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JOURNAL REVIEW

CO_2 geological storage: A review on present and future prospects

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Abstract−CO_2 can be stored in geological media for hundreds to thousands of years depending on the location and trapping mechanism(s) involved. A saline aquifer presents the largest capacity available for CO_2 storage among all geological storage options. Two main methodologies proposed by the Department of Energy, US (DOE) and carbon sequestration leadership forum (CSLF) are used for capacity estimation of geological locations for CO_2 storage. A study conducted by Global CCS Institute in 2010 identified 80 large scale integrated projects which will prove to be a huge step in building confidence and commercialization of storage projects in the near future. Use of reliable monitoring tools and accurate simulation software is a must for safe and cost-effective CO_2 storage.

Key words: Carbon Dioxide, Geological Storage, Capacity Estimation, Sequestration Projects, Monitoring

INTRODUCTION

Carbon capture and storage (CCS) has advanced towards commercialization, especially through the commissioning of CCS pilot plants, continued learning from projects already in operation and the development of legal and regulatory frameworks. While much progress has been achieved, the recommendation made by the G8 Leaders at the 2008 Hokkaido Toyako Summit that 20 large scale CCS demonstration projects should be launched by 2010 remains a challenge [1]. Storage being the integral part for implementation of CCS is still in a progressing phase. Many researchers and organizations are studying various storage sites and steps needed to assure a safe and cost-effective storage site. Michael et al. [2] presented a review of the existing saline aquifers storage projects with key technical site data, monitoring techniques used and injection strategies. Enhanced oil recovery (EOR) is a mature technique, but interest has increased with the CO_2 storage opportunities. In the United States, approximately 73 EOR operations inject up to 30 Mton of CO_2 per year. CO_2 storage in coal seams is an emerging technique and in demonstration phase [3]. Reeves et al. [4-6] have summarized experience and results from the Allinson enhanced coal bed methane (ECBM) pilot plant, the world's first ECBM project. Many other researchers [7-11] have studied and explained regional CO_2 storage in coal seams. All of these studies are focused on one specific storage option. The purpose of this study is to present an up-to-date overall review of all geological storage options, including a summary of the CO_2 storage mechanism at different locations, previous CO_2 storage projects, capacities calculation methods, monitoring techniques deployed at storage sites and future prospects of storage projects. This study also presents the importance of simulation tools used for modeling the storage sites and comparison of CO_2 storage cost estimates of previous researches.

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TRAPPING MECHANISMS

CO_2 is injected usually in the supercritical form into the saline aquifer or depleted oil or gas reservoir. The point at which CO_2 transforms from critical to supercritical point is 31.1 C and 7.38 MPa [12-16]. Most of the geological formations consist of layers of porous rocks capped by a non-porous rock(s) above them. Once injected, supercritical CO_2 is 30-40% less dense than a typical aqueous saline [17,18]. The supercritical CO_2 tends to be buoyant and will rise upward through the rock until it encounters a barrier of non-porous rock. In supercritical form, a larger volume of CO_2 can be stored in the pore space available [19,20]. CO_2 can be trapped by a number of different mechanisms and depend on specific geological conditions.

- Structural or stratigraphic traps, typical of hydrocarbon accumulations [21]
- Hydrodynamic traps, where the dissolved and immiscible CO_2 travels with the formation water for very long residence (migration) times [22]
- Residual gas trapping, where the CO_2 becomes trapped in the pore spaces by capillary pressure forces [17,23,24]
- Solubility trapping, where the CO_2 dissolves into the formation water [25,26]
- Mineral trapping, where the CO_2 precipitates as new carbonate minerals [8,27]
- Adsorption trapping, where the CO_2 adsorbs onto the surface of coal [3,8]

Time is also an important factor in the long-term storage and behavior of CO_2. As the time goes on, more CO_2 dissolves into the formation water [17,22]. Table 1 shows the summary of various chemical and physical trapping mechanism characteristics.

POSSIBLE STORAGE SITES

CO_2 can be stored in geological media by injection into oil and

Table 1. Characteristics of trapping mechanism (Adapted from Bradshaw et al., 2007 [28])

Trapping Mechanism	Nature of trapping	Effective time frame	Areal size	Occurrence in basins
Structural and Stratigraphic	Buoyancy trapping within anticline, fold, fault block, pinch-out. CO_2 remains as a fluid below physical trap (seal)	Immediate	10 to 100 s km	Dependent on basins tectonic evolution. Hundreds of small traps to single large traps per basin
Hydrodynamic	CO_2 migrates through reservoir beneath seal, moving with or against the regional ground water flow system whist other physical and chemical trapping mechanisms operate on the CO_2	Immediate	Basin scale, e.g. 10,000 km	Along migration pathway of CO_2 with or against the direction of the flow system that may move at rates of cm per year
Residual gas	CO_2 fills interstices between pores of the grains of the rocks	Immediate to thousands of years	Basin scale, e.g. 1000 s km	Along migration pathway of CO_2
Dissolution	CO_2 migrates through reservoir beneath seal and eventually dissolves into formation fluid	100 to 1000 s of years if migrating more than 1000 s of years if gas cap in structural trap and longer if reservoir is thin and has low permeability	Basin scale, e.g. 10,000 s km	Along migration pathway of CO_2 both up dip and down dip
Mineral precipitation	CO_2 reacts with existing rock to form new stable minerals	10 to 1000 s of years	Basin scale, e.g. 10,000 s km	Along migration pathway of CO_2
Coal adsorption	CO_2 preferentially adsorbs onto coal surface	Immediate	10 to 100 s km	Limited to extent of thick coal seams in basins that are relatively shallow

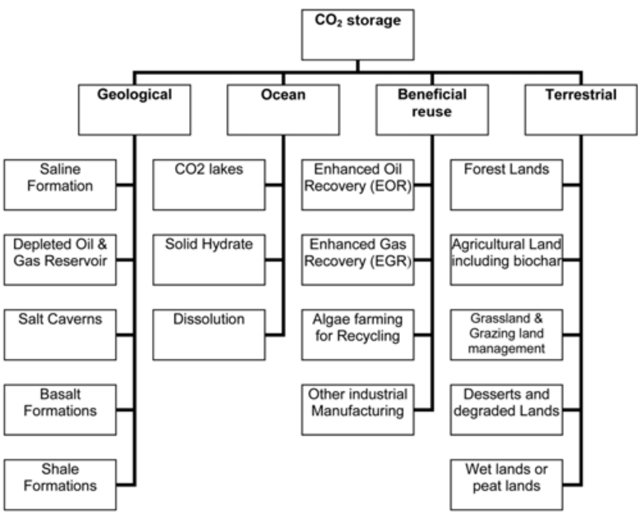

Fig. 1. Possible CO_2 storage options (Modified from Global CCS Institute Report, [30]).

gas reservoirs, unminable coal seams and deep saline aquifers that are saturated with water whose salinity makes it unfit for human, animal, agricultural and industrial usage [3,29]. Fig. 1 shows the tree diagram of possible CO_2 storage sites, and Table 2 shows the key characteristics of some potential storage sites.

CURRENT SITUATION AND FUTURE OF STORAGE PROJECTS

Saline aquifers, which are found worldwide, present the largest capacity available for CO_2 storage [3]. By the end of 2008, approximately 20 Mton of CO_2 had been successfully injected into saline aquifers by existing operations. Currently, the highest injection rate and total storage volume for a single storage operation are approximately 1 M ton CO_2/year and 25 M ton, respectively [2]. Fig. 2 shows the active and planned CO_2 storage projects around the world for potential storage sites. The Global CCS Institute conducted a survey [30] in 2009 showing that within 219 active or planned CCS projects, 129 projects involve a form of storage as shown in Fig. 3. Of the projects active or planned for geological storage, 53% are for storage in a saline aquifer and 28% are for storage in depleted oil and gas fields. Of the projects considering beneficial reuse, 55% are for enhanced oil recovery (EOR) and 11% are for enhanced gas recovery (EGR)/enhanced coal bed methane (ECBM).

A study commissioned by the Global CCS Institute in 2010 [39] identified 80 largescale integrated projects at various stages of development around the world. The Global CCS institute categorized these storage projects as shown in Fig. 4. As of April 2010, public funding commitments were in the range of US$ 26.6 billion to 36.1 billion [1]. Governments have announced their commitments to launch 19 to 43 large-scale integrated projects before 2020, details shown in

Table 2. Key characteristics of potential storage sites (Modified from 31)

	Advantages	Challenge	Project example	Data availability
Depleted oil & gas reservoir	• Global storage capacity of 140Gt and 40Gt for disused gas and oil fields respectively • Characteristics of reservoirs are well known • Existing infrastructure of wells and pipelines can be used • Proven containment over geologic time	• Concern over leaky wells or improperly abandoned wells- a safety threat • Today very few reservoirs depleted	• CO2CRC Otway project [32]	Good
Saline aquifers	• Best potential CO_2 storage capacity (1000~10^4 Gt) [3] • Stored CO_2 expected to be isolated from the near surface for thousands of years • Widespread presence over much of the world • Offshore aquifers eliminate most safety concerns	• Lack of characterization experience • Absence of financial incentive	• InSalah gas project, Algeria [33] • Sleipner project, Norway [34] • Gorgon project, Australia [35] • US DOE Regional partnership Program projects • Ketzin, Germany [36,37]	Good- in progress
Enhanced oil recovery (EOR)	• Additional oil, making it economically attractive • Injection of CO_2 commercially done today • Any undue risks not involved to humans or environment	• Could often be cheaper to obtain CO_2 from natural sources • Global storage capacity may be limited • For today's blow down reservoir operations need to store CO_2 under pressure	• Weyburn, Wasson (Denver) • Wasson (ODC) SACROC • Salt Creek	Excellent
Coal bed storage	• CH_4 by-product makes option economically attractive • Coal deposit present worldwide	• Unminable coal seams are likely to be hundreds of meter deep, hence less permeable and limiting the capacity of CO_2 stored	• Qinshui Basin • Recopal • Alberta ECBM	Limited

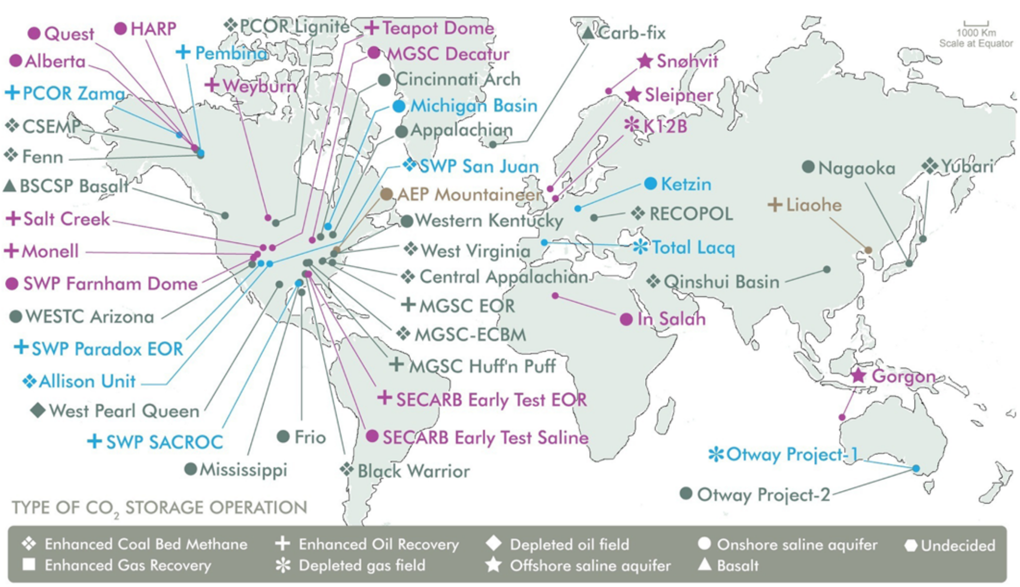

Fig. 2. Location of sites where activities relevant to CO_2 storage are planned or under way (as of April 2010) [38].

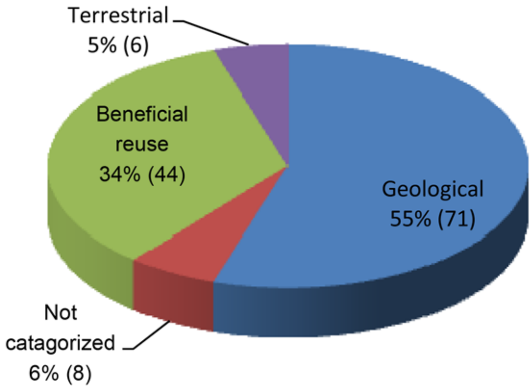

Fig. 3. Active or planned CCS projects by storage type [30].

Table 3. Funding and project announcement from governments and international organizations (as of April 2010) [1]

Country	Funding committed (US $ Billion)	Number of projects committed by 2020
Australia	2 to 6	3 to 5
Canada	3.5	Upto 6
European commission	4 to 6	6 to 12
Japan	0.1	1 to 2
Norway	1	1 to 2
Korea	1	1 to 2
United kingdom	11 to 14.5	4
United states	4	5 to 10
Total	**26.6 to 36.1**	**19 to 43**

Table 3. According to an IEA report [1], 39 projects involving storage are planned to be operational by 2015, which will be a major step in commercialization of CCS projects. This trend of rapid CCS implementation by 2015 is also prominent from the Global CCS Institute report [30], which is represented in graphical form in Fig. 5.

POTENTIAL SALINE AQUIFER STORAGE

Existing regional to basin scale capacity estimates are highly variable and in many instances contradictory. Bradshaw et al. [28] listed various CO_2 storage capacity estimates for the world and selected regions done under various studies. Koide et al. [40]; Hendricks et al. [41] presented an approach to estimate the CO_2 storage capacity considering only structural traps within a saline aquifer while Bruant et al. [42] presented capacity estimation taking in account the entire aquifer. Dooley et al. [43] compiled various storage capacities from different parts of world based on the data available and studies conducted previously. Fig. 6 represents the updated first-order theoretical storage capacity estimate. A technical study report

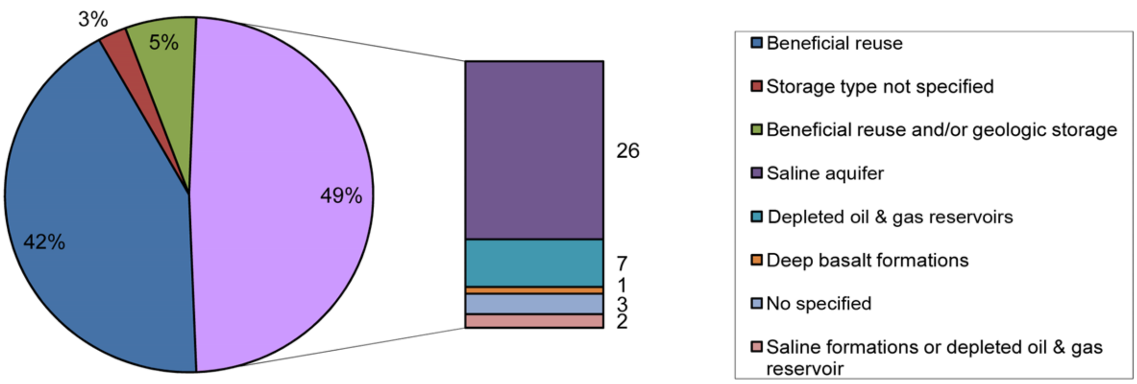

Fig. 4. Categorization of 80 active or planned storage projects (Modified from 39).

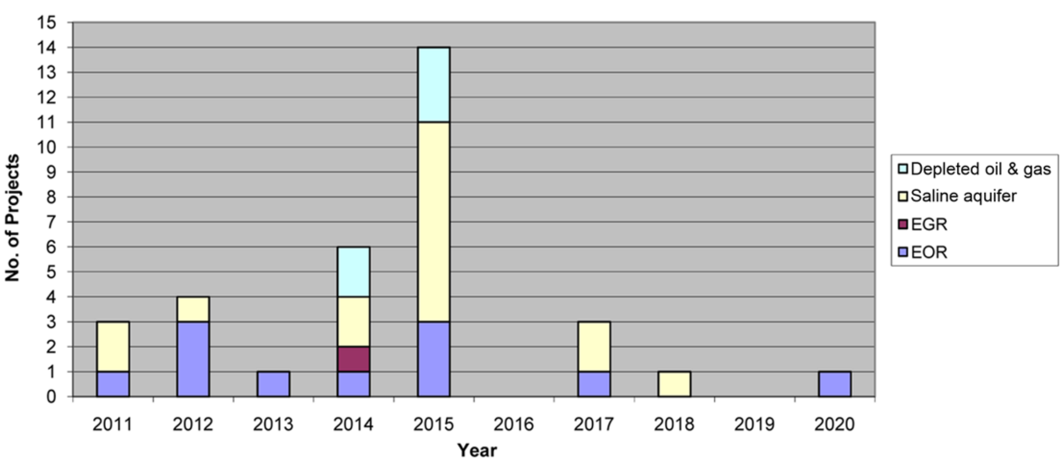

Fig. 5. Number of projects Vs storage type up to 2020 (Interoperated from Global CCS Institute report 2009, [30]).

Fig. 6. Theoretical storage capacity estimate [44].

Table 4. Regional saline aquifer storage estimate

Country	Storage capacity (Gt)	Source
Brazil	2000	Ketzer et al. 2007 [45]
China	1435	Li 2007 [46]
Germany	20	May et al. 2005 [47]
Great Britain	14	Holloway et al. 2006 [48]
India	300	Sonde 2007 [49]
Japan	102	Suekane et al. 2008 [50]
Poland	5	Wojcicki et al. 2007 [51]
South Africa	20	Engelbrecht et al. 2004 [52]
US+ Canada	2150 (920-3380)	DOE 2007a [53]

by IEA [44] on saline aquifer storage presents regional saline aquifer capacity estimates as shown in Table 4.

CAPACITY ESTIMATION OF STORAGE SITES

The storage capacity of CO_2 is an estimate of the quantity of CO_2 that can be stored in a subsurface geologic formation. Because of uncertainties inherent in subsurface evaluation, exact quantification of geological properties is not possible, and therefore storage capacity is always at best an approximation of the amount of CO_2 that can be stored [44]. Because the CO_2 industry is not mature, there are few active CO_2 storage projects which can provide site specific information; hence low and high range capacity estimates are usually reported. Primarily, two methodologies are currently in use for estimation of storage capacity of CO_2 published by DOEa [53] and CSLF [54]. Detailed comparison of the two methodologies was performed by CSLF [55] and CO2CRC [56].

1. DOE Methodology [53,55-57]

The DOE defines static and dynamic methods for estimation of sub-surface storage volumes. The static methods are volumetric and compressibility based, while dynamic methods are applied after the injection is started. The volumetric method uses porosity (ϕ), area (A) and thickness (h) in a Monte Carlo simulation approach to estimate expected uncertainty in the efficiency of the storage capacity from a combination of trapping mechanisms [57]. Storage efficiency factor (E) provides a mean of estimating storage volume adjusting the uncertainty in capacity estimates.

Saline Aquifer	$G=A\ h_g\ \phi_t\ \rho\ E$	(1)
Oil & Gas Fields	$G=\rho A\ h_n\ \phi_e\ (1-S_w)\ B\ E$	(2)
Coal Seams	$G=A\ h_g\ C\ \rho\ E$	(3)

2. CSLF Methodology [54-56]

The use of CO_2 for EOR is a familiar technique but saline aquifers and deep unminable coal seams generally have limited data availability to estimate storage capacity volume. There are number of trapping mechanisms for geological storage of CO_2 in saline aquifers namely, structural and stratigraphic trapping, residual gas saturation trapping, dissolution, precipitation and hydrodynamic trapping. In reality, the various trapping mechanisms do not operate in isolation but in complex, interdependent and time-dependent ways. So, CSLF methodology differentiates capacity calculation for different trapping mechanisms.

Saline Aquifer	Structural & Stratigraphic trap	$V_t=A\ \phi\ h\ (1-S_{wirr})$ $V_e=C_c\ V_t$	(4) (5)
	Solubility trap	$M_t=\iiint \phi(\rho_s X_s^{CO2}-\rho_0 X_0^{CO2})\ dxdydz$ $M_t=A\ \phi\ h\ (\rho_s X_s^{CO2}-\rho_0 X_0^{CO2})$ $M_e=C\ M_t$	(6) (7) (8)
	Residual trap	$V_t=\Delta V_{trap}\ \phi\ S_{CO2}$	(9)
Gas Fields	$M_t=\rho_{CO2}\ R_f(1-F_{IG})\ OGIP\ [(P_s Z_r T_r]/(P_r Z_s T_s)]$		(10)
Oil Fields	$M_t=\rho_{CO2}\ [R_f*OOIP/B_f-V_{iW}+V_{pw}]$		(11)
Oil & Gas reservoir based on geometry	$M_t=\rho_{CO2}\ [R_{fAh}\ \phi\ (1-S_w)-V_{iW}+V_{pw}]$ $M_e=C_m\ C_b\ C_h\ C_w\ C_a\ M_t=C_e\ M_t$		(12) (13)
Coal Seams	$M_t=\rho_{CO2s}\ A\ h\ \tilde{}n_c\ G_c\ (1-f_a-f_m)$ $Gcs=V_L\ *(P/P+P_L)$ $M_e=R_f\ C'\ M_t$		(14) (15) (16)

3. Comparison of Methodologies

The methodologies proposed by DOE and CSLF can be compared to each other if the assumptions made are the same. In case of CO_2 storage in coal beds, both the DOE and CSLF recommend that the maximum depth to be considered is where coal permeability becomes less than 1 mD. For CO_2 sequestration in oil and gas reservoirs, the fundamental assumption is that the volume previously occupied by hydrocarbon is available for CO_2 storage, which is in agreement with both DOE and CSLF proposed approaches, assumptions and methodologies [55]. CSLF provides individual equations for each of the trapping mechanisms, but the coefficients for storage capacity efficiency have not yet been determined. If the CSLF methodology resolves the storage efficiency factors, then perhaps it will be the more viable option, but until then the use of the DOE proposed methodology, which already includes efficiency factors, is recommended [56].

4. Other Researches

$$G_{CO2}=A*h*\phi*\rho_{CO2}*0.01*0.02*10^{-12} \tag{17}$$

Hendriks et al. [41] suggested Eq. (17) to estimate storage capacity of CO_2 in saline aquifers. This equation represents a simplified version of the DOE proposed methodology. Multiplication by 0.01 and 0.02 assumes that 1% of the aquifer is part of a structural trap and 2% sweep efficiency, respectively.

MONITORING TECHNIQUES

Reliable and cost-effective monitoring will be an important part of making geologic sequestration a safe, effective and acceptable method for CO_2 control. Monitoring will be required as part of the permitting process for underground injection and will be used for a number of purposes, such as tracking the location of the plume of injected CO_2, ensuring that injection and abandoned wells are not leaking, and verifying the quantity of CO_2 that has been injected underground. Monitoring is essential to making geological storage reliable and safe. By itself, monitoring cannot guarantee safety, but it determines safe storage of injected CO_2 [58].

The DOE defines atmospheric, near-surface and sub-surface monitoring techniques in the report "Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations," [58]; a brief summary of these techniques is presented here:

1. Atmospheric Monitoring Techniques

Monitoring Technique	Function
CO_2 Detectors	Sensors for monitoring CO_2 in air
Eddy Covariance	Atmospheric flux measurement technique to measure atmospheric CO_2 concentrations at a height above the ground surface.
Advanced leak detection system	Carried by aircraft or terrestrial vehicles for quantification of CO_2 fluxes from the soil
Laser Systems and LIDAR	Open-path device that uses a laser to shine a beam with a wavelength that absorbs CO_2
Tracers (Isotopes)	Natural isotopic composition and/or compounds injected into the target formation along with the CO_2 to determine the flow direction and early leak detection.

2. Near Surface Monitoring Techniques

Monitoring Technique	Function
Ecosystem stress monitoring	Satellite or airplane-based optical method after emission has occurred
Tracers	CO_2 soluble compounds injected along with the CO_2 into the target formation used to determine the hydrologic properties, flow direction and low-mass leak detection.
Groundwater monitoring	Sampling of water or vadose zone/soil (near surface) for basic chemical analysis for early detection prior to large emissions.
Thermal Hyperspectral Imaging	An aerial remote-sensing approach primarily for enhanced coal bed methane recovery and sequestration.
Synthetic Aperture Radar (SAR & InSAR)	A satellite-based technology in which radar waves are sent to the ground to detect surface deformation.
Color Infrared (CIR) Transparency Films	A vegetative stress technology deployed on satellites or aerially to indicate vegetative health, which can be an indicator of CO_2 or brine leakage.
Tiltmeter	Measures small changes in elevation via mapping tilt. Mature oil field technology for monitoring stream or water injection, CO_2 flooding and hydrofracturing.
Flux Accumulation Chamber	Quantifies the CO_2 flux from the soil, but only from a small, predefined area
Induced Polarization	Geophysical imaging technology commonly used in conjunction with DC resistivity to distinguish metallic minerals and conductive aquifers from clay minerals in subsurface materials
Spontaneous (Self) Potential	Measurement of natural potential differences resulting from electrochemical reactions in the subsurface.
Soil and Vadose Zone Gas Monitoring	CO_2 retained in soil gasses provides a longer residence time. Detection of elevated CO_2 concentrations well above background levels provides indication of leak and migration from the target reservoir.
Shallow 2-D Seismic	High resolution images showing the presence of gas phase CO_2.

3. Subsurface Monitoring Techniques

Monitoring Technique	Function
Multi-component 3-D Surface Seismic Timelapse Survey	This technology can provide high-quality information on distribution and migration of CO_2
Vertical Seismic Profile (VSP)	This technology that can provide robust information on CO_2 concentration and migration.
Magnetotelluric Sounding	Calculates changes in electromagnetic field resulting from variations in electrical properties of CO_2 and formation fluids.
Electromagnetic Resistivity	Measures the electrical conductivity of the subsurface including soil, ground water, and rock.
Electromagnetic Induction Tomography (EMIT)	Wellbore measurement using a rock parameter, such as resistivity or temperature, to monitor fluid composition in wellbore and very useful for wellbore leakage
Annulus Pressure Monitoring	A mechanical integrity test on the annular volume of a well to detect leakage from the casing, packer or tubing.

Pulsed Neutron Capture	Capable of depicting oil saturation, lithology, porosity, oil, gas and water by implementing pulsed neutron techniques.
Electrical Resistance Tomography(ERT)	High resolution technique to monitor CO_2 movement between wells
Sonic (Acoustic) Logging	Oil field technology used to characterize lithology, determine porosity, and travel time of the reservoir rock.
2-D Seismic Survey	Can be used to monitor "bright spots" of CO_2 in the subsurface
Time-lapse Gravity	Use of gravity to monitor changes in density of fluid resulting from injection of CO_2
Density Logging (RHOB Log)	Can estimate formation density and porosity at varying depths
Optical Logging	Optical imaging tools to provide detailed digital images of the well casing
Cement Bond Log (Ultrasonic Well Logging)	Implement sonic attenuation and travel time to determine whether casing is cemented or free. Allows for proactive remediation prior to leakage
Gamma Ray Logging	Use of natural gamma radiation to characterize the rock or sediment in a borehole
Microseismic (Passive) Survey	This technology can provide provides high-quality, high resolution subsurface characterization data and can provide effects of subsurface injection on geologic processes.
Crosswell Seismic Survey	Enables subsurface characterization between those wells
Aqueous Geochemistry	Chemical measurement of saline brine in storage reservoir.
Resistivity Log	Used to characterize the fluids and rock or sediment in a borehole.

Various monitoring is employed at different storage locations; Table 5 shows a summary of the monitoring techniques used at some projects.

SIMULATION TOOLS

Once the CO_2 is injected into a reservoir for storage, it behaves in a specific way depending on type of storage, storage conditions, fluid characteristics, injection rates and trapping mechanism involved. For safe, economical and efficient storage, it is important to understand and predict the behavior of CO_2 to be injected at a specific

Table 5. Summary of monitoring techniques at some projects

Project	Category	Monitoring techniques
Sleipner (2, 3, 59-69)	Saline aquifer	• Time-lapse seismic • Time-lapse gravity • Micro-seismic
Weyburn (44, 58, 70, 71)	EOR	• 4D, 9C surface seismic • 3D, 3C vertical seismic profile (VSP) • Cross-well seismic • Geochemical sampling analysis • Tracer injection monitoring • Conventional production data analysis • Passive seismic
Otway (3, 58, 71, 72)	Depleted gas field	• Lo Flo • Flux tower • Flask sampling • CO_2 sniffers • Headspace gas sampling • Surface soil gas • Hydrodynamic sampling • Groundwater chemistry • Downhole fluid sampling • VSP • 3D surface seismic • Borehole seismic • Microseismic • High resolution travel-time • Logging pressure/temperature

Table 6. Various simulator tools for CO_2 storage modeling (modified from 58)

Simulation tool name	Main sequestration application	Reference
GMI-SFIB, ABCUS	Modeling stresses applied to reservoirs during and after injection	DOE, US
Eclipse, GEM-GHG, NUFT	Model plume dispersion	Lindeberg et al. [73] Kumar et al. [74] Zhou et al. [75] Johnson et al. [76,77] Nghiem et al. [78]
PFLOTRAN, STOMP	Model plume dispersion and CO_2 interaction with reservoir fluids	White and Oostrom [79]
TOUGH-FLAC	Model plume dispersion and impact of stresses due to CO_2 interactions	White et al. [80,81]
TOUGHREACT, VIP Reservoir	Model plume dispersion and CO_2 trapping	Audigane et al. [59,82] Andre et al. [83] Xu et al. [84-86] Pruess and Garcia [87] Xu and Pruess [88]
NFFLOW-FRACGEN	CO_2 flow through fractured networks	DOE, US
SIMED	Reservoir modeling of Coal Seam	Kreft et al. [89] Van der Meer et al. [90]
PHREEQC	Long term mineral trapping and porosity changes due to CO_2 presence	Gunter et al. [91] Gaus et al. [92] Hellevang et al. [93]

site, guided by previous available data. To forecast the CO_2 behavior and expected pressure/temperature changes after injection, simulation tools are used. Table 6 shows the application of some simulation tools used in various studies. Simulations are used to predict temporal and spatial migration of the injected CO_2 plume, effect of geochemical reactions on CO_2 trapping and long-term porosity and permeability, cap rock and wellbore integrity, the impact of thermal/compositional gradients in the reservoir, pathways of CO_2 out of the reservoir, the importance of secondary barriers, effects of unplanned hydraulic fracturing, the extent of upward migration of CO_2 along the outside of the well casing, impacts of cement dissolution and consequences of wellbore failure [51]. Effective monitoring can

Table 7. CO_2 storage cost estimates for different options

	On or offshore	Expected cost $/t CO_2 stored	Cost range US $/t CO_2 stored	Location	Reference
Saline aquifer	Onshore	0.5	0.5-5.1	Australia	Allinson et al. [94]
	Offshore	3.4	0.5-30.2	Australia	Allinson et al. [94]
	Onshore	2.5	1.9-6.2	US	Bock et al. [95]
	Onshore	2.8	1.9-6.2	Europe	Hendricks et al. [96]
	Offshore	7.7	4.7-12.0	Europe	Hendricks et al. [96]
Depleted oil	Oil	1.3	0.5-4	US	Bock et al. [95]
and gas reservoir	Gas	2.4	0.5-12.2	US	Bock et al. [95]
	Onshore	1.7	1.2-3.8	Europe	Hendricks et al. [96]
	Offshore	6.0	3.8-8.1	US	Bock et al. [95]
EOR		−14.8	−92~66.7	US	Bock et al. [95]
	Onshore		−10.5~10.5	Europe	Hendricks et al. [96]
	Offshore		−10.5~21.0		Hendricks et al. [96]
ECBM			−20.0~150.0		IEA [97]
	Onshore	−8.1	−26.4~11.1	US	Bock et al. [95]
			0~31.5	Europe	Hendricks et al. [96]
				Canada	Wong et al. [98]

verify whether the monitored results are the same as expected from the simulation model or not. This is mainly important in the early stages of a project to calibrate the model and alter the basis of simulation for long-term performance if required. Simulation tools have been used for research, pilot and commercial projects including the Weyburn, Frio, West Pearl Queen and ECBM West Virginia [51].

COST OF STORAGE

Storage cost of CO_2 depends on the type of storage option, location, depth and characteristics of the storage reservoir formation and the benefits and prices of any saleable products (in case of EOR, EGR, and ECBM). IPCC [3] estimated that the total cost for saline aquifer storage ranges from US$ 0.5-8.0/ton CO_2 avoided including the monitoring cost of US$ 0.1-0.3/ton CO_2. Table 7 shows the storage cost estimates for different locations.

Onshore storage cost depends on location, terrain and other geographic factors. The unit costs are usually higher for platforms or sub-sea facilities. Hendricks et al. [41] studied the injection cost for onshore and offshore aquifers at different depths as shown in Table 8. Table 9 presents the cost data for various active CO_2 storage projects.

CONCLUSION

Early CO_2 projects have been visible and their success will likely impact future CO_2 storage projects. By 2015, a number of more storage projects will be operational, which will be helpful in decreasing knowledge gaps. Beneficial reuse ways of storing CO_2 presents an economically feasible opportunity along with CO_2 atmospheric reduction. Presently, the number of operational EGR, ECBM projects and their data availability is limited, but they could be a potential CO_2 storage location in future. Previous CO_2 capacity estimates have some uncertainty and contradictory values; there is a need to close this gap before large-scale storage implementation since it could be a leakage threat. Monitoring techniques needs to be more mature to have accurate data and avoid repeatability issues. Potential cost of geological storage is known, which depends on location, depth, reservoir characteristics and other associated factors.

Table 8. Injection costs for onshore & offshore aquifer [41]

Depth (m)	Onshore aquifer US$/t CO_2 avoided	Offshore aquifer US$/t CO_2 avoided
1000	2.24	5.60
2000	3.36	9.08
3000	7.34	14.18

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NOMENCLATURE

A	: area that defines the region begin assessed for CO_2 storage
B	: formation volume factor
B_f	: formation volume factor
C	: coefficient
C'	: completion factor
C_a	: aquifer strength coefficient
C_b	: buoyancy coefficient
C_c	: capacity coefficient
C_h	: heterogeneity coefficient
C_m	: mobility coefficient
C_w	: water saturation coefficient
E	: CO_2 storage efficiency factor
F_{IG}	: fraction of gas injected
f_a	: ash weight fraction of coal
f_m	: moisture weight fraction of coal
G	: estimate of CO_2 storage capacity
G_c	: coal gas content
Gcs	: coal gas content at saturation
h	: average thickness
h_g	: gross thickness of saline formation/ coal seam for which CO_2 storage is assessed within the basin or region defined by area A
M_e	: effective storage capacity
M_t	: theoretical storage capacity
$\bar{n}_c$	: bulk coal density
OGIP	: original gas in place
OOIP	: original oil in place
P	: total pressure
P_L	: langmuir pressure
P_r	: pressure at reservoir condition
P_s	: pressure at surface condition

Table 9. Cost of various commercial CO_2 storage projects [3,44,99]

Project	Cost	Injection start	Injection finish	Injection rate (ton/day)	Capacity (kTon)	Status
Sleipner	US$ 96 M	1996		2700	20000	Operative
Weyburn	US$ 1.1 Billion	2000		5000	20000	Operative
InSalah	US$ 100 M	2004		3500	17000	Operative
Snohvit	US$ 191 M	2008		2000	23000	Operative
Ketzin	US$ 19 M	2008	2010	86	60	Operative
Otway	US$ 38.10M*+	2008	2010	150	100	Operative
Gorgon	US$ 800.95 M*	2014		12300	129000	Under Construction

*Exchange rate: 1 USD=1.05 AUD

+Phase 1 injection: 2008-2010

R_f : recovery factor
S_{CO2} : trapped CO_2 saturation after flow reversal
S_w : average water saturation within the total area A and net thickness h_n
S_{wirr} : irreducible water saturation
S_w : average water saturation
T_r : temp at reservoir condition
T_s : temp at surface condition
V_e : effective storage volume
V_L : langmuir volume
V_t : theoretical storage volume
V_{iW} : volume of injected water
V_{pw} : volume of produced water
V_{trap} : rock volume previously saturated with CO_2 that is invaded by water
X_0^{CO2} : initial CO_2 content in water formation
X_s^{CO2} : CO_2 content in water formation at saturation
Z_r : gas compressibility at reservoir condition
Z_s : gas compressibility at surface condition

Greek Letters

ϕ : porosity
ϕ_t : average total porosity of entire saline formation over thickness h_g
ϕ_e : average effective porosity over net thickness h_n
ρ : density of CO_2 under (pressure, temperature) that represents storage conditions
ρ_{CO2} : density of CO_2
ρ_{CO2s} : CO_2 density at surface condition

Abbreviations and Acronyms

CCS : carbon capture and storage
CIR : color Infrared
CO2CRC : cooperative research centre for greenhouse gas technologies
CSLF : carbon sequestration leadership forum
DOE : department of Energy
EOR : enhanced oil recovery
ECBM : enhanced coal bed methane
EGR : enhanced gas recovery
EMIT : electromagnetic induction tomography
ERT : electrical resistance tomography
IEA : international energy agency
IPCC : intergovernmental panel on climate change
SAR : synthetic aperture radar
VSP : vertical seismic profile

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