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Significant aspects of carbon capture and storage – A review

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ABSTRACT

Excessive emission of greenhouse gases into the atmosphere has resulted in a progressive climate change and global warming in the past decades. There have been many approaches developed to reduce the emission of Carbon Dioxide (CO_2) into the atmosphere, among which Carbon Capture and Storage (CCS) techniques has been recognized as the most promising method. This paper provides a deeper insight about the CCS technology where CO_2 is captured and stored in deep geological formations for stabilization of the earth's temperature. Principles of capturing and storage for a long-term sequestration are also discussed together with the processes, mechanisms and interactions induced by supercritical CO_2 upon injection into subsurface geological sites.

1. Introduction

Unprecedented changes in the climate system and significant increase of the surface temperature have been reported in the past decades [1]. Carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O), also known as greenhouse gases, have been releasing in the atmosphere for decades. They are recognized nowadays as the major factors behind the undesirable climate change. Burning fossil fuels for power generation, industrial processes and transportations have led to the huge increase of CO_2 concentration in the atmosphere while agricultural activities and deforestation are the main cause of increase in the concentration of CH_4 and N_2O [2].

Many studies were carried out in the past decade to reduce the increasing concentration of CO_2 in the atmosphere where several approaches such as reduction of energy consumption, swapping to fuels with shorter carbon chains, and capturing and storage of CO_2 have been proposed [3]. It was then appeared that the carbon capture and storage (CCS) technology can be a promising approach to save the climate by injecting CO_2 into geological formations [3–5]. In fact, if implemented successfully, the CCS can reduce the concentrations of CO_2 to 450 ppm by 2100 [2].

The concept of CCS was introduced in 1977, when it was suggested that CO_2 could be captured from the coal power plant and injected into suitable geological formations [6]. The International Energy Agency has claimed that this technology has the capability to reduce 17% of global CO_2 emission by 2050, and as such the CCS must be part of the policy in every single country worldwide to mitigate the sever effect of global warming [3]. A total number of 800 sedimentary basins across the continents have been determined as a suitable geological site for CO_2 storage [7]. Thus, many CCS projects have been initiated in the past few years such as CO_2SINK, In-Salah, RECOPOL, Sleipner, and Otway in different countries [8–14]. Among these, Sleipner and In-Salah are the pioneer CCS projects. Sleipner in Norway was initiated in 1996 to inject CO_2 in a saline aquifer with the capacity of 0.9 million tons per year (Mt/yr). In-Salah, an industrial-scale demonstration CCS project located in Algeria, was started to test the feasibility of CCS for re-injection of CO_2 into an aquifer with the capacity of 1.2 Mt/year [15]. CO_2SINK, on the other hand, is a research, development, and demonstration project located at Ketzin, Germany operated by Shell to inject/monitor CO_2 in a deep onshore saline aquifer. RECOPOL (Reduction of CO_2 emission by the means of CO_2 storage in the coal seams of the Silesian Coal Basin in Poland) is a pilot enhanced coalbed methane recovery (ECBM) project which is known as the first demonstration project to analyze economic and technical feasibility of storing CO_2 in the coal seams [16]. Having said that, several CCS projects have been executed in the past decades and now there are 22 large-scale ongoing CCS projects worldwide. Three large scale CCS projects have been launched recently in 2016 and 2017 with the following details [16]:

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(1) The Tomakomai CCS Demonstration Project started in 2016 by capturing CO_2 from a hydrogen production facility and injecting it into the near-shore deep geologic formations.
(2) The Illinois Industrial Carbon Capture and Storage Project is the world's first large-scale bioenergy CCS project started in 2017 to inject CO_2 into a deep saline formation with the scale of 1 Mtpa.
(3) The Petra Nova Carbon Capture Project in Texas with CO_2 capturing capacity of 1.4 Mtpa is the world's largest post-combustion CO_2 project initiated in 2017.

Having said that, the CCS technology is still young and requires more studies to ensure that capturing, transportation, injection and storage of CO_2 can be safely done in subsurface geological formations without contamination of surface/subsurface resources. In this study, attempts are made to provide a deeper look into different aspects of CCS and indicate how CO_2 can be safely stored in deep geological formations for a long period of time.

2. Principles of CO_2 capture, storage and monitoring

Technically speaking, the CCS practice involves capturing of carbon dioxide from power plants, industrial sites and natural gas wells, and transporting it through pipelines to a favorable geological site for permanent storage [3]. There are, however, many parameters, processes and phenomena included in this practice which must be very carefully measured, recorded and monitored to ensure that injected CO_2 is remained confined for thousands of years without seeping back to the surface. In this section, a general overview of the CCS technology is presented, and further discussions are provided.

2.1. CO_2 properties, flow and transport

Selection of a suitable geologic site for CO_2 storage depends on many parameters including the physical properties of CO_2 and its phase change under different pressure and temperature conditions. In fact, CO_2 can appear in different phases (i.e., gas, liquid, solid, and supercritical) but during injection in the geological formations located at the depths greater than 800 m, it often appears as a supercritical fluid due to the significant increase of pressure and temperature [4,17]. The phase diagram of CO_2 is shown in Fig. 1.

The efficiency of CO_2 storage in geological media, which is defined based on the volume of CO_2 stored per unit volume [7], enhances with increasing the density of CO_2 and improves the safety of storage due to the reduction of the buoyancy force. The controlling factors associated with the variation of CO_2 density are geological conditions and geochemical interactions. For instance, the density of CO_2 may increase or decrease significantly with depth, depending on the temperature gradient [18,19]. Thus, cold sedimentary basins with a low temperature gradient would be a better choice for CO_2 storage [3]. Another factor related to the density of CO_2, particularly in depleted gas reservoirs, is the contamination induced by the mixing of CO_2 with methane (CH_4), which may reduce the density and the storage safety [20].

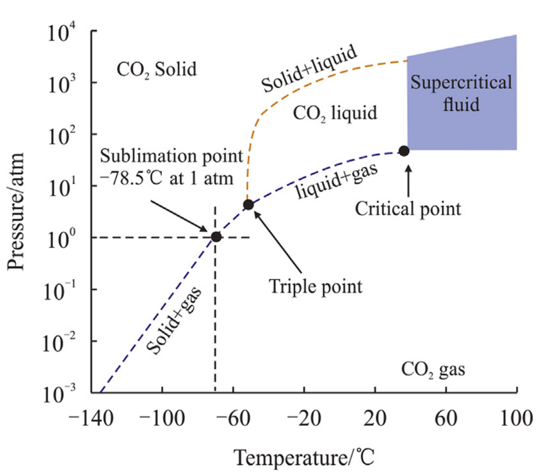

Fig. 1. Phase diagram of CO_2.

Solubility of CO_2 in water and their interfacial tension are other important factors during and after injection, which control the storage mechanisms. However, both of them often increase with pressure and decrease with the elevation of temperature [3,21,22].

Thus, once injected into deep geological formations, the primary flow and transport mechanisms that control the migration of CO_2 include [23]:

(1) Fluid flow in the porous media with respect to the pressure gradient;
(2) Fluid flow as a result of natural hydraulic gradients;
(3) Buoyancy pressure initiated due to the differences between the density of CO_2 and the formation fluids;
(4) Diffusion;
(5) Dispersion and fingering because of the reservoir heterogeneities and mobility contrast between CO_2 and formation fluids;
(6) CO_2 dissolution into the resident fluid;
(7) Mineralization;
(8) Phase trapping;
(9) Adsorption of CO_2 by the organic materials.

2.2. CO_2 capture and separation

During combustion, CO_2 is generated and can be captured by employing an appropriate removal process. There are various CO_2 capturing technologies but they generally increase the cost of a CCS project by 70–80%. As such, more studies should be done to reduce the operational cost and energy penalty of CCS practices [24]. Technically, four main technological options are available for CO_2 capturing from large point sources such as fossil fuel power plants. These technological options include post-combustion, pre-combustion, oxy-fueling, and capturing from the industrial processes (e.g., oil refineries, biogas sweetening and production of ammonia, cement, iron and steel) [25,26], as shown in Fig. 2.

Generally, the post-combustion technology can only be used for the exhaust gas with a low CO_2 concentration (4–14% v/v) which limits the application of this capturing method. It can, however, extract highly pure CO_2 for enhanced oil recovery, urea production and the food/beverage industries. To date, several gas separation technologies have been investigated to improve the post-combustion capture including: a) absorption, b) adsorption, c) cryogenic distillation, and d) membrane separation [25,27,28]. Comparatively, membranes (i.e., thin semi-permeable barriers) are increasingly used for the projects dealing with large flows, high CO_2 contents, or those in remote locations [29]. In the pre-combustion capture systems, on the other hand, fuel is converted by oxygen or steam to get a mixture of H_2 and CO_2. CO_2 can then be detached from H_2 and send for storage. A key benefit of this method is the high concentration of CO_2 in the output stream. In the oxy-fuel combustion, pure oxygen is obtained from a cryogenic air separation or membranes. The products upon combustion are basically CO_2 and H_2O, which are separated by condensing water [30]. Mitsubishi Heavy Industries, Ltd. (MHI) has supplied four CO_2 capture plants of commercial scale to recover CO_2 from flue gas in the chemical and fertilizer industries. For instance, CO_2 recovery plant [30] with a CO_2 recovery of 200 tones/day was installed in 1999 in Malaysia. Another CO_2 recovery plant in Japan with a capacity of 330 tones/day was started to operate in 2005. CO_2 recovery plants with the capacity of 450 tones/day, linked with urea production facilities, was delivered in 2006 at two different locations in India [31]. A brief summary of these capturing and separation technologies is given in Table 1.

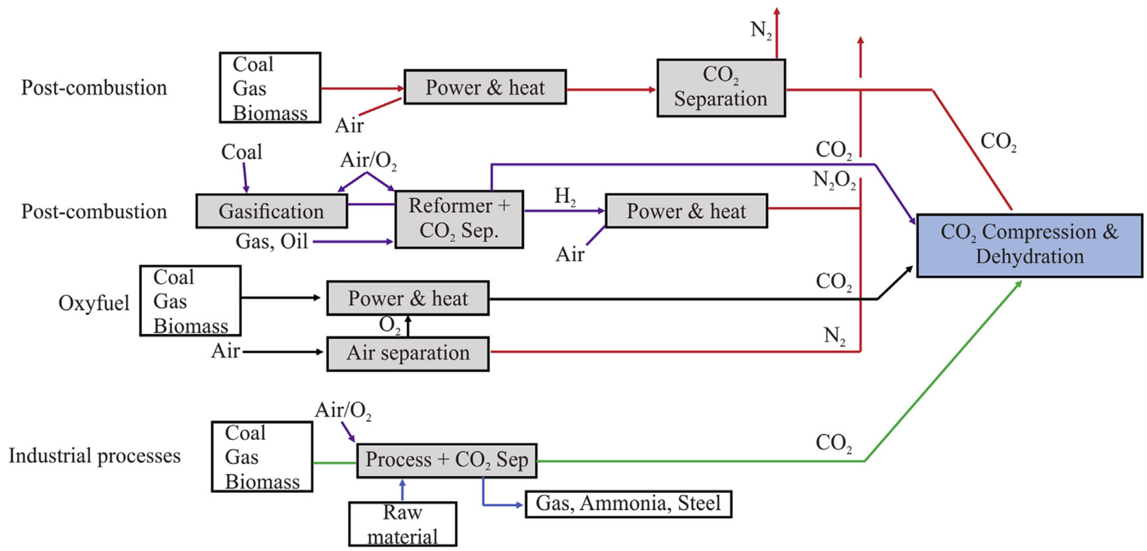

Fig. 2. CO_2 capturing systems (Reproduced from IPCC 2005 with permission).

2.3. CO_2 transport

Generally, there are several ways to transport CO_2 to the storage site after capturing and separation. From the storage site point of view, a large quantity of CO_2 can be transported through pipelines in a cost-effective way. The cost of this transportation, however, depends on the operational conditions, onshore and offshore locations and the size and composition of pipelines [32]. According to IPCC [3], transportation cost from a source to a site is estimated to be around 1–8 USD/tCO_2 per 250 km pipeline. The report released indicated that as long as the distance between the major source and prospective sedimentary basins is less than 300 km, transportation may not induce a significant cost on the CCS projects [3]. During the capturing practice, impurities (e.g., N_2, O_2 and Ar) which are often mixed with CO_2 may also pose additional costs on the storage projects and reduce the storage capacity. Hence, they should be removed before injection [33]. Furthermore, the moisture of CO_2 needs to be separated to reduce corrosions and hydration, which can impose additional costs [34]. Thereafter, CO_2 is compressed in supercritical form with a density of about 900 kgm^{-3}. CO_2 transport in liquid CO_2 which appears in supercritical form is more effective due to its lower density and relatively high pressure drops per unit of length [30]. Thus, operational cost included in a storage project must be considered and evaluated at the early stages before initiating the injection.

2.4. CO_2 storage

Storage site selection for a CCS project is initiated by basin and regional-scale suitability assessments. Only sedimentary basins with oil and gas reservoirs, deep sandstone and carbonate aquifers, coal beds, and salt beds are often targeted for a CO_2 sequestration practice [7]. Comparatively, active or depleted oil and gas reservoirs and deep aquifers have been recognized as the best CCS sites for a large-scale disposal of CO_2 [12,20,35–45]. The advantages and disadvantages of these geologic formations are given in Table 2.

After the basin scale assessment, a preliminary and comprehensive

Table 1
Carbon capture and separations options with application [25].

Capture option	Separation technology	Method	Applications
Pre-conversion	Absorption by physical solvent	• Selexol, rectisol	Power plants (IGCC)
	Absorption by chemical solvents	• Amine-based solvent, e.g. monoethanolamine (MEA)	Ammonia production
	Adsorption by porous organic frameworks	• Porous organic frameworks membranes	Gas separations
Post-conversion	Absorption by chemical solvents	• Amine-based solvent, e.g. monoethanolamine (MEA), diethanolamine (DEA), and hindered amine (KS-1) • Alkaline solvents, e.g. NaOH and $Ca(OH)_2$ • Ionic liquids	Power plants; iron and steel industry; cement industry; oil refineries
	Adsorption by solid sorbents	• Amine-based solid sorbents • Alkali earth metal-based solid sorbents, e.g. $CaCO_3$ • Alkali metal carbonate solid sorbents, e.g. Na_2CO_3 and K_2CO_3	No application reported
		• Porous organic frameworks – polymers	Power plants
	Membrane separation	• Polymeric membranes, e.g. polymeric gas permeation membranes • Inorganic membranes, e.g. zeolites • Hybrid membranes	Power plants; natural gas sweetening
	Cryogenic separation	• Cryogenic separation	Power plants
	Pressure/vacuum swing adsorption	• Zeolites • Activated carbon	Power plants; iron and steel industry
Oxy-fuel combustion	Separation of oxygen from air	• Oxy-fuel process	Power plants; iron and steel industry; cement industry
		• Chemical looping combustion	Power plants
		• Chemical looping reforming	Power plants; syngas production and upgrading

Table 2
Comparison of various types of geological carbon storage sites [44].

Geological medium	Advantage	Disadvantage
Unminable coal seams	• Large capacity • Enhanced methane Production	• High cost • Not available in all region
Mined salt domes	• Custom design • Storage integrity	• High cost • Not available in all regions
Deep saline aquifers	• Large capacity • Widespread availability	• Unknown storage integrity
Active or depleted oil and gas reservoirs	• Proven storage integrity • Enhanced hydrocarbon recovery • Established infrastructure	• Not available in all regions • May not be available for immediate injection • Multiphase flow complications associated with residual hydrocarbon

assessment should be done to evaluate the storage site at the reservoir scales to understand the key CO_2 storage aspects [17,19,46,47] using experimental, analytical and numerical approaches [17,48–53]. Previous successful implemented pilot projects such as Jilin, Ordos and Jingbian can also be considered as a guideline [15]. It should be noted that the key CO_2 storage aspects includes storage capacity [46,54], injectivity [17,46], trapping mechanisms (i.e., structural, capillary, dissolution, and mineral) [17,46], and containment [17,46]. Storage capacity, on this occasion, is defined as the total usable storage volume of a geological medium. Prediction of the storage capacity in depleted oil and gas reservoirs is often done by using recoverable reserves, reservoir properties and in-situ CO_2 characteristics. In the case of CO_2-Enhanced Oil Recovery (EOR), the storage capacity can be determined more accurately through numerical simulations. For the coal beds, thickness and CO_2 adsorption isotherms, recovery and completion factors are often considered to determine the theoretical CO_2 storage capacity. Assessment of the storage capacity in deep saline aquifers is not a straightforward task though, because of different trapping mechanisms which might be active simultaneously in the medium at different rates [55].

Injectivity, on the other hand, is the rate by which the fluid can be injected into a storage medium without fracturing the caprock [56]. Controlling factors such as porosity, permeability, thickness and heterogeneity play important roles to have an effective and favorable injectivity [17,57]. However, the brine displacement influenced by the heterogeneity level of the storage medium has a significant impact on the plume migration and storage capacity [58]. Thus, these parameters are assumed equally important in the storage site selection and modelling of multiphase flows [59,60]. There are, of course, many other influencing factors related to the depleted gas/oil reservoirs such as pore throat radius, residual gas/water saturation, residual oil/condensate saturation, and injection well types, which may need to be part of the preliminary assessment for the injectivity potential evaluation [17,61]. Moreover, CO_2 injection may have a significant impact on the integrity of wells used as an injector due to CO_2 dissolution, brine-pH variation and mineral dissolution/precipitation. These reactions may change the rock properties around the well and ceases the injectivity [56].

When planning for CO_2 injection, apart from the containment security and adequate storage volume, the injectivity and storage efficiency of the chosen storage site must be evaluated. Optimization of these factors is essential to have the highest storage capacity and initiate a cost effective injection operation [16]. However, pressure buildup during injection in saline aquifers and depleted hydrocarbon reservoirs can put a limit on the effective geological storage. As such, injection strategies for the pressure management must be implemented. Water production to relieve the pressure buildup during CO_2 injection is one of the strategies that can be considered under these circumstances [62]. However, a disposal option for the produced formation water might cause geological and regulatory issues when the costs of adding injection wells or the expense of water disposal is counted [63]. The number of injection wells may also need to be included in the injection strategy. For instance, commercial CO_2 storage operations with the rate of 1 $MtCO_2$/year may need one well (Sleipner project) or three wells (In Salah project).

Trapping mechanism is the third key storage aspect taking place in the storage site and help to have CO_2 confined in the chosen geological sites. Once occurred, trapping of CO_2 mitigates the safety and seepage issues of CCS projects [64,65]. Depending on the in-situ temperature and original pressure, CO_2 can be stored in a geological medium either as a gas, liquid or supercritical fluid by: 1) stratigraphic and structural trapping in the absence of barriers; 2) residual trapping by capillary forces; 3) dissolution trapping in brine; 4) mineral trapping by precipitation; 5) adsorption trapping in coal bed seams; and 6) cavern trapping in mined salt caverns. However, the type of trapping mechanism initiated during CO_2 storage depends on the rock characteristics and storage conditions [4]. Comparatively, the capillary trapping is recognized as a rapid, effective and safe mechanism to immobilized CO_2 in subsurface formations [20]. Fig. 3 demonstrates few of these trapping mechanisms.

Containment, is the las key storage aspects of CCS technology, forming by faults and impermeable seals (caprock). It ensure that CO_2 stays in the injected formation for a long period of time without entering into other formations, contaminating water resources and seepage to the surface [66]. The integrity of these seals may, however, be compromised by the geochemical interactions that may lead to irreversible geomechanical changes of the storage sites or its caprock [40]. These changes may create leakage pathways if the injected fluid pressure exceeds the facture initiation pressure of the caprock due to the reduction of strength. This situation may become far worse in deep brine aquifers where carbonic acids is generated by the dissolution of CO_2 in brine [67]. As a result, seals and faults evaluations must be done before, during and after CO_2 injection to ensure that they can support the injected/reservoir pressure for a significant period of time [68]. Containment evaluation in terms of seal capacity and seal geometry

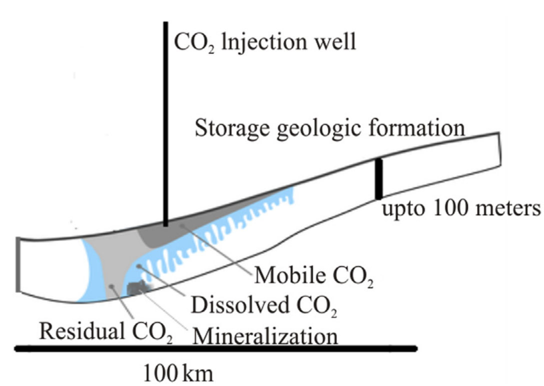

Fig. 3. A schematic demonstration of structural, residual, dissolution and mineral trappings.

(lateral continuity and thickness) is another aspect, which must not be neglected. For instance, capillary entry pressure must always be greater than the buoyancy force of the maximum produced CO_2 column height [17], as otherwise leakage and migration of CO_2 may take place even during injection. It should be noted that the column height of CO_2 is a function of rock's pore-throat size, wettability, and the interfacial tension between CO_2 and water [68].

2.5. CO_2 monitoring for safety

CO_2 monitoring during and after injection must be done to ensure that the injected fluid is migrating into the storage site and remined confined. In fact, monitoring is a mitigation measure to evaluate the reservoir behavior during and after injection.

There are many surface and subsurface monitoring techniques developed so far where crucial measurements such as the rate of injection, composition and pressure/temperature variation are recorded on the surface. Downhole pressure/temperature measurements in the injection/observatory wells are also used to tune the reservoir models and predict the maximum injection rate along with the storage capacity [69]. Time lapse (4-D) seismic measurements appeared to be a reliable approach in the offshore industrial scale projects of Sleipner and Snøhvit, for the assessment of CO_2 plume migration [70]. Gravimetry might also be useful in giving complementary information on CO_2 insitu density and dissolution rates in the formation water, if seismic data cannot be acquired due to budget limitations [71]. Geochemical monitoring techniques using non-reactive and reactive tracers might be another good means to quantitatively characterize the physical and geochemical changes at the field scale but they are often not as much practical as the seismic data [72].

2.6. Economics and safety of CCS

Economic feasibility of CCS is a critical concern that must be considered based on the technological cost of planning and operation [73,74]. These costs can be further divided into a number of different categories including CO_2 separation, transportation (typically with compressors and pipelines) and injection. High CO_2 concentration may also cause health issues and raise the risks of health and safety [75]. A dense phase CO_2 forms an acidic solution in brine which rises corrosion and degradations issue for the reservoir seals. Supercritical CO_2 with and without impurities needs to be carefully assessed since impurities may change its physical and transport properties. Moreover, types of impurity, their combination and quantity may have a severe impact on the recompression distance, compressor power and pipeline capacity [76].

3. Summary

Concentration of greenhouse gases in the atmosphere is progressively increasing in the past decades, causing global warming and climate change. Carbon Dioxide (CO_2) injection into geological formations is one of the promising techniques developed in the past decade to reduce the amount of CO_2 released into the atmosphere. In this paper, a general overview of an effective mitigation approach known as Carbon Capture and Storage (CCS) technology was presented. It appeared that a preliminary assessment at the basin and reservoir scales must be done to select a suitable storage site at the initial stage of CCS planning. This would require a comprehensive characterization of the key storage parameters including capacity, injectivity, trapping mechanisms, and containment. Monitoring is perhaps the last stage of a successful CCS project where 4D seismic data are employed to monitor the migration of the injected fluid into the reservoir as injection progresses.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.petlm.2018.12.007.

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