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State of the art review of CO_2 Storage Site Selection and Characterisation Methods

CGS Europe Key Report

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CGS Europe Key Report

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PREFACE

This report is the result of a joint effort carried out by various members of the CGS Europe project (www.cgseurope.net) - the “Pan-European Coordination Action on CO_2 Geological Storage”, funded within the 7th framework programme of the EU. The report is based on current literature on site selection of CO_2 geological storage sites.

The report is not a monograph, but rather an edited compendium of contributions from individual network partners. Hence, chapters and sections may vary in style and level of detail. The authors gratefully acknowledge the various CGS Europe partners who participated in reviewing the draft and the resulting fruitful discussions.

The report is public so that any interested party can readily make use of it. CGS Europe does not claim completeness, nor comprehensive consideration of all legal or regulatory requirements on CO_2 site selection in Europe.

The authors hope that this report will provide concise and ultimately helpful information to various stakeholder groups including scientists, competent authorities, operators and regulators. The reader is expected to have some basic understanding of CO_2 geological storage.

EXECUTIVE SUMMARY

Carbon dioxide Capture and Storage (CCS) is a technology that could contribute significantly to reduced CO_2 emissions to the atmosphere. By capturing carbon dioxide emitted from industrial processes, compressing it and injecting the CO_2 into underground geological reservoirs of porous rock for permanent storage, it provides a bridging solution to mitigate the climate change while renewable energy sources and other low carbon industrial technologies are developed to large-scale implementation.

The selection and characterisation of potential CO_2 storage sites are essential steps in progressing a CCS project. The site selection process should demonstrate that the site has sufficient capacity to store the expected CO_2 volume and sufficient injectivity for the expected rate of CO_2 capture and supply. The integrity of the site has to be assessed for the period of time required by the regulatory authority, so as avoid any unacceptable risks to the environment, human health or other uses of the subsurface.

The main objective of this report is to identify and review site selection and characterisation methods. This report presents and discusses all the steps required to assess the capacity, performance and integrity of a site. Simulation of CO_2 storage in an underground formation requires a complex multi-disciplinary effort, with the analysis of a number of interacting processes, including geology, multi-phase flow and transport, geochemistry and geomechanics. A site characterisation first calls for the geological characterisation and modelling of the site at basin and reservoir scales and the modelling of flow and transport mechanisms so as to simulate the short-term to mid-term behaviour of the storage. As well as hydrodynamic effects, geomechanical effects generated by the injection of a large volume of fluid in the subsurface have to be modelled over a long period. Modelling geochemical and biological processes is essential to understand the geochemical feedback on the reservoir properties and the trapping mechanisms that will occur. All these skills and knowledge are required to assess potential environmental impacts and risks. The estimation of the economical viability of the project is also essential to decide whether a geologically suitable storage site can actually be developed for CCS. In parallel with the technical aspect of characterising the site, public perception and acceptance appears to be a potential major impediment to deployment of CCS and so social activities towards local communities have to be performed at a very early stage.

Geological characterisation of the site (Chapter 2)

The first step in site selection is the screening of suitable formations and structures against specific suitability criteria and a more or less parallel assessment of storage capacity. In the case of saline aquifers, there is a sequence of capacity estimates that form a conceptual “storage capacity pyramid” ranging from initial assessments of geology to feasibility studies. Hydrocarbon fields, and to a lesser extent coal beds, have a narrower range of capacity categories and uncertainties because of the pre-existing knowledge available. Site selection should include a comprehensive assessment of quality and integrity of caprock as well as feasibility of the reservoir. Then site ranking follows, based on results of all previous studies; the problem is to weight the criteria against storage safety and feasibility.

Flow modelling (Chapter 3)

Computer simulation of CO_2 storage reservoir dynamics is one of the technologies that have been developed in the oil and gas industry. Flow modelling evaluates the behaviour of injected CO_2 based on the active processes in the reservoir. Flow modelling can be used in different phases of a CO_2 storage project. Before starting injection, the plume migration pathway and storage capacity of the reservoir are estimated using simulation models. During operations, models may show whether the project is performing as planned. Post-operational use of flow modelling helps the quantification of secondary trapping mechanisms and prediction of the plume behaviour. The predictive model is calibrated and refined by comparing field data and model results for the estimation of longer-term performance. The reservoir modelling study requires site-specific parameters in order to simulate the dynamic behaviour of the injected CO_2. Several mechanisms control the spread and storage of CO_2 in the storage medium, such as buoyancy forces, diffusion, dissolution into the formation fluid and the phase behaviour of CO_2. Therefore, simulation models are required to handle fluid interactions, mobility and density differences, salinity dependant dissolution and capillary effects. Besides CO_2 storage in the deep saline aquifers or depleted gas or oil reservoir, coal seams having CO_2 adsorption capacity can also be used as a storage medium. There are several numerical models that have different features and capabilities including TOUGH2, TOUGHREACT, Eclipse, CMG, PumaFlow, *etc.* These models are tested and being used to simulate several field projects. Depending on the conditions of the field and the project requirements, flow models have been generated and a better understanding of the processes associated with long-term geological CO_2 storage has been achieved.

Reactive flow modelling (Chapter 4)

Reactive flow modelling is a promising tool for assessing long term effects, predicting the spatial and temporal evolution of injected CO_2 and related gas-fluid-rock interactions, and assessing well integrity. Reactive flow modelling offers a wide set of useful tools for assessing the geologic storage site in different operational phases: pre-injection, during injection and post-injection. The modelling required, and the resolution that can be achieved during the site selection phase depends mainly on the availability of data and the geology of the storage site.

Coupled Geomechanical and Flow Modelling (Chapter 5)

Injection of CO_2 into a geological formation results in hydrodynamic effects as wells as pore pressure changes, which in turn affects the stress state. During the injection phase of a CO_2 storage project, the increase in pressure changes the effective stress and may lead to rock deformation, which may result in shear slip or tensile opening of pre-existing faults, or creation of new fractures. Therefore, modelling the geomechanical properties of the reservoir along with the fluid transport is vital for the safe storage of CO_2. The reservoir pressure starts to decrease when CO_2 injection ceases. The reservoir is considered to be secure against geomechanical failure as the pressure decays towards a stable condition. Compression of both the injected and in-situ fluids and expansion of the pore space may lead to ground lift and, in some cases, seismicity. The reservoir properties (*e.g.* permeability) may also be affected. The development of a static 3D geologic model, the careful assessment of the stress field and coupled modelling of pore pressure and stress changes, help the assessment of possible fault/fracture development and surface heave. The data required for coupled geomechanical and flow modelling include rock compressibility, Young’s modulus, Poisson’s ratio, compressive strength, and formation fracture pressure. The coupled geomechanical and flow simulations should be used to assess the likelihood of potential leakage and rates relative to key risks, such as CO_2 entry into the caprock.

Environmental Impact and risk assessment (Chapter 6)

Risks from the geological storage of CO_2 primarily result from the consequences of unintended leakage from the storage formation. Such risks might range between short and potential longer-term, that can be larger or smaller, diffuse leakages. Depending on the CO_2 storage site setting, onshore and offshore effects may arise. Risk assessment is the process that examines and evaluates the potential for adverse health, safety and environmental effects on human health, the environment, and potentially other receptors resulting from CO_2 exposure and leakage of injected or displaced fluids via wells, faults, fractures, and due to seismic events. The identification of potential leakage pathways is integrated with a Measurement, Monitoring and Verification (MMV) plan. The risk assessment results are used to ensure the safety and acceptability of geological storage. The process involves determining both the consequences and likelihood of an event. Risk mitigation is the planning for and implementation of contingency plans, should the need to remediate adverse impacts arise. A good monitoring and mitigation plan reduces the risk associated with many potential consequences.

Economic analysis (Chapter 7)

Costs estimates on CO_2 storage involve a high degree of uncertainty, given the significant variations in technical characteristics, scale and applications between projects. There is also uncertainty over how costs will develop with time. Site selection and the economics of storage will drive the commercial feasibility of large-scale integrated CCS projects and without appropriate storage options CCS may not become a cost-effective CO_2 mitigation option.

The Zero Emissions Platform has recently published a study on CO_2 Storage costs, 'The Costs of CO_2 Storage, Post-demonstration CCS in the EU'. The cost estimates reported range between €1-7/tonne CO_2 stored for the cheapest option (onshore depleted oil and gas fields with re-usable wells) to €6-20/tonne CO_2 stored for the most expensive alternative (offshore deep saline aquifers). Uncertainty ranges within each case are in line with the natural variability of storage candidates. Key drivers influencing the economics of storage were found to be the reservoir capacity (higher costs for smaller reservoirs); the site location (higher costs offshore than onshore); the amount of existing site information (more available information for depleted oil and gas fields allow for lower costs, little information for deep saline aquifers require higher costs); the existence of re-usable infrastructure (wells, offshore structure); and the reservoir quality.

Public perception and acceptance (Chapter 8)

Based on past experiences, non-technical aspects of the selection of CO_2 storage sites such as public perception and acceptance have become as important as technical aspects. A number of social research studies have been carried out over the years to investigate public perception of the technology. An important outcome of these studies is that social features are unique to each site, requiring a case by case approach. Communication strategies need to take into account the varied cultural patterns of the communities involved. In this report, open access sources of information are used to compile a reference list of relevant studies.

1 INTRODUCTION

The main objective of this report is to identify and review site selection and characterisation methods. This report presents and discusses all the steps required to assess the capacity, performance and integrity of a site. Simulation of CO_2 storage in an underground formation requires a complex multi-disciplinary effort, with the analysis of a number of interacting processes, including geology, multi-phase flow and transport, geochemistry and geomechanics. A site characterisation first calls for the geological characterisation and modelling of the site at basin and reservoir scales and the modelling of flow and transport mechanisms so as to simulate the short-term to mid-term behaviour of the storage. As well as hydrodynamic effects, geomechanical effects generated by the injection of a large volume of fluid in the subsurface have to be modelled over a long period. Modelling geochemical and biological processes is essential to understand the geochemical feedback on the reservoir properties and the trapping mechanisms that will occur. All these skills and knowledge are required to assess potential environmental impacts and risks. The estimation of the economical viability of the project is also essential to decide whether a geologically suitable storage site can actually be developed for CCS. In parallel with the technical aspect of characterising the site, public perception and acceptance appears to be a potential major impediment to deployment of CCS and so social activities towards local communities have to be performed at a very early stage.

It is widely accepted that prolific burning of fossil fuels has raised the amount of CO_2 in the atmosphere to levels at which it is contributing to climate change and that de-carbonising energy is necessary to avert catastrophic and irreversible change. Carbon Capture and Storage (CCS) is a technology that could contribute significantly to reduced CO_2 emissions to the atmosphere. It works by removing CO_2 from the pre- or post-combustion exhaust gas of power stations and other industrial processes and injecting the CO_2 into underground geological reservoirs of porous rock for permanent storage. While not eliminating society's dependence on fossil fuels, it provides a bridging solution to mitigate the problem while renewable energy sources are developed to large-scale implementation and the acceptability of nuclear power into the future is resolved.

The selection and characterisation of potential CO_2 storage sites are probably the most important steps for ensuring the safety and integrity of a CO_2 storage project and are essential in developing a CCS project. In essence, a site selection process should demonstrate that the site has: sufficient capacity to store the expected CO_2 volume; sufficient injectivity for the expected rate of CO_2 capture and supply; and sufficient containment to store safely the injected CO_2 for the period of time required by the regulatory authority, so as not to pose unacceptable risks to the environment, human health or other uses of the subsurface.

Guidelines have been published by several bodies on the necessary steps and process involved in selecting and managing a storage site within whatever regulatory environment applies (WRI, 2008; CO2CRC, 2008; NETL, 2010a, b). It is not the purpose or intention of this report to repeat those, but rather to focus in detail on geoscience aspects of site selection.

Types of storage sites

There are three main types of reservoir for geological storage of carbon dioxide as a fluid: depleted oil and gas fields, saline aquifers and coal beds. Research is also being directed at storing CO_2 by forming solid carbonate minerals by combining CO_2 with reactive rocks with high Fe, Mg and Ca content, such as mafic and ultramafic igneous rocks – this latter form of storage is not considered in this report.

A considerable amount of understanding, experience and technology developed by oil and gas operations is directly applicable to storage site characterisation and selection. CO_2 can 'replace' oil and gas in fields that have been depleted, or it can be used to prolong oil or gas production from fields that are still active. Enhanced Oil Recovery (EOR) and Enhanced Gas Recovery (EGR) are processes in which CO_2 is injected into a reservoir to increase the amount of hydrocarbons extracted, thus providing an economic benefit whilst also potentially storing CO_2. The main requirement is to ensure that injected CO_2 is not produced with the oil or gas and the EOR/EGR project becomes a CO_2 storage project. Depleted oil and gas fields have the obvious attraction as storage sites that containment at the site has already been demonstrated by the retention of hydrocarbons for millions of years. It is important to ensure, however, that extraction of the hydrocarbons has not damaged the integrity of the reservoir or seal by pressure reduction and that extraction wells do not provide potential leakage pathways for CO_2. Another major advantage of depleted reservoirs over saline aquifers is that there will be large amounts of geological and engineering data already available for site characterisation.

Saline aquifers are sedimentary rock units in which pore space is saturated with saline water that is unsuitable for consumption or irrigation. Such units are widely distributed and can be of very large volume and extent. They therefore have the potential to provide large storage capacity in areas without depleted hydrocarbon reservoirs. However, because they have not previously had an economic or resource value, they are generally much less-well understood than hydrocarbon reservoirs and so assessment of their CO_2 storage potential carries more uncertainty regarding containment security and fluid flow properties.

Carbon dioxide storage in coal beds is through adsorption onto the coal surfaces rather than filling of pore space. CO_2 is preferentially adsorbed and thus displaces methane (CH_4) from the coal. As with EOR, this process can be used to produce coal bed methane and so CO_2 storage can be combined with hydrocarbon production. In fact, as methane has a higher greenhouse effect than CO_2, any CO_2 coal storage projects must include methane production and use, to avoid emission to the atmosphere and result in greenhouse gas emission reduction.

Trapping mechanisms

For CO_2 storage involving partial filling of pore space, it is necessary to inject and store CO_2 in its dense supercritical form, in order to maximise use of the available porosity. The critical point for CO_2 is at 31.1°C and 7.38 MPa; this equates to a depth of approximately 800 m at typical crustal temperatures.

The CO_2trapping mechanisms include:

- physical trapping in structural and stratigraphic traps, in which the CO_2 is contained in closures produced by the geometrical arrangement of reservoir and seal rocks and faults;
- residual trapping, in which some portion of migrating CO_2 remains trapped in pore spaces by capillary forces;
- solubility trapping, in which some portion of the CO_2 dissolves into the formation water;
- hydrodynamic trapping, in which, although the dissolved and free CO_2 migrates with formation water through the reservoir, very long residence times mean it is effectively stored permanently;
- mineral trapping, in which the CO_2 precipitates as new carbonate minerals and so is permanently stored with high security;
- adsorption trapping, in which gaseous CO_2 adsorbs onto the surface of coal.

Estimating the volumes and proportions of CO_2 that would be trapped by each of these mechanisms is a key part of a site characterisation. Increased understanding of trapping mechanisms is an important area for scientific research.

Site selection

The first stage of a site selection process for CO_2 storage is a screening of national or regional geology to identify large areas of potentially suitable sedimentary basins. Basins can be assessed and ranked using criteria such as size, depth, stratigraphy (reservoir-seal pairs or potentially injectable coal seams), seismicity, geothermal characteristics, accessibility, proximity to CO_2 sources etc. Basin identified as having potentially suitable assets for CO_2 storage can then be assessed at basin and sub-basin scale to locate possible closures and traps, the distribution of reservoir–seal pairs at suitable depths, or coal seams, using existing data such as geological maps, seismic surveys and well data.

Prospective storage sites can be ranked for the following factors:

- *Storage Capacity*. A simple estimate can be made of storage capacity from the area of the identified trap, thickness of the reservoir below the critical depth and the porosity, and this compared to the likely CO_2 supply that the site may need to accommodate. Not all of the total pore space in the reservoir can be filled with CO_2 and key parameter in capacity estimates is the efficiency or utilisation factor, the fraction of the pore volume that can be occupied by or will retain injected CO_2. This is a function of the fluid already present in the reservoir, pore size and shape, grain mineralogy and reservoir heterogeneity at all scales. Efficiency factors can vary widely from site to site and have a major effect on capacity calculations. Values used are typically around 40 % for depleted gas fields, and range 0.1 – 6 % for saline aquifers; establishing a reliable value for a site before injection of CO_2begins is clearly important and a challenge for future research. The efficiency factor can be maximised by careful injection strategy and well planning.
- *Injectivity Potential*. Reservoir characteristics, such as permeability, porosity and pressure will control the rate at which CO_2can be injected into the reservoir. In practise, injectivity can be increased by extending the length of wellbore within the reservoir by drilling horizontal wells and/or by increasing the number of wells.
- *Containment*. For a seal/caprock to be effective for storage, it must be laterally continuous and sufficiently thick over the proposed injection reservoir, with low vertical permeability and high capillary entry pressure. An effective seal can be demonstrated by a pressure or salinity differential, or a history of trapping oil or gas. The size and spacing of faulting is also a factor, but it is particularly important to assess whether faults are likely to be sealing or migration pathways. The migration distance over which CO_2 can travel in the reservoir will affect the probability of the more secure trapping mechanisms: residual, hydrodynamic or mineralisation.

  It is also important to ensure that any existing wells or other artificial breech of the seal will also trap CO_2 and not provide an escape pathway.
- *Site Logistics*. Economic and logistical factors will control whether a geologically suitable storage site can actually be used. Excessively deep wells or long pipelines may make a site uneconomical. On the other hand, clusters of CO_2 sources sharing pipeline and storage site facilities can make a project more economical. Cooperation among projects at a regional scale will be required to benefit from shared facilities and avoid problems from using the same storage complex.
- *Existing Natural Resources*. Competing use of the same underground space, or sterilisation of alternative underground resources that could potentially be compromised by CO_2 storage, such as oil and gas, mineable coal, potable water, a geothermal energy source, may require national or regional policies on relative importance of the conflicting interests. Proximity to population centres, national parks or other protected sites, could limit surface operations, either because of legislation or because of negative public reaction.

A key consideration in any project is the selection of the stage to begin the outreach process to best avoid delays caused by negative reaction from communities around potential locations for CO_2 storage. General consensus from studies and experience seems to be that early is better, to open lines of communication and develop community understanding before fear of the unknown or manipulation by alternative agendas get embedded.

Once a potential storage site has been identified by the basin-scale assessment described above, it has to be evaluated through a detailed site characterisation, to add quantitative confidence that the site will geologically store the required quantity of CO_2 to the level of security and for the period required by the regulatory authority. The geoscience aspects of a detailed site characterisation as well as the economic aspects are described in the following chapters of this report, which comprise best practice recommendations from international studies and working groups in CO_2 storage site selection. In addition, key references are listed for societal aspects:

- Chapter 2 - Geological characterisation of the site - This chapter describes the creation of a geological model with which to assess the volume, injectivity, storage efficiency and lifetime of the reservoir; potential leakage and how to avoid or mitigate it; and the long-term behaviour and fate of the stored CO_2 and displaced brine.
- Chapter 3 - Flow modelling - This chapter describes the modelling of flow and transport mechanisms and the numerical models that are used. The purposes of fluid flow simulations are also illustrated on some examples of CO_2 injection pilots.
- Chapter 4 - Reactive flow modelling - This chapter presents an overview of reactive flow modelling (solute transport modelling). The state of current knowledge within geochemical and solute transport modelling is presented as well as an overview of what has to be modelled and for how long. The state of the art of chemical and solute transport modelling and its applications status, concentrating on reactive flow modelling, as well as the important role played by available data are discussed.
- Chapter 5 - Coupled geomechanical and flow modelling – This chapter presents the scope of geomechanical modelling and the data required to assess the long-term performance of CO_2 storage. The different issues of geomechanical modelling are then presented and illustrated on case studies. Finally, coupling methods are presented.
- Chapter 6 - Environmental impact and risk assessment - This chapter presents an overview of the risk assessment process that determines both the consequences and likelihood of an event and that is the input for good monitoring and mitigation plan.
- Chapter 7 - Economic analysis – This chapter presents the cost associated to CO_2 storage emphasising the great uncertainties on these costs and their site dependency.
- Chapter 8 - Public perception and acceptance - This is widely perceived to be a potential major impediment to deployment of CCS. Concerns over safety, permanence of storage and adverse impacts on environment, health and property prices need to be carefully managed at local and national scales. How, when and by whom the CCS message should be delivered are likely to vary from site to site depending on local cultural factors. Therefore, this report does not seek to be prescriptive, but rather, presents references to major studies on the issue.

2 GEOLOGICAL CHARACTERISATION OF THE SITE

The first step in site selection is the screening of potentially suitable formations and structures against specific criteria. The most developed criteria are for CO_2 storage in saline aquifers (Chadwick et al., 2006), and pertain to safety and feasibility issues. In the case of hydrocarbon fields and coal beds, the available criteria are not as comprehensive.

In the case of saline aquifers, there is a sequence of capacity estimate types that form a conceptual storage capacity pyramid (e.g. Bachu, 2003; Kaldi and Gibson-Poole, 2008) ranging from initial assessments of theoretical storage capacity based on regional geology to matched capacity estimates based on field scale feasibility studies and field testing. Hydrocarbon fields and, to a lesser extent, coal beds have a narrower range of capacity categories and uncertainties because of the pre-existing knowledge available from long-term production activities.

The insufficient knowledge about saline aquifer formations and structures, as well as public concerns in the case of onshore CO_2 storage, requires that site selection in this case should include comprehensive assessment of the quality and integrity of caprock followed by assessment of the safety and feasibility of CO_2 storage in the reservoir.

Based on the results of CO_2 storage site safety and feasibility studies, storage site ranking is carried out by weighing the site scores for all criteria.

2.1 Site screening criteria

Site screening represents the coarsest scale of assessment with the least site specific details. Depending on the size of area in question, regional sedimentary basins assessment, trans-border basins or smaller parts of sedimentary basins are taken into consideration in the following sequence (Chadwick *et al*., 2006; Kaldi and Gibson-Poole, 2008):

- Identify sedimentary basins or smaller areas (sandstone and to lesser extent carbonate sediments in the case of storage in saline aquifers, coal basins)
- Review the characteristics of sedimentary basins or smaller areas (*e.g.* tectonic setting, faulting, hydrodynamic regimes, extent and thickness of perspective sedimentary formations)
- Qualitative and (if possible) quantitative ranking of sedimentary basins or smaller areas in order of suitability.

2.1.1 Saline aquifer

Tab. 2-1 presents the criteria proposed in the CO2STORE Best Practice Manual (Chadwick *et al*., 2006) for screening saline aquifer formations and structures suitable for demo or large scale industrial projects.

Obviously, it is essential to acquire geological data sufficient to evaluate the formations and structures (Fig. 2-1) against these key geological and reservoir criteria.

- The upper depth of the reservoir corresponds to the minimum pressure and temperature at which CO_2 is found in dense, less mobile phase – so called supercritical phase. The lower depth is less accurately defined, depending on reservoir parameters, which usually deteriorate at this level, sometimes deeper.

Tab. 2-1: Criteria proposed in the CO2STORE projects (Chadwick *et al*., 2006).

	Positive indicators	**Cautionary indicators**
Storage capacity		
Total storage capacity	Total capacity of reservoir estimated to be much larger than the total amount produced from the CO_2 source	Total capacity of reservoir estimated to be similar to or less than the total amount proceed from the CO_2 source
Reservoir properties		
Depth	> 1000 m, < 2500 m	< 800 m, > 2500 m
Reservoir thickness (net)	> 50 m	< 20 m
Porosity	> 20 %	< 10 %
Permeability	> 300 mD	< 10 – 100 mD
Salinity	> 100 gl^{-1}	< 30gl^{-1}
Caprock properties		
Lateral continuity	Unfaulted	Lateral variations, fullting
Thickness	> 100 m	< 20 m
Capillary entry pressure	Capillary entry pressure much greater than buoyancy force of maximum predicted CO_2 column height	Capillary entry pressure similar to buoyancy force of maximum predicted CO_2 column height

- Reservoir parameters – thickness (net), porosity and permeability define reservoir performance and feasibility of its use. Higher values indicate a better reservoir. In principle, sandstone rather than carbonate reservoirs are preferred.

- High salinity value is an indication that no contact of the reservoir and potable aquifers occurs.

- The quality and integrity of caprock preventing leakage from the reservoir is no less important than reservoir properties. The greater the thickness of continuous impermeable formation (e.g. shale), the better the caprock integrity is. Faults parting the entire caprock are in general a negative indicator, although a fault can be either a migration path or a barrier. Multiple caprock formations are recommended, provided they have sufficient thickness. The capillary entry pressure is also an important caprock parameter. This parameter informs the additional pressure build-up caused by injected CO_2, especially on the top of a structural closure (see Fig. 2-2).

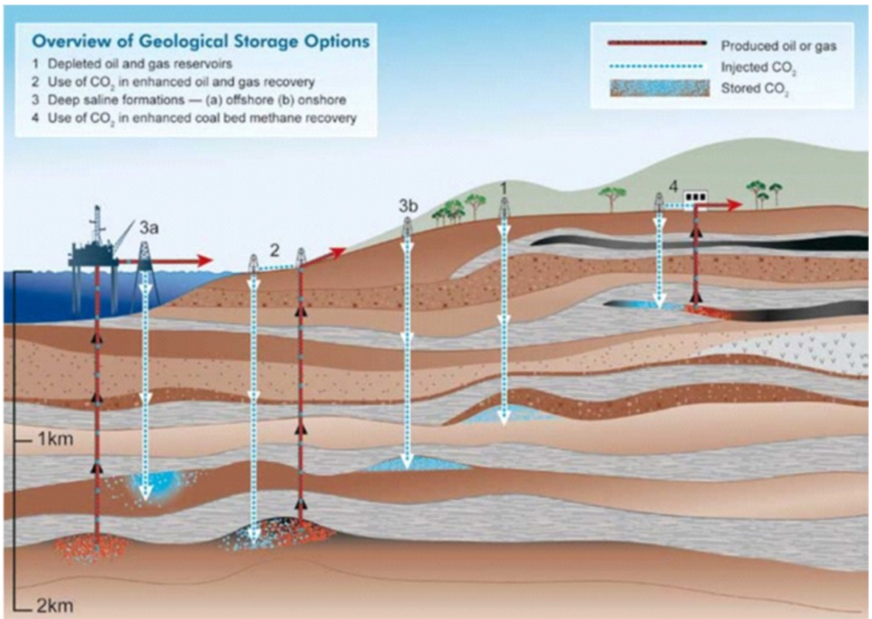

Fig. 2-1: Methods for storing CO_2 in deep underground geological formations (after IPCC, 2005 & CO2CRC).

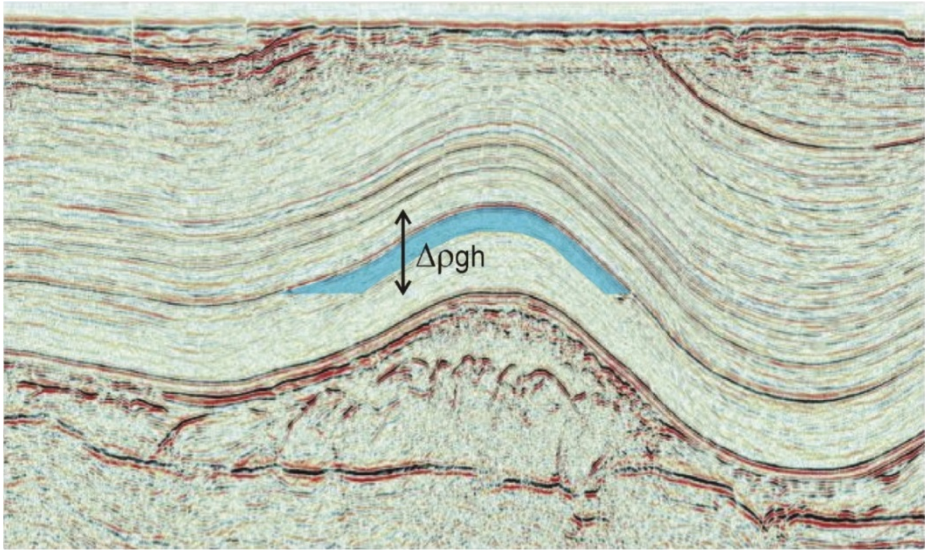

Fig. 2-2: Buoyancy forces acting on the crest of the structural closure (after the CO2STORE manual – Chadwick et al., 2006).

2.1.2 Hydrocarbon fields

Depleted or depleting hydrocarbon fields usually have a long production record and come with a great deal of knowledge about their geometry and reservoir properties. These are proven storage sites because the hydrocarbon fields are traps by definition. It is difficult to define criteria for the usability of depleted gas fields for CO_2 geological storage – certainly bigger fields are better suited for this purpose, but an economic scenario together with CO_2 availability are also required. The issue of enhanced hydrocarbon recovery is clearer, especially in the case of CO_2-EOR (Vangkilde-Pedersen *et al.*, 2008) where miscible flood (Fig. 2-3), ensuring a high (additional) recovery, is preferred.

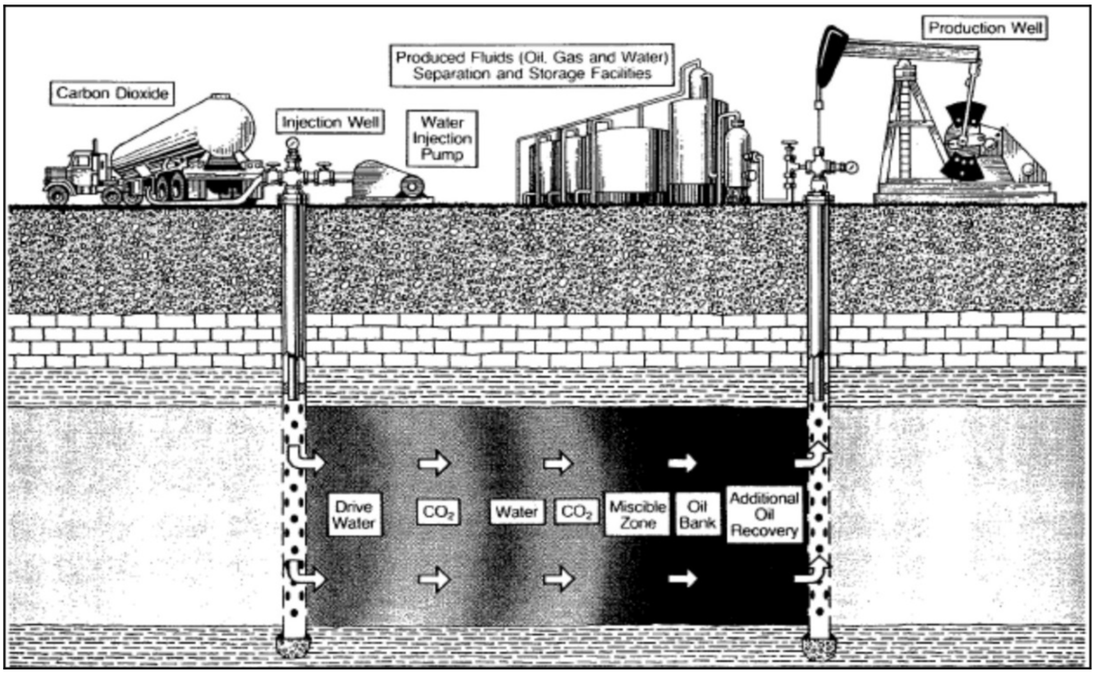

Fig. 2-3: CO_2-EOR miscible flood process (Green and Willhite, 1998).

Tab. 2-2 presents the most commonly applied CO_2-EOR criteria (after Taber *et al*., 1997). Conditions for miscible flood (mixture of oil and CO_2 appears close to the injection front causing a relative high pressure build-up in surroundings) are defined for a wide range of oil types and reservoirs, with the exception of heavy oils, for which immiscible flood applies. In the case of heavy oils, the CO_2-EOR mechanism is the buoyancy force, not unlike as in the saline aquifers; however, this is less effective and less profitable than the miscible flood.

Tab. 2-2: CO_2 flooding (Enhanced Oil Recovery) criteria proposed by Taber *et al*. (1997).

Criterion/ Mechanism	Oil gravity [API] (current projects)	Depth	Composition	Viscosity [cP] (current projects)	Oil saturation [% PV] (current projects)	Reservoir formation	Average permeability
Miscible flood	>40 32 - 39.9 28 - 31.9 22 - 27.9 *(27 - 44)*	>830 m >930 m >1100 m > 1330 m	High percentage of intermediate hydrocarbons (especially C5 - C12)	<10 (0.3 - 6)	>20 (15 - 70)	Sandstones or carbonates; relatively thin unless dipping	Sufficient injection rates maintained
Immiscible flood	13-22	>600 m					

2.1.3 Coal beds

In the case of coal fields, the screening criteria are not as elaborated as the criteria for saline aquifers and hydrocarbon fields. In the GESTCO project, entire basins have been studied, selected on the basis of known coal and coal bed methane resources (Tongeren and Laenen, 2001; Bergen and Wildenborg, 2002; May, 2003). Areas of current coal exploitation were not considered. The upper depth limit of CO_2 injection into coal beds might be restricted by previous or ongoing mining activities. The lower depth of the use of the CO_2-ECBM recovery (CO_2 injection for Enhanced Coal Bed Methane recovery) was assumed as an economic limit - most likely up to 1500-2000 m, depending on the study area and the basin production history. Suitable areas or fields within coal basins can, in principle, be selected on the basis of higher content of (methane) gas in place - for example in Belgian basins (Tongeren and Laenen, 2001), the value of at least 250 mln m^3/km^2 was recommended.

Similar criteria were applied in the EU GeoCapacity project (Wójcicki *et al*., 2007; Vangkilde-Pedersen *et al*., 2008), in which the recommended depth range was 1-2 km. The presence of coal bed methane reserves is an additional important factor (the definition of reserves depends on country, basin and economic considerations – *cf.* Fig. 2-4 and Tab. 2-3). Areas and depth ranges were ongoing or abandoned mining activities have taken place were not recommended due to safety reasons.

Tab. 2-3: General criteria for coal beds (used in the GESTCO and EU GeoCapacity projects).

Criterion	Safety	Depth	Gas in place
Recommendations	Beyond area and depth range of mining activities	Upper: see-Safety; Lower: 1000-2000 m	Known reserves (economic, *e.g.* 250 Mm^3/km^2) ($Mm^3=10^6$ m^3)

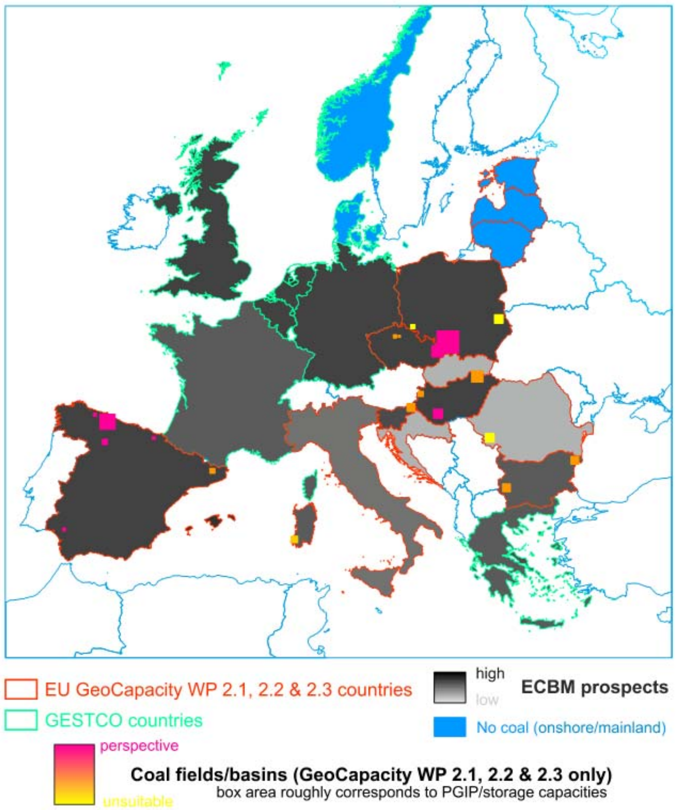

Fig. 2-4: Estimated CO_2-ECBMR potential of EU GeoCapacity & GESTCO countries – after Wójcicki *et al*. (2007)

2.2 Storage capacity estimation methods

2.2.1 Saline aquifer reservoirs

Several methods have been proposed to calculate the CO_2 storage capacity for saline formations. The method used is chosen depending on the available data. Most methods assume that CO_2 storage is achieved by increasing the pressure in the saline formation. Owing to the limited compressibility of fluids and rock, substantial volumes of saline formation are required to maintain useful storage capacity.

When only limited knowledge is available on a potential storage volume, the storage capacity can be estimated from the bulk volume of the saline formation, considering an average porosity and a storage efficiency factor by multiplication. The bulk formation volume is the volume that is hydraulically connected.

The approach that was used to estimate storage capacity in deep saline aquifers in GeoCapacity project was a slightly simplified and/or modified version of the method presented in Bachu *et al.* (2007). Bachu *et al.* (2007) define both theoretical and effective storage capacity for a basin or region as the sum of the storage capacity of individual structural or stratigraphic traps in the said area/volume. They then distinguish between theoretical and effective storage capacity by applying a storage efficiency factor (capacity coefficient). The efficiency factor includes the cumulative effects of trap heterogeneity, CO_2 buoyancy and sweep efficiency; however, the efficiency factor is site-specific and needs to be determined through numerical simulations and/or fieldwork.

An estimate based on the bulk volume of a regional aquifer is, therefore, by nature theoretical. However, theoretical storage capacity estimates are not very useful as they are based on assumptions that are known to be inaccurate. Therefore, applying different storage efficiency factors to the bulk volume of the aquifer is preferred. For bulk volumes of regional aquifers, a storage efficiency factor of 2 % is proposed based on work by the US DOE (Frailey, 2007). Frailey (2007) found values ranging between 1.8 and 2.2 % for the storage efficiency factor of the bulk volume of a regional aquifer through Monte Carlo simulations (with low and high values of 1 % and 4 %, respectively).

Capacity estimation standards based on the work and publications of the CSLF (Bachu *et al*., 2007) do not provide advice on the value of trap specific storage efficiency factor, other than it is very much site-specific. Discussions on storage efficiency factors in several research projects have led to further work on this issue by the IEA and the CSLF. In the EU GeoCapacity project, two different approaches were developed for trap-specific storage efficiency factors, one for open or semi-closed aquifer systems and one for closed aquifer systems.

Bachu *et al.* (2007) include the net to gross ratio (NG) in both theoretical and the effective capacity estimates, which is meaningful when assessing individual traps. The net to gross ratio is, however, also a site specific parameter, which depends on the local geological conditions and is not necessarily well known or homogeneously distributed throughout a region. It may, therefore, not be meaningful to establish an average value for a regional aquifer based on few observations. If limited information is available, a default value of 0.25 is suggested. This value may be too high in some cases, but will for many cases be a conservative value. When considering the NG ratio, it should normally be possible to provide a best estimate of the reservoir porosity of a regional aquifer.

CO_2 density is a function of pressure and temperature and can be obtained from different models (*e.g,* Span and Wagner, 1996 and Peneloux *et al*., 1982). Again, it may not be meaningful to establish an average value for a regional aquifer based on insufficient observations.

As a regional estimate based on bulk volume of an aquifer rather than trap volumes is already subject to great uncertainty (thickness and extent of aquifer, storage efficiency factor, *etc.*), the exact values of the net to gross ratio and the CO_2 density are not essential. Furthermore, as the value of the storage efficiency factor is generalised rather than based on specific geological conditions, a regional estimate calculated using this methodology should be regarded as only indicative.

When information to estimate the pressure increase that can be applied to the hydraulically connected volume is available, a more reliable estimate of the storage capacity of a saline formation can be obtained. Combined with the compressibility of the fluids and rock, the storage capacity estimate can be derived using the following equation (see, *e.g.* Frailey, 2007).

$$M_{CO_2b} = A \times h \times NG \times \phi \times \rho_{CO_2r} \times \Delta p \times (\beta_r+\beta_f)$$

where in addition to the parameters defined in Tab. 2-4, Δp is the pressures increase (relative to the initial pressure), β_r is the compressibility of the matrix; β_f is compressibility of the fluid.

Tab. 2-4: Parameters used in the static capacity assessment of saline aquifers (Vangkilde-Pedersen *et al*., 2008).

Parameter	M_{CO_2}	**A**	**h**	**NG**	**φ**	ρ_{CO_2r}	S_{eff}
Description	Regional or trap aquifer storage capacity	Area of aquifer	Average thickness of aquifer	Average net to gross ratio of aquifer	Average reservoir porosity	CO_2 density at reservoir conditions	Storage efficiency factor
Typical values	Gtonnes to Mtonnes	Thousands to tens of km^2	Hundreds of meters	Tens of percent	10-30%	0.6-0.8 g/cm^3	2-3% (regional)* 10-40% (trap - closed to fully open)*

**Also reservoir properties matter (if better, the coefficient is higher); if* $S_{eff}=0$, *then* M_{CO_2} *is simply a theoretical capacity.*

If the knowledge and level of detail exists and regional capacity estimates are available, it is more reliable to provide storage capacity estimates that take into account the volume in traps, where the buoyant CO_2 can be safely retained. It should be emphasised here that storage capacity in saline formations is not only limited by the pressure increase that can be sustained by the formation, but also by the traps where CO_2 collects after injection. The volume of CO_2 that is derived from the connected volume and assumed pressure increase must be stored in an open structure that will retain the CO_2. The pressure in this volume can be increased to create space for CO_2 within the structure. The volume of CO_2 that can be trapped is defined by the volume in the traps to its spill point. The smaller of these two volumes (CO_2 volume from pressure increase, trap volume) defines the total storage volume.

The most accurate storage capacity estimate is obtained after a detailed site characterisation study. In such a study, all available data is collected, a detailed geological model of the connected volume is created and a reservoir engineering study is performed to obtain a realistic storage and injection capacity estimate.

Storage capacity estimations for saline aquifer reservoirs are often presented in the form of a storage pyramid (Bachu, 2003; Kaldi and Gibson-Poole, 2008; Vangkilde-Pedersen *et al*., 2008). Fig. 2-5 and 2-6 present two such examples. Depending on whether the detailed structure geometry and reservoir parameters are known, assessment of the realistic capacity might require new geophysical surveys and well drilling. It should be noted that, in any case, reliable economic evaluation cannot be completed without acquisition of new geological data.

Generally, for matched (or practical) capacity an injection scenario and simulations are necessary (discussed in the following sections); while realistic (or effective) capacity, as a minimum, can be assessed using a robust static capacity estimation approach (Vangkilde-Pedersen *et al*., 2008).

For this approach, based on calculation of pore space volume available for injection and storage, the following formula on static capacity assessment has been recommended in the EU GeoCapacity project (Vangkilde-Pedersen *et al*., 2008; Tab. 2-4) after CSLF guidelines (Bachu *et al*., 2007):

$$\mathbf{M_{CO_2} = A \times h \times NG \times \varphi \times \rho_{CO_2r} \times S_{eff}}$$

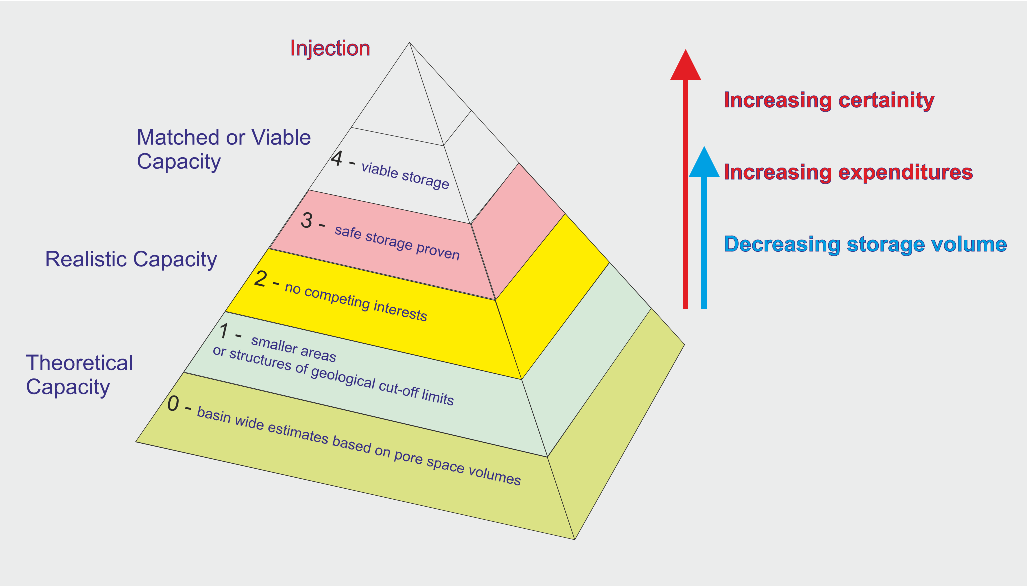

Fig. 2-5: Storage capacity pyramid for saline aquifers (modified after Bachu, 2003).

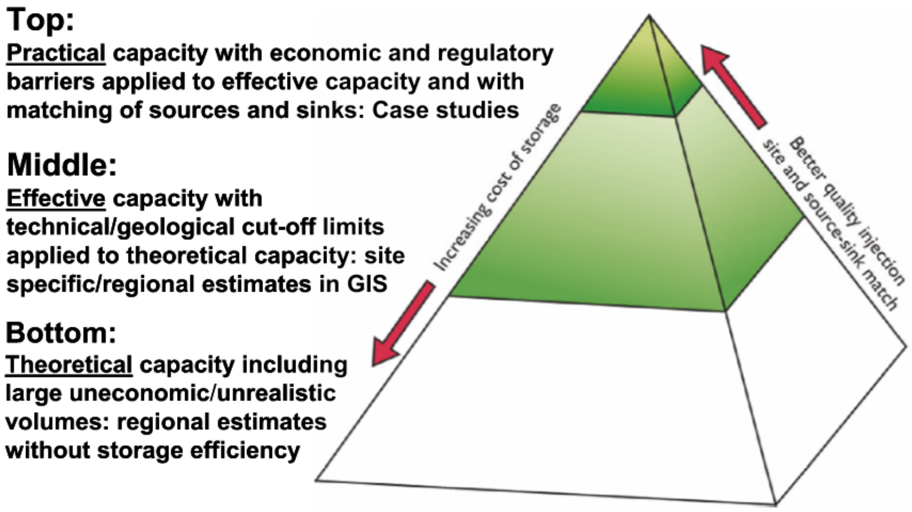

Fig. 2-6: A simplified storage capacity pyramid for saline aquifers (Vangkilde-Pedersen et al., 2008).

2.2.2 Hydrocarbon fields

CO_2 storage capacity estimations of European hydrocarbon fields have been carried out in the GESTCO (Schuppers *et al*., 2003) and the EU GeoCapacity projects (Vangkilde-Pedersen *et al*., 2008). For all fields, the equivalent of practical or realistic capacity was assessed. These were static capacities estimated on the assumption that the volume occupied by recoverable hydrocarbons (recovery ratio as using standard production technology, without CO_2 injection) in the reservoir can be filled up again by injected carbon dioxide. For a number of case studies, injection scenarios were analysed, and the equivalent of matched or practical capacity was obtained.

Especially in the case of gas fields, the formation factor – i.e. the volume produced gas occupies in the reservoir divided by its volume on at the surface - is essential to provide a reliable estimate of static CO_2 storage capacity (see Fig. 2-7, density of natural gas within the reservoir is 100-300 kg/m^3, while at the surface is less than 1 kg/m^3).

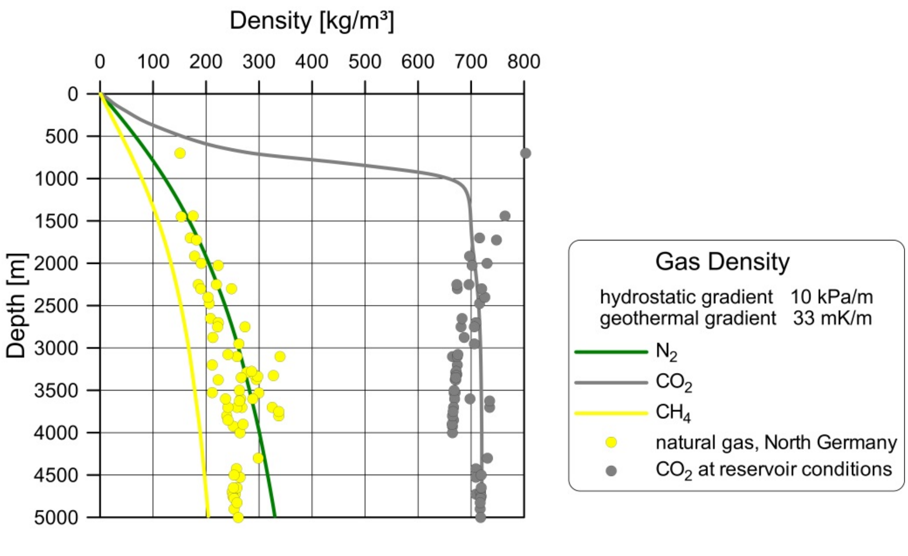

Fig. 2-7: Density variation of natural gas and CO_2 with depth (Schuppers *et al*., 2003).

The following, simplified formula was used in order to estimate the static capacities of hydrocarbon fields (Schuppers *et al*., 2003; Tab. 2-5):

$$M_{CO_2} = \rho_{co_2r} \times UR_p \times B$$

The capacity can also be calculated using Bachu (2008) Phase III formula:

$$M_{CO_2} = \rho_{co_2r} \times (R_f \times OOIP / B_f - V_{iw} + V_{pw})$$

where OOIP is original oil in place.

In this last expression, UR_p in fact represents R_f OGIP and R_f OOIP, respectively, but the formula does not take F_{ig}, V_{iw} and V_{pw} into account. UR_p is the sum of the cumulative production and the proven reserves and typically, the methodology for calculating/estimating the proven reserves varies from country to country.

Tab. 2-5: Parameters used in the static capacity assessment of hydrocarbon fields (GESTCO and EU GeoCapacity projects; Schuppers *et al*., 2003 and Vangkilde-Pedersen *et al*., 2008).

Parameter	M_{CO_2}	ρ_{co_2r}	UR_p	**B**
Description	Hydrocarbon field storage capacity	CO_2 density at reservoir conditions	Proven ultimate* recoverable oil or gas	Oil or gas formation factor
Typical values	Oil & Gas: Mtonnes to hundreds of Mtonnes	0.6-0.8 g/cm^3	Oil - Mm^3 (10^6 m^3) to hundreds of Mm^3 Gas – Bm^3 (10^9 m^3) to hundreds of Bm^3	Oil - slightly bigger than 1; Gas - far smaller than 1 (e.g. 0.003-0.007)

**For gas fields in case gas is re-injected the amount shall be extracted from* UR_p; *Regarding* UR_p *of oil fields where water is injected and produced the injected one shall decrease and the produced increase* UR_p.

The ultimate recoverable oil and gas can be given, on a field by field basis, as the sum of produced volumes and expected reserves, or by applying a fixed conversion factor to the expected ultimate recoverable oil and gas.

The formation volume factor used for oil varies regionally and/or locally depending on the oil type and the formation volume factor used for gas should vary with depth as a function of pressure and temperature. Likewise the CO_2 density should also vary with depth as a function of pressure and temperature. Both may, however, in some countries, have been applied as constant average values to all hydrocarbon fields.

The methodology used for hydrocarbon fields yields theoretical storage capacity, according to the methodology described by Bachu *et al*. (2007). To reach effective storage capacity, a number of capacity coefficients representing mobility, buoyancy, heterogeneity, water saturation and aquifer strength were introduced, all of which reduce the storage capacity. However, if there are insufficient data for estimating the values of these capacity coefficients, it is not possible to distinguish between theoretical and effective storage capacity for hydrocarbon fields.

2.2.3 Coal beds

In the GESTCO project (Tongeren and Laenen, 2001; Bergen and Wildenborg, 2002; May, 2003) and in the EU GeoCapacity project (Wójcicki *et al*., 2007; Vangkilde-Pedersen *et al*., 2008) two approaches to storage capacity estimations for coal bed methane fields were presented.

In the first approach, it was assumed adsorption capacity of coal beds, where methane reserves occur, was 33 m^3 of CO_2 per tonne of coal (*e.g.* May, 2003). This is the most optimistic estimation of coal bed storage capacity, of minimal ash content and moisture and high methane content.

The second approach takes into consideration CO_2 to CH_4 exchange ratio (Bergen and Wildenborg, 2002; Vangkilde-Pedersen *et al.*, 2008; Tab. 2-6). The exchange ratio depends mainly on the methane content and CO_2 to CH_4 adsorption/desorption potential, which means that usually one molecule of CO_2 can be exchanged for 1.5 to 6 molecules of CH_4 depending on pressure, depth (Fig. 2-8) and coal maturity/rank. The following relationships were used in the EU GeoCapacity assessment and the GESTCO project, in order to calculate the CO_2 to CH_4 exchange potential. In most cases, un-mineable coal beds at 1-2 km depth were considered and in some cases injection scenarios were evaluated (practical/matched capacities assessed):

$$\mathbf{S = PGIP \times \rho_{CO_2} \times ER}$$

$$\mathbf{PGIP = V_{coal\ daf} \times \rho_{coal} \times C_{CH_4} \times CF \times RF}$$

The symbols are explained in Tab. 2-6, daf stands for dry ash free.

Tab. 2-6: Parameters used in the static capacity assessment of coal beds (modified after Vangkilde-Pedersen *et al.*, 2008).

Parameter	S	PGIP	ρ_{CO_2}	ER	$V_{coal\ daf}$	ρ_{coal}	C_{CH_4}	CF*	RF*
	Storage capacity (realistic/ effective)	Producible gas in place	CO_2 density at reservoir conditions	CO_2 to CH_4 exchange ratio	Coal volume dry, ash, free	Average coal bed density	Methane content in pure coal	Completion factor, i.e. "working" part of the coal bed)	Recovery factor, i.e. recoverable percentage of gas in place
Typical values	Mtonnes to tens of Mtonnes (individual fields and small basins), hundreds of Mtonnes (large basins)	Bcms to tens of Bcms	0.6-0.8 g/ccm (1-2 km depth range)	1.5-6 (brown coal/lignite - higher than hard coal, pressure increases the ratio)	Millions to billions cubic meters	0.9-1.4 g/cm^3	2.5-50 m^3/t (most often 5-10 m^3/t)	Up to 0.6 (60%) (a vertical well, in a horizontal one possibly higher)	0.2-0.8 (20-80%)

** If both parameters are 1, this is theoretical capacity; otherwise if values are realistic - effective/realistic capacity is obtained.*

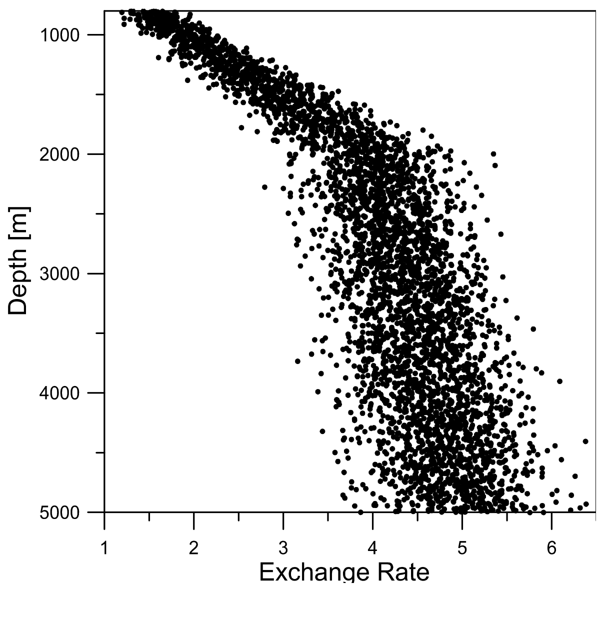

Fig. 2-8: Simulated distribution of CO_2 - CH_4 exchange ratio of hard coal beds in Germany (May, 2003).

2.3 Safety of CO_2 storage in saline aquifers

Since CO_2 is less dense than saline water, it tends to migrate upward within the saline aquifer system; therefore, a caprock above the storage unit is required. Caprocks significantly retard the movement of fluids (Couples, 2005). Without a caprock, hydrocarbons (oil or gas) generated at depth would have long ago migrated toward the surface and either biodegraded to heavier oil or escaped to the atmosphere. In the same manner, injected CO_2 will not remain trapped in a storage reservoir unless adequate caprocks are present.

Caprocks are an essential geological element of petroleum and CO_2 reservoirs. A caprock (*i.e.,* seal) is a low-permeability lithological unit capable of impeding hydrocarbon or CO_2 movement upward, causing these buoyant fluids and gases to spread laterally, filling any stratigraphic or structural trap it encounters. Effective caprocks for liquid and gaseous accumulations are typically thick, laterally continuous, ductile rocks with high capillary entry pressures. The most common caprock lithologies over commercial petroleum reservoirs are evaporates and shales. There may be several layers of caprocks. The lowermost caprock directly overlying the reservoir is then called the principal caprock and the overlaying layers of caprocks are referred to as secondary caprocks.

2.3.1 Assessment of the quality and integrity of the caprock

The quality and integrity of caprock preventing leakage from the reservoir is no less important than good reservoir properties for effective CO_2 storage. This is especially relevant for insufficiently explored saline aquifer structures.

Caprock quality and integrity (*i.e.* whether it would be an impermeable barrier for trapped CO_2 for millennia) can be assessed using information from wells (drill cores, well logging) and seismic data, as in the case of reservoirs. Although the study methods are usually site specific, in general the following analyses are applied to evaluate caprock structures (Chadwick *et al*., 2006):

- permeability and threshold capillary entry pressure measurements on drill core samples;
- analyses of mineralogical composition (minerals important for CO_2-brine-rock interaction, *e.g.* carbonates, to a lesser extent albite, chlorite, muscovite, *etc.*) of drill core samples;
- pore water analyses in order to assess pore water origin of drill core samples;
- caprock reactivity (with CO_2 and brine) laboratory analyses of drill core samples and modelling;
- evaluation of seismic sections and maps in order to identify faults within and above the principal caprock and/or facies changes within the caprock;
- evaluation/modelling of fault properties within and above the principal caprock (tightness/stress/leakage likelihood).

2.3.2 Storage in onshore aquifers

Storage in onshore aquifers offers a large potential and might be the only choice for inland areas (one example from central Poland, about 400 km from Baltic coast is shown in Fig. 2-9). This is, however, a sensitive issue because of high population density in and around areas where large industrial CO_2 emission sources are present (Vangkilde-Pedersen, 2008) and public opposition may not be uncommon.

Safety issues need to be addressed during the site selection phase, otherwise the whole selection process may need to be revised. In general, the provisions of the 2009/31/EC Directive on geological storage of carbon dioxide, in particular Annex 1 to the Directive, can be applied as the first step based on available data.

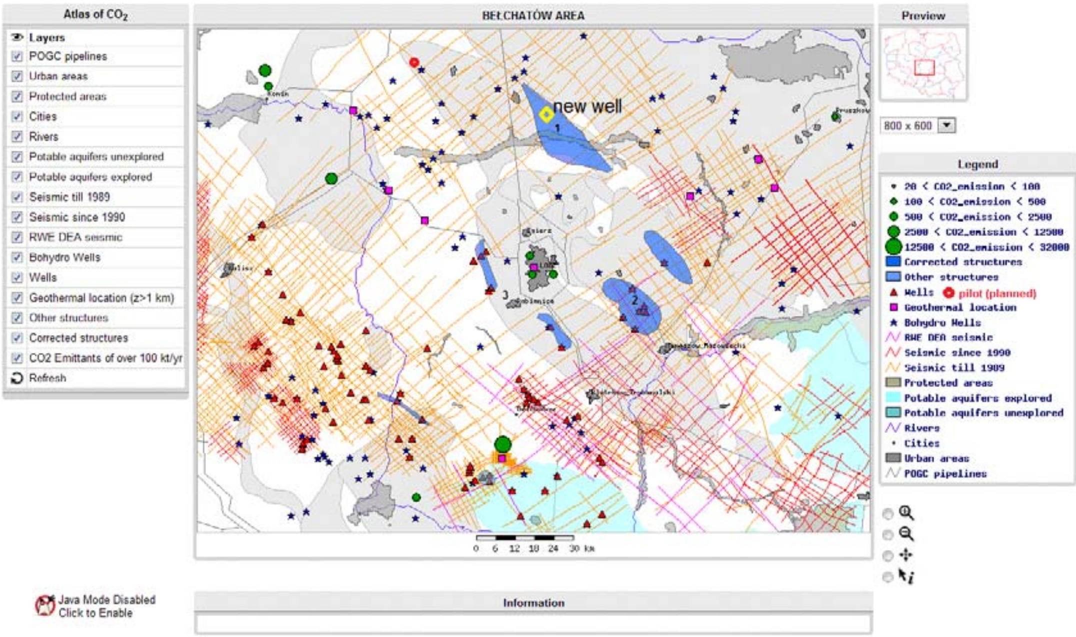

Fig. 2-9: Storage options for the Bełchatów CCS demo project in central Poland (Polish National Programme on Safe CO_2 Storage: http://skladowanie.pgi.gov.pl).

A preliminary model of the storage site is then constructed; possible hazards are identified; exposures and effects on humans and the environment (e.g. groundwater resources) are assessed; the risks are evaluated together with sensitivity assessment (importance of particular parameters of the model – Tab. 2-7); and finally possible risks to health, safety and environment are summarised.

Tab. 2-7: Parameters important for evaluation of storage safety in onshore saline aquifers (after Chadwick *et al*., 2006).

Parameter	Depth (of the reservoir)	Caprock thickness	Caprock quality and integrity	Capillary entry pressure	Closure	Salinity
Description	CO_2 in supercritical phase (depth and pressure correlate well, temperature depends on local geothermal gradient)	Primary at least of 20 m, recommended over 100 m and/or other caprock complexes above	Low permeability, high capillary entry pressure, rather no faulting and lateral facies' changes within the caprock complex	Much higher than buoyancy force of the column of CO_2 injected (injection simulations assess the safe amount of CO_2)	Anticline height sufficient the plume will not exceed the spill point (injection simulations necessary in order to assess safe amount)	Over 30 g/l guarantees no exchange of brine with potable water occurs in the reservoir; if less porewater analyses necessary

2.3.3 CO_2 storage in offshore saline aquifers

A large part of the European storage capacity is found in offshore saline aquifers, especially in the North Sea region, around Britain and Ireland, to some extent in the Barents Sea and likely in the Baltic Sea (Vangkilde-Pedersen *et al.*, 2008). The first and best known industrial CCS project in this domain is Sleipner in the Norwegian sector of North Sea (Chadwick *et al*., 2006; Fig. 2-10), from which a comprehensive information package is available. A couple of other offshore projects followed; Snøhvit, and K12-B. These projects were developed by the hydrocarbon industry years before the 2009/31/EC Directive on geological storage of carbon dioxide were proposed - rather these guidelines were based on findings of the projects.

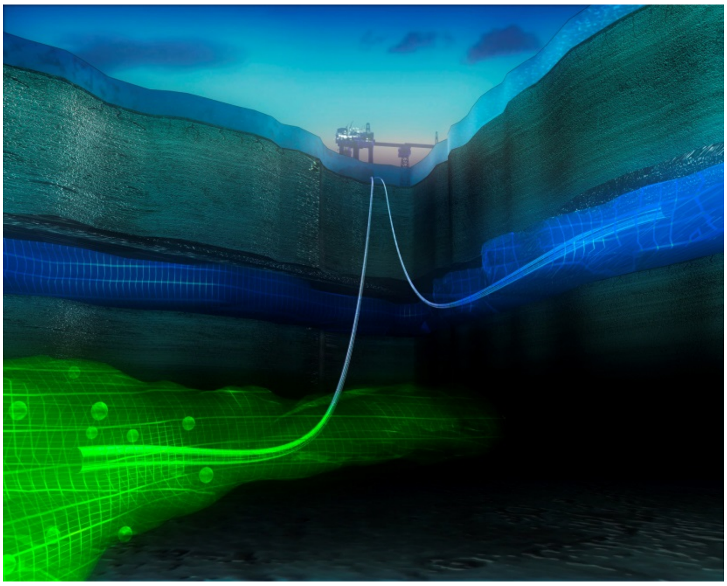

Fig. 2-10: The Sleipner project - CO_2 is stored in saline aquifer above gas field (Digitalt, Alligator film/BUG, Statoil ASA).

Tab. 2-8: Parameters important for the evaluation of storage safety in offshore saline aquifers. (after Chadwick et al., 2006).

Parameter	Depth (of the reservoir)	Caprock thickness	Caprock quality and integrity	Capillary entry pressure	Closure
Description	CO_2 in supercritical phase (depth and pressure correlate well, temperature depends on local geothermal gradient)	Primary at least of 20 m, recommended over 100 m and/or other caprock complexes above	Low permeability, high capillary entry pressure, rather no faulting and lateral facies' changes within the caprock complex	Much higher than buoyancy force of the column of injected CO_2 (injection simulations assess the safe amount of CO_2)	Anticline height sufficient the plume will not exceed the spill point (injection simulations necessary in order to assess the controllable amount)

The obvious safety precaution for storage in saline aquifers offshore is to avoid direct conflicts with hydrocarbon production, though pressure build-up within an aquifer just below the gas horizon might be beneficial to gas production. Insignificant leaks from natural pathways are usually ignored because such phenomena are known to occur naturally. Failures of transport and storage infrastructure (wells) do matter, as well as major leakages due to faulting and insufficient quality and integrity of caprock; the criteria presented above have to be applied in order to avoid such a situation when selecting storage sites. In principle, similar parameters are important for offshore as for onshore storage (Tab. 2-8), except the fact that groundwater protection is not important offshore.

2.4 CO_2 storage site ranking criteria

2.4.1 Site ranking criteria for saline aquifers

Site ranking is in principle based on results of screening and storage capacity estimations, which make a preliminary characterisation and storage safety assessment, together with the analysis of potential conflicts of use. First, Tab. 2-1 presented earlier should be completed for every site considered and existing knowledge gaps identified. However, this assessment only considers the results of the preliminary screening. In the CO2QUALSTORE project (Aarnes, 2010), an approach based on risk identification evaluating the above mentioned outcomes has been used (Tab. 2-9). Although the approach is universal, saline aquifers are considered more sensitively than depleted/depleting hydrocarbon fields and un-mineable coal beds.

Tab. 2-9: Screening and ranking of storage sites after the CO2QUALSTORE project (Aarnes, 2010).

Screening activities	Deliverables
Define screening basis	
Initiate the phase and develop criteria for nominating one or more sites for further assessment	List of criteria that a site should meet to be eligible for further site assessment
Develop screening plan	
Describe screening actions required for fulfilling the criteria defined in screening basis step	Screening plan
Review available data and identify potential sites	
Review available data and identify potential sites	List of potential storage sites
Estimate capacity and level of uncertainty	
Prepare capacity estimates and estimates of uncertainty of input and output parameters	Capacity estimates with quantified uncertainties for potential storage sites
Identification and assessment of risks and uncertainties	
Develop initial register of risks and uncertainties	Initial risk register
Select site(s) for further assessment	
Decide which sites, if any, should be assessed further	Screening report and final selection of site(s) nominated for further assessment
M2: Shortlist storage sites	
Main question: Is there an adequate level certainty that further site assessment will provide confidence that at least one of the nominated storage sites is suitable for long term geologic storage of the intended volumes of CO_2? ***Decision:*** Commit budget and resources for the assessment stage.	

In particular, the following risks have to be addressed from this viewpoint:

- legal and regulatory (is it possible to obtain storage permit; document the screening results; avoid conflicts of use of the subsurface for other resources - e.g. hydrocarbons, geothermal, gas/waste storage, etc.; locate storage and transport infrastructure as planned - no conflicts with land use);
- geological and environmental (reservoirs, tectonics, hydrogeology and natural hazards evaluated; reservoir and caprock properties known sufficiently together with aquifers and caprocks within overburden where CO_2 could leak; storage capacity and injectivity known sufficiently; existing wells identified as possible leakage paths; possible impact to vulnerable natural resources identified - potable aquifers, nature protected areas).

For example, the presence of areas of protected wildlife and nature (Fig. 2-11) onshore, within coastal areas and in some areas further offshore would make it impossible to develop injection infrastructure in some areas (the authority would likely not risk granting a storage permit) and difficult to develop transport infrastructure.

Often, existing knowledge gaps and uncertainties might be so significant that drilling new wells and carrying out new seismic and other geophysical surveys is necessary to evaluate and rank preliminary identified sites (as in the case of the Bełchatów demo project Fig. 2-9). Then the whole procedure listed in Tab. 2-1 has to be repeated and further steps taken, as indicated in Fig. 2-12 (Aarnes, 2010).

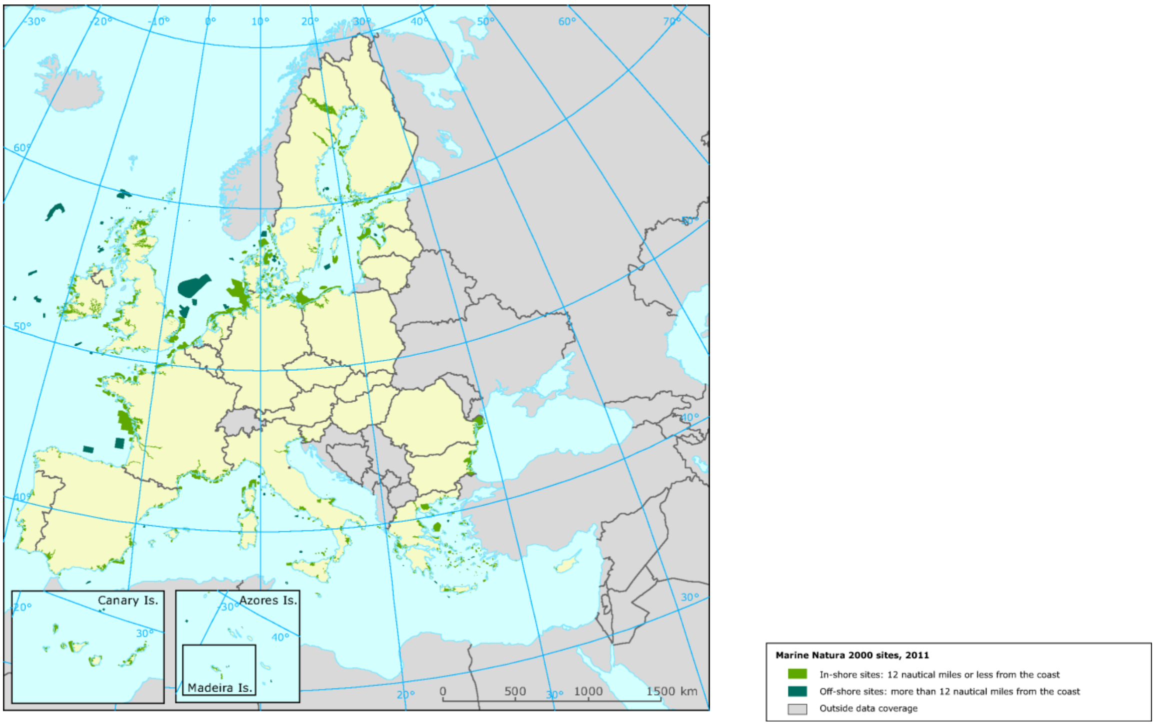

Fig. 2-11 - NATURA 2000 protected areas in the EU (European Environment Agency).

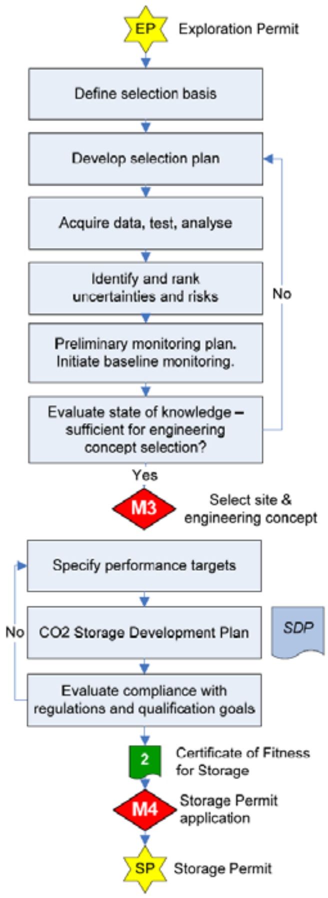

Fig. 2-12: Site ranking and selection procedure after the CO2QUALSTORE project (Aarnes, 2010).

2.4.2 Ranking criteria for hydrocarbon fields and coal beds

As with saline aquifers, site ranking for hydrocarbon fields and coal beds is in principle based on the results of screening and storage capacity estimations that form the preliminary characterisation and storage safety assessment, together with the assessment of potential conflicts of use, which are not so numerous in this case (Tab. 2-10).

For the preliminary screening of hydrocarbon fields, Tab. 2-2 presented earlier is completed while for coal beds Tab. 2-3 is appropriate. Then, following the CO2QUALSTORE guidelines, the following risks have to be addressed:

- legal and regulatory (is it possible to obtain storage permit; document the screening results; avoid conflicts of use of the subsurface for other resources/applications; no conflicts with land use);
- geological and environmental (reservoirs, tectonics, hydrogeology and natural hazards are evaluated; review the industrial history of the sites considered; storage capacity and injectivity may be known sufficiently; existing wells should be identified as they may pose possible leakage paths (Fig. 2-13); possible impact to vulnerable natural resources are identified including potable aquifers, protected areas).

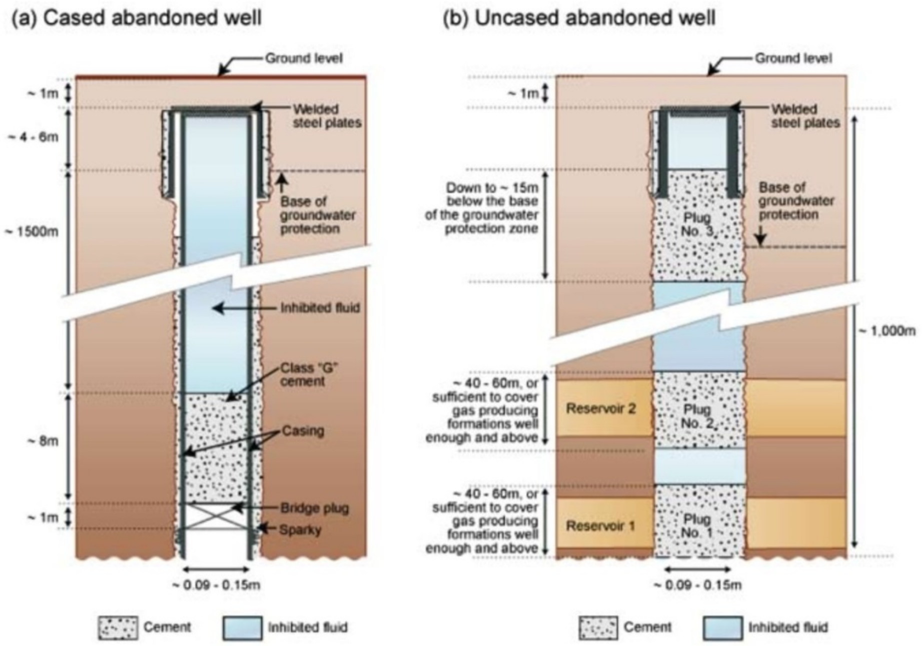

Fig. 2-13: Conventional well abandonment normally practised at hydrocarbon fields (IPCC, 2005).

Tab. 2-10: Possible conflicts of use for depleted hydrocarbon fields and un-mineable coal beds (after IPCC, 2005).

Type	Hydrocarbon fields (depleted/depleting)	Coal beds ("un-mineable" at present)
Possible Conflicts (with)	Gas storages	Technology developments would make coal mining for the beds in question cost efficient, underground coal gasification

2.5 Conclusions

The preliminary geological characterisation of potential CO_2 storage sites includes site screening, preliminary storage capacity assessment and then ranking leading to selection of optimal storage site for a CCS project.

The whole process cannot be carried out without taking into consideration legal and regulatory, environmental, technical and even to some extent economic aspects of CO_2 geological storage.

The most significant knowledge gaps and uncertainties may exist in the case of CO_2 storage in saline aquifers, where often insufficient information is available to evaluate the sites in question against principal screening criteria. For onshore saline aquifers, criteria related to safety of underground potable water resources are considered the most important. Although offshore storage does not relate to such problems, prevention of significant leaks from reservoir to the sea bottom through natural or man-made pathways is the main safety concern.

In the case of saline aquifers, it is often difficult to make a reliable site ranking and selection without acquiring new data, including drilling new exploratory wells, carrying out new seismic surveys and other characterisation surveys.

There are more possible conflicts of use of the subsurface in the case of onshore than offshore saline aquifer CO_2 storage and fewer conflicts for depleted hydrocarbon fields and un-mineable coal beds.

3 FLOW MODELLING

Injection of CO_2 into deep geological formations involves deploying many of the technologies and methodologies that have been developed in the oil and gas (exploration and production) industry including computer simulation of storage reservoir dynamics.

The mechanisms that control the behaviour of injected CO_2 need to be evaluated through fluid flow modelling based on an understanding of the processes that are active in the reservoir and the available injection/production and monitoring data.

Site characterisation and storage system modelling work helps to design a robust monitoring, verification and accounting system that provides data for validating modelling results, monitoring potential leakage, and providing confidence that the CO_2 would remain in the subsurface. A number of existing reservoir simulators have been used or further developed to evaluate underground multi-phase flow, seepage through the caprock, geomechanical impact, or flow in fractured media.

This chapter describes the CO_2 flow and transport mechanisms that occur in storage systems, briefly presents available numerical modelling tools and provides an overview of the flow modelling work carried out at industrial field and pilot sites around the world.

Injection of CO_2 into deep geological formations involves deploying many of the technologies and methodologies that have been developed in the oil and gas (exploration and production) industry. Computer simulation of storage reservoir dynamics is one of these technologies, along with well-drilling technology, injection technology, and monitoring methods.

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Reservoir and storage system simulations are used to determine (modified from NETL, 2009):

- the temporal and spatial migration of the injected CO_2 plume;
- the effect of geochemical reactions on CO_2 trapping and long-term porosity and permeability behaviour;
- the caprock and wellbore integrity;
- the impact of thermal/compositional gradients in the reservoir;
- the pathways that may allow CO_2 to migrate out of the main storage reservoir;
- the importance of secondary barriers;
- the effects of unplanned hydraulic fracturing;
- the extent of upward migration of CO_2 along the outside of the well casing;
- the impacts of cement dissolution; and consequences of wellbore failure.

The aim of flow modelling is different in each phase of the CO_2 storage project. During the pre-operational phase, simulation models are used to predict CO_2 plume migration and the effectiveness of solubility, residual gas (capillary) and mineral trapping. During operations, comparison between simulated and monitored plume migration are used to refine and calibrate the model, and then update forecasts of plume migration. This iterative approach is required to develop confidence in the prediction of plume behaviour. During the post-operational phase, a similar iterative approach is used to predict post-injection plume behaviour with a primary focus on quantifying the secondary trapping mechanisms that will eventually immobilise the CO_2.

One of the main purposes of developing predictive models is to confirm that the storage project is performing as planned/expected. Data collected during the early monitoring phase can be used to address potentials risks and mitigate circumstances when the project may not be performing adequately. Inconsistencies between field data and model predictions, which may suggest a leak, would trigger another level of monitoring to determine the CO_2 leakage pathway and the potential plume location and extent. The predictive model that is calibrated and refined using these data forms the basis for predicting longer-term performance. Model calibration and performance confirmation can be done by comparing model predictions with monitoring data. Therefore, parameters that will be monitored should include the data needed for this comparison such as downhole pressure, actual injection and production rates, 3-D seismic data, tracer data, data from geophysical logs, geochemical data from cores, and reservoir fluid test data, etc. Reservoir pressure data may be obtained either by downhole pressure sensors or estimated using surface pressure and injection data (NETL, 2009).

Besides CO_2 storage in the deep saline aquifers or depleted gas or oil reservoirs, the enhanced coalbed methane (ECBM) recovery with CO_2 storage is also modelled. In addition to monitoring, verification, and risk assessment of CO_2 storage in coal seams, optimisation of methane recovery using CO_2 is addressed by numerical modelling. ECBM simulators are used to define the physical and operational boundaries and trade-offs for safe and effective CO_2 storage and ECBM recovery. Simulations are used to determine the monitoring networks that are needed to predict both the migration of CO_2 and within the coal seam and the recovery of CH_4 from the coal seam.

A reservoir modelling study starts with the development of a geological model for the storage site that consists of the reservoir, the primary seals, and may include the overlying formation, shallow aquifer(s) and the vadose zone. Reservoir simulation models require site-specific geological parameters both physical (lithology, pressures, temperatures) and chemical (groundwater and formation fluid compositions, soil gas composition) to properly simulate plume fate and transport over time.

Modelling of the shallow groundwater will provide insights into groundwater flow directions and the potential for transport of groundwater that may be impacted by the CO_2 injection process and require migration off site.

3.1 Flow and transport mechanisms

The accuracy of flow models depends mainly on the quality of the input parameters and their capability in handling the following flow and transport processes that control the spread of CO_2 in the storage medium (Metz *et al.*, 2005):

- fluid flow (migration) in response to pressure gradients created by the injection process,
- fluid flow in response to natural hydraulic gradients,
- buoyancy caused by the density differences between CO_2 and formation fluids,
- diffusion,

- dispersion and fingering caused by formation heterogeneities and mobility contrast between CO_2 and formation fluid,
- dissolution into the formation fluid,
- mineralisation,
- pore space (relative permeability) trapping,
- adsorption of CO_2 onto organic material.

Some of the main flow processes of CO_2 are illustrated by Iding and Ringrose, 2009 in Fig. 3-1.

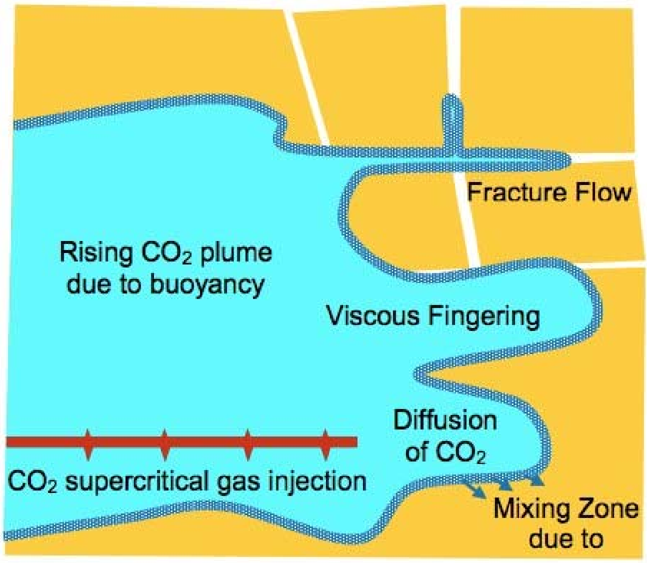

Fig. 3-1: Main flow and CO_2 transport mechanisms (Iding and Ringrose, 2009).

When modelling reservoir behaviour, it is important to consider and adequately represent the different geological formations within the storage system and their characteristics.

3.1.1 Structural trapping

The injected carbon dioxide tends to rise towards the top of the formation due to buoyancy forces, where it will be trapped by an almost impermeable caprock, such as shale. This is referred to as 'structural trapping'. A sealing cap rock is required to allow accumulation of CO_2 in a geological trap over a long time period. If the caprock contains fractures and/or faults, which may be connected to another permeable layer, it cannot act as a sealing boundary. Besides, it should be at a desired depth (> 800 m) to keep the CO_2 in supercritical state. The modelling of the amount and shape of the plume accumulated under a cap-rock depends heavily on the earth model.

3.1.2 Miscible vs. immiscible flow

Carbon dioxide injected into saline aquifers in a liquid or liquid-like supercritical dense phase does not mix with the host reservoir fluid and an immiscible flow occurs. The presence of two or more phases tends to decrease the effective phase permeability and thus slow down the rate of migration. On the other hand, if CO_2 is injected into a (depleted) gas reservoir, a single miscible fluid phase consisting of natural gas and CO_2 is formed locally. Van der Meer at al., 2009 states that although CH_4 and CO_2 are fully miscible, instant mixing does not seem to occur in the reservoir and therefore gravity segregation is an important factor for CO_2 storage in depleted gas reservoirs. Carbon dioxide injected into an oil reservoir may be miscible or immiscible with oil, depending on the oil composition and the pressure and temperature of the system. Under miscible conditions, the oil swells and becomes less viscous. As a result, it flows more easily leading to increased oil production. When this oil is pumped to the surface, CO_2 coming out of the solution is captured by surface facilities for further injection (Whittaker *et al.,* 2011). The flow of CO_2 in coalbeds is more complex because of shrinkage and swelling of the coal itself and the adsorption and desorption of the gases (Korre *et al.,* 2007, 2009).

3.1.3 Viscous fingering

Supercritical CO_2 is much less viscous than water and oil (by an order of magnitude or more) and this induces a considerable mobility difference between CO_2 and in-situ formation fluids. Due to this difference, only some of the oil and water can be displaced and viscous fingering can cause CO_2 to bypass much of the pore space, depending on the heterogeneity and anisotropy of rock permeability. Viscous fingering leads to an average saturation of CO_2 in the range of 30-60% left behind in the reservoir. On the other hand, viscous fingering is limited in the natural gas reservoirs since CO_2 is more viscous than natural gas. Lengler *et al*., 2010 recommends the use of 3D simulations when processes are active in two main planes, that is, gravity effects in the vertical plane and viscous fingering and channelling in the horizontal plane. Silin *et al*., 2009 and Lengler *et al*., 2010 stated that the dispersion of the front of the plume is caused by the heterogeneity, rather than a consequence of intrinsic instabilities such as viscous fingering.

3.1.4 Buoyancy

Injection of CO_2 into saline formations creates strong buoyancy forces because of the large density difference between CO_2 and the formation water. The strength of the buoyancy forces in oil reservoirs is not as high as in saline aquifers and depends on the miscibility of the CO_2 and oil. In oil reservoirs and saline formations, the buoyant CO_2 plume migrates upwards. With CO_2 being denser than the natural gas, the migration takes place in the opposite direction in a depleted gas reservoir.

3.1.5 Dissolution

Some of the CO_2 will dissolve into the formation water as it migrates through the formation. Simulation results show that up to 30% of the injected CO_2 may dissolve in formation water over tens of years (Doughty *et al*., 2001). Large scale models suggest that the injected CO_2 will eventually dissolve in formation water over centuries (McPherson and Cole, 2000; Ennis-King *et al*., 2003). It will take much longer for CO_2 to be completely dissolved, if there is no flow of formation water because of reduced contact with unsaturated formation water. Water saturated with CO_2 is slightly denser than fresh formation water, depending on salinity. Reservoir studies and simulations have shown that the denser CO_2-saturated brine will eventually sink, which may trigger free convection and thus enhance the CO_2 dissolution process (Lindeberg and Bergmo, 2003).

Solubility of CO_2 in brine decreases with increasing pressure, decreasing temperature and increasing salinity. Calculations indicate that, depending on the salinity and depth, 20–60 kg CO_2 can dissolve in 1 m^3 of formation fluid (Holt *et al*., 1995; Koide *et al*., 1995).

3.1.6 Residual trapping

Physical trapping can also occur as residual CO_2 is immobilised in the storage reservoir pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces. When the degree of trapping is high and the formation is thick, injection at the bottom of the formation may lead to complete trapping of the CO_2 stream. Holtz (2002) demonstrated that as high as 15-20% of the injected CO_2 can be trapped in pore spaces. Over time, the trapped CO_2 is expected to dissolve into the formation water.

3.1.7 Adsorption and Desorption

Preferential sorption occurs when CO_2 molecules attach to the surfaces of coal and certain organic-rich shales, displacing other molecules such as methane. Dynamic permeability models (Shi and Durucan, 2005; Palmer and Mansoori, 1996) account for the impact of matrix swelling (caused by CO_2 injection) as well as matrix shrinkage (caused by methane production or N_2 flooding) on the formation permeability and thus allow the absolute permeability of the seams to be updated at the end of each time step during a simulation run.

3.2 Overview of numerical models used in flow modelling for CO_2 storage

3.2.1 TOUGH2

TOUGH2 is a general-purpose numerical simulator for multi-phase, multi-component fluid and heat flow in porous and fractured media. It uses a multi-phase extension of Darcy's law that includes relative permeability and capillary-pressure effects and incorporates accurate phase-partitioning and thermo-physical properties of all fluid phases and components. TOUGH2 is capable of dealing with two-phase (liquid, gas), three-component (water, salt, CO_2) systems in pressure/temperature regimes above the critical point of CO_2.

3.2.2 TOUGHREACT

TOUGHREACT is an adaptation of TOUGH2 to reactive transport modelling that considers geochemical fluid-rock interactions during multiphase fluid flow. TOUGHREACT is designed to run with several equations of state routines, such as ECO2N that is developed specifically for treating CO_2-water-salt systems typically encountered in the case of CO_2 geological storage in saline aquifers.

3.2.3 ECLIPSE

Schlumberger's ECLIPSE 300 software is a compositional simulator that can handle CO_2 flooding, with the gas soluble in oil and water phases, for CO_2 storage under different conditions, including fractured reservoirs. Compositional simulation is useful when an equation of state is required to describe reservoir fluid phase behaviour or the compositional changes associated with depth and dissolution behaviour.

3.2.4 CGM

The Craig-Geffen-Morse (CGM) water flooding model uses geological and hydrological information, along with assumptions concerning CO_2/brine multiphase behaviour, as input to predict the evolving behaviour of the injected CO_2 through time.

3.2.5 CMG-GEM

Numerical simulations using reservoir parameters and a simple geomechanical model based on rock and fluid compressibilities can be performed with the commercial simulator GEM from Computer Modelling Group (CMG).

3.2.6 PumaFlow

PumaFlow is IFPEN's new generation reservoir simulator, featuring advanced physical formulations and high performance computing. It is based on a three-phase, three dimensional and multicomponent reservoir simulator for general purpose black oil and compositional simulations. It is designed to simulate a wide variety of production processes including miscible gas injection, CO_2 injection for Enhanced Oil Recovery (EOR), thermal production of heavy oil and chemical EOR (ASP). It allows the handling of complex geometries with unstructured grids and sub-gridding capabilities and includes an advanced dual medium formulation for the simulation of fractured reservoirs.

3.2.7 Coores™

Coores™ (CO_2 Reservoir Environmental Simulator) is a research code designed by IFPEN to study CO_2 storage processes from the well to the basin scale. With a structured or unstructured grid, Coores™ simulates multi-component three-phase and 3-D fluid flow in heterogeneous porous media. Molar conservation equations are solved with a fully coupled system linearised by a Newton approach. To take into account mineralogy changes, the transport model is coupled with a geochemistry reactor, Arxim. Permeability and capillarity pressure changes due to porosity variations are taken into account with different porosity-permeability and porosity-capillarity pressure laws such as Kozeny-Carman, Labrid or Fair-Hatch laws.

3.3 Flow Modelling in CO_2 Injection Operations

3.3.1 K12-B Gas Field

The K12-B gas field is located in the Dutch sector of the North Sea. The top of the reservoir lies approximately 3800 m below sea level. Since 1987, the K12-B gas field has been producing natural gas that has an initial CO_2 content of 13%. From 2004 onwards, part of the separated CO_2 is re-injected into the gas field and various tests have been performed in order to investigate various aspects of offshore underground storage of CO_2 in nearly depleted gas fields. These tests are focused on two objectives: the well integrity and the analysis of the migration of the CO_2 in the reservoir. Multi-finger imaging tools, cement bond log, down-hole video log, electromagnetic imaging tool, gamma ray and scale sampling methods were used to gain confidence on the well integrity. Another goal for the monitoring activities implemented at K12-B is to gain a better understanding of the behaviour of the CO_2 in the injection wells and the migration of the CO_2 in the reservoir. For this reason reservoir simulations have been updated several times over the years as more data become available. The bottom hole pressure and temperature data were taken by means of down-hole memory gauges. The measured pressure response to rapid rate changes is history matched by adjusting relative permeability. By changes in local permeability, well skin factors and water influx from the underlying aquifer, reservoir models were able to match the measured data. Vandeweijer *et al.,* 2011 concluded that the reservoir permeability is not affected by the CO_2 injection and the existing theoretical correlations and software applications are good at predicting the reservoir response and CO_2 phase behaviour. Audigane *et al.,* 2011 investigated the efficiency of CO_2 enhanced gas recovery at K12-B field using the TOUGHREACT simulator (Fig. 3-2). After 10 years of CO_2 injection, they concluded that the main trapping mechanisms at K12-B are structural and solubility trapping and there is little geochemical fluid-rock interaction.

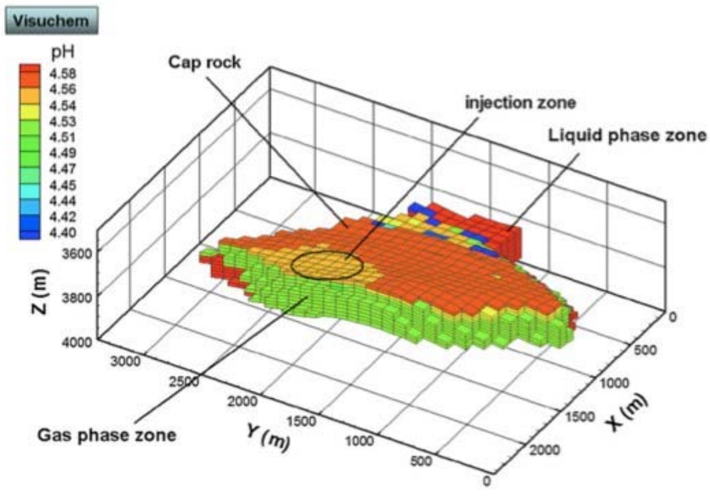

Fig. 3-2: The 3D visualization of reactive flow simulation of CO_2 injection in the K12-B field (Audigane et *al.,* 2011).

3.3.2 Weyburn and Midale Oil Fields

CO_2 injection has been widely applied for enhanced oil recovery (EOR) purposes at more than 70 sites worldwide. Injection of CO_2 into the Weyburn Oil Field of southeast Saskatchewan, Canada, began in 2000 with the intention of reversing the decline in oil production. After 10 years of CO_2 injection, oil production in this 50 year old field has increased by 60%. Moreover, it has been estimated that about a further 155 million barrels of incremental oil may be recovered that will extend the life of the field by more than 30 years. Similarly, in the adjacent Midale Oil Field, full field CO_2 injection began in September 2005 with a forecast 60 million barrels of incremental production over a period of 30 to 40 years. The Great Plains Synfuel Plant near Beulah produces 13,000 tonnes of CO_2 daily as a by-product of lignite gasification, 60% of which (8,000 tonnes) is injected in the Weyburn and Midale Fields. More than 18 Mt of greenhouse gases are currently stored in these two depleting oil fields, with an expected ultimate combined storage of around 40 Mt CO_2 (Whittaker *et al*., 2011).

A research program has been developed for the Weyburn EOR project with the aim of achieving a better understanding of the processes associated with long-term geological storage of greenhouse gases. The programme has four main themes: 1) geological characterisation; 2) prediction, monitoring, and verification of CO_2 movements; 3) CO_2 storage capacity and distribution predictions and application of economic limits; and 4) long-term risk assessment of the storage site. Different aspects of the EOR project have so far been studied in over 50 research projects. Within the Weyburn-Midale region (40 x 50 km) there are more than 4,000 wells that penetrate to reservoir-level depths. Due to the large number of wells in the study area, a less conventional approach to flow modelling - invasion percolation methodology - has been employed. The invasion percolation model constructed for Weyburn contains 2 billion cells of 20×20×5 m. During the initial phase of the project (2000 to 2004), a deterministic numerical simulation approach was used to model the migration of the injected CO_2 for 5,000 years. A significant number of publications have been generated from the studies including recently published papers in the GHGT-10 conference (Hawkes *et a*l., 2011; Rostron and Whittaker, 2011; White and Team, 2011). During the Weyburn final phase project, the evolution of reservoir brine chemistry has been studied and is used to show the role of fractures in controlling flow. This is expected in forthcoming publications.

3.3.3 The Frio Brine Pilot Experiments

The Frio Brine Pilot Experiment was designed to test storage performance of a typical subsurface environment in an area where large-volume sources and sinks are abundant, near Houston, Texas, USA (Fig. 3-3). The experiment site had two wells, a down-dip injector and a dedicated observation well, which is 30 m up-dip of the injector. A relatively small volume of pure CO_2 (1,600 tonnes) was injected over a 10-day period into a high-permeability brine-bearing sandstone at 1500 m depth.

Reservoir simulations were carried out at each stage of the pilot using TOUGH2. Initial modelling was carried out to help design the experiment using probabilistic realisations constrained by predicted ranges of fluid properties and rock heterogeneity. As site-specific data became available, they were incorporated into the model. Model results were used to select the field site and the placement of the new injection well relative to the existing well (used as an observation well), to define the perforation and injection zone, and to optimize the volume and duration of injection. Simulated saturations of CO_2 were used to select appropriate monitoring tools.

Numerical simulation also showed that significant amounts of CO_2 would be trapped during the post-injection stage as the relative permeability to gas would decrease over time (two-phase trapping) (Hovorka *et al*., 2006). In addition, the modelling work has helped to identify significant areas of uncertainty that need to be resolved by field testing. Another usage of the flow model was to consider the heterogeneities that exist in the formation. Models show that CO_2 moves into the rock volume with a relatively smooth front at a rate proportional to zone permeability (Hovorka *et al*., 2005).

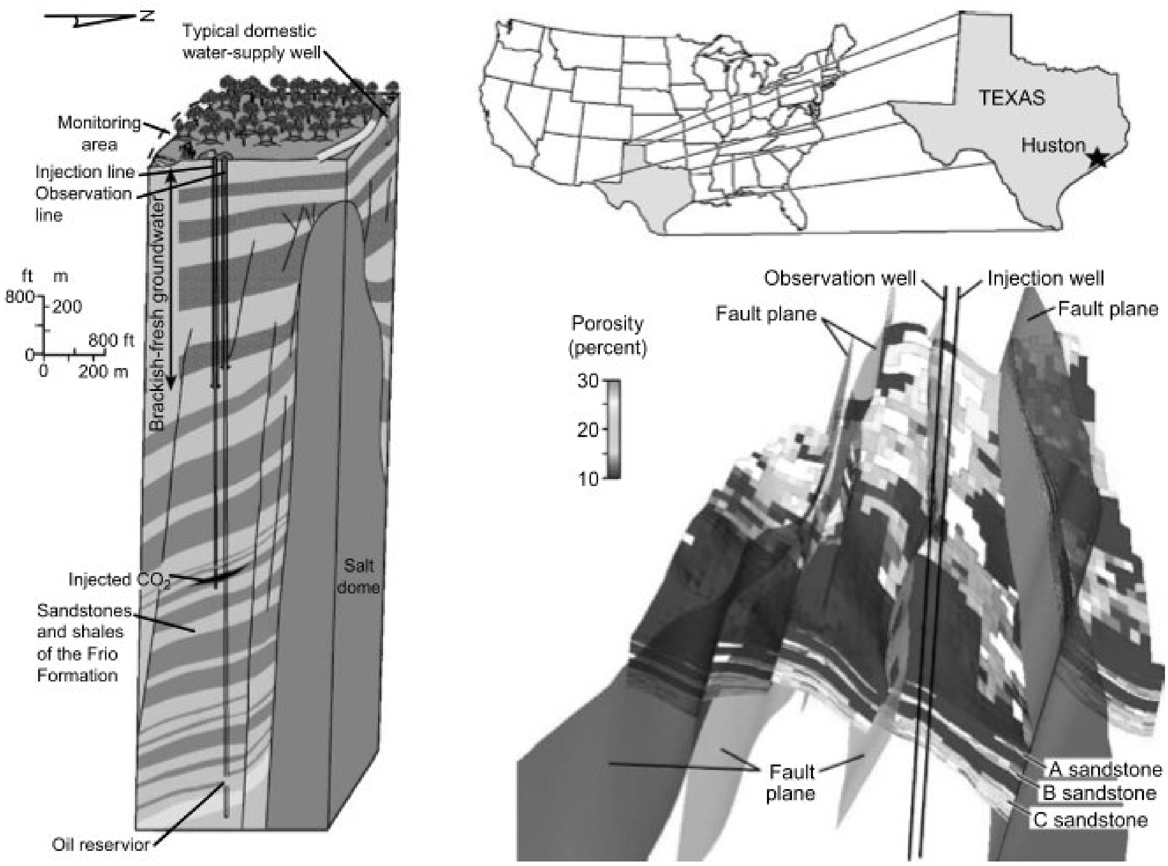

Fig. 3-3: Frio experimental site setting showing geologic context near South Liberty Salt Dome and detail of injection well location in a gridded reservoir model made using seismic data of the fault block (Hovorka *et al*., 2006).

In the period between September and October 2006, the Frio-II brine pilot injected about 380 tonnes of CO_2 into the Blue sand of the Frio Formation. This 5-day injection was at the same site as the Frio-I pilot, but 150 m deeper (1657 m). The fluvial Blue sand is 17m thick, has a dip of 18°, approximately 30% porosity and permeability of 1 to over 4 Darcies. This small-scale pilot test was used to calibrate models and techniques, at an intermediate scale between core/logs and surface seismic methods, for extrapolation to the larger scales. An accurate model of the plume extent and spatial distribution in a small-scale pilot adds confidence to the model estimates of the key properties such as residual CO_2 saturation and the associated reservoir CO_2 storage capacity. Monitoring provides constraints to improve the model accuracy, but often the only quantitative measurements available are CO_2 'breakthough' time and downhole P/T at an observation well with the addition of sparsely conducted well logs. Daley *et a*l. 2011 integrated the cross-well continuous active-source seismic monitoring (CASSM) data with the reservoir model to obtain an improved model of the CO_2 plume and the reservoir properties.

3.3.4 Nagaoka Pilot Site

A pilot project of CO_2 storage was conducted at an onshore site in Nagaoka, Japan. The target aquifer was early Pleistocene sandstone, which is around 60 m thick and found at 1100 m below the ground surface. During the 554-day injection period, which commenced in 2003, around 10,400 tonnes of CO_2 were stored. Three monitoring wells were completed around an injection well and several monitoring schemes, including continuous measurements of pressure and temperature, well logging, crosswell tomography, and in situ fluid sampling, were employed (Sato *et al*., 2010). Flow simulation provided valuable insights into the process of macro- and meso-scale migration.

The 4 km × 4.4 km area was taken as the simulation space domain and was discretised using LGR (local grid refinement) with the 5 m × 5 m grid blocks covering the test area. To represent formation heterogeneity, the aquifer was split into seven grid layers, based on the layering by well correlation. The total number of grid blocks of the model was approximately 100,000. Pore volume modifiers were applied to the boundary grid blocks representing the exterior extension of the formation.

In the early years of the project, simulation studies were performed to examine the technical feasibility of the planned injection scheme and to optimise the locations of three observation wells, as well as to examine the technical feasibility of the injection scheme. The simulation studies using the petro-physical data from the injector (IW-1) showed the injected CO_2 would spread in a nearly circular area. The provisional locations of the observation wells were determined based upon the numerical simulation results.

To interpret the observation data collected from various monitoring tools and assess probable distributions of the injected CO_2, history matching was carried out during the injection period and then repeatedly after 3 years of monitoring. The observed data used in the history matching were monitored bottomhole pressures, free CO_2 arrival times to the observation wells, and approximate CO_2 distributions, which was estimated through crosswell seismic tomography (Sato *et a*l., 2010).

3.3.5 Sleipner CO_2 Storage Project

The Sleipner CO_2 storage project is the world's largest and longest running Carbon Capture and Storage (CCS) project. The Sleipner fields are situated in the Norwegian North Sea. They produce gas with a high CO_2 content from Jurassic and Tertiary reservoirs. The CO_2 is separated from the hydrocarbons at the Sleipner T platform and, since 1996, 13 million tonnes of CO_2 have been injected into the Utsira Formation of Miocene age. This formation consists of up to 300 m thick sandstones with 90 – 98 % sand content, with average porosity of 35 – 40 %, net/gross ratio of 0.90 – 0.97, and permeabilities in the 1-8 Darcies range. The subsurface CO_2 plume has been monitored from the surface by six time-lapse seismic surveys. Chadwick *et al*., 2009 presented seismic images of the CO_2 plume at Sleipner showing its development up to 2006 (Fig. 3-4). The first repeat seismic survey (1999) revealed that migrating CO_2 had spread to nine distinct layers – one of these lying above a 5 - 6.5 m thick shale. The migrating CO_2 cumulating under the low-permeability layers appears to have been fed from a central vertical feeder, which is referred as a seismic chimney in the seismic data. (Alnes *et al*., 2011; Hermanrud *et al*., 2009).

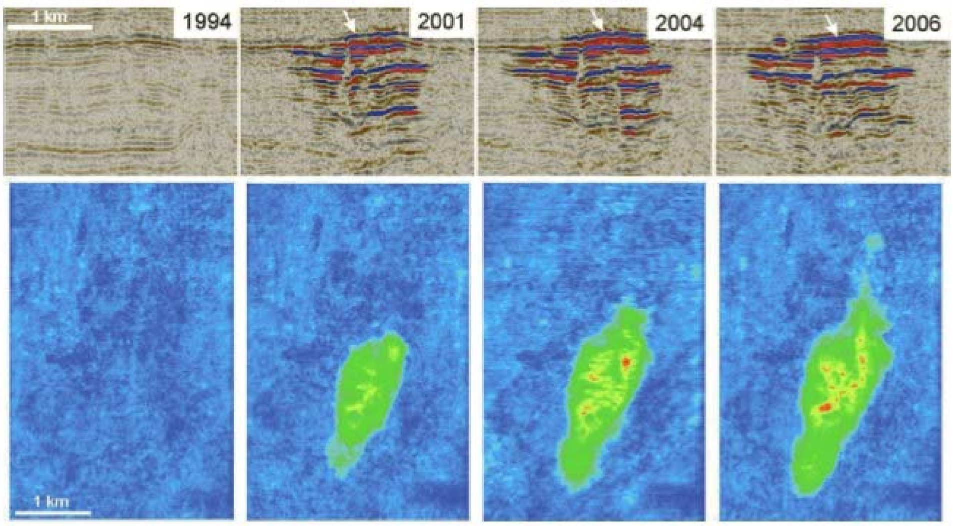

Fig. 3-4: Seismic images of the Sleipner plume showing its development to 2006. Top) N-S seismic section through the plume. Topmost CO_2 layer arrowed. Bottom) plan views of the plume showing total integrated reflection amplitude (Chadwick *et al*., 2009).

Instead of a complex numerical approach, Bickle *et al.,* 2007 studied CO_2 migration and accumulation at the Sleipner storage site in the North Sea using modified well-known solutions for (axisymmetric) gravity flows within a permeable medium. The results indicate that CO_2 accumulation under the shallower low-permeability layers within the reservoir started sometime after the start of injection of CO_2 in the field. Modelling of the time variation of thickness in two of these layers indicated that their CO_2 input increased with time. Conversely, under the deeper layers net CO_2 inputs appear to decrease with time. It seems most probable that the deeper layers progressively leaked more CO_2 through their thin caprock mudstones with time and the growth of the overlying layers reflects this increasing supply of CO_2 from below.

The reactive transport modelling study conducted by BRGM (Picot-Colbeaux *et. al.,* 2009) using TOUGHREACT showed that after three years of injection, the primary trapping process is the geological structure of the system. The upward migration of the free CO_2 due to buoyancy forces is prevented by the low-permeability shale layers but mainly by the caprock formation overlying the reservoir aquifer. The dissolution mechanism is also modelled and it was seen that although the solubilisation had started, it did not represent more than 10% of the injected CO_2 amount (Audigane *et al*., 2011).

One of the studies to understand plume evolution and storage performance is performed by Chadwick and Noy (2010). The need for the adjustments on the capillary entry pressure and the permeability of the intra-reservoir mudstone in a 2D THOUGH2 flow model (Fig. 3-5) in order to match the observed arrival time of CO_2 at top of the reservoir, showed that CO_2 migration through the mudstones is actually not by Darcy flow but via some form of pathway flow, possibly associated with networks of small faults or perhaps holes. According to the 3D THOUGH2 flow model, the increased CO_2 fluxes to the topmost layer suggest that the feeder pathways are evolving, becoming either more transmissive with time and/or increasing in number. The history match of the lateral spreading rates could be achieved by using very high anisotropic permeabilities as can be seen in Fig. 3-6.

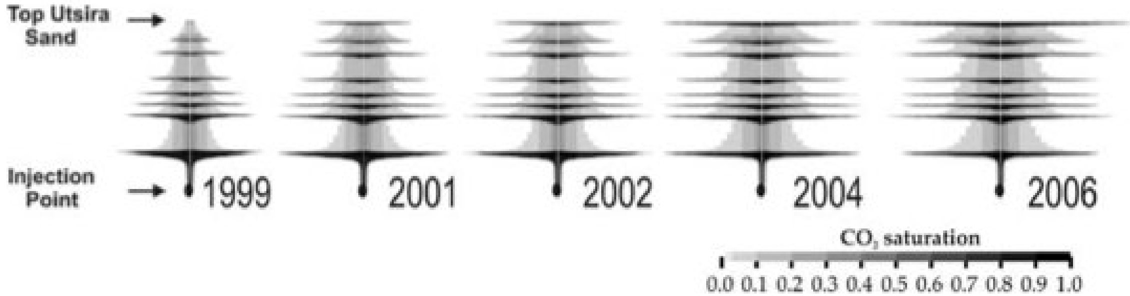

Fig. 3-5: Simulated growth of the CO_2 plume from 1999 to 2006 from the THOUGH2 axisymmetrical flow model (Chadwick and Noy, 2010).

Migration of CO_2 through permeable pathways, formed by overlapping turbidite lobes or channels, in otherwise sealing cap-rocks has been modelled by Grimstad *et al.,* 2009. The simulation results are then fitted using an analytical expression. It was concluded that the longer it takes the CO_2 to migrate to the surface, the larger the lateral spread of the CO_2 plume would be.

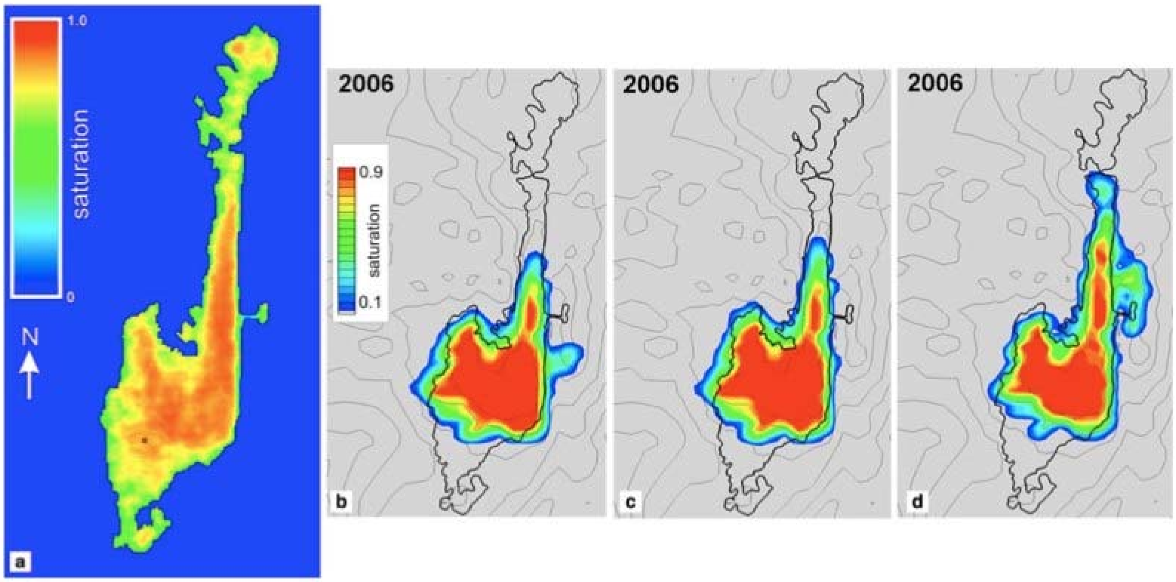

Fig. 3-6: The topmost layer in 2006. a) observed extents; b) THOUGH2 simulation with k=6 Darcy; c) THOUGH2 simulation with k=3 Darcy east-west and 10 Darcy north-south; d) THOUGH2 simulation with k=3 Darcy east-west, 10 Darcy north-south and higher reservoir temperature (Chadwick and Noy, 2010).

3.3.6 In Salah CO_2 Storage Project

The In Salah project in Algeria is an industrial-scale CO_2 storage project that has been in operation since 2004. CO_2 from several gas fields, which have a CO_2 content of 5-10%, is removed from the production stream to meet the gas export specification of 0.3% CO_2. Rather than vent the separated CO_2 to atmosphere (as was normal industry practice for such gas plants), joint venture (JV) partners invested an incremental $100 million in a project to compress, dehydrate, transport, and inject about 70% of that CO_2 into a deep saline formation down-dip of the producing gas horizon. The injection formation is a 20 m thick Carboniferous sandstone, 1900 m below ground with around 15% porosity and 10 mD permeability (Fig. 3-7). Three state-of-the-art horizontal CO_2 injection wells were drilled perpendicular to the minimum horizontal stress direction, and therefore the dominant fracture orientation, to maximise the injection capacity. By the end of 2008, over 2.5 million tonnes of CO_2 had been stored underground.

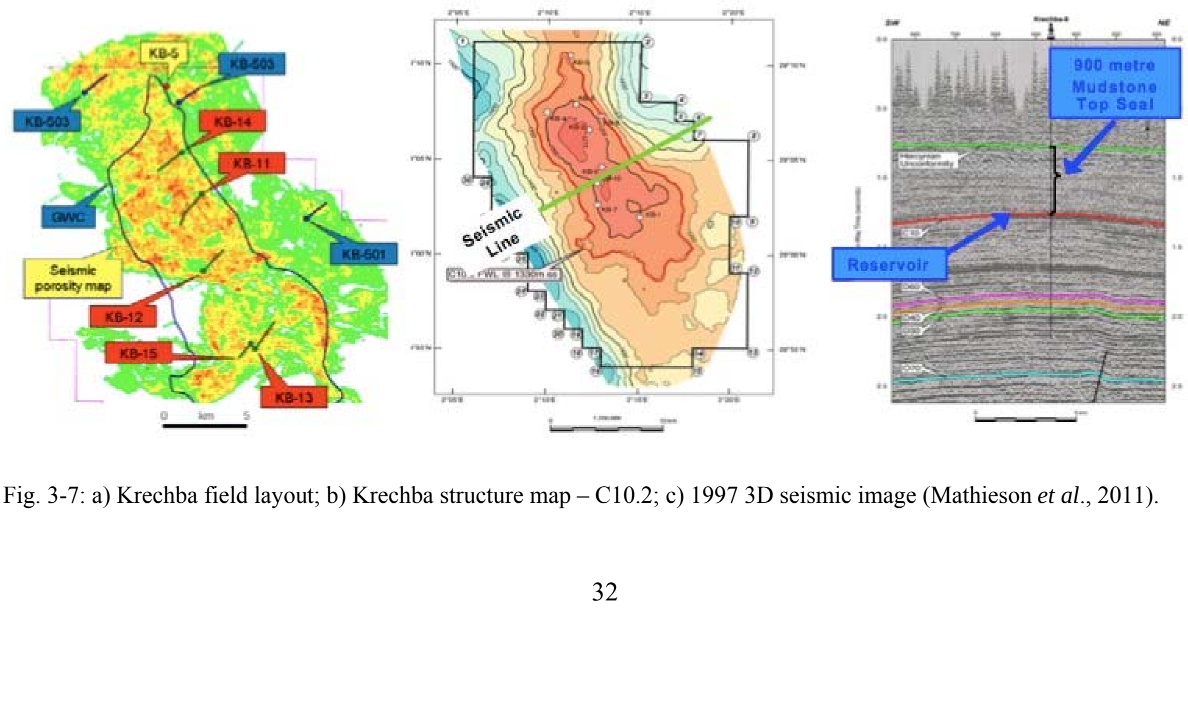

Fig. 3-7: a) Krechba field layout; b) Krechba structure map – C10.2; c) 1997 3D seismic image (Mathieson *et al*., 2011).

The interferometric synthetic aperture radar (InSAR) technique has been used to measure the surface movement caused by CO_2 injection in the In Salah CO_2 storage project (Vasco *et al*., 2008). Surface uplift has been detected over all three of the In Salah CO_2 injection wells with corresponding subsidence also observed over the gas production area. The distinctive two-lobed uplift pattern over KB- 502 suggests the tensile opening of a structural discontinuity at depth. Shi *et al.* (2012) conducted a simulation study by history matching the dynamic behaviour of the fault (zone) transmissibility with the estimated flowing bottom-hole pressure at KB-502. The results are found to be consistent with the stress analysis and the field observations as shown in Fig. 3-7. Specifically, it is believed that, prior to March 2006, the two-lobed surface response is primarily caused by CO_2 injection induced tensile reactivation of a non-sealing fault zone and its subsequent confined growth (lateral propagation and widening) within the C10 formation. The increasingly pronounced uplift pattern observed after March 2006, against a steady decline in the FBHP, is predominantly the result of localised CO_2 migration into and pressurisation of a fracture (or fault damage) zone in the lower caprock at the top of the tight sandstone formation (C10.3) overlying the main storage reservoir (C10.2) by the elevated injection pressure.

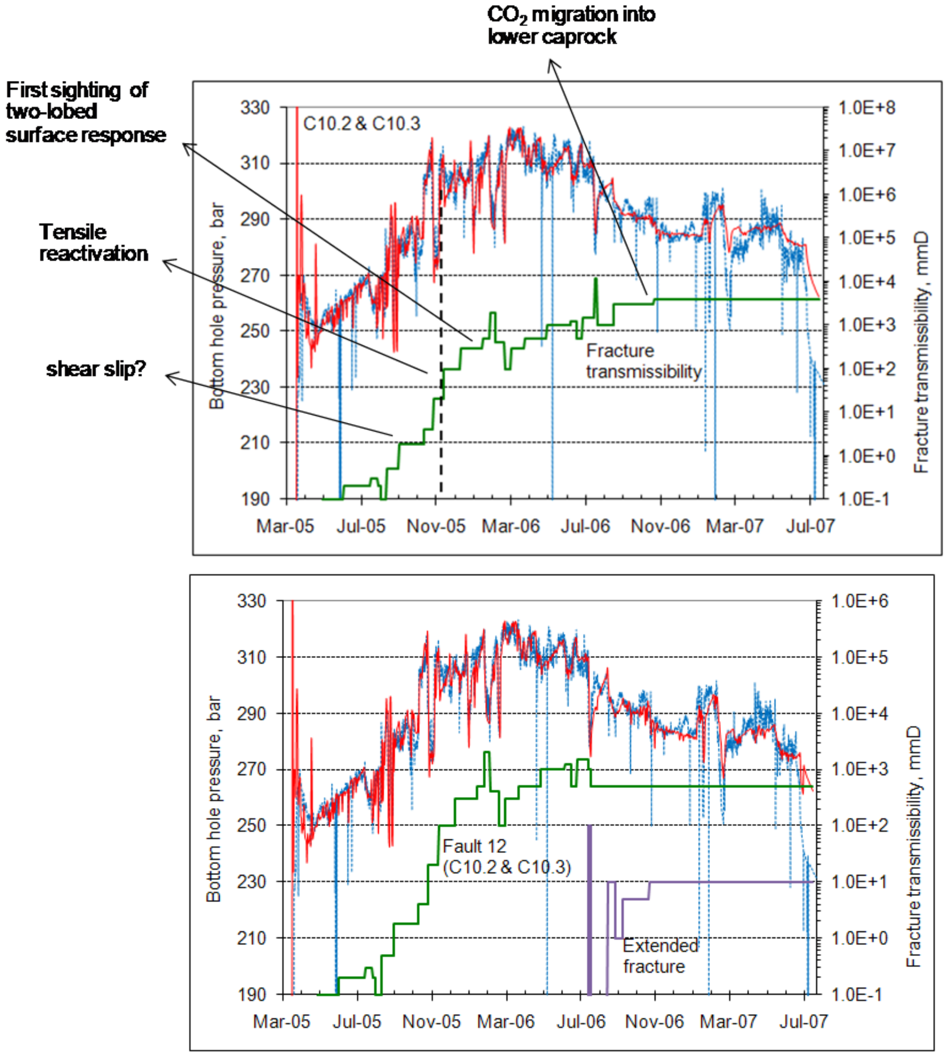

Fig. 3-8: History matching of the JIP field BHP using dynamic fracture transmissibility: a) fracture growth confined to C10.2 and C10.3; b) implementation of vertical fracture extension (Shi *et al*., 2012).

3.4 Conclusions

Understanding the fate of the injected CO_2 in the storage reservoir is a complex task. One of the methods that can be used to evaluate the mechanisms that control the behaviour of CO_2 is flow modelling. The computer simulation technology developed for the petroleum industry has been used for geological CO_2 storage as well. However, the requirement to develop new simulators that can handle the flow and transport mechanisms specific to CO_2 storage mediums and scenarios is unavoidable. Considerable progress has been made in modelling the spread of a CO_2 plume in the reservoir, which could be used in every phase of a CO_2 storage project. The use of the simulators to model current large-scale projects gives fruitful results and, of course, new challenges for the prediction of plume behaviour.

4 REACTIVE FLOW MODELLING

During the site selection phase, modelling is an essential tool for the design of an injection and long-term storage plan assisting in the assessment of storage capacity, injectivity, plume evolution, trapping phases and caprock integrity. Although modelling parameters and modelling objectives are site specific and dependent on the regulations in place, modelling results are and will continue to be used by regulators and decision makers. Modelling plays a major role in the injection and post injection phases of a CO_2 storage project.

This chapter presents reactive transport modelling which is essential to predict spatial and temporal evolution of injected CO_2 and related gas-fluid-rock interactions and assess well integrity.

4.1 Reactive flow and transport modelling for CO_2 storage

Long-term estimates of trapping mechanisms introduced in the previous chapters, *i.e.,* structural, solubility and mineral trapping, require the development of a reactive transport model able to accurately describe hydrodynamic and geochemical processes (Audigane, *et al.,* 2007). The potential geochemical feedback on physical properties through highly coupled processes has been recognised as being of great importance for CCS (*e.g.* Czernichowski-Lauriol *et al*., 1996). During recent years, chemical and solute transport modelling for CCS has made significant progress, building upon the earlier coupled flow models developed for both geothermal systems and radioactive waste disposal. Reactive modelling has evolved from simple, chemical, batch models assuming only interactions between CO_2 dissolved in brine and host rocks, without taking into account any flow aspects, to complex three-dimensional fully coupled chemical and flow models accounting for the geological complexity of the storage reservoir and caprock(s) (Gaus *et al*., 2008).

Current solute transport model codes consider either two components (*e.g.* CO_2, fluid) or three components (CO_2, oil, fluid) as well as density dependent flow, dissolution of CO_2, chemical speciation, dissolution of minerals of the host rock and precipitation of new secondary phases, and porosity changes in the host rock as a consequence of these processes. To address these processes the equations of conservation of energy, momentum, mass and solute mass, together with constitutive laws are coupled in either an implicit or an explicit manner (Gaus *et al*., 2008).

The success of CO_2 storage and its worldwide deployment might largely depend on the understanding of the interaction of CO_2 with fluids and minerals within the reservoir for thousands of years. Saline reservoirs in sedimentary basins constitute one of the best targets for the CCS projects due to their massive storage capacity. The formation waters in these reservoirs are characterised by salinities ranging from 5,000 to > 350,000 mg/L dissolved solids. They cannot be considered as water resource because they usually contain dissolved species *e.g.* metals and organic components (Kharaka and Hanor, 2007). The chemistry of these waters is the result of various different hydrogeochemical processes. Hence, the injection of CO_2 into such reservoirs constitutes an additional process that influences the chemistry of these waters and increases the chemical reactivity of the system. Although dry CO_2 does not react, wet CO_2 reacts and forms a weak acid (H_2CO_3) that almost immediately dissociates. This makes the pH of the brine to decrease.

$$CO_{2(g)} + H_2O \leftrightarrow CO_{2(aq)} + H_2O \; H_2CO_3^{\circ} \leftrightarrow HCO_3^- + H^+ \leftrightarrow CO_3^{2-} + 2H^+$$

The above series of linked reversible reactions is controlled by in-situ temperature, pressure and salinity. As stated in Gaus *et al*. (2008), there is evidence that dissolved CO_2 may have an important impact during

CO_2 storage operations and, may influence the success or failure of a carbon storage project. Once injected, CO_2 dissolves into the fluids present in the formation and might induce geochemical reactions in the reservoir, the well infrastructure and the reservoir caprock that need to be fully evaluated. From enhanced oil recovery (EOR) operations, there is indirect evidence of geochemical reactions in the near-well environment causing injectivity difficulties (Czernichowski-Lauriol *et al.*, 1996). Generally, injectivity changes are poorly explained and have been tentatively attributed to multiphase flow, CO_2/oil interactions and/or CO_2/mineral interactions (Cailly *et al*., 2005). Only occasionally, increased injectivity is observed. Evidence of geochemical interactions caused by the presence of CO_2 in geological sequences where CO_2 occurs naturally (*e.g.* natural CO_2 storage analogues) is particularly valuable since it illustrates the long-term impact of CO_2 on natural rocks that cannot easily be reproduced during experiments or short-term field tests. In some natural analogues, chemical equilibrium is not reached, even over very long (geological) contact times (Haszeldine *et al*., 2005). This suggests that chemical equilibrium might not be attained during the expected lifetime of a CCS storage site, *i.e.*, thousands to hundreds of thousands of years (Gaus *et al*., 2008).

4.2 Objectives of geochemical modelling in CO_2 geological storage

The study of rock-CO_2-fluid chemical interactions is essential to assess storage integrity. It allows evaluation of the injected CO_2 behaviour, and thus provides a guide for monitoring during and after injection. Storage integrity issues which may be addressed by reactive transport modelling of CO_2 and fluid flow in the subsurface include: confinement in the injection zone, CO_2 partitioning into the rock and fluid phases via mineralisation and dissolution, and potential impacts to groundwater from CO_2 leakage.

In the previous chapter, various modelling codes allowing the modelling of chemical processes in the subsurface have been described. These models range from equilibrium models, reaction-path models and kinetic models, to coupled reactive transport models. Reactive transport models account for the coupling between transport and chemical reaction. They are thus more computationally intensive than non-coupled codes because of additional reactions, multiple variables and associated degrees of freedom (NETL, 2011).

Gaus *et al.* (2008) have identified three main application domains when assessing the geochemical impact of CO_2 storage. They are presented in the following sub-sections.

4.2.1 Long-term integrity modelling

Modelling of long-term integrity aims to assess the ultimate fate of the injected CO_2 and its impacts on physical properties. Four processes are distinguished: structural trapping, residual CO_2 trapping, dissolution trapping and mineral trapping, described in the previous chapter.

Structural trapping represents the supercritical CO_2 that is trapped within the pore space as a buoyant immiscible fluid phase, according to the heterogeneity of the storage zone lithology. Residual CO_2 trapping represents the supercritical CO_2 that is permanently trapped within small pores and cannot be remobilised. Dissolution trapping represents the CO_2 dissolved in the liquid phase (oil or fluid). The final mechanism, mineral trapping, represents the CO_2 that is incorporated into new secondary minerals due to chemical precipitation (Gaus *et al.*, 2008).

Long-term integrity modelling aims to predict the ultimate fate of the injected CO_2, accounting for the geometry of the reservoir in a simplified way. Studies can thus be based on one-dimensional (Knauss *et al.*, 2005; Xu *et al.*, 2005), two-dimensional (Audigane *et al.*, 2007; Johnson *et al.*, 2001; White *et al.*, 2005) or three-dimensional (Nghiem *et al.*, 2004; Le Gallo *et al.*, 2006) transport. As long as geometries remain simple, it is possible to identify dominant geochemical interactions from the calculated species concentrations and the amounts of minerals dissolving and precipitating. This is also true for two-dimensional models involving a slightly more complex geology (Johnson *et al.*, 2001, 2004; Audigane *et* *al.*, 2007). Gaus *et al.* (2008) noted, that when the complexity of the model grid and the number of layers increase, identification of dominant geochemical reactions becomes increasingly difficult.

4.2.2 Injectivity modelling

When modelling the injectivity phenomena, the time scale of interest is the injection period itself and generally, the space scale is limited to only the immediate environment surrounding the borehole. The main purpose of injectivity modelling is to assess if the physical and chemical properties of the well are not being affected by the injected CO_2 (Fig. 4-1). One area of current concern investigated by coupled modelling is the potential for porosity changes due to geochemical interactions (André *et al.*, 2007; Bacci *et al.*, 2009a; Bacci *et al.*, 2011) and how this affects the injectivity (Gaus *et al.*, 2008, Bacci *et al.*, 2009b; Bacci *et al.*, 2012; Bacci *et al.*, 2013).

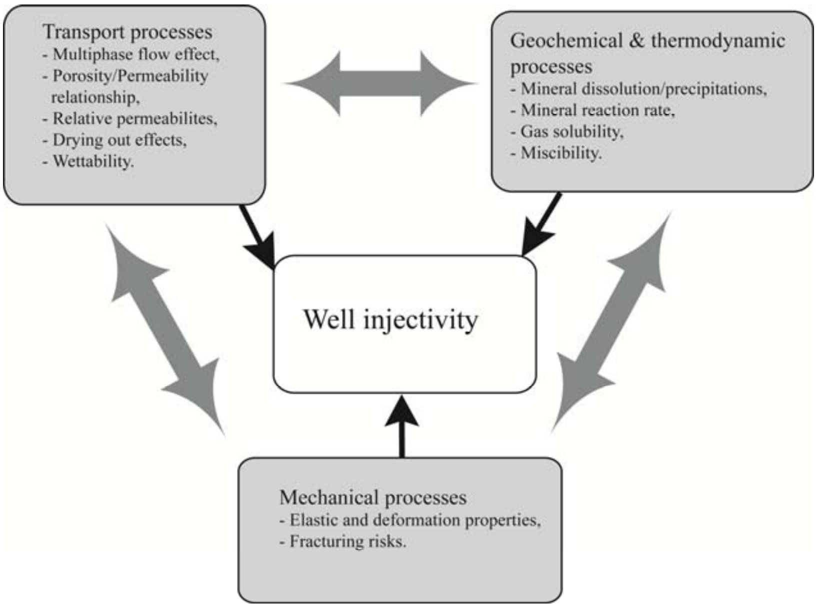

Fig. 4-1: Main processes involved by CO_2 injection, interactions between them and qualitative influence on well injectivity (Gaus *et al.,* 2008).

A detailed knowledge of the reservoir and processes expected to occur near the vicinity of the injection well during the injection phase is required. An injection of millions of tons CO_2 per year may cause thermal, hydraulic, and mechanical as well as chemical perturbations around the area of the injection well (Gaus *et al.*, 2008). Code TOUGHREACT (Xu *et al.*, 2006) has been applied to study the behaviour near the well during supercritical CO_2 injection (André *et al.*, 2007). The results demonstrated that the chemical processes vary accordingly to the distance from the injection well. In the case of CO_2 injection, the possible development of a dry-zone, centred round the injector (Regnault *et al.*, 2005) has to be considered: salt precipitation in the near vicinity of the injector might induce a decrease in porosity and consequently affect well injectivity (André *et al.*, 2007; Bacci *et al*., 2011, 2013).

4.2.3 Well integrity modelling

Well integrity modelling focuses on the geochemical impacts of CO_2 on the well completion itself. Well completions are made of a sheath of cement surrounding a casing (*i.e.,* pipe) made of steel. The cement sheath seals the annulus between the casing and the borehole walls and prevents the migration of fluid between the formation rocks and the casing. Cements are also used to plug the casing in case of well abandonment. Over its life, the cement is exposed to fluids of varying composition (*e.g.* saline brine, CO_2-

rich phase fluids, two-component fluids). Chemical interactions will occur between the brine, the gas mixture and the cements and borehole steels. A typical reaction sequence is the carbonation of the constituent cement minerals by CO_2. This reaction may impact the cement mineralogy and porosity and thus its transport and mechanical properties. For example, reaction may cause an increase of permeability, diffusivity, increased fissures and annular space between the casing and the cement sheath, thus creating paths for leakage to surface (Gaus *et al*., 2008).

For CO_2 storage purposes, modelling of well cement degradation due to the presence of CO_2 needs to be performed at low, acidic pH values. Jacquemet (2006), Carey and Lichtner (2007) and Carey *et al.* (2007) have modelled cement degradation using one dimensional models without accounting for the geometry of the well itself. Two studies, conducted by Pfingsten (2002) and Burnol *et al.* (2006), although conducted for nuclear waste purposes, are recommended by Gaus *et al.* (2008) since carbonation of cement is modelled. Pfingsten (2002) emphasises the need for additional data linking permeability and diffusivity to porosity, since carbonation is likely to significantly decrease porosity (Thiery, 2005; Jacquemet, 2006). As concluded by Burnol *et al.* (2006), future modelling should also account for possible carbonation in two-phase conditions, *e.g.* by intrusion of gas within the cement. Regnault *et al.* (2005) and Jacquemet (2006) demonstrated experimentally that significant carbonation can also occur in complete absence of brine. In addition, reactions with other gaseous components, such as SO_2 and SO_3, and cement should also be considered.

4.3 Geochemical modelling codes for CO_2 storage applications

A number of geochemical modelling codes have been used for CCS related work. TOUGHREACT is an enhancement of the multiphase fluid and heat flow code TOUGH2 to reactive transport (Xu and Pruess, 2001). The version developed by Xu *et al.* (2006) allows modelling of supercritical CO_2 injection in a reservoir by considering hydraulic processes, thermal variations and chemical phenomena. Both dissolution and precipitation processes are integrated within this code, together with a feedback mechanism for porosity and permeability changes. Other modelling codes continue to be developed; SIMUSCOPP was introduced by Le Thiez *et al*. (1996), STOMP by White and Oostrom (2006), HYTEC code by Lagneau *et al*. (2005). Johnson *et al*. (2001, 2004) developed a software package based on the codes of NUFT. Audigane *et al*. (2006, 2007) have presented a 2D axial model using TOUGHREACT and 3D model using TOUGHREACT and code TOUGH2/EOS7C (Audigane *et al*., 2009), White *et al*. (2001, 2005) have developed the reactive transport code CHEMTOUGH and Nghiem *et al*. (2004) have developed and used the commercial code GEM-GHG.

4.4 Reactive transport modelling applications

Xiao *et al.* (2009) summarised the advances in reactive transport modelling of CO_2 storage and reviewed the key technical issues on; (1) the short- and long-term behaviour of CO_2 injected in geological formations; (2) the role of reservoir mineral heterogeneity on injection performance and storage security; (3) the effect of gas mixtures (*e.g.* H_2S and SO_2) on CO_2 storage; and (4) the physical and chemical processes acting in case of CO_2 leakage from the primary storage reservoir.

Using the TOUGHREACT reactive transport modelling code, Xiao *et al.* (2009) investigated mixed $CO_2/H_2S/SO_2$ injection and storage in both siliciclastic and carbonate reservoirs for a 1D radial reactive transport model design simulating CO_2 injection 2 km depth and 70°C temperature in a siliciclastic and carbonate reservoir. CO_2 and other gases were injected into the reservoir at a rate of 1 million tonnes per year over a 100 years period. The reactive transport models simulate the system from 0 to 10,000 years. Three scenarios of mixed gas injections were selected: (a) CO_2 only, (b) $CO_2 + H_2S$, and (c) $CO_2 + SO_2$, in which CO_2 is injected as gas phase while both H_2S and SO_2 (~5% each) are injected as aqueous solutes.

The reservoirs are specified to have an initial porosity of 30% and an initial permeability of 100 mD. The siliciclastic and carbonate reservoirs were defined by hypothetical mineral assemblages, representing an oligoclase feldspar-rich sandstone reservoir and a limestone-rich reservoir (Xiao *et al.* 2009).

Simulations provided estimates of pH evolution, mineral dissolution/precipitation and CO_2 storage for sandstone reservoir injections and pH evolution and mineral dissolution/precipitation for carbonate reservoir injection. The evolution of porosity was modelled for both reservoirs (Fig. 4-2 and 4-3). In the siliciclastic reservoir, whatever the injected gas is (CO_2 only, CO_2 + H_2S, and CO_2 + SO_2), injection induces an increase of porosity (that is much more important in case of CO_2 + SO_2) close to the well due to net mineral dissolution, and a decrease away from the well due to mineral trapping in all three cases (Xiao *et al.* 2009). In the carbonate reservoir, a significant increase of the porosity (30% to 40% after 100 years) is observed when CO_2 or CO_2 + H_2S is injected due to calcite dissolution near the well bore. These results indicate that there is little mineral trapping in all three mixed gas injection scenarios, suggesting limited CO_2 storage capacity in a limestone dominated carbonate reservoir. Xiao *et al.* (2009) concludes that reactive transport modelling provides valuable insights for describing, analysing, interpreting, and assessing the physical properties and dynamic behaviours of injected CO_2 as well as for facilitating the screening and evaluation of CO_2 storage strategy.

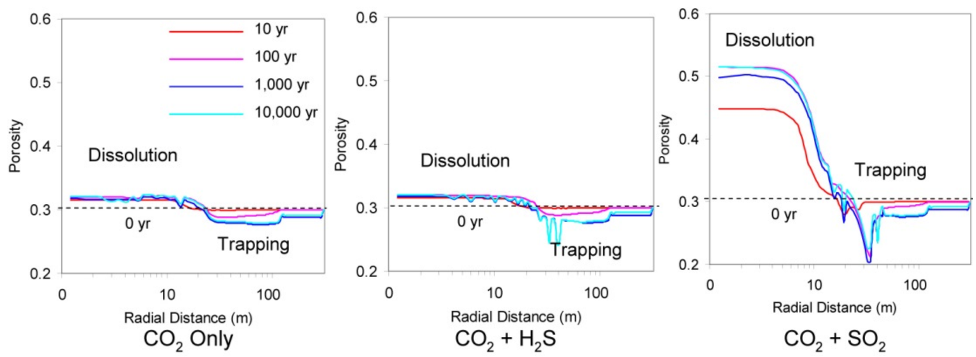

Fig. 4-2: Porosity evolution as a function of radial distance simulated at 10, 100, 1,000, and 10,000 years for the mixed gas injection scenarios in a siliciclastic reservoir (Xiao *et al.*, 2009).

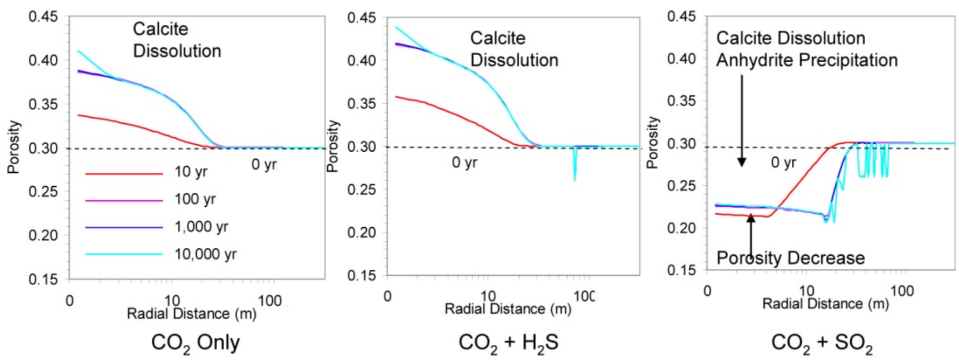

Fig. 4-3: Porosity evolution as a function of radial distance simulated at 10, 100, 1,000, and 10,000 years for three mixed gas injection scenarios in a carbonate reservoir (Xiao *et al.*, 2009)

4.5 Reactive transport modelling in the Sleipner storage project

Audigane *et al.* (2007) presented a 2D reactive transport model of long-term geological storage of carbon dioxide in the Utsira Formation in Sleipner. Although their results discussed here were not obtained during the site selection phase, they provide a good impression of what should be anticipated when planning a

CO_2 geological storage. Audigane *et al.* (2007) used the reactive transport code TOUGHREACT and perform a 25 year injection scenario followed by a 10,000 year storage period. They presented detailed information on the different numerical modelling approaches, as well as a complete reference list dealing with reactive transport modelling. In particular, the numerical method and its implementation in TOUGHREACT are introduced. Details on equations, conditions on the dissolution of CO_2 and kinetics of mineral dissolution and precipitation are well described.

The site itself, the Sleipner West natural gas field, is located in the centre of the North Sea. CO_2 is injected into the Utsira Formation, which is located above the gas reservoir. The Utsira Formation is a large sandy aquifer extending over 26,100 km^2 located at a depth from 700 to 1,000 m (Audigane *et al.*, 2007). Details on Utsira Formation mineral composition and formation waters are described in the paper as well as comparison between batch geochemical modelling and batch simulations are compared.

Audigane *et al.* (2007) have approximated the Utsira Formation geometry by a vertical 2D mesh with a cylindrical geometrical configuration, centred on an injection point located 155 m beneath the top of the 184 m thick formation. The mesh contains 22 layers in the vertical direction and 52 in the radial direction. The first cell has a radius of 10 m, and is followed by 20 cells with radial increments increasing in logarithmic progression out to 1 km. Beyond 1 km, 15 cells are present with another logarithmic progression to 3 km. Beyond 3 km, 10 more increments are present with logarithmic progression to a radial distance of 10 km, and finally 5 cells extend out 100 km from the injection point; an additional cell with a large volume allows the model to act as an infinite medium (Audigane *et al.*, 2007). Audigane *et al.* (2007) justify the use of radial mesh geometry by the approximate circular shape of the CO_2 plume observed from seismic surveys.

Hydraulic initial and boundary conditions used in the simulations are shown in Tab. 4-1. Audigane *et al.* (2007) consider homogeneous sand and shale formations, with relative permeability derived from core measurements. They simulate CO_2 injection at a rate of 30 kg/sec for 25 years while accounting for an initial pressure of 90 bars at the top of the formation.

Tab. 4-1: Hydrogeological parameters for the 2D model used to simulate CO_2 injection at Sleipner with TOUGHREACT (Audigane *et al.*, 2007).

	Sand	Shale
Permeability	3.0×10^{-12} m²	10^{-14} m²
Porosity	0.42	0.1025
Temperature	37°C	37°C
Pore compressibility	4.5×10^{-10} Pa^{-1}	4.5×10^{-10} Pa^{-1}
Relative permeability model:		
. Liquid (van Genuchten, 1980)		
$k_{rl} = \sqrt{S^*}\left\{1-\left(1-\left[S^*\right]^{1/m}\right)^m\right\}^2$	$S^* = (S_l - S_{lr})/(1-S_{lr})$	
Residual liquid saturation	$S_{lr} = 0.05$	$S_{lr} = 0.05$
Exponent	$m = 0.75$	$m = 0.75$
. Gas (Corey, 1954)		
$k_{rg} = \begin{cases} 1-k_{rl} & if \quad S_{gr} = 0 \\ (1-\hat{S})^2(1-\hat{S}^2) & if \quad S_{gr} < 0 \end{cases}$	$\hat{S} = (S_l - S_{lr})/(1-S_{lr}-S_g)$	
Residual gas saturation	$S_{gr} = 0.20$	$S_{gr} = 0.20$
Capillary pressure (van Genuchten, 1980)		
$P_{cap} = -P_0\left(\left[S^*\right]^{-1/m}-1\right)^{1-m}$	$S^* = (S_l - S_{lr})/(1-S_{lr})$	
Residual liquid saturation	$S_{lr} = 0.05$	$S_{lr} = 0.05$
Exponent	$m = 0.65$	$m = 0.65$
Coefficient	$P_0 = 1.43$kPa	$P_0 = 1.43$kPa

Geochemical initial conditions for sand and shale mineralogies and for formation waters for the 2D model are identical to the batch system considered earlier in Audigane *et al.* (2006). A low salinity value of 32 g/l is assumed for the formation water in both the sand and the shale.

The short-term simulations, *i.e.,* 25-year injection period, show that the supercritical CO_2 plume extends laterally about 300 m away from the injection point, which is consistent with seismic observations (Audigane *et al.,* 2007). The presence of four intra-shale aquifers gives rise to CO_2 accumulations at four different depths and slows the upward CO_2 migration. CO_2 dissolution slightly increases brine density and gives rise to a negative (downward) buoyancy force. At the end of the 25 year injection period, a slight downward migration of the brine enriched in CO_2 can be observed. Dissolution of CO_2 makes the brine more acidic and short-term acidification occurs mainly in the area where supercritical CO_2 is present. Changes in porosity are minor. For more detailed short-term results, the reader should refer to Audigane *et al.* (2007).

The long-term simulations, i.e., 10 000 years, show the extent of the CO_2 plume and dissolved CO2 (Fig. 4-4). The reader should refer to Audigane *et al.* (2007) for details. At the end of CO_2 injection, supercritical CO_2 migrates quickly upwards, and most of the supercritical CO_2 accumulates just below the cap rock, except residual CO_2 that is trapped in sediments. The CO_2 plume extends to a maximum radius of 2,000 m around the injection point. CO_2 starts to dissolve in the brine, and the free gas is completely dissolved after 6,000 years. The brine containing dissolved CO_2 tends to migrate downward as it is approximately 10 kg/m^3 denser than brine without CO_2. Molecular diffusion from the gas plume to the brine induces a hydrodynamically unstable layering leading to the development of convective currents in the formation. The brine containing dissolved CO_2 is carried downward and is progressively replaced by brine with less CO_2. Streamlines of fluid migration showing convective cells are represented in Fig. 4-4 after 2,000 years of simulation. The slow brine convection accelerates CO_2 dissolution. After 10,000 years, a large volume near the bottom of the formation contains brine with dissolved CO_2 out to a radius of 4,000 m.

Key results of Audigane *et al.* (2007) are the following:

- The role of convective mixing is crucial for long term CO_2 dissolution;
- The process of gas dissolution and subsequent buoyant convection and mixing of brine involves a range of spatial scales;
- The interaction between flow and geochemical reactions and its impact on the overall reactivity can be accurately assessed only through coupled modelling and;
- For long-term reactivity, the evolution of the acidity is crucial; it is directly linked to the amount of CO_2 dissolved in the brine.

Audigane *et al.* (2007) identified four main types of geochemical interactions:

- Calcite dissolution and precipitation;
- Albite alteration;
- Muscovite alteration.

The assessment of the amount of CO_2 stored and the induced porosity changes are presented as a mass balance of carbon dioxide in mineral, supercritical and aqueous phases (Fig. 4-5). Mineral trapping obviously plays a minor role, although it increases slowly with time and therefore contributes to long-term stability of the storage process. Regarding the spatial distribution of CO_2 stored in minerals, the simulated mineral storage occurs mainly at the top of the reservoir and in the major downward convection zone above the injection point. The induced porosity changes are minor: a decrease of less than 2.5 % in the sands, and an increase of up to 15 % in the shales (Fig. 4-6). Audigane *et al.* (2007) point out that the difference in the porosity changes between sands and shales illustrate the importance of coupled transport and chemical reaction modelling: in the shales the porosity change is the inverse of what was seen in the batch modelling (Audigane *et al.,* 2007).

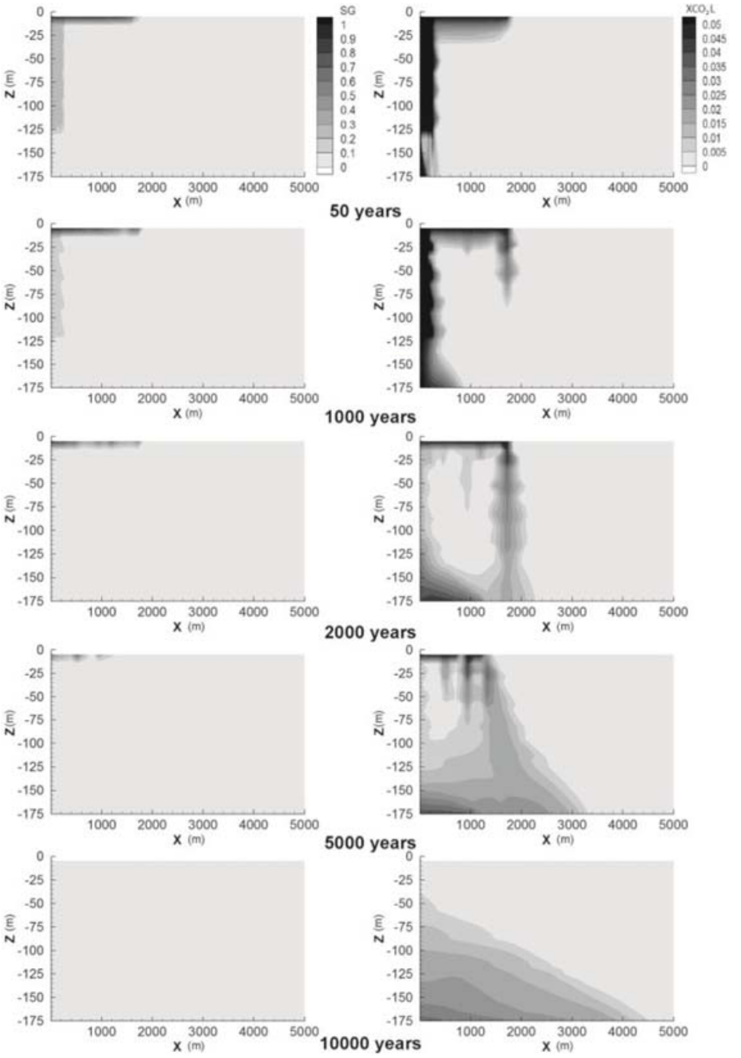

Fig. 4-4: Supercritical CO_2 gas phase (SG) migration and mass fraction of the dissolved CO_2 in the brine (XCO2L) simulated from 50 years after injection until 10 000 years (Audigane *et al*.,. 2007).

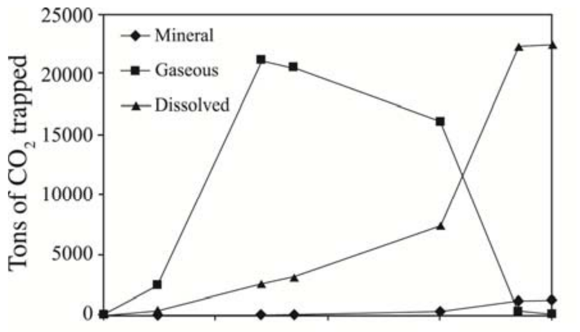

Fig. 4-5: Total amounts of carbon dioxide present as a free (supercritical) gas phase, dissolved in the aqueous phase, and sequestered in minerals (Audigane *et al*., 2007)

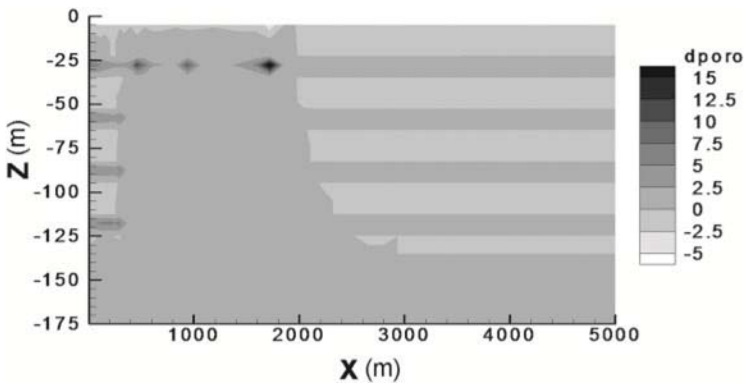

Fig. 4-6: Porosity changes after 10,000 years of simulation (Audigane *et al*., 2007).

Audigane *et al.* (2007) conclude that the geochemical reactivity of the Utsira Formation is rather low, so that mineral trapping makes only minor contributions to CO_2 storage. Solubility trapping is the dominant long-term storage mechanism, which appears to be essentially complete after 5 000 years. Physical and chemical heterogeneity play important roles in the geochemical evolution and associated changes in porosity. The Audigane *et al.* (2007) results suggest that the Utsira sand is unlikely to undergo major chemical changes due to CO_2 injection. Anticipated porosity changes are relatively minor, with a slight long-term decrease expected in the sands and a more significant increase in the shales. Density differences between brines with different dissolved CO_2 concentrations give rise to convective flows that cross the shale layers, mobilizing species that subsequently promote precipitation further downstream. Processes in which dissolution of minerals occurs in one region while precipitation occurs in another region with different mineralogy can only be analysed and modelled by coupling flow and transport with chemical reactions. The strong interplay between multiphase and density dependent flows with rock-fluid interactions makes it difficult to interpret modelled results in terms of a few dominant reactions. Separate batch geochemical modelling provides useful guidance for interpretation, but Audigane *et al.* (2007) show that in some cases the coupling to transport can give rise to qualitatively different behaviour to that derived from batch models.

4.6 Conclusions

Reactive transport modelling offers a wide set of useful tools for assessing the geologic storage site in different operational phases: pre-injection, during injection and post-injection. Inputs for reactive transport modelling depend mainly on the availability of data, on the geological model and the regulations. Multiple simulations should be performed based on different geostatistical realisations of the geology in order to allow estimation of variability of the key output parameters, and the time span for simulations should extend beyond the anticipated injection period and post-injection period prior to the transfer of responsibility. Very interesting and useful guidelines and best practices are available such as the CO2QUALSTORE (2009) and the NETL (2011) Best Practises for Risk Analysis and Simulation for Geologic Storage of CO_2.

Case studies show that reactive transport modelling provides valuable insights for analysing and assessing the dynamic behaviours of injected CO_2, identifying and characterising potential storage sites, and managing injection performance and reducing costs (Xiao *et al*., 2009).

5 COUPLED GEOMECHANICAL AND FLOW MODELLING

Injection of CO_2 into a geological formation results in hydrodynamic effects as wells as pore pressure changes, which in turn affects the stress state. During the injection phase of a CO_2 storage project, the increase in pressure changes the effective stress and may lead to rock deformation, which may result in shear slip or tensile opening of pre-existing faults, or creation of new fractures. Therefore, modelling the geomechanical properties of the reservoir along with the fluid transport is vital for the safe storage of CO_2. The reservoir pressure starts to decrease when CO_2 injection ceases. The reservoir is considered to be secure against geomechanical failure as the pressure decays towards a stable condition. Compression of both the injected and in-situ fluids and expansion of the pore space may lead to ground lift and, in some cases, seismicity. The reservoir properties (e.g. permeability) may also be affected. The development of a static 3D geologic model, the careful assessment of the stress field and coupled modelling of pore pressure and stress changes, help the assessment of possible fault/fracture development and surface heave. The data required for coupled geomechanical and flow modelling include rock compressibility, Young's modulus, Poisson's ratio, compressive strength, and formation fracture pressure. The coupled geomechanical and flow simulations should be used to assess the likelihood of potential leakage and rates relative to key risks, such as CO_2 entry into the caprock.

Simulation of CO_2 storage in an underground formation requires a complex multi-disciplinary effort, with the analysis of a number of interacting processes, including multi-phase flow and transport, geochemistry and geomechanics.

Injection of a large volume of fluid in the subsurface over a period can have geomechanical as well as hydrodynamic effects. During the injection phase of a CO_2 storage project, the (average) pore pressure in the storage formation would increase with continuous CO_2 injection. Spatially, the pressure increase would be highest at the injection well. Changes in the pore pressure will in turn alter the stress state. The associated changes in the effective stress (total stress minus the product of pore pressure and the Biot constant) cause rock to deform. If the injection-induced pressure increase is too large, shear slip or tensile opening of pre-existing fault(s) in the storage reservoir/caprock may occur, or new fractures may be created. This may cause a previously sealing fault to become conductive, and thus potentially compromise the caprock seal. Induced shear-stress changes may also induce micro-seismicity and even earthquakes of moderate local magnitudes (Bachu, 2008). For example, in Germany earthquakes up to magnitudes of 2.6 to 2.8, triggered by natural gas production, have been reported (Chadwick *et al*., 2008).

The injected fluids are accommodated in the subsurface through local displacement of resident fluids (water, oil or gas), compression of both the injected and in situ fluids, and expansion of the pore space that sometimes may lead to ground heaving (Bachu, 2008). Fractured and faulted reservoirs are generally highly compacted and, thus, severely affected by stress changes induced by reservoir thermal variations (*e.g.* cold CO_2 injection).

Storage reservoir pressure will start to subside when CO_2 injection ceases. The risk of leakage is expected to decrease as the pressure decays towards a stable condition. When the reservoir pressure reduces to this stable level, the reservoir is considered secure against geomechanical failure due to the internal forces (Chalaturnyk *et al*., 2005).

Geomechanical data, among other properties, are required under the EU CCS Directive (2009) during the storage site characterisation stage in order to evaluate the geomechanical effects of CO_2 injection.

Knowledge of the elastic properties of the storage formation/caprock, pre-existing fault strength properties, if any, in situ stress state, *etc.* allow the estimation of the fracturing pressure and, therefore, the determination of the upper limit of injection pressure. They also help to assess and predict the reservoir behaviour with respect to its overall capacity and avoid critical pressure build-up.

CO_2 transport model simulations provide the information necessary to determine whether there is potential CO_2 leakage through the caprock. Three key areas of simulation - focusing on faults and fractures, subsurface behaviour and fate of CO_2, and geomechanical/mechanical/flow models - show that numerical modelling is critical to CO_2 storage evaluation and risk assessment. Monitoring programs or computer simulations can be used to determine whether hydraulic fracturing would pose a risk to the confining layer, based on site-specific information.

Gaus (2010) stated that the coupling of geomechanical codes with coupled flow-transport codes remains a further challenge, although it is much-needed in order to assess the interplay between the two phenomena. This does not only require code development, but also the availability of the necessary datasets to feed into these codes and the correct treatment of uncertainties, since both geomechanical and geochemical processes are defined by highly uncertain parameters.

5.1 Geomechanical terms and processes in CO_2 storage

Stress is a measure of the amount of force exerted per unit area. There are 9 stress components: three normal stress components and six shear components. Normal stresses (either tensile or compressive) are due to the forces acting at the right angle to a plane, while shear stresses result from parallel forces. There are three planes, termed principal planes, where there are no sheer stresses and only normal stresses, called principal stresses. In tectonically inactive regions, the vertical stress, due to the weight of the column of overburden, is often the maximum principle stress. With increasing depth, the ratio of the horizontal stresses to the vertical stress approaches to unity (van Golf-Racht, 1982).

During hydrocarbon production, pore pressure depletion leads to corresponding changes in the stress field, not only the effective stresses but also the total stresses. The relationship between total stress and effective stress is defined by effective stress law, where the effective stress is the difference between total stress and the pore pressure times the poro-elastic (Biot) constant. Both deformation/strain and the yield/failure of a rock are controlled by the effective stress. Fluid injection/production-induced pore pressure changes may lead to surface heave/subsidence, and sometimes seismicity. The reservoir properties (*e.g.* permeability) may also be affected. The coupling between pore pressure and stress, the ratio of the induced change in the (total) minimum horizontal stress and the pore pressure change is referred to as the stress path.

Injection of CO_2 into a subsurface formation affects the in situ stress field mainly by the following processes:

- hydraulic fracturing,
- shear parting,
- expansion of the host rock, and
- fault slip (reactivation).

During CO_2 injection, a reservoir may develop plastic behaviour (stress path is not reversible), and pre-existing faults may reactivate or even new faults may be generated. The type of stress regime affects the potential for mechanical failure and the type of failure. Therefore, careful estimation of the stress field is essential for design and performance assessment of an industrial CO_2-injection operation. It has been reported that at an injection site, shear failure along pre-existing fractures would probably occur earlier than tensile failure (Rutqvist *et al.,* 2008).

The Mohr-Coulomb failure criterion is widely used for the analysis of shear failure in rocks subject to deviatoric stress loading. The onset of shear failure at a weak plane is affected by its orientation relative to the in situ principal stresses. The knowledge of which stresses are the major and minor principal stress is essential for the assessment of shear failure. For example, under a strike-slip fault stress regime (where horizontal stress is larger than vertical stress), the deviatoric stresses acting on the reservoir are largely maintained during hydrocarbon production. On the other hand, there tends to be an immediate increase in the deviatoric stresses under a normal fault stress regime.

During CO_2 injection into a depleted hydrocarbon reservoir, the initial stress state would be recovered as the reservoir pressure is brought back to its initial value, provided that the stress path is reversible during CO_2 injection. Further increase in the reservoir pressure would generally result in an increase in the deviatoric stresses, as well as a general reduction in the effective minor stress, thus leading to an increasing risk of shear failure in the strike-slip fault stress region. This leads to the concept of maximum sustainable pore pressure (for safe CO_2 storage), above which rock shear failure or fault re-activation might occur (Shi and Durucan, 2009).

Injection-induced pressure increase, if sufficiently large, could lead to a compromise of the caprock seal, and thus potential geomechanical consequences should be assessed prior to commencing CO_2 injection. Two main effects need to be considered: fracture dilation due to increased pore pressures and induced shear slip due either to raised pore pressures or a reduction in normal stress due to buoyancy forces exerted by the CO_2 plume. Fracture orientations that are likely to be conducive to fluid flow or susceptible to seismic slip can be determined relative to the principal stress axes, if the in situ stress is known (Chadwick *et al.,* 2008).

5.2 Geomechanical site characterisation

Sufficiently representative and detailed characterisation of potential storage sites is essential for accurate simulation of their long-term storage performance. Geomechanical characterisation of the host and caprocks of the target reservoir and the assessment of the long-term behaviour of the overburden in a CO_2 storage scenario require the determination of mechanical (elastic) properties of these rocks. The first step for geomechanical assessment involves the development of a static 3D geologic model of the storage site (*e.g.* using Petrel, EarthVision, *etc.*), which specifies stratigraphic contacts, structures, faults, well locations, and other salient features that have been identified from baseline well logs, seismic surveys, surface maps, *etc.* Within this geologic model, the distinct strata are populated with representative hydrological, geochemical, and geomechanical attribute data, which are typically obtained at sparsely-distributed locations through geophysical surveys, core/fluid sampling programs, and associated analytical studies, then extrapolated between imaging/sampling locations using geostatistical methods. Hydrological data would include temperature, pressure, porosity, permeability, and ambient flow gradients. Geochemical data may include detailed mineralogy and fluid-phase compositions/saturations, while geomechanical data may include in situ stress fields and fracture densities, apertures, and orientations (Johnson, 2009). Aarnes *et al.* (2010) gives a comprehensive list for the geomechanical data requirements, such as rock compressibility, Young’s modulus, Poisson’s ratio, compressive strength, tensile strength, in situ vertical total stress, in situ major horizontal and minor horizontal total stress, formation fracturing pressure, fault valving pressure, fault reactivation pressure, *etc.*

For geological storage of CO_2, an important element of the model is whether conductive features exist within the caprock. Therefore, particular attention should be given to collecting data for the primary caprock and describing its properties relevant to storage containment. For storage sites that have a caprock that has contained hydrocarbons over geologic time scales, the task is focused on the characterisation of the geomechanical properties of the caprock and any pre-existing fault planes through the caprock. These can be used to estimate threshold reservoir pressures for creating new fractures through the caprock or activating existing fractures.

Caprocks consist typically of sediments from distal depositional environments, which are characterised by relatively uniform conditions over large areas. Caprock lithology, fluid-flow and geomechanical properties are therefore likely to vary much less than those of the reservoir rocks. Consequently, extrapolation of lithology-related caprock properties from a small number of wells over a large potential footprint area can be better constrained than extrapolation of reservoir properties. However, relevant caprock properties due to deformation (faults, joints) cannot easily be extrapolated but require detailed local assessment covering the whole footprint area. The regional seismic stratigraphy of the caprock should be discernible from 2D seismic data, as would major faults that cut it. Smaller structural features, for example 'polygonal' type minor faults that characterise some shale sequences, generally require good quality 3D seismic data for their proper identification. Very small structures, fractures and joints are usually below the limit of seismic detection resolution. Assessment of the presence of microfractures in the subsurface is challenging, because mechanical deformation and depressurisation during coring may induce microfractures in core samples that are difficult to distinguish from those that formed in situ. Consequently, careful coring and preservation of cores is a prerequisite for successful microfracture assessment (Chadwick *et al.,* 2008).

The presence of fractures and their azimuth can be determined from core examination. Vertical in-situ stress can be obtained from density logs. Mechanical properties such as elastic properties for different formations can be obtained using dipole sonic logs as well.

Among the tests applied on core samples to measure rock geomechanical properties, uniaxial compression is the most widely performed method, where stress is applied only in one direction. This test is used to determine uniaxial or unconfined strength, Young's modulus and Poisson's ratio. On the other hand, stress is applied in all three directions in a triaxial compression test. From a triaxial compression test, the complete stress-strain curve may be obtained. A complete stress-strain curve records the core response to loading up to rock failure and beyond (post-failure). It provides information on the strength (maximum axial stress reached), yield stress point (marking the departure from linear elastic behaviour), and residual (post-failure) strength of the rock sample under a given confining pressure.

During geomechanical simulations, the initial stress state and stress/displacement boundary conditions for the model domain need to be defined.

5.3 Case studies and need for geomechanical coupled simulations

It is *a priori* necessary to predict that a potential storage site has a good sealing capacity, so that the injected CO_2 would be safely contained. The caprock and exiting wells are the main types of potential weak points in a storage system. An accurate assessment of storage performance may require the modelling of coupled processes: multiphase flow, kinetically-controlled geochemical reactions and geomechanical deformation. For example, porosity/permeability of the reservoir rock may be altered due to concomitant mineral precipitation/dissolution and fracture-aperture evolution (Johnson, 2009). This interplay of geochemical and geomechanical processes, within both the reservoir and, most importantly, the caprock, can strongly influence storage containment, capacity and the CO_2 plume distribution.

A series of dynamic flow simulation and geomechanical analysis models that are consistent with the geological model should be built to predict the impacts of the planned storage operation. These models will usually only represent a sub-set of the domain for the geological model where CO_2 is expected to migrate, or geomechanical responses to any pressure increase which may occur (Aarnes *et al.,* 2010). The model will allow prediction of flow of CO_2 from the injection well(s) into the storage formation for the duration of injection operations, and the long-term evolution of the CO_2 plume after the cessation of injection. The dynamic model should give quantified estimates of CO_2 volume, concentration and spatial distribution at an appropriate temporal resolution. In particular, the coupled geomechanical and flow simulations should be planned and executed to assess leakage probabilities and rates relative to key risks, such as:

- CO_2 entry into the caprock (*e.g.* due to pressure in excess of capillary entry pressure of the caprock or due to caprock degradation);
- leakage through inadequately sealed wells;
- upward flux of CO_2 or formation fluids in fracture and fault zones.

Coupled flow and geomechanical modelling studies increase our understanding as discussed in the following sections.

5.3.1 Large-scale geomechanical modelling

Rutqvist *et al.* (2008) modelled multi-layer systems using a coupling between TOUGH2 and FLAC3D. In this study, CO_2 is injected as supercritical fluid for 30 years. It spreads both laterally and upward, displacing the native brine. During the injection period, the reservoir pressure increases gradually but stays below the lithostatic stress at the depth of the injection zone. The poro-elastic modelling showed that the effective stress decreases as fluid pressure increases within the CO_2 storage system, as shown in Fig. 5-1. Le Gallo *et al.* (2006) presented the long-term impact of CO_2 injection into a saline aquifer using the reactive transport model COORES and the geomechanical model ABAQUS. Shi and Durucan (2009) performed a coupled geomechanical-reservoir modelling study using Schlumberger's ECLIPSE 300 simulator. The aim of the study was to evaluate the hydro-mechanical response of the reservoir rock and overburden formations to historical and current gas production rates and several CO_2 injection scenarios at Atzbach-Schwanenstadt natural gas field. The simulation results in terms of the vertical deformation at the top of the reservoir and changes in the vertical effective stress after 40 years CO_2 injection are presented in Fig. 5-2.

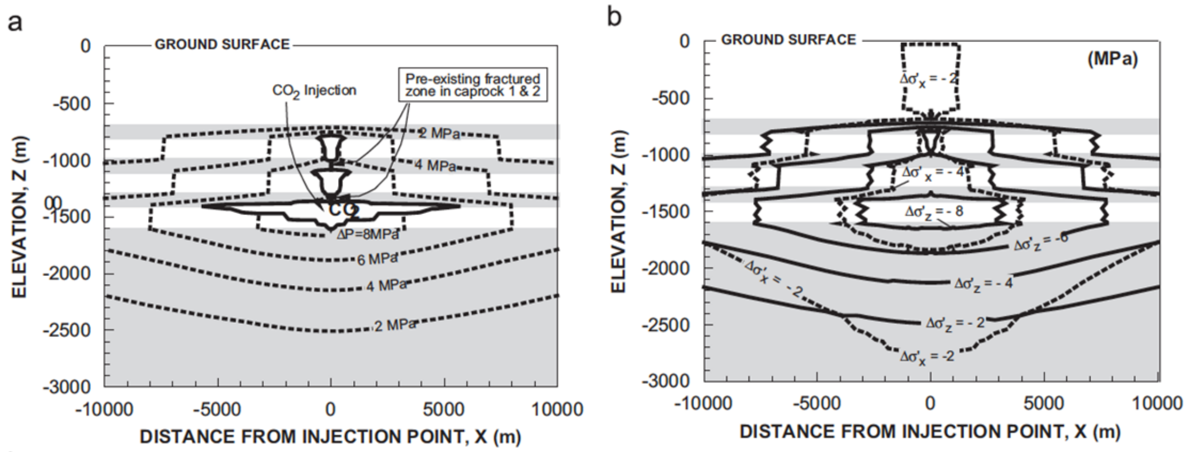

Fig. 5-1: Simulated coupled reservoir-geomechanical responses after 30 years of CO_2-injection into a multi-layered and faulted system: a) spread of CO_2 rich fluid (solid-line contours) and changes in fluid pressure (dashed-line contours); b) fluid-pressure induced changes in vertical (solid-line contours) and horizontal (dashed-line contours) effective stresses (Rutqvist *et al.*, 2008).

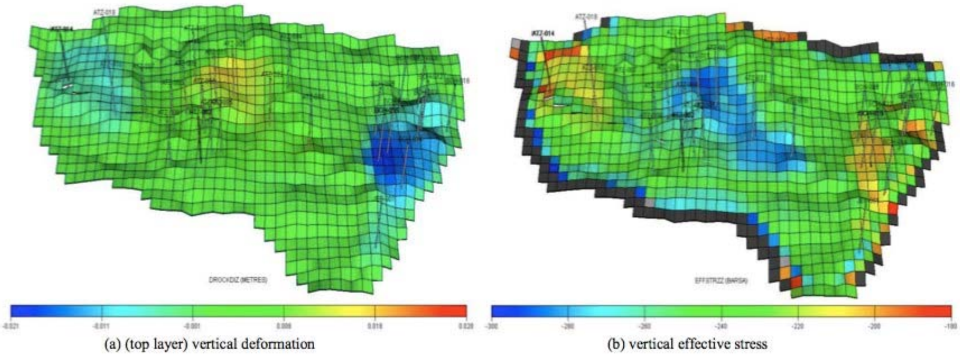

Fig. 5-2: Simulated distribution of vertical deformation and effective vertical stress at 2050 (Shi *et al.,* 2009).

5.3.2 Surface uplift

Comerlati *et al*., (2006) investigated the potential of CO_2 injection below the Venice Lagoon using available geological, geophysical, hydrologic, and geomechanical data, and with the aid of advanced numerical models. Using a coupled flow-geomechanical model, the amount of the rise of the ground surface because of the reduction of the effective stress in the aquifer and consequent rock expansion could be estimated. A seven cm uplift has been obtained with the most probable parameter selection (base case) (Fig. 5-3).

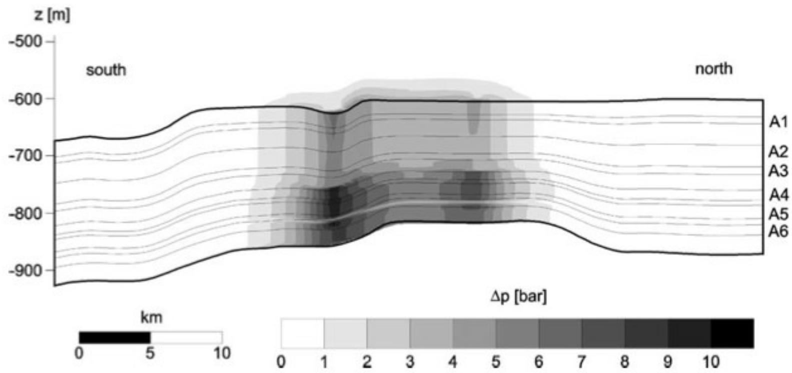

Fig. 5-3: Base case predicted overpressure along the north-south cross-section of Venice Lagoon at the end of a 10 year simulation period (Comerlati *et al.*, 2006).

Another area where the surface uplift caused by the injection of CO_2 has been studied is the In Salah gas field in Algeria. Using the surface deformation detected by Interferometric Synthetic Aperture Radar (InSAR) around three different injection wells (KB501, KB502 and KB503), methods that provide early warnings about potential leakage of CO_2 from the reservoir and the possibility of monitoring the injection performance have been tested. The InSAR data show a surface uplift of the order of 5 mm per year above active CO_2 injection wells and the uplift pattern extends several km from the injection wells (Onuma and Ohkawa, 2009; Vasco *et al.,* 2008). The surface heave pattern of NW-SE trending elongation suggests a relationship between structural features and the distribution of the CO_2 plume. Onuma and Ohkawa (2009) concluded that when an adequate number of interferometry pairs are available, the deformation time series can be detected, which may be supplemental data for refining the model of underground distribution of injected CO_2. The InSAR data was used by Rutqvist *et al.* (2009) to constrain the coupled reservoir-geomechanical model. The uplift depends on the magnitude of pressure change, injection volume and elastic properties of the reservoir and overburden. The sensitivity studies showed that although most of the observed uplift magnitude can be explained by poro-elastic expansion of the 20 m thick injection zone, there could also be a significant contribution from pressure changes within the adjacent caprock. Using small-scale faults and fractures, an integrated geomechanical model, which includes the Carboniferous (C10.2) injection zone, the caprock overburden and underburden was constructed by Gemmer *et al.* (2012) in order to predict the fluid flow and rock mechanical response to pore pressure changes. The stress and strain resulting from the injection of CO_2 is simulated with ABAQUS software using a two-dimensional plane-strain finite element model (Fig. 5-4). Pressure/fluid-flow in fractures seen in the seismic interpretation that is indicated by seismic time-shifts is validated by the estimated stress change through the geomechanical model. The observed 2 cm of uplift could only be explained by an unrealistically low stiffness. Therefore, Gemmer *et al.,* 2012 studied the effects of the rock mechanical properties on the surface displacement pattern by a number of sensitivity models. The distinct uplift of the ground surface observed directly above the fault/fracture zone at the KB-502 location (Fig. 5-5) could be explained by cases where pre-existing faulting and fracturing has led to material weakening due to reduction of the cohesion or reduction of the minimum horizontal stress.

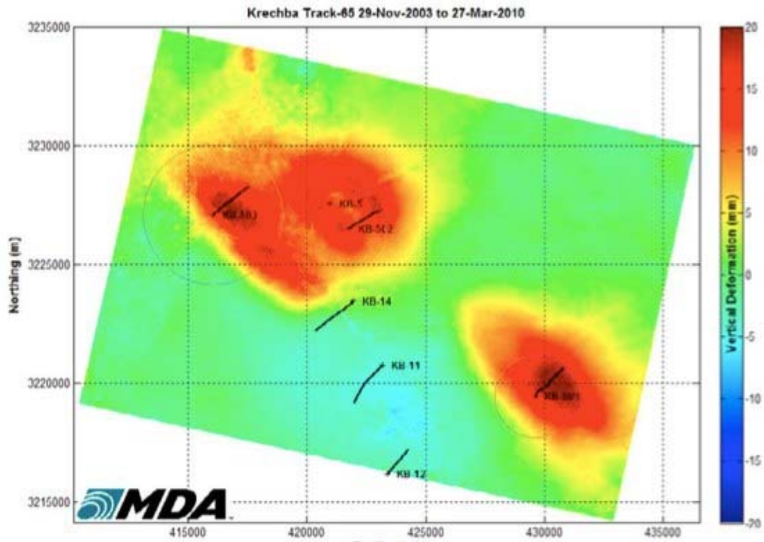

Fig. 5-4: Satellite image of cumulative surface deformation at Krechba due to CO_2 injection (Mathieson *et al*., 2011).

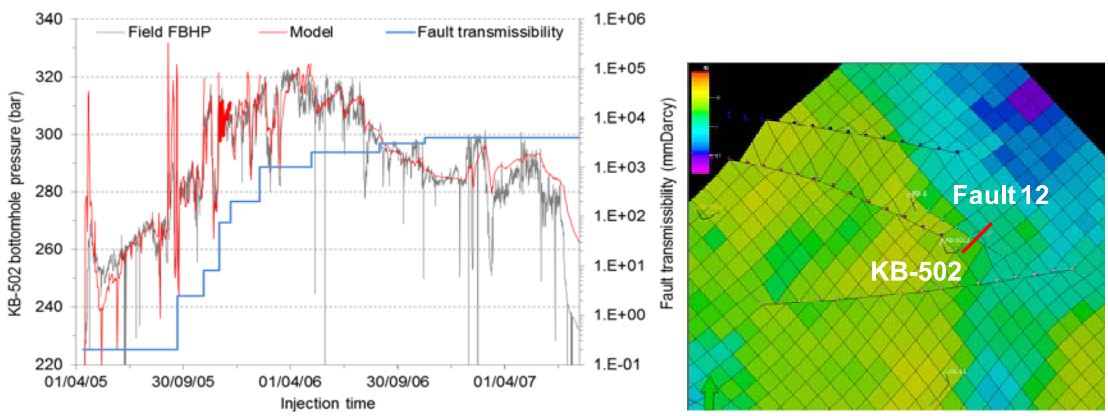

Fig. 5-5: a) History matching of the CO_2 injection pressure at In Salah at injection well KB-502 b) implementation of the fault zone contained in C10.2-3 in the reservoir model (Shi *et al*., 2013).

5.3.3 Pressure response

The effects of the underlying and overlying mud rocks on the reservoir pressure during CO_2 injection based on rock and fluid compressibilities have been studied using a commercial numerical simulator called CMG-GEM by Chang *et al*. (2011). The geological characteristics of a typical oil field near a salt diapir in the Gulf Coast basin in the Southern United States are used in this theoretical study. The authors proposed that compressible mudrock layers surrounding a target formation would increase the compressibility of the whole storage system, thus resulting in a lower pressure increase than would otherwise be. Consequently, the risk of failure/reactivation of pre-existing weak or discontinuous structures would be reduced. Moreover, vertical pressure diffusion into the compressible mudrock is shown to result in slower lateral pressure propagation.

5.3.4 Fault re-activation and/or shear failure

Shi and Durucan (2009) assessed the potential for shear failure and/or re-activation of pre-existing faults because of changes in the reservoir pressure due to natural gas production and CO_2 injection in a nearly depleted gas reservoir at Atzbach-Schwanenstadt in Austria. A Mohr-Coulomb shear failure analysis was carried out for the gas reservoir undergoing reservoir pressure depletion and then re-pressurisation due to CO_2 injection, in particular considering the regional strike-slip fault stress regime relevant to the gas field.

Soltanzadeh *et al.* (2009) studied the fault reactivation potential during fluid injection or production within and surrounding reservoirs by combining an induced stress change analysis, which was conducted using a semi-analytical model based on the theory of inclusions for a poro-elastic material and the concept of Coulomb failure stress change. The results of a synthetic case study showed that, for a thrust-fault stress regime, fault reactivation is likely to occur within the reservoir and adjacent to its flanks during injection into a reservoir. On the other hand, for a normal fault stress regime, only faults located in rocks overlying and underlying the reservoir tend towards reactivation. In Fig. 5-6, a normal fault stress regime was considered with faults dipping at 60° from horizontal. During production, there is a tendency towards normal fault reactivation within the reservoir and in the rocks near the lateral flanks of the reservoir (*i.e.,* the regions with $\lambda<0$). Similarly, there is a tendency towards normal fault reactivation above and below the reservoir during injection (*i.e.,* the regions with $\lambda>0$).

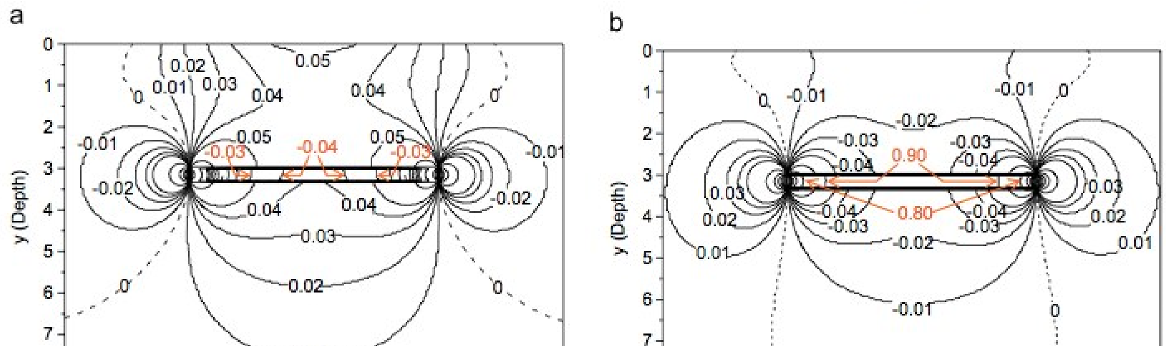

Fig. 5-6: Variation in fault reactivation factor (λ) for a rectangular reservoir: a) a fault dip angle of 60° in a normal fault stress regime; and (b) a fault dip angle of 30° in a thrust fault stress regime (Soltanzadeh *et al*., 2009)

5.3.5 Reactive transport

The intense flushing of the reservoir rock around CO_2 injectors with large quantities of dried super critical CO_2 can cause desiccation of the remaining brine in the pore space, leading to substantial precipitation of salts and sulphate minerals, blocking the pores and diminished injectivity. On the other hand, carbonate dissolution by the acidified brine could cause porosity and permeability to increase.

Both precipitation and dissolution can cause geomechanical effects, given that large pressure variations can occur close to the injector. Although Thermal-Hydraulic-Chemical (THC) codes present many advantages in forecasting injection flow rates or chemical processes, they only consider interactions between minerals and aqueous phases. THC codes do not integrate the mechanical deformation involved in CO_2 injection. For the time being, fully coupled thermal–hydraulic–chemical–mechanical codes are still in the development stage. The first simulations, with external coupling between the reactive transport model and geomechanical model, give encouraging results. Johnson *et al.* (2005) simulated long-term caprock integrity as a function of geochemical and geomechanical contributions to permeability evolution using the reactive transport simulator NUFT and distinct-element geomechanical model LDEC (Gaus *et al.,* 2008).

Li *et al.* (2006) built a model that uses a sequential coupling approach to investigate the thermo-hydro-mechanical behaviour of CO_2 injection around a fault environment. The effects of temperature, initial geological stress, injection pressure and CO_2 buoyancy on the mechanical behaviour of the fault were studied. The injection pressure has a larger influence on the relative slip change of the fault than the buoyancy induced by the CO_2 plume. Although at the initial stage of the injection the pore pressure of the storage formations is affected by the injection pressure, as time passes, the CO_2 plume-induced buoyancy plays a key role, influencing the pore pressure of the storage system.

Heffer *et al.* (2007) suggested that statistical modelling using the principal component analysis of well rate fluctuations can be used to identify the faults that are mechanically active during project development. Coupled geomechanical-flow models were used to demonstrate the observed correlations between rate and fault-related characteristics.

Chang and Bryant (2009) studied the effects of declined and inclined faults on the behaviour of CO_2 plumes in 2D and 3D formations. Several fault properties (conductive *vs.* sealing, angle relative to dip, distance from initial plume location) were examined to understand the dynamics of CO_2 behaviour such as residual phase trapping and direction of the plume. They stated that a large amount of CO_2 leaks into the fault below the top seal. However, the fault also creates a virtual source for up-dip migration into the permeable bed. This attenuates the leakage and results in significant additional residual saturation trapping, as can be seen in Fig. 5-7.

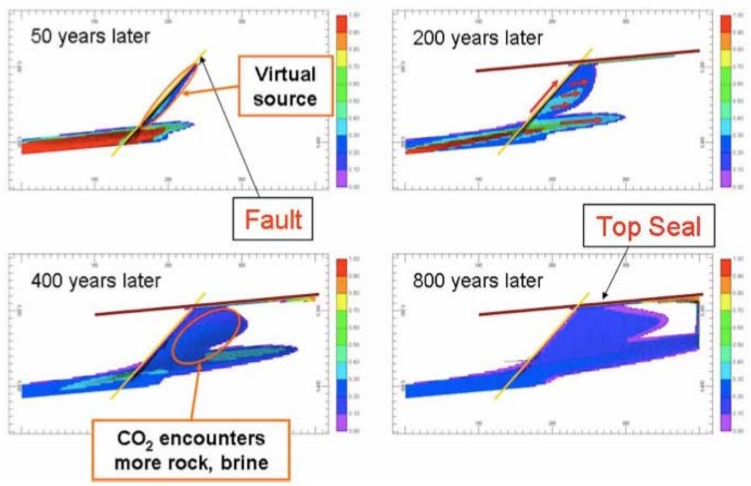

Fig. 5-7: Inclined and conductive fault's effect on CO_2 plume behavior (Chang and Bryant, 2009).

5.3.6 Storage Capacity Estimation

The simplest method for estimating storage capacity is the volumetric method. In this method, the capacity is estimated as a fraction of the calculated pore space volume in the target storage formation and structure, as constrained by an assumed realistic range of filling with supercritical CO_2 at the estimated reservoir average temperature and pressure. At the other end of the complexity scale, one could estimate capacity using reservoir flow simulators and geomechanical analysis tools. As explained by Aarnes *et al.* (2010), this approach requires that the underground is explicitly represented in a three-dimensional digital geo-cellular model including the most relevant structural and petrophysical features, and the dynamic processes, *e.g.* injection, fluid movement and spatial and temporal pressure responses. The capacity could then be estimated to reflect the maximum volume of CO_2 that can be injected without causing too large a pressure increase, CO_2-spill at structural spill points, or migration through other potential leakage pathways. Inferences about the potential for leakage can, in some cases, be made from regional knowledge, interpretation of seismic surveys or geomechanical modelling.

5.3.7 EOR Operations

When CO_2 is stored as a component of EOR projects, the initial depletion of the reservoir, and all the influences associated with exploitation, production, and EOR processes may affect the integrity of bounding seals. Jimenez *et al.* (2005) studied the integrity of the Weyburn system under EOR-CO_2 storage conditions using a mechanical earth model. A geomechanical analysis of the system was carried out using the pressure information in an explicit coupling where pressures were used as input for a geomechanical model. The large stiffness of the reservoir and the low pressure gradients lead to a minimum distortion of the reservoir and bounding seals, and insignificant changes in the in-situ stresses. Consequently, the hydraulic integrity of the caprock is preserved throughout the pre-CO_2 injection history of the reservoir, and the uniformity of caprock deformations has little influence on wellbore hydraulic integrity. In addition, pressures were increased synthetically to assess the performance of the reservoir post-EOR or in the actual CO_2 storage phase. It was found that hydraulic fracturing will be due to the mechanism of failure instead of shear failure. Therefore, the authors proposed that in order to maximise the volume of CO_2 stored, it will be necessary to adjust the operation of the field to raise the pressure as uniformly as possible and maintain good control of injection pressures.

Vidal-Gilbert *et al.* (2009) modelled the geomechanical behaviour of an oil field reservoir that is used as a CO_2 storage medium. In situ stresses and rock mechanical properties were determined using a 3D model. The pressure data obtained from reservoir simulations were integrated as input for a geomechanical model. Hence, the coupling is called a one-way coupling. The stress changes extracted from the model were also combined with a Mohr-Coulomb analysis to determine the fault slip tendency.

5.3.8 Leakage risk through a fault

Chang *et al.* (2008) developed a quasi-1D single phase flow model to examine the CO_2 upward migration along a fault, CO_2 lateral movement from the fault into permeable layers and a continued but attenuated CO_2 flux along the fault above the layers. The presented 1D model is compared with full-physics simulations in 2D. They concluded that although more CO_2 escapes from a deeper storage formation through a fault, less CO_2 reaches top of the fault. Thus, attenuation can reduce risk associated with CO_2 reaching the top of the fault.

5.4 Methods of coupling flow and geomechanics

In conventional fluid flow formulations, the pore volume variation only depends on the pore volume compressibility coefficient. The rock compressibility is assumed to be constant and the reservoir permeability is unaffected by pore pressure changes. However, the injection of CO_2, especially into highly compacted, faulted and fractured formations, causes a strain localisation on fracture and fault planes and results in a change in permeability or transmissibility. To account for geomechanical effects due to stress changes in and around the injection formation, the fluid flow problem must be solved with a geomechanical model that can predict the evolution of stress dependent parameters, such as porosity, rock compressibility, and permeability. The coupling can be carried out by integrating the mechanical concepts in reservoir simulation. The geomechanical equilibrium equation and the fluid mass balance equation should be solved iteratively. In the case of highly compacted, faulted and fractured reservoirs, the coupling may also lead to a modification of the transmissibility matrix due to fracture and fault permeability enhancement resulting from rock deformation (Longuemare *et al.,* 2002).

The fully coupled and partially coupled approaches can be used to solve the stress dependent CO_2 geological storage problem.

The fully coupled approach simultaneously solves the whole set of equations in one simulator. The fully coupled method offers internal consistency for the simultaneous resolution of both flow and stress equations, but the hydraulic or geomechanical mechanisms are often simplified by comparison with conventional uncoupled geomechanical and reservoir approaches. TOUGH-FRAC, a simulator for non-isothermal multiphase flow in porous media with geomechanical coupling, is an example of such a code which models plume dispersion and impact of stresses due to CO_2 interactions.

5.5 Conclusions

Injection of CO_2 in a geological medium results in pore pressure changes, which in turn affects the stress-state. The change in geomechanical conditions may have adverse effects on the stability of the storage reservoir. A good understanding of the elastic properties of the reservoir and overburden, pre-existing faults and fractures and the initial stress state is vital to evaluate the fluid flow and rock mechanical response to pressure changes. Geomechanical coupled flow models integrating the fluid flow and the stress field may be used in many areas of geological CO_2 storage. By combining the geomechanical coupled flow simulation results with measured mechanical changes during the injection phase, the key risks that may lead to leakage of injected CO_2 could be assessed early. Studies have shown the importance of building a good rock mechanical property model and that the fractures and faults have a significant role in controlling the pressure and saturation distribution.

6 ENVIRONMENTAL IMPACT AND RISK ASSESSMENT

Risks from geological storage of CO_2 primarily result from the consequences of unintended leakage from the storage formation that might can range between short-term potentially large leakages and long-term, more diffuse leakages, onshore and offshore storage settings. Risk assessment for CO_2 storage is the process that examines and evaluates the potential for adverse health, safety and environmental effects on human health, the environment, and potentially other receptors resulting from CO_2 exposure and leakage of injected or displaced fluids via wells, faults, fractures, and seismic events. The identification of potential leakage pathways is integrated with a MMV (Measurement, Monitoring and Verification) plan. Risk assessment is used to ensure the safety and acceptability of geological storage. It involves determining both the consequences and likelihood of an event. Risk mitigation is the planning for and implementation of contingency plans, should the need arise, to remediate adverse impacts. A good monitoring and mitigation plan will decrease the risk and uncertainty associated with many potential consequences.

Risk is defined as a function of the probability of an event that causes harm and its consequence, *i.e.*, "risk = probability × impact or consequences". In general, overall risk can be considered as the sum of the products of individual risk impacts and probabilities, although it is necessary to express the various risks in the same unit (*e.g.* financial) while risks can be various in nature (human life, leakage rate, financial loss, etc). In addition, considering overall risk might not be relevant and considering a series of risk levels might be more appropriate. For CO_2 geological storage, the main issue is adverse impacts that might result from a potential loss of storage integrity leading to unplanned CO_2 migration out of the confining zone. Other types of risk must also be considered such as geomechanical effects, water flow changes, *etc*. Potential consequences are related to public safety and health, environmental (ecosystem) safety, greenhouse gas emissions to the atmosphere, interference with other uses of the subsoil (*e.g.* water and hydrocarbons), economic viability of the project (*e.g.* financial loss for investors or insurers) and public acceptance. Fig. 6-1 (EPA, 2008) shows a conceptual framework of vulnerability evaluation for geological storage of carbon dioxide.

Operators and regulators have to determine an acceptable level of risk for CCS. To establish a reference baseline for acceptable levels of risk, it may be useful to apply metrics which allow ranking the different risks, and compare for instance the *health, safety and environmental (HSE)* potential risks related to the CCS projects with potential risks arising from other large-scale public/private infrastructure developments (dams, railways, airports, *etc.*) or analogue activities (oil and gas exploration, natural gas storage, acid gas disposal, *etc.*). Of course, all these processes act on different time scales that have also to be accounted for. In particular, CO_2 escape from the storage reservoir might be assumed to occur over an extended time scale (centuries to millennia) that has to be considered in each risk scenario (DNV, 2010). A first common risk criterion is that risks associated with an activity should not be disproportionate to the benefits. Although risks associated with properly managed CCS projects are expected to be very low, the risk perceived by the public may be higher and benefits regarding climate change impacts and energy security may be difficult for the public to relate to. A second basic principle for setting risk criteria is that an activity should not impose risks that can "reasonably" be avoided. In general, the risk can always be reduced further by implementation of additional safeguards, but at the price of a higher cost. Defining an acceptable level of risk is, therefore, closely related to the viability of the project, the cost of implementation of preventive safeguards and the cost of possible corrective measures (DNV, 2010).

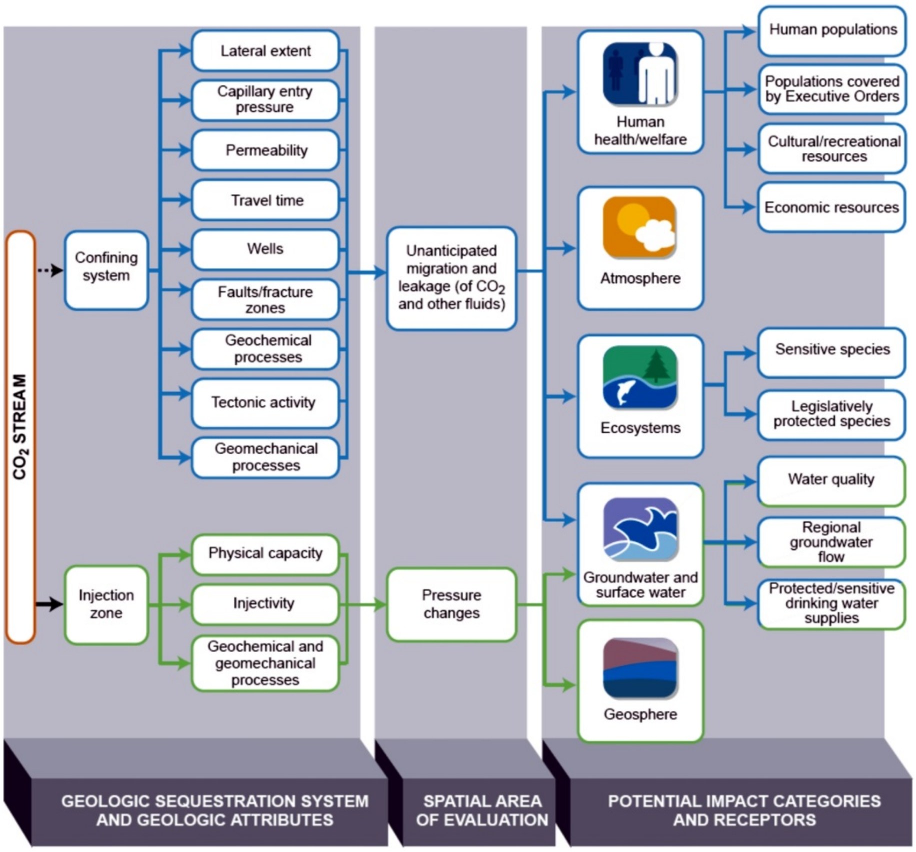

Fig. 6-1: Vulnerability Evaluation Framework (VEF) for geological storage of carbon dioxide (EPA, 2008).

6.1 Health, safety and environmental risks and impacts

Health, safety and environmental (HSE) risks fall into two main categories: global risks and local risks as presented in Fig. 6-2 for geological storage of CO_2 (Chadwick *et al.*, 2008).

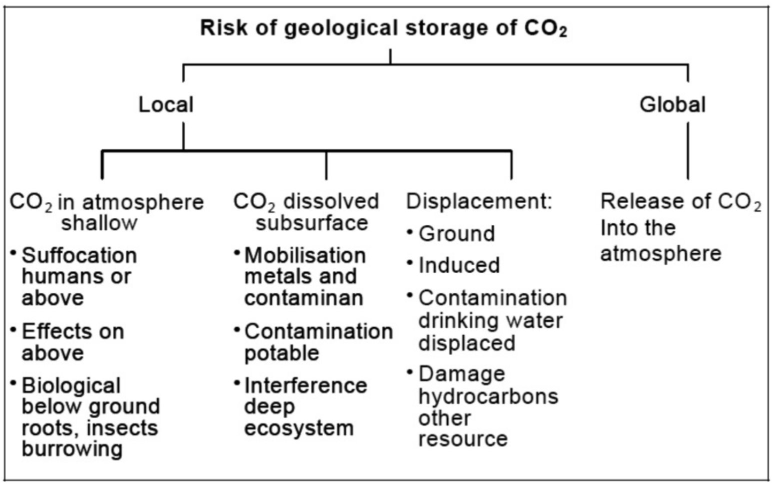

Fig. 6-2: Health, safety and environmental (HSE) risks associated with geological storage of CO_2. After Wilson *et al*. (2003) and Chadwick *et al*. (2008).

The global risks are related to release of CO_2 to the atmosphere that might contribute significantly to climate change in case a significant amount leaks from the storage formation to the atmosphere. Predicting the global impact on climate change due to a release of CO_2 depends on the quantity, duration and timing of the release (IPCC, 2005a, b; Chadwick *et al*., 2008; WRI, 2008).

Local health, safety and environmental hazards might arise from three main causes: (i) direct effects of elevated gas-phase CO_2 concentrations in the shallow subsurface and near-surface environment, (ii) effects of dissolved CO_2 on groundwater chemistry, and (iii) effects that arise from the displacement of fluids by the injected CO_2 (IPCC, 2005a,b). Local environmental impacts resulting from a release of CO_2 will depend more on the duration, the spatial and temporal distribution of fluxes and the resulting CO_2 concentrations and the ambient conditions than on the total amount of CO_2 released (IPCC, 2005; Chadwick *et al.,* 2008).

The main local HSE risk of concern to humans is elevated CO_2 concentrations in the atmosphere. Although CO_2 is non-toxic, it can be dangerous to life when concentrations are higher than 7-10% in volume because of resultant reduction in oxygen concentrations, causing unconsciousness, change of blood pH and failure of respiratory muscles. For humans, concentrations above 50,000 ppm can cause unconsciousness, with possible death at concentrations above 100,000 ppm. Such concentrations might arise in the case of sudden leaks from well blowouts (IPCC, 2005; Chadwick *et al*., 2008; WRI, 2008).

Potential HSE risks should be distinguished between onshore and offshore storage settings, since unwanted effects may have more severe consequences in densely populated areas and in environmentally sensitive locations than in sparsely utilised rural areas or offshore (Chadwick *et al.,* 2008).

6.1.1 Local environmental impacts and risks at offshore storage sites

Slow leakages of CO_2 from a storage reservoir beneath the ocean would not generally pose an immediate threat to humans. In the open ocean, released CO_2 will be partly dissolved in the water column, and any remaining CO_2 escaping to the atmosphere will be mixed with air and rapidly diluted (Chadwick *et al*., 2008). For people on ships and offshore installations, the situation might however be critical in case they are located directly above the site of a catastrophic leakage. The risk that a ship might conceivably sink in a large rising gas bubble has not been assessed.

Leakage from offshore pipelines, wells, and reservoirs could adversely affect a larger area because of the dissolution and acidification of the surrounding seawater. They should be modelled with regard to possible CO_2 concentrations in the pelagic and surface zones and biological effects assessed thereafter (Chadwick *et al*., 2008). Seepage from offshore geological storage sites might pose a hazard to benthic environments and organisms as the CO_2 moves from deep geological structures through benthic sediments to the ocean. While leaking CO_2 might be hazardous to the benthic environment, the seabed and overlying seawater will also act as a barrier, reducing the escape of seeping CO_2 to the atmosphere. These hazards are distinctly different from the environmental effects of the dissolved CO_2 on aquatic life in the water column.

6.1.2 Local environmental impacts and risks at onshore storage sites

Onshore pipeline routes and development of the storage site may cause some environmental disturbance and interfere with other interests (land owners, nature protection areas, military training, *etc*.). The risks of CO_2 leakage during separation, transport and injection are well known and subject to health and safety regulations. Potential CO_2 leakage during pipeline transport and injection are usually restricted to the immediate vicinity of the leak, but they might represent a threat to people, animals and biodiversity of ecosystems nearby (Oldenburg *et al*., 2003).

CO_2 quickly dissipates into the atmosphere; however, since it is heavier than air, there are known fatalities associated with natural releases of CO_2 (Lewicki *et al*., 2006; WRI, 2008). Risks associated to a diffuse subsurface CO_2 leakage on human health and safety are minimal in many regions, because of atmospheric mixing that prevents high atmospheric CO_2 concentrations from making contact with a potential receptor (Bogen *et al*., 2006; Lewicki *et al*., 2006). In the atmosphere, CO_2 concentrations are actually likely to be diluted rapidly below critical levels due to ground-layer turbulence. This can be observed at natural CO_2 emissions sites and has also been confirmed by a leaking storage scenario (Oldenburg *et al*., 2003). However whenever surface conditions allow leaking CO_2 to locally accumulate in areas with poor ventilation, high concentrations might be reached in depressions and confined spaces (basements or shallow dips in the ground) and might then be hazardous to humans and other living organisms causing stress or even asphyxiation (Chadwick *et al.,* 2008; WRI, 2008). In built-up areas for instance, CO_2 might accumulate in underground rooms of buildings, where even small rates of seepage can lead to hazardous concentrations in case of badly ventilated rooms (Chadwick *et al*., 2008).

Slow leakages of CO_2 are known to have detrimental effects on burrowing fauna and flora. Indeed, air being much less mixed in soils than at the surface, hazardous concentrations in the ground might result from CO_2 fluxes far smaller than those required to produce harm to above-ground organisms (Benson *et al*., 2002; Saripalli *et al*., 2003). At organism level, tolerance thresholds related to increased CO_2 concentrations vary between species. However, because of differences in sensitivity, it might be difficult to determine a well-defined threshold beyond which CO_2 cannot be tolerated and a continuum of impacts on ecosystems is more likely to occur (Chadwick *et al*., 2008), such as acidification of soils and displacement of oxygen in soils (IPCC, 2005a). Plants will be affected as soon as roots become saturated with CO_2 (WRI, 2008). The main characteristic of long-term elevated CO_2 zones at the surface is actually the lack of vegetation: CO_2 releases into vegetated areas cause noticeable die-off. In areas where significant impacts on vegetation have occurred, CO_2 makes up about 20–95% of the soil gas, whereas normal soil gas usually contains about 0.2–4% CO_2. Carbon dioxide concentrations above 5% might be dangerous for vegetation and for concentration about 20%, CO_2 becomes phytotoxic. Today there is no evidence of any terrestrial impact on vegetation from current CO_2 storage projects. However it has to be noted that the effect of CO_2 on subsurface microbial populations is not well studied (IPCC, 2005).

Impacts of CO_2 leakage on potential deep subsurface ecosystems, in and around the reservoir, might be significant (*e.g.* on microbes in the deep subsurface), but they might be considered as acceptable from an environmental viewpoint.

Brines displaced from deep formations by injected CO_2 can potentially migrate or leak through fractures or defective wells to shallow aquifers and contaminate shallower drinkable water formations by *e.g.* increasing their salinity. In the worst case, infiltration of saline water into groundwater or into the shallow subsurface could impact wildlife habitat, restrict or eliminate agricultural use of land and pollute surface waters (IPCC, 2005). Risks to groundwater quality also arise from the potential for CO_2 to mobilize organic or inorganic compounds, acidification, and contamination by trace compounds in the CO_2 stream.. Possible groundwater pollution from migrating CO_2 will cause a decrease in pH in groundwater aquifers and may cause dissolution and alteration of minerals from rocks and soils that could release elements such as heavy metals, potentially contaminating fresh water supplies (Chadwick *et al.,* 2008). In carbonate aquifers, carbonate dissolution along localised fluid (water and CO_2) paths could create larger voids that might create sinkholes at the surface. Rapid ascent of water in larger fault zones accelerated by rising and expanding gas-bubbles could cause vigorous eruptions and surface craters in soil and incompetent rocks. Similarly, in fine-clastic unconsolidated sediments, suspensions might form and cause mud-volcanism and mudflows. Foundations of buildings might be damaged by seepage of carbonated groundwater in shallow unconsolidated sediments and soils, for example, historical city centres, other heritage objects, or archaeological sites. Undetected accumulations of CO_2-supersaturated water or gaseous CO_2 in shallow traps might be a risk for future drilling. Long-term risks might result from the gravitational sinking of dense CO_2 saturated brines; if they come into contact with salt formations this could lead to a degassing of the formation water and the ascent of CO_2 outside of the original closed storage structure.

Injection of CO_2 deep underground causes changes in pore-fluid pressures and in the geomechanical stress fields that propagate far beyond the volume occupied by the injected fluid (IPCC, 2005). Geomechanical risks are not necessarily directly linked to CO_2 leakage (Chadwick *et al*., 2008). Under some circumstances, injection of large fluid volumes can generate seismic activity (Wesson and Craig, 1987). In most cases, these effects will remain quite small, but in certain circumstances they might be quite large. Differential movements along reactivated fault-lines in the caprocks could cause seismicity (Chadwick *et al*., 2008). Fault re-activation depends primarily on the extent and magnitude of the pore-fluid-pressure perturbations and is thus related to the quantity and rate of fluid injected (IPCC, 2005a). Injection of CO_2 near a fault will thus not automatically trigger a large earthquake (WRI, 2008). Neotectonically active or volcanic areas should of course be avoided (Chadwick *et al*., 2008). Lastly, it must be kept in mind that, even without causing any damage, microseismicity induced by CO_2 injection might result in public concern. Non-seismic displacements of the Earth's surface could also damage built infrastructure, comparable to the effects of subsidence in underground mining areas. Vertical uplift above large reservoirs could affect lake levels and shift streams in lowland areas with low topographic relief. The risk of initiating a mud diapir in unconsolidated (plastic, water-rich, undercompacted) reservoir and overburden strata, possibly including the entire reservoir, because of the buoyancy of stored CO_2 has not yet been investigated (Chadwick *et al*., 2008).

6.1.3 Evaluation of consequences versus environmental criteria

In order to determine site-specific criteria, it will be necessary to know local baseline conditions, such as groundwater chemistry, ecosystem composition, average wind speed and direction, topography, sensitivity of ecosystems in the area and population. For CO_2 concentrations in air, it may be possible to use generic standards, such as existing regulations for work environment conditions in which the effects of exposure to elevated CO_2 concentrations on humans are well documented. Another issue when establishing environmental criteria is the assessment of consequences the criteria should be based upon. Environmental quality standards (EQS) are set as the total maximum concentration/dose from different sources to an ecosystem. The authorities are responsible for setting requirements, environmental criteria and limit values. Since CCS is a new concept, input from industry and other stakeholders will be important for the development and determination of acceptable levels and limits that can be used when performing a risk analysis and assessing potential consequences of leakage. It is desirable that there is a consensus in the development of environmental criteria in the field of CCS.

6.2 Risk analysis

Risk analysis involves interactive exchange among risk assessors, risk managers, regulators, local community, news media and interest groups. A qualitative type of risk analysis should be performed at the early stages of a project to help site screening, site selection, communicating project aspects to the public, and aiding regulators in permitting projects. Subsequent to more detailed site characterisation and modelling efforts, quantitative risk analysis may be performed to estimate the likelihood of human health and environmental risks. Furthermore, stakeholders such as regulators and insurers may require risk analysis to support incentives, such as loan guarantees to large projects. A successful risk analysis will always be linked to monitoring and modelling plans for a given storage site. The risk analysis results can be used by industry, investors, and insurers to understand the potential liability associated with projects and build that into the cost of developing a CCS project (NETL, 2011). Once risks are understood, a project developer must take steps to avoid or manage the risks that are not judged acceptable. In the *risk management* step (Fig. 6-3), inputs from the risk assessment and characterization processes, and a variety of social, political, and techno-economic parameters are used to prioritize, monitor, control and mitigate risks (NETL, 2011).

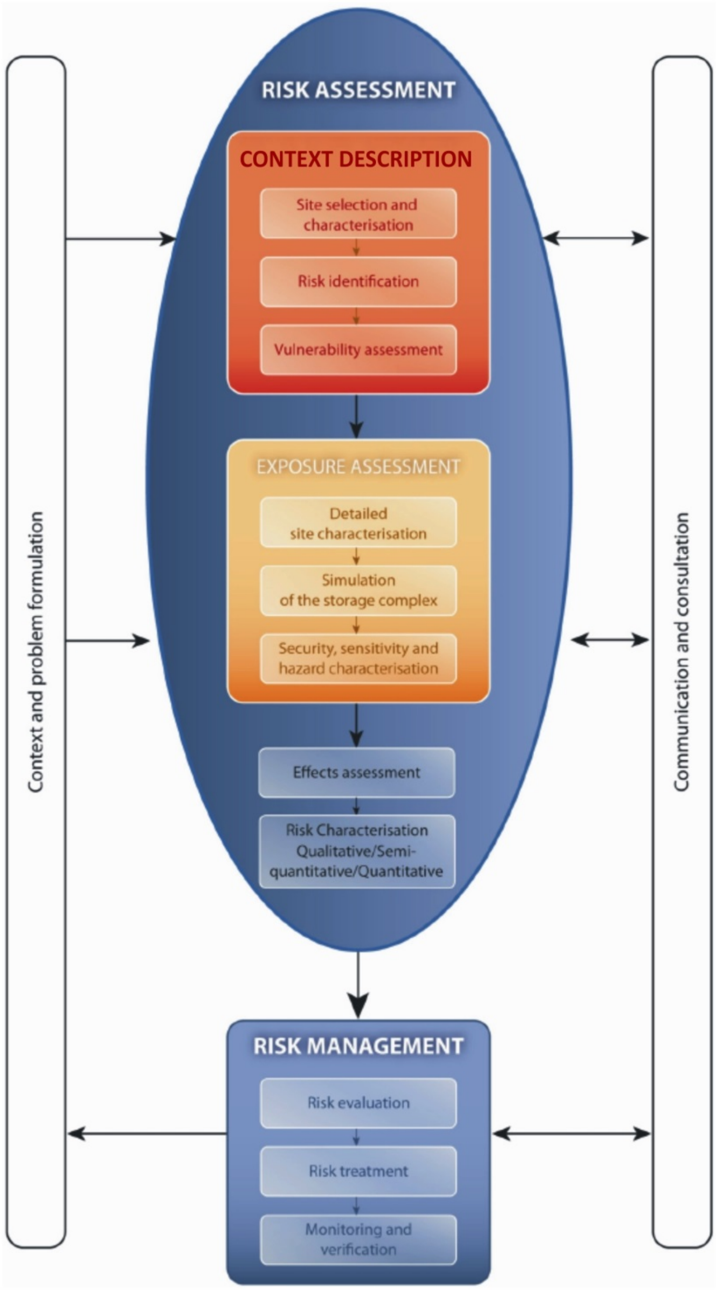

Fig. 6-3. Risk management workflow diagram for a commercial-scale storage deployment program. Adapted from Korre and Durucan (2009); NETL (2011) - modified.

It is important to distinguish between *risk* and *uncertainty*, although they may be related (DNV, 2010). Uncertainty is a critical factor to assess in the context of risk/performance assessment (NETL, 2011) that can be related to different features:

a) *Parameter uncertainty*, associated with input parameters, is commonly recognized and addressed in modelling approaches, via *e.g.* numbers of simulations based on a randomly sampling of uncertain parameters (Monte Carlo approach).

b) *Conceptual model uncertainty*, concerning how the real world (geological cross-sections, faults or fractures zones, etc.) is represented and abstracted.

c) *Modelling uncertainty*, concerning the underlying mathematical modelling and its inherent assumptions, *e.g.* boundary conditions. Modelling uncertainty can be assessed qualitatively by comparison of results from different mathematical models, via benchmarking exercises, which are recommended to enhance modelling credibility and confidence.

d) *Scenario/event uncertainty*, relating to whether scenarios/events representing all potential hazards have been identified and analysed (Stenhouse *et al*., 2009).

A core part of qualitative or quantitative ranking of risks for CGS involves assessing the level of knowledge available, and the subsequent implications on the level of risk. Proper management of uncertainty helps to manage down the assessed level of risk throughout the life of a CGS project. In particular, if risks are ranked conservatively, reducing uncertainty will generally result in a lowering of the assessed risk (DNV, 2010).

An important step of a detailed risk assessment is the qualitative or semi-quantitative prioritisation of the risks, where risks are categorised and ranked in terms of likelihood and magnitude of consequence. The ranking allows high-priority risks to be identified and plans for mitigating or controlling them to be developed, while lower-priority risks can be placed on a watch list. Other risks, with mid- or unknown-priorities, may undergo further analysis or investigation. As more information is obtained from site characterisation, modelling, and monitoring, the risk priorities can be updated. Later stages may also include model simulations to assess the probabilities and impacts of selected scenarios. Such plans will heavily rely on monitoring data and will generally stipulate an "if-then" process: if the monitoring system detects a problem, then specific actions will be performed to address the problem, either immediate action or need for an additional, focused monitoring. A good monitoring and mitigation plan will decrease the risk and uncertainty associated with many potential consequences (NETL, 2011).

6.2.1 Probabilistic risk assessment

In probabilistic risk assessments, explicit probability distributions are used for some (or all) parameters. The required probability distributions may be derived directly from data or may involve formal quantification of expert judgements (Morgan and Henrion, 1999). However, probabilistic risk assessment may require a simplification of models because of limitations on available computing resources (IPCC, 2005) to answer the issue regarding uncertainty *vs*. parameter uncertainty (*e.g.* detailed assessment with a coarse model *vs*. investigation of a few parameter values with a detailed model). Probabilistic risk assessment typically requires a mix of objective and subjective data that allows ranking of issues and results through an integrative and quantitative approach including explicitly uncertainties (CSLF, 2009).

6.2.2 Risk assessment methodologies

A number of different assessment methodologies have been and are being applied to CCS-related projects. The main methodologies being used are: (a) *scenario analysis,* analyzing how a CO_2 storage system might evolve in particular in terms of CO_2 migration/leakage, (b) *fault / event tree analysis,* to evaluate as a combination of possible steps the network of pathways for CO_2 release and migration starting from the storage reservoir and ending at a particular point of interest, (c) *expert judgment*, to derive from relevant experience and expertise in a specific area, the likelihood of CO_2 leakage, (d) *screening-level analysis,* which can be useful to compare safety characteristics of different sites based on expert opinion (Stenhouse *et al*., 2009). In parallel with methodologies, a variety of approaches are available for mathematical modelling, which can be classified under three general categories: (a) *numerical models*, which use discretization methods to model detailed processes describing the system evolution over space and time, (b) *analytical / semi-analytical models, which* are mathematical models in which the solution to the equations used to describe changes in the system can be expressed as an analytical or semi-analytical function, typically as a function of time in the case of risk assessment for CCS projects, and (c) *compartment or mixing-cell models*, representing a large family of models, where the model comprises a series of individual compartments representing different physical domains of the total storage system. All of the above-mentioned models can be run deterministically or probabilistically (Stenhouse *et al*., 2009).

Risk Assessment methodologies are generally classified in two main groups: qualitative and quantitative.

- *Qualitative Risk Assessment* does not provide concrete or numerical results. In case of a lack of data and/or specific knowledge, time and expertise, qualitative risk assessment may be sufficient and more effective. Among the most common qualitative methods are the *Features, Events, and Processes (FEP)*, and the *Vulnerability Evaluation Framework (VEF)*.
- *Quantitative Methods* are used in well-known systems where the level of uncertainty is relatively low. Two main kinds of methods belong to this group: *Deterministic Risk Assessment (DRA)* and *Probabilistic Risk Assessment (PRA)*. DRA does not handle uncertainty, but is useful in determining trends due to its single parameter variation. It gives very accurate results when the input parameters are exactly known. PRA, on the other hand, can statistically quantify the uncertainty associated with parameters describing the processes in deterministic models. PRA is the most preferable method of assessing long-term risk in complex systems (Condor *et al*., 2011).

Table 6.1 summarizes the main characteristics of some risk assessment methods. It should be noted that some methods are not considered in this table, *e.g.* Preliminary Hazard Analysis (PHA), Failure Mode and Effects Analysis (FMEA), Fault Tree Analysis (FTA) and Fuzzy Logic.

Tab. 6-1: Risk Assessment Methods (Condor *et al*., 2011).

Method	Goal	Data needed	Industrial application	Application for GSC
DRA	Analytical point estimate calculations	Numerical and qualitative expert estimation for scenario development and model development	Safety engineering (sensitivity analysis)	Initial risk assessment. No uncertainty estimations
PRA	Predict the probability of safety failures of complex systems	Numerical qualitative expert estimation for scenario development, model development quantifying PDFs	Safety engineering	Detailed risk assessment. Uncertainty estimation
FEP	Scenario development	Qualitative expert estimation for scenario development	Scenario analysis	Screening and Site selection
VEF	Conceptual framework for regulators and technical experts	Qualitative expert estimation to identify which areas should be in-depth studied	Hazard identification and potential consequences	Framework for site selection and regulator guidance
SWIFT	Elaborate hypothesis	Qualitative expert estimation to identify hazards	Hazard identification in engineering	Hazard and consequence mapping
MCA / MAUT	Evaluation of alternatives in multiple objective	Qualitative and numerical expert estimation for data input utility	Decision making	Framework for screening and site selection
RISQUE	Systemic process with participation of expert panels	Qualitative and numerical expert estimation in event-tree approach	Hazard identification and potential consequences	Hazard and consequence mapping
CFA / SRF	Estimation of risk based on probabilities of occurrence in individual features	Qualitative and quantitative estimation of risk and uncertainty	Development of simple probabilistic models	Managing risks in GSC sites
MOSAR	Identifying and preventing risks	Qualitative and quantitative data for a well-known system	Risk reduction in complex systems	Systematic risk analysis for well-known sites
ESL	Identification of uncertainties in decisions	Qualitative and quantitative understanding of uncertainties	Reduction of uncertainties in well-known systems	Detailed PRA and dealing with uncertainties
P&R	Risk mapping in wellbores under the criteria of degradation scenarios	Qualitative and quantitative data for wellbores	Risk evaluation under the concept of ALARP	Long-term well integrity
SMA	Estimation of risk based on probabilities.	Quantitative estimation of risk and PDFs	Development of complex models in well-known systems	PRA for the whole CCS chain

The Features, Events and Processes (FEP) method consists of listing relevant factors that describe the current state and possible future evolution of a site. The FEP analysis is useful in the licensing and certification stages of project development..

The Vulnerability Evaluation Framework (VEF) is a qualitative method which systematically identifies conditions that could increase or decrease the potential for adverse impacts (*i.e.,* susceptibility to consequences). The VEF (EPA, 2008) is not designed as a site selection tool, it does not aim to establish performance standards, or to specify data requirements. It is a conceptual framework designed to help regulators and technical experts in framing specific considerations and identifying areas that require design evaluation, specific risk assessment, monitoring, and management (Condor *et al*., 2011).

The Risk Identification and Strategy using Quantitative Evaluation (RISQUE) proposed by Bowden and Rigg (2004) is a systematic quantitative process based on the judgment of a panel of experts. It delivers a transparent risk assessment in a process that can interface with the wider community and allow stakeholders to assess whether the CO_2 injection process is safe, measurable and verifiable. It has been applied in Australia, under the GEODISC research program, to assess the risk posed by conceptual CO_2 injection in four selected areas (Dongara, Petrel, Gippsland, and Carnavarcon). The approach relies on quantitative techniques to characterize risks in terms of both likelihood of identified risk events occurring (such as CO_2 escape and inadequate injectivity into the storage site) and consequences (such as environmental damage and loss of life). It consists in five stages:

Stage 1- Establishing the context, *i.e.,* assessment of the nature of the activities and potential impacts,

Stage 2- Risk identification,

Stage 3 - Risk analysis, *i.e.,* quantification and modeling of probabilities and consequences for each substantive risk event,

Stage 4 – Development of risk management strategy, *i.e.,* defining and evaluating options for action plans to treat key risk events,

Stage 5 - Implementation of the risk management strategy (Bowden and Rigg, 2004).

RISQUE methodology in conjunction with a modified Delphi approach was proposed for assessing and quantifying risk in CO_2 geological storage projects aiming at the reduction of uncertainties. The RISQUE process does not routinely include a continual and progressive technology risk component but the modified Delphi process could address this potential need. The RISQUE method addresses the risks but in a linear scheme, whereas in complex programmatic settings, risks are considered in a non-linear scheme, chosen by interveners or stakeholders. The modified Delphi technique, when planned and implemented well, can bring all elements of risk, presumably from the non-linear ‘risk-space’ into a controlled input for the RISQUE process. It quantifies and qualifies the risks perceived by others into a set of consensus risks, in a re-iterative agreement process, and weight those factors against the expert panel of the RISQUE process. As the RISQUE process proceeds, the Delphi re-iterative process continues using smaller subgroups and continued quantified and qualified weighted input (Wyatt *et al.,* 2009).

The Structured What-If Technique (SWIFT) is a form of Delphi risk analysis used for qualitative hazard identification that was attempted by Vendrig *et al*. (2003), who identified major hazards through a “Structured What-If Technique” involving an expert panel (CSLF, 2009). The method was developed as an efficient alternative to the Hazard and Operability (HAZOP) technique and to the Failure Modes and Effects Analysis (FMEA) for providing highly effective hazard identification in situations and systems where none of them were adequate. It consists of a series of “what-if…?” or “How could…?” questions to identify situations, issues or threats of potential harm. There is no single standard approach to SWIFT which is flexible and has to be modified to suit each individual application (Vendrig *et al*. 2003; Condor *et al*., 2011).

The Certification Framework (CF or CFA) is a simple risk assessment approach for evaluating CO_2 and brine leakage risk at GCS sites (Oldenburg *et al*., 2009). It is similar to VEF, but it adds values for the leakage probability (Condor *et al*., 2011). Its purpose is to provide a framework for project proponents, regulators, and the public to analyse the risks of geologic CO_2 storage in a simple and transparent way to certify start-up and decommissioning of storage sites. The CF currently emphasizes leakage risk associated with subsurface processes and excludes compression, transportation, and injection-well leakage risks. It is designed to be simple by using (a) proxy concentrations or fluxes for quantifying impact rather than complicated exposure functions, (b) list of pre-computed CO_2 injection results, and (c) simple framework for calculating leakage risk. For quantification of risk, the system is divided into compartments that can be subsurface (hydrocarbon reservoirs or underground sources of water), at surface (local sites where leakage occurs) and distant sites (Condor *et al*., 2011). The CF approach has to be based on a clear and precise terminology in order to communicate to the full spectrum of stakeholders:

- *Effective trapping* (proposed overarching requirement for safety and effectiveness),
- S*torage region* (3D volume of the subsurface intended to contain injected CO_2),
- *Leakage*,
- *Compartment* (region containing vulnerable entities, e.g. environment and resources),
- *Impact,*
- *Risk,*
- *CO_2 leakage risk* (risk to compartments arising from CO_2 migration, *i.e.* the product of the probability of intersection of leakage paths with compartments (Oldenburg *et al*., 2009; Dodds *et al*., 2011).

In the CF, impacts occur to compartments such as HMR (Hydrocarbon and Mineral Resource), HS (Health and Safety), USDW (Underground Source of Drinking Water), NSE (Near-Surface Environment), and ECA (Emission Credits and Atmosphere). Wells and faults are assumed to be the only potential leakage conduits. Fig. 6-4 shows the CF conceptualization of the system into source, conduits and compartments (left-hand side), and a flow chart of the general CF logic and inputs and output (right-hand side). A similar method to the CF approach is the Screening and Ranking Framework (SRF) which is based on the assumption that if the primary seal or containment leaks, the second seal will act. If the second seal fails, then the leakage will be attenuated or dispersed (Oldenburg, 2008; Condor *et al*., 2011).

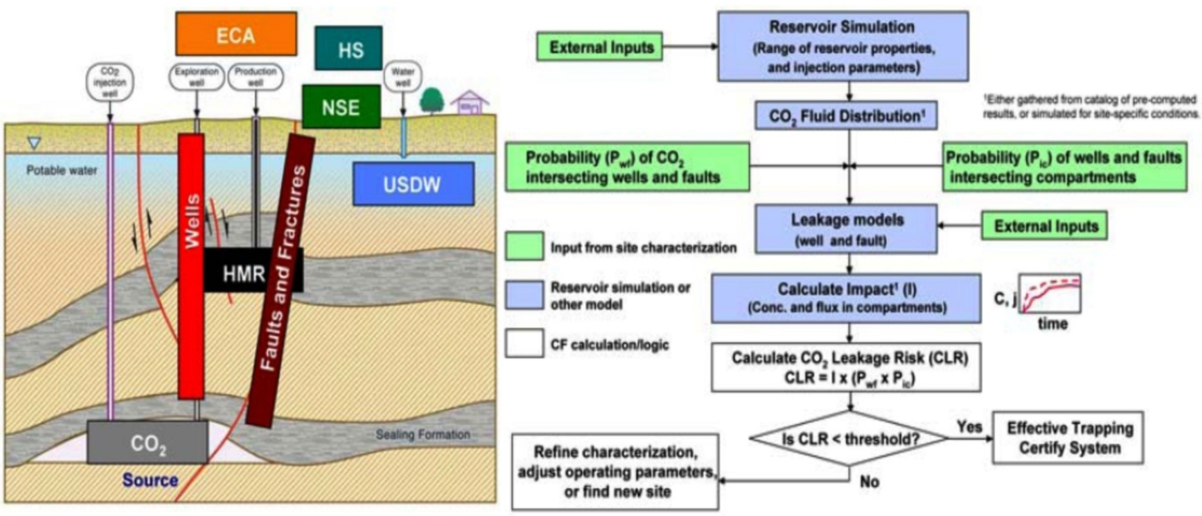

Fig. 6-4: Generic schematic of compartments and conduits in the CF (left-hand side), and flow chart of the CF approach (right-hand side) (Oldenburg *et al*., 2009).

The Multi-Criteria Assessment (MCA) covers a variety of non-monetary evaluation techniques sharing a basic framework under which a number of alternatives can be scored against a series of defined or fixed criteria. This list of criteria is proposed according to the fundamental goals of the CGS. These criteria can then be categorized in groups. Multi-criteria assessment (MCA) appears to hold much potential as a useful tool for characterising and better understanding differences in stakeholder assessments of CCS and its implications, and for identifying options around which greater consensus on the desirability (or otherwise) of CCS as a mitigation strategy might emerge (Gough and Shackley, 2006). This method delivers a rich profile of the views and preferences of participants and thus enables 'mapping' key issues that will affect the prospects for further development. A similar method is the Multi-Attribute Utility Theory (MAUT). The main difference between MAUT and MCA is that MAUT assumes a dependency of preferences of criteria, enabling the inclusion of subjective elements (Scholz and Tietje, 2002; Condor *et al*., 2011).

The Evidence Support Logic (ESL) has been designed to identify the amount of uncertainty or conflict involved in a decision. This involves systematically breaking down the question under consideration into a logical hypothetic model whose elements expose basic judgements and opinions related to the quality of evidence associated with a particular interpretation or proposition. A decision-support tool called TESLA implements Evidence Support Logic (ESL). The method involves constructing decision trees to reflect: (1) the Performance Assessment's context since decision depends on the storage project's stage of development and the aims of the stakeholders); (2) the FEPs that may influence the system being evaluated; (3) the kinds of information that enable assessments about the characteristics and effects of interactions among these FEPs. The decision tree consists of a hierarchy of hypotheses, which links the main hypothesis of interest (*e.g.* insignificant CO_2 leakage from a deep storage reservoir) to data or information (*e.g.* geological evidence for the existence of a cap rock, experimental evidence for the effective sealing of boreholes, output from supporting modelling studies *etc*). The 'evidence' for or against each hypothesis is the extent to which information leads to confidence in the hypothesis' dependability or falsehood respectively (Metcalfe *et al*., 2009). The 'evidence' may correspond to quantitative information (*e.g.* numerical model output, measurements in boreholes *etc*) or qualitative information (*e.g.* anecdotal evidence that a particular kind of borehole seal is effective). Each item of qualitative or quantitative information is then mapped into two values on a numerical scale of 0 to 1 representing evidence for and against. This representation of evidence is a type of Interval Probability Theory, which employs three-value logic. Experts assign values to each hypothesis representing the amount of supporting evidence, the amount of refuting evidence and the amount of uncertainty or conflict in the evidence. (Metcalfe *et al*., 2009; Condor *et al*., 2011).

The Method Organized for a Systematic Analysis of Risk (MOSAR) allows the analysis of the technical risks of a system and then identifies the prevention means in order to neutralize them. It consists of two main steps (Fig. 6-5). First step, 'A', allows the analysis of major risks. Second step 'B' makes a detailed analysis of project implementation and specifically defines the safety tools related to the technical dysfunction (all dysfunctions are found with this step). The MOSAR method is a systematic method which relies on a step by step method, in which no step can be neglected. This does not prevent flexibility: when an unexpected event arises or a new danger source appears, it can included at the beginning of the method without changing all the process. This method is built level by level where each level gives a specific information so that it is possible to stop at a chosen level. Unexpected events, such as physical harm and material, fauna, flora, ground and economic damages or unpleasant effects on the population, are defined. MOSAR is based on site observations and facts and is applicable to a specific installation because it accounts for technical aspects, site morphology and geology, politics, and economic and social aspects into account. It presents the advantage of creating improbable and unforeseeable risk scenarios with a first analysis, but whose implementation can be extremely beneficial. The important subjectivity of MOSAR has been noticed and this should be viewed as a strong point and not as a hindrance (Cherkaoui and Lopez, 2009).

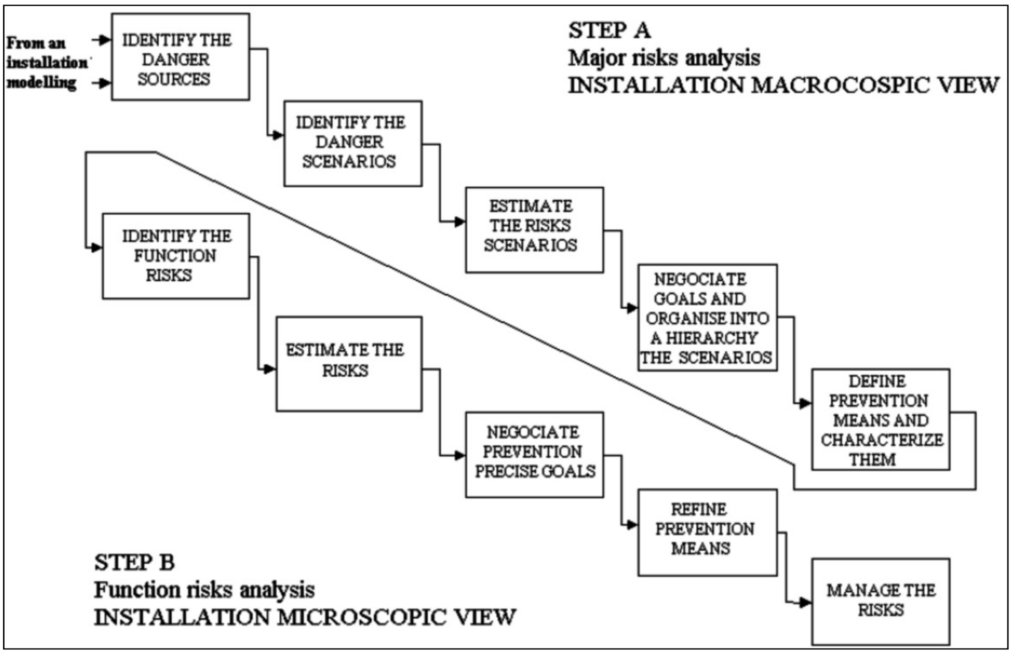

Fig. 6-5: The MOSAR method: Steps A and B (Cherkaoui and Lopez, 2009).

The Performance and Risk (P&R) assessment (or Performance and Risk Management methodology - P&RTM), for well integrity was developed by Schlumberger and OXAND. The uncertainties of the system are converted into the notion of probability and the quantity of CO_2 leakage mass assessed into the notion of severity. It also includes the definition of a Risk Acceptance Limit (RAL), which brings forwards the criteria of unacceptable risks. The methodology is based on experience in material ageing and risk assessment of complex systems, where probabilistic simulations are performed. It accounts for all stakes involved in well integrity management and enables the full integration of uncertainties as part of risk estimation. The methodology improves common approaches based on FEPs as it quantifies risk levels. It provides useful and reliable tools to support decisions for well integrity management strategies or emergency plans. Updating risk assessment with incoming data allows an evolving vision of risk levels to optimize interventions in time. The main objectives of the risk-based methodology regarding well integrity are to identify and quantify risks associated with CO_2 leakages along wells over time (from tens to thousands of years), to evaluate risks and to propose relevant actions to reduce unacceptable risks (Le Guen *et al*., 2008; Le Guen *et al*. 2009; Condor *et al*., 2011)

A hybrid system-process model CO_2-PENS (Predicting Engineered Natural Systems) is a probabilistic simulation tool designed to incorporate CO_2 injection and sequestration knowledge from the petroleum industry to perform risk assessment of sites. It includes economic tools, as well as models for the physical and chemical interactions of CO_2 in a geological reservoir (Viswanathan *et al*., 2008; Stauffer *et al*., 2009). This model is based on a PID (Process Influence Diagram)-like approach extending the FEPs analysis. The CO_2-PENS tool aims at integrating in a system-level model a number of process-level models representing the storage reservoir, the cap rock, the potential release mechanisms, the transport of CO_2 from the reservoir and the release of CO_2 in surface. The CO_2-PENS system model allows both a simplified analytical description of processes and the use of detailed process models. It links high level system models (*i.e.,* reservoir model) to the process level (wellbore leakage, chemical interaction of CO_2) and represents thus a hybrid coupled process and system model designed to simulate CO_2 pathways, such as capture, transport, injection into geological reservoirs, potential leakage from the reservoir and migration of escaped CO_2. Due to its modular architecture, the tool allows incorporation of additional process models by linking to dynamic linked libraries (DLL) and coupling of the well leakage module with the atmospheric model is feasible. At each time step in the system model, the wellbore module is queried to predict the leakage rate into the top aquifer. Simulation of wellbore leakage is complicated and simulation approaches require PDFs with respect to potential failure mechanisms as input parameters to take account of uncertainties. CO_2-PENS is being used in risk assessments for several of the field tests and demonstrations being conducted as part of the United States Department of Energy's (US DOE's) Regional Carbon Sequestration Partnership efforts (CSLF, 2009).

The System Modelling Approach (SMA) is part of the CO_2-PENS and was developed in Los Alamos National Laboratory and originally designed to perform probabilistic simulations for the whole CCS chain. The long-term fate of the injected CO_2, including possible migration patterns out of the target formation, is simulated through probability distributions (Stauffer *et al.*, 2009). Oldenburg and Bryant (2007) decompose the system into process-level models. They focus on a simple certification framework. The storage complex is divided into compartments. The likelihood of a leak is evaluated by estimating the probability that a leakage pathway encounters the CO_2 plume on the one side, and a target on the other side. The CO_2 flux across the pathway is simulated through deterministic simplified models, and the impacts of the release compared to acceptable thresholds. A level of risk is obtained by the product of the values of the probability and the consequences (CSLF, 2009).

Researchers for the Weyburn CO_2 Monitoring and Storage Project have developed a program called CQUESTRA (CQ-1) and applied it to components of the project (Whittaker *et al.*, 2004). The probabilistic conceptual model (PCM) consists of two components: the model domain, which defines the geologic setting, and the model processes, which include the physical and chemical processes that define CO_2 mass transport and storage. The model domain is divided into four broad areas: the biosphere, the upper geosphere (all aquifers and aquitards above the reservoir), the wells, and the lower geosphere (reservoir and the aquifers and aquitards below the cap rock). Local variability in formation porosity, permeability, Darcy flow velocity, *etc.*, is incorporated into Probability Distribution Functions (PDFs) to capture the uncertainty in the PCM's domain features and processes. Once the physical PCM domain is fully described, CQ-1 quantifies the main driving forces relevant to the storage of CO_2 in a reservoir. CQ-1 was used to model the Weyburn system for a period of 5,000 years after completion of EOR CO_2 injection. A Monte Carlo simulation method was used to sample the probability distribution functions for the CQ-1 input parameters (Deel *et al.*, 2007).

6.2.3 Features, Events and Processes methodology as an approach to risk assessment for CO_2 storage

Many of the ongoing risk assessment efforts are now cooperating to identify, classify and screen all factors that may influence the safety of storage facilities, by using the Features, Events and Processes (FEP) methodology (IPCC, 2005). Risk identification (or qualification) of hazards includes estimation of the probability of specific features, events, and processes (FEPs) that could contribute to, or prevent, unplanned CO_2 migration from the confining zone (NETL, 2011; DNV, 2010):

- *Features* include the physical characteristics or properties of the system, such as lithology, porosity, permeability, caprock thickness, faults, wells, leaky wellbores and nearby communities.
- *Events* include discrete occurrences that may occur in the future affecting one or more components of the system, such as earthquakes, subsidence, drilling, penetration of the storage site by new wells, injection pressure increases, borehole casing leak, pipe fracture and well blow-outs.
- *Processes* include physico-chemical processes, often marked by gradual or continuous changes, that influence the evolution of the system; chemical reactions, precipitation of minerals, ground water flow, multiphase flow, CO_2 phase behaviour, gravity-driven CO_2 movement or residual saturation trapping, geomechanical stress changes and corrosion of borehole casing.

Fig. 6-6 illustrates the relationship between, features, events and processes (FEP) and potential risk impacts. For example, the storage reservoir may have insufficient capacity or injectivity, leading to the risk that CO_2 injection cannot be sustained over the life of the project. The impact assessment would estimate the techno-economic and societal impacts of such a scenario (NETL, 2011).

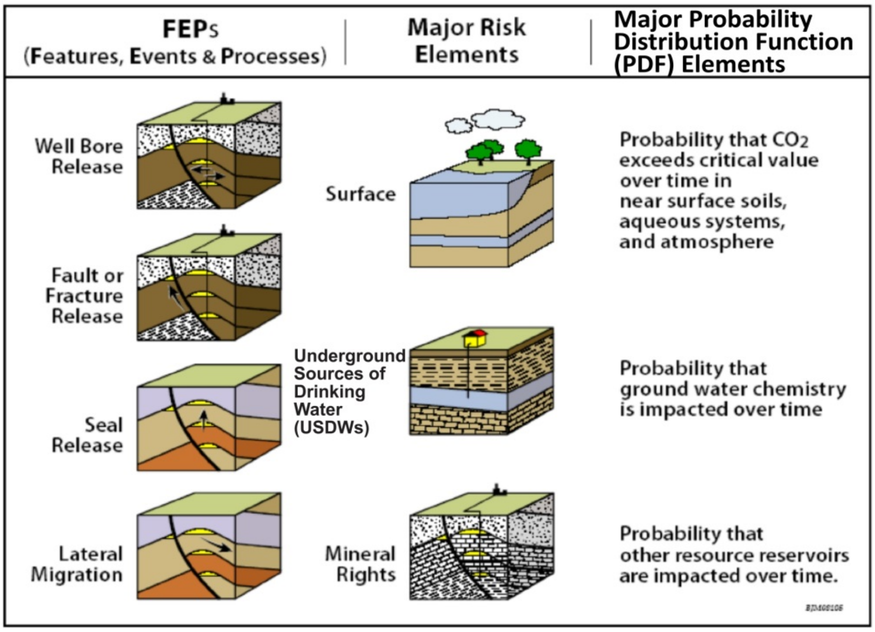

Fig. 6-6: Examples of relationships among Features, Events, Processes, and Potential Impacts (NETL, 2011).

The risk assessment is based on simulations of different scenarios built up from FEPs. Main steps in the assessment are: (a) establishing risk assessment criteria, (b) description of the geological system by investigation and screening of all features, events and processes (FEPs) that are relevant to the long-term safety, so called FEP analysis, (c) identification of the most important FEPs, (d) scenario selection and analysis based on the FEP analysis, (e) system model development using numerical reservoir simulation, and (f) qualitative and quantitative consequence analysis (NETL, 2011; Chadwick *et al*., 2008). The very first step of risk assessment is the definition of the assessment basis, which consists of: (a) risk acceptance criteria, (b) containment concept and (c) setting of the storage site.

In some cases, for the assessment of a storage structure, a modified performance assessment (PA) methodology can be used. PA is a system analysis that predicts the behaviour or "performance" of an element of a geological storage project (specified system) relative to one or more performance standards (system performance indicators). If the indicator is a health, safety and environmental (HSE) effect, the PA is termed a safety assessment.

The FEP analysis is performed using databases developed in earlier CO_2 safety assessment studies (Wildenborg *et al*., 2005; Maul and Savage, 2004). The databases are used as selection tools for early screening of relevant FEPs. The main steps in the FEP analysis are illustrated in Fig. 6-7. The main tools that support the process are the FEP database and the visual analyser (Chadwick *et al*., 2008). A distinction can be made between features as static factors, and events and processes (EPs) as dynamic factors. For each individual EP the following aspects can be evaluated: (i) specifications of how the EP is interpreted, *e.g.* its relation to safety, (ii) semi-quantitative probability that an EP will occur, and (iii) potential impact if the EP occurs. EP grouping can be carried out and criteria for EP groups can be based on the information that is available in the FEP database (Wildenborg *et al*., 2005), such as: (i) common parameters (distinct features such as permeability, rock strength, etc), (ii) process types (mechanical, chemical, thermal, hydraulic, biological), (iii) effect type (on matrix, fluid, stored CO_2, indirect), (iv) timescale of EP occurrence (in 100 years, in 1000 years or in 10000 years), (v) duration scale of EP while occurring (hours, days, centuries and longer), and (vi) spatial scale (metres, km, tens of km, basin scale) (Chadwick *et al*., 2008).

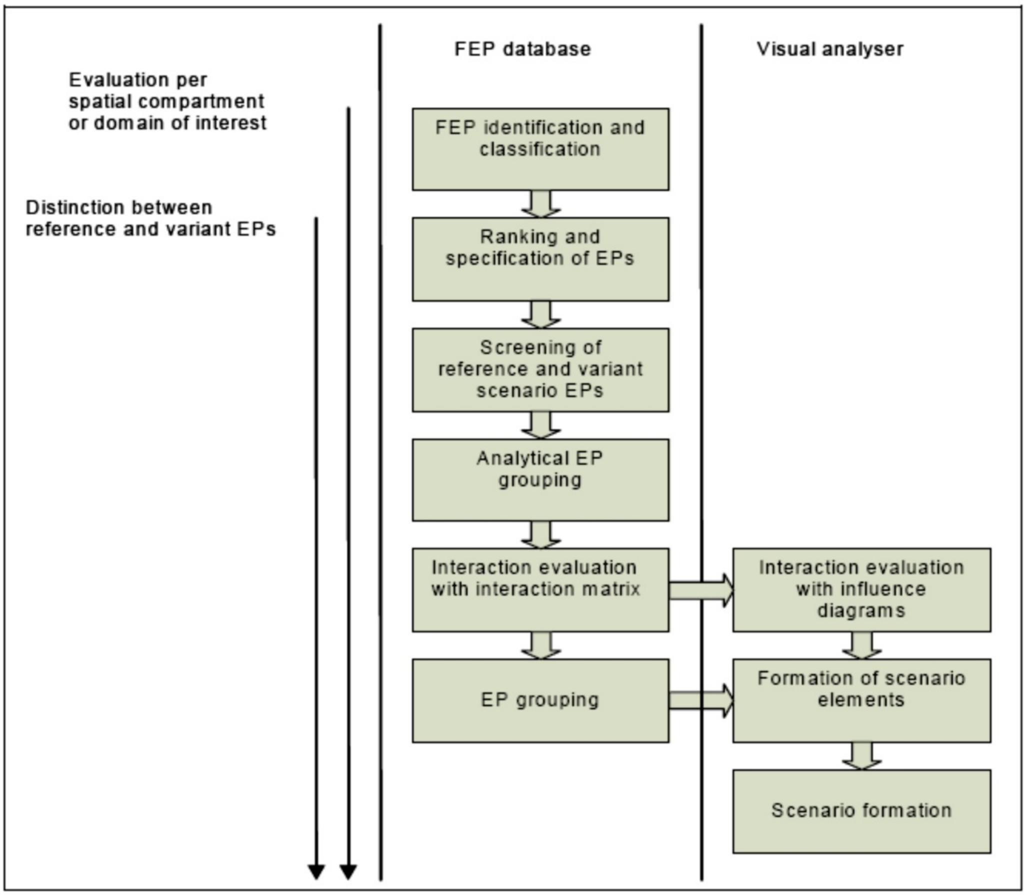

Fig. 6-7: Main steps in used FEP analysis methodology. Based on the analysis process in Wildenborg *et al*. (2005) and Chadwick *et al*. (2008).

The FEP database holds FEPs that may have a potential effect on the safety of the storage system (Chadwick *et al*., 2008). It can help the site-specific description of the system and identification of site-specific issues, allowing comprehensive evaluation of each site's unique characteristics (CSLF, 2009). FEP database also ties information on individual FEPs to relevant literature and allow classification with respect to likelihood, spatial scale, time scale and so on. However, there are alternative approaches (IPCC, 2005). All FEPs in the database have a complete set of identification and classification attributes (Fig. 6-8). These attributes have been assigned generically, and could be used to filter case-specific FEPs with respect to the assessment basis (Chadwick *et al*., 2008).

Detailed lists of FEPs for geologic systems have evolved for various environmental needs, and these have been adapted to a generic database for geologic storage of CO_2 by Quintessa (*Savage et al*., 2004; Maul *et al*., 2005). The Quintessa database (http://www.quintessa-online.com/fep.php) currently includes around 200 FEPs in a hierarchical structure, with individual FEPs grouped into eight categories. Each FEP has a text description and an associated discussion of its relevance to long-term performance and safety. Key references from the published literature are included to enable retrieval of more detailed information for each FEP. The database incorporates hyperlinks to other relevant sources of information (reports, websites, maps, photographs, videos, *etc*.), and is searchable in a variety of ways. The generic FEP database is intended to be the first stage in developing a FEP-based auditing capability for more detailed project-specific FEP databases. At present there are no project specific FEP databases in the system, but the capability is present and it is hoped that some project-specific databases will be added in the near future.

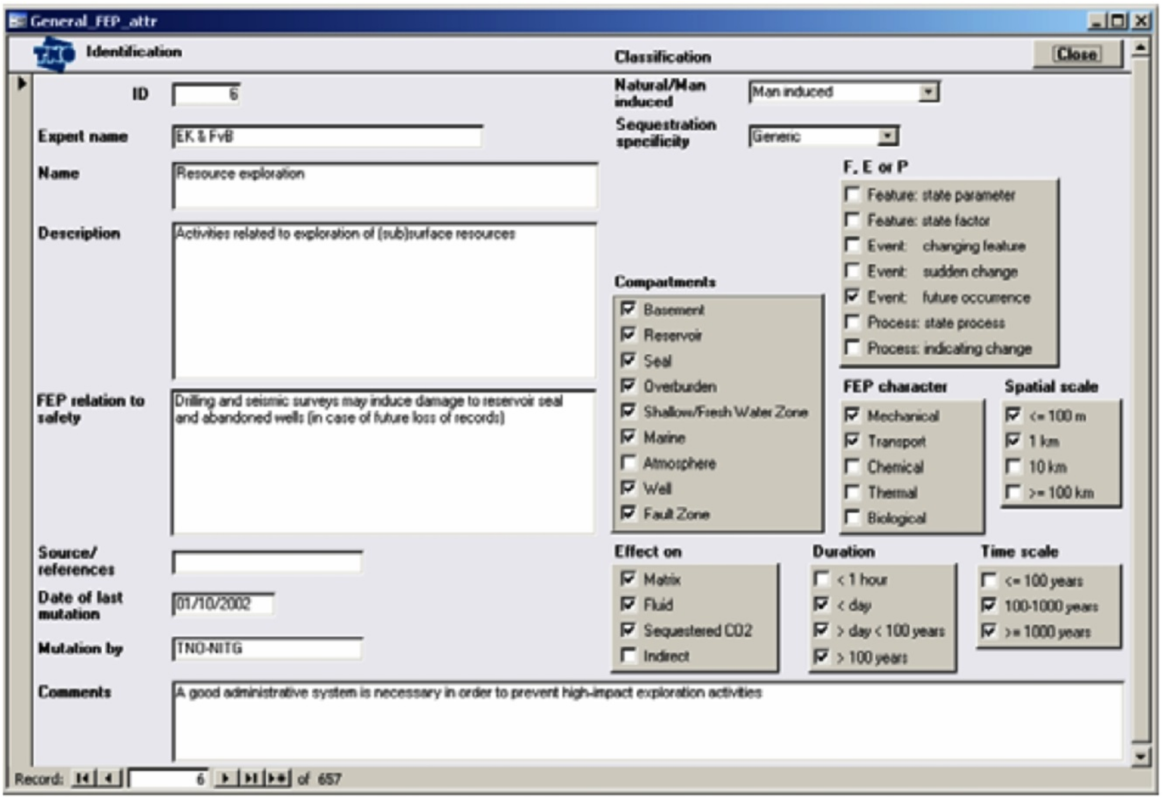

Fig. 6-8: FEP Example of generic FEP attributes in the FEP database (Chadwick *et al*., 2008).

Utilising the definition of the storage system set out in the assessment basis, the FEPs are ranked and screened in order to identify the FEPs that are likely or very likely to occur. These FEPs are grouped and assigned to specific zones within the geological storage system (compartments). Because the future evolution of a geologic system cannot be precisely determined, various possible scenarios for possible evolutions of the system and situations of particular interest are developed (NETL, 2011). Most risk assessments involve the use of scenarios that describe possible future states of the storage facility and events that result in leakage of CO_2 or other risks. Each scenario may be considered as an assemblage of selected FEPs (IPCC, 2005). Some risk assessments define a reference scenario that represents the most probable evolution of the system. Variant scenarios are then constructed with alternative FEPs. Various methods are used to structure and rationalize the process of scenario definition in an attempt to reduce the role of subjective judgements in determining the outcomes (IPCC, 2005). For example, based on the FEP analysis and the scenario formation, some “what if?” scenarios can be identified for simulation: (i) reference scenario assuming that no failure of the containment zone occurs, (ii) leaking seal scenario assuming that the seal will fail by geochemical processes, whereby CO_2 enhances the permeability of the caprock and migrates into the overburden. (iii) leaking well scenario assuming that the sealing capacity of an existing old well will fail, followed by transport of CO_2 along the well trajectory, (iv) leaking fault scenario assuming that there is a fault through the caprock, and that the sealing capacity of the fault will fail, followed by CO_2 escape from the containment zone along the fault (Chadwick *et al*., 2008). The data input to early stage risk assessment will frequently be associated with significant uncertainty. Consequently, early stage risk assessment may be qualitative, based on FEPs, to lead to site selection or data characterization. It should be refined over time to incorporate new data, and at least at the closure of a project a minimal confidence should be gained to proceed with transfer of responsibility. Such analyses are typically based on expert elicitation activities, implying that the results to some extent depend on the subjective views and opinions of the experts involved. A key challenge is therefore how to enhance repeatability and consistency of risk assessments to make the associated process and results verifiable and auditable (DNV, 2010).

The FEP assessment methodology is useful but still has gaps in knowledge. This concerns many aspects, *e.g.* safety and risk terminology, usage of FEP database, scenario evaluation, assessment criteria, modelling tools and so on (Chadwick *et al.*, 2008). Figure 6.9 shows different stages in a FEP analysis, from identification to scenario formation. The FEP approach has been used in many of the initial CO_2 storage efforts, such as Sleipner in Norway (Torp and Gale, 2003), Weyburn in Canada (Stenhouse *et al.*, 2006a&b), In Salah in Algeria (Riddiford *et al.*, 2005), and the Decatur Project in the Illinois basin of the United States (Hnottavange-Telleen *et al.*, 2009).

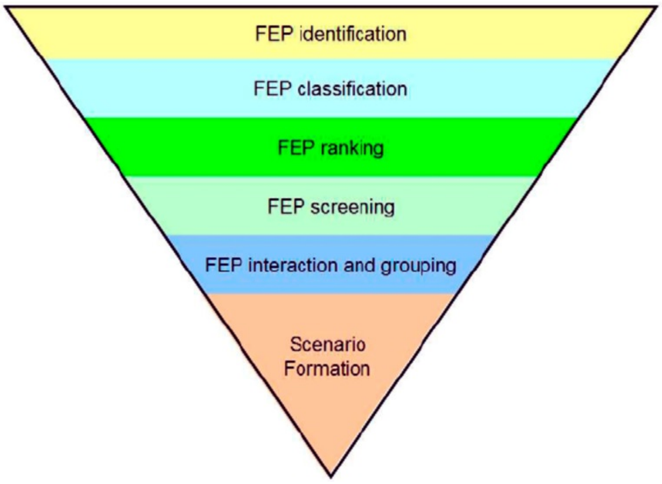

Fig. 6-9: Different stages in a FEP analysis, from identification to scenario formation (Savage *et al.*, 2004; Condor *et al.*, 2011).

Relational approaches with FEPs

There are a number of different ways in which the FEPs and their relationships can be developed to describe a site's behaviour. The retained FEPs are classified in both spatial and contextual terms (Savage *et al.*, 2005; Korre and Durucan, 2009). Three approaches have been used (CSLF, 2009):

a) *A "top-down" approach*. An example of this approach is the Master Directed Diagram (MDD) approach, which was developed by Nirex of the UK (Nirex, 1998). An MDD is a diagram like a tree-like structure that has some of the attributes of a network.

b) *The Process Influence Diagram (PID) approach*, which identifies and represents all possible influences between all FEPs within a system.

c) *The interaction matrix approach.* FEPs representing components of the system under consideration are placed on the leading diagonal elements (LDEs) of the matrix. Interactions between LDEs are then noted in the off-diagonal elements (ODEs).

Among these approaches, the PID has been used for the risk assessment in the Weyburn CO_2 storage project (Stenhouse *et al.*, 2005) and matrix representations of FEP interactions was applied to a hypothetical CO_2 storage project (Savage *et al.*, 2005; Korre and Durucan, 2009).

Regarding FEP methodology, there is some discussion as to whether a 'bottom-up' or 'top-down' approach is the best. 'Bottom-up' involves identifying every conceivable FEP and then building scenarios from these. This approach is time-consuming and might miss key scenarios through 'participant exhaustion' and time limitations. The 'bottom-up' approach uses the database directly to develop the assessment tools. 'Top-down' involves identifying a limited number of key risk scenarios. This approach might miss important FEPs, and important potential scenarios. In the 'top-down' approach, a FEP database can be used as an audit tool to ensure all relevant FEPs are included in the models, to document the reasons why others have not been considered (Condor *at al.*, 2011) and to check completeness of the scenarios built. Overall, the 'top-down approach is favoured, but irrespective of the approach, it is important that the link between FEPs and scenarios is fully documented. An important issue connected with FEP/scenario risk analysis is that worst-case processes tend to be emphasised irrespective of how (un)likely they are to actually occur. Thus, leakage scenarios tend to get highlighted and qualifying uncertainties and assumptions ignored. Overall, quantitative assessment of the probability of any particular scenario occurring is very difficult, particularly for scenarios involving geological FEPs (*e.g*. fault leakage, caprock failure *etc*). An alternative to quantitative risk analysis may be to set out a storage plan, based on robust site characterisation, identify site-specific containment risks (and uncertainties), and design an efficient monitoring and remediation strategy (Chadwick *et al*., 2008).

Steps after FEPs analysis

After FEPs analysis, *detailed site characterization* and *simulation* provide data to assess exposure due to the vulnerabilities in a qualitative or quantitative manner. Successful CO_2 geological storage requires thorough *site characterization*, especially for storage in saline formations that have not previously been considered an economic resource, as well as a clear understanding of the processes and mechanisms by which CO_2 is transported and trapped (NETL, 2011). The *estimated exposure* indicates the probability that a particular negative event would occur. In the subsequent step, the effects of the vulnerabilities (impacts) are assessed using qualitative or quantitative tools. The impacts and exposure data from the previous two stages are used to assess the risk in the final step of the risk assessment process, namely, *risk characterization* (Figure6. 4), through which the probability of the occurrence of events and the magnitude of loss from them are determined (*effects assessment*). In risk characterization, exposure and effects data are integrated to produce qualitative, semi-quantitative, or quantitative measures of risk. Ultimately, the set of quantitative and qualitative risk factors and their potential impacts become the basis for developing practical *risk management* and *mitigation plans* (NETL, 2011).

6.3 Risk assessment tools for CGS projects in various field cases

A survey of various risk assessment tools that incorporate geologic CCS risk assessment methodologies was conducted and updated with feedback from individuals involved in the development of specific risk assessment methodologies (Tab. 6-2).

Tab. 6-2: A Summary of geologic carbon storage risk assessment Tools (NETL, 2011)

Tool	Methodology Family
Quintessa FEP database	Qualitative, FEPs screened by experts
TNO Risk Assessment Methodology	Expert-elicited probability and consequence matrices
CO2QUALSTORE guideline, DNV	Qualitative/Semi-quantitative with "panel" inputs
Carbon Storage Scenario Identification Framework (CASSIF), TNO	Qualitative, scenario-based
Risk Identification and Strategy using Quantitative Evaluation (RISQUE), URS	Semi-quantitative, expert-elicited probability and consequence matrices
Screening and Ranking Framework (SRF), LBNL	Qualitative, expert-elicited probabilities
Certification Framework (CF), LBNL	Quantitative, system-level model, probabilities partly calculated using fuzzy logic
Vulnerability Evaluation Framework (VEF), U.S. EPA	Qualitative
Performance Assessment (PA), Quintessa	Evidence-support (three-valued) logic (ESL) Distinguishes cases of poor-quality data from uncertain data
CarbonWorkFlow* Process for Long-term CO_2 Storage	Semi-quantitative; FEPs ranked through expert elicitation using a risk matrix approach
CarbonSCORE* software to preassess potential CO_2 storage sites	All evaluated criteria are quantitatively weighted, jointly evaluated, and summarized
Oxand Performance & Risk (P&R™) Methodology	Quantitative Risk matrix evaluation: semi-quantitative
CO_2-PENS, LANL	Quantitative, hybrid system-process model

* *mark of Schlumberger*

Work undertaken to amend the conventions regulating injections under the sea-bed (*i.e.,* the London Convention/Protocol and the OSPAR Convention) have led to an agreement on a risk assessment framework (OSPAR, 2007) consisting of six essential steps. A methodological framework for assessing risks associated with CO_2 storage operations has been developed in the EC-funded project CO2ReMoVe. A study for the IEA Greenhouse Gas Programme (IEA GHG, 2007) examined the transposition of the usual Environmental Impact Assessment frameworks for use with CCS (CSLF, 2009).

The OSPAR Framework for Risk Assessment and Management (FRAM) of Storage of CO_2 Streams in Geological Formations (OSPAR, 2007) describes an iterative process that is proposed for continual improvement of the management of a storage project during its lifetime. It has been designed to meet the requirements of off-shore storage settings. The same framework with small adjustments would also be applicable for onshore CO_2 storage settings. It suggests that a simple conservative deterministic assessment is sufficient when adverse consequences are insignificant, but when a precautionary approach is necessary, the assessment should include probabilistic approaches to achieve acceptable results. This frameworks consists of the six following stages with some modifications for onshore storage settings:

- Problem formulation defining the boundaries of the assessment and including scenarios and pathways (*i.e.,* suitability of deep geological formations, nature of overburden, characteristics of marine/land environment, need for long-term monitoring),
- Site selection and characterization (*i.e.,* collection and evaluation of data concerning the site),
- Exposure assessment (*i.e.,* characterization and movement of the CO_2 stream),
- Effects assessment (*i.e.,* assembly of information to describe the response of receptors),
- Risk characterization (*i.e.,* integration of exposure and effect data to estimate the likely adverse impact),
- Risk management (*i.e.,* including monitoring, mitigation and remediation measures).

The FRAM approach is relevant to all phases throughout the life time of a CO_2 storage project defined by the OSPAR (2007) including planning, construction, operation, site-closure and post-closure (OSPAR, 2007; Korre and Durucan, 2009).

In Europe, two EU Directives require the assessment of the impacts of major projects on the environment before they can be authorized: (a) Strategic Environmental Assessment (SEA) Directive, relating to proposed plans and programmes; and (b) Environmental Assessment Directive, which requires that the environmental consequences of individual projects are identified and assessed before authorization is given, in particular the direct and indirect effects of a project on (i) human beings, fauna and flora; (ii) soil, water, air, climate and the landscape; (iii) material assets and the cultural heritage; and (iv) the interaction between the above factors (Stenhouse *et al*., 2009). In January 2008, the European Commission proposed a Directive to enable environmentally-safe capture and geological storage of CO_2 in the EU as part of a major legislative package. The final version of the Directive (2009/31/EC) was published in the Official Journal of the European Union on 23rd April 2009 (EC, 2009). The EU member states are responsible for the transposition of the Directive to national legislation. In Annexes I and II of the Directive, the criteria for the characterization and assessment of potential storage complex and surrounding area and the criteria for establishing and updating the monitoring plan are described respectively. The characterisation and assessment of the potential storage complex and surrounding area referred to in Article 4(3) can be carried out in three steps:

Step 1 - Data collection covering the intrinsic characteristics of the storage complex;

Step 2 - Building the three-dimensional static geological earth model or a set of such models of the candidate storage complex including the caprock and the hydraulically connected areas and fluids shall be built using computer reservoir simulators;

Step 3 - Characterisation of the storage dynamic behaviour, sensitivity characterisation and risk assessment based on dynamic modelling, comprising a variety of time-step simulations of CO_2 injection into the storage site using the three-dimensional static geological earth model(s) in the computerised storage complex simulator (the risk assessment will comprise hazard characterisation, exposure assessment, effects assessment and risk characterisation).

6.4 Application of risk assessment activities in various field cases and countries

Risk assessment activities have been performed for several CGS pilot sites or projects in some countries. Most activities have relied heavily on FEPs analysis, and some have additionally conducted process-level simulations for predicted fate of CO_2 in the reservoir (CSLF, 2009).

6.4.1 Weyburn, Canada

At Weyburn (Canada), the long-term behavior of the CO_2 and leakage risks at were assessed within a methodological framework based on the FEPs (Stenhouse *et al*., 2005). The Quintessa FEP database was initially developed for this application. A number of simulations were performed. Fully probabilistic calculations find a 95% probability that the cumulative amount of CO_2 released after 5,000 years will be less than 1% of the total amount stored (Walton *et al*., 2004). A deterministic model for transport in the reservoir with probabilistic model for leakage through wells shows a maximum release of 0.14% of the total amount of CO_2 stored (Zhou *et al.,* 2004). The Weyburn risk analysis indicated that the most probable path for transmission of CO_2 from one stratum to another or to the biosphere is along a well bore. Therefore, wells must be carefully drilled and monitored. Application of the CQ-1 program based on simulations showed that CO_2 may migrate from the initial formation tending to dissolve in the aquifers above the reservoir. Based on the Monte Carlo simulation method, after 5,000 years, the mean release to the biosphere of CO_2 in place will be 0.2%. 5-34% of CO_2 initially in place in the Weyburn formation will migrate to upper and lower aquifers. There is 95% probability that 98.7-99.5% of the initial CO_2 in place will remain stored in the geosphere for 5,000 years (*Deel et al*., 2007).

6.4.2 Latrobe Valley and Otway Basin, Australia

The GEODISC-RISQUE approach (Quantitative Risk Assessment) has been used for several field cases in Australia, *e.g.* the Latrobe Valley located within the Gippsland Basin (Hooper *et al.,* 2005) and the Otway Basin (Sharma and Cook, 2007). This semi-quantitative methodology relies on expert-panel analysis of hazardous events (*i.e.,* risk events such as leakage from existing exploration and production wells or injection and monitoring wells, leakage from permeable zones in seals and regional-scale over-pressurisation, leakage from faults through seals and earthquake-induced fractures, leakage from exceeding the "spill point" of the storage site and incorrectly predicting the migration direction, loss of containment and event risks quotients), for which the likelihood, consequences, and timescale of occurrence of each is assessed (Hooper *et al*., 2005).

a) The Quantitative Risk Assessment (QRA) carried out for the containment issue of the Latrobe Valley CO_2 Storage Assessment (LVCSA) project. The context of the QRA for the studied site was defined, including injection timeframes, locations, and amounts; reservoirs and expected plume migration (including to existing wells and faults) and eventual traps (CSLF, 2009). The LVCSA risk assessment process has provided strong indication that the Gippsland Basin can be safe and effective site for CO_2 for thousands of years. A CO_2 leakage rate of 1% over 1,000 years is commonly used as an acceptable level for storage assurance and the targeted reservoirs within the offshore Gippsland Basin are predicted to be below that level. The risk assessment identified a number of issues and mitigation measures that will need to be addressed by project proponents. Several specific mitigation actions have already been factored into the costings for the project. The LVCSA indicates that all issues associated with proposed injection are manageable (Hooper *et al.,* 2005).

b) The CO2CRC's Otway Basin Pilot Project (OBPP) is located in Victoria. Risk areas have been identified through the project's risk assessment process and an extensive monitoring and verification scheme has been proposed to address some of these issues. A Quantitative Risk Assessment (QRA) was performed using the RISQUE method. The process involves the use of expert panels to provide input into a quantitative risk analysis and management framework. The expert panel considered the data gathered since 2005 and the initial risk assessment and updated the risk assessment for the pilot project. Both the engineered system (wells) and the natural system (site geology, reservoir formation, overlying and underlying formations and groundwater flow regimes) were considered. The QRA can be modified as new data becomes available. At a planning confidence level of 80% it was seen that (a) no single risk events exceeded acceptable risk quotient, and (b) total risk event quotient was less than acceptable target (1% leakage over 1,000 years, thus a low risk). Major risks events are leakage from existing faults, and leakage from wells (in particular damage to cement) (CSLF, 2009; O'Brien, 2008).

6.4.3 Latrobe Valley and Otway Basin, Australia

The Chevron-Shell-ExxonMobil Gorgon Project will store CO_2 resulting from the production of natural gas in the Greater Gorgon area fields (coast of Western Australia). On September 14, 2009, Chevron Australia and its Foundation Participants, ExxonMobil and Shell announced a Final Investment Decision on the Gorgon Project. In August 2009 the Gorgon Project also completed its environmental assessment process. The environmental approvals were the result of 6 years of preparation, including the research and contributions of numerous independent experts and extensive community consultation. The EIS (Environmental Impact Statement) completed in May 2006 details the risk assessment process used as well as its results. The environmental risk assessment process has evaluated the likelihood (using a qualitative scoring system) and consequences of adverse environmental impacts. Potential risks and environmental consequences were identified by technical experts in a broad range of fields through a series of workshops. Some deterministic "what if" scenarios as well as a probabilistic approach were taken with respect to managing uncertainties associated with CO_2 storage, including identifying, evaluating, and generating options for managing subsurface risks. Extensive monitoring activities are planned to manage and reduce uncertainty associated with CO_2 injection / storage activities. A plan has been proposed to manage events such as unpredicted migration of the CO_2, unacceptable formation pressures, corrosion of pipelines and wells, and others. The probability of CO_2 migrating to the surface has been determined to be remote. Studies of the area have determined that the containment risk (risk of containment failure) is extremely low, and unacceptable risk associated with CO_2 storage at any point would likely result in venting of the CO_2 to the atmosphere. Potential impacts on the project were evaluated in terms of: health, safety, and environmental issues; containment; monitoring and verification; injectivity; capacity; risk to hydrocarbon / other assets; cost. Responses to these potential impacts (such as using relief wells, if necessary, to release formation pressure and mitigate the risk of migration along faults or fractures) were developed and are described in the EIS (CSLF, 2009; Chevron Australia Pty Ltd, 2006; http://www.chevronaustralia.com/ourbusinesses/gorgon.aspx).

6.4.4 In Salah, Algeria

In the In Salah CO_2 storage project, different Quantitative Risk Assessments (QRA) methodologies have been conducted. Pre-injection risk assessment highlighted the key risks and informed the baseline data acquisition programme and early monitoring (Mathiesson, 2012). Four methods were applied to this project (Dodds *et al*., 2011; Paulley *et al*., 2011): the RISQUE QRA process developed for CO2CRC (Bowden and Rigg, 2004); the Certification Framework (CF) (Oldenburg *et al*., 2009); the Quantitative Risk Through Time Analysis (QRTT), an approach developed within BP, and the FEPs approach.

a) Based on the *URS RISQUE method*, the risk quotient for 'migration direction' was determined where a likelihood of the event was assessed a value of a 'possible' (0.01) to 'highly probable' (0.1) with a leakage rate of 200,000 to 250,000 T/yr. The leakage rate was based on future injection rates and modeled plume migration. It was assumed that, if this risk was to eventuate, there would be a delay in the detection of up to 5 years due to data acquisition, interpretation and implementation of a response strategy. Three response actions were evaluated to demonstrate the effect of differing responses on the risk quotient. The expert group evaluated the relative reduction in likelihoods and/or consequences that could reasonably be achieved through implementing three possible risk response actions. The dominant containment risk event seems to be migration direction, which would be considered to be an unacceptable risk since it exceeds the target risk for a single event by around one order of magnitude. All of the other containment risk events show risk levels that are more than one order of magnitude less than the target for individual events and are therefore considered to pose an acceptable risk. Migration direction poses around two orders of magnitude more risk than the second highest event, well leakage. There are many potential processes that could allow this loss of containment by migration direction (*e.g.* uncertainty regarding the location and depth of the structural spill-point, possibility of a fractured reservoir) (Dodds *et al*., 2011).

b) The *Certification Framework (CF)* was applied at two different stages in the state of knowledge of the project: (a) at the pre-injection stage, using data available just prior to injection around mid-2004; and (2) after four years of injection (September 2008) to be comparable to the other risk assessments. The main risk drivers for the project are CO_2 leakage into potable groundwater and into the natural gas cap. The CF approach takes great care in defining boundaries of the storage region. Both well leakage and fault/fracture leakage are likely under some conditions, but overall the risk is low due to ongoing mitigation and monitoring activities. Results of the application of the CF during these different state-of-knowledge periods show that the assessment of likelihood of various leakage scenarios increased as more information became available, while assessment of impact stayed the same (Oldenburg *et al*., 2008). The overall CO_2 Leakage Risk (CLR) as determined by the CF method is estimated as low for the In Salah Storage project at Krechba. The largest risk is to USDW by CO_2 leakage into wells via poorly cemented annuli and a subsurface blowout via casing defects and available research indicates such an event has less than a 1% probability over the project life. However given the known poor seal integrity at several suspended legacy appraisal wells within the lease area, this probability is likely higher at Krechba (Dodds *et al*., 2011).

c) The *QRTT (Quantitative Risk Through Time)* technique is an internal BP methodology that evaluates the relationship between the risk mechanisms for CO_2 loss and the stochastically forecasted, changing dynamics of the storage system (*i.e*., formation pressure, fluid chemistry). The In Salah QRTT analysis was carried out over three pathways to represent the risk mechanics from the three injectors. The URS 2008 RISQUE risk assessment outputs were used to populate the QRTT tool. To assign pressure dependency on the various risks, it was assumed that the likelihoods for relevant risk were judged at the maximum likely pressure that the risk mechanism would experience. The temporal risk analysis of the In Salah CO_2 storage project is displayed as a series of risk curves for cumulative risk, overburden integrity, well integrity and lateral leakage. The temporal risk output shows that the heightened leakage risk for the project occurs during the operational (injection phase). The majority of risk is a consequence of the high injection pressure relative to the low permeability and small pressure window of operation for the In Salah Project. The key risk controlling this is migration direction. Well leakage risk is moderate through the 1,000 year risk period (Dodds *et al*., 2011).

d) A *structured qualitative* approach needed to support assessment has been applied to this industrial scale project at Krechba. A *qualitative Performance Assessment (PA)* framework was devised and implemented. The approach included identification of the *FEPs* that describe the Krechba system and its likely evolution. An ‘expected evolution’ scenario was then identified by systematically evaluating existing knowledge. Scenarios describing potential situations that could involve alternative evolution mechanisms were also identified; these included consideration of mechanisms that could in principal lead to containment failure. These scenarios can be analysed to show that they are either unlikely to occur and/or will be limited impact and so do not represent threats to adequate performance. After audit against Quintessa's freely available generic online CO_2 FEP database to ensure demonstrate comprehensiveness, the site-specific scenarios identified and the associated list of remaining uncertainties, were used to prioritise future (*e.g.* systems modelling) work. The process was systematic, transparent and in line with guidance from documents concerning legislation and regulation. The outcomes have been used to identify uncertainties, prioritise ongoing work, including systems modelling approaches, and update the FEP and scenario descriptions (Paulley *et al.,* 2011).

6.4.5 Planned storage project - Decatur Project in Illinois, USA

Schlumberger Carbon Services (a service provider for carbon dioxide capture and storage; measurement, monitoring, and verification; and risk assessments) recently presented an example of a risk assessment for a planned storage project in Illinois (Hnottavange-Telleen *et al*., 2009). To develop this risk assessment, Schlumberger convened a group of experts to rank a list of more than 80 risk elements - or features, events, and processes (FEPs) - based on 'likelihood' (L) and 'severity' (S). These rankings were developed through a group process and independent surveys of the experts. The rankings were assessed through two methods. First, the team developed a combined (L*S) ranking and compared group and individual ratings. Second, the team mapped FEPs on a grid, with severity on the vertical axis and likelihood on the horizontal axis. These approaches provide the project team with a good assessment of concerns that could arise at the specific site and will enable them to both incorporate those risks into the reservoir models and also to mitigate those risks through careful planning and operations. Results are being used to rationalize and shape risk-reduction measures, especially those involving well engineering and subsurface characterization (WRI, 2008; Hnottavange-Telleen *et al*., 2009). This kind of assessment also helps the team to design a monitoring plan and interact with the public and regulators. It is important to note that this kind of assessment can be repeated over time; it is not a static analysis (WRI, 2008). Risk evaluation influences plans for monitoring and external communications, and informs the construction and quantitative attribution of flow simulations and system models (Hnottavange-Telleen *et al*., 2009). The project in Illinois is a qualitative ranking case study.

6.4.6 Storage project in Kalundborg, Denmark

In order to address properly the risks related to underground storage of CO_2 in the Kalundborg case study the Quintessa database (*www.quintessa.org/consultancy/index.html?co2GeoStorage.html*) of features, events and processes (FEPs) was used (Chadwick *et al*., 2008), with the chosen FEPs being included for their relevance to the long-term safety and performance of the storage system after injection of CO_2 has been completed and the injection boreholes have been sealed. Some FEPs associated with the injection phase are nevertheless considered where these can affect long-term performance. In the Kalundborg case study, the most important FEPs resulting from the auditing are as follows: (i) geological features, (ii) overpressuring - reservoir characteristics, (iii) effects of pressurisation of reservoir on caprock, (iv) undetected features, faults at top of reservoir long-term fate of CO_2, (v) reversibility - fingering leading to CO_2 escaping the trap, (vi) impact on society and humans, (vii) public opposition to the storage project, and (viii) impacts on humans - health effects of CO_2. In addition to the risk assessment performed through the Quintessa database a number of other project risks has been considered. The project in Kalundborg is just a risk identification case study.

6.4.7 CO_2 storage project in Schwarze Pumpe – Schweinrich, Germany

For the assessment of the Schweinrich storage structure in Germany, a modified *performance assessment (PA)* methodology was used comprising the following steps: (i) definition of the assessment basis, (ii) FEP analysis, (iii) safety scenario formation, (iv) development of dedicated models for probabilistic simulation of safety scenarios, and (v) safety evaluation against HSE effects. The FEP database holds FEPs that may have a potential effect on the safety of the storage system. The latest version of the database contains a total number of 657 FEPs, extracted from various sources. All FEPs have a complete set of identification and classification attributes. These attributes have been assigned generically, and could be used to filter case-specific FEPs with respect to the assessment basis. Case specific FEPs for the Schweinrich case were identified according to the following criteria:

a) FEPs should have a timescale of occurrence less than 1000 years,

b) FEPs should lie within the spatial domains of reservoir, seal, overburden and fault,

c) FEPs in the spatial domains shallow subsurface, ocean, atmosphere and underburdon are omitted,

d) FEPs with respect to well integrity and engineering are not evaluated since the design and completion of future injection wells is unknown. EPs for the Schweinrich case will be divided into geochemical EPs acting on long timescales (about 1,000 years), and into geomechanical EPs valid for both short and long timescales of occurrence and duration.

Two EP groups were identified: a leaking fault EP group and a leaking seal EP group. The geomechanical EPs all relate to the leaking fault EP group. The geochemical EPs relate to both the leaking fault and the leaking seal EP group (Chadwick *et al.,* 2008). Some limitations are applicable to the Schweinrich case study, as follows:

- *Time frame:* The time frame for the FEP analysis was set to 1,000 years. Hazards that may occur as consequence of the identified safety factors were evaluated for 10,000 years, *i.e*., the simulation period was 10,000 years.
- *Spatial domain of the investigated storage system*: The reservoir, seal, overburden, faults and wells compartments were evaluated. The shallow subsurface, ocean (not relevant for structure Schweinrich), atmosphere and underburden compartments were excluded. This selection process is related to the available input data and limitations in the model.
- *Probability of occurrence of evaluated scenarios:* No attempt to quantify the probability of occurrence of the evaluated scenarios has been made. Instead, it was assumed that the scenarios will definitely occur, *i.e.,* the probability of occurrence of the CO_2 leakage scenarios is set to 1. These evaluated scenarios represent worst cases.
- *Input data:* The study used input data that were gained from former geological surveys of the area.
- *Model limitations*

Based on the FEP analysis and the scenario formation, the following "what if?" scenarios were identified for simulation:

- Reference scenario assuming no failure of the containment zone occurs,
- Leaking seal scenario assuming seal failure by geochemical processes and CO_2 migration into the overburden,
- Leaking well scenario.

Model software was used for the simulation of four scenarios. In the Schweinrich case, the scenarios present hypothetical future flow and fate of CO_2 in the next 10,000 years. The potential impact of each scenario was expressed as the maximum concentration and flux of CO_2 in the pore system in the shallowest overburden unit, Pleistocene sediments (which form the topmost subsurface layer in the simulation models). No outcome was simulated regarding groundwater deterioration and mobilisation of heavy metals, since no modelling of the flow and fate of CO_2 in the unsaturated zone was conducted. In case of uncertainty on input parameters that were not varied stochastically, the worst-case scenario values were generally selected. Outcome distributions are consequently biased towards the worst-case scenarios. A 2D radial flow model was used to represent the reference scenario, the seal leakage scenario (Fig. 6-10a) and the well leakage scenario (Fig. 6-10b), while a 3D orthogonal model was used to represent the fault leakage scenario (Fig. 6-10c). Simulation was carried out with a 3D multiphase flow simulator called SIMED II. The amount of injected CO_2, its lateral spread in time and the reservoir pressure were calibrated to the fine-scaled 3D SIMED II model over the injection period of 40 years.

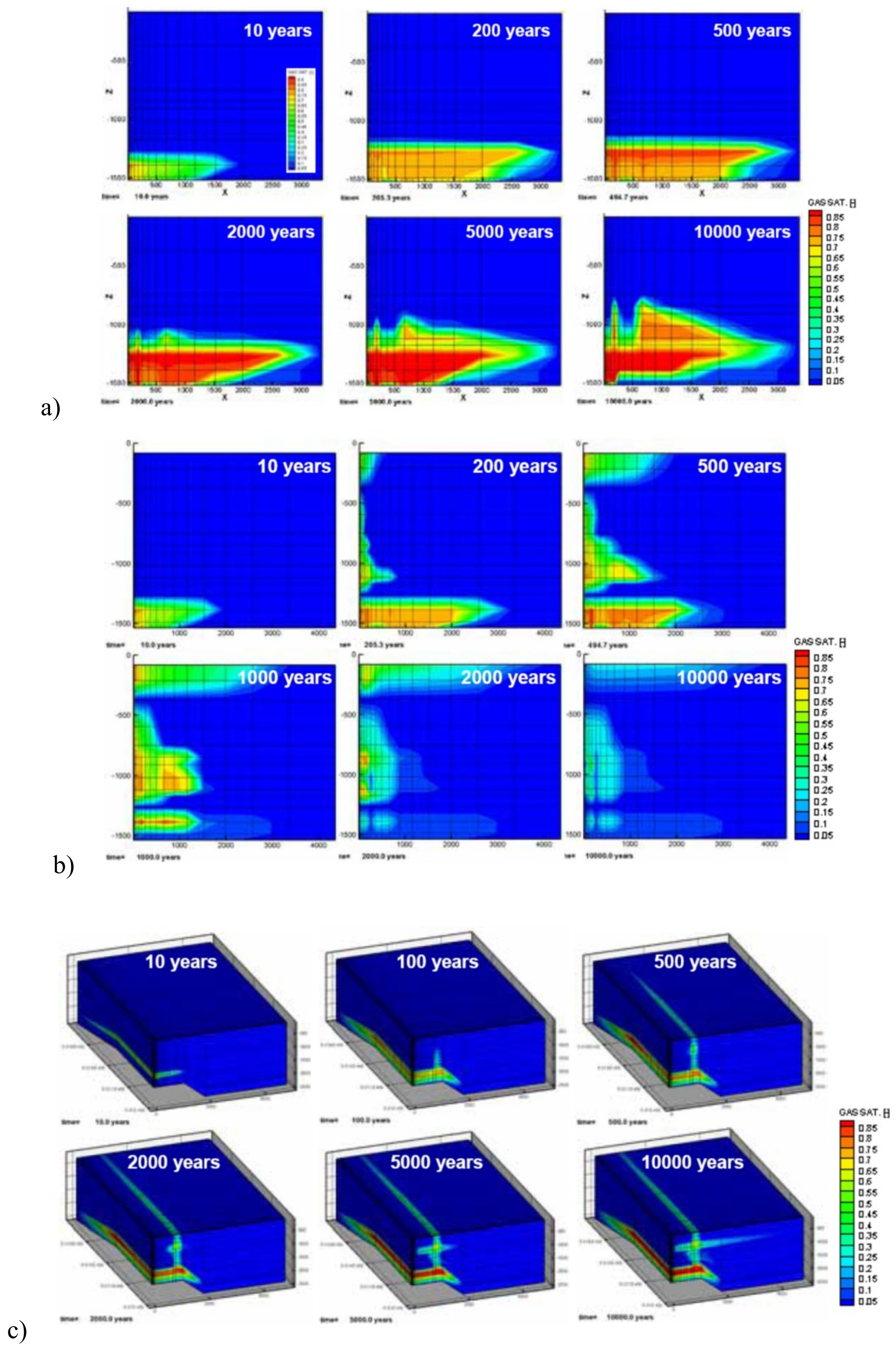

Fig. 6-10: Simulated CO_2 saturations from the hypothetical leaking a) seal, b) well and c) fault scenario (probability of occurrence is set to 1) in the Schweinrich case (Chadwick *et al*., 2008).

This deterministic model represented the injection of CO_2 on the flanks of the Schweinrich structure by 10 injection wells. In this model, the accumulation of CO_2 was mainly in the topmost reservoir layer. The representation of the stochastic models was strongly simplified. Each 'what if?' scenario was evaluated with 1,000 model runs with varying stochastic parameters. Based on the results from these model runs concerning the safety of the reference scenario, no CO_2 reaches the uppermost overburden sediments after 10,000 years. Regarding the leaking seal scenario, although CO_2 passes through the seal in this scenario, the velocity of upward migration of CO_2 is fairly small and therefore, no CO_2 reaches the uppermost overburden. The leaking well scenario is easily the most significant in terms of modelled CO_2 fluxes and CO_2 concentrations in the shallow overburden. The probability that such a scenario will be valid depends on the existence of an old well, designed for a purpose other than CO_2 storage, penetrating through the caprock. The critical safety factor in the leaking well scenario is the magnitude of the increase of the (vertical) permeability in the well zone, which would be improved by using a proper cement type. However, the best way to avoid the leaking well scenario is to design the injection wells in such a way that the scenario cannot occur, for example by designing the wells so that the caprock is not penetrated and that the wells enter the anticlinal structure from below the spill point. This can be done by the use of directionally drilled deviated wells that inject the CO_2 at the flanks of the reservoir. The leaking fault scenario indicates moderate CO_2 fluxes and CO_2 concentrations in the shallow overburden. Modelled maximum surface fluxes are comparable to observed leakage rates from natural CO_2 accumulations in Europe and Australia. The maximum concentrations may lead to adverse effects in groundwater and freshwater ecosystems. The critical safety factor is the vertical permeability of the fault zone. It is important to stress that the probability of the above-mentioned four scenarios actually occurring has not been assessed. They represent hypothetical 'worst-case' situations that may well have a very low probability (Chadwick *et al*., 2008). It is obvious that the storage project in Schwarze Pumpe - Schweinrich tries to go quantitative.

7 ECONOMIC ANALYSIS

Costs estimates on CO_2 storage involve a high degree of uncertainty, given the significant variations in technical characteristics, scale and applications between projects. There is also uncertainty over how costs will develop with time. Site selection and the economics of storage will drive the commerciality of large-scale integrated CCS projects and without appropriate storage options, CCS may not be a cost-effective CO_2 mitigation option.

A small number of studies, articles and reports focus exclusively on the cost of CO_2 storage for CCS. There is a high degree of uncertainty in estimating the costs of CO_2 storage, given the significant variations between projects' technical characteristics, scale and applications. There is also uncertainty over how costs will develop with time (IPCC, 2005; IEA, 2009; GCI, 2010). Still, the storage site selection will drive the commerciality of large-scale integrated CCS projects and without appropriate storage options CCS may not be a cost-effective CO_2 mitigation option (GCI, 2011).

7.1 Storage site selection economics

According to the EU GeoCapacity project several specific geological criteria are required for a site to be suitable for CO_2 storage:

- Appropriate depth of reservoir to guarantee that CO_2 reaches its supercritical dense phase but not so deep that permeability and porosity are low;
- Integrity of seal to prevent migration of CO_2 from the storage site;
- Enough CO_2 storage capacity to receive the CO_2 projected to be released from the source; and
- Adequate petrophysical reservoir properties to guarantee CO_2 injectivity to be economically feasible and that satisfactory CO_2 will be retained (GeoCapacity, 2005).

These criteria hinge on the values of a number of geological and physical parameters and it is critical in the search for appropriate sites for CO_2 storage to assess whether the criteria listed above and their related geological and physical parameters are satisfied. Screening sedimentary basins for CO_2 storage potential is the first phase in a site selection procedure: it aims to identify predictable, laterally continuous, permeable reservoir rocks overlain by potentially good quality caprocks at an appropriate depth. The screening phase gives an indication of those sites which appear suitable based on existing data. The screening should therefore narrow the search at an initial phase so that overpriced and time-consuming additional studies such as collecting and interpreting seismic data are confined to small prospective regions (EU Geocapacity, 2005).

If a number of similarly appropriate CO_2 sites are identified in the screening procedure, other non-geological criteria such as economic, logistical and conflict of interest considerations can be used to select which of those sites shall be investigated in further detail. According to the Global CCS Institute report, Global Status of CCS (GCCSI, 2010), in the initial demonstration phase of CCS development there is a strong economic driver to find storage locations close to emissions sources. In regions deprived of adequate storage potential, long-distance transport of CO_2 by pipeline or ship might be feasible in the long-term once wide-scale deployment of CCS underpins the scale efficiencies that are necessary to moderate the price of CO_2 transport over great distances.

The prospects for economic savings using proximate zones for storage needs to be balanced with consideration of the storage risk of candidate sites. Risk analysis and cost-benefit of the trade-offs between the storage asset quality, distance of transport and treatment of risk is less mature in CCS when compared to decision analysis in other more established resource sectors. Tested and well-established economic risk-based investment decision methods, adapted from, for instance, the oil and gas sector should be considered. In some cases, storage site selection and commitment have been too strongly based on the proximity to the emission source without considering a range of storage options. This can lead to a commitment to a single site or area prematurely. Such lack of integrated analysis can and has impacted significantly on timeline and economics for projects. In some cases, aggressive timing targets can lead to taking on higher risks, particularly for storage, if there are a limited number of choices. Viable storage capacity is that subset of the effective capacity that results from technical, legal, regulatory, infrastructural and general economic aspects of CO_2 storage. As such, it is susceptible to rapid changes as technology, policies, regulations and economics develop.

7.2 CO_2 storage costs

The ZEP has recently published a study on CO_2 storage costs (ZEP, 2011). As external cost data proved scarce and the development of a generic model prohibitive from a time and resources perspective, the ZEP study utilised the technical and economical knowledge of ZEP members with substantial research and experimental experience in the area of CO_2 storage and associated costs. A "bottom-up" approach, based on potentially relevant cost components, was taken and data consolidated into a robust and consistent model. Owing to the varied representation within the group and the use of external parties for review, all data and assumptions were challenged, vetted and verified by the principle of consensus (IEAGHG, 2012).

7.2.1 Cost estimation cases

CCS development can be separated into three different phases: demonstration, early commercial deployment and full commercial deployment; the costing exercise reported in the ZEP study focused on early commercial deployment, with demonstration projects assessed as a special case for comparison. To simulate the difference between early commercial deployment and full commercial deployment the effect of learning has been used (IEAGHG, 2012).

In order to cover a set of potential storage configurations and also provide reliable cost estimates, storage options were separated in six main "representative" cases according to key differentiating features: depleted oil and gas fields (DOGF) *vs*. deep saline aquifers (SA); offshore *vs*. onshore (Ons/Offs); and whether there is the possibility of re-using existing (legacy) wells (Leg/NoLeg) (Tab. 7-1). Note that the choice was made to restrict the costing exercise to reservoirs with a depth of 1000 to 3000 m.

Tab. 7-1: ZEP Storage cases. After IEAGHG, 2012.

Case	Location	Type	Re-useable legacy wells	Abbreviation
1	Onshore	DOGF	Yes	Ons.DOGF.Leg
2	Onshore	DOGF	No	Ons.DOGF.NoLeg
3	Onshore	SA	No	Ons.SA.NoLeg
4	Offshore	DOGF	Yes	Offs.DOGF.Leg
5	Offshore	DOGF	No	Offs.DOGF.NoLeg
6	Offshore	SA	No	Offs.SA.NoLeg

For each of the six cases, three scenarios (“Low”, “Medium” and “High”) were defined to yield a final storage cost range estimate. The ZEP study also presents a cost breakdown for project components/phases and sensitivity analyses to determine which of the 26 cost elements considered in the study carried the most impact on the final cost.

Data
Generally, DOGF has more data when compared to undeveloped SA. Noteworthy cost differences between DOGF and SA consequently arise in terms of acquiring the necessary data to assess, characterise, develop and monitor the storage sites. Additionally, the cost of exploration to find a proper site is comparatively inferior for DOGF compared to SA, as most of these costs have already been committed a long time ago, while costs for exploring aquifers will still have to be supported.

Field capacity
Based on GeoCapacity Project data, the estimated capacity of individual sites varies significantly, with only a minority exceeding 200 Mt. The base case has been taken to be three storage sites for a typical CO_2 stream. Two other cases were considered for sensitivity analysis of the effect of site capacity: five fields and one field for each CO_2 stream.

Re-use of wells (“legacy wells”)
For SA, it was assumed that no existing well could be re-used for the purpose of CO_2 storage. Nonetheless, the possibility of exploration wells being re-used for either injection or monitoring was considered.

For DOGF, two distinct cases were appraised. The first considers the re-use of existing wells, subject to including possible work over costs to ensure their suitability as injection/monitoring wells. In the second case, existing wells are considered unsuitable for re-use. An optimisation process needs to be established in order to balance the work over of an adequate number of wells *vs*. drilling new wells on the one hand and, on the other hand, properly abandoning wells that may represent a risk to permanent CO_2 storage.

Hence, the two cases considered may be seen as boundary cases for what could happen in reality. For simplification reasons, it was assumed that sites with wells that can technically and/or financially not be remediated, or would achieve an unacceptable well integrity, will be de-selected from the site selection procedure.

Assumptions
A number of common assumptions were established and applied for consistency across ZEP studies on the costs of CCS. The assumptions with the maximum impact on storage cost estimates are summarised below. Note that to remain independent of the capture technology selection, storage costs relate to tonnage of CO_2 stored, not abated (IEAGHG, 2012).

Energy costs
As a result of limited energy requirement of CO_2 storage, parasitic emissions caused by storage activities are considered as low.

Project lifetime
The project operational life is assumed to be 40 years of injection for commercial projects and 25 years for demonstration projects. In both cases, this is followed by 20 years of post-injection monitoring, before hand-over of liability to the Competent Authority. The commercial case is taken as the base case, whereas the demonstration phase is modelled using a sensitivity analysis (shortening the lifetime of the project). Note that 40 years is longer than the average expected lifetime of a wellbore without intervention.

CO_2 stream
Another assumption is an annual storage rate of 5 Mt, which calls for 200 Mt of CO_2 storage capacity over a 40-year plant lifetime. Such capacity matches up with the CO_2 emissions of a typical coal-fired power plant equipped with CO_2 capture technologies. Deviation of this rate has not been modelled explicitly, but

it is dealt with by varying the available storage field capacities. The CO_2 was assumed to be delivered by pipeline or ship in dense phase and in a state that is “fit-for-purpose” for injection, meaning that no further pressurising or conditioning equipment is required at the injection location.

Availability of storage
A basic consideration is the availability and capacity of suitable storage sites. Data were made available from the EU GeoCapacity Project database, comprising 991 potential storage sites in SA and 1388 DOGF in Europe.

Currency and time value of money
The reported costs are in Euros, cost basis is European. As input is centred on global experience in a predominantly dollar-based industry, the currency exchange rate used in the ZEP study for conversion is $1.387 = €1. Expenses are split between capital expenditure (CAPEX) and operational costs (OPEX). The CAPEX/OPEX split applied is specific to storage projects and operations.

The cost of capital for investment, WACC (Weighted Average Cost of Capital) is assumed to be 8% as a base case. WACC could be of great importance given the long duration of projects. For that reason, sensitivity studies were also carried out, within ZEP studies, with values of WACC of 6% and 10%, in line with previously published work.

The CAPEX was annualised and discounted back to present via WACC. The OPEX was not adjusted, *i.e.,* it was assumed that the influence of inflation would be cancelled out by the effect of discounting. Note that the results vindicate this hypothesis, *e.g.* the learning rate applicable to OPEX costs has very little influence on the overall expenditures.

Post-closure, monitoring, measurements and verification (MMV) costs are handled in the same manner as decommissioning costs, with one supplementary step. The costs (taking place in years 41-60) are first summed, then transformed into Present Value by means of the discount factor for year 40, and then annualised. As a result, the discount factor used (1/21.7 for 8% WACC) is somewhat too large. However, since costs are incurred so late in the life of the project, their impact to the cost of storage is already very small, so the effect of using the correct discount factor, which is even minor, is not material.

Summary of all the cost elements considered
A total of 26 cost elements were considered for the computation of the cost of CO_2 storage. Cost items were presented with their base case value (“most likely”). For the top eight cost drivers, those considered to have a major impact on the overall cost of storing CO_2, “minimum” and “maximum” values used for computing cost ranges and carrying out sensitivity studies were also reported. Tab. 7-2 presents the eight major cost drivers with the associated “most likely”, “minimum” and “maximum” values that have been used for the sensitivity analysis.

Tab. 7-3 presents the other 18 cost elements together with their associated values. The motive for not considering such cost elements in a sensitivity analysis was that either the resulting sensitivity would be small as the cost effect of these cost elements is small, or the sensitivity range would be too small as that particular parameter is well understood from experience in the oil and gas exploration and production industry.

Tab. 7-2: Main cost elements of the ZEP study. After IEAGHG (2012).

Cost driver	Medium case assumption	Sensitivities	Rationale
Field capacity	66 Mt per field	• 200 Mt per field • 40 Mt per field	Based on GeoCapacity project data
Well injection	0.8 Mt/yr per well	• 2.5 Mt/yr • 0.2 Mt/yr[1]	Medium value based on actual projects; High and low based on oil and gas industry experience
Liability transfer costs	€1.00 per tonne CO_2 stored	• €0.2 • €2.00	Rough estimate of liability transfer cost; Wide ranges reflect uncertainty
WACC	8%	• 6% • 10%	Same range as McKinsey study, September 2008
Well depth	2000m	• 1000m • 3000m	Well costs strongly depend on depth[2]
Well completion costs	Based on Industry experience, offshore cost 3 times onshore cost	• -50% • +50%	Ranges based on actual project experience
#Observation wells	1 for onshore; nil for offshore	• 2 for onshore; • 1 for offshore	1 well extra to better monitor the field
# Exploration wells	4 for SA; nil for DOGF	• 2 for SA, nil for DOGF • 7 for SA, nil for DOGF	DOGF are known, therefore no sensitivities needed; SA reflects expected success rate

[1] 0.2 Mt/yr not modelled for offshore cases as costs would become too high to be viable.
[2] Supercritical state of CO_2 occurs at depths below 700-800m.

Tab. 7-3: Additional cost elements considered for storage in the ZEP study. After IEAGHG (2012).

Cost driver	Assumption
Re-use of exploration wells	1 out of 3 wells is re-usable as an injection well; others are not located correctly, do not match the injection depth etc.
Utilisation	Utilisation is 86%, implying a peak production of 116% average
Contingency wells	10% of the required number of injection wells is added as a contingency, with a minimum of 1 per field
Well re-tooling cost	Re-tooling legacy wells as exploration wells, or exploration wells as injection wells, costs 10% of building the required well from scratch
Operations and Maintenance	4% of CAPEX cots for platform and new wells
Injection testing	Fixed cost per field
Modelling/logging costs	Fixed cost per field; SA costs ~ 2 times as much as DOGF
Seismic survey costs + MMV Baseline	Fixed cost per field; offshore costs ~ 2 times as much as onshore. In addition, at the end of its economic life, final seismic survey is performed prior to handover (costs discounted for time value of money)
MMV recurring costs	Fixed cost per field; offshore costs ~ 2 times as much as onshore
Permitting costs	€1M per project
Well remediation costs	Provision ranging from nil to 60% of new well costs, based on the possibility of risky wells and the costs of handling them
Platform costs	For offshore there are platform costs: SA is assumed to require a new platform; DOGF is assumed to require refurbishment of an existing platform
Decommissioning	15% of CAPEX of all operational wells and CAPEX platform
Post-closure monitoring	20 years after closure, at 10% of yearly MMV expenses during first 40 years
Economic life	40 years; demonstration phase 25 years (in line with assumptions for CO_2 capture)
Learning rate	0% as CO_2 storage technologies are well known and build on oil and gas industry experience
Exchange rate	1.387 USD/EUR (as of 6 October 2010)
Plant CO_2 yearly captured	CO_2 captured is assumed to be 5Mt per year. Variation in the amount captured is implicitly modelled by variation in storage field capacity as a sensitivity

7.2.2 Results

Cost overview totals

The cost model was run for each case with the input cost elements set to their base (most probable) values, according to the case. The corresponding costs have been termed the “Medium” scenario. Subsequently the model was run to determine the three main uncorrelated drivers that had the largest impact on cost: field capacity, well capacity (injectivity times the life of the well) and liability. Other cost items associated to well capacity sometimes have a large impact on cost (*e.g.* well completion cost), but these are related to the well capacity driver. Liability, though, is entirely decoupled from other items and has a great impact on Low cost scenarios (IEAGHG, 2012).

Low and High cost scenarios were then attained as follows: for each case, the model was run with these three chief drivers set to their minimum values for the Low cost scenarios and maximum values for the High cost scenarios, while taking care of their combined effects. Such a procedure has the advantage over mathematically more rigorous techniques (*e.g.* Monte Carlo techniques) that the Low and High scenarios correspond to a transparent set of input cost elements, while still representing realistic (reasonably probable) Low and High scenarios.

The total storage costs estimated by the ZEP study are presented in Fig. 7-1 with the CAPEX/OPEX per case presented in Tab. 7-4, 7-5, 7-6, 7-7, 7-8 and 7-9.

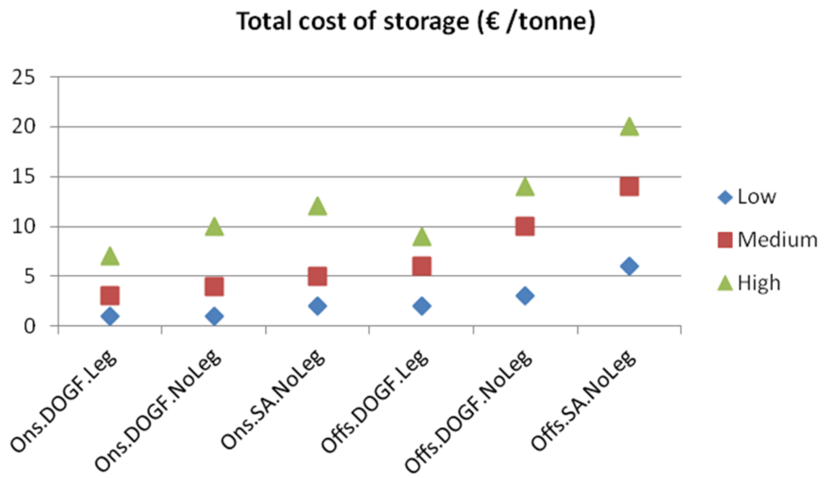

Fig. 7-1: Total cost of storage (€/tonne). After IEAGHG (2012).

Tab. 7-4: Ons.DOGF.Leg cost summary – annualised CAPEX takes the WACC into account, after IEAGHG, 2012.

	Ons.DOGF.Leg		
	Low	Medium	High
CO_2 stored (Mt)	200	66	40
Lifetime (yr)	40	40	40
CO_2 rate (Mt p a)	5	2	1
CAPEX (M€)	27	27	29
Annualised CAPEX (M€ p a)	2	2	2
OPEX (M€ p a)	2	3	4
CAPEX (€ per tonne)	0	0	1
Annualised CAPEX (€ per tonne)	0	1	2
OPEX (€ per tonne)	0	2	4
Cost of storage (€ per tonne)	1	3	7

Tab. 7-5: Ons.DOGF.NoLeg cost summary – annualised CAPEX takes the WACC into account. After IEAGHG (2012).

	Ons.DOGF.NoLeg		
	Low	Medium	High
CO_2 stored (Mt)	200	66	40
Lifetime (yr)	40	40	40
CO_2 rate (Mt p a)	5	2	1
CAPEX (M€)	48	48	68
Annualised CAPEX (M€ p a)	4	4	6
OPEX (M€ p a)	2	3	4
CAPEX (€ per tonne)	0	1	2
Annualised CAPEX (€ per tonne)	1	2	6
OPEX (€ per tonne)	0	2	4
Cost of storage (€ per tonne)	1	4	10

Tab. 7-6: Ons.SA.NoLeg cost summary – annualised CAPEX takes the WACC into account. After IEAGHG (2012).

	Ons.SA.NoLeg		
	Low	Medium	High
CO_2 stored (Mt)	200	66	40
Lifetime (yr)	40	40	40
CO_2 rate (Mt p a)	5	2	1
CAPEX (M€)	70	70	89
Annualised CAPEX (M€ p a)	6	6	7
OPEX (M€ p a)	2	3	4
CAPEX (€ per tonne)	0	1	2
Annualised CAPEX (€ per tonne)	1	4	7
OPEX (€ per tonne)	0	2	4
Cost of storage (€ per tonne)	2	5	12

Tab. 7-7: Offs.DOGF.Leg cost summary – annualised CAPEX takes the WACC into account. After IEAGHG (2012).

	Offs.DOGF.Leg		
	Low	Medium	High
CO_2 stored (Mt)	200	66	40
Lifetime (yr)	40	40	40
CO_2 rate (Mt p a)	5	2	1
CAPEX (M€)	56	48	44
Annualised CAPEX (M€ p a)	5	4	4
OPEX (M€ p a)	6	6	6
CAPEX (€ per tonne)	0	1	1
Annualised CAPEX (€ per tonne)	1	2	4
OPEX (€ per tonne)	1	4	6
Cost of storage (€ per tonne)	2	6	9

Tab. 7-8: Offs.DOGF.NoLeg cost summary – annualised CAPEX takes the WACC into account. After IEAGHG (2012).

	Offs.DOGF.NoLeg		
	Low	**Medium**	**High**
CO_2 stored (Mt)	200	66	40
Lifetime (yr)	40	40	40
CO_2 rate (Mt p a)	5	2	1
CAPEX (M€)	127	120	96
Annualised CAPEX (M€ p a)	11	10	8
OPEX (M€ p a)	6	6	6
CAPEX (€ per tonne)	1	2	2
Annualised CAPEX (€ per tonne)	2	6	8
OPEX (€ per tonne)	1	4	6
Cost of storage (€ per tonne)	3	10	14

Tab. 7-9: Offs.SA.NoLeg cost summary – annualised CAPEX takes the WACC into account. After IEAGHG (2012).

	Offs.SA.NoLeg		
	Low	Medium	High
CO_2 stored (Mt)	200	66	40
Lifetime (yr)	40	40	40
CO_2 rate (Mt p a)	5	2	1
CAPEX (M€)	238	199	169
Annualised CAPEX (M€ p a)	20	17	14
OPEX (M€ p a)	8	7	6
CAPEX (€ per tonne)	1	3	4
Annualised CAPEX (€ per tonne)	4	10	14
OPEX (€ per tonne)	2	4	6
Cost of storage (€ per tonne)	6	14	20

Cost breakdown per project phase

Cost analysis per project phase provides insights regarding cost differentiators between cases and the succeeding project phases and associated cost components were consequently defined in the ZEP study (Tab. 7-10).

Tab. 7-10: Project phases and associated cost elements. After IEAGHG (2012).

Phase	Description	Typical cost elements
Pre-FID	Activities prior to decision whether to go ahead with injection	Seismic survey, exploration wells, injection testing, modelling, permitting
Structure	Construction of supporting structure for injection wells (e.g. offshore platform)	New build or refurbishment (offshore)
Injection wells	Construction of injectors	Drilling of new wells, refurbishing of legacy wells
Operating	CO_2 injection phase (40 years)	Operations and maintenance OPEX
MMV	Monitoring activities (both during the injection and the post-injection phase)	Drilling of observation wells, monitoring OPEX, final seismic survey
Close down	Close down activities	Decommissioning, liability transfer

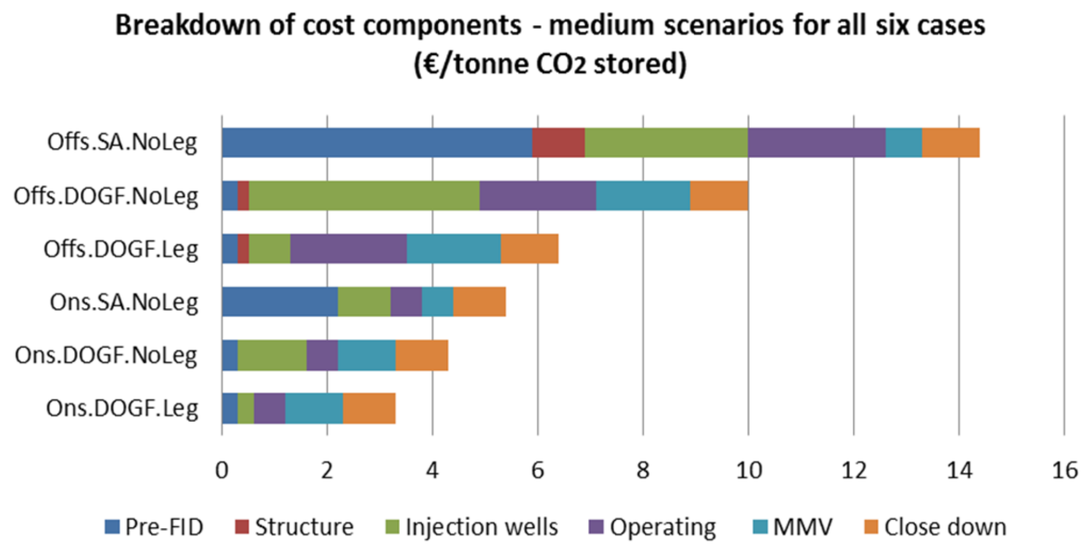

Fig. 7-2: Breakdown of cost components – medium scenarios for all six cases (€/tonne CO_2 stored), after IEAGHG, 2012.

Variations and uncertainties

A broad sensitivity study was done in all the cases, not just for the three cost elements that were used to compute the ranges of cost - field capacity, well capacity and liability -, but also for the other top five cost elements that have a substantial effect on cost, *i.e.,* well completion, reservoir depth, WACC and the number of new observation and exploration wells. The cost impact of the other 18 cost elements was not found to be significant enough to be taken into account in the sensitivity study (IEAGHG, 2012).

7.3 Key conclusions of the ZEP report

The CO_2 storage cost estimates reported in the ZEP report fluctuate between €1-7/tonne CO_2 stored for the cheapest option (onshore DOGF with re-usable wells) to €6-20/tonne CO_2 stored for the most expensive alternative (offshore SA). Uncertainty ranges within each case are in line with the natural variability of storage candidates, namely, reservoir capacity and injectivity. The effect of the learning rate was found to be negligible.

The ZEP report highlights substantial differentiators in the economics of storage, the key being:

- Reservoir capacity (higher cost for smaller reservoirs);
- Site location (higher costs offshore than onshore);
- Site information level (high for DOGF, meaning lower costs; low for SA, meaning higher costs);
- Existence of re-usable infrastructure (wells, offshore structure);
- Reservoir quality (injectivity; poorer quality reservoirs leading to higher costs).

The cost sensitivity studies revealed that:

- Field capacity has the highest impact on cost in four cases and the second largest effect in the other two cases. Consequently, selection of appropriate storage reservoirs with respect to their capacity is a key element to cut the costs of CO_2 storage. Therefore, exploration and reservoir characterisation are vital activities for CO_2 storage as they allow selection of a storage reservoir of suitable dimensions. This is of particular importance in the case of offshore SA, where the use of larger reservoirs results in considerably lower costs than for smaller ones (economy of scale benefit);

- Well capacity is the top second contributor to variations of cost for onshore cases and thus the design and placement of wells is a basic activity for such cases;
- Well completion costs are the succeeding most important factor for offshore cases, highlighting the specificities of that offshore environment;
- The top two items for all cases relate to storage capacity and injectivity;
- The assumed cost of liability is equal for all cases when reported per tonne of CO_2 stored. Therefore, its relative weight is the largest for cases where the total cost of storage per CO_2 tonne stored is the smallest, that is to say onshore.

Finally, regarding demonstration projects, the ZEP study concludes that it is very likely that the costs per tonne of CO_2 stored will be significantly higher than those of projects in the early commercial phase. Such a conclusion should be taken into account when financing demonstration projects and when comparing the actual costs of demonstration projects with those of early commercial projects.

8 PUBLIC PERCEPTION AND ACCEPTANCE

This section has been included in this report because of the importance of non-technical aspects for the selection of CO_2 storage sites. The aim is to provide a comprehensive and up to date reference list on public perception and acceptance which are provided as a separate Appendix.

Social issues have been raised in relation to the siting of storage facilities, particularly onshore and are becoming increasingly recognised as an essential factor for the success of a siting process. In relation to these issues a number of social research studies have been carried on over the years to investigate public perception of the technology, how to inform local communities and to understand public reactions to planned and/or on-going projects. An important outcome of these studies concerns the need to complement geological site characterisation with social site characterisation. Of course, just like geological features, social features are unique to each site, which makes for the need of a case-by-case approach. At the same time, the worldwide dimension of social research studies is essential to account for the varied cultural patterns in different regions/countries, providing consistent support to project developers thanks to information resources coming from a range of different experiences.

Open access sources of information were used to compile the reference list of relevant studies provided by

- institutions (such as Global CCS Institute GCCSI, World Resources Institute WRI, Scottish Carbon and Storage SCCS, Centre for Low Emission Technology cLET, US Department of Energy – National Energy Technology Laboratory DOE-NETL),
    - national and international agencies (International Energy Agency IEA, Commonwealth Scientific and Industrial Research Organisation CSIRO, Italian national agency for new technologies, energy and sustainable economic development ENEA),
    - scientific, governmental and stakeholders initiatives and networks (European Technology Platform for Zero Emission Fossil Fuel Powerplants ZEP, Carbon Sequestration Leadership Forum CSLF, Fossil Energy Coalition Network FENCO–ERA),
    - non-governmental organisation (Bellona),
    - R&D projects (ACCSEPT, Create Acceptance, NearCO2, SiteChar, ECO2),
- as well as sources published by various publishers
    - international journals (Energy Procedia – Elsevier, Environmental and Resource Economy – Springer, International Journal of Greenhouse Gas Control – Elsevier, Technological Forecasting and Social Change – Elsevier, Climate Policy – Elsevier, Energy Policy – Elsevier, InTech – open access publisher)

The list of public perception and acceptance references is organised in alphabetical order of the source in the Appendix.

9 CONCLUSIONS AND RECOMMENDATIONS

This report compiles and reviews published guidelines on the selection and management of a geological CO_2 storage site as constrained by the existing regulatory environments.

Storage site selection is the first step for CCS to proceed to a full-chain technology solution to greenhouse gas emissions reduction. Detailed characterisation and monitoring of the site is required for ensuring and demonstrating safety and integrity of the storage project. In essence, a site selection process should demonstrate that the site has: sufficient capacity to accept the expected CO_2 volume, sufficient injectivity for the expected rate of CO_2 capture and supply; and sufficient containment to store the injected CO_2 for the period of time required by the regulatory authority, so as not to pose unacceptable risks to the environment, human health or other uses of the subsurface.

This report considers a stepwise progression of studies through geological characterisation to flow and geomechanical modelling, and also includes environmental risk and economic assessments. Bibliographic coverage is also provided for the area of public awareness and acceptance.

Geological characterization of the site

Geological characterization requires a progressive approach from regional screening to successive refinement through data acquisition and modelling to produce capacity assessment and ranking, leading to selection of the optimal storage site for a CCS project. The process must take account of legal and regulatory regimes, environmental constraints, and economic aspects pertaining to the site.

The biggest knowledge gaps and uncertainties generally exist for storage in saline aquifers, where often few data are available to evaluate the sites against principal screening criteria and drilling new, exploratory wells and acquiring new seismic and other geophysical surveys will be required. For depleted hydrocarbon fields, many exploration and production data will be available to assist with an accurate storage assessment.

Conflicts of the use of subsurface must also be managed. There may be competing interests in natural gas storage, geothermal energy or other uses of the same reservoir system.

Flow modelling

During site assessment and the pre-operational phase, simulation models are used to predict CO_2 plume migration and the effectiveness of solubility, residual gas (capillary) and mineral trapping. During operations, comparison between simulated and monitored plume migration is used to refine and calibrate the model and update forecasts of plume migration. This iterative approach is required to develop confidence in the prediction of plume behaviour. During the post-operational phase, a similar iterative approach is used to predict post-injection plume behaviour — with a primary focus on quantifying the secondary trapping mechanisms that will eventually immobilise the CO_2.

Several numerical modelling packages are available for flow modelling in CO_2 storage. The accuracy of flow models depends on the quality of the input parameters and their capability in handling the various flow and transport processes that control the spread of CO_2 in the storage medium: fluid flow in response to natural hydraulic gradients or pressure gradients created by the injection process; buoyancy; diffusion; and the various trapping mechanisms.

The results of flow modelling versus monitored plume migration in several CO_2 storage projects and injection pilot studies have been reviewed.

Reactive flow modelling

Reactive flow modelling combines hydrodynamic modelling and geochemical modelling to provide a complete calculation over time of the amount of CO_2 trapped through a combination of structural, dissolution or mineral trapping. The storage site can be modelled through its different operational phases: pre-injection, injection and post-injection, to assess the geochemical impact of CO_2 on injectivity and long-term integrity of the site. The uncertainties affecting the modelled results are strongly influenced by the chemical parameters such as the mineral phases, their kinetics and the reactive surface area. One should, therefore, carefully select the codes for modelling with reference to the specific conditions in the selected site (see, for example, results from the Sleipner site as discussed by Gaus *et al*. (2008).

Coupled geomechanical and flow modelling

Injection of a large volume of fluid in the subsurface over a period of time can have geomechanical effects. Changes in pore pressure during injection will change the effective stress and cause rock to deform. If the injection-induced pressure increase is too large, shear slip or tensile opening of pre-existing faults in the storage reservoir/caprock may occur, and a previously sealing fault may become conductive, leading to leakage. Induced shear-stress changes may also induce micro-seismicity and even earthquakes of moderate local magnitudes. Different situations will pertain to injection into a depleted, underpressured hydrocarbon reservoir and a previously undisturbed saline aquifer.

Geomechanical data, such as the elastic properties of the storage formation and caprock, pre-existing fault strength properties, and in situ stress state need to be included in coupled geomechanical-fluid flow numerical models for rigorous CO_2 storage evaluation and risk assessment during site characterisation. The interplay of geochemical and geomechanical processes within the reservoir and the caprock can strongly influence storage containment, capacity and the CO_2 plume distribution. The coupling of geomechanical codes with flow-transport codes for numerical modelling remains a challenge fully; coupled thermal–hydraulic–chemical–mechanical codes are still in the development stage. Examples of coupled simulations using different codes and their results at specific sites are reviewed in Chapter 5.

Environmental impact and risk assessment

It may be stated that the overriding global risk is that without geological storage of CO_2, emissions will continue to reach the atmosphere and contribute significantly to climate change.

Risks from geological storage of CO_2 primarily result from the consequences of unintended leakage from the storage formation. Leakage can range between short-term potentially large leakages (injection well failures or leakage up abandoned wells) and long-term, more diffuse leakages through undetected faults, fractures or through leaking wells. Potential risks can also be distinguished between onshore and offshore storage settings. Hazards to humans, ecosystems and groundwater include: elevated gas-phase CO_2 concentrations in the shallow subsurface and near-surface environment effecting humans and other living organisms; acidification of soils and displacement of oxygen in soils; undetected accumulations of CO_2-supersaturated water or gaseous CO_2 in shallow traps that might be a risk for future drilling; possible groundwater contamination both from CO_2 leaking directly into an aquifer or displaced brines entering the aquifer during the injection process.

Other risks arise from CO_2 injection into the deep subsurface, including fault activation and induced microseismicity, changes in the geomechanical stress field and vertical uplift above large reservoirs, and surface geotechnical effects caused by unexpected migration of CO_2 or water through faults and fractures.

Risk assessment for CO_2 storage is the process that examines and evaluates the potential for adverse health, safety and environmental effects on human health, the environment, and potentially other receptors resulting from CO_2 exposure and leakage of injected or displaced fluids via wells, faults, fractures, and seismic events. The identification of potential leakage pathways is integrated with a MMV (Measurement, Monitoring and Verification) plan. Risk assessment is used to ensure the safety and acceptability of geological storage and it involves determining both the consequences and likelihood of an event. Risk mitigation is the planning for and implementation of contingency plans, should the need arise, to remediate adverse impacts. A good monitoring and mitigation plan will decrease the risk and uncertainty associated with many potential consequences.

Many of the ongoing risk assessment efforts are cooperating to identify, classify and screen all factors that may influence the safety of storage facilities, using the Features, Events and Processes (FEP) methodology. Because the future evolution of a geologic system cannot be precisely determined, various possible scenarios for possible evolutions of the system and situations of particular interest are developed. Most risk assessments involve the use of scenarios that describe possible future states of the storage facility and events that result in leakage of CO_2 or other risks. The FEP assessment methodology is useful but still has gaps in knowledge and there is some discussion as to whether a 'bottom-up' (identifying every conceivable FEP and then building scenarios from these) or 'top-down' (identifying a limited number of key risk scenarios and developing a limited FEP listing from these) approach is best.

In the evaluation of consequences versus environmental criteria, the criteria must correspond to amounts or concentrations that are measurable and acceptable levels and limit values must therefore be determined.

Economic analysis

According to the ZEP report *"The Costs of CO_2 Capture, Transport and Storage: Post-demonstration CCS in the EU"*, the cost of CO_2 storage will range from €1 to €7 per tonne CO_2 stored for a depleted oil or gas field with re-usable wells to €6 to €20 per tonne CO_2 stored for offshore saline aquifers. Uncertainty ranges within each case are due to the natural variability of the storage-limiting parameters, reservoir capacity and injectivity, and structural factors such as site location, level of existing data and availability of re-usable infrastructure and wells. Costs will be higher for smaller and poorer quality reservoirs, for offshore sites, and where significant data collection or infrastructural development is required. The effect of the learning rate was found to be negligible (implying that existing knowledge can anticipate the technological issues involved).

Cost sensitivity analysis reveals that the top two factors for all cases are storage capacity and injectivity. Therefore, exploration and reservoir characterisation are vital activities for CO_2 storage as they allow selection of a storage reservoir with lowest storage costs. Capacity is of particular importance in the case of offshore saline aquifers, where the use of larger reservoirs results in considerably lower costs than for smaller ones (economy of scale benefit). Well capacity is the top second contributor to variations of cost for onshore cases and thus the design and placement of wells is a basic activity for such cases. Well completion costs are the succeeding most important factor for offshore cases, highlighting the specificities of that offshore environment. The assumed cost of liability is equal for all cases when reported per tonne of CO_2 stored. Therefore its relative weight is the largest for cases where the total cost of storage per CO_2 tonne stored is the smallest (probably onshore).

Regarding demonstration projects, the ZEP study concludes that it is very likely that the costs per tonne of CO_2 stored will be significantly higher than those of projects in the early commercial phase. This should be taken into account when financing demonstration projects and when comparing the actual costs of demonstration projects with those of early commercial projects.

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