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Phase II Final Report from the Task Force for Review and Identification of Standards for CO_2 Storage Capacity Estimation

Background

At the meeting of the Technical Group in Melbourne, Australia on September 15, 2004, a Task Force was created to review and identify standards for CO_2 storage capacity estimation. This Task Force presently consists of Canada (lead), Australia, the European Commission, France, Norway, the United Kingdom, and the United States. The Task Force has previously issued a Phase I report (in August 2005) which served to document the nature of the problem such as the relationship between assessment scale and the level of detail and resolution of the storage capacity. This report of the Task Force's Phase II activities summarizes the Phase I findings and provides suggested methodologies for the estimation of CO_2 storage capacity in three types of geologic structures: uneconomic coal beds, oil and gas reservoirs, and deep saline aquifers.

Estimation of CO_2 Storage Capacity in Geological Media
- Phase 2 -

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Executive Summary

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. 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.

CO_2 storage capacity can be conceptualized as a resource pyramid, in which the degree of geological and economic uncertainty associated with a capacity estimate is represented by its place on the pyramid. In essence, the best-known and highest quality capacity is placed at the apex of the pyramid and the poorly known and/or poor quality capacity is placed at its base. Theoretical storage capacity, which is defined as the physical limit of what the geological system can accept, is represented by the entire pyramid. The effective storage capacity is a subset of the theoretical capacity and is obtained by applying a range geological and engineering cut-off limits to a storage capacity assessment. The practical storage capacity is that subset of the effective capacity that is obtained by considering other technical, legal and regulatory, infrastructure and economic barriers to CO_2 geological storage. The 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.

CO_2 storage capacity assessments may be conducted at a variety of scales. The country-scale assessment is a high level of assessment performed for a contiguous geographic area defined by national jurisdiction. The basin-scale assessment is a more detailed level of assessment focusing on a particular sedimentary basin. The regional-scale assessment is performed at an increasing level of detail for a large, geographically-contiguous portion of a sedimentary basin. 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. The site-scale assessment is performed for the specific storage unit, usually to model the behaviour of the injected CO_2.

Estimation of the CO_2 storage capacity in oil and gas reservoirs is straightforward because they are generally well-defined both spatially and in terms of reserves, and they are much better characterized than coal beds and saline water-bearing aquifers. The storage capacity in each reservoir is calculated on the basis of its recoverable hydrocarbon reserves, its reservoir properties and in situ CO_2 characteristics. 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, once an oil reservoir has been identified as suitable for CO_2-EOR, its CO_2 storage capacity can be roughly evaluated on the basis of worldwide field experience or more accurately through numerical simulations. The technical challenge in defining the storage capacity of oil reservoirs undergoing CO_2-EOR is co-optimizing oil recovery and CO_2 storage.

Determination of the theoretical CO_2 storage capacity in coal beds is based on coal thickness and CO_2 adsorption isotherms. A major challenge is determining which coal beds might be suitable for CO_2 storage, i.e. which coal beds are uneconomic. 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 because four trapping mechanisms that act at different rates are involved and, at times, all mechanisms may be operating simultaneously. This makes it very difficult to estimate theoretical, effective and practical CO_2 storage capacities, either individually by process, or cumulatively, for a deep saline aquifer.

At present, the level of detail and resolution required in the data make reliable and accurate estimation of deep saline aquifer CO_2 storage capacity practical only at the local and site-specific scales. This is a key issue. It is generally thought that saline aquifers account for the majority of the potential CO_2 storage capacity in a jurisdiction, and policymakers want to know whether there is sufficient practical CO_2 storage capacity in their jurisdiction for CCGS to be an effective greenhouse gas mitigation option. More assessments need to be undertaken so that rules of thumb can be developed.

The current review provides a clear set of definitions and methodologies for the assessment of CO_2 storage capacity in geological media, however, it also points to the need for future work, within and outside CSLF, to determine the various reduction coefficients that are needed to estimate effective and practical storage capacities. These coefficients can be evaluated through laboratory experiments, numerical simulations and field experience and measurements. It is recommended that the Task Force on CO_2 Storage Capacity Estimation continues in a new Phase 3 and consider addressing some, or all of the following matters:

1) Coordination of methodology for CO_2 storage capacity estimation with other national and international groups working on this subject, including the Geologic Working Group of the USDOE Regional Carbon Sequestration Partnership Program. This work could include further development and refinement of the Resource pyramid for CO_2 storage capacity in geological media along the lines of resources and reserves definitions used in the oil & gas and mining industries.
2) Compilation of a collection of representative case-studies of CO_2 storage capacity estimation at various scales and in different geological settings, including evaluation and use of various coefficients that are used in CO_2 storage capacity estimations and for which no or very few numerical values are available.
3) Provision of support to the Task Force on Capacity Building in training and applying the methodologies for estimating CO_2 storage capacity along the full chain from country-scale to site-scale, and from theoretical to matched capacity, to one or more developing economies in CSLF.

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1. Introduction

Three approaches can be taken to mitigating anthropogenic CO_2 emissions to the atmosphere in response to climate change: 1) increasing energy efficiency and conservation, 2) switching to less carbon-intensive fuels or to renewables, solar and nuclear energy, and 3) artificially increasing the capacity and capture rate of CO_2 sinks. The latter could be achieved through manipulating biological processes to capture and sequester CO_2 that has already been emitted and dispersed in the atmosphere, and through the capture of CO_2 from large stationary sources prior to potential release into the atmosphere, and storage in various media (this process is known as Carbon Capture and Storage, or CCS). A significant reduction in global 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 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). Utilization and storage of CO_2 in industrial processes is quantitatively insignificant and likely to remain so in the foreseeable future. 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., 2006).

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; Bradshaw et al., 2007). Geographically, storage capacity estimates have been produced for Australia, Canada, northern Europe, Japan, USA, and projects are under way to assess the storage capacity in southern and eastern Europe. No storage capacity estimates exist for other regions of the globe, although a prospectivity study has been completed in 2005 for APEC countries along the Pacific Rim (from Korea to Indonesia; Newlands et al., 2006).

CSLF recognized the need to provide consistent and accepted methodologies for estimating CO_2 storage capacity in developed and developing countries alike. In 2004 the

Technical Group of CSLF established a *Taskforce for Review and Development of Standard Methodology for Storage Capacity Estimation*. In 2005, the Taskforce presented the results of Phase 1 of the assignment in a Discussion Paper in which previous estimates were critically analyzed and gaps in knowledge and/or methodology were identified (CSLF, 2005). This report presents the results of Phase 2 of the Taskforce assignment, namely definitions, concepts and methodologies to be used in estimating CO_2 storage capacity. The concepts, definitions and methodologies presented in this report should serve as a basis in CSLF member countries for collecting the necessary data and properly estimating the CO_2 storage capacity in geological media in their jurisdiction[1].

2. Concepts and Definitions

A series of concepts and definitions are introduced here to clarify terminology and subsequently-proposed approaches and methodology.

2.1 Relevant Geological and Hydrogeological Concepts

Sedimentary rocks are formed by the deposition, compression and cementation of mineral and rock particles, but often including material of organic origin, and may be classified as:

1) terrigenous (i.e., derived from the breakdown of pre-existing rocks exposed on land, e.g., sandstones, conglomerate, shale),
2) organic (i.e., produced either directly or indirectly by organic processes, e.g. peat, coal, some carbonates),
3) chemical (i.e., produced by precipitation from water, e.g., some carbonates and all evaporites such as salt), and
4) volcanogenic (i.e., produced by the fall-out of particles after a volcanic eruption; e.g., tuffs and bentonites).

Metamorphic rocks are aggregate of minerals formed by the recrystallization of pre-existing rocks in response to changes in pressure, temperature, or volatile content (e.g., slate, schist, gneiss). Igneous (magmatic) rocks are rocks that have crystallized from magma and may be classified as:

1) intrusive or plutonic (i.e., rock bodies, which have crystallized at great depth, e.g., granite, gabbro), and
2) extrusive or volcanic (i.e., magma ejected at the earth's surface, either on land or under water; e.g., basalt, andesite).

Sedimentary basins are subsiding or subsided areas of the Earth's crust that permit the net accumulation of sediments and consist of variably consolidated rocks with various

[1] It is worth mentioning here that, as a result of similar inconsistencies in evaluating the CO_2 storage capacity across the U.S., the U.S. Department of Energy (USDOE) Regional Carbon Sequestration Partnership Program has established in 2006 a Geologic Working Group for developing standards to produce a National Capacity Assessment of the amount of CO_2 that can be stored in subsurface environments in the U.S. The objectives and activities of this Working Group are similar to those of the CSLF Task Force for Review and Development of Standard Methodology for Storage Capacity estimation.

degrees of space within them. This space is in the form of pores (intergranular porosity) and/or fractures (fracture porosity) and is filled with fluids. The vast majority of the space in sedimentary basins is intergranular porosity. By far the great majority of the pore space is filled with water; other fluids, found in lesser quantities, are hydrocarbon oils and gases, and other gases that have a deep-sourced origin such as CO_2 and H_2S. The water in the subsurface may have a meteoric origin (i.e. rain and snowmelt that infiltrates into the ground in recharge areas such as porous and permeable rock formations at high elevation), a connate origin (e.g., seawater in sediments at the time of sediment deposition at the bottom of the sea), or may be even the result of deep geochemical reactions that produce water. As a result of various flow and geochemical processes that take place over geological timescales, the salinity of water in the ground commonly increases with depth.

Before proceeding with providing methodology for estimating CO_2 storage capacity in deep saline aquifers and in oil and gas reservoirs, a few definitions are needed to establish a common understanding and terminology. In water resources engineering and hydrogeology, an **aquifer** is defined as a layer, formation, or group of formations 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). For example, sandstone and unconsolidated sand beds are aquifers, shale and clay beds are aquitards (these generally have relatively high porosity, but have very low permeability), and salt and anhydrite beds are aquicludes (they have very low if any porosity, and extremely low permeability). Aquifers, regardless of their lithology, are defined in terms of their hydraulic properties and are separated by intervening aquitards or aquicludes (i.e., a porous and permeable sandstone bed and a porous and permeable carbonate bed in contact form a single aquifer with variable properties). The key elements in these definitions are that the pore space is saturated with water, and that the geological units allow or prevent its withdrawal (production), depending on rock permeability. If an aquifer allows water withdrawal, then it will also allow injection of fluids. The most common fluid 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 in oil fields for pressure maintenance and/or enhanced oil recovery.

Generally, in petroleum engineering the term **hydrocarbon reservoir** is used to designate porous and permeable rocks that contain fluids other than water, such as hydrocarbons (oil and/or gas), CO_2 and H_2S, and this definition is specifically used in this report. From a hydrodynamic point of view (flow of fluids), 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., water in the former, other 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. Another important feature is that, with very few

exceptions, 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 that overlies a reservoir and retains the hydrocarbons and/or other gases. Cap rocks are either aquitards or aquicludes. Low permeability rocks (aquitards or aquicludes) also underlie aquifers and hydrocarbon reservoirs.

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. Groundwater is defined as water with salinity less than 4,000 or 5,000 ppm (mg/l) total dissolved solids (TDS), depending on jurisdiction. For comparison, seawater has a salinity of approximately 33,000 ppm. Groundwater is protected in most if not all jurisdictions. Some jurisdictions, where water supply is already, or is becoming a problem, are contemplating increasing the salinity limit of protected groundwater to 10,000 ppm because this slightly more saline water can be used after treatment. Groundwater is usually protected by well surface casing.

The term **formation water** is applied here to water that has greater salinity and is commonly deeper than groundwater as defined above. **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. The IPCC Special Report on CO_2 Capture and Storage (2005) used the term "deep saline formations" when referring to deep saline aquifers, but that terminology is ambiguous because the term "formation" is a geological term that applies to a stratigraphic and/or lithologic unit, with no specification in regard to its saturating fluid and hydraulic properties (water and the ability to withdraw it, respectively).

Coals are sedimentary rocks of organic nature, formed by the lithification and "thermal cooking" of organic material (peat) under increasing pressure and temperature as it is buried in the Earth's crust under the weight of sediments deposited on top of it. Coal has generally a brittle structure and a system of micropores, which allow gas diffusion, and cleats (fractures) that allow the flow of gas (methane, CO_2) and/or water. Coal permeability decreases with depth and depends on other coal characteristics, such that coal beds, or part s of coal beds, can be aquifers or aquitards, thus allowing or impeding, respectively, the flow of water.

2.2 CO_2 Trapping Mechanisms

Geological storage of CO_2 is achieved through a combination of physical and chemical trapping mechanisms (IPCC, 2005). Each mechanism is effective over different timeframes and 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*). In the context of CCGS, CO_2 migration is defined as lateral flow within the targeted injection and storage unit (formation, reservoir, 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.

Under favorable circumstances, injected CO_2 may migrate in the subsurface at extremely low velocities such that it would take time on a geological scale (millions of years) to reach the surface, before which it may become trapped by a combination of the mechanisms outlined above. Very large masses of CO_2 potentially could be stored in this way, which is commonly described as *hydrodynamic trapping*.

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).

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. On the other hand, 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 (i.e., 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.

[2] The term "static" was chosen here to describe the non-migrating nature of the stored CO_2 in such 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 even just "structural/stratigraphic" trapping.

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)[3]. If containment issues are resolved, basalts may be a candidate primarily for mineral storage, which generally operates on a very long time scale but in the case of basalts may operate much more quickly. Organic-rich shales have also been proposed for CO_2 storage because, in theory, they have storage potential due to their CO_2 adsorption properties. However, the storage volumes may be limited, and the very low permeability of shales precludes the injection of large volumes of CO_2 without jeopardizing storage integrity and security (IPCC, 2005). Thus, the only geological media of any significant capacity on a global scale are, in ascending order of their size: coal beds, oil reservoirs, gas reservoirs and deep saline aquifers (IPCC, 2005). Consequently, **this report focuses only on the development of definitions and standards that could be used for estimating the CO_2 storage capacity in unmineable coal beds, oil and gas reservoirs, and deep saline aquifers**. The storage capacity of man-made caverns can be calculated easily from cavern geometry (volume), temperature and pressure. If CO_2 storage in other geological media proves technologically and economically feasible in the future, and if these media prove to have sufficient storage capacity, then the methodology needed to estimate their storage capacity will be determined at that time.

2.3 Operating Time Frames

The various CO_2 storage mechanisms listed above have different operating time frames (IPCC, 2005), as illustrated in Figure 1. The most important characteristic of dissolution and, particularly, mineral trapping mechanisms - readily apparent from this figure - 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. The same applies to residual-gas trapping (Figure 1). Dissolution and mineralization may affect monitoring processes and procedures, but less so capacity during injection. From an operational point of view, it is most important that the mass of CO_2 injected should at no time exceed the amount that will be trapped during the injection period *or thereafter*. Therefore if potential storage capacity is to be used to the maximum, especially in hydrodynamic trapping concepts, modelling of the long-term fate of the injected CO_2 may be necessary, to estimate the effectiveness of the slower storage processes.

Although some thought has been given to surface dissolution of CO_2 in water, prior to injection, this potential process, which still has to be demonstrated from energy and economic points of view, will not be addressed here because CO_2-saturated water is not buoyant and is miscible with formation water, and because the problem then becomes one

[3] Sedimentary layers that occur between basalt flows could be used for CO_2 storage provided that they meet the capacity, injectivity and confinement requirements, in which case the methodology for capacity estimation for aquifers would apply. However, if CO_2 storage is to occur in the basalt layers themselves, then the capacity, permeability and confinement of these strata has to be demonstrated, since their porosity and permeability are not intergranular, as in sedimentary rocks, but rather fracture-based.

of "water-disposal" rather than of CO_2 storage. Thus, the main focus of this report is on assessing the capacity needed during the operational phase of CO_2 storage operations.

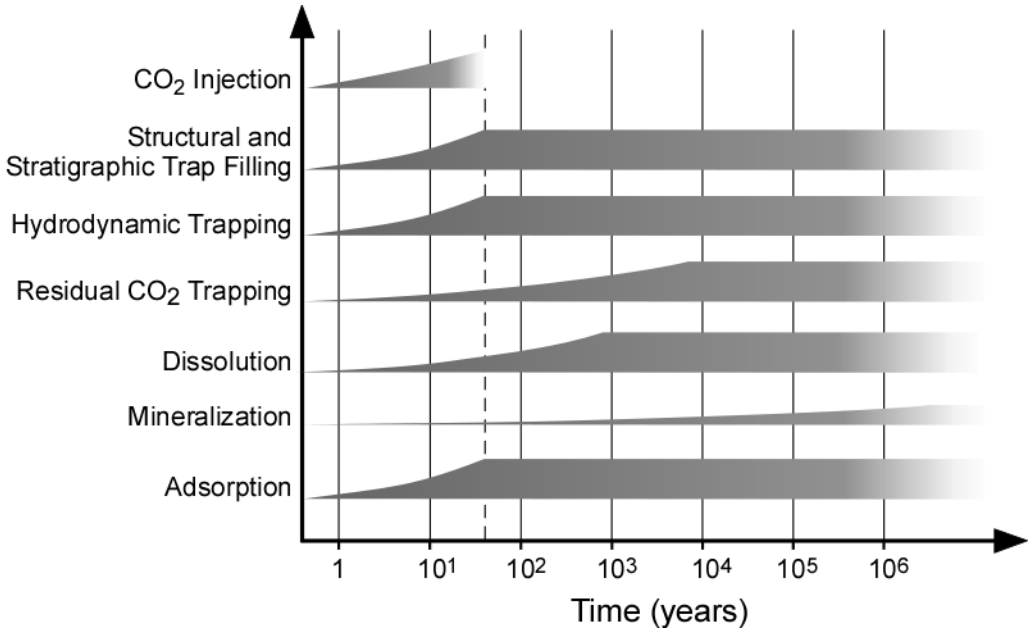

Figure 1. Operating time frame of various CO_2 geological-storage mechanisms (modified from IPCC, 2005).

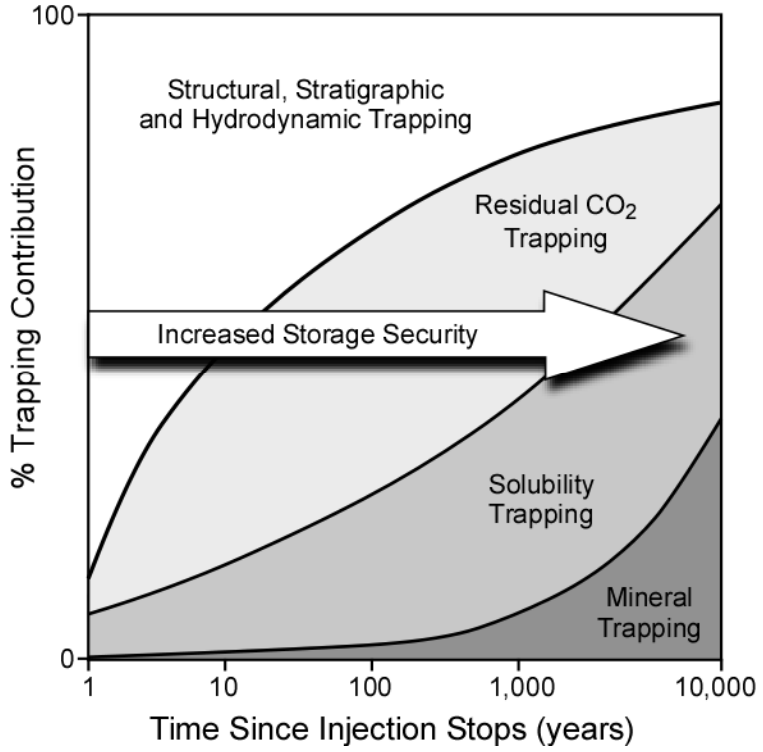

Figure 2. Contribution and storage security of various CO_2 geological-storage mechanisms (from IPCC, 2005).

3. Summary of Phase 1 Findings

In addition to documenting the main reasons for the wide range and discrepancy of various estimates of CO_2 storage capacity performed with different methodologies and data, the Phase 1 analysis has preliminarily introduced several concepts and definitions, and has identified gaps that are briefly reviewed here to provide the foundation for the methodologies that will be subsequently presented.

3.1 Resource-Reserve Pyramid Concept

CO_2 storage capacity constitutes a geological resource (or commodity) whose availability can be expressed using the concepts of resources and reserves, in the same way as other energy and mineral commodities such as oil and gas, coal, uranium, iron, gold, etc., are classified[4]. The need for guidelines for estimating CO_2 storage capacity has recently been identified (CSLF, 2005; Frailey et al., 2006a), driven by governments, which need to assess available "supplies", and by industry, which needs to manage business processes. CO_2 storage capacity will probably constitute an asset whose ownership is still a matter of debate. The following constitutes an attempt at such classification using concepts from both the petroleum and mineral industries, fully recognizing that it will evolve in time.

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., existing commodity whose location and characteristics are known, being assessed on the basis of scarce data), and *undiscovered, or inferred* (i.e., not found yet 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. Their assessment integrates 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. For this reason, many jurisdictions and/or companies update annually their resource and reserves estimates (e.g. this is common practice in the oil and gas industry) and it is recommended that CO_2 storage capacity estimates follow a similar procedure.

[4]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

Using this concept, the following ***Techno-Economic Resource-Reserve Pyramid for CO_2 Storage Capacity*** (CSLF, 2005; Bradshaw et al., 2006) is introduced and illustrated in Figure 3. Storage capacity in this pyramid is expressed in mass CO_2 (e.g., Mt or Gt CO_2). The various capacities described below are nested within the resource-reserves pyramid, and their size and position varies in time as data, knowledge, technology, policy and 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 type 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. It assumes that the entire volume is accessible and utilized to its full capacity to store CO_2 in the pore space, or dissolved at maximum saturation in formation fluids, or adsorbed at 100% saturation in the entire coal mass. This 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.

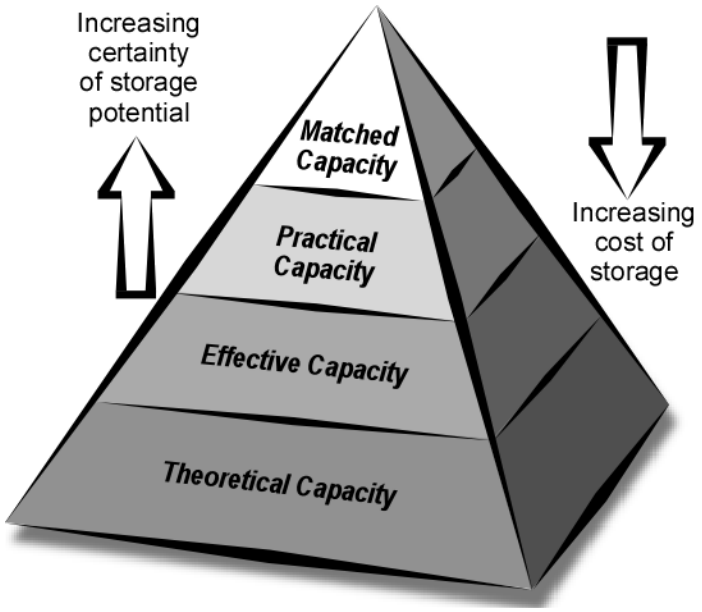

Figure 3. Techno-Economic Resource-Reserve pyramid for CO_2 storage capacity in geological media within a jurisdiction or geographic region (modified from CSLF, 2005; Bradshaw et al., 2006). The pyramid shows the relationship between Theoretical, Effective, Practical and Matched capacities.

Effective Storage Capacity (Bachu and Shaw, 2005)**,** called previously **Realistic Capacity** (CSLF, 2005) 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 be physically accessed. This estimate usually changes with the acquisition of new data and/or knowledge.

Practical (or Viable) Storage Capacity 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.

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

3.2 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.

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. Such studies have been performed or are in progress for continental-size countries such as Australia and Canada, and for groups of countries defined by some commonality criterion (geographic or organizational) in Europe and Asia (e.g., Bradshaw et al., 2002; Bachu, 2003; Christensen and Holloway, 2004, Newlands and Langford, 2005).

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 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 (e.g., only oil and gas reservoirs). Such assessments have been performed in Canada for oil and gas reservoirs in the Alberta and Williston basins (Bachu and Shaw, 2005), in the UK sector of the

Southern North Sea (Holloway et al., 2006) and the East Irish Sea Basin (Kirk, 2005), in the French Paris Basin and some French coal basin prospects (Bonijoly et al., 2003, 2006), and in the Petrel Sub-basin in Australia (Gibson-Poole et al., 2002).

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. Such assessments are undertaken usually to identify sites for CO_2 storage (e.g., Gibson-Poole et al., 2004) and to provide a framework for evaluating the long term fate of the injected CO_2 (e.g., a region of 200 km × 200 km was evaluated around the Weyburn project in the Williston basin in Canada). The relationship between basin-scale and regional-scale assessments may reverse in the sense that in the case of very large sedimentary basins like Alberta in Canada that has an area of approximately 900,000 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.

Basin- and regional-scale CO_2 storage capacity assessments should exclude areas where risks of leakage or negative impacts on the environment or existing resources are not known but nevertheless are expected. The storage area(s) must be delineated using the available geological and environmental data (data that are generally, but not exclusively, produced by governmental organizations). More specifically, it is unwise to include in CO_2 storage capacity assessments areas affected by major faults, or active faults or great dip. Areas where permits are allocated for natural resource exploration, particularly for oil and gas, should be included in CO_2 storage capacity evaluations, but then a proper resource management process should be used to determine if that storage capacity should remain at the "effective" level or could be moved to the "practical level".

Local-Scale or (Prospect-Level) 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. In the case of sites that pass the selection and permitting process, the local (or prospect-level) assessment forms the basis for detailed engineering design of the CO_2 storage site. Such studies are in progress in France and Australia (Brosse et al., 2006; Gibson-Poole et al., 2006).

Site-Scale Assessment is performed for the specific storage unit (hydrocarbon reservoir, deep saline aquifer or coal bed), usually to model the behaviour of the injected CO_2 (it is equivalent to the reservoir scale in petroleum engineering). Examples of such assessments are the Utsira aquifer at Sleipner in the North Sea, and the Weyburn oil pool at Weyburn in the Williston basin.

The level of detail and data accuracy required by these assessments increase as the size of the area and sedimentary succession under study decreases. Country- and basin-scale assessments are most likely to be performed by governmental agencies to assess broadly the CO_2 storage potential and establish future directions. Local- and site-scale assessments are/will be performed by industry in preparation for site selection, permitting, design and construction. Regional-scale assessments may be performed by governmental agencies and/or industry depending on scope and purpose.

3.3 Gaps Identified by, and Recommendations of, Phase 1

The Phase 1 report (CSLF, 2005) has identified gaps that led to the confusion and wide discrepancy in earlier CO_2 storage capacity estimates. Estimates to date, mostly done by scientists as the field of CO_2 capture and storage advanced, are lacking:

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

As a result of the analysis, the Phase 1 report made a series of recommendations to be implemented in Phase 2 of this Taskforce assignment and to be used in future estimations of CO_2 storage capacity, mainly:

- development and adoption of clear definitions;
- adoption or development of clear and consistent methodologies appropriate to each assessment scale;
- provision of examples of proper application of recommended methodology.

The following sections of this report will address the issues identified and recommendations made in the Phase 1 report.

The report is not about country-scale estimation, where only the potential for, but not the capacity can be estimated, nor about local- and site-scale assessments, where specific and detailed numerical models have to be used. It is focused mainly on estimating CO_2 storage capacity at the basin and regional scales using geological and resource-reserve data.

4. Estimation of CO_2 Storage Capacity in Coal Beds

Carbon dioxide storage in coal beds occurs when CO_2 is preferentially adsorbed onto coal. Coal contains a natural system of fractures called cleats, which imparts some

permeability to the system. Between the cleats, the solid coal does not contain macropores through which fluids can flow, but does contain a very large number of micropores into which gas molecules can diffuse from the cleat. The combined surface area of the micropores, which form adsorption sites for gas molecules, is very high, and the adsorbed molecules can be very tightly packed. Coal can physically adsorb many gases, for which it has different affinities (Figure 4; Chikatamarla and Bustin, 2003). In the presence of multiple gases (e.g., CH_4, CO_2, N_2) the amount of each in the adsorbed state would be approximately in the proportion of their respective affinities (Reeves and Schoeling, 2001). Coal has higher affinity for *gaseous* CO_2 than for methane (Figure 4), which naturally occurs in coals, the volumetric ratio between the two ranging from as low as 1 for mature coals such as anthracite, to as high as 10 for younger, less altered coals. Thus, CO_2 storage in coal beds is based on the concept that the injected CO_2 will replace the methane in coal and stay adsorbed onto the coal surface as long as the coal is undisturbed (i.e., the pressure doesn't drop). The freed methane, which is also a greenhouse gas with a radiative effect 21 times stronger by weight than that of CO_2, has to be entirely captured and used as a source of energy (cannot/should not be vented) to ensure a net greenhouse gas mitigation outcome, hence the name of the whole process as enhanced coalbed methane recovery (ECBMR).

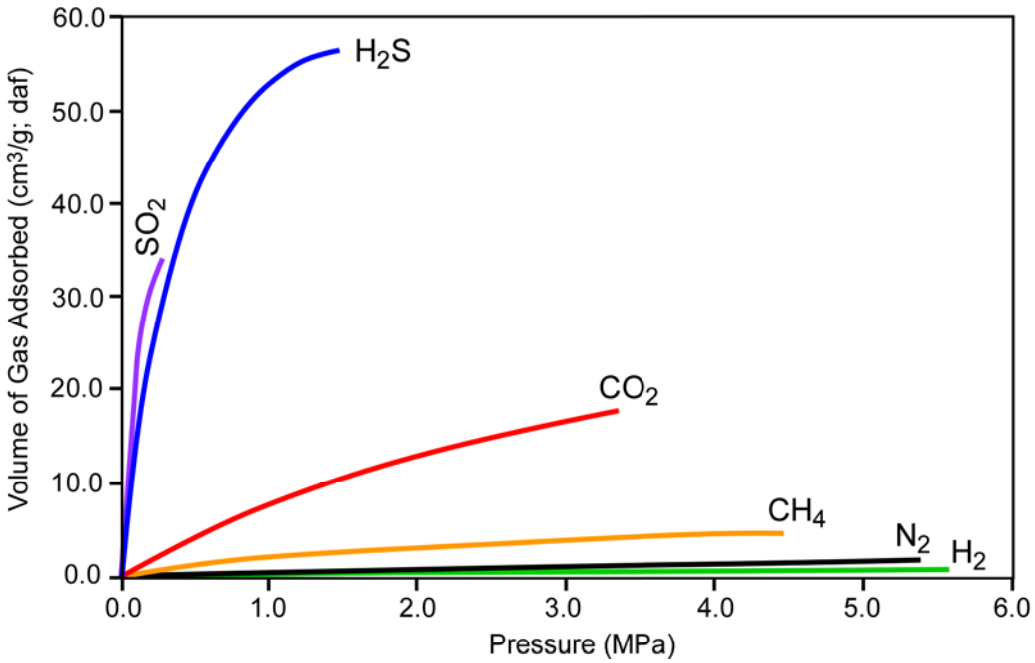

Figure 4. Adsorption of various gases on coal (from Chikatamarla & Bustin, 2003).

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.

4.1 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) aspects. The first depends on coal properties and behaviour 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 is affected by physical (mechanical) and chemical factors. It varies widely and generally decreases with increasing depth as a result of cleat closure with increasing effective stress. The permeability of shallow coals (a few hundred metres deep) is on the order of millidarcies (mD) and higher, while the permeability of deep coals is on the order of microdarcies (μD), which is too low to allow CO_2 injection and flow without fracturing. Coalbed methane can not be produced if permeability is less than 1 md (Zuber et al., 1996), and this is generally reached in the depth range of 1,300-1,500 m. It is for this reason that most of the coalbed methane producing wells in the world are less than 1000 m deep (IPCC, 2005) and that's why the depth of 1,300-1,500 m is considered as the depth limit of possible CO_2 storage in coals.

Coal is a polymer-like substance that is often 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). 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 (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 reduce the depth limit for CO_2 storage in coals to approximately 1,000 m.

Adsorption is a process that applies to gases. The process of CO_2 trapping in coals at temperatures and pressures above the critical point is not well understood, and it seems that adsorption is replaced by absorption and the CO_2 diffuses in coal (Larsen, 2003). The transition from one process to the other is not sharp, but rather gradual. At the high temperature and pressure conditions that correspond to supercritical CO_2, it is not clear whether CO_2 is adsorbed by coal, occupies the pore space like a fluid with very low viscosity, or infuses into the coal matrix. Under these conditions coals are not a good storage medium because CO_2 might be highly mobile and migrate out of the coals into the adjacent strata or within the coals themselves, with the potential for leakage into shallow

groundwater aquifers and even to the surface. Thus, until the basic science of CO_2 storage in coal advances to clarify these points, it seems that it would be safe to consider that CO_2 should be stored only in coal beds that are at such temperature and pressure conditions that CO_2 is in gaseous phase. For hydrostatic conditions and average geothermal gradients this would correspond to depths in the 700-800 m range.

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 won't be economic under any circumstances and can be safely considered as uneconomic. As an example, coals in the Illinois Basin in the USA are not considered for possible CO_2 storage if they are shallow (<500 ft, i.e., <152 m) regardless of thickness, or deep (>1000 ft, i.e., 305 m) and of a certain thickness (>1.5 ft, i.e., 0.52 m) (Frailey et al., 2006b). At intermediate depths (500-1000 ft, i.e.152-305m), only coals less than 3.5 ft (1.1. m) and greater than 1.5 ft (0.52 m) were considered as potential targets for CO_2 storage. Numerical definitions of the thickness and depth range of these uneconomic coals 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 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. For example, in Alberta, Canada, coal beds shallower than 100 m have permeabilities greater than 50-70 mD and up to 100 D, water wells as deep as 300 m penetrate coal seams, and the depth of groundwater protection reaches down to 500 m depth and more. 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 4,000 or 5,000 mg/l total dissolved solids (TDS) to 10,000 mg/l TDS. This means greater depths of protected groundwater, hence less coals potentially available for CO_2 storage.

This discussion on various limitations imposed on the coal beds that would be available for CO_2 storage shows 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 coals is highly dependent on 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.

4.2 Estimation of CO_2 Storage Capacity

Once the region of applicability has been established, the CO_2 storage capacity in the respective region can be estimated. Two parameters are determinant in evaluating a CBM prospect or a CO_2 storage prospect: 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):

$$IGIP = A \times h \times \tilde{n}_C \times G_C \times (1 - f_a - f_m) \quad (1)$$

where A and h are the area and effective thickness of the coal zone, respectively, $\tilde{n}_C$ is the bulk coal density (generally $\tilde{n}_C \approx 1.4$ 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 gas adsorption capacity of coal generally depends on pressure, temperature and coal characteristics. For a given temperature, the relation between pressure P and gas content at saturation, G_{CS}, is generally assumed to follow a pressure-dependent Langmuir isotherm of the form:

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

where 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 Langmuir isotherm expressed by eq. (2) displays an increase in adsorption capacity with increasing pressure as the gas content G_{CS} tends asymptotically towards V_L with increasing pressure P (e.g., Figure 4). This behaviour 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. On the other hand, the gas adsorption capacity decreases with increasing temperature, and, since both pressure and temperature increase with depth, after a certain depth the 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). Ideally, Langmuir isotherms should be known (measured) for various temperatures and coal characteristics for any given coal bed considered for CO_2 storage.

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 (see Figure 4). 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. This capacity represents the ultimate storage limit that could be attained. 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. The producible gas in place (*PGIP*) represents only a fraction of the initial gas in place, and can be estimated according to (van Bergen et al., 2001):

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

where R_f is the recovery factor and C is 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. Given the higher affinity of coal for CO_2 than for methane, one may safely assume that the recovery factor R_f for CBM and the storage factor R_s for CO_2 are higher in CO_2 enhanced coalbed methane recovery operations, although 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 affected by the presence of other gases, usually being reduced. Although the assumption is that methane and other hydrocarbon gases present in the coal will be replaced by CO_2, 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 modelling, 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.

To conclude, estimation of the CO_2 storage capacity in coal beds should follow the following steps:

- Identification and delineation of the coal beds suitable for CO_2 storage on the basis of depth, coal permeability, regulatory restrictions and economic limitations;
- Evaluation of the theoretical CO_2 storage capacity on the basis of coal thickness, ash and moisture content, and Langmuir adsorption isotherms for CO_2;
- Estimation of the practical CO_2 storage capacity on the basis of storage and completion factors (for which there is no practical experience to date);
- Selection of prospective areas on the basis of estimated storage capacity;
- Selection of potential storage sites on the basis of CO_2 source location and supply rate; and
- Numerical modeling of CO_2 injection and storage and of methane production.

For illustration, Figure 5 presents the successive evaluation of theoretical, effective and practical CO_2 storage capacities for the Ardley Coal Zone in Alberta, Canada, and the identification of prospective areas for CO_2 storage in coal beds with an estimated storage capacity of ~800 Mt CO_2 over ~3300 km^2 (Bachu, 2007). Only coal deeper than 300 m was considered, up to the depth where CO_2 would undergo a phase change from gaseous to supercritical. Only areas with capacity greater than 200 kt CO_2/km^2 were considered as prospective.

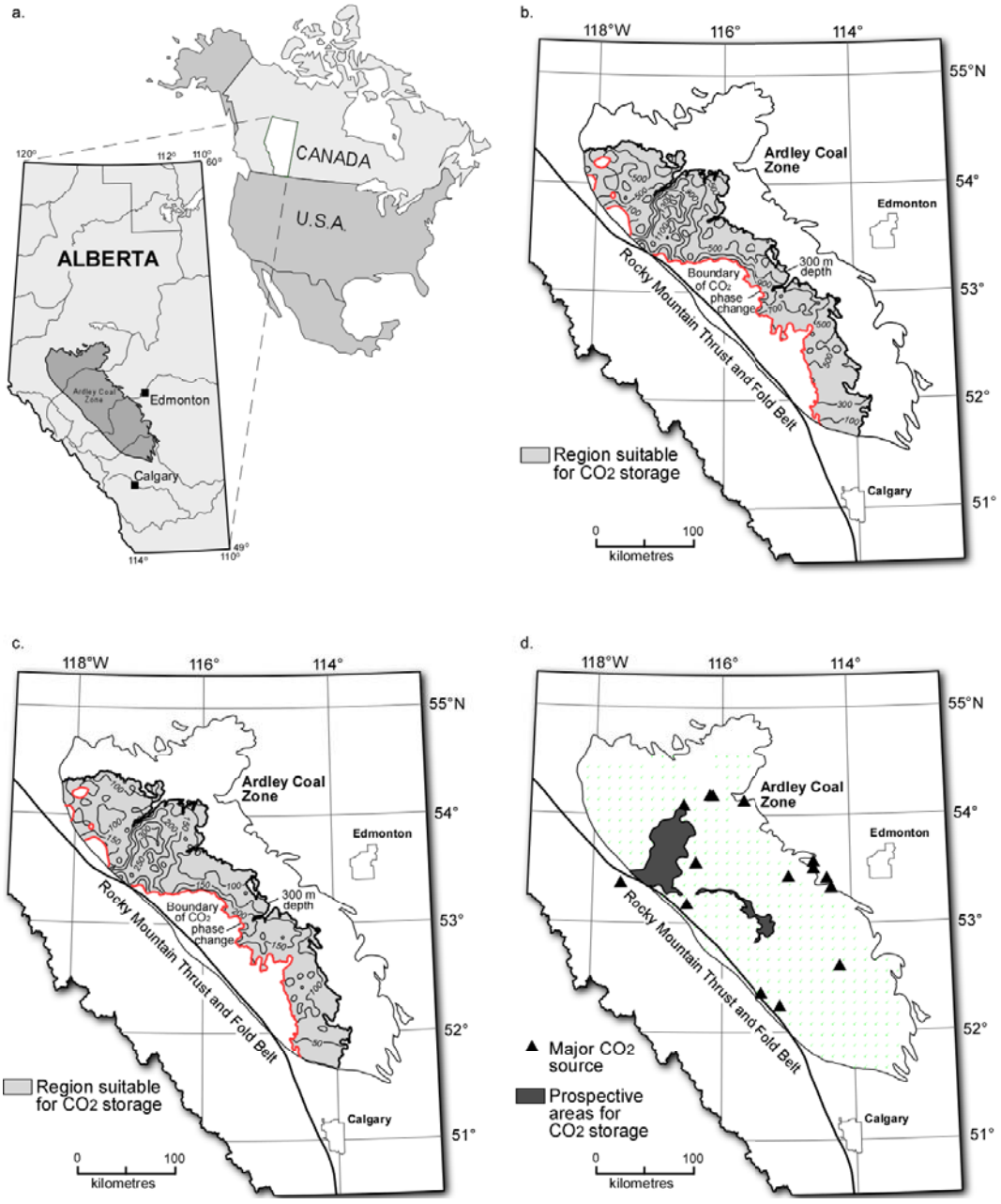

Figure 5. CO_2 storage capacity in the Ardley Coal Zone, Alberta, Canada: a) location, b) theoretical capacity in the region of suitability, c) effective capacity, and d) practical, and possibly matched capacity (from Bachu, 2007). Isolines are in kt CO_2/km^2.

5. 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. This is because, unlike coals and aquifers, oil and gas reservoirs are better known and characterized than the other two 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 characteristics such as phase behaviour and density.

The fundamental assumption that is made in storage capacity calculations is that the volume previously occupied by the produced hydrocarbons becomes, by and large, available for CO_2 storage. This assumption is generally valid for reservoirs that are not in hydrodynamic contact with an aquifer, or that are not flooded during secondary and tertiary oil recovery (pressure-depleted fields). 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 residual 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_{CO2t}, is given by:

$$M_{CO2t} = \rho_{CO2r} \times R_f \times (1 - F_{IG}) \times OGIP \times [(P_s \times Z_r \times T_r) / (P_r \times Z_s \times T_s)] \quad (4)$$

for gas reservoirs, and by:

$$M_{CO2t} = \rho_{CO2r} \times [R_f \times OOIP / B_f - V_{iw} + V_{pw}] \quad (5)$$

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:

$$M_{CO2t} = \rho_{CO2r} \times [R_f \times A \times h \times \phi \times (1 - S_w) - V_{iw} + V_{pw}] \quad (6)$$

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_{CO2} 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 sedimentary basin) is the sum of storage capacities in the individual reservoirs, and is based on discovered recoverable oil and gas in place. A simple extrapolation should be used to account for the theoretical storage capacity in undiscovered oil and gas reservoirs, producing the **ultimate theoretical storage capacity** M_{CO2u}:

$$M_{CO2u} = (OGIP_u / OGIP_d) \times [\sum M_{CO2t}]_g + (OOIP_u / OOIP_d) \times [\sum M_{CO2t}]_o \quad (7)$$

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 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 (Bondor, 1992; Doughty and Preuss, 2004). 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 Preuss, 2004):

$$M_{CO2e} = C_m \times C_b \times C_h \times C_w \times C_a \times M_{CO2t} \equiv C_e \times M_{CO2t} \qquad (8)$$

where M_{CO2e} 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 to 23% of OOIP) and CO_2 utilization (0.7 to 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 and methodologies for estimating the values of these capacity coefficients, mostly on the basis of 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. Estimating an **ultimate effective** storage capacity could be done similarly to the ultimate theoretical storage capacity (eq. 7), but in this case the extrapolation is more tenuous because the effect of the various coefficients in eq. (8) is more difficult to apply to undiscovered reserves.

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 enough, and if its lifespan is long enough, to justify the needed investment and reduce the cost per tonne of stored CO_2. 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. An example of application is provided for western Canada, where the theoretical storage capacity of ~12 Gt CO_2 in ~35,000 oil and gas pools reduces 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).

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 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). An analytical method developed by Shaw and Bachu (2002) can be used then for the oil reservoirs identified as suitable for CO_2 EOR to estimate at the regional and/or basin scale the CO_2 storage capacity in EOR using information available in reserves data bases and without the need of detailed knowledge of reservoir geometry and geology, and of specific PVT analyses and numerical simulations. 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 9,149 analyzed oil pools in western Canada, only 4,748 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 reduces 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).

6. Estimation of CO_2 Storage Capacity in Deep Saline Aquifers

The processes by which CO_2 can become trapped in deep saline aquifers are:
1) physical trapping (static, residual-saturation and hydrodynamic)
2) geochemical (dissolution and mineral)
These are fully described in the Introduction:

A theoretical methodology for estimating the CO_2 stored by each of these processes 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.

6.1 Storage Capacity in Structural and Stratigraphic Traps

Storing CO_2 in structural and stratigraphic traps, (*static trapping*, see Introduction), is similar to storing CO_2 in depleted oil and gas reservoirs, the only difference being that the trap is 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_{CO2t}, can be calculated with the formula:

$$V_{CO2t} = V_{trap} \times \phi \times (1 - S_{wirr}) \equiv A \times h \times \phi \times (1 - S_{wirr}) \quad (9)$$

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:

$$V_{CO2t} = \iiint \phi(1 - S_{wirr})dxdydz \quad (9')$$

The **effective** storage volume, V_{CO2e}, is given in a manner similar to oil and gas reservoirs by:

$$V_{CO2e} = C_c \times V_{CO2t} \quad (10)$$

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 CO_2 density, ρ_{CO2}, depends on the pressure in the trap once it is filled with CO_2, and this pressure is not known *a priori* but depends on permeability, relative permeability to formation water and CO_2, dimensions and volume and the nature of trap boundaries, and may vary with the injection strategy (number and/or inclination of injection wells, etc.). However, this pressure has to be higher than the initial water pressure in the trap, P_i, in order to achieve CO_2 injection, but it has to be lower than the maximum bottomhole 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:

$$\min M_{CO2} = \rho_{CO2}(P_i, T) \times V_{trap} \leq M_{CO2} \leq \max M_{CO2} = \rho_{CO2}(P_{max}, T) \times V_{trap} \quad (11)$$

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.

6.2 Storage Capacity in Residual-Gas Traps

The concept of residual-gas trapping is intrinsically linked with hydrodynamic trapping in as much 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 (wetting phase) moves back into the pore space (during an imbibition cycle), after it was expelled from the pore space (during a drainage cycle) by the injected and/or migrating CO_2 (non-wetting phase) and is due to the hysteretic properties of relative permeability[5]. During injection, CO_2 saturation increases in a drainage-like process, 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 in an imbibition-like process. A trail of residual, immobile CO_2 is left behind the plume as it migrates upward (Juanes et al., 2006). Thus, residual-gas trapping cannot happen in structural and stratigraphic traps where only water drainage occurs when CO_2 is injected, i.e. it largely, if not entirely, takes place after injection has stopped.

If ΔV_{trap} represents the rock volume previously saturated with CO_2 that is invaded by water, and S_{CO2t} is the trapped CO_2 saturation after flow reversal (Juanes et al., 2006), then the storage volume can be estimated with the formula:

[5] When a non-wetting fluid, like oil or CO_2, moves into, or invades a porous medium saturated with a wetting fluid (most commonly water), the latter is displaced from some of the pore space (a process referred to as drainage, hence the term "drainage cycle"), but it returns when the non-wetting fluid retreats or moves out (a process referred to as imbibition, hence the term "imbibition cycle). Some residual, discontinuous water is left in the pore space when the non-wetting phase attains maximum saturation during the drainage cycle, and vice-versa, some residual, discontinuous and immobile non-wetting fluid remains in the pore space when the wetting fluid reaches maximum saturation during the imbibition cycle. Hysteresis refers to irreversibility, or path-dependence of relative permeabilities and capillary pressures on the saturation path and history.

$$V_{CO2t} = \Delta V_{trap} \times \phi \times S_{CO2t} \quad (12)$$

The trapped CO_2 saturation, S_{CO2t}, 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_{CO2t} 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 value thus obtained can therefore be included in effective, practical or matched capacities, depending on the estimation purpose and level of detail.

6.3 Storage Capacity in Solubility Traps

Solubility trapping is based on CO_2 dissolution into formation water. Carbon dioxide solubility increases with pressure and decreases with increasing temperature and water salinity. Carbon dioxide may mix with, and then dissolve in, formation water through the processes of diffusion (an extremely slow process), dispersion and convection. Solubility trapping is a continuous, time-dependent process estimated to be most effective over time periods in the order of centuries. Therefore, the CO_2 storage capacity through solubility trapping has to be evaluated for a specified point in time.

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. Modelling indicates that convection can occur under favorable conditions. Because CO_2-saturated water is heavier by ~1% than the original formation water, if the rock permeability is sufficiently high, convection cells 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 may form naturally (Lindeberg and Wessel-Berg, 1997; Ennis-King and Paterson, 2005). 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 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. Lately, some thought is being given to accelerating the dissolution process by artificially forcing the removal of the CO_2-saturated layer and its replacement by unsaturated water (Leonenko et al., 2006). 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. Furthermore, 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).

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):

$$M_{CO2t} = \iiint \phi(\rho_S X_S^{CO2} - \rho_0 X_0^{CO2}) dxdydz \qquad (13)$$

where ϕ is porosity, ρ is the density of formation water, X^{CO2} is 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 carbon dioxide content and carbon dioxide 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:

$$M_{CO2t} = A \times h \times \phi \times (\rho_S X_S^{CO2} - \rho_0 X_0^{CO2}) \qquad (13')$$

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 to 100 kg CO_2/m^3 formation water, or, when rock porosity is taken into account, of 1.5 to 34.5 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_{CO2e}, 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:

$$M_{CO2e} = C \times M_{CO2t} \qquad (14)$$

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. It may be possible to evaluate through numerical simulations a functional expression for the coefficient *C*, or even just a single value.

Solubility trapping is very dependent on the chemical characteristics of the host formation water and on pressure and temperature (Gunter et al., 2004), hence estimation of the CO_2 storage capacity in solution is very site specific. Considering also the time dependency of the processes involved, basin- and regional-scale estimates of storage capacity cannot be calculated with any meaningful reliability or accuracy, except by extrapolation of site-specific calculations.

6.4 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., 2005). 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.

6.5 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[6]. 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 will 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.

6.6 Summary

Evaluation of the CO_2 storage capacity in deep saline aquifers is very complex due to the various trapping mechanisms involved that act at different rates and, at times, simultaneously. Saline aquifer CO_2 storage capacity evolves through time and can best be estimated through numerical modeling. This, 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-

[6] The exception being residual saturation trapping, which does not start to operate until injection stops but thereafter may proceed simultaneously with trapping by other mechanisms

specific scales. However, the storage capacity that is relevant is that capacity that can be accessed and achieved during the injection stage of a CO_2 storage project, and if some trapping processes have a negligible contribution during this stage, they may be neglected (this could most likely be the case of mineral trapping). 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. However, the overall CO_2 storage capacity, theoretical and effective, can be broadly defined as the maximum volume of CO_2 that can be injected in a water-bearing formation without resulting in a spill, leak or other undesirable effects *during and/or after* the injection period. This comprises:

- the amount of CO_2 that will be eventually immobilized by filling any and all structural and stratigraphic traps, and
- any additional amount of CO_2 that will be stored by residual gas saturation, dissolution and mineral precipitation along the CO_2 migration path from the injection point(s) to the final trapping place.

Some of the methods presented previously for estimating CO_2 storage capacity in deep saline aquifers are applicable only at the local and site specific scales due to the level of data resolution and accuracy needed in the estimation and/or to the need of using numerical modelling. However, if sufficient representative case studies are presented over time, it may be possible to build up enough knowledge and experience to allow some rules of thumb to develop for various geological storage scenarios.

7. 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 and In Salah. 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 report represents an attempt to introduce a consistent and systematic set of definitions and methodologies to be used by CSLF members and other entities and jurisdictions in assessing the CO_2 storage capacity available to them. 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 is the concept of the resource-reserves pyramid. Resources are those quantities of a commodity that are estimated at a given time to exist within a jurisdiction or a geographic area, and are of two types: discovered, or in-place, and undiscovered, or inferred. Reserves are those quantities of a commodity that are known to exist and that are commercially recoverable. Their assessment integrates technical, economic, environmental, societal and regulatory factors available at the time of the assessment. Both resource and reserve estimates evolve in time as new discoveries are made, technology advances and economic conditions change, and for this reason it is recommended that CO_2 storage capacity assessments are updated periodically.

The theoretical storage capacity represents the physical limit of what the geological system can accept. This 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. Many of the previous CO_2 storage capacity estimates fit into this theoretical category. The effective storage capacity is 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. The practical storage capacity is that subset of the effective capacity that is obtained by considering other technical, legal and regulatory, infrastructure and economic barriers to CO_2 geological storage. The 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. The difference between matched and practical storage capacities represents stranded storage capacity that cannot be realized because of current lack of infrastructure. The certainty of storage potential increases and the cost of storage decreases as evaluation move from theoretical to matched storage capacity.

Another fundamental element to assessing CO_2 storage capacity is the assessment scale. 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. 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. 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. Such assessments are undertaken usually to identify sites for CO_2 storage. 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. The site-scale assessment is performed for the specific storage unit, usually to model the

behaviour of the injected CO_2. The level of detail and data accuracy increase as the size of the area and sedimentary succession under study decreases.

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 behaviour 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 uneconomic 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 based on site-specific numerical simulations or field experience.

Table 1 summarizes the scale of applicability for 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.

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[1]	Coefficients Needed[2]	Assessment Scale				
				Country	Basin	Regional	Local	Site Specific
Oil & 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	-	-	-	√	√

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

[2] – 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

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.

The current review provides a clear set of definitions and methodologies needed for the assessment of CO_2 storage capacity in geological media, however, it also points to the need for future work for determination of the various reduction coefficients that are needed in estimations of effective and practical storage capacities. These coefficients can be evaluated based on laboratory experiments, numerical simulations and field experience and measurements. 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.

8. Recommendations

This report concludes Phase 2 of activities of the CSLF Task Force on CO_2 Storage Capacity Estimation and provides a set of consistent definitions and recommended approaches and methodologies for estimating CO_2 storage capacity in coal beds, oil and gas reservoirs, and deep saline aquifers. However, given that CO_2 storage in geological media is still in its infancy and the lack of agreed approaches and experience in storage capacity estimation, there are still gaps in the methodology that need covering, in a continuing process, ideally under the CSLF sponsorship.

Therefore, it is recommended that the Task Force on CO_2 Storage Capacity Estimation continues its activities in a new Phase 3 to start at the time of adoption by the CSLF Technical Group of this recommendation.

Some or all of the following matters could be considered in future Phase 3 activities.

1. Coordination of methodology for CO_2 storage capacity estimation with other national and international groups working on this subject, including the Geologic Working Group of the USDOE Regional Carbon Sequestration Partnership Program that developed similar guidelines in the fall of 2006 (see footnote on p. 6 for details). This work could also include further development and refinement of the Techno-Economic Resource-Reserve pyramid for CO_2 storage capacity in geological media (p. 13), along the lines of resources and reserves used in the oil & gas and mining industries.

2. Compilation of a collection of representative case-studies of CO_2 storage capacity estimation at various scales and in different geological settings, to be used as examples by CSLF members when proceeding with similar estimations within their jurisdiction. This should include compilation of data on various coefficients that are used in CO_2 storage capacity estimations and for which no or very few numerical values are available. Since CSLF cannot undertake a laboratory and/or field program for direct determination of such coefficients, the activity would consist of literature searches and watch for any such data that would come to light as a result of experimental and field programs implemented around the world.

3. Provision of support to the Task Force on Capacity Building in training and applying the methodologies for estimating CO_2 storage capacity along the full chain from country-scale to site-scale, and from theoretical to matched capacity, to one or more developing economies in CSLF.

Given the complexity and magnitude of these activities, not necessarily all of them will be undertaken in the proposed Phase 3; the Task Force will decide which ones will be undertaken depending on resources and member's availability. These recommendations should be integrated into the PIRT Technology Gaps Analysis for Storage.

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