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Multi-Phase Flow and Trapping of CO_2 in Saline Aquifers

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Abstract

Improved fundamental understanding of multi-phase flow and trapping in CO_2-brine systems will be needed to take advantage of the potentially large storage capacity of saline aquifers. The Global Climate and Energy Project is conducting laboratory experiments and theoretical studies of CO_2 transport and trapping in saline aquifers. Results of these studies provide the understanding needed to predict the storage capacity of saline aquifers, the spatial extent of the plume of injected CO_2, the rate of migration during the injection and post-injection periods, and the amount and timing of capillary and solubility trapping. This paper summarizes the results of this work. Taken together these studies of multi-phase flow and trapping can begin to provide a quantitative assessment of the fate and transport of injected CO_2—and how it will evolve over time and depends on the physical and chemical properties of the storage reservoir and seal.

Introduction

Saline aquifers have the largest potential capacity to store CO_2, possibly on the order of 10^4 Gt (billion metric tonnes) CO_2 (IPCC, 2005). If this large capacity is available, it could provide enough capacity for storage of hundreds of years or more of today's CO_2 emission from fossil fuel use. Taking advantage of the large potential storage capacity will require the ability to answer a number of key questions, namely:

- What fraction of the pore volume of the reservoir will be filled with CO_2?
- What will be the size of the plume of injected CO_2?
- Over the entire footprint of the plume, is the seal effective for permanent containment of CO_2?
- How quickly and to what extent will solubility trapping, capillary trapping and mineral trapping immobilize CO_2 in the storage reservoir?
- Will brine displaced by CO_2 migrate out of the storage reservoir into shallow groundwater aquifers used for drinking water?

Answering these questions will require improving fundamental understanding of the complex interplay of viscous and gravity forces, phase behavior, multiphase displacement dynamics, thermodynamic and kinetic controls on rock-brine-CO_2 interactions and basin-scale hydrogeology.

A schematic illustrating the primary processes affecting many of these issues is illustrated in Figure 1. At the pore level, viscous and capillary processes control the distribution of saturation between the wetting (brine) and non-wetting (CO_2) phases. Within the storage reservoir, geologic heterogeneity restricts the flow of both the wetting and non-wetting fluid to the higher permeability strata. Interestingly, for CO_2 storage, the presence of low permeability strata within the storage reservoir may have the beneficial effect of counteracting the effects of buoyancy flow, by locally preventing vertical flow of CO_2. The large density difference between CO_2 (~700 kg/m^3) and brine (~1000 kg/m^3) at typical storage conditions will be on the order of 300 kg/m^3. This large density difference results in strong buoyancy forces, causing the CO_2 plume to rise to the top of the storage reservoir—and bypass potential capacity in the lower portions of the storage reservoir. Finally, if the seal of the storage reservoir is not flat, CO_2 will move asymmetrically, driving CO_2 in the updip direction. The GCEP Project is evaluating all of these processes, at spatial scales from the core scale up to the reservoir scale, and time scales up to thousands of years.

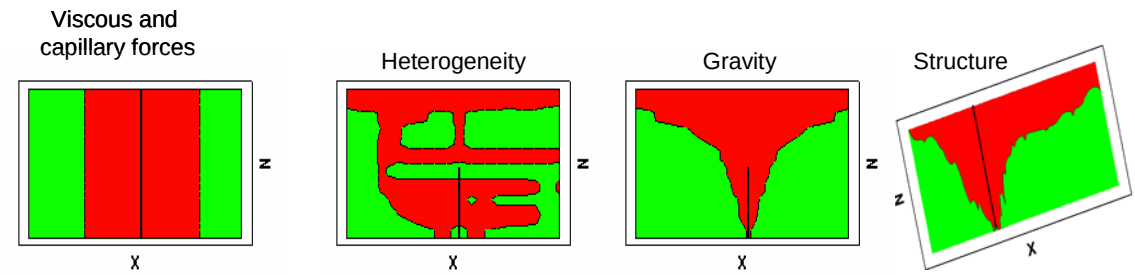

Figure 1. A schematic showing the processes controlling migration on CO_2 in a saline aquifer. Viscous and capillary forces control displacement at the pore level. Heterogeneity focuses flow in high permeability channels and locally counteracts the effects of buoyancy driven flow. Buoyancy forces drive CO_2 upwards until it encounters the seal of the storage reservoir. Dipping seals lead to asymmetric and updip migration.

Over the past several years there has been a growing interest in gaining a better understanding the long term fate of the injected CO_2. This interest is driven in part by concerns about long term stewardship and liability. After the injection phase of the project is completed and the wells have been abandoned, there are unanswered questions regarding stewardship and liability, namely:

- How long and how much monitoring is required?
- If a leak is detected, what can be done to stop it?
- Who is responsible for monitoring and potential remediation?
- What kind of financial instruments can be used to ensure that financial resources are available to remedy any unforeseen problems?
- Can long term liability be transferred to a shared risk pool?
- Will state or federal governments assume long term liability?

These questions have motivated an effort to gain a better understanding of how health, safety and environmental risks evolve over the life of a storage project.

Four mechanisms contribute to secure CO_2 storage: 1) structural and stratigraphic trapping beneath fine textured rocks that provide a permeability and capillary barrier to leakage; 2) solubility trapping when CO_2 dissolves in the aquifer water; 3) capillary trapping (also called residual gas trapping) that occurs when water imbibes back into the CO_2 plume; and 4) mineral trapping caused by conversion of CO_2 into carbonates (IPCC, 2005). Importantly, each of these trapping mechanisms is expected to increase over time—resulting in progressively more secure storage of CO_2. Consequently, the risks of health, safety and environmental impacts are also expected to decrease over time. In addition, after the injection phase of the project is complete, the pressure in the storage reservoir will decrease, lowering the driving forces for leakage through the seal or abandoned wells.

Based on this understanding, we have developed a conceptual model for how health, safety and environmental risks will evolve over the lifecycle of a storage project. Figure 2 illustrates the main features of this model. As the project gets underway the risk of leakage or other environmental risks increases due to pressure buildup in the storage reservoir, potential contact between the injected CO_2 and active or abandoned wells that may leak, and uncertainties with regard to the rate and direction of CO_2 migration. During this phase of the project, monitoring data will be obtained and history matching will be used to calibrate, refine and eventually verify simulation models used to predict storage performance. Once a reliable site-specific predictive model has been developed, risk will stabilize or even decrease. After injection stops, the risks of health, safety and environmental impacts decrease because the reservoir pressure decreases and the effectiveness of secondary trapping mechanisms increase over time. Similarly, monitoring data and history matching can be used to assess the evolution of the secondary trapping mechanisms that increase storage security and decrease risks of environmental impacts. The rate of pressure decline will be highly site specific. Similarly, the rates at which the secondary trapping mechanisms become effective are also highly site specific. GCEP is performing theoretical and laboratory studies together with field-scale simulations to improve fundamental understanding of these trapping processes and develop quantitative approaches for predicting them.

Demonstrating and building confidence that storage security will increase over time will help to design cost-effective approaches for addressing issues of long term stewardship and liability. The prospects of assuming long term liability are far less daunting in light of progressively diminishing risks. Moreover, if it can be shown that post-closure risks are less than operating risks, an actuarial basis for pricing insurance or some other risk-sharing vehicle could be established based on operating experience.

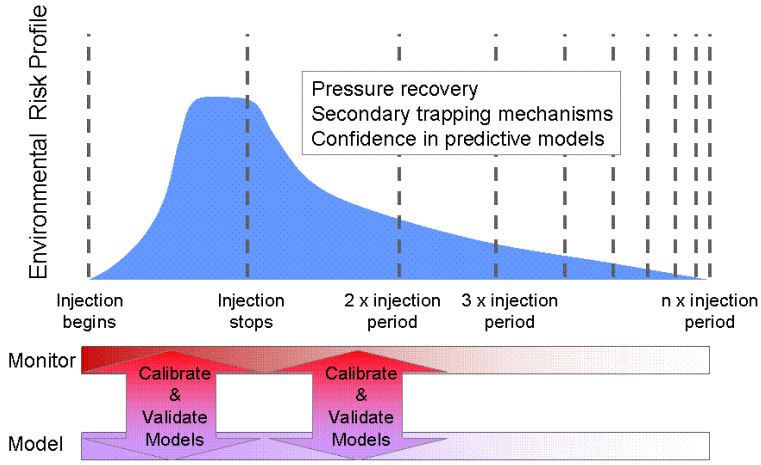

Figure 2. A schematic showing the environmental risk profile for a hypothetical storage project. As the project gets underway the risk of leakage or other environmental risks increases due to pressure buildup in the storage reservoir, potential contact between the injected CO_2 and active or abandoned wells that may leak, and uncertainties with regard to the rate and direction of CO_2 migration. After injection stops, the risk of health, safety and environmental impacts decrease because the storage reservoir pressure decreases and the effectiveness of secondary trapping mechanisms increase over time.

Global Climate and Energy Project Research

A description of the individual GCEP research projects is provided below. A more detailed description of all these projects in available at http://gcep.stanford.edu/research/index.html.

Experimental Investigations of Multi-phase Flow of CO_2 and Brine *(Benson)*

The goal of this project is to improve fundamental understanding of multiphase flow of CO_2 and brine in sedimentary rocks—and how capillary trapping can immobilize CO_2 in the post-injection period where water is imbibed back into the CO_2 plume. Multi-phase flow and trapping experiments of CO_2 and brine are conducted at reservoir conditions, under a range of flowrates and using different types of rocks that are likely to be used as storage reservoirs. X-ray CT scanning is being used to examine sub-core scale transport and trapping processes. The displacement data is interpreted using numerical simulation and history matching to elucidate the parameters and process that control brine displacement and trapping.

Sequestration in Subsurface Formations *(Tchelepi, Durlofsky, Aziz)*

The overall objective of this project is to develop a numerical simulation framework for modeling CO_2 sequestration operations in large-scale heterogeneous formations, such as deep saline aquifers and depleted oil and gas reservoirs. This framework is constructed based on in-depth understanding of the physics in the parameter space of interest for geologic sequestration of CO_2, accurate and computationally efficient numerical algorithms for modeling flow and transport processes in large-scale porous formations, and a flexible extensible computational framework for the design and optimization of CO_2 projects during both the injection and long term storage periods. This research platform has been designed to enable modeling, decision making and optimization under uncertainty as will be required in practical settings. During the past year, research was conducted in several interrelated areas: (1) vertical migration of CO_2 plumes in porous media, (2) propagation of CO_2 plumes in sloping aquifers with residual trapping, (3) construction of high-order adaptive implicit methods, (4) algebraic multiscale formulation for compressible multiphase flow, (5) stochastic framework for non-equilibrium models of multiphase flow in porous media, and (6) modeling CO_2 mineralization reactions in a general-purpose flow simulator.

Rapid Prediction of CO_2 Movement in Aquifers, Coal Beds, and Oil and Gas Reservoirs (*Orr, Kovscek)*

This project evaluated the physical mechanisms of processes designed to store CO_2 in subsurface porous media as well as the time scales associated with those mechanisms. Two studies demonstrated the use of compositional simulation for design of CO_2 storage projects in oil and gas reservoir settings. Conventional finite difference compositional simulation was used to examine co-optimization of enhanced oil recovery and CO_2 storage. Streamline compositional simulation was used to predict performance of combined storage of CO_2 and enhanced gas recovery.

The time scales associated with CO_2 storage in deep formations that contain salt water were considered in three ways. The impact of convective mixing of brine-saturated CO_2 (which is slightly denser than brine alone) on the time scale for

dissolution of CO_2 was considered using linear stability theory and high order simulation. Those studies showed that convective overturn sped dissolution over diffusion alone, but the time for onset of convective overturn was quite long unless the permeability was quite high. The interplay of gravity segregation and capillary trapping of CO_2 as an immobile residual phase was examined using conventional finite-difference simulation. That study indicated that significant trapping of CO_2 as a residual phase happened on the time scale of a few multiples of the time periods in which CO_2 was injected. More CO_2 was trapped when viscous forces dominated than when gravity forces dominated the flow. Compositional streamline simulation with gravity was used to demonstrate that high resolution simulation is practical and much more efficient computationally for large aquifer systems in comparison to conventional finite-difference simulation.

Assessing Seal Capacity of Exploited Oil and Gas Reservoirs, Aquifers, and Coal Beds for Potential Use in CO_2 Sequestration (*Zoback)*

This project investigated two types of geologic formations for CO_2 sequestration, coal beds and deep saline aquifers. The work on coal beds examined the effectiveness of CO_2 sequestration and enhanced coal bed methane production using reservoir simulations for the Power River Basin (PRB) in Wyoming. The research on deep saline aquifers assessed two issues: 1) whether CO_2 injection rates could be maintained at pressures consistent with geomechanical constrains while sequestering CO_2 volumes emitted by typical power plants in the Ohio River Valley, and 2) whether the potential exists for induced seismicity if leakage and vertical migration of CO_2 results in appreciable pressure changes in the caprock. This study demonstrated that pressure constraints can severely limit storage capacity in regions with low permeability, thin storage reservoirs.

Geophysical Monitoring of Geologic Sequestration (*Harris)*

The focus of this research is the development of a novel approach to continuous 4-D seismic monitoring. In order to make continuous observations practical, sparse spatial coverage from low-power coded or continuous-wave sources is used. This research indicates that the quality of sparse data imaging can be improved through use of special imaging algorithms that take advantage of temporal regularization and predictive model evolution. Simulation tools have been developed and used to simulate our monitoring strategies with high-performance computer clusters. Field testing is needed to demonstrate the potential of these new dynamic monitoring approaches.

Conclusions

Saline aquifers have a large potential for CO_2 storage—but greater fundamental understanding will be needed to answer important questions about the CO_2 storage capacity, plume size and plume evolution. In particular, improved understanding of the secondary trapping mechanisms that immobilize CO_2 will increase confidence in this option. GCEP is performing fundamental research on a breadth of topics to address these issues. Progress is being made on many fronts—in the laboratory, theory and simulation. Field-scale experiments will be needed to test and refine these ideas, and to build confidence in CO_2 storage in saline aquifers.

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