HEALTH, SAFETY AND ENVIRONMENTAL RISKS OF UNDERGROUND CO_2 STORAGE – OVERVIEW OF MECHANISMS AND CURRENT KNOWLEDGE

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Abstract. CO_2 capture and storage (CCS) in geological reservoirs may be part of a strategy to reduce global anthropogenic CO_2 emissions. Insight in the risks associated with underground CO_2 storage is needed to ensure that it can be applied as safe and effective greenhouse mitigation option. This paper aims to give an overview of the current (gaps in) knowledge of risks associated with underground CO_2 storage and research areas that need to be addressed to increase our understanding in those risks. Risks caused by a failure in surface installations are understood and can be minimised by risk abatement technologies and safety measures. The risks caused by underground CO_2 storage (CO_2 and CH_4 leakage, seismicity, ground movement and brine displacement) are less well understood. Main R&D objective is to determine the processes controlling leakage through/along wells, faults and fractures to assess leakage rates and to assess the effects on (marine) ecosystems. Although R&D activities currently being undertaken are working on these issues, it is expected that further demonstration projects and experimental work is needed to provide data for more thorough risk assessment.

1. Introduction

In order to stabilise the concentration of greenhouse gasses in the atmosphere, many countries have committed themselves to reduce their greenhouse gas emissions. These emissions are dominated by CO_2 and to a large extent related to fossil fuel use. Reduction of CO_2 emissions can be realised by means of a diverse portfolio of options covering energy and material efficiency improvements, afforestation, increased use of renewable and nuclear energy and decrease of the carbon intensity of fossil fuels. The latter option comprises a shift from coal towards gas and carbon dioxide removal, in which CO_2 emitted at stationary sources is captured and stored in geological reservoirs or the ocean. It is becoming clear that energy and material efficiency improvements and the increased use of renewable energy sources cannot achieve the emission reductions required to reach long-term atmospheric stabilisation targets below 550 ppm CO_2 (Pacala and Socolow, 2004). The use of nuclear energy meets public resistance in many countries. Given the large amounts of fossil fuels (especially coal) that can be extracted at low costs, cleaner use of fossil fuels by capturing and storing CO_2 is considered to be a potential element of a strategy to substantially reduce global anthropogenic CO_2 emissions in the coming decades (Herzog et al., 1997; IPCC, 2001a; Pacala and Socolow, 2004; Turkenburg, 1997).

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TABLE I
Geological reservoir types and estimated global storage capacity (Hendriks et al., 2002; IEA GHG, 1998; IEA GHG, 2000; IEA GHG, 2001)

Reservoir type	Global capacity (Gt CO_2)
Depleted oil and gas fields[a]	920
Deep saline aquifers	240–10 000
Unminable coal seams[b]	40–270

[a]Including oil and gas fields approaching the end of their economically productive life (by primary and secondary production). In these reservoirs, injection of CO_2 may enhance the oil/gas yield (enhanced oil/gas recovery or EOR/EGR).
[b]In these reservoirs, injection of CO_2 can result in the production of coal bed methane (enhanced coal bed methane recovery or ECBM).

The technical potential or capacity (see Table I) is sufficient to store worldwide emissions for several decades up to several hundred years.

A key factor affecting the implementation of CCS are the risks associated with underground CO_2 storage. Gaining a better understanding and quantification of these risks is needed to ensure that they will comply with safety standards (also after injection has been completed). Risk assessment is a first step in a strategy to set up management and control measures to minimise risks of underground CO_2 storage. Also, it helps to facilitate the formulation of standards and regulatory frameworks required for large-scale application of CCS. To date, a wide variety of activities studying the risks of underground CO_2 storage have been completed and are being performed. The risks associated with underground CO_2 storage have been discussed extensively in an EU study on underground disposal of CO_2 (Holloway, 1996). However, in the meantime new insights have been obtained into the risks of CCS.

The objective of this article is to give an overview of the knowledge and especially the gaps in knowledge with regard health, safety and environmental risks of CCS, useful for policymakers to prioritise R&D, set standards and define strategies. The overview is based on a review of scientific literature and information gained from R&D projects, supported by expert consultation.

Health, safety and environmental risks can be caused by operation of surface and injection installations and by storage of CO_2 in a geological reservoir. CO_2 capture and compression are commonly applied technologies in industry to produce high-purity CO_2 for various industrial applications (enhanced oil recovery, carbonisation of beverages, cooling, drinking water treatment, welding, foam production). The associated risks are considered to be acceptable according current industry standards and therefore not discussed in this paper. The risks associated with surface and injection installations are discussed very briefly in this paper. We will focus on the risks associated with CO_2 storage in geological formations. The risks associated with CO_2 storage in the ocean are not considered.

The core of this paper describes the (gaps in) knowledge on the risks that may occur when transporting, injecting and storing CO_2 in geological formations (Sections 2 and 3). Section 4 discusses the results of various risk assessments. The knowledge that can be obtained from experience with industrial and natural analogues, which show similarities with underground CO_2 storage, is considered in Section 5. This knowledge is used to get insight into factors and processes that may be (ir)relevant to the risks of underground CO_2 storage. In Section 6, knowledge gaps are summarised and compared to an overview of ongoing R&D activities. Subsequently, research areas and priorities can be formulated to reduce gaps in knowledge.

2. Risks Associated with Surface and Injection Installations

Surface and injection installations comprise a transmission pipeline,[1] (booster stations), CO_2 delivery station, a pipeline distribution network, injection well(s) and a monitoring system. When hydrocarbons are produced simultaneously, the system also comprises production wells and surface facilities to produce, clean, compress and transport the extracted hydrocarbons.

CO_2 produced from natural CO_2 fields or captured from industrial facilities is transported and injected on a commercial scale for enhanced oil recovery (CO_2-EOR), principally in the USA. Worldwide, approximately 3100 km of pipeline exists with a capacity of circa 45 Mt CO_2/yr (Gale and Davison, 2003). The major risk associated with pipeline transport is a pipeline failure, which can be either a (pin)hole or rupture, resulting in CO_2 release. The accident record for CO_2 pipelines in the USA shows 10 accidents from 1990 to 2001 without any injuries or fatalities,[2] corresponding to a frequency of 3.2×10^{-4} incidents per km per year (Gale and Davison, 2003). Statistics of incidents with natural gas and hazardous liquid pipelines between 1986 and 2001 in the USA show a frequency of 1.7×10^{-4} and 8.2×10^{-4} per km per year, respectively (Gale and Davison, 2003). Since CO_2 is not explosive or inflammable, the consequences in case of leakage are expected to be less severe than for natural gas. However, in contrast to natural gas, which is dispersed quickly into the air, CO_2 might cause dangerous situations when it is able to accumulate in confined spaces, as it is denser then air (see Section 3.1.2). The possible consequences of a rupture of a buried pipeline transporting 250 t liquid CO_2/h at 60 bar have been analysed in (Kruse and Tekeila, 1996). The results of the model indicate that the safety distances to the pipe at which concentrations of minimal 5% will occur for 60 s, lie between 600 and 150 m, depending on the distance between safety valves.

The major risk associated with injection is a well failure, which may result in escape of CO_2 that will migrate upwards due to its relatively low density in comparison to water. The likelihood of a sudden escape of all CO_2 stored in an underground reservoir is very small due to the limited capacity of the injection system (Holloway, 1996). In the majority of well failures, an amount equal to the content of the well tubing will be released. In normal cases, this leak will be detected by the monitoring system, resulting in the closure of the back flow preventer and the emergency shutdown valve at the well head (Holloway, 1996).

Failure of the back-flow preventer or packer may result in a well blowout (Holloway, 1996). A blowout is an uncontrolled flow of reservoir fluids (which can be CO_2, but also salt water, oil, gas or a mixture of these) into the well bore to the surface. Apart from CO_2 release, the potential consequences are casualties among operators and economic damage caused by explosion or fire when upcoming hydrocarbons are ignited or by parts of the well, which can be launched by the pressure release. The frequency of blowouts from offshore gas wells has been estimated at 1×10^{-4} per well year, based on a database of blowouts in the Gulf of Mexico and the North Sea between 1980 and 1996 (CMPT, 1999). Other estimates based on both oil and gas wells give a frequency of 3×10^{-4} per well year (IEA GHG, 2003).

Summarising, there is a lot of industrial experience with extraction, processing, transport and injection of CO_2. Additionally, the experience with hydrocarbons and other chemicals is partly applicable to CO_2 transport and injection. Industrial experience with CO_2 and other gases shows that the risks from industrial facilities are manageable using standard engineering controls and procedures (Benson et al., 2002).

3. Risks Associated with CO_2 Storage in Geological Reservoirs

The risks of CO_2 storage in a geological reservoir can be divided into five categories (see Figure 1):

- *CO_2 leakage:* CO_2 migration out of the reservoir to other formations, from where it may escape into the atmosphere.
- *CH_4 leakage:* CO_2 injection might cause CH_4 present in the reservoir to migrate out of the reservoir to other formations and possibly into the atmosphere.
- *Seismicity:* The occurrence of (micro) earth tremors caused by CO_2 injection.
- *Ground movement:* Subsidence or uplift of the earth surface as a consequence of pressure changes induced by CO_2 injection.
- *Displacement of brine:* Flow of brine to other formations (possibly sweet water formations) caused by injection of CO_2 in open aquifers.

We will mainly focus on the risk of CO_2 leakage, for which the mechanisms, local and global effects will be discussed extensively in Sections 3.1.1 to 3.1.3. The mechanisms and effects of the other risks are discussed in less detail.

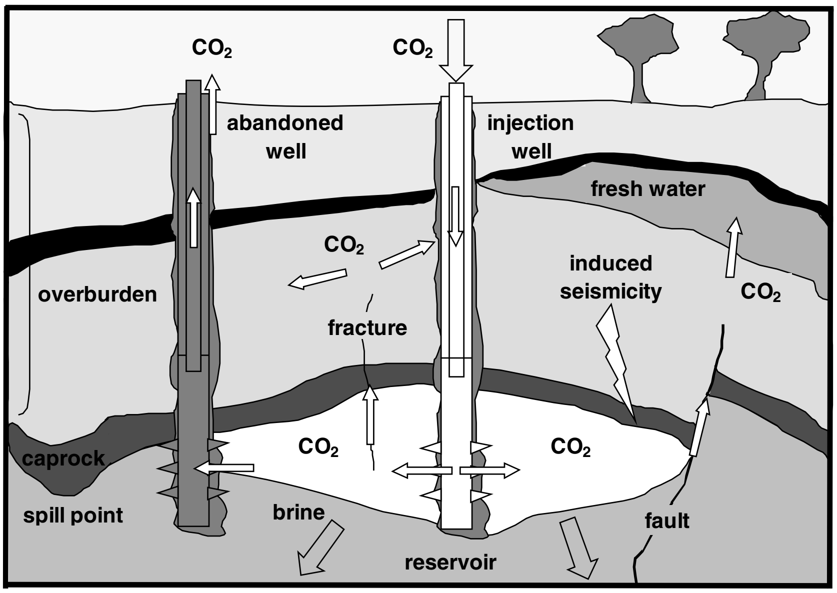

Figure 1. Risks of underground CO_2 storage. Black arrows represent CO_2 flows (along fractures, abandoned wells and faults). White arrows represent brine displacement as a consequence of CO_2 injection.

3.1. CO_2 LEAKAGE

When CO_2 is injected in geological reservoirs, it might potentially migrate out of the reservoir through the subsurface, migrate laterally in overburden formations and finally leak into the atmosphere/biosphere. The potential for leakage will depend on well and cap rock (seal) integrity and the trapping mechanism. CO_2 can be retained in reservoirs by means of the following trapping mechanisms (Bachu et al., 1994; Ennis-King and Paterson, 2001; Gunter et al., 1993; Hitchon et al., 1999):

- When injecting CO_2 in a hydrocarbon reservoir, gaseous or supercritical CO_2 will rise up due to buoyancy effects. The presence of geological traps such as low-permeable cap rock will prevent the CO_2 to migrate further; CO_2 will accumulate under the cap rock.
- CO_2 injected in deep saline aquifers might take thousands to millions of years to migrate from injection point to the surface due to the extremely low flow rates encountered in these formations (hydrodynamic trapping).
- CO_2 can partly be trapped in the pore space by capillary forces (residual gas trapping).
- Since CO_2 is highly soluble in water and also dissolves in oil, solubility trapping is an important trapping mechanism. When injecting CO_2 into an aquifer, CO_2 will mainly be present as supercritical fluid before it fully dissolves. Model calculations of CO_2 injection in an Australian formation indicate that

complete dissolution is expected to take place on a time scale ranging from 10 000 to 100 000 yr (Ennis-King and Paterson, 2003). Simulations of CO_2 injection into the Utsira formation at the Sleipner site[3] suggest that CO_2 will be dissolved completely after 5000 to 50 000 yr (Lindeberg and Bergmo, 2003). When the CO_2 is completely dissolved, leakage is no longer possible, since free CO_2 is not present anymore, provided that no CO_2 is released as a consequence of pressure and temperature changes in the reservoir.

- Dissolved CO_2 can react with silicates and carbonates to form bicarbonate or carbonate ions (ionic trapping).
- CO_2 can also react with minerals and organic matter present in the geologic formations to become part of the solid matrix, also referred to as mineral trapping. This is the most secure form of trapping. However, the extent to which injected CO_2 reacts with minerals present in either sandstone or carbonate reservoirs is considered to be low. Reservoir simulations of aquifers similar to the Utsira formation at Sleipner revealed that less than 1% precipitates as carbonate minerals after 20 yr (Johnson and Nitao, 2003). On the longer term, limited additional reaction is expected (IEA GHG, 2003).
- In coal seams, CO_2 will be trapped by adsorption to the coal surface displacing adsorbed methane and by physical trapping in the cleats within the coal. Due to adsorption to the coal surface, less "free" CO_2 is present. Consequently, the risk of leakage in coal seams is expected to be smaller than for hydrocarbon reservoirs and deep saline aquifers, where CO_2 is predominantly present in free state in the first phase after injection.

The permeability of the overburden, the formations above the target reservoir, is another critical factor for leakage, since it determines the retention time of CO_2 in the subsurface. Simulation of CO_2 diffusion through the 700 m overburden above the Utsira formation at Sleipner indicate that it will take more than 500 000 yr for CO_2 to reach the sea floor (Lindeberg and Bergmo, 2003). A model simulating the release of CO_2 from an aquifer at 1000 m depth in the Netherlands indicated a breakthrough time of CO_2 to reach the surface of about 5500 yr assuming a permeability of 1 mDarcy (Holloway, 1996).

3.1.1. *Mechanisms of CO_2 Leakage*

3.1.1.1. *Depleted Oil and Gas Fields.* Hydrocarbon reservoirs, which generally have been well researched, are considered to be safe sinks for CO_2 storage, since these media have held oil/gas for geological timescales (i.e. millions of years) without major incidents of sudden migration. Many gas reservoirs are holding significant quantities of CO_2 as well, giving further confidence that CO_2 can be stored safely without large releases of CO_2. However, there is a risk that CO_2 escapes from the reservoir through or along wells or by means of a cap rock failure. CO_2 might also escape via spill points[4] or dissolve in fluid flows in the reservoir rock beneath the CO_2 accumulation to surrounding formations, which may cause leakage.

CO_2 leakage through or along wells after the injection phase can be caused by casing or cementation defects due to improper design or construction, corrosion of the casing and deterioration of cement plugs by CO_2 and/or brine. Abandoned wells can be an important migration pathway, since depleted oil/gas reservoirs are generally "punctured" by a large number of non-operative wells, some of them in bad condition. Especially unidentified and poorly (improperly plugged) abandoned wells are potential point sources. Moreover, control and maintenance of abandoned wells is a complex matter in several regions in the world.

Diffusion of CO_2 through the cement or steal casing is a process, which will progress very slowly (in the order of 20 cm in 100 yr) (Seinen et al., 1994). However, it is uncertain how the well bore integrity (the cement and casing) is affected by CO_2 and brine considering a storage timescale of 100's to 10 000's of years. Degradation may affect permeability of cement, which might increase leakage rates in time. Over long time scales, wells may thus serve as preferential leakage pathways and may therefore represent a significant (long-term) risk (Celia and Bachu, 2003).

In order to assess potential leakage of a certain reservoir, detailed information must be available on the number, type and age of wells, completion technique and type of materials used. This information will not always be available in some regions, making it hard to get a quantitative estimation of leakage potential.

A *cap rock failure* is a generic term for various mechanisms described below:

- Capillary leakage occurs when the pressure difference of fluid phase and the water phase in the pores adjacent to the cap rock is higher than the capillary entry pressure of the cap rock. Since the capillary entry pressure of a cap rock has generally been sufficient to retain hydrocarbons and the capillary entry pressure can be measured, capillary leakage of CO_2 is not considered to be a problem (Jimenez and Chalaturnyk, 2003).
- Diffusion of CO_2 through the cap rock is expected to be a very slow process, but can be the controlling mechanism for leakage on the long-term (Jimenez and Chalaturnyk, 2003).
- CO_2 might leak through man-made fractures, also referred to as hydraulic fracturing. Fractures can be created by over pressuring the reservoir. Fractures could be sealed in time by precipitation of newly formed minerals, but could also be re-opened as a consequence of new changes in stresses during storage of CO_2 (Jimenez and Chalaturnyk, 2003). Also earlier production/injection processes to exploit hydrocarbon reservoirs may have created fractures. In the selection of a suitable reservoir, the impact of primary, secondary and tertiary recovery processes[5] on the hydraulic integrity of the bounding seals should therefore be assessed (Jimenez and Chalaturnyk, 2003).

  In order to prevent fracturing, the maximum injection pressure should always be kept below the level at which the cap rock may shear (fracture pressure) (Over et al., 1999). The risk of leakage through fracturing is low as long as the storage pressure does not exceed the initial reservoir pressure. However,

there is a certain level of overpressure, at which CO_2 can be safely contained. This "safety factor" depends on the stress state of the cap rock, which depends on depth, pore pressure, rock properties and sedimentary and tectonic history. The maximum injection pressure can be predicted by determining the in-situ stress profile (Holloway, 1996).
- Dilatant[6] shear formation and fracturing may occur in cap rocks, which can ultimately create preferential flow paths and increasing the cap rock permeability and consequently the risk of CO_2 leakage. However, shear deformation can also result in a reduced permeability (Jimenez and Chalaturnyk, 2003).
- High-permeability zones might exist or be formed by reaction of CO_2 with the cap rock, causing the cap rock to dissolve. CO_2 can dehydrate clay shales in the cap rock, thereby increasing its permeability.
- CO_2 might leak through open (non-sealing) faults, which extend into the cap rock. The risk of leakage along faults can be minimised by performing a detailed analysis of the geological setting of the reservoir prior to injection and selecting only those reservoirs with no/minimal faulting.
- Seismic disturbances might cause cap rock failure (Saripalli et al., 2003).

Of these mechanisms, leakage along or trough wells, faults and fractures are generally considered to be the most important leakage pathways. However, there is still a lack of understanding in the physics of CO_2 leakage (i.e. the processes that control leakage) through wells and faults. Also, there is a lack of data to close the knowledge gap (IEA GHG, 2004).

3.1.1.2. *Deep Saline Aquifers.* Leakage from deep saline aquifers basically occurs via the same mechanisms as discussed above. A major difference with hydrocarbon reservoirs is that aquifers generally do not have cap rocks or seals that have stood the test of time in retaining gasses. Since deep saline aquifers are not of economical interest such as hydrocarbon-reservoirs, the number of wells penetrating aquifers, and consequently the potential for CO_2 leakage through/along wells is lower in comparison to hydrocarbon fields.

Another difference with hydrocarbon reservoirs is the fact that CO_2 storage in an aquifer will induce a (temporary) pressure increase in the reservoir, because the space to store CO_2 only becomes available as a result of compression of the fluids and rock in the reservoir, or displacement of formation water into adjacent formations or to the surface (Holloway, 1996). This pressure increase might trigger fracture zones, which might end up in CO_2 migrating upwards (Over et al., 1999).

Deep saline aquifers have not been researched that well as hydrocarbon reservoirs. An extensive research programme, the completed SACS project followed by the ongoing CO2STORE project, has been set up to study and monitor CO_2 injected in the Utsira aquifer at Sleipner. Seismic surveys that have been acquired so far (latest in 2002) do not indicate any CO_2 leakage to levels shallower than the Utsira Sand (Arts et al., 2004). Diffusion through the cap rock is expected to be the main leakage transport mechanism, although this is expected to be very slow; modelling indicates that this process will take millions of years (Lindeberg and Bergmo, 2003). Reactive transport model simulations of Sleipner indicate that after 120 yr, mineral precipitation caused by CO_2 will have decreased the porosity and permeability of the cap rock base from 5 to 2.3% and from 3 to 0.3 mDarcy, respectively (Johnson and Nitao, 2003). These results suggest that the sealing properties of the cap rock are enhanced by CO_2 storage.

3.1.1.3. *Unminable Coal Seams.* Coal seams are unique in the sense that injected CO_2 is to a large extent adsorbed to the coal matrix, replacing coal bed methane, as CO_2 is more easily adsorbed to coal than methane. In general, it is argued that if coal seams have held methane for millions of years, it will probably retain CO_2 for similar timescales.

However, there are still several aspects to be studied on the interaction between CO_2 and coal seams. Especially the chemical reactions and physical processes that could occur during CO_2 injection into coal seams and their impact on the integrity of the coal seams are not well understood. One of these reactions is swelling of the coal matrix when injecting CO_2, which might cause a reduction in the permeability. Swelling might also induce stresses on the overlying and underlying rock strata in non ideal coal seams (thin, low permeable and highly faulted), that could cause faulting and possible migration pathways out of the coal seam (Gale, 2003).

3.1.2. *Local Effects of CO_2 Leakage*

CO_2 might cause health effects when exposed to humans, animals and ecosystems at elevated concentrations. Health effects of elevated CO_2 concentrations on human beings and animals are well understood. Prolonged exposure to high CO_2 levels, above 20–30%, will cause death by suffocation to humans and the majority of air-breathing animals (Benson et al., 2002). Deaths from catastrophic releases of CO_2 are known from industrial accidents and natural disasters in volcanic areas. The sudden release of 0.24 Mt CO_2 from Lake Nyos (Cameroon) in 1986 caused the deaths of at least 1700 people and thousands of animals. The most widely accepted hypothesis to explain the sudden release is an overturn of the deep lake as the bottom part became oversaturated with CO_2, caused by a slow leak of CO_2 from magmatic sources into the deep lake waters (Holloway, 1997). Although a spontaneous release as occurred at Lake Nyos is no analogue for CO_2 leakage from a geological reservoir, a similar situation could occur in which anthropogenic CO_2 leaking from a geological reservoir accumulates in a deep lake. This can be prevented by selecting reservoirs without any lakes in vicinity or with proven connection to lakes. If leaking CO_2 nonetheless accumulates in a lake, the hazard can be mitigated by degassing the lake (Benson et al., 2002).

The incident at Lake Nyos illustrates that the health hazard caused by CO_2 releases depends also on the nature of release and not only on the total volume released. Since CO_2 is heavier than air, leakage of relatively small quantities of

CO_2 poses a lethal threat when CO_2 is able to accumulate in confined spaces such as valleys or cellars. The topography around Lake Nyos played a crucial role in the disaster, since it provides ideal conditions for the emitted CO_2 cloud to remain concentrated rather than disperse (Holloway, 1997). Atmospheric dispersion modelling indicates that small, isolated leaks ($\sim$0.1–100 g/m^2/day) will quickly disperse under typical topographic conditions and wind velocities, not posing lethal threats (IEA GHG, 2004).

Obviously, the potential impact on human beings of a sudden release of CO_2 from an offshore reservoir will be lower than from an onshore reservoir. From that perspective, offshore reservoirs deserve preference in selecting reservoirs for storage practices.

In general, the environmental and ecological effects are less well understood as health effects on humans, although natural CO_2 leaks have provided insight in the relation between leakage rates and environmental/ecological impact.

Fresh, potable groundwater, located in the 100–200 m of the subsurface, could be contaminated by leakage of CO_2. Even small CO_2 leaks may possibly cause significant deteriorations in the quality of potable groundwater. An increase in CO_2 concentration might cause a decrease in pH to a level of 4–5, which might cause calcium dissolution, increase in the hardness of water and change in the concentration of trace elements (Holloway, 1996). A model simulating the pH change and the enhanced dissolution of trace metals caused by CO_2 dissolution shows that in poorly buffered aquifers, trace metals can be released (by dissolution/desorption) to levels that exceed drinking water standards (Jaffe and Wang, 2003). However, mineral dissolution kinetics, an important parameter affecting trace metal concentration, have not been characterised completely yet. Also surface water could be contaminated by leakage, which could affect aquatic ecosystems by decreasing the pH, especially in stagnant or stably stratified waters (Benson et al., 2002).

Elevation of CO_2 concentrations in the soil due to leakage is likely to lower the soil pH, and adversely impact the chemistry of nutrients, redox sensitive elements and trace metals, as well as plant growth (Saripalli et al., 2003). Plants usually have a higher resistance against CO_2 than mammals, but persistent leaks could suppress respiration in the root zone. Tree kills associated with soil gas concentrations in the range of 20–30% CO_2 have been observed at Mammoth Mountain, California, where volcanic outgassing of CO_2 (0.13–0.44 Mt CO_2/yr) has been occurring since at least 1990 (Benson et al., 2002).

The effects of CO_2 on subsurface organisms dwelling in deep geologic formations and the effects on marine ecosystems are not well known (Benson et al., 2002; IEA GHG, 2004). Various studies (Herzog et al., 1996; Takeuchi et al., 1997) and research projects have been/are conducted in which the impact of pH decrease caused by CO_2 injection in the ocean on marine ecosystems (plankton) were/are studied. However, there is a large difference between injection of relatively large quantities CO_2 in the ocean and small leaks of CO_2 from offshore reservoirs to the seafloor.

3.1.3. *Global Effects of CO_2 Leakage*

From a global perspective, leakage of CO_2 from reservoirs would make CO_2 storage less effective as mitigation option. The crucial question is what leakage rates are acceptable to assure stabilisation of atmospheric greenhouse concentrations in the coming century is not endangered. Obviously, the acceptable leakage rate depends on stabilisation targets and the extent and timing of CO_2 storage.

Let us assume 1000 GtC will be stored between now and 2300. In order to stabilise greenhouse gas emissions at a level of 450–750 ppm, annual anthropogenic greenhouse gas emissions must be reduced to circa 2 to 4 GtC per year in 2300, with a faster cut in emissions for the more stringent stabilisation concentrations (Wigley et al., 1996). If we assume only 1–10% of an allowable emission of 3 GtC per year on average may be caused by leakage from underground reservoirs, the maximum long-term leakage rate would be circa 0.003–0.03%/yr.

Various studies have been performed in which acceptable leakage rates have been assessed by means of modelling. Hawkins (2003) calculated the emission caused by leakage in a scenario in which the CO_2 reduction required to reach a stabilization level of 450 ppm from the IPCC IS92a reference case emissions to 2100 is completely covered by underground CO_2 storage (total storage of circa 800 GtC). The results show that with a 99.9% storage retention time (0.1% annual leakage rate), emissions from leaks rise to the total allowable emission rate by 2200. According Hepple and Benson (2003), leakage rates must be less than 0.01% per year for stabilisation targets of 350, 450 and 550 ppm CO_2, and be less than 0.1% per year to meet stabilisation targets of 650 and 750 ppm. The average total amount of carbon stored to 2300 ranged from 930 to 2490 GtC, depending on the stabilisation target. Lindeberg and Bergmo (2003) used a more realistic model to calculate required average residence time of CO_2 in geological reservoirs, in which geological and physical features are accounted for. According their calculations, an average residence time of at least 10 000 yr is required, corresponding to an average annual leakage rate of 0.01%. Although there is a certain range in the acceptable leakage rate (caused mainly by different assumptions on reference and extent of CO_2 storage), most authors seem to agree that the mean annual leakage rate should not exceed 0.1%.

3.2. CH_4 LEAKAGE

The injection of CO_2 in depleted hydrocarbon reservoirs, coal beds and deep saline aquifers might result in leakage of methane and light alkanes, which is ubiquitous in the former two reservoirs and moderately common in deep saline aquifers (Klusman, 2003). An important feature of CH_4 is that it is more mobile than supercritical CO_2.

Like CO_2 leakage, CH_4 leakage may have both local and global impacts. On a local scale, CH_4 may affect shallow water quality and poses a lethal threat when accumulating in confined spaces such as basements. Since the global warming potential (GWP) of methane is circa 23 times that of CO_2 (IPCC, 2001b), CH_4 leakage is an important factor to be assessed in order to verify the effectiveness as greenhouse gas mitigation option.

3.3. INDUCED SEISMICITY

The injection of large amounts of fluid into a reservoir increases the pore pressure and thereby modifies its mechanical state (existing underground stress fields). This might induce fracturing or activate faults, such that micro-seismicity and even damaging earth tremors might occur (Holloway, 1996). Potential effects of reservoir-induced seismicity (RIS) are damage to the cap rock and wells, which might cause CO_2 leakage, and damage to buildings and infrastructure.

Oil and gas reservoirs may be sources of reservoir-induced seismicity, generally when fluids are extracted, causing pressure changes in the reservoir (Holloway, 1996). Reservoir-induced seismicity has also been observed in liquid waste injection and underground gas storage (UGS) in geological formations (Benson et al., 2002; Over et al., 1999), as will be described in Sections 5.3 and 5.5. Generally, there are few cases of seismic activity in industrial analogues reported in literature and large quantities of brine, liquid waste, natural gas and CO_2 have been injected so far, which suggests that the probability of seismicity is low. Nevertheless, seismicity must be carefully monitored.

The risk of seismicity caused by CO_2 storage can be minimised by controlling the injection pressure. In situ stresses and pore fluid pressures need to be determined in order to assess the maximum injection pressure and identify faults that have high potential for reactivation (Streit and Hillis, 2003). The problem of seismicity might be more serious when CO_2 is injected into a reservoir in tectonically active regions (with high density of active faults), which can be found in e.g. Japan and California (Li et al., 2003).

3.4. GROUND MOVEMENT

It is possible that the earth's surface will sink or rise because of man-made pressure changes, which might cause damage to buildings and infrastructure and might also trigger seismicity. Several cases of subsidence in history (mainly during exploitation of oil and gas fields) are known and well documented (e.g. Groningen gas field). In general, the mechanism of subsidence is well understood, but prediction is considered to be difficult (Holloway, 1996).

It is not envisaged that uplift will take place in a CO_2 reservoir as long as the maximum storage pressure is kept below the geostatic pressure. However, in a reservoir that is under high tectonic stresses, any significant reduction of the grain pressure (pressure acting between individual rock particles) may trigger faults. This may lead to uplifting or down-faulting of the surface (Holloway, 1996). Subsidence can also be caused by a chemical reaction between CO_2 dissolved in brine and the reservoir rock, which may cause dissolution of the reservoir rock (chemical compaction). Consequently, the reservoir may cave in under the weight of the overburden formation. Chemical compaction or dissolution of the reservoir rock will particularly be a matter of concern in carbonate rocks with a high porosity (Holloway, 1996).

3.5. DISPLACEMENT OF BRINE

The injection of CO_2 in aquifers might cause displacement of saline groundwater (brine). This may cause undesirable effects such as a rise of the water table (which could have negative impact on land quality and use) and an increase in salinity of sweet water reservoirs used for drinking water extraction and irrigation. The fate of brine displaced by the injected CO_2 and the risks it entails remains uncertain (Benson et al., 2002).

4. Risk Assessment Studies

A risk assessment has been performed for a conceptual CO_2 surface and injection system, using industry records on frequencies of leakage occurrences. Results indicated leakage rates below 0.03% of the annual CO_2 storage rate. It was concluded that multiple fatality risks are very unlikely. The risk of fatality for individuals may exceed typical risk criteria for industrial facilities for some modules, but can fall within acceptable limits with additional (technical) measures (IEA GHG, 2004).

Risk assessment case studies have been performed for two oil fields: the Forties field in the North Sea and the Weyburn field in Canada.[7] At the Forties field, the cap rock is not faulted and there is limited fluid flow in the field, so the risk of leakage through the cap rock and via the underlying aquifer is considered to be negligible. However, the long-term impact of CO_2 on the cap rock integrity and leakage through or along wells have not been assessed in detail (IEA GHG, 2004).

Both deterministic and probabilistic modelling has been performed to assess the long-term migration of CO_2 in the Weyburn oilfield. The deterministic approach indicates that the total amount of CO_2 removed from the EOR area 5000 yr after the end of injection is 26.8% of the initial CO_2 in place at the end of EOR. The majority (18.2%) moves into the geosphere below, 8.6% migrates laterally outside the EOR area and only 0.02% diffuses through the cap rock. The maximum cumulative leakage through/along abandoned wells (circa 1000) corresponds to 0.14% of the initial CO_2 in place at the end of EOR. However, better insight is needed in long-term degradation characteristics of cement and casings (Whittaker et al., 2004).

The probabilistic performance assessment has not been completely developed, but results of benchmarking with a reservoir simulation are consistent. The analysis indicates an average cumulative CO_2 release to the biosphere of 0.2% of the initial CO_2 in place. The analysis shows there is a 95% probability that 98.7 to 99.5% of the initial CO_2 in place will remain stored for 5000 yr (Whittaker et al., 2004).

The models use a base scenario describing the expected future system development and leakage pathways, in which the cap rock integrity is not impaired. Geomechanical performance assessments show that the cap rock integrity has been maintained during historical injection/production and will be maintained given current CO_2 injection pressures. This assessment also indicates that salt dissolution by CO_2 will probably have minimal influence on seal integrity (Whittaker et al., 2004).

Also a more generic risk assessment methodology has been developed, in which leakage from a "typical" deep saline aquifer has been modelled to estimate leakage rates from wellhead and cap rock failure (Saripalli et al., 2003). Results indicate that leakage through a failed cap rock poses the highest risk to all environmental media. The calculated flux from a continuous fracture corresponds to a leakage rate of 0.1% of the total volume stored per year. Leakage rates through permeable zones in the cap rock are estimated at 0.05% of the total volume scored per year. Spatial frequency of cap rock failures within the area of review was estimated at 0.01 for both a fractured cap rock and high-permeability zones, assuming that 1% of the cap rock area spread over an area of review of 50 km radius is fractured and another 1% is highly permeable. Although the estimated frequency of 2×10^{-5} for a major wellhead failure based on statistics of UGS accidents in the USA and Canada is much lower, the consequences (CO_2 flux) of such event are larger (Saripalli et al., 2003).

Obviously, cap rock failure is strongly dependent upon the site-specific geological characteristics and should be evaluated based on a geological assessment. Also failure rates of wells exposed to CO_2 are expected to be different than the statistical average from wells applied in UGS, as CO_2 is corrosive and reactive. Additionally, the frequency of well failures might be much higher in other regions in the world.

5. Industrial and Natural Analogues for Underground CO_2 Storage

Industrial analogues for underground CO_2 storage can be found in enhanced oil recovery with CO_2, acid gas injection, disposal of industrial and nuclear waste in underground reservoirs and underground storage of natural gas. At least some of these analogues are common practices in several countries, for which extensive risk assessments have been performed. Natural analogues include reservoirs where CO_2 has been successfully trapped for geological timescales and reservoirs where CO_2 is migrating to the surface.

Underground CO_2 storage differs from industrial and natural analogues in various aspects (in compound stored, quantities of fluid stored and timeframe considered for storage). Nevertheless, there are strong similarities, which make analogues valuable to get insights that might increase our understanding in the risks of underground CO_2 storage. Industrial analogues might also provide useful insights in risk assessment and management (i.e. monitoring) and mitigation strategies for geologic storage of CO_2 (Benson et al., 2002).

5.1. CO_2 ENHANCED OIL RECOVERY

CO_2-EOR is applied on a commercial scale in various countries to enhance the lifetime of depleted oilfields by injecting CO_2 into these reservoirs (IEA GHG, 2000). In the USA, circa 70 projects are in operation, injecting over 100 000 t/day (Grigg, 2002). CO_2 injection (often alternated with water injection) can achieve enhanced oil recovery by mobilising the oil through miscible or immiscible displacement. At the production well, oil, water, CO_2 and natural gas are produced and separated, after which CO_2 is recycled to the injection well. Only a part of the injected CO_2 is stored by dissolution in immobile oil. Although the purpose of CO_2-EOR is primarily oil production and not CO_2 storage, CO_2-EOR practices could enable us to study the behaviour of CO_2 in the reservoir and the risks of leakage. Monitoring CO_2 in the reservoir might increase our insight in the storage of CO_2 in immobile oil and leakage through abandoned wells and via fractures and faults extending into the cap rock. Unfortunately, CO_2 storage characteristics in the EOR industry have not been well documented (IEA GHG, 2000), the Weyburn project being the first with a monitoring programme.

From EOR operative experience in the USA it has been concluded that seals are maintaining their integrity and retaining CO_2 in place. No significant leakages have occurred during CO_2 injection period, although several operators mentioned that CO_2 migrated through fractures or via flanks of the structure to zones that are in communication with the injection zone (Grigg, 2002). Soil gas measurements at the Rangely Weber oil field, where CO_2 is injected to enhance oil recovery, have been performed driven by concerns of leakage as a consequence of reservoir over pressuring. These measurements indicate annual fluxes of maximally 3800 t CO_2 (0.13 g CO_2/day/m^2) and 400 t of thermogenic CH_4 (=25 300 t CO_2 equivalents) originating from deep sources over an area of 78 km^2 (Klusman, 2003). The CO_2 flux corresponds to approximately 0.1% of the annual injection and 0.02% of the cumulative CO_2 storage.[8] These observations are reason to assess the impact of reservoir over pressuring as a consequence of CO_2 injection more carefully.

5.2. ACID GAS INJECTION

Oil and natural gas generally contain varying amounts of hydrogen sulphide (H_2S), a toxic gas, and CO_2, acidic components that have to be removed before the product is sent to the market. After the acid gases have been removed by absorption, H_2S can be converted into elemental sulphur and CO_2 vented to the atmosphere.

Alternatively, H_2S can be flared (causing SO_2 emission) or the gases (containing between 15 and 98% CO_2) can be re-injected into a geological formation. In western Canada, increasingly more oil and gas producers are turning to acid gas re-injection. Although the purpose of acid gas injection is to dispose of H_2S, significant quantities of CO_2 are injected simultaneously, because it is not economic to separate the gases (IEA GHG, 2002).

There are currently 39 acid gas injection projects operating in Canada. In the period 1989 to 2002, close to 1.5 Mt CO_2 and 1 Mt H_2S have been successfully injected into depleted hydrocarbon reservoirs and saline aquifers. In the USA, another 16 acid gas injection operations exist (IEA GHG, 2002). The young history indicates that acid gas injection is mature from an engineering point of view, but the fate of acid gas in the reservoirs has not been monitored yet, which is crucial to get insight in subsurface behaviour and risk of leakage. The acid gas injection operations provide a unique, commercial scale analogue for CO_2 geological storage, since CO_2 is injected in similar formations and conditions as considered for underground CO_2 storage, also with the purpose of permanent storage (in contrast to CO_2-EOR). Monitoring injected acid gas might increase the insight on long-term containment of CO_2 and leakage by cap rock and well failures. In addition, information on reservoir characteristics of acid gas injection operations can be used to screen and identify sites for underground CO_2 storage.

5.3. UNDERGROUND DISPOSAL OF INDUSTRIAL WASTE

The technology of deep well injection of hazardous industrial liquid wastes has many similarities to the technology of CO_2 storage in deep saline aquifers. Many of the formations currently used for deep well disposal of industrial waste are also suitable candidates for CO_2 storage (Benson et al., 2002).

The risks involved in underground disposal of industrial waste also play a role in underground CO_2 storage. Examples of seismicity have been observed at injection sites of industrial waste (Holloway, 1996). The re-injection of liquid waste in the Rocky Mountain Arsenal (USA) well caused several earthquakes ranging between 0.5 and 5.3 on the Richter scale. Also a blowout of liquid waste has been reported (Benson et al., 2002). Early performance of underground disposal of industrial waste in the USA (before the introduction of more stringent regulations) showed many examples of well failures and contamination of drinking water aquifers. Failures were attributed to poor characterisation of the confining units, improper well completion techniques, use of well construction materials that were incompatible with the waste streams and consequently corroded, inconsistent or inadequate monitoring, and leakage through abandoned wells (Benson et al., 2002). Recently, the Chemical Manufacturers Association (MCA) undertook a probabilistic risk assessment of component failure of a hazardous waste well system and showed that failure of any of the system components under current regulations was in most cases much less than 10^{-6} per year (Benson et al., 2002).

However, the chemical and physical features of CO_2 are different from industrial waste such as industrial organic waste or brine water co-produced with oil/gas production. The density of CO_2 is lower than that of liquid waste and therefore, buoyancy forces will tend to drive CO_2 upward, whereas injected fluid wastes tend to migrate away from the injection well with little buoyant force driving it up or down (Benson et al., 2002). The effects caused by leakage are comparable neither. This makes the use of underground disposal of industrial waste for underground CO_2 storage rather limited.

5.4. UNDERGROUND DISPOSAL OF NUCLEAR WASTE

Like CO_2 storage, safe nuclear waste disposal requires understanding the complex, coupled physical–chemical–mechanical processes that will occur over periods of hundreds to thousands of years (Benson et al., 2002). Underground disposal of nuclear waste differs in many aspects (physical/chemical features, effects, disposal method and media) from geological CO_2 storage. The lessons to be learned from underground disposal of nuclear waste should be found in the area of risk assessment methodology, monitoring, and public outreach (specifically what went wrong in this process).

The FEP methodology developed in the nuclear waste area might be a suitable framework to identify and evaluate the (long-term) risks associated with underground CO_2 storage (Benson et al., 2002). The FEP framework is a procedure to identify, classify and screen all relevant Features, Events, and Processes that may cause or affect risks. *Features* refer to geologic features, such as stratigraphic layering and faults or fracture zones. *Events* refer to occurrences such as changes in precipitation fluxes, seismic activities, and mining enterprises. *Processes* refer to physical/chemical and other processes active at the site such as buoyancy flow of variable-density fluids and chemical sorption. By combining critical FEPs (selected by expert opinion on basis of probability and consequence), scenarios are constructed and selected for performance assessment (by modelling). These scenarios describe possible future evolutions or states of the storage facility (Wildenborg et al., 2002). Within the IEA GHG Weyburn CO_2 monitoring and storage project and the CCP project, this method is adapted for the purposes of CO_2 storage (Wildenborg et al., 2002).

5.5. UNDERGROUND STORAGE OF NATURAL GAS

Underground natural gas storage (UGS) in depleted oil and gas fields and in aquifers is applied to help meet cyclic seasonal and/or daily demands for gas. Generally, UGS has been applied safely and efficiently, although there have been a number of documented cases where leakage has occurred (Benson et al., 2002). Nine reservoirs of the circa 600 storage reservoirs operated in the United States, Canada and Europe have experienced leakage. Five cases were due to defective wells (casing corrosion and improperly plugged wells), three cases were due to cap rock failure and one case was due to inaccurate reservoir selection (too shallow) (Perry, 2004). One of the main causes of leakage is that many UGS projects are operated at overpressures (Benson et al., 2002).

In order to reduce the risks of leakage in UGS projects, reservoirs should be characterised extensively, wells should be well constructed, monitored and maintained, over pressuring should be avoided and abandoned wells in the area should be located and plugged. In case of a leaking well, the well can generally be repaired or plugged. In case of leakage related to high storage pressure or a cap rock failure, the pressure in the reservoir needs to be reduced (Benson et al., 2002). In all reported cases of leakage remediation procedures were and continue to be effective (Perry, 2004).

There are also a limited number of cases of reservoir-induced seismicity caused by UGS; in Germiny (France), gas storage in an aquifer caused light earth shocks with a maximum of 1.5 on the Richter scale. However, investigations have shown the risk of earth tremors in case of gas storage in empty gas fields to be small, even at an over-pressure of 10% above initial reservoir pressure (Over et al., 1999).

UGS experience is useful for underground CO_2 storage (i.e. increase our knowledge on leakage mechanisms and pathways) as UGS is in many ways analogous to CO_2 storage. Equal storage reservoirs and injection technologies are applied and natural gas behaves similarly to CO_2 (it is less dense than water and tends to rise to the top of the storage structure). However, CO_2 is denser and more viscous (and thus less mobile), reactive (in particular when dissolved in water) and not explosive nor flammable. Moreover, the duration of CO_2 storage is longer than it is for UGS and much larger volumes are involved. These differences deserve special attention when assessing risks of CO_2 storage using insights obtained from UGS.

5.6. NATURAL ANALOGUES

CO_2 reservoirs and CO_2 containing oil and gas fields[9] are natural analogues where CO_2 has been contained for geologic timescales. No catastrophic CO_2 releases from CO_2 and hydrocarbon reservoirs have been reported in literature, although all reservoirs are thought to leak over geologic time (Benson et al., 2002).

CO_2 containing reservoirs are ideal to assess long-term effects of underground CO_2 storage (e.g. on cap rock integrity). Within the GEODISC project, the Ladbroke Grove gas field in South Australia has been studied. CO_2 originating from nearby volcanoes has migrated into the reservoir between 1 million and 4500 yr ago. Mineralogical analysis has revealed that some of the CO_2 has been permanently stored by mineralisation due to the high amount of reactive minerals present in the reservoir, although the majority of CO_2 is stored in gaseous and aqueous phases (Watson et al., 2003).

At sites where CO_2 is actively leaking, leakage rates and pathways can be assessed by soil gas and flux measurements and also the impacts of leakage can be determined. At Mammoth Mountain in California, volcanic outgassing of CO_2 occurs through faults and fractures. The leakage rate varies between 25 and 7000 g CO_2/day/m^2 (IEA GHG, 2003). Within NASCENT, various leaking and non-leaking CO_2 reservoirs have been studied to identify leaking conditions and consequences. At Mátraderecske, a village in Hungary, the average CO_2 flux is 240–480 g CO_2/day/m^2, with a maximum at 19 200 g CO_2/day/m^2 along faults (Pearce et al., 2003). In Ciampino, Italy, fluxes of 700 g CO_2/day/m^2 have been measured. Such high fluxes can result in lethal concentrations in basements if not properly ventilated. Also soil gas concentrations might occur resulting in tree-crop death. At some CO_2 producing fields, there is evidence of groundwater pollution due to increased Ca^{2+}, Mg^{2+}, HCO_3^- concentration and total hardness (IEA GHG, 2004).

These natural analogues indicate that CO_2 migration to the surface occurs predominantly through faults and fractures. However, studies of fractures within NASCENT have indicated that open fractures through which CO_2 leaked might have been sealed in time by formation of carbonates. The role of fractures in controlling leakage is not completely clear yet (IEA GHG, 2004).

6. R&D Topics

The previous sections have revealed a number of gaps in knowledge with regard the risks of underground CO_2 storage that require further research efforts:

- Processes that control leakage through or along wells should be determined. Long-term degradation characteristics of cement and casings need to be studied to estimate CO_2 fluxes and failure rates of abandoned wells.
- Processes that control leakage through faults and fractures need to be determined. Sealing of fractures by mineral precipitation needs further attention.
- Geochemical impact of CO_2 injection on reservoir rock and cap rock integrity
- Chemical reactions and physical processes that could occur as a result of CO_2 injection in coal seams
- Effects of leakage on (marine) ecosystems

Data and insight in processes that control leakage and field data are needed to assess realistic leakage rates (fluxes) in order to validate the values calculated by analytical and numerical models. One might increase insight on processes controlling leakage by performing leakage experiments, in which CO_2 is injected in reservoirs with proven leakage pathways such as non-sealing faults.

Well failure and the impact of CO_2 on cement and casings are being studied within various projects (see Table II). A well bore integrity model is being developed and refined and laboratory work is performed in which various cement types are exposed to CO_2 under different pressures (IEA GHG, 2004).

TABLE II

Summary of major R&D projects on risks of underground CO_2 storage (see http://www.co2storage.info/ for detailed description)

Project	Funding source(s)	Systems	Country	Project aims (related to risks of underground CO_2 storage)	Completion
CO_2 capture project (CCP) (SMV team)	– Industry sources – European Commission – US DOE – Klimatek	CO_2-EOR/ EGR/ECBM aquifers	USA and Europe	• Develop, evaluate and apply tools and methodologies for risk assessment, risk mitigation and risk remediation, long term monitoring and verification of CO_2 movement in geological formations • Assess sealing capacity of tubulars & cement by experiments	2004
GEODISC	– The Australian Greenhouse Office – industry sources	CO_2-EOR aquifers natural analogues	Australia	• Increase understanding of CO_2-water systems and interaction between fluids and reservoir rocks and cap rock by experiments • Monitor CO_2 injection via modelling of seismic characteristics • Assess and quantify risks associated with CO_2 injection • Develop enhanced understanding of CO_2 trapping through study of natural analogues	2003
RITE R&D projects for geological sequestration of CO_2	Not available	aquifers (on & offshore)	Japan	• Increase understanding of CO_2 behaviour and interactions in an aquifer by means of experiments, models and injection tests • Evaluate monitoring methods for the assessment of environmental impact and safety	2005
NACS	– US DOE – industry sources	natural analogues	USA	Study CO_2 trapping to evaluate the safety and security of geological storage processes	2004/2005

(Continued on next page)

TABLE II
(*Continued*)

Project	Funding source(s)	Systems	Country	Project aims (related to risks of underground CO_2 storage)	Completion
NASCENT	– European Commission – industry sources	natural analogues	Europe	Address key issues associated with geological CO_2 storage that include long-term safety, stability of storage underground, and potential environmental effects of leakage: • Interaction between CO_2-water and reservoir rocks and cap rock (geochemistry) • Geomechanical testing and gas migration studies in low permeability cap rocks • Identification of pathways through soil gas surveys for CO_2 and associated tracer gases • Perform geochemical analyses of carbonated waters to assess the effects of CO_2 on groundwater	2004
SACS/ CO2STORE	– European Commission – national authorities – industry sources	aquifer offshore	Norway	• Monitor the injected CO_2 using repeat seismic monitoring to study the behaviour of CO_2 in the reservoir • Validate geophysical modelling	SACS 2002 CO2store 2006
GEO-SEQ	– US DOE – industry sources	CO_2-EOR/ EGR/ECBM aquifers	USA	Optimise a set of monitoring technologies ready for full-scale field demonstration in oil, gas, brine, and coal bed formations	2004
Weyburn CO_2 Monitoring Project	various governmental and industry sources	CO_2-EOR	Canada	• Assess geochemical impacts on the formation's CO_2 storage integrity and capacity • Monitor the movement of various fluids within the reservoir • Characterise fluid and phase behaviour to establish the mechanisms that govern the distribution and displacement of the CO_2-rich fluids • Develop better monitoring tools and techniques	2004

A number of research activities are underway to study the role of faults in natural CO_2 reservoirs and the geochemical impact of CO_2 on cap rock performance (IEA GHG, 2004). A core sample from the cap rock above the Utsira formation in the North Sea has been taken for analysis and experiments to assess the impact of CO_2 (IEA GHG, 2003). Field measurements are necessary to determine the large-scale features of the cap rock that could not be tested on laboratory samples, such as continuity and the presence of faults or fractures (Benson et al., 2002).

Various R&D programmes are dedicated to study the behaviour and impact of CO_2 on coal seams.

Although there is some knowledge on the relation between CO_2 leakage and death of animals and trees, the impact of CO_2 on whole ecosystems, especially offshore, is not well understood. As many storage reservoirs are located offshore, it is important to study the impacts of CO_2 leakage on marine ecosystems (which might affect fish populations). Although no specific project is dedicated to the impact of CO_2 leaks on marine ecosystems, there are several research projects on ocean storage studying the impact of large-scale CO_2 on marine organisms, which might increase our insights in this area.

Monitoring will play an important role in studying these research topics. It can be used to get insight in a wide range of parameters such as CO_2 behaviour, reservoir and cap rock performance, migration pathways, solubility, geochemical interactions (among which mineral trapping), groundwater and soil quality, ecosystem impacts and micro-seismicity associated with CO_2 injection (Benson and Myer, 2002).

Seismic methods are highly developed and can cover a large area with high resolution. The migration of CO_2 injected into the Utsira aquifer under the North Sea is monitored by means of time-lapse seismic surveys. It appeared that the overall effect of the accumulated CO_2 on the seismic signal is significant, making time-lapse seismic surveying a highly suitable geophysical technique for monitoring CO_2 injection into a saline aquifer (Arts et al., 2003). One of the shortcomings of geophysical techniques is the difficulty in quantifying the amount of CO_2 that is present and the rate of leakage might it occur. Myer et al. (2003) studied the resolution of seismic monitoring and concluded that a plume of circa 20 000 t CO_2 at 2000 m depth may be detectable. Other work suggests that the detectable volume of CO_2 would be much smaller (Benson and Myer, 2002).

By combining geophysical measurements with other techniques, such as formation pressure measurements and reservoir simulation, it will be possible to obtain more quantitative estimates of leakage rates (Benson and Myer, 2002). This will require additional research efforts and field-testing. Various research programmes are running to optimise existing monitoring techniques. More research is also required on techniques for monitoring the integrity (cement plugs, corrosion of casing) of abandoned wells. Methods for monitoring these aspects are studied within the CCP project (Wildenborg et al., 2002).

Finally, besides the required R&D to increase our insight in risks itself, also a common risk assessment methodology able to assess long-term effects of underground CO_2 storage should be further developed.

7. Conclusions and Recommendations

The review of the (gaps in) knowledge of risks associated with underground CO_2 storage and research areas that require more attention are summarised in Table III. The risks associated with pipeline transport and surface and injection facilities of CO_2 are known and can be minimised by risk abatement technologies and safety measures.

Although industrial and natural analogues suggest that CO_2 can be stored safely in geological reservoirs for thousands to millions of years, various issues need to be studied in more detail to assess (long-term) risks of underground CO_2 storage. Generally, there is a lack of knowledge and data to quantify the processes controlling/causing risks, which can partly be explained by the fact that underground CO_2 storage is a relatively young area. Most of the (demonstration) projects are still in their early stages. Another complicating factor is that underground storage encompasses long-term effects, which are difficult to assess by means of CO_2 injection operations or laboratory experiments.

Leakage of CO_2 from the reservoir is the main R&D issue. Leakage through or along wells, faults and fractures is generally considered to be the most important leakage pathways. The potential for leakage will depend on trapping mechanism and well, cap rock and overburden integrity. The type of reservoir in which CO_2 is stored is another important factor for leakage. Hydrocarbon fields are generally well studied and considered to be safe reservoirs for CO_2 storage, since they have held oil, gas and often CO_2 for millions of years without catastrophic leakage. However, these reservoirs are generally punctured by a large number of abandoned wells, some in bad condition, offering a potential leakage pathway. Deep saline aquifers and unminable coal seams have not been studied that comprehensively. Especially aquifers need to be studied in more detail as these reservoirs represent an enormous potential CO_2 storage capacity. The risk of leakage might be higher than for hydrocarbon fields, as the cap rock integrity has generally not been proven. Coal seams generally have held coal bed methane for million of years and, moreover, CO_2 is adsorbed more easily than methane, so the risk of CO_2 leakage is expected to be low.

One of the principal objectives in future R&D is to determine the processes that control leakage through/along wells, faults and fractures to assess (a range of) leakage rates for various geological reservoirs. Research topics include the quantification of degradation of cement and casing by CO_2 and the role of fault sealing by mineral precipitation. Although experiments and models suggest that the geochemical impact of CO_2 on the cap rock integrity is minimal or even positive, further work is required in this area. The leakage rate at its turn is required to quantify

TABLE III
Overview (gaps in) knowledge and R&D issues related to risks of underground CO_2 storage

Risk	Chance	Potential consequences/effects	Major R&D topics
Pipeline, surface and injection facilities			
Pipeline failure	Frequency minor incident in order of 10^{-4} per km year	CO_2 escape (effects see "CO_2 leakage") The consequences can be minimised by application of risk abatement technologies and safety procedures	(1)
Surface equipment failure	Can be estimated from industrial experience with CO_2 and other gases	CO_2 escape (effects see "CO_2 leakage") The consequences can be minimised by application of risk abatement technologies and safety procedures	(1)
Well failure (during injection)	– Can be estimated from CO_2-EOR, acid gas injection and UGS experience – Frequency well blowout offshore gas fields estimated at 10^{-4}per well year	– CO_2 escape (effects see "CO_2 leakage") – Well blowout might cause casualties among operators The consequences can be minimised by application of risk abatement technologies and safety procedures	(1)

(*Continued on next page*)

TABLE III
(*Continued*)

Risk	Chance	Potential consequences/effects	Major R&D topics
Underground storage			
CO_2 and CH_4 leakage	– Frequency well failure (after injection) unknown – Frequency cap rock failure is unknown (site/reservoir specific) – Chance on CO_2 leakage is generally expected to be lowest for coal seams and highest for deep saline aquifers	– Health hazard to people and animals (understood) – (Marine) ecosystem impact (not understood) – Affect soil and groundwater quality (understood) – Make CO_2 storage ineffective as mitigation option	– Determine processes that control leakage through wells, faults and fractures to assess leakage rate – Impact of CO_2 on well (cement, casing) and cap rock integrity require more research – Effects on (marine) ecosystems need to be studied – Hydrocarbon reservoirs relatively well studied. Deep saline aquifers (which have not always proven cap rock) and coal seams (chemical and physical processes) require more research.
Seismicity	Unknown. The frequency can be reduced by controlling injection pressure	– Damage to buildings and infrastructure – Cap rock damage, which might cause CO_2 leakage	– Impact induced seismicity on cap rock integrity
Ground movement	Unknown	– Damage to buildings and infrastructure – Seismicity	(1)
Displacement of brine	Unknown	– Rise water table – Increase salinity drinking water resources	(1)

(1) These risks are generally understood or considered to be minimal/controllable with risk abatement technologies and safety procedures. Therefore, research topics for these risks are not discussed in literature.

the effects on human beings, ecosystems and groundwater quality. The effects of elevated CO_2 concentrations on human beings, animals and even for some biota are understood, but the effects on (marine) ecosystems need further research.

Various research programmes and projects on geological CO_2 storage exist, in which risks are being studied. Most of these programmes are still running and will be finished in the period 2004–2005. Research items include possible migration pathways of CO_2 and interaction between CO_2 and the reservoir, cap rock and well bore. Quite a variety of reservoirs are being studied: deep saline aquifers, hydrocarbon reservoirs and coal seams in the USA, Europe, Australia and Japan. There are several ongoing programmes studying industrial and natural analogues. Industrial analogues where CO_2 is injected (CO_2-EOR and acid gas injection) offer the opportunity to study the behaviour of CO_2 in geological reservoirs. Natural analogues are useful in providing a better understanding of leakage through faults and fractures, long-term physical and chemical interactions between CO_2 and the reservoir/cap rocks and effects on groundwater and ecosystems.

These R&D programmes cover the major research issues with the exception of impacts on marine ecosystems. However, it is expected that more work is to be done as understanding the processes controlling leakage requires many field and experimental data. Additionally, risks strongly depend on reservoir and other site-specific conditions (cap rock, stratigraphic layers overburden, onshore/offshore, presence of water resources, ecosystems), for which a large variety exists. The site-specific nature of risks requires that a variety of pilot and demonstration storage projects be carried out, monitored and assessed.

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Notes

[1] Although CO_2 transport generally occurs by high-pressure pipelines, transport by tankers might be a viable option for offshore reservoirs.

[2]Note that these pipelines are mainly sited in areas of low to medium population density.

[3]The Sleipner project is the first commercial scale CO_2 storage project. Since 1996, annually circa 1 million tons of CO_2 removed from natural gas is injected into the Utsira formation, a saline aquifer 1000 m below the floor of the North Sea. A total of 20 Mt is expected to be stored over the projects lifetime.

[4]The structurally lowest point in a hydrocarbon reservoir (see Figure 1). Once a reservoir has been filled to its spill point, CO_2 or hydrocarbons will spill or leak out.

[5]After primary recovery (pressure depletion) and secondary recovery (waterflooding, injection of water), the oil recovery can be increased by means of tertiary recovery techniques such as CO_2 or thermal-EOR.

[6]Dilantacy is the increase in the volume of rocks as a result of deformation.

[7]The Forties oil field is considered for CO_2-EOR. In the Weyburn project, circa 5000 t CO_2/day is injected into the Weyburn oilfields in Canada in order to boost oil production and store CO_2 since October 2000.

[8]Injection started in 1986. Since then, 57 Mt has been injected and 22.3 Mt CO_2 has been stored. Annual injection rate in 1998 was circa 3 Mt, which increased slightly in the period 1998–2003 (IEA GHG, 2000; Wackowski, 2003).

[9]One in ten gas fields contain 1–5% CO_2 and one in hundred contain on average 50% CO_2, some fields even exceeding 80% (Bains and Worden, 2001).

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