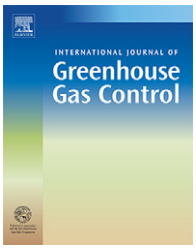
available at www.sciencedirect.com

ScienceDirect

journal homepage: www.elsevier.com/locate/ijggc



CO_2 storage capacity estimation: Methodology and gaps

Stefan Bachu [a,*], *Didier Bonijoly* [b], *John Bradshaw* [c], *Robert Burruss* [d], *Sam Holloway* [e], *Niels Peter Christensen* [f], *Odd Magne Mathiassen* [g]

[a] *Alberta Energy and Utilities Board, 4999-98th Avenue NW, Edmonton, AB, Canada T6B 2X3*
[b] *BRGM-CDG/DIR 3, Avenue Claude Guillemin, BP 6009 45060 Orleans cedex 2, France*
[c] *Geoscience Australia, GPO Box 378, Canberra, ACT 2601, Australia*
[d] *US Geological Survey, National Center MS 956, 12201 Sunrise Valley Drive, Reston, VA 20192, USA*
[e] *British Geological Survey, Keyworth, Nottingham NG12 5GG, UK*
[f] *Geological Survey of Denmark and Greenland (GEUS), Vester Voldgade 10, DK-1250, Copenhagen K, Denmark*
[g] *Norwegian Petroleum Directorate, P.O. Box 600, N-4003 Stavanger, Norway*

ARTICLE INFO

Article history:
Received 25 April 2007
Received in revised form
1 June 2007
Accepted 1 June 2007
Published on line 2 August 2007

Keywords:
CO_2 geological storage
Capacity estimation
Oil and gas reservoirs
Coal beds
Deep saline aquifers

ABSTRACT

Implementation of CO_2 capture and geological storage (CCGS) technology at the scale needed to achieve a significant and meaningful reduction in CO_2 emissions requires knowledge of the available CO_2 storage capacity. CO_2 storage capacity assessments may be conducted at various scales—in decreasing order of size and increasing order of resolution: country, basin, regional, local and site-specific. Estimation of the CO_2 storage capacity in depleted oil and gas reservoirs is straightforward and is based on recoverable reserves, reservoir properties and in situ CO_2 characteristics. In the case of CO_2-EOR, the CO_2 storage capacity can be roughly evaluated on the basis of worldwide field experience or more accurately through numerical simulations. Determination of the theoretical CO_2 storage capacity in coal beds is based on coal thickness and CO_2 adsorption isotherms, and recovery and completion factors. Evaluation of the CO_2 storage capacity in deep saline aquifers is very complex because four trapping mechanisms that act at different rates are involved and, at times, all mechanisms may be operating simultaneously. The level of detail and resolution required in the data make reliable and accurate estimation of CO_2 storage capacity in deep saline aquifers practical only at the local and site-specific scales. This paper follows a previous one on issues and development of standards for CO_2 storage capacity estimation, and provides a clear set of definitions and methodologies for the assessment of CO_2 storage capacity in geological media. Notwithstanding the defined methodologies suggested for estimating CO_2 storage capacity, major challenges lie ahead because of lack of data, particularly for coal beds and deep saline aquifers, lack of knowledge about the coefficients that reduce storage capacity from theoretical to effective and to practical, and lack of knowledge about the interplay between various trapping mechanisms at work in deep saline aquifers.

© 2007 Elsevier Ltd. All rights reserved.

1. Introduction

A significant reduction in global CO_2 emissions can be achieved only through the broad and deep application, in developed and developing countries alike, of a portfolio of measures that includes major technological breakthroughs, increasing the share of non-fossil forms of energy production, and carbon capture and storage (IEA, 2004). The latter

* *Corresponding author*. Tel.: +1 780 427 1517; fax: +1 780 422 1459.
E-mail address: Stefan.Bachu@gov.ab.ca (S. Bachu).
1750-5836/$ – see front matter © 2007 Elsevier Ltd. All rights reserved.
doi:10.1016/S1750-5836(07)00086-2

comprises the capture of CO_2 from large stationary sources, transportation to a storage site, and isolation from the atmosphere for significant periods of time (centuries to millennia). Three forms of CO_2 storage have been identified: in deep geological media, through surface mineral carbonation, and in oceans (IPCC, 2005). Of the three forms of CO_2 storage, mineral carbonation is very costly and creates a significant environmental imprint, while ocean storage is an immature technology that will alter the local chemical environment, likely endanger ocean organisms and have ecosystem consequences (IPCC, 2005). In contrast, CO_2 capture and geological storage (CCGS) is a technology that: (1) is immediately applicable as a result of the experience gained mainly in oil and gas exploration and production, deep waste disposal and groundwater protection; (2) has large capacity, although unevenly distributed around the globe, and (3) has retention times of centuries to millions of years (IPCC, 2005). However, a series of barriers stand in the way of immediate full-scale implementation of CCGS, among them a general lack of knowledge about the location and capacity of potential geological storage sites (CSLF, 2005; IPCC, 2005; Bradshaw et al., 2007).

Previous attempts to assess CO_2 storage capacity used a wide variety of approaches and methodologies that considered various trapping mechanisms. The assessments used data sets of variable size and quality, and have produced widely varying estimates of inconsistent quality and reliability (CSLF, 2005; IPCC, 2005, Chapter 5.3; Bradshaw et al., 2007). The Carbon Sequestration Leadership Forum (CSLF) recognized early on the need to provide consistent and accepted methodologies for estimating CO_2 storage capacity in developed and developing countries alike, and established in 2004 a *Task Force for Review and Development of Standard Methodology for Storage Capacity Estimation*. The Task Force presented in 2005 the results of Phase 1 of the assignment in a document in which previous estimates were critically analyzed and gaps in knowledge and/or methodology were identified (CSLF, 2005; Bradshaw et al., 2007). Many CO_2 storage capacity estimates, made by scientists as the field of CCGS advanced, are lacking:

- Clear and accepted definitions;
- Recognition and proper use of different scales in assessments;
- Recognition of the time scales and parallel, sometimes competitive nature, of various trapping mechanisms;
- Consistent methodologies and guidelines for capacity estimations;
- Proper documentation regarding data, constraints and methodologies used;
- Proper reporting procedures and practices;
- Recognition of the fact that, as with any Earth commodity, storage capacity estimates vary in time as new data become available and as technology and economic conditions change.

In a report on Phase 2 of the assignment[1], the Task Force presented standardized definitions and methodology for the estimation of CO_2 storage capacity in uneconomic coal beds, oil and gas reservoirs and deep saline aquifers, identifying at the same time current gaps in knowledge. This paper presents a summary of the CSLF Task Force findings, namely definitions, concepts and methodologies that are recommended to be used in collecting the necessary data and properly estimating CO_2 storage capacity in geological media.

2. The multi-faceted aspects of CO_2 storage capacity estimation

2.1. Types of geological media

Geological storage of CO_2 is achieved through a combination of physical and chemical trapping mechanisms that are effective over different timeframes and scales (IPCC, 2005). These differences need to be taken into consideration when estimating storage capacity. Physical trapping occurs when CO_2 is immobilized as a free gas or supercritical fluid. There are two types of physical trapping: *static trapping*[2] in stratigraphic and structural traps, or in man-made caverns; and *residual-gas trapping* in the pore space at irreducible gas saturation. Chemical trapping occurs when CO_2 dissolves in subsurface fluids (*solubility and ionic trapping*) and may then be involved in chemical reactions with the rock matrix (*mineral trapping*), or becomes adsorbed onto mineral surfaces (*adsorption trapping*).

Under favorable circumstances, injected CO_2 may migrate in the subsurface at extremely low velocities such that, theoretically, it would take time on a geological scale (tens of thousands to millions of years) to potentially reach the surface, before which it becomes trapped by a combination of the mechanisms outlined above, thus avoiding leakage. Very large masses of CO_2 potentially could be stored in this way, which is commonly described as *hydrodynamic trapping*. For clarification, in the context of CCGS, CO_2 migration is defined as lateral flow within the targeted injection and storage unit (formation, reservoir and coal bed), while upwards, cross-formational CO_2 flow out of the storage unit is defined as leakage, which may be just to another overlying unit, to shallow groundwater or even to the surface.

These mechanisms for CO_2 storage can occur in the following geological media in sedimentary basins (IPCC, 2005):

- oil and gas reservoirs;
- deep saline aquifers, saturated with brackish water or brine;
- coal seams (sorption is the only potentially practical technique for CO_2 storage in coal seams and is not a significant storage mechanism in the other classes of geological media).

For clarification of the terminology used in this paper, an *aquifer* is defined as a layer, formation, or group of formations

[1] http://cslforum.org/documents/PhaseIIReportStorageCapacityMeasurementTaskForce.pdf.

[2] The term "static" was chosen here to describe the non-migrating nature of the stored CO_2 in a closed trap, as opposed to the migrating nature of mobile CO_2 in an open, hydrodynamic trap. Other terminology used in literature to describe this trapping mechanism includes "permeability" trapping and "confinement" trapping, to indicate the presence of a lateral permeability barrier that precludes lateral migration of CO_2, and "structural/stratigraphic" trapping.

of permeable rocks, saturated with water and with a degree of permeability that allows water withdrawal through wells (de Marsily, 1986, p. 115). *Aquitards* are porous layers or beds from which water cannot be produced through wells, but where the vertical flow is significant enough over large areas to feed adjacent aquifers, and *aquicludes* are layers or beds that have generally extremely low, if any, porosity and permeability (de Marsily, 1986, p. 131). Aquifers, regardless of their lithology (sandstones or carbonates), are defined in terms of their hydraulic properties and are separated by intervening aquitards (e.g. shales) or aquicludes (e.g., salt beds). If an aquifer allows water withdrawal, then it will also allow injection of fluids. The most common fluid currently injected into aquifers is waste water, but acid gas for disposal, natural gas for temporary (seasonal) storage, and CO_2 for permanent storage are also injected. Water, natural gas, CO_2 and/or solvents are injected into oil fields for pressure maintenance and/or enhanced oil recovery. Generally, the term *reservoir* is used to designate porous and permeable rocks that contain various combinations of fluids other than water, such as hydrocarbons (oil and/or gas), CO_2 and H_2S (e.g., sour gas is gas that contains CO_2 and/or H_2S), and this definition is specifically used here. From a hydrodynamic (flow of fluids) point of view, aquifers and reservoirs are equivalent, the difference between the two categories being not in their porosity and permeability characteristics, but in the type of fluid that is present in the pore space (i.e., rock-wetting water in the former and other, non-wetting fluids in the latter). However, an important distinction between reservoirs and aquifers is the spatially discrete and discontinuous nature of the former versus the continuous nature of latter. Also, generally, hydrocarbon reservoirs are underlain by or contiguous with aquifers, hence in contact with them. Hydrocarbon reservoirs are actually structural or stratigraphic traps at the top of aquifers that have been charged with oil and/or gas during the process of hydrocarbon generation, migration and accumulation. *Caprock* (or seal) is defined as the low-permeability rock (aquitard or aquiclude) that overlies a reservoir and retains the hydrocarbons and/or other gases.

The term *groundwater* is usually applied to the water found in shallow aquifers that has relatively low salinity and that is or can be used for human consumption or for agricultural and industrial processes without necessitating any, or only minimal, treatment. Depending on jurisdiction, groundwater is defined as water with salinity less than 3000 or 4000 ppm (mg/l) total dissolved solids (TDSs), and this groundwater is usually protected by well surface casing. In some jurisdictions, groundwater protection is extended to useable sources of drinking water, which are defined for water salinity up to 10,000 ppm. For comparison, seawater has a salinity of approximately 33,000 ppm. Groundwater is protected in most if not all jurisdictions. The term *formation water* is applied here to water whose salinity is greater than that of protected groundwater, commonly found at greater depths. *Deep saline aquifers* are those aquifers that, as the name implies, are deep, and that are saturated with (saline) formation water. It is these aquifers that are being considered for CO_2 storage and that are likely to have the largest storage capacity of all classes of potential geological storage sites.

Storage capacity is intuitively a volumetric (spatial) concept, while injectivity (ability to inject a fluid) is a time-dependent (flow rate) concept; however, in the case of CO_2 storage capacity the second affects the first by eliminating from consideration geological media that may posses volumetric capacity but have no injectivity. For example, shales, which may have porosity as high as 30–40%, have little or no injectivity, and instead of constituting a storage medium they may actually be a barrier to CO_2 escape from a storage site (i.e., form a caprock). Thus, the existence of injectivity has been identified as a pre-requisite for CO_2 geological storage (IPCC, 2005) and only geological media that possess both the volumetric capacity and the necessary injectivity should be considered for CO_2 storage. Injectivity depends on rock permeability and fluid viscosity, but generally rocks with permeability less than 0.1 millidarcies (10^{-16} m^2) are considered as being barriers to flow. In low-permeability rocks, injectivity can be enhanced by well stimulation (e.g., rock fracturing) or by increasing the number of injection wells.

Man-made underground cavities (e.g., salt caverns), have been also proposed for CO_2 storage (IPCC, 2005), but they have comparatively small capacity and are limited geographically; however, they may play an important role for temporary storage and/or as a buffer in collector and distributor systems between CO_2 sources and storage sites, being basically part of the CO_2 transportation system, and not of the storage system. Their storage capacity can be calculated easily from cavern geometry (volume), temperature and pressure (Dusseault et al., 2004).

Lately, basalts have been promoted as a possible storage medium for CO_2 that would be suitable for regions lacking sedimentary basins, such as the Pacific Northwest in the USA and the Deccan Plateau in India, but their suitability for CO_2 storage still needs to be demonstrated (IPCC, 2005). Thus, the geological media of significant capacity on a global scale currently under consideration are, in ascending order of their size: coal beds, oil reservoirs, gas reservoirs and deep saline aquifers (IPCC, 2005), and this paper focuses only on estimating the CO_2 storage capacity in these geological media.

2.2. *Operating time frames*

The various CO_2 storage mechanisms listed above have different operating time frames (IPCC, 2005), as illustrated in Fig. 1a. The most important characteristic of residual-gas, dissolution and, particularly, mineral trapping mechanisms is that generally they operate slowly, over a very long time scale, measured in centuries to millennia, and that their contribution to CO storage capacity is almost negligible during the operational phase of injection, which is in the order of decades. Dissolution and mineralization may affect monitoring processes and procedures, but less so capacity during injection. However, residual-gas trapping, dissolution and mineralization of CO_2 play an essential role in increasing the security and safety of CO_2 geological storage after cessation of injection as less and less CO_2 will be in free, mobile phase over time (Fig. 1b).

2.3. *Resource–reserve pyramid*

CO_2 storage capacity constitutes a geological resource (or commodity) whose availability can be expressed using the

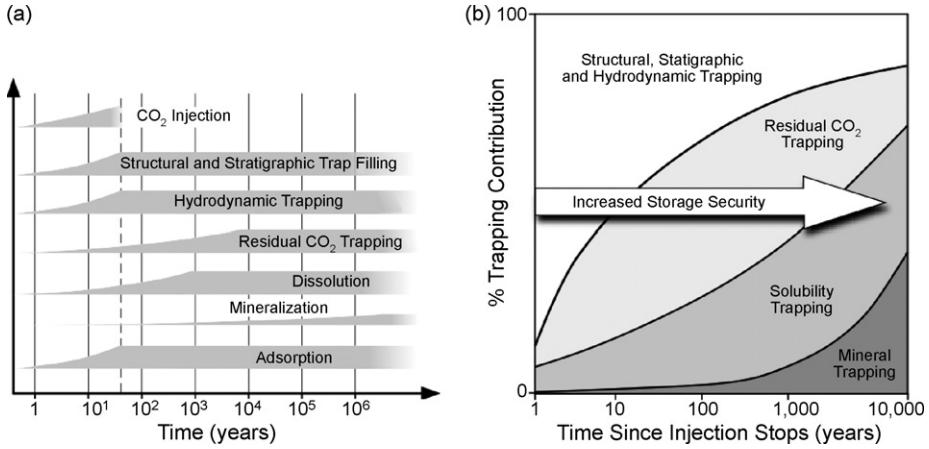


Fig. 1 – Time dependency of processes involved in CO_2 geological storage: (a) operating time frame and (b) storage security (after IPCC, 2005).

concepts of resources and reserves (CSLF, 2005; Frailey et al., 2006a; Bradshaw et al., 2007), in the same way as other energy and mineral commodities such as oil and gas, coal, uranium, iron, gold, etc., are classified.[3] *Resources* are those quantities of a commodity that are estimated at a given time to exist within a jurisdiction or a geographic area. Resources are of two types: *discovered, or in-place* (i.e., an existing commodity whose location and characteristics are known, being assessed on the basis of existing data), and *undiscovered, or inferred* (i.e., not yet found but assumed to exist based on inferences from geological knowledge and/or various analyses). *Reserves* are those quantities of a commodity that are known to exist and that are commercially recoverable under present technological and economic conditions. Their assessment integrates the technical, economic, environmental, societal and regulatory factors available at the time of the assessment. Reserves are a subset of resources, and usually accessibility, technology and economic cutoffs are used to define and delineate reserves. Both resource and reserve estimates evolve in time as new discoveries are made, technology advances and economic conditions change, and therefore it is recommended that CO_2 storage capacity estimates are updated continuously.

The *Techno-Economic Resource–Reserve Pyramid for CO_2 Storage Capacity* (CSLF, 2005; Bradshaw et al., 2007) is illustrated in Fig. 2a. Storage capacity in this pyramid is expressed in mass CO_2 (e.g., Mt or Gt CO_2) rather than volume, because the volume of a given mass of stored CO_2 depends on the pressure and temperature at which it is stored. The various storage capacities are nested within the pyramid, and their size and position varies in time as data, knowledge, technology, policy, regulatory framework and economics of CO_2 geological storage change. For this reason it is absolutely essential that, when an estimate of storage capacity is performed, the nature of the estimate and its position in the resource pyramid are specified. *Theoretical Storage Capacity* represents the physical limit of what the geological system can accept and it occupies the whole of the resource pyramid. There are various possible interpretations regarding the physical limit of a system, such as being the entire pore space, or only the pore space from which the original resident fluids (water, oil or gas) can be displaced (i.e., pore space minus the irreducible residual saturation of the initial fluid), and this definition still requires clarification although in practice it is not critical. The theoretical storage capacity represents a maximum upper limit to a capacity estimate, however it is an unrealistic number as in practice there always will be physical, technical, regulatory and economic limitations that prevent full utilization of this storage capacity. Moreover, at the national or jurisdictional level, it commonly includes very poorly known storage potential in sedimentary basins that may be sparsely described geologically. The *Effective Storage Capacity*, called previously ''Realistic Capacity'' (CSLF, 2005; Bradshaw et al., 2007) represents a subset of the theoretical capacity and is obtained by applying a range of technical (geological and engineering) cut-off limits to a storage capacity assessment, including consideration of that part of theoretical storage capacity that can actually be physically accessed. This estimate usually changes with the acquisition of new data and/or knowledge. *Practical Storage Capacity* (called ''Viable Capacity'' in Bradshaw et al., 2007) is that subset of the effective capacity that is obtained by considering technical, legal and regulatory, infrastructure and general economic barriers to CO_2 geological storage. As such, it is prone to rapid changes as technology, policy, regulations and/or economics change. The Practical Storage Capacity corresponds to the reserves used in the energy and mining industries. Finally, *Matched Storage Capacity* is that subset of the practical capacity that is obtained by detailed matching of large stationary CO_2 sources with geological storage sites that are adequate in terms of capacity, injectivity and supply rate. This capacity is at the top of the resource pyramid and corresponds to the proved marketable reserves used by the mining industry. The difference between matched and practical storage capacities

[3] http://www.spe.org/specma/binary/files/4675179GuidelinesEvaluationReservesResources05Nov.pdf#search=%22Classification%20and%20Nomenclature%20Systems%20for%20Petroleum%20and%20Petroleum%20Reserves%22, http://www.cim.org/definitions/cimdef1.pdf, http://www.jorc.org/pdf/coalguidelines2001.pdf#search=%22guidelines%20coal%20resource%20reserve%22.

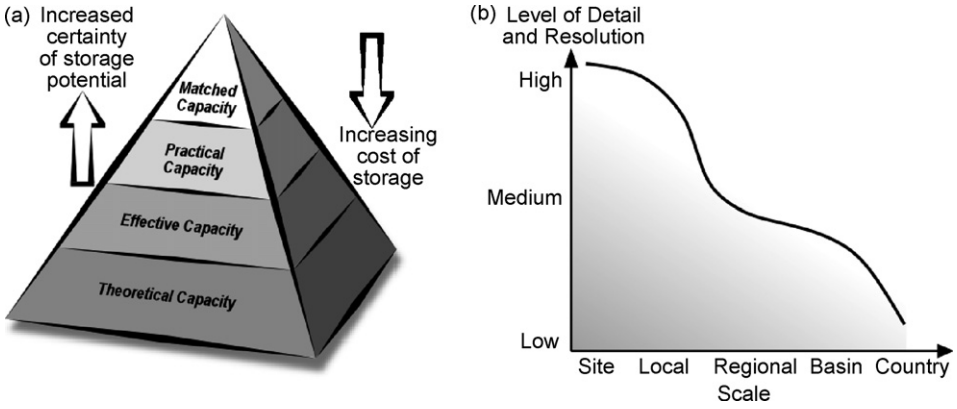


Fig. 2 – Variation in size and resolution of various storage capacities: (a) Techno-economic resource pyramid (after Bradshaw et al., 2007) and (b) data and assessment scales.

represents *stranded storage capacity* that cannot be realized because of lack of infrastructure and/or CO_2 sources within economic distance.

2.4. *Assessment scale and resolution*

The methodology to be applied in CO_2 storage capacity estimation, and the types and level of detail of the necessary data vary, depending on the scale and resolution of the assessment. The *Country-Scale Assessment* is a high level of assessment performed for a contiguous geographic area defined by national jurisdiction (country) and usually encompasses several sedimentary basins and/or parts thereof if a basin is shared between two or more jurisdictions. Such an assessment should be performed to determine whether there is sufficient CO_2 storage capacity in a country, what type or types of storage capacity are available and what challenges (risks) may exist, without necessarily quantifying that country's potential. The data requirements and resolution are minimal for this type of assessment and are usually found in the public domain. In most cases the outcome of such an assessment is the identification of sedimentary basins within that country that have high storage potential and that should form the object of further studies (e.g., Bradshaw et al., 2002; Bachu, 2003; Christensen and Holloway, 2004; Newlands et al., 2006). The *Basin-Scale Assessment* is a more detailed level of assessment focusing on a particular sedimentary basin to evaluate and quantify its storage potential and to identify the best (or more prospective) regions and/or sites for CO_2 storage and their type, often in relation to the major stationary CO_2 sources in the basin or in its proximity. In most cases a basin is areally smaller than a country, but in some cases it may straddle countries or may be shared by several (e.g., the Williston basin shared by Canada and the US, and the North Sea basin shared by Norway, UK, Denmark, Germany and Netherlands). This level of assessment requires more data categories and a greater level of detail than the regional assessment, sometimes focusing on a specific type of storage, like oil and gas reservoirs, coal or deep saline aquifers (e.g., Bachu and Shaw, 2005; Holloway et al., 2006; Bonijoly et al., 2003; Gibson-Poole et al., 2002). The *Regional-Scale Assessment* is performed at an increasing level of detail for a large, geographically contiguous portion of a sedimentary basin, usually defined by the presence of large CO_2 sources and/or by its known large potential for CO_2 storage. The relationship between the above assessment scales may reverse in the sense that in the case of very large sedimentary basins, like the Alberta basin in Canada that has an area of more than 800,000 km^2, a region is smaller than the basin as a whole, while in some other cases, a region, like northwestern Australia, may include several smaller basins.

The *Local-Scale Assessment* is very detailed, usually performed at a pre-engineering level when one or several candidate sites for CO_2 storage are examined to determine site capacity, injectivity and containment prior to site-selection decisions. This type of assessment is based on public and proprietary data and information that may or may not exist at the time of initiating the assessment. In the latter case data will have to be collected as part of the assessment process. The assessment usually involves numerical modeling of storage processes and economic analysis. In most cases this type of analysis will likely form the basis for the permitting process for injection sites. The *Site-Scale Assessment* is performed for the specific storage unit (hydrocarbon reservoir, deep saline aquifer or coal bed), usually to model the behavior of the injected CO_2 (it is equivalent to the reservoir scale in petroleum engineering).

The level of detail and data accuracy required by these assessments increase as the size of the area and sedimentary succession under study decreases (Fig. 2b). Country- and basin-scale assessments should normally be performed by governmental agencies to assess broadly the CO_2 storage potential and establish future directions. Local- and site-scale assessments will most likely be performed by industry in preparation for site selection, permitting, design and construction. Regional-scale assessments may be performed by government agencies and/or industry, depending on scope and purpose. The cost of acquiring the necessary data usually will increase with increasing resolution and level of detail, but so will the level of confidence in the estimated storage capacity. Similarly, the degree of certainty in the storage capacity estimate increases as the assessment moves towards the apex of the resource–reserves pyramid, while the cost of accessing and using less economic sites increases as the

capacity at the top is used and/or more distant sites with smaller individual capacity are being used (Fig. 2a).

3. Estimation of CO_2 storage capacity in coal beds

Carbon dioxide storage in coal beds is a technology that is only in the demonstration phase (IPCC, 2005), and its success will affect its applicability and, consequently, the evaluation of the capacity for CO_2 storage in coal beds. Besides estimating storage capacity *per se*, a major issue is the identification of coal beds suitable for storage.

3.1. *Identification of coal beds suitable for CO_2 storage*

The suitability of coals for CO_2 storage can be assessed on the basis of technical, economic and regulatory (resource protection) criteria. The first depends on coal properties and behavior in the presence of CO_2, the second depends on technology and economic environment, and the third depends on the presence of other resources, particularly groundwater, and the future use of the coal as an energy mineral, that need to be protected.

Technical Limitations to using coals for CO_2 storage refer to coal permeability and adsorption properties. Permeability is a determining factor in the viability of a CO_2 storage site, and currently it is considered that coal permeability has to be greater than 1 mD for successful CO_2 injection and/or coalbed methane (CBM) production. Coal permeability varies widely and generally decreases with increasing depth as a result of cleat closure with increasing effective stress. Coalbed methane cannot be produced if permeability is less than 1 md (Zuber et al., 1996), and this is generally reached in the depth range of 1300–1500 m, which is considered also as the depth limit of possible CO_2 storage in coals (IPCC, 2005). Coal is a polymer-like substance that is affected by the gas with which it is in contact. Coal swells as CO_2 is adsorbed, which further reduces permeability and injectivity (IPCC, 2005). Coal swelling generally increases with increasing gas affinity to coal (e.g., CO_2 versus methane), and may reduce permeability by two orders of magnitude or more (Shi and Durucan, 2005; Cui et al., 2007). In addition, the injected CO_2 may react with the coal and/or formation water, leading to solids precipitation and further permeability reduction (Reeves and Schoeling, 2001; Zhang et al., 1993). Carbon dioxide is a "plasticizer" for coal, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure (Larsen, 2003; IPCC, 2005). Coal plasticization, destroys the permeability that would allow CO_2 injection. Thus, these combined effects on permeability caused by the presence of CO_2 would further reduce the depth limit for CO_2 storage in coals to approximately 800–1000 m.

Economic Limitations are those that depend on coal characteristics such as depth, thickness and number of seams, on the presence of other resources, and on the economics of coal mining. Many coal beds that are considered uneconomic today may become economic in the future, and this energy resource should not be sterilized. This category comprises shallow coals that can be mined in open-pit operations, and deep, thick coals that can be mined underground. Thin coals at intermediate depths most likely would not be economic under any circumstances and can be safely considered as uneconomic (Frailey et al., 2006b). Numerical definitions of these coals (thickness and depth range) still have to be developed and likely depend on jurisdiction and coal characteristics.

Regulatory Limitations refer to coal beds that are unavailable for CO_2 storage because of restrictions imposed by regulatory agencies to protect other resources or for public safety. Many shallow coals have sufficiently high permeability and connectivity that they either constitute by themselves, or are in hydraulic communication with, shallow groundwater aquifers used for water supply. In this case, only coals that are deeper than the depth of groundwater protection could be considered for CO_2 storage. The requirement to protect groundwater resources may impose very severe limitations on CO_2 storage in coals, as some jurisdictions either have already changed or are currently considering changing the definition of protected groundwater from 3000 or 4000 mg/l total dissolved solids (TDSs) to 10,000 mg/l TDS. This means greater depths of protected groundwater, hence less coals potentially available for CO_2 storage.

The various limitations imposed on the coal beds that would be available for CO_2 storage indicate that, generally, only thin coals in a relatively narrow depth window should be considered for CO_2 storage, but the specific outcome for any given coal is highly dependent on local coal characteristics, economics and regulatory regime. These considerations should be used in basin and regional scale assessments of the potential and capacity for CO_2 storage in coals. For example, in a recent estimate of CO_2 storage capacity in Alberta, Canada, Bachu (2007) used coal thickness and the depths of groundwater wells and of the CO_2 phase transition from gaseous to supercritical to identify the coals suitable for CO_2 storage.

3.2. *Estimation of CO_2 storage capacity*

Once the coals suitable for CO_2 storage have been identified, the storage capacity can be estimated by analogy with reserves estimation for CBM, which is based on the total gas in place (capacity) and reservoir deliverability (White et al., 2005). In the case of a gas already adsorbed by the coal, like coalbed methane, the initial gas in place (IGIP) is usually calculated with the relation (e.g., van Bergen et al., 2001; White et al., 2005):

$$\mathrm{IGIP} = Ah\tilde{n}_C G_C(1 - f_a - f_m) \quad (1)$$

where A and h are the area and effective thickness of the coal zone, respectively, $\tilde{n}_C$ is the bulk coal density (generally $\tilde{n}_C \approx 1.4\,\mathrm{t/m^3}$), G_C is the coal gas content, and f_a and f_m are the ash and moisture weight fraction of the coal, respectively. The coal gas adsorption capacity, which depends on pressure, temperature and coal characteristics, is generally assumed to follow a pressure-dependent Langmuir isotherm of the form:

$$G_{CS} = V_L \frac{P}{P + P_L} \quad (2)$$

where G_{CS} is the gas content at saturation, P the pressure, and V_L and P_L are Langmuir volume and pressure, respectively. The

Langmuir volume, V_L, represents the maximum gas adsorption capacity of a particular coal at the given temperature, and is usually given in cc/g, which is equivalent to m^3/t. The asymptotic behavior of the Langmuir isotherm reflects mono-layer adsorption on a surface, where the maximum represents the state of a completely covered surface that cannot adsorb any more gas molecules. Gas adsorption capacity decreases with increasing temperature and increases with increasing pressure. At shallow depths the pressure effect dominates and gas adsorption capacity increases with depth but, after a certain depth the temperature effect becomes dominant and gas adsorption capacity decreases. Coal composition, rank, ash content and moisture content affect the coal adsorption capacity in a complex way that has not been quantified to date. The presence of non-organic material (ash) and water in the coal reduces its adsorption capacity (White et al., 2005).

In the case of CO_2 storage in coal beds, the basic assumption is that CO_2 will replace methane and other hydrocarbon gases present in the coal as a result of coal's higher affinity for CO_2 than for these gases. Thus, Eqs. (1) and (2) can be used in a reverse mode to estimate the theoretical capacity for CO_2 storage of a coal bed if all the coal is accessed by CO_2 and will adsorb CO_2 to 100% saturation. To express the CO_2 storage capacity in mass rather than volume of CO_2, the results have to be multiplied by CO_2 density at standard conditions of 1.873 kg/m^3. Estimating the effective storage capacity is similar to the reduction of initial gas in place (IGIP) to producible gas in place (PGIP) in the case of gas production from coals (van Bergen et al., 2001):

$$\mathrm{PGIP} = R_f C \mathrm{IGIP} \tag{3}$$

where R_f is the recovery factor and C the completion factor, and together they express the reservoir gas deliverability. The completion factor C represents an estimate of that part of the net cumulative coal thickness within the drilled coal zone that will contribute to gas production or storage, it strongly depends on the individual thickness of the separate coal seams and on the distance between them, and is lower for thin coal seams than for thick ones. The recovery factor R_f represents the fraction of gas that can be produced from the coal seams. In conventional CBM production, R_f strongly depends on the pressure drop that can be realized by pumping out large volumes of water (coal dewatering) and ranges between 20 and 60% (van Bergen et al., 2001). For CO_2 storage, its equivalent would be the *storage factor* R_s, for which there is no field experience to date to allow quantification. Finally, the coal adsorption capacity for any given gas, in this case CO_2, is usually reduced by the presence of other gases. Although the assumption is that methane and other hydrocarbon gases present in the coal will be completely replaced by CO_2, in reality a reduction in the adsorption capacity is nevertheless to be expected.

The practical and matched CO_2 storage capacities have to be evaluated on a case-by-case basis using economic considerations, location of CO_2 sources, various regulatory requirements, and numerical and economic modeling, keeping in mind that CO_2 storage and CBM production require a high well density and it is uneconomic to develop the necessary infrastructure for areas with low storage capacity.

4. Estimation of CO_2 storage capacity in oil and gas reservoirs

Estimation of the CO_2 storage capacity in oil and gas reservoirs is the simplest, relatively speaking, and most straightforward of the three media considered for CO_2 geological storage because oil and gas reservoirs are better known and characterized than coals and aquifers, as a result of exploration for and production of hydrocarbons. Also unlike coal beds and deep saline aquifers, oil and gas reservoirs are discrete rather than continuous, such that the capacity for CO_2 storage in hydrocarbon reservoirs in any particular region at any scale is given by the sum of the capacities of all reservoirs in that area, calculated on the basis of reservoir properties such as original oil or gas in place, recovery factor, temperature, pressure, rock volume and porosity, as well as in situ CO_2 density.

The fundamental assumption that is made in storage capacity calculations is that the volume previously occupied by the produced hydrocarbons is available for CO_2 storage. This assumption is generally valid for pressure-depleted reservoirs that are not in hydrodynamic contact with an aquifer, or that are not flooded during secondary and tertiary oil recovery. In reservoirs that are in hydrodynamic contact with an underlying aquifer, formation water invades the reservoir as the pressure declines because of production, leading to a decrease in the pore space available for CO_2 storage, but CO_2 injection can partially reverse the aquifer influx, thus making more pore space available for CO_2. Not all the previously hydrocarbon-saturated pore space will become available for CO_2 because some of the invading water may be trapped in the pore space due to capillarity, viscous fingering and gravity effects (Stevens et al., 2001). Another important assumption is that CO_2 will be injected into depleted oil and gas reservoirs until the reservoir pressure is brought back to the original, or virgin, reservoir pressure. In some cases reservoir depletion may damage the integrity of the reservoir and/or caprock, in which case the pressure cannot be brought back to the initial reservoir pressure and the capacity would be lower, while in other cases the pressure can be raised beyond the original reservoir pressure as long as it remains safely below the lesser of the capillary entry pressure and the threshold rock-fracturing pressure of the seal (caprock), in which case the CO_2 storage capacity would be higher due to CO_2 compression. However, raising the storage pressure to or beyond the original reservoir pressure requires a case-by-case reservoir analysis that is not practical for basin-scale evaluations. In many cases the structure that hosts a hydrocarbon reservoir is not filled with oil and/or gas to the spill point. In such cases, the additional pore space down to the spill point can also be used for CO_2 storage, but, to achieve this, the pressure has to be increased beyond the original reservoir pressure, as discussed previously; this seems to be the case for the majority of fields in the Danish sector of the North Sea.

Both regional and basin scale assessments are based on reserves databases that list oil and gas reserves and various reservoir characteristics. Solution gas should not be considered in storage capacity calculations because it is implicitly taken into account in oil reservoirs through the oil shrinkage factor. Since reserves databases indicate the volume of

original gas and oil in place (OGIP and OOIP) at surface conditions, the theoretical mass storage capacity for CO_2 storage in a reservoir at in situ conditions, M_{CO_2t}, is given by:

$$M_{CO_2t} = \rho_{CO_2r} R_f (1 - F_{IG}) OGIP \left[\frac{(P_s Z_r T_r)}{(P_r Z_s T_s)}\right] \quad (4)$$

for gas reservoirs, and by:

$$M_{CO_2t} = \rho_{CO_2r} \left[\frac{R_f OOIP}{B_f} - V_{iw} + V_{pw}\right] \quad (5)$$

for oil reservoirs.

An alternate equation for calculating the CO_2 storage capacity in oil and gas reservoirs is based on the geometry of the reservoir (areal extent and thickness) as given in reserves data bases:

$$M_{CO_2t} = \rho_{CO_2r} [R_f A h \phi (1 - S_w) - V_{iw} + V_{pw}] \quad (6)$$

In the above equations R_f is the recovery factor, F_{IG} is the fraction of injected gas, P, T and Z denote pressure, temperature and the gas compressibility factor, respectively, B_f is the formation volume factor that brings the oil volume from standard conditions to in situ conditions, V_{iw} and V_{pw} are the volumes of injected and produced water, respectively (applicable in the case of oil reservoirs), and A, h, ϕ and S_w are reservoir area, thickness, porosity and water saturation, respectively. If gas or miscible solvent is injected in oil reservoirs in tertiary recovery, then the mass balance of these should be added to Eq. (5) or (6). The subscripts "r" and "s" in Eq. (4) denote reservoir and surface conditions, respectively. The CO_2 density at reservoir conditions ρ_{CO_2r} is calculated from equations of state (e.g., Span and Wagner, 1996). The volumes of injected and/or produced water, solvent or gas can be calculated from production records. In the case of reservoirs with strong aquifer support (water drive), the volumes of injected and produced water may be negligible by comparison with the amount of invading water.

As mentioned previously, the total storage capacity for a region (defined on the basis of geography, jurisdiction or geology) is the sum of storage capacities in the individual reservoirs, and is based on discovered recoverable oil and gas in place. A simple extrapolation could be used to account for the theoretical storage capacity in undiscovered oil and gas reservoirs, producing the *ultimate theoretical storage capacity* M_{CO_2u}:

$$M_{CO_2u} = (OGIP_u/OGIP_d)\left[\sum M_{CO_2t}\right]_g + (OOIP_u/OOIP_d)\left[\sum M_{CO_2t}\right]_o \quad (7)$$

where the subscripts u, d, g and o stand for ultimate, discovered, gas and oil, respectively. As an illustration, the ultimate CO_2 storage capacity in oil reservoirs in Alberta, Canada, would be ~1 Gt CO_2 on the basis of initial established reserves of 17 Bbbl and ultimate recoverable reserves of 19.7 Bbbl (AEUB, 2006; Bachu and Shaw, 2005). The results, however, should be used with caution because they will be only as good as the estimates of undiscovered oil and gas reservoirs, which in many jurisdictions around the world are of poor quality.

In the case of reservoirs underlain by aquifers, the reservoir fluid (oil and/or gas) was originally in hydrodynamic equilibrium with the aquifer water. As hydrocarbons are produced and the pressure in the reservoir declines, a pressure differential is created that drives aquifer water up into the reservoir, invading the reservoir. If CO_2 is then injected into the reservoir, the pore space invaded by water may not all become available for CO_2 storage, resulting in a net reduction of reservoir capacity (Bachu and Shaw, 2003). The pore volume invaded by water from underlying aquifers cannot be estimated without detailed monitoring of the oil–water interface and detailed knowledge of reservoir characteristics. The reduced storage volume may eventually become available if the reservoir pressure caused by CO_2 injection is allowed to increase beyond the original reservoir pressure, which may or may not always be allowed or possible. Furthermore, the hysteresis caused by relative permeability effects may also prevent complete withdrawal of invaded water, leading to a permanent loss of storage space. Notwithstanding the effect of an underlying aquifer, three other factors control the effectiveness of the CO_2 storage process: CO_2 mobility with respect to oil and water; the density contrast between CO_2 and reservoir oil and water, which leads to gravity segregation; and reservoir heterogeneity (IPCC, 2005). All these processes and reservoir characteristics that reduce the actual volume available for CO_2 storage can be expressed by capacity coefficients ($C < 1$) in the form (Doughty and Pruess, 2004):

$$M_{CO_2e} = C_m C_b C_h C_w C_a M_{CO_2t} \equiv C_e M_{CO_2t} \quad (8)$$

where M_{CO_2e} is the effective reservoir capacity for CO_2 storage, the subscripts m, b, h, w and a stand for mobility, buoyancy, heterogeneity, water saturation, and aquifer strength, respectively, and refer to the phenomena discussed previously, and the coefficient C_e is a single effective capacity coefficient that incorporates the cumulative effects of all the other. These capacity coefficients likely vary widely, depending on reservoir characteristics, and this explains the wide range of incremental oil recovery (7–23% of OOIP) and CO_2 utilization (0.7–4.7 m^3 CO_2/m^3 recovered oil at reservoir conditions) observed for 25 CO_2-flood EOR operations in Texas (Holt et al., 1995). Unfortunately, there are very few studies that estimate the values of these capacity coefficients, and most are based on numerical simulations (e.g., Bachu and Shaw, 2005, for aquifer invasion and values of the coefficient C_a), and generally there are no data or past experience for the specific case of CO_2 storage in depleted hydrocarbon reservoirs.

The practical CO_2 storage capacity in hydrocarbon reservoirs in a region could be obtained from the effective capacity by considering such factors as reservoir depth and size. Many reservoirs are relatively small in volume, and have a low capacity for CO_2 storage, rendering them uneconomic. Building the infrastructure for CO_2 capture, transportation and injection is less costly if the size of the sink is large, and if its lifespan is long enough, to justify the needed investment and reduce the cost per tonne of stored CO_2. As an example, the theoretical storage capacity of ~12 Gt CO_2 in ~35,000 oil and gas pools in western Canada is reduced on this basis to a practical storage capacity of ~4.1 Gt CO_2 in <1000 pools that have individual storage capacity greater than 1 Mt CO_2 each (Bachu and Shaw, 2005). More detailed analysis, based on

economic criteria, should be applied for the selection of the best oil and gas reservoirs for CO_2 storage to determine the practical CO_2 storage capacity.

A special case of CO_2 storage in oil reservoirs is CO_2 flood enhanced oil recovery (EOR). Estimation of the storage capacity in CO_2-EOR is not based on the reservoir volume that will be made available for storage at reservoir depletion, but on detailed, case-by-case numerical reservoir simulations that predict reservoir behavior, the amount of additional recoverable oil and the amounts of CO_2 that need to be injected and are recovered as part of the EOR process. Due to the very nature of the EOR process and of the numerical simulations, the obtained storage capacity estimate for a reservoir is already at the level of an effective estimate. Furthermore, the level of detail required in numerical simulations generally precludes regional and basin scale estimations of CO_2 storage capacity in CO_2 EOR. However, based on the experience to date, screening and identification of oil reservoirs suitable for CO_2-EOR can be performed at the regional and basin scales using various criteria such as reservoir depth, temperature and pressure, minimum miscibility pressure (MMP) and oil gravity (Taber et al., 1997; Kovscek, 2002; Shaw and Bachu, 2002). Further application of screening criteria such as reservoir size and recoverable oil reduce the effective storage capacity to practical storage capacity. Again as an illustration, of 9149 analyzed oil pools in western Canada, only 4748 are suitable for CO_2-EOR on the basis of the criteria enumerated previously, with an effective storage capacity of 638 Mt CO_2 that drops to 450 Mt CO_2 practical storage capacity in 81 oil pools with individual capacity greater than 1 Mt CO_2 each (Bachu and Shaw, 2005).

5. Estimation of CO_2 storage capacity in deep saline aquifers

A theoretical methodology for estimating the CO_2 stored by the various processes operating in deep saline aquifers is given below. Given that in reality the various trapping mechanisms do not operate in isolation but in complex, interdependent and time-dependent ways, an attempt is then made to describe how they might combine to produce hydrodynamic trapping of CO_2.

5.1. *Storage capacity in structural and stratigraphic traps*

Storing CO_2 in structural and stratigraphic traps, (*static trapping*), is similar to storing CO_2 in depleted oil and gas reservoirs, the only difference being that the trap is initially saturated with water instead of containing hydrocarbons. The location and geometry of these traps needs to be known and determined using the standard techniques used in hydrocarbon exploration. If the geometric volume V_{trap} of the structural or stratigraphic trap down to the spill point is known, as well as its porosity ϕ and the irreducible water saturation S_{wirr}, then the theoretical volume available for CO_2 storage, V_{CO_2t}, can be calculated with the formula:

$$V_{CO_2t} = V_{trap}\phi(1 - S_{wirr}) \equiv Ah\phi(1 - S_{wirr}) \tag{9}$$

where A and h are the trap area and average thickness, respectively. This volume is time-independent, and depends on trap characteristics alone. Relation (9) assumes constant porosity and irreducible water saturation, and is applicable when average or characteristic values are used. If the spatial variability of ϕ and S_{wirr} is known, then the following relation should be used:

$$V_{CO_2t} = \int\int\int \phi(1 - S_{wirr})\,dxdydz \tag{9'}$$

The effective storage volume, V_{CO_2e}, is given in a manner similar to oil and gas reservoirs by:

$$V_{CO_2e} = C_c V_{CO_2t} \tag{10}$$

where C_c is a capacity coefficient that incorporates the cumulative effects of trap heterogeneity, CO_2 buoyancy and sweep efficiency. Currently there are no values in the literature for this capacity coefficient, which is site-specific and needs to be determined through numerical simulations and/or field work.

Calculating the mass of CO_2 that corresponds to the effective storage volume is more difficult because the mass of CO_2 that can be stored in the trap at the pre-determined limiting pressure is a function of reservoir permeability, rock relative permeability to formation water and CO_2, dimensions and volume and the nature of the reservoir boundaries, and may vary with the injection strategy (number or inclination of injection wells, etc.). The injection pressure has to be higher than the initial water pressure in the trap, P_i, in order to achieve CO_2 injection, and the pre-determined limiting pressure has to be lower than the maximum bottom hole injection pressure, P_{max}, that regulatory agencies usually impose in order to avoid rock fracturing. The maximum injection pressure should also be less than the threshold entry pressure of the caprock (seal). Thus, the mass of CO_2 that would be stored in a structural or stratigraphic trap would be between these two limits:

$$\begin{aligned}\min M_{CO_2} &= \rho_{CO_2}(P_i, T)V_{trap} \le M_{CO_2} \le \max M_{CO_2} \\ &= \rho_{CO_2}(P_{max}, T)V_{trap}\end{aligned} \tag{11}$$

where T is temperature in the trap. The mass capacity of a trap may vary in time if pressure varies because, although the volume of the trap remains constant, CO_2 density varies with varying pressure. Thus, if the pressure in the trap decays after cessation of injection, the stored CO_2 will expand, and if the trap was originally filled to the spill point, then some CO_2 will migrate past the spill point into the open system of the underlying aquifer.

Relations (9)–(11) can be applied to both theoretical and effective storage capacity estimates for basin- and regional-scale assessments by applying them individually to all the structural and stratigraphic traps identified as potential candidates for CO_2 storage and summing the resulting individual capacities. In the case of local- and site-scale assessments, numerical modeling will likely provide an estimate of the CO_2 pressure in the structural or stratigraphic trap, in which case the mass of stored CO_2 can be calculated based on CO_2 density in a straightforward manner.

5.2. *Storage capacity in residual-gas traps*

The concept of residual-gas trapping is intrinsically linked with hydrodynamic trapping inasmuch as it applies only to a

migrating plume of CO_2. This trapping mechanism is based on the irreducible gas saturation left in the wake of a migrating stream or plume of CO_2 when water moves back into the pore space, after it was expelled from the pore space by the injected and/or migrating CO_2. It is due to the hysteretic properties of relative permeability. During injection, CO_2 saturation increases, and vertical and lateral flow paths are created as CO_2 migrates laterally away from the injection wells and to the top of the aquifer due to buoyancy forces. Once injection stops, CO_2 continues to migrate upward and displace water at the leading edge of the plume, while at the trailing edge water displaces CO_2. A trail of residual, immobile CO_2 is left behind the plume as it migrates upward (Juanes et al., 2006). Thus, residual-gas trapping largely, if not entirely, takes place after injection has stopped, and cannot happen in structural and stratigraphic traps where only water drainage occurs when CO_2 is injected.

If ΔV_{trap} represents the rock volume previously saturated with CO_2 that is invaded by water, and S_{CO_2t} is the trapped CO_2 saturation after flow reversal (Juanes et al., 2006), then the storage volume can be estimated with the formula:

$$V_{CO_2t} = \Delta V_{trap} \phi S_{CO_2t} \tag{12}$$

The trapped CO_2 saturation, S_{CO_2t}, depends on the actual CO_2 saturation at flow reversal and on the hysteretic path of relative permeability for CO_2–brine systems for the respective aquifer rock (Juanes et al., 2006). Unlike in the case of structural and stratigraphic traps, the storage volume in residual-gas trapping is time-dependent; increasing through time as the plume of CO_2 first spreads and then migrates. Consequently, the CO_2 storage capacity in residual-gas traps has to be evaluated at a specific point in time, and will vary in time as long as the injected CO_2 continues to migrate. The mass of stored CO_2 is obtained by multiplying the storage volume by the density of CO_2 at in situ conditions, but this density is both time- and position-dependent as pressure and temperature vary along the flow path and as, for the same location, pressure builds up or decays, depending on the stage of the storage operation.

While porosity ϕ and relative permeability characteristics can be determined through laboratory measurements on core-scale rock samples, the trapped CO_2 saturation S_{CO_2t} and the volume ΔV_{trap} can be determined only through numerical simulations (e.g., Kumar et al., 2005; Juanes et al., 2006). Thus, estimation of the CO_2 storage capacity through residual-gas trapping can be achieved only in local- and site-scale assessments, but not in basin- and regional-scale assessments. The values thus obtained can therefore be included in effective, practical or matched capacities, depending on the estimation purpose and level of detail.

5.3. *Storage capacity in solubility traps*

Solubility trapping is a continuous, time-dependent process estimated to be most effective over time periods in the order of centuries. Carbon dioxide may mix with, and then dissolve in, formation water through diffusion (an extremely slow process), dispersion and convection. The rate at which solubility trapping occurs depends principally on the amount of free-phase CO_2 coming into contact with formation water unsaturated with CO_2. Once migration of the CO_2 has stopped (effectively shutting off dispersion) the water in contact with CO_2 becomes saturated with CO_2, and diffusion becomes the main mixing process, unless natural formation water flow induced by a hydraulic gradient within the aquifer, or cellular convection within the pore system of the aquifer removes the saturated water and replaces it with unsaturated water. Because CO_2–saturated water is heavier by ~1% than the original formation water, if the rock permeability is sufficiently high and if the aquifer is sufficiently thick, convection cells may form that will continually remove the layer of CO_2–saturated water that forms at the contact with the free-phase CO_2, replacing it with unsaturated water, thus enhancing the dissolution process (Lindeberg and Wessel-Berg, 1997; Ennis-King and Paterson, 2003). Because CO_2 needs to come in contact with unsaturated water, the dissolution process is much slower and the storage capacity through this trapping mechanism is much lower once the CO_2 has become immobilized in structural and stratigraphic traps, where CO_2 comes into contact with formation water only at the base of the trap. When the CO_2 is migrating, lateral contact occurs as well, bringing CO_2 into contact with a larger amount of unsaturated water. Solubility trapping is less favorable in thin aquifers, especially if the injected CO_2 comes into contact with the underlying aquitard or aquiclude (bottom seal). Regardless of the retarding or enhancing processes discussed above, CO_2 storage through solubility trapping is a relatively slow, time-dependent process that is predicted to be mostly active after cessation of injection, and can be properly assessed only through numerical simulations at the local- and site-scale for a specified point in time.

At the basin- and regional-scale, the theoretical CO_2 storage capacity in solution can be estimated using the relation (after Bachu and Adams, 2003):

$$M_{CO_2t} = \int\int\int \phi(\rho_S X_S^{CO_2} - \rho_0 X_0^{CO_2})\, dxdydz \tag{13}$$

where ϕ is the porosity, ρ the density of formation water, X^{CO_2} the carbon dioxide content (mass fraction) in formation water and the subscripts 0 and S stand for initial carbon dioxide content and carbon dioxide content at saturation, respectively. The initial CO_2 content and CO_2 content at saturation depend on the pressure, temperature and salinity distribution in the aquifer, and, because of their variation, a process of volumetric integration needs to be used. If average values are being used for aquifer thickness and porosity and for carbon dioxide content in aquifer water (initial and at saturation), then the following simpler relation can be used:

$$M_{CO_2t} = Ah\phi\left(\rho_S X_S^{CO_2} - \rho_0 X_0^{CO_2}\right) \tag{13'}$$

where A and h are aquifer area and thickness. To illustrate the potential for CO_2 storage in solution, calculations for the Viking aquifer in the Alberta Basin, Canada, indicate a theoretical storage capacity of 24–100 kg CO_2/m^3 formation water, or, when rock porosity is taken into account, of 1.5–4.5 kg CO_2/m^3 rock (Bachu and Adams, 2003).

However, the theoretical storage capacity estimate for an entire aquifer is unrealistic, mainly because it assumes that

all the water in the entire pore space of the entire aquifer will be accessed by and saturated with CO_2. The effective storage capacity, M_{CO_2e}, needs to be determined using a relationship similar to relation (3) for storage capacity in coal beds, and relation (8) for storage capacity in oil and gas reservoirs:

$$M_{CO_2e} = C \times M_{CO_2t} \quad (14)$$

where C is a coefficient that includes the effect of all factors that affect the spread and dissolution of CO_2 in the whole aquifer volume under consideration. Given the strong time-dependence of CO_2 dissolution, the coefficient C should arguably be time-dependent.

5.4. *Storage capacity in mineral traps*

Like solubility trapping, mineral trapping is very dependent on the chemical composition of formation waters and of the rock matrix, and on temperature and pressure. In addition, it depends on the contact surface (interface) between the mineral grains and the formation water containing dissolved CO_2, and on the flow rate of fluids past the interface (Gunter et al., 2004). The size of the interface depends on grain and pore size, and on grain contacts (i.e., the grain-to-grain contact surface is not available for mineral reactions). The flow rate depends on rock permeability, hydraulic gradients and water viscosity, which itself depends on water temperature and salinity, and much less so on pressure. The complexity of the chemical and physical processes involved and the level of detailed knowledge and data needed to estimate the amount of CO_2 that would be trapped through mineral precipitation preclude any meaningful basin- and regional-scale estimation of CO_2 storage capacity, notwithstanding the very long timeframe needed for this type of CO_2 storage to make an impact. Only local- and site-scale numerical simulations, backed up where possible by laboratory experiments and field data, can provide an estimate of the amount of stored CO_2 and timeframe for CO_2 storage through mineral trapping. Recent work suggests that the CO_2 storage capacity through mineral trapping per unit of rock volume can be comparable to the storage capacity through solubility trapping, although it can take several thousand years for geochemical reactions to have a significant impact (Xu et al., 2003; Perkins et al., 2004). Like residual-gas and solubility trapping, mineral trapping is a time-dependent process operating on the scale of millennia, hence the CO_2 storage capacity needs to be estimated for a particular point in time.

5.5. *Storage capacity in hydrodynamic traps*

Unlike the other trapping mechanisms, hydrodynamic trapping of CO_2 (Bachu et al., 1994) is not based on a single, specific physical or chemical trapping mechanism, but is a combination of the mechanisms reviewed previously, which operate simultaneously but at different rates while a plume of injected CO_2 is expanding and migrating. Injection of CO_2 into a deep laterally unconfined aquifer rather than a structural or stratigraphic trap leads to trapping of CO_2 by all the previous mechanisms approximately as follows:

- During injection the most important characteristics, as in structural and stratigraphic trapping, are availability of pore space and injectivity. Carbon dioxide will be stored in any small (including unmappable) structural and stratigraphic traps (“bumps”) along the migration path of the CO_2 plume.
- CO_2 dissolution starts as soon as CO_2 contacts formation water, and the storage capacity depends not only on the in situ pressure, temperature and water salinity, but also on the volume of water that is contacted by the injected CO_2 (however, the amount of CO_2 stored through dissolution during the injection phase is likely to be comparatively low);
- Mineral precipitation of CO_2 may also occur almost from the beginning of injection, but CO_2 dissolution has to occur first, and the storage capacity depends on in situ conditions and rock mineralogy, and also on the rock surface contacted by the CO_2–saturated water (it is an extremely slow process);
- Residual gas trapping occurs as the plume of CO_2 migrates through the aquifer after injection has stopped. The injected CO_2 continues to migrate leaving in its wake immobile, free-phase CO_2 trapped in the pore space at irreducible saturation. As this CO_2 comes in contact with the invading water, it may dissolve over time.

Given the length of travel time through deep regional-scale flow systems, the injected CO_2 can be retained in the subsurface for millennia to millions of years, during which CO_2 can be completely trapped through residual gas trapping, dissolution and mineral precipitation such that no mobile, free-phase CO_2 will exist in the system, as modeled in various numerical simulations (e.g., McPherson and Cole, 2000; Ennis-King et al., 2003).

Because hydrodynamic trapping is based on several CO_2 trapping mechanisms acting at times simultaneously and sometimes being mutually exclusive, the CO_2 storage capacity has to be evaluated at a specific point in time as the sum of the storage capacities achieved by its component trapping mechanisms. Given the combination and complexity of the processes involved and of their different time scales, it is not possible to evaluate the CO_2 storage capacity at basin and regional scales except in the broadest terms by extrapolating from local-scale simulations in the relevant aquifer. Numerical simulations can provide answers for specific cases of CO_2 injection in deep saline aquifers.

6. Summary and conclusions

Carbon dioxide capture and geological storage (CCGS) is a means for reducing greenhouse gas emissions into the atmosphere that, technologically, is immediately available, as demonstrated by analogue commercial-scale operations in CO_2 enhanced oil recovery (EOR), natural gas storage and acid gas disposal, including CO_2 injection at Sleipner in the North Sea and In Salah in Algeria. However, for implementation of this technology at the scale needed to achieve a significant and meaningful reduction in CO_2 emissions, governments and industry need to know more about CO_2 storage capacity. More

specifically, there is a need to know what storage media are available (hydrocarbon reservoirs, coal beds or deep saline aquifers), what the main trapping mechanisms are (stratigraphic and structural traps, residual gas saturation, dissolution, mineral precipitation, and/or adsorption), how much capacity there is, and where it is located. Previous attempts to assess CO_2 storage capacity used a variety of approaches and methodologies, and data sets of variable size and quality, resulting in widely varying estimates of inconsistent quality and reliability. This paper represents an attempt to introduce a consistent and systematic set of definitions and methodologies to be used in assessing CO_2 storage capacity. Although a clear approach is recommended, there are still gaps in knowledge that will be covered only through further studies and field experience.

Fundamental to the assessment of CO_2 storage capacity are the concepts of: (1) different operating timeframes for the various trapping mechanisms, (2) different assessment scales, and (3) the resource–reserves pyramid. The level of certainty in storage capacity estimates and the level of detail and data accuracy increase as the evaluation moves from theoretical to matched storage capacity, and from large scales (country and/or basin) to small scales (local and site specific).

Estimation of the CO_2 storage capacity in oil and gas reservoirs is straightforward because, unlike coal beds and deep saline aquifers, oil and gas reservoirs are discrete rather than continuous and are much better characterized, such that the capacity for CO_2 storage in any particular region at any scale is given by the sum of the capacities in all the reservoirs in that area. The storage capacity in each hydrocarbon reservoir is calculated on the basis of reservoir properties such as original oil or gas in place, recovery factor, temperature, pressure, rock volume, porosity and water saturation, as well as in situ CO_2 characteristics such as phase behavior and density. The effective storage capacity is based on various coefficients whose numerical values have to be determined through numerical simulations and field experience. Practical and matched storage capacities can be determined through the application of various cutoffs and reservoir simulations.

In the case of CO_2-enhanced oil recovery, the CO_2 storage capacity can be evaluated broadly on the basis of worldwide field experience of more than 30 years of CO_2-EOR, and through numerical simulations. The challenging aspect is the identification of oil reservoirs that are suitable for CO_2-EOR and co-optimization of oil recovery and CO_2 storage.

Determination of the theoretical CO_2 storage capacity in coal beds is relatively straightforward, and is based on coal thickness and CO_2 adsorption isotherms. However, the major challenge is determining suitable coal beds that can be used for CO_2 storage on the basis of various criteria relating to coal properties such as permeability and seam thickness, CO_2 phase, regulatory protection of other resources such as groundwater, and economics of coal mining. In other words, the challenge is in identifying those coal beds that are, and will be, uneconomic to develop as an energy mineral, and yet suitable for CO_2 storage. Evaluation of the effective storage capacity depends on recovery and completion factors for which no numerical values are available to date. Practical and matched storage capacities need to be evaluated on a case-by-case basis using numerical and economic modeling.

Evaluation of the CO_2 storage capacity in deep saline aquifers is very complex due to the various trapping mechanisms involved that act on different time scales, particularly dissolution and mineral precipitation. Because of the time dependency, except for storage in stratigraphic and structural traps, the CO_2 storage capacity has to be estimated at a specific point in time, and can be achieved through numerical modeling. This aspect and the level of detail and resolution in the required data make estimation of CO_2 storage capacity practical only at the local and site-specific scales. However, the relevant storage capacity is that capacity that can be accessed and achieved during the injection stage, and if some trapping processes have a negligible contribution during this stage, they may be neglected. The same complexity and time dependency makes it very difficult to estimate theoretical, effective and practical CO_2 storage capacities, both individually by process, and cumulatively, for a deep saline aquifer. Again, certain coefficients can be evaluated only on the basis of site-specific numerical simulations or field experience.

Table 1 – Applicability of current methodologies for estimating CO_2 storage capacity to various assessment scales and storage mechanisms

Storage mechanism	Trapping mechanism	Temporal nature[a]	Coefficients needed[b]	Assessment scale				
				Country	Basin	Regional	Local	Site specific
Oil and gas reservoirs	Stratigraphic and structural	No	Yes	✓	✓	✓	✓	✓
	Enhanced oil recovery	No	Yes	–	–	–	✓	✓
Coal beds	Adsorption	No	Yes	✓	✓	✓	✓	✓
Deep saline aquifers	Stratigraphic and structural	No	Yes	✓	✓	✓	✓	✓
	Residual gas	Yes	?	–	–	–	✓	✓
	Solubility	Yes	Yes	–	–	–	✓	✓
	Mineral precipitation	Yes	Yes	–	–	–	✓	✓
	Hydrodynamic	Yes	Yes	–	–	–	✓	✓

Note: For trapping mechanisms that can be assessed only at local or site specific scales, it may be possible to be assessed at higher scales once detailed experience and knowledge develop that allow extrapolation at regional scales, and/or through probabilistic methods.

[a] A trapping mechanism has a temporal nature if the physical or chemical storage process continues after cessation of injection.

[b] Various coefficients need to be estimated to cascade the storage capacity estimate down from theoretical to effective and to practical. These coefficients have to be determined based on field experience and/or numerical simulations.

Table 1 summarizes the scale of applicability of current methodologies for estimating CO_2 storage capacity, the temporal nature of the storage mechanism, and the need for "reduction" coefficients when increasing the resolution and decreasing the scale of the assessment and moving up the resources–reserves pyramid.

The current review provides a clear set of definitions and methodologies needed for the assessment of CO_2 storage capacity in geological media. Nevertheless, evaluating CO_2 storage capacity poses significant challenges which can be grouped into the following three categories.

(1) Lack of data. In this respect, only oil and gas reservoirs generally possess sufficient data as a result of exploration and production; data for deep uneconomic coal beds and saline aquifers are scarce and generally have low spatial resolution. Collecting the data necessary for proper storage capacity assessments requires significant resources, comparable to those expended in the exploration for oil and gas.
(2) Lack of information about the physical and chemical processes, and engineering and economic aspects that reduce storage capacity from theoretical to effective and to practical, including the respective reduction coefficients.
(3) Lack of a good understanding of the interplay between various storage mechanisms acting on different time scales in deep saline aquifers.

Addressing these gaps in knowledge requires a major effort for further clarification and possibly quantification of some definitions, data collection and determination of the various reduction coefficients that are needed in CO_2 storage capacity estimations. This should be based on laboratory experiments, numerical simulations and field experience and measurements.

REFERENCES

AEUB (Alberta Energy Utilities Board), 2006. Alberta's Energy Reserves 2005 and Supply/Demand Outlook 2006–2015. Alberta Energy and Utilities Board, Calgary, AB, Canada.

Bachu, S., 2003. Screening and ranking of sedimentary basins for sequestration of CO_2 in geological media in response to climate change. Environ. Geol. 44, 277–289, doi:10.1007/s00254-003-0762-9.

Bachu, S., 2007. Carbon dioxide storage capacity in uneconomic coal beds in Alberta, Canada: methodology, potential and site identification. Int. J. Greenhouse Gas Control 1, 374–385, doi:10.1016/S1750-5836(07)00070-9.

Bachu, S., Adams, J.J., 2003. Sequestration of CO_2 in geological media in response to climate change: capacity of deep saline aquifers to sequester CO_2 in solution. Energy Convers. Manag. 44 (20), 3151–3175.

Bachu, S., Shaw, J.C., 2003. Evaluation of the CO_2 sequestration capacity in Alberta's oil and gas reservoirs at depletion and the effect of underlying aquifers. J. Can. Petrol. Technol. 42 (9), 51–61.

Bachu, S., Shaw, J.C., 2005. CO_2 storage in oil and gas reservoirs in western Canada: effect of aquifers, potential for CO_2-flood enhanced oil recovery and practical capacity. In: Rubin, E.S., Keith, D.W., Gilboy, C.F. (Eds.), Proceedings of the Seventh International Conference on Greenhouse Gas Control Technologies, Volume 1: Peer-Reviewed Papers and Overviews. Elsevier, pp. 361–369.

Bachu, S., Gunter, W.D., Perkins, E.H., 1994. Aquifer disposal of CO_2: hydrodynamic and mineral trapping. Energy Convers. Manag. 35 (4), 269–279.

Bonijoly, D., Barbier, J., Cotiche, C., Herbrich, B., Kervevan, C., Matray, J.M., Menjoz, A., Robelin, C., Thierry, D., 2003. Feasibility of CO_2 Storage in Geothermal Reservoirs, Example of the Paris Basin–France. Report BRGM/RP-52349-FR, Bureau de Recherches Geologiques et Minieres (BRGM), Orleans, France,135 p.

Bradshaw, J., Bradshaw, B.E., Allinson, G., Rigg, A.J., Nguyen, V., Spencer, A., 2002. The potential for geological sequestration of CO_2 in Australia: preliminary findings and implications for new gas field development. Aust. Petrol. Prod. Explor. Assoc. J. 42 (1), 25–46.

Bradshaw, J., Bachu, S., Bonijoly, D., Burruss, R., Holloway, S., Christensen, N.P., Mathiassen, O.M., 2007. CO_2 storage capacity estimation: issues and development of standards. Int. J. Greenhouse Gas Control 1, 62–68.

Christensen, N.P., Holloway, S. (compilers), 2004. Geological Storage of CO_2 from Combustion of Fossil Fuel; Summary Report of the European Union Fifth Framework Programme for Research and Development; Project No. ENK6-CT-1999-00010, Geological Survey of Denmark and Greenland, Copenhagen, DK, 34 p. & 3 CD-ROMs.

CSLF (Carbon Sequestration Leadership Forum), 2005: A Taskforce for Review and Development of Standards with Regards to Storage Capacity Measurement; CSLF-T-2005-9 15, 16p. http://www.cslforum.org/documents/Taskforce_Storage_Capacity_Estimation_Version_2.pdf.

Cui, X, Bustin, R.M., Chikatamarla, L., 2007. Adsorption-induced coal swelling and stress: Implications for methane production and acid gas sequestration into coal seams. J. Geophys. Res. In press.

Doughty, C., Pruess, K., 2004. Modeling supercritical carbon dioxide injection in heterogeneous porous media. Vadose Zone J. 3 (3), 837–847.

Dusseault, M.B., Bachu, S., Rothenburg, L., 2004. Sequestration of CO_2 in salt caverns. J. Can. Petrol. Technol. 43 (11), 49–55.

Ennis-King, J.P., Paterson, L., 2003. Role of convective mixing in the long-term storage of carbon dioxide in deep saline formations. SPE J. 10, 349–356.

Ennis-King, J.P., Gibson-Poole, C.M., Lang, S.C., Paterson, L., 2003. Long term numerical simulation of geological storage of CO_2 in the Petrel sub-basin, North West Australia. In: Gale, J., Kaya, Y. (Eds.), Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies, vol. I. Pergamon, pp. 507–511.

Frailey, S.M., Finley, R.J., Hickman, T.S., 2006a. CO_2 sequestration: storage capacity guideline needed. Oil Gas J. 104 (30), 44–49.

Frailey, S.M., Rittenhouse, S., Knepp, R., Anderson, A., Leetaru, H., Korse, C., Rupp, J., Finley, R.J., 2006b. Reservoir simulation and GIS modeling as tools for defining geological sequestration capacity: an optimal approach toward more specific assessments, Illinois basin, USA. In: Gale, J., Rokke, N., Zweigel, P., Svenson, H. (Eds.), Proceedings of the Eigth International Conference on Greenhouse Gas Control Technologies. Elsevier, CD-ROM.

Gibson-Poole, C.M., Lang, S.C., Streit, J.E., Kraishan, G.M., Hillis, R.R., 2002. Assessing a basin's potential for geological sequestration of carbon dioxide: an example from the Mesozoic of the Petrel Sub-basin, NW Australia. In: Keep, M., Moss, S.J. (Eds.), The Sedimentary Basins of Western Australia 3, Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth, WA, AU, pp. 439–463.

Gunter, W.D., Bachu, S., Benson, S.M., 2004. The role of hydrogeological and geochemical trapping in sedimentary basins for secure geological storage for carbon dioxide. In: Baines, S.J., Worden, R.H. (Eds.), Geological Storage of Carbon Dioxide. Geological Society Special Publication 233, London, UK, pp. 129–145.

Holloway, S., Vincent, C.J., Bentham, M.S., Kirk, K.L., 2006. Top-down and bottom-up estimates of CO_2 storage capacity in the UK sector of the Southern North Sea Basin. Environ. Geosci. 13 (2), 71–84.

Holt, T., Jensen, J.I., Lindeberg, E., 1995. Underground storage of CO_2 in aquifers and oil reservoirs. Energy Convers. Manag. 36, 535–538.

IEA-International Energy Agency, 2004. Prospects for CO_2 Capture and Storage. IEA/OECD, Paris, France, p. 249.

IPCC—Intergovernmental Panel on Climate Change, 2005. In: Metz, B., Davidson, O., de Coninck, H.C., Loos, M., Meyer, L.A. (Eds.), Special Report on Carbon Dioxide Capture and Storage. Cambridge University Press, Cambridge, UK and New York, NY, USA, Chapter 5, pp. 195–276.

Juanes, R., Spiteri, E.J., Orr Jr., F.M., Blunt, M.J., 2006. Impact of relative permeability hysteresis on geological CO_2 storage. Water Resour. Res. 42, W12418, doi:10.1029/2005WR004806.

Kovscek, A.R., 2002. Screening criteria for CO_2 storage in oil reservoirs. Petrol. Sci. Technol. 20 (7/8), 841–866.

Kumar, A., Noh, M.H., Sepehrnoori, K., Pope, G.A., Bryant, S.L., Lake, L.W., 2005. Simulating CO_2 storage in deep saline aquifers. In: Benson, S.M. (Ed.), Carbon Dioxide Capture for Storage in Deep Geologic Formations—Results from the CO_2 Capture Project, vol. 2: Geologic Storage of Carbon Dioxide with Monitoring and Verification. Elsevier, London, UK, pp. 898–977.

Larsen, J.W., 2003. The effects of dissolved CO_2 on coal structure and properties. Int. J. Coal Geol. 57, 63–70.

Lindeberg, E., Wessel-Berg, D., 1997. Vertical convection in an aquifer column under a gas cap of CO_2. Energy Convers. Manag. 38S, 229–234.

Marsily, G.de, 1986. Quantitative Hydrogeology. Academic Press, San Diego, CA, p. 440.

McPherson, B.J.O.L., Cole, B.S., 2000. Multiphase CO_2 flow, transport and sequestration in the Powder River basin, Wyoming, USA. J. Geochem. Explor. 69–70 (6), 65–70.

Newlands, I.K., Langford, R.P., Causebook, R., 2006. Assessing the CO_2 storage prospectivity of developing economies in APEC—applying methodologies developed in GEODISC to selected sedimentary basins in the Eastern Asian region. In: Gale, J., Rokke, N., Zweigel, P., Svenson, H. (Eds.), Proceedings of the Eigth International Conference on Greenhouse Gas Control Technologies. Elsevier, CD-ROM.

Perkins, E., Czernichowski-Lauriol, I., Azaroual, M., Durst, P., 2004. Long term predictions of CO_2 storage by mineral and solubility trapping in the Weyburn Midale Reservoir. In: Wilson, M., Morris, T., Gale, J., Thambimuthu, K. (Eds.), Proceedings of the Seventh International Conference on Greenhouse Gas Control Technologies, vol. II. Elsevier, pp. 2093–2101.

Reeves, S.R., Schoeling, L., 2001. Geological sequestration of CO_2 in coal seams: reservoir mechanisms, field performance, and economics. In: Williams, D.J., Durie, R.A., McMullan, P., Paulson, C.A.J., Smith, A.Y. (Eds.), Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies. CSIRO Publishing, Collingwood, VIC, Australia, pp. 593–598.

Shaw, J., Bachu, S., 2002. Screening, evaluation, and ranking of oil reservoirs suitable for CO_2-flood EOR and carbon dioxide sequestration. J. Can. Petrol. Technol. 41 (9), 51–61.

Shi, J.-Q., Durucan, S., 2005. A numerical simulation study of the Allison Unit CO_2-ECBM pilot: the effect of matrix shrinkage and swelling on ECBM production and CO_2 injectivity. In: Rubin, E.S., Keith, D.W., Gilboy, C.F. (Eds.), Proceedings of the Seventh International Conference on Greenhouse Gas Control Technologies, vol. 1: Peer-Reviewed Papers and Overviews. Elsevier, pp. 431–439.

Span, P., Wagner, W., 1996. A new equation of state for carbon dioxide covering the fluid region from the triple-point temperature to 1100 K at pressures up to 800 MPa. J. Chem. Ref. Data 25 (6), 1509–1596.

Stevens, S.H., Kuuskra, V.A., Gale, J., 2001. Sequestration of CO_2 in depleted oil & gas fields: global capacity, costs and barriers. In: Williams, D.J., Durie, R.A., McMullan, P., Paulson, C.A.J., Smith, A.Y. (Eds.), Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies. CSIRO Publishing, Collingwood, VIC, Australia, pp. 278–283.

Taber, J.J., Martin, F.D., Seright, R.S., 1997. EOR screening criteria revisited—part 1: introduction to screening criteria and enhanced recovery field projects. SPE Reservoir Eng. 12 (3), 189–198.

van Bergen, F., Pagnier, H.J.M., Kroos, B.M., van der Meer, L.G.H., 2001. CO_2-sequestration in the Netherlands: inventory of the potential for the combination of subsurface carbon dioxide disposal with enhanced coalbed methane production. In: Williams, D.J., Durie, R.A., McMullan, P., Paulson, C.A.J., Smith, A.Y. (Eds.), Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies. CSIRO Publishing, Collingwood, VIC, Australia, pp. 555–560.

White, C.M., Smith, D.H., Jones, K.L., Goodman, A.L., Jikich, S.A., LaCount, R.B., DuBose, S.B., Ozdemir, E., Morsi, B.I., Schroeder, K.T., 2005. Sequestration of carbon dioxide in coal with enhanced coalbed methane recovery—a review. Energy Fuels 19 (3), 659–724.

Xu, T., Apps, J.A., Pruess, K., 2003. Reactive geochemical transport simulation to study mineral trapping for CO_2 disposal in deep arenaceous formations. J. Geophys. Res. 108 (B2), 2071–2084.

Zhang, C.J., Smith, M., McCoy, B.J., 1993. In: Kiran, E., Brennecke, J.F. (Eds.), Kinetics of Supercritical Fluid Extraction of Coal: Physical and Chemical Processes. Supercritical Fluid Engineering Science: Fundamentals and Applications. American Chemical Society, Washington, DC, pp. 363–379.

Zuber, D.M., Saulsberry, J.L., Sparks, D.P., 1996. Developing and managing the reservoir. In: Saulsberry, J.L., Shafer, P.S., Schraufnagel, R.A. (Eds.), A Guide to Coalbed Methane Reservoir Engineering. Gas Research Institute, Chicago. IL, USA, pp. 7.1–7.28.