

Modelling of Geological Carbon Sequestration in Saline Aquifers

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Abstract—The fossil fuels mainly coal is the backbone for energy generation in India. But the burning of fossil fuels releases CO₂. Carbon sequestration involves long-term storage of carbon dioxide or other forms of carbon to lessen global warming. Storage of CO₂ in saline aquifers is an important strategy and a viable option for reducing the amount of CO₂ released to the atmosphere, hence to reduce the global warming. The paper presents an overall idea of CO₂ sequestration in saline aquifers including principles of CO₂ sequestration, CO₂ phase behavior, CO₂-water-rock interaction, and CO₂ trapping mechanisms. The storage capacity and CO₂ infectivity are discussed as the main determinants of the storage potential of saline aquifers. Moreover, a site section process is addressed considering basin characteristics, reservoir characteristics, and economic and social concerns. Three main procedures are presented to investigate the suitability of a site for CO₂ sequestration, with site screening and detailed site characterization.

Index Terms— CO₂ sequestration, Saline aquifer, CO₂ storage.

1) INTRODUCTION

Due the worldwide consumption of fossil fuels such as oil, natural gas, and coal as well as due to human activities, the concentration of CO₂ in the atmosphere is increasing day by day, which is about 280 ppm to more than 380 ppm over the last 250 years, and is now rising at a rate of about 1 ppm per year, leading to measurable global warming (Yang Fang, Bai Baojun, Tang Dazhen, Shari Dunn-Norman, David Wronkiewicz, 2010; Sprunt, 2006; IEA, 2008; USGS, 2008). Growing concerns about global warming and the challenge of CO₂ emissions regulation highlight the need to develop effective and economical means to sequester CO₂. To contain and ultimately reduce the carbon dioxide emissions there are three main ways to be considered: (i) Energy conservation and efficiency, (ii) Substitute lower carbon or carbon free energy sources (renewable, nuclear, hydropower and low carbon fuels), (iii) Capture, reuse and geological storage of carbon. geologic carbon storage can be planned in: Saline formations, Oil and natural gas reservoirs, unmineable coal areas, organic-rich shales, basalt formations.

Saline formations are of porous rock and filled with brine, or salty water, which extends large volumes deep underground. Saline formations containing water that has a total dissolved solids (TDS) concentration of less than 10,000 are not

suitable underground sources of drinking water (USDW). Therefore, any formation that contains brine with TDS levels greater than >10,000 TDS can be considered for CO₂ storage. They have the largest potential volume for storing CO₂ around the world. The first field test was in the Sleipner West Field, North Sea. CO₂ has been injected into the Utsira Formation- a saline sandstone aquifer since 1996. In United Kingdom, Southern North Sea basin, East Irish Sea basin saline and North and central North Sea aquifers are considered as good candidate for CO₂ storage on the basis of following criteria: lithology (clean sandstone), porosity (>10%), depth (> 800m), Thickness (>20 m), Permeability (>200 mD), Salinity >30,000 mg/l (IEA 2008). Potential storage sites should be in a geologically stable area, as tectonic activity could create pathways for the CO₂ to migrate out of the reservoir through the cap rock (low permeability seal) into the overburden and potentially to surface. Saline aquifers can be sandstones or limestones, but to be a potential storage reservoir for CO₂ they must fulfil those mentioned criteria. Therefore, the CO₂ sequestration and storage in saline aquifer requires systematic investigation. Reducing carbon emissions in a safe, effective, and economical manner requires an understanding of CO₂ sequestration mechanisms and considerations for potential storage sites.

Oil and natural gas reservoirs are one of the geologic storage sites because they have held hydrocarbons for thousands to millions of years and have conditions suitable for CO₂ storage. Injecting CO₂ can also enhance oil production by pushing fluids towards producing wells through a process called enhanced oil recovery (EOR). CO₂ has the affinity to adsorbed on the coal surface. In coal seams, the injected CO₂ can be chemically trapped by being adsorbed (or adhered) to the surface of the coal while CH₄ is released and produced. This trapping mechanism allows for permanent storage of CO₂.

The paper presents a general review of current status and concepts of CO₂ sequestration in saline aquifers as well as explains how CO₂ can be stored in saline aquifers and criteria of potential CO₂ storage site selection. Moreover, an attempt has been made to analyse the economic sustainability of the same.

2) CO₂ TRAPPING MECHANISMS IN AQUIFERS

Storage of CO₂ in saline aquifers may be in both “confined” and “unconfined” aquifers. Storage in confined aquifers depends on trapping of the CO₂ by structural (e.g. anticlines) and /or stratigraphic (e.g. sandstone pinchout, sandstone lenses) features, and is closely analogous to gas storage mechanisms of petroleum traps, or indeed to natural gas storage in subsurface aquifers.

Manuscript received November, 2017.

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CO₂ Phase Behavior:

The critical point is 31.1 °C and 7.38 MPa, at which CO₂ becomes a supercritical fluid (having high density like a liquid, but moves like a gas) which means it can be stored in great amounts and easily occupy an entire available space.

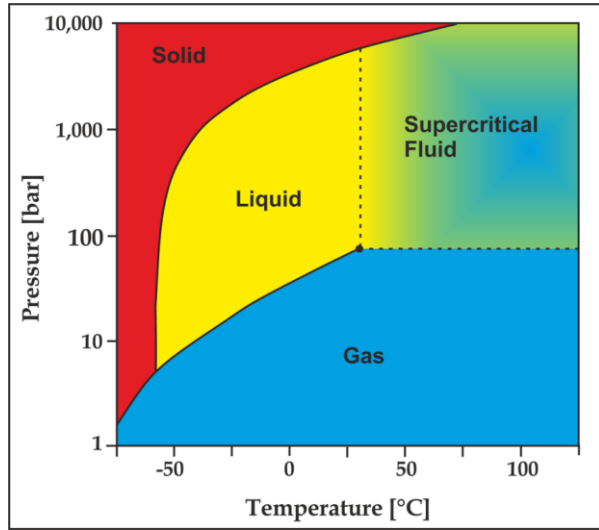


Figure 1: CO₂ Phase Diagram (IEA, 2008; Bachu, 2008)

The density of CO₂ stored underground depends on the pressure and temperature. Depending on the precise pressure and temperature conditions in the storage reservoir, CO₂ undergoes a relatively rapid change in density at depths between about 600 and 1000 m, becoming a dense phase supercritical fluid rather than a gas. As the gaseous and supercritical CO₂ are less dense than the water or brine in the void spaces of aquifers, they are buoyant relative to water or brine.

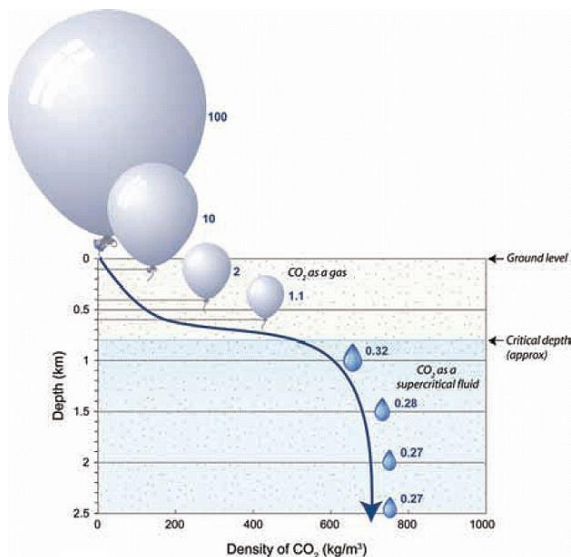


Figure 2: Density of CO₂ vs. Depth under normal conditions (Kaldi and Gibson-Poole, 2008)

CO₂ Water-Rock Interaction:

Carbon Dioxide dissolves in formation water/brine. First, it simply dissolves. Then equilibrium is established between the dissolved CO₂ and carbonic acid H₂CO₃, which

dissociates into HCO₃⁻ and CO₃²⁻. Next, the carbonate anions interact with cations in the formation water such as Ca²⁺ and Mg²⁺ to precipitate carbonate minerals. Extensive deposits of Limestone and Dolomites have been formed this way. The mutual solubility of CO₂ and brine affects the injection process and flow properties in three ways. First, CO₂ dissolves in brine increasing its density. Second, CO₂ dissolves in brine and reacts with water, forming an acid. Finally, H₂O dissolves into CO₂ increasing the salinity of brine (Hurtler et al. 2007). In general, CO₂ solubility increases with increasing pressure and decreases with increasing temperature and brine salinity (Ulker et al. 2007). When injected into the formation, CO₂ spreads in the porous medium, displacing formation water and occupying an increasing portion of the flow domain. It is then trapped through a combination of physical and chemical processes. These processes are classified according to the coverage area: Geological trapping, Geochemical trapping and Hydrodynamic trapping. Structural and Stratigraphic trapping occurs when the free phase CO₂ is trapped by the structure of the formation and seal rock units. Residual Saturation trapping occurs when CO₂ is trapped in pore space by capillary pressure forces. Solubility and Ionic trapping occurs when CO₂ dissolves into the formation water. Mineral trapping when CO₂ is involved in further chemical reactions with the rock matrix to form new stable minerals. Migration trapping when very large masses of CO₂ could potentially be stored by this means, and migrates in the subsurface at extremely low velocities, reaching the surface after millions of years.

Storage Capacity:

It is an estimation of the amount of CO₂ that can be stored in geologic formations. It depends on pore volume, porosity and most importantly, microscopic and volumetric displacement efficiencies (Cinar et al. 2007; Bradshaw et al, 2007). Factors affecting this are, Density of CO₂ at reservoir conditions, the interconnected pore space volume, and fluid property. Solubility affects storage capacity significantly because it determines the amount of gas that dissolves in the brine. The reactions among CO₂, brine, and the formation rock could change formation porosity and permeability (not affected by quartz, slightly affected by illite and kaolinite, and strongly affected by Calcite and Dolomite).

$$G_{CO_2} = A \cdot h_g \cdot \phi_{tot} \cdot p \cdot E$$

- G_{CO₂} -> Mass estimate of saline formation CO₂ storage capacity
- A -> Geographical area that defines the basin
- h_g -> Gross thickness of saline formation
- φ_{tot} -> Average total porosity of entire saline formation
- p -> Density of CO₂
- E -> CO₂ storage efficiency factor that reflects a fraction of the total pore volume that is filled, or connected, by CO₂

CO₂ Injectivity:

Injectivity measures the possibility of placing a fluid into a geologic formation, which contains the rate at which CO₂ can be injected and the ability of CO₂ to migrate from the

injection well. It directly determines the suitability of a site for CO₂ storage.

Injectivity (I) is defined as the ratio of a well volumetric flow rate (q) to the corresponding pressure drop or flow potential (Δp):

$$I = q/\Delta p$$

As the volume of CO₂ builds up, the pressure required to place CO₂ into the formation gradually increases, and the injectivity decreases.

Injectivity is governed by permeability, relative permeability, rock fracture characteristics, and rock compressibility (Cinar et al. 2007).

Injectivity can be assessed by characterizing reservoir quality, geometry and connectivity, and CO₂ Water-Rock Interaction (Kaldi and Gibson-Poole, 2008).

Basin Type and Tectonic Setting: Site should be in relatively stable tectonic setting so that the stored CO₂ will not be released by tectonic movement. Preferred sedimentary basins are intracratonic, foreland, and passive-margin basins.

The basin flow system should be deep and regional in scale. Cold basins are more favorable than warm basins because they have low surface temperatures and geothermal gradients. Ideally, basin should be rich in energy resources, its hydrocarbon resources should be mostly recovered, and it should have advanced production.

Reservoir Characteristics:

Faults, fractures and unconformities are undesirable as they may create pathways for CO₂ to migrate through the cap rock to the surface (Hesse et al. 2006). Cap rock, an impermeable low-porosity layer that prevents vertical CO₂ migration, provides the main trapping mechanism for long term storage security (Bentham and Kirby, 2005). Size: The reservoir must be large enough to store the quantities of CO₂ planned, e.g. the life time emissions of one power plant (Bentham and Kirby, 2005).

A storage site is preferred to be deep enough to keep CO₂ supercritical so that a great amount of CO₂ can be stored. Bases on worldwide average conditions, an approximate minimum subsurface depth is about 800m (800-1,000m for cold basins, and 1,500-2,000m for warm basins) (Bentham and Kirby, 2005; Imbus et al. 2006). These parameters would maximize the capacity and minimize the cost of well drilling, CO₂ compression, and injection (Bachu, 2003).

Porosity and Permeability parameters must be sufficiently high to allow injection and provide sufficient volume for CO₂.

Fluid properties, such as, brine salinity and composition, viscosity, density, pressure and temperature, are fundamental parameters, that directly and strongly affect CO₂ phase, solubility, and dissolution, thus controlling the effectiveness of trapping. Higher salinity results in lower solubility of CO₂.

Economic and social concerns (distance from CO₂ source, depth, accessibility, existing natural resources), site containment (seal capacity, thickness, trap type, fault), storage capacity (pore volume, size, CO₂ density), and Injectivity (permeability, porosity, thickness).

Injectivity (reservoir quality, geometry and connectivity, CO₂ water-rock interactions), containment (geomechanics, hydrodynamics, seal capacity), storage capacity (geological

model, pore volume). Injection phase (injection rate, well design, injection strategy), post injection phase (long-term migration, dynamic flow behavior, ultimate destination and form, sweep efficiency and capacity).

Socio-economic Characterization: Economics (cost of CO₂ compression, transport and injection), risks and uncertainty, monitoring and verification.

Inject CO₂ in a selected site and monitor CO₂ behavior, verification of formation properties, CO₂ saturation and distribution, etc.

The main issues affecting potential for injection of CO₂ in saline aquifers are the rate at which CO₂ can be disposed, the available storage capacity, the presence of a low permeability cap rock, the potential for CO₂ leakage, uncertainty and possibility of failure due to incomplete knowledge of subsurface conditions, and the corrosion resistance of materials to be used in the system. Factors that influence storage capacity and should be determined are well typed, injection rate, CO₂ purity, and injection strategy. Vertical wells are commonly used for CO₂ injection. But if the geology characteristic of a CO₂ storage site can be well described, horizontal wells are desirable. Two advantages over vertical wells are: large volume of CO₂ can be stored without reaching the top of the aquifer, and a higher injection rate can be expected. Horizontal wells can significantly improve injectivity and storage capacity-especially in low permeability formations.

3. Status of CCS in India

Although India endorsed the Kyoto Protocol in August 2002, as a non-Annex 1 country, it does not currently have binding GHG emissions reduction targets under international law. Coal is expected to remain the dominant energy source in India through at least 2050 (TERI, 2006). The IEA predicts that India will be in the top three emitters of the world by 2030 in terms of total CO₂ emitted each year. J. Condor et al. / Energy Procedia 4 (2011) 6125–6132 6127 4 Condor, J.; Unatrakarn, D.; Asghari, K.; Wilson, M./ Energy Procedia 00 (2010) 000–000 According to Cleantech Group, about 80% of the electricity supplied to homes, farms and factories in India comes from coal-fired generation plants, one third of which are old, inefficient, and emit harmful gases. If all these were modernized it would reduce emissions by 10 million to 13 million metric tones of CO₂ equivalent each year (Razwan Maximiuc, 2009).

To date, the Government of India has not introduced any policies or legislation dedicated to encouraging the development of CCS and as a matter of fact, currently this technology is not a priority. Industry stakeholders indicated that the governments of developed countries should contribute initial financing to CCS projects in India through international financing institutions such as the World Bank, the IMF, and the ADB. The resources for adaptation and mitigation of climate change will be provided from the budgets of the remaining years of the 11th Five Year Plan (2007-2012) and through to the end of the 12th Five Year Plan (2013-2017) (Sibley, 2009; Kapila, 2009).

Other initiatives include partnerships with US labs such as NETL in the Big Sky Carbon Sequestration Partnership (BSCSP), the CO₂ Geological Storage Project (CO₂GSP) partnership with the Pacific Northwest National Lab, the

Integrated Research and Action for Development (IRADe), and the Institute of reservoir Studies.

At present, there is limited knowledge in geological capacity due to a general lack of essential data. Initial attempts at evaluating the storage potential in India were made by Singh and estimated that roughly 5 Gt CO₂ could be stored in unmineable coal seams, 7 Gt in depleted oil and gas reservoirs, 360 Gt in offshore and onshore deep saline aquifers, and 200 Gt via mineralization in basalt rock (McGrail, B. P., H. T. Schaefer, A. M. Ho, Y., J. Dooley and C. L. Davidson, 2006). These capacity, however, are far from centers of emissions and may increase the cost of transportation.

Regarding to legislation, India does not have any integrated policies dedicated to encouraging the development of CCS. The National CDM Authority of the Ministry of Environment and Forestry, Government of India has initiated executive moves to investigate the potential of CCS. Analysts are of the view that linking CCS with the CDM is necessary before India can support the inclusion of CCS under the CDM umbrella (GCCSI, 2009).

Conclusion

Saline aquifers provide enormous capacity for CO₂ sequestration in most sedimentary basins worldwide. The characteristics of saline aquifers for CO₂ sequestration can be summarized as follows:

1) Carbon dioxide can be stored in saline aquifers through geological trapping, geochemical trapping, and hydrodynamic trapping. The potential for CO₂ storage in saline aquifers is largely determined by storage capacity and CO₂ injectivity. Storage capacity depends on aquifer volume, porosity, and displacement efficiencies, while CO₂ injectivity is governed by permeability, porosity, relative permeability, rock fracture characteristics, and rock compressibility. Evaluation of CO₂ storage capacity in saline aquifers is complex, due to limited data and various trapping mechanisms involved that act on different time scales. The mutual solubility of CO₂ and brine strongly affect storage capacity and injectivity. Chemical reactions among CO₂, brine, and formation rock affect the long-term fate of CO₂, although their impact is less significant.

2) Potential storage sites can be selected by assessing the basin and reservoir characteristics, as well as economic and social factors. Three main procedures are site screening, detailed site characterization, and pilot field-scale test. These procedures can be done by using traditional site characterization methods, laboratory experiments, and numerical simulation. A site suitable for CO₂ storage should be in a geologically stable area and minimally faulted, fractured, or folded. It should have strong confining seals and adequate size, depth, permeability, and porosity. The ideal site would be a confining unit in a cold basin with strongly harmonious sedimentary sequences and no significant diagenesis. It would be deeper than 800 m, well characterized, and easy to operate.

3) Engineering factors such as well type, injection rate, CO₂ purity, and injection strategy must be considered. Horizontal wells can achieve larger storage volumes of CO₂ and higher injection rate than vertical wells. Lower injection rates can increase storage capacity and efficiency. Higher purity of the injection CO₂ results in a greater storage

capacity. Brine injection as well benefits storage during CO₂ injection.

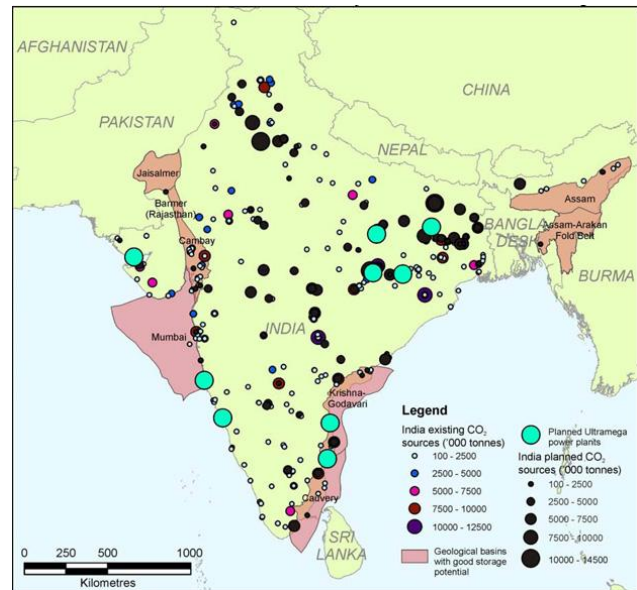


Figure 2: India's existing and planned CO₂ sources and geological basins with good storage potential (after GCCSI)

In India, regions of Haryana, Punjab, Gujarat, Orissa and Rajasthan are rich in saline aquifers which can be useful for CO₂ Sequestration.

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