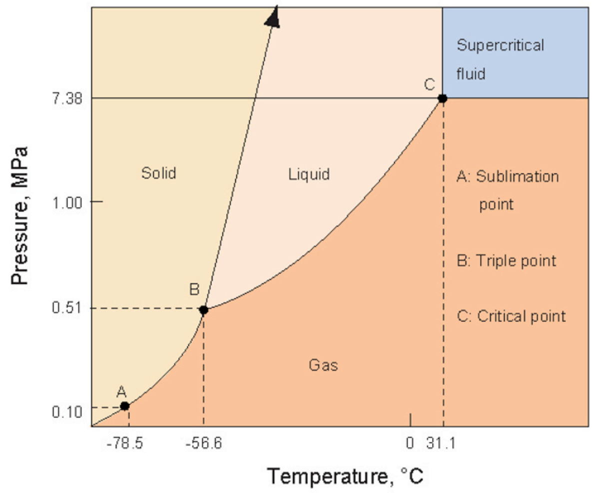

Fig. 1 CO_2 phase diagram (from IEA, 2008; Bachu, 2000)

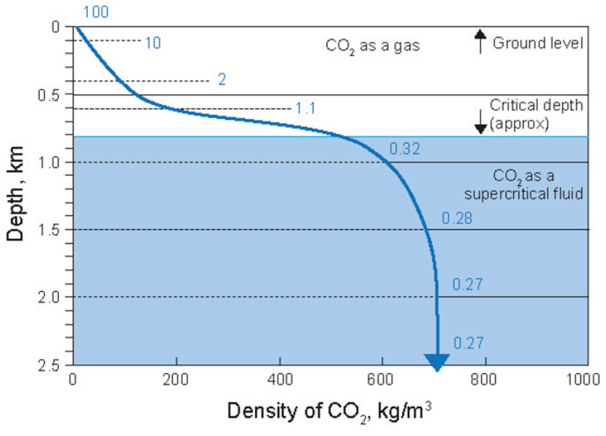

Fig. 2 Density of CO_2 vs. depth under normal conditions (from Kaldi and Gibson-Poole, 2008) (eg. 100 m^3 of CO_2 at surface would occupy 0.32 m^3 at 1 km)

Supercritical CO_2 injection can avoid the prior separation of CO_2 into liquid and gas phases, and also provides longer residence time than gaseous CO_2 injection. Supercritical CO_2 storage is preferred because it is much denser and takes up much less volume than gaseous CO_2. Although supercritical CO_2 injection and storage would be ideal, such conditions are not necessary (Izgec et al, 2005).

2.2 CO_2-water-rock interaction

Carbon dioxide dissolves in formation water/brine. First, it simply dissolves. Then equilibrium is established between the dissolved CO_2 and carbonic acid H_2CO_3, which dissociates into $HCO_3^{\square}$ and $CO_3^{2\square}$. About 1% of the dissolved CO_2 exists as carbonic acid H_2CO_3.

$$CO_2\,(g) \longrightarrow CO_2\,(aq)$$

$$CO_2\,(aq) + H_2O\,(l) \rightleftharpoons H_2CO_3\,(aq)$$
$$\rightleftharpoons H^+ + HCO_3^- \rightleftharpoons 2H^+ + CO_3^{2-}$$

Next, the carbonate anion $CO_3^{2\square}$ interacts with cations in formation water such as Ca^{2+} and Mg^{2+} to precipitate carbonate minerals. Extensive deposits of limestone and dolomite have been formed in this way. Meanwhile, minerals can dissolve in acidic solutions. The reactions that occur depend on the mineral composition of the formation rock. The most common mineral reactions in formations are:

$$\text{Calcite} + H^+ = Ca^{2+} + HCO_3^-$$

$$\text{Kaolinite} + 6H^+ = 5H_2O + SiO_2\,(aq) + 2Al^{3+}$$

$$\text{Illite} + 8H^+ = 5H_2O + 0.6K^+ + 0.25Mg^{2+}$$
$$+ 2.3Al^{3+} + 3.5SiO_2\,(aq)$$

$$\text{Dolomite} + 2H^+ = Ca^{2+} + Mg^{2+} + HCO_3^-$$

$$\text{Quartz} == SiO_2\,(aq)$$

The mutual solubility of CO_2 and brine affects the injection process and flow properties in three ways: First, CO_2 dissolves in brine increasing its density. Second, CO_2 dissolves in brine and reacts with water, forming an acid. Finally, H_2O dissolves into CO_2 increasing the salinity of brine (Hurter et al, 2007).

The solubility of CO_2 in brine is much higher than that of hydrocarbon components. It depends essentially on pressure, temperature, total salinity and brine composition, density difference between CO_2 and brine, and critical CO_2 saturations. In general, CO_2 solubility increases with increasing pressure and decreases with increasing temperature and brine salinity (Ülker et al, 2007).

The reactions among CO_2, brine, and formation minerals play an important role in formations with a large number of proton sinks, such as feldspar and clay minerals. Homogenous reactions among components in the aqueous phase are faster than precipitation or dissolution. Carbonates such as calcite and dolomites are most reactive and tend to precipitate, whereas the main clay minerals tend to dissolve (Rochelle et al, 2004; Calabrese and Blunt, 2005).

These chemical processes are affected by temperature and pressure, flow regime (which varies significantly around the well and can strongly affect the interactions between the circulating fluids and the rock), multiphase flow of CO_2 and water, rock composition and brine composition, and initial pore structure (which affects permeability reductions after CO_2 injection, leading to solution-dissolution kinetics) (Izgec et al, 2005).

In general, some reactions may be beneficial to storage, but others may result in mineral dissolution, facilitating the formation of migration pathways. An understanding of the direction, rate, and magnitude of such reactions is necessary to ensure the host formation sequestering CO_2 safely over a long period of time (Reichle, 1999; Pruess and Garcia, 2002; Rochelle et al, 2004). Chemical reactions affect the long-term fate of CO_2, although their impact is of relatively little significance. Individual formations vary in structure, mineralogy, and hydrogeology. Each storage operation must consider local geological, geochemical, and hydrogeological conditions (Reichle, 1999; Calabrese and Blunt, 2005).

2.3 CO_2 trapping mechanisms

Under normal sedimentary basin conditions, supercritical CO_2 is 30%-40% less dense than typical formation water (Kaldi and Gibson-Poole, 2008). When injected into the formation, CO_2 spreads in the porous medium, displacing formation water and occupying an increasing portion of the flow domain (Pruess and Garcia, 2002; Reichle, 1999). It is then trapped through a combination of physical and chemical processes.

These processes can be classified into three main mechanisms according to the coverage area, namely geological trapping, geochemical trapping, and hydrodynamic trapping. Each category contains several specific trapping mechanisms. As shown in Table 1, structural and stratigraphic trappings occur when the free-phase CO_2 is trapped by the structure of the formation and seal rock units (in a manner similar to hydrocarbon accumulations). Residual saturation trapping occurs when CO_2 is trapped in pore space by capillary pressure forces (Holtz, 2002; Flett et al, 2005). Solubility trapping and ionic trapping occur when CO_2 dissolves into the formation water (Koide et al, 1992). Mineral trapping occurs when CO_2 is involved in further chemical reactions with the rock matrix to form new stable minerals (Gunter et al, 1993). Under favorable circumstances, injected CO_2 migrates in the subsurface at extremely low velocities, reaching the surface after millions of years, and then only if not trapped by a combination of the mechanisms mentioned above. Very large masses of CO_2 could potentially be stored by this means, which is commonly described as hydrodynamic trapping, also known as migration trapping (Bachu et al, 2007; IPCC, 2005).

Table 1 Characteristics of trapping mechanisms in saline aquifers
(Extracted or modified from IPCC, 2005; Bradshaw et al, 2007)

Trapping mechanism		Characteristics		
		Nature of trapping	Capacity limitation/benefits	Potential size
Geological trapping Reservoir scale (km)	Structural and stratigraphic trapping	Buoyancy within anticline, fold, fault block, pinch-out. CO_2 remains below physical trap	Without hydraulic system, limited by compression of reservoir fluid. With hydraulic system, displace formation fluid	Significant
Geochemical trapping Well scale (cm to m)	Residual gas trapping	CO_2 fills interstices between pores of rock grains	Can equal 15%-20% of reservoir volume. Eventually dissolves into formation water	Very large
	Solubility and ionic trapping (Dissolution)	CO_2 migrates through reservoir beneath seal and eventually dissolves into formation water	CO_2 saturated water may migrate towards the basin center. Limited by CO_2 -water contact and favor highly permeable (vertical) and thick reservoirs	Very large
	Mineral trapping	CO_2 reacts with existing rock to form new stable minerals	Reaction rate is slow. Precipitation could reduce injectivity. Approaches ‘permanent’ trapping.	Significant
Hydrodynamic trapping Basin scale (100km)	Migration trapping	CO_2 migrates through reservoir beneath seal, moving with the regional flow system while other trapping mechanisms work	No physical trap may exist; totally reliant on slow transport mechanism and chemical processes. Can include all other trapping mechanisms along the migration pathway	Very large

Each mechanism is effective over different time frames (Fig. 3), and these differences must be taken into consideration when estimating storage capacity. The common characteristic of dissolution, residual gas trapping, and particularly mineral trapping is that these processes generally operate slowly, over a very long period measured in centuries to millennia. Further, their contribution to CO_2 storage capacity is negligible during the operational phase of injection, which lasts for decades (Bachu et al, 2007).

Carbon dioxide can be sequestered in saline aquifers by all the mechanisms mentioned above, which lead to storage of CO_2 as a free phase in pore space or as a dissolved phase in formation water, or to the conversion of CO_2 to rock matrix (Izgec et al, 2005). During injection, all the trapping mechanisms are either unavailable or of slight importance. Hydrodynamic trapping requires a longer dissolution time and eventual convective mixing, and mineral trapping occurs over still longer time periods (Cinar et al, 2007a; 2007b). However, the amount of CO_2 that could potentially be stored in saline aquifers for a reasonable length of time is very large (Bentham and Kirby, 2005), which is about 250 to 900 gigatons of carbon as estimated by USGS, 2008.

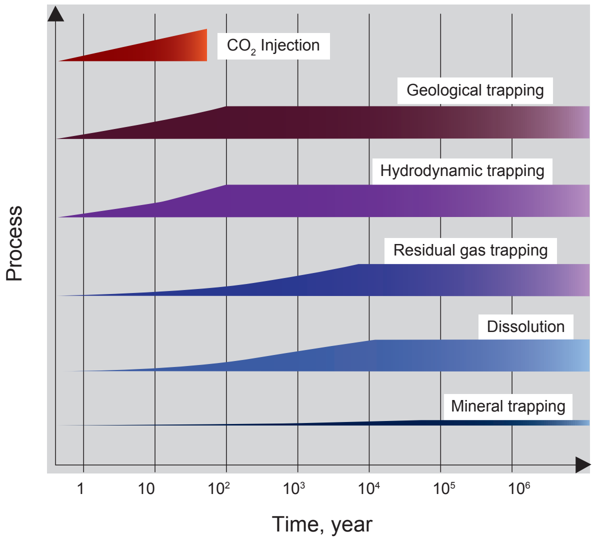

Fig. 3 Time scales of CO_2 injection and geological storage processes (From IPCC, 2005; Bachu et al, 2007)

3 Storage potential

The potential for CO_2 storage in saline aquifers is largely determined by two fundamental features: a site's capacity to accommodate large amounts of CO_2 and its ability to effectively store CO_2 for a long time, namely storage capacity and CO_2 injectivity (Cinar et al, 2007a; 2007b).

3.1 Storage capacity

The storage capacity of CO_2 is an estimation of the amount of CO_2 that can be stored in geologic formations. It depends on pore volume, porosity, and most importantly, volumetric and microscopic displacement efficiencies (Cinar, et al, 2007a; Bradshaw et al, 2007).

Factors affecting CO_2 storage capacity include CO_2 density at reservoir conditions, the interconnected pore volume, and fluid property. The storage capacity of CO_2 therefore should be evaluated accounting for factors such as injection rate, the dip and heterogeneity of the reservoir, and structural closures along the migration path. In addition, different trapping mechanisms must be considered for long-term storage prospect, especially in saline aquifers (Gibson-Poole et al, 2007).

Solubility affects storage capacity significantly because it determines the amount of gas that dissolves in the brine. As simulation work shows, the solubility of CO_2 strongly affects the storage capacity, and neglecting this factor can lead to underestimation of storage by up to 16% (Obi E-O and Blunt, 2004). This difference is more apparent when the injection rate is low; at low injection rates gravitational effects are prevalent, and the injected fluid has sufficient time to reach the bottom of the reservoir and mix with the aquifer. However, the storage efficiency is not strongly influenced by the solubility where the water saturation is low (Obi E-O and Blunt, 2004).

The reactions among CO_2, brine, and the formation rock could change formation porosity and permeability, subsequently affecting fluid-flow patterns and determining the mass of CO_2 that can be stored (Izgec et al, 2005; Noh et al, 2004). Calabrese and Blunt (2005) performed a simulation to investigate the influence of mineral reactions on storage capacity. The results indicate that the variation in porosity and permeability are not affected by quartz; they are only slightly affected by illite and kaolinite, and strongly affected by calcite and dolomite. After 200 years, all variations in total pore volume with respect to the initial conditions are lower than 1%.

DOE (2006) provides a relatively simple volumetric equation for the calculation of CO_2 storage capacity in saline aquifers (Eq. (1) and Table 2) based on the concept that CO_2 occupies some pore space within a permeable rock:

$$G_{CO_2} = Ah_g\Phi_{tot}\rho E \tag{1}$$

Table 2 Volumetric equation parameters for capacity calculation in saline formations (DOE, 2006)

Parameter	Units	Description
G_{CO_2}	M	Mass estimate of saline-formation CO_2 storage capacity
A	L^2	Geographical area that defines the basin or region being assessed for CO_2 storage capacity calculation
h_g	L	Gross thickness of saline formations for which CO_2 storage is assessed within the basin or region defined by A
Φ_{tot}	L^3/L^3	Average total porosity of entire saline formation over thickness h_g
ρ	M/L^3	Density of CO_2 evaluated at pressure and temperature that represents storage conditions anticipated for a specific geologic unit averaged over the depth range associated with h_g
E	L^3/L^3	CO_2 storage efficiency factor that reflects a fraction of the total pore volume that is filled, or contacted, by CO_2

The storage efficiency factor (E) in Eq. (1) estimates storage volume for a region with the level of knowledge (or uncertainty) in some specific parameters by adjusting total gross thickness to net gross thickness, total area to net area, and total porosity to effective porosity actually containing CO_2.

To determine the storage efficiency factor for the region, assuming CO_2 injection wells placed regularly, a reasonable maximum prospective storage volume may be estimated by multiplying the storage efficiency terms. Terms used to define the entire pore volume include net to total area, net to gross thickness, and effective to total porosity ratio. Terms used to define the fraction of pore volume accessed by CO_2 from injection wells include areal displacement efficiency, vertical displacement efficiency, gravity, and microscopic displacement efficiency.

However, evaluation of CO_2 storage capacity in saline aquifers is complex due to the limited data available for assessing storage volumes and various trapping mechanisms involved that act on different time scales – particularly dissolution and mineral precipitation. Because of the time dependency, CO_2 storage capacity must be estimated at a specific point in time, except for storage in stratigraphic and structural traps, and can be achieved through numerical modeling (Bachu et al, 2007).

3.2 CO_2 injectivity

Injectivity measures the possibility of placing a fluid into a geological formation, which contains the rate at which CO_2 can be injected and the ability of CO_2 to migrate from the injection well. It directly determines the suitability of a site for CO_2 storage.

Injectivity (I) is defined as the ratio of a well volumetric flow rate (q) to the corresponding pressure drop or flow potential (Δp):

$$I = \frac{q}{\Delta p} \tag{2}$$

As the volume of CO_2 builds up, the pressure required to place CO_2 into the formation gradually increases, and the injectivity decreases. Moreover, maximum pressure applied during injection is limited by the maximum acceptable pressure increase possible without reactivating existing faults or creating new fissures (Schembre-McCabe et al, 2007).

Injectivity is governed by permeability, relative permeability, rock fracture characteristics, and rock compressibility (Cinar et al, 2007a). These parameters in turn depend on factors such as the depositional environment, reservoir heterogeneity, structure characteristics, and fluid properties. Injectivity can be assessed by characterizing reservoir quality (heterogeneity, porosity, and permeability), geometry and connectivity, and CO_2-water-rock interactions (Kaldi and Gibson-Poole, 2008).

In saline aquifers, CO_2 solubility affects pressure drop which in turn affects injectivity. During injection, CO_2 displaces water and accumulates as free gas at the crest of the aquifer. It also dissolves in water. Clearly, the transition of CO_2 from the free gas phase into the dissolved phase in water has a pressure-reducing effect. However, the dissolved CO_2 molecules have a volumetric effect on water, resulting in a pressure increase. The overall reduction in pressure caused by dissolution is proportional to the amount of CO_2 dissolved. A simulation carried out by Van der Meer and Van Wees (2006) shows that about 28% of the injected CO_2 might dissolve within 10,000 years, yielding a pressure reduction of some 5%.

Also, chemical reactions among CO_2, water, and rock can change the mineralogy and pore systems. Mineral dissolution may lead to porosity and permeability rise, thereby increasing injectivity. On the other hand, the movement of fine clay particles and the precipitation of new minerals can result in porosity and permeability drop, thereby decreasing injectivity. The overall effect of chemical reactions on injectivity depends on the specific properties of a site.

In addition, many saline aquifers have low permeability due either to depositional or diagenetic processes, which can cause large pressure gradients near the wellbore and considerably restrict injectivity. Therefore, for the near-wellbore area, it requires higher permeability. But for an area outside the influence radius of the wellbore, relatively lower permeability is preferred because it provides longer residence time and enhances residual trapping, dissolution, and mineral trapping (Bachu et al, 2000).

4 Site selection

Careful site selection is crucial for successful geological storage of CO_2. Three basic requirements must be met: adequate connected porosity, CO_2 density large enough to ensure economical storage, and formation injectivity large enough to avoid a large pressure increase when injecting CO_2 (Doughty et al, 2008). Generally, the process must consider the basin and reservoir characteristics, as well as economic and social concerns. It contains different scales of screening and characterization. Summaries of site selection workflow and methods used are presented in Fig. 4 and Table 3.

As shown in Fig. 4, basin suitability and identification of prospective sites are fundamental screening procedures in site selection. They provide information about geology background and important parameters such as size, depth, porosity, and permeability. The techniques involved include geological mapping, geophysical imaging, well logging, core analysis, and hydraulic well testing (Doughty et al, 2007). A series of screening criteria developed by Bachu (2003) are as listed below.

Basin characteristics

1) Basin type and tectonic setting: A CO_2 storage site must be in a relatively stable tectonic setting so that the stored CO_2 will not be released by tectonic movement. The preferred sedimentary basins are intracratonic, foreland, and passive-margin basins.

2) Hydrodynamic and geothermal regimes: To minimize the risk of leakage and also increase the effectiveness of CO_2 storage, the basin flow system should be deep and regional in scale, and driven by topography or erosion rebound. Cold basins are more favorable than warm basins because they have low surface temperatures and geothermal gradients (cold basins: marine basins with a surface temperature of 3-4 °C

Table 3 Methods used in site selection

Method	Description	Information obtained
Traditional site characterization methods	Review existing data 3D seismic analysis Geological mapping and geophysical imaging Well logging and core analysis Hydraulic well testing	1. Basin suitability 2. Site details (size, depth, thickness, containment, etc.) 3. Structure of target formation and overlaying cap rock 4. Extent, continuity, and variability of layers 5. Permeability, porosity, relative permeability parameters
Laboratory experiments	CO_2/brine injection test	1. Major parameters such as reaction frequencies and coefficient 2. Specific porosity/permeability relationships 3. CO_2 injectivity
Numerical simulation	Simulating an abstract model of a particular system using software such as ECLIPSE, STARS, TOUGH2, NUFT, TRANSTOUGH, STOMP, etc.	1. CO_2 phase behavior, including thermal effects 2. CO_2 migration 3. Geochemistry and solid matrix deformation 4. Geomechanics 5. Engineering strategies

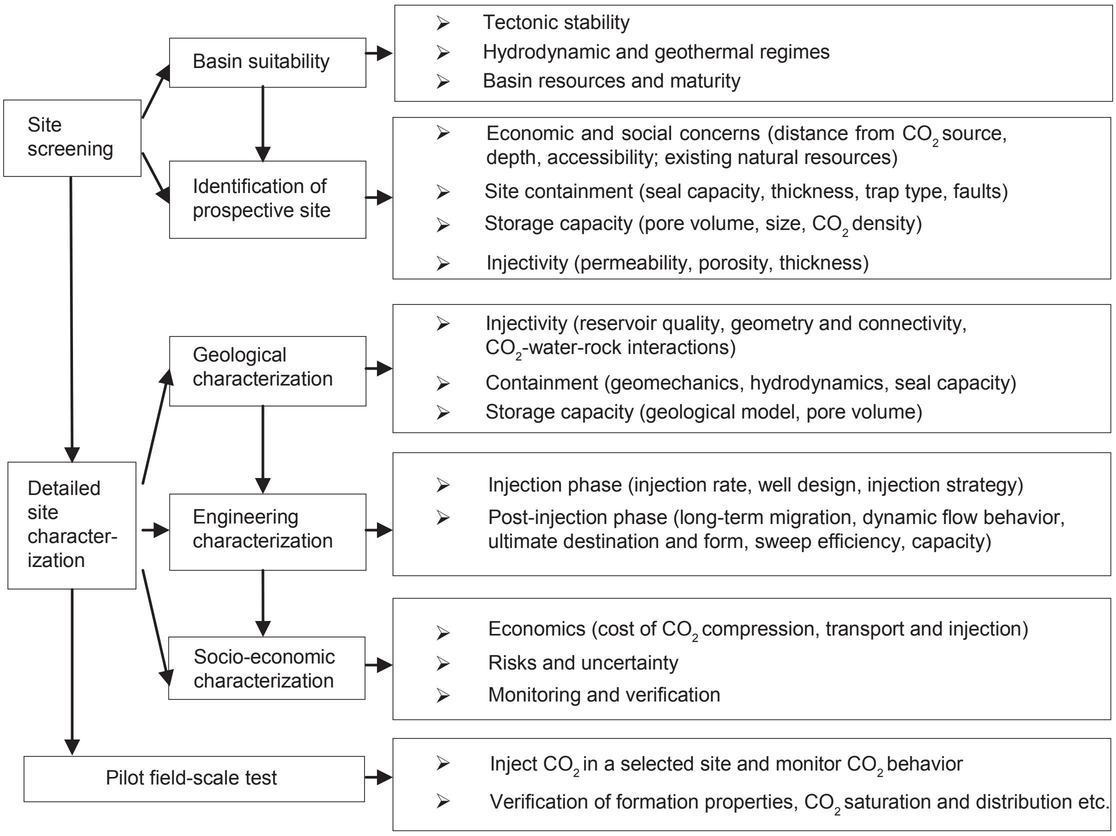

Fig. 4 Site selection workflow for CO_2 storage (partly extracted and modified from Kaldi and Gibson-Poole, 2008)

at the bottom of the sea, continental (sub) Arctic and (sub) Antarctic basins, which are −2 °C below the permafrost. Warm basins: continental temperate basins of 4-10 °C, and continental tropical basins of 10-25 °C). These thermal properties permit storage of CO_2 with higher density at shallower depths.

3) Basin resources and maturity: It is important to know the fossil-energy potential of the basin (i.e., quantities of oil and gas or coals it contains), and the degree of exploration and production underway. Ideally, the basin should be rich in energy resources, its hydrocarbon resources should be mostly recovered, and it should have advanced production.

Reservoir characteristics

1) Geologic structure: Faults, fractures, and unconformities are undesirable because they may create pathways for CO_2 to migrate through the cap rock to the surface. Sloping aquifers are preferred targets for CO_2 storage because they provide effective residential trapping to reduce the volume of mobile CO_2. Moreover, the increased vertical sweep of such aquifers decreases the maximum migration distance as the slope increases (Hesse et al, 2006).

2) Cap rock integrity: Cap rock, an impermeable low-porosity layer that prevents vertical CO_2 migration, provides the main trapping mechanism for longterm storage security

(Bentham and Kirby, 2005). Cap rock properties must be determined to ensure the presence of effective reservoir-seal pairs.

3) Size: The reservoir must be large enough to store the quantities of CO_2 planned, e.g., the lifetime emissions of one power plant (Bentham and Kirby, 2005).

4) Depth: A storage site is preferred to be deep enough to keep CO_2 supercritical so that a great amount of CO_2 can be stored (Bachu, 2003; Bentham and Kirby, 2005; Sengul, 2006). The minimum depth at which CO_2 supercritical conditions are met depends on surface temperature and geothermal gradients (Bachu, 2000, 2002). Based on worldwide average conditions, an approximate minimum subsurface depth is about 800 m (Fig. 5) (Bentham and Kirby, 2005; Imbus et al, 2006). For worldwide sedimentary basins with surface temperatures between 0 and 30 °C, geothermal gradients between 20 and 60 °C/km, the optimum depth is 800-1,000 m for cold basins and 1,500-2,000 m for warm basins. These parameters would maximize the capacity and minimize the cost of well drilling, CO_2 compression, and injection (Bachu, 2003).

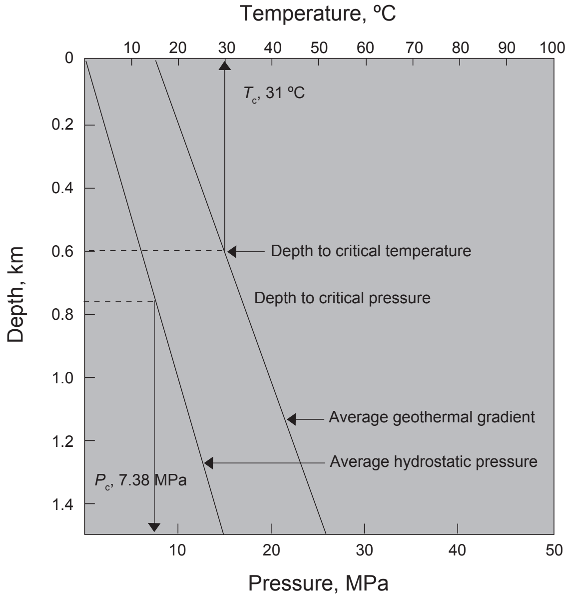

Fig. 5 Estimated depths to critical temperature and pressure for CO_2 (Holliday et al, 1991)

5) Porosity and permeability: These parameters must be sufficiently high to allow injection and provide sufficient volume for CO_2. Crystalline and metamorphic rocks, such as granite, are not suitable for CO_2 storage because they do not have the porosity and permeability needed for CO_2 injection (Bachu, 2003). Large unfaulted or high-permeability reservoirs are preferred (Bentham and Kirby, 2005).

6) Fluid properties and rock mineralogy: Fluid properties, such as brine salinity and composition, viscosity, density, pressure, and temperature, are fundamental parameters that directly and strongly affect CO_2 phase, solubility, and dissolution, thus controlling the effectiveness of trapping. For instance, higher salinity results in lower solubility of CO_2 (APEC, 2005). Mineral composition plays an important role in chemical reactions in the formation (as mentioned in the section on CO_2-water-rock interaction above).

Economic and social concerns

The cost of CO_2 storage is affected by basin location (marine or continental), climatic conditions, transportation distances, and injection depth. The ideal site would be at an intermediate depth below an onshore basin near a CO_2 source, with a temperate climate and well-developed infrastructure. Such a site would be easy to access with roads, pipelines, and wells (for continental basins), or drilling and production platforms (for marine basins) (Bachu, 2003; Gibson-Poole et al, 2007).

For safety and effectiveness, the ideal site would be legal and publicly accepted. It would avoid contamination of energy, mineral, and groundwater resources so that there would be no use conflicts (such as energy exploration, natural gas storage, water extraction, and mining). Finally, the site would ensure no risk to life – plants, animals, or humans – and no leakage for the desired time period (Bachu, 2003; Bentham and Kirby, 2005).

Once a prospective site has been identified, detailed site characterization needs to be done to assess its storage potential which includes geology characterization, engineering characterization, and socio-economic characterization. Key factors that must be evaluated are CO_2 injectivity, site containment, storage capacity, economical and technical feasibility, and existing natural resources. In this process, the injection of CO_2 should be studied in the laboratory to investigate experimentally the various situations that may occur during the process. Such studies would generate data such as the solution and deposition reaction frequencies and the Kozeny-Carman coefficient, which are major parameters that must be calibrated to obtain a match (Izgec et al, 2005). Specific porosity/permeability relationships as a function of the flow regime must be elaborated and introduced in the numerical models (Wellman et al, 2002). The injectivity of CO_2, which is very case-dependent, must also be determined. To yield relevant recommendations for field applications, the work must be performed under representative conditions (fluids, rock, pressure, and temperature) (Egermann et al, 2005). Numerical simulation of CO_2 injection must be performed to understand the behavior and storage potential of CO_2. Such simulation requires modeling complex hydrologic, chemical, and thermal processes (Bacon et al, 2006; Nghiem et al, 2004; Xu et al, 2003). Also, engineering strategies can be simulated to ensure storage security, capacity, and effectiveness. These strategies include controlling injection pressure and injection rate, applying newly developed injection approaches to store CO_2 safely and efficiently, and testing a gel treatment for the formation. Such simulation work remains in the developmental stage; however, three factors need to be considered, physical and chemical processes important to the CO_2 injection problem, computational limitations in CO_2 modeling, and data needs (Princeton University, 2005).

Finally, a pilot field-scale test is needed for verification purposes of laboratory parameters and numerical models. This step is necessary in site selection for any commercial CO_2 storage project. With real field observations, adjustments of parameters can be made to get a better understanding, and new features can be added into the numerical models to help injection design and predictions.

5 Operational aspects

From an engineering perspective, the main issues affecting potential for injection of CO_2 in saline aquifers are the rate at which CO_2 can be disposed, the available storage capacity, the presence of a low permeability cap rock, the potential for CO_2 leakage, uncertainty and possibility of failure due to incomplete knowledge of subsurface conditions, and the corrosion resistance of materials to be used in the system (Pruess and Garcia, 2003). Factors that influence storage capacity and should be determined are well type, injection rate, CO_2 purity, and injection strategy. Among them, injection rate and CO_2 purity are the key determinants of storage capacity (Calabrese and Blunt, 2005).

5.1 Well type

Vertical wells are commonly used for CO_2 injection. But if the geology characteristic of a CO_2 storage site can be well described, horizontal wells are desirable. Horizontal wells have two advantages over vertical wells for CO_2 storage: A larger volume of CO_2 can be stored without reaching the top of the aquifer, and a higher injection rate can be expected (Ozah et al, 2005). Horizontal wells can significantly improve injectivity and storage capacity – especially in low permeability formations. The injection rates of horizontal wells can be 4-5 times of those of vertical wells without increasing in the injection pressure (Jikich et al, 2003).

5.2 Injection rate

Storage capacity decreases as the injection rate increases. The maximum storage capacity is reached with the lowest injection rate, which also extends the injection. A simulation performed by Calabrese and Blunt (2005) shows that with the highest injection rate, storage capacity is decreased by about 27%.

Further, storage efficiency decreases as the injection rates increases. At lower injection rates, the denser CO_2 could fall to the bottom of the gas zone and dissolve in the aquifer. At a high rate, the movement of CO_2 is much more affected by the reservoir heterogeneity. The resultant channeling, due to the presence of high permeability paths, dominates the transport. These channels affect in particular the zones with higher water saturation, because the contrast between the mobility of CO_2 and that of the more viscous water is unfavorable (Calabrese and Blunt, 2005).

5.3 CO_2 purity

The purity of the injection CO_2 strongly affects the storage capacity. Mixing N_2 with CO_2 decreases the total mass that can be stored, whereas mixing H_2S with CO_2 increases the total mass.

CO_2/N_2 injection

A simulation performed by Calabrese and Blunt (2005) compared the injection of pure CO_2 with the injection of fluid composed of 90% CO_2 and 10% N_2. The results show the total mass injected ($CO_2 + N_2$) at each injection point is about 20% lower than the total mass of CO_2 injected in the base case.

CO_2/H_2S injection

The amount of H_2S dissolved in brine is 10% greater than CO_2. When a CO_2/H_2S mixture is injected, H_2S is more soluble and flows a shorter distance in the aquifer than CO_2. Ozah et al (2005) simulated the injection of a mixture of 70% CO_2 and 30% H_2S for 50 years, followed by natural-gradient flow for 10,000 years. Approximately 67% of the total injected CO_2 was trapped as residual gas when injected with H_2S, which is a 2% increase over the level of entrapment achieved with the injection of pure CO_2. Also, the percentage of CO_2 remaining as mobile gas decreased from 5% to 2.6%.

5.4 Injection strategy

Simulation studies imply that only about 2% of the pore space will contain CO_2 if CO_2 is injected alone (Obi E-O and Blunt, 2004). However, injecting CO_2 and water reduces the mobility contrast between the injected and displaced phases, leading to a more uniform sweep of the reservoir (Lake, 1989). Qi et al (2007) designed an efficient and easy injection approach, that is, CO_2 and brine are injected into an aquifer together, followed by the injection of brine alone. The simulation results show that this method renders 80%-95% of the CO_2 immobile in pore scale droplets in the porous rock, and CO_2 is trapped within decades, thus reducing the need for extensive monitoring over centuries.

6 Conclusions

Saline aquifers provide enormous capacity for CO_2 sequestration in most sedimentary basins worldwide. The characteristics of saline aquifers for CO_2 sequestration can be summarized as follows:

1) Carbon dioxide can be stored in saline aquifers through geological trapping, geochemical trapping, and hydrodynamic trapping. The potential for CO_2 storage in saline aquifers is largely determined by storage capacity and CO_2 injectivity. Storage capacity depends on aquifer volume, porosity, and displacement efficiencies, while CO_2 injectivity is governed by permeability, porosity, relative permeability, rock fracture characteristics, and rock compressibility. Evaluation of CO_2 storage capacity in saline aquifers is complex, due to limited data and various trapping mechanisms involved that act on different time scales. The mutual solubility of CO_2 and brine strongly affect storage capacity and injectivity. Chemical reactions among CO_2, brine, and formation rock affect the long-term fate of CO_2, although their impact is less significant.

2) Potential storage sites can be selected by assessing the basin and reservoir characteristics, as well as economic and social factors. Three main procedures are site screening, detailed site characterization, and pilot field-scale test.

These procedures can be done by using traditional site characterization methods, laboratory experiments, and numerical simulation. A site suitable for CO_2 storage should be in a geologically stable area and minimally faulted, fractured, or folded. It should have strong confining seals and adequate size, depth, permeability, and porosity. The ideal site would be a confining unit in a cold basin with strongly harmonious sedimentary sequences and no significant diagenesis. It would be deeper than 800 m, well characterized, and easy to operate.

3) Engineering factors such as well type, injection rate, CO_2 purity, and injection strategy must be considered. Horizontal wells can achieve larger storage volumes of CO_2 and higher injection rate than vertical wells. Lower injection rates can increase storage capacity and efficiency. Higher purity of the injection CO_2 results in a greater storage capacity. Brine injection as well benefits storage during CO_2 injection.

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