Title
International Symposium on Site Characterization for CO2 Geological Storage

Author
Tsang, Chin-Fu

Publication Date
2006-02-23

CO2SC 2006

International Symposium on Site Characterization for CO_2 Geological Storage

March 20 – 22, 2006

Proceedings of Extended Abstracts (with CD)

Lawrence Berkeley National Laboratory (LBNL)
Berkeley, California

SPONSORS

U.S. Environmental Protection Agency (EPA)
(Office of Air and Radiation and Office of Water)

CO-SPONSORS

International Association of Hydrogeologists (IAH)
American Institute of Hydrology (AIH)
Ground Water Protection Council (GWPC)
International Association of Hydraulic Engineering and Research (IAHR)

SYMPOSIUM ADVISORY BOARD

ORGANIZING COMMITTEE

Jens Birkholzer, LBNL, Co-Chair
Chin-Fu Tsang, LBNL, Co-Chair
Sally Benson, LBNL
Anhar Karimjee, EPA
Bruce Kobelski, EPA

INTRODUCTION

Several technological options have been proposed to stabilize atmospheric concentrations of CO_2. One proposed remedy is to separate and capture CO_2 from fossil-fuel power plants and other stationary industrial sources and to inject the CO_2 into deep subsurface formations for long-term storage and sequestration.

Characterization of geologic formations for sequestration of large quantities of CO_2 needs to be carefully considered to ensure that sites are suitable for long-term storage and that there will be no adverse impacts to human health or the environment. The Intergovernmental Panel on Climate Change (IPCC) Special Report on Carbon Dioxide Capture and Storage (Final Draft, October 2005) states that "Site characterization, selection and performance prediction are crucial for successful geological storage. Before selecting a site, the geological setting must be characterized to determine if the overlying cap rock will provide an effective seal, if there is a sufficiently voluminous and permeable storage formation, and whether any abandoned or active wells will compromise the integrity of the seal....Moreover, the availability of good site characterization data is critical for the reliability of models."

This International Symposium on Site Characterization for CO_2 Geological Storage (CO2SC) addresses the particular issue of site characterization and site selection related to the geologic storage of carbon dioxide. Presentations and discussions cover the various aspects associated with characterization and selection of potential CO_2 storage sites, with emphasis on advances in process understanding, development of measurement methods, identification of key site features and parameters, site characterization strategies, and case studies.

ABSTRACT CATEGORIES

This volume of extended abstracts is a summary of the rich diversity of topics addressed at the Symposium. For convenience, the topics are divided into nine broad categories:

- Overview Paper
- Site Selection and Characterization: General Framework
- Site Characterization Methods
- Regional-Scale Site Selection
- Site Characterization Case Studies
- Leakage from Storage Formations: Pathways, Effects, and Implications for Site Characterization
- Fundamental Processes and Technical Issues Related to Site Characterization
- Screening and Characterization Tools
- Regulatory and Social Issues

Within each category, the extended abstracts are ordered alphabetically by the first author of each contribution. The printed volume is in black/white. A CD is enclosed which contains color versions of all extended abstracts if submitted in color.

ABSTRACT CATEGORIES

CONTENTS

The extended abstracts are grouped according to the categories listed on the previous page, and within each category, they are listed alphabetically by first author. This volume is in black and white but the enclosed CD includes color versions of all the figures, if they are submitted in color.

OVERVIEW PAPER

SITE SELECTION AND CHARACTERIZATION: GENERAL FRAMEWORK

SITE CHARACTERIZATION METHODS

REGIONAL-SCALE SITE SELECTION

SITE CHARACTERIZATION CASE STUDIES

LEAKAGE FROM STORAGE FORMATIONS: PATHWAYS, EFFECTS, AND IMPLICATIONS FOR SITE CHARACTERIZATION

FUNDAMENTAL PROCESSES AND TECHNICAL ISSUES RELATED TO SITE CHARACTERIZATION

SCREENING AND CHARACTERIZATION TOOLS

REGULATORY AND SOCIAL ISSUES

OVERVIEW PAPER

SITE CHARACTERIZATION

Peter J. Cook

Chief Executive
Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)
GPO Box 463
Canberra, ACT, 2601, Australia
e-mail: pjcook@co2crc.com.au

BACKGROUND

This talk will consider what is meant by site characterization, what is the nature (and magnitude) of the task (of site characterization) that we are facing, and what have we learned from examples of storage site characterization carried out over the last decade.

DEFINING SITE CHARACTERIZATION

The term "site characterization" was first used by the nuclear waste industry, but there is no agreed definition, nor is the manner in which the term is used for nuclear waste repositories necessarily suitable for CO_2. The term has also been used to describe the activities needed to gather the hydrogeological information and design effective remedies for contaminated soils and groundwater. Site characterization is used in the context of siting and permitting Class I and II injection wells. Site characterization has also been an integral part of oil and gas exploration and production and groundwater resource evaluations, although the term is rarely used in that context.

Site characterization for deep geological storage of CO_2 is defined here as

"*The collection, analysis and interpretation of subsurface, surface and atmospheric data (geoscientific, spatial, engineering, social, economic, environmental) and the application of that knowledge to judge, with a degree of confidence, if an identified site will geologically store a specific quantity of CO_2 for a defined period of time and meet all required health, safety, environmental and regulatory standards*".

There are a number of the terms within this suggested definition that require amplification, and further consideration. For example is characterization an action that occurs only prior to commencement of CO_2 injection or does site characterization continue to occur (and be refined) throughout the injection phase, as well as during later monitoring and verification stages?

At a minimum, critical aspects of site characterization include demonstrating:

- an adequate seal is present to prevent upward migration of CO_2 into drinking water aquifers,
- the volume of the storage formation is sufficient to accommodate the desired quantity of CO_2 ,
- the injectivity is adequate to avoid pressure buildup to unacceptably high levels with a reasonable number of injection wells; and
- injection of CO_2 will not damage the seal as a result of geomechanical deformation or geochemical interactions.

Should a specific (e.g. high) degree of confidence be given in the definition or is it acceptable for "degree of confidence" to range widely from site to site? Should site characterization aim to meet regulatory standards or in fact will we be using the first storage projects as the basis for developing regulatory standards? Are different levels of site characterization and degree of confidence needed for storage in oil and gas reservoirs, compared to saline formations?

And what about characterization of the "carbon dioxide"? It is unlikely that we will be storing 100% CO_2. Therefore just as in the case of deep injection for hazardous and industrial wastes, where the waste stream is characterized in order to define Class I, Class II and Class III wastes, in some way it will be necessary to also characterize the CO_2 "gas" being stored, because of the potential impact of some impurities (H_2S, SO_2) on the storage and seal formations within the site.

Do well designs and completions fall within the ambit of "site characterization"? If they are existing wells then clearly they do. But if they are wells that are planned, can they also be considered to be an integral part of site characterization?

In the nuclear waste sector, site characterization has been considered for example at Yucca Mountain, to cover not only those activities that may be considered "site characterization", but scientific investigations aimed at improving fundamental understanding of the fate and transport of radionuclides in that environment. It is important to have a focused and disciplined approach in order that site characterization for CO_2 storage can be undertaken in a timely and open manner and held to reasonable cost limits, without adversely impacting on the quality of the investigation. Given that there could be hundreds to thousands of geological storage sites developed over the coming decades, it is important that cost and timeliness as well as access to an adequate technical skills and knowledge base is always borne in mind.

STORAGE MODELS

To date only a limited number of sites have been characterized comprehensively usually sites where storage of CO_2 is underway or at an advanced stadge of planning (Fig 1) and therefore the learnings are limited. Not surprisingly, storage locations were based not solely on a wish to identify and utilize the best site. Indeed it is absolutely essential at the start of site characterization to seek to identify and confirm sites that are fit for purpose rather than to be perfect. The sites were an inevitable compromise between a range of competing features such the location of the source of CO_2, existing infrastructure, market signals on the price of carbon (in the case of Sleipner), costs etcetera.

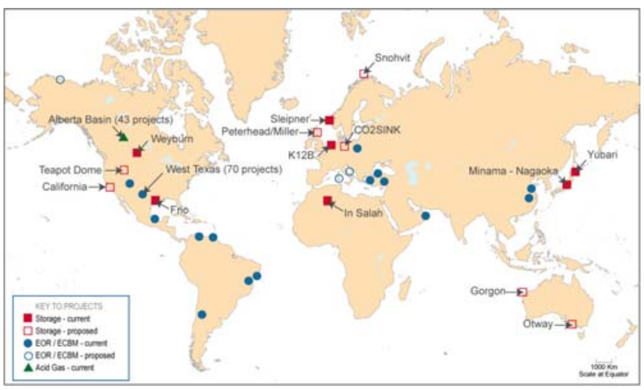


Figure 1. Projects and proposed projects involving injection/storage of CO_2.

Until now, the storage model most widely employed has been the saline formation model (Fig 2). This assumes, or seeks to establish, the presence of a widespread, thick, high permeability formation (usually, though not necessarily a sandstone), at a depth of greater than 800m with minimal faulting, in which the groundwater is saline (greater than say 10,000 ppm tds).

This is capped by an extensive, thick, fine grained low transmissivity formation (the top seal) that does not allow the vertical migration of CO_2. Ideally there is also a bottom seal underlying the storage formation. In many ways this should be one of the easiest site types to characterize, except for the crucial fact that the amount of information available on deep saline formations in most parts of the world is very limited, suggesting a major new phase of geological investigation will be necessary in many regions where there are major stationary sources of CO_2. This needs to get underway soon. It would also be more efficient to carry out coordinated regional scale investigations, to avoid duplicative, piecemeal, and costly site characterization on a project-by-project basis.

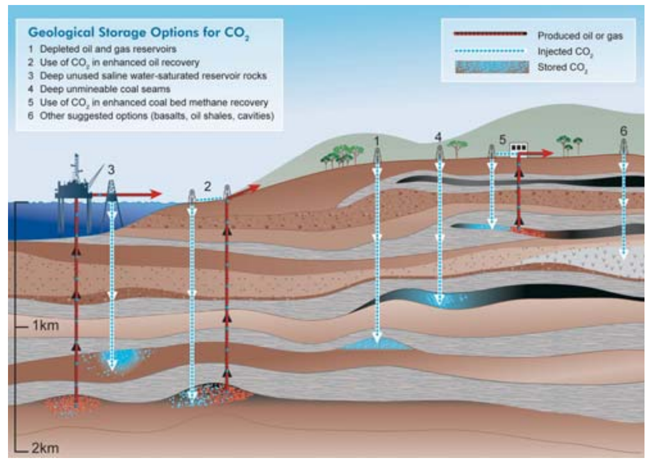


Figure 2. Options for geological storage for CO2 (after CO2CRC and IPCC, 2005).

Depleted oil and gas fields provide opportunities for very comprehensive characterization but are atypical in terms of the level of detail available and it is therefore important they do not become a de facto (and unrealistic) standard for all sites.

At the same time there are many lessons to be learned from the characterization undertaken for the Frio Brine Project and the Otway Basin Project *(*Fig1*)* for example, and some of these examples need to be considered in detail.

Some of the less conventional storage options present particular challenges in terms of characterization. Storage in coals will require a very different approach to characterization than that used for saline formations.

For example in many, perhaps most instances, it will be necessary to extract coal seam methane or groundwater in order to create the "space" into which the CO_2 can then be injected. Characterization relating to storage in low permeability systems may also be significantly different to high permeability systems. For example, injection may require a large number of vertical wells.

More likely, injection will be through a small number of long reach horizontal wells; this will require more detailed knowledge of facies changes within the proposed low permeability storage formation. Combining EOR with storage provides a further complexity to characterization in that confirming suitability of the site (and the oil) for EOR will be part of the characterization process. Even more challenging will be characterization of volcanic storage systems, should these prove to be worthy of consideration.

The clear message from all this is that whilst there will be some generic aspects to site characterization there will also be a range of parameters that will need to be collected, depending on the particular circumstances or situations.

The difficulty will then be to ensure in meeting those different situations, that standards for storage are maintained or there is a transparent acceptance of varying standards in terms of level of confidence, the quantity of CO_2 that will be stored, or the length of time for which it will be stored.

MAGNITUDE OF THE TASK

Finally, it is important to consider the magnitude of the task that we are likely to face. Based on existing and probable projects by 2015 there could be as few as seven commercial projects geologically storing CO_2, with the total cumulative tonnage of CO_2 storage being on the order of 100 million tonnes (Table 1).

On the other hand, depending on the success of the various commercial and demonstration projects carried out between now and 2015, we could be looking at an enormous effort to adequately characterize dozens and perhaps hundreds of potential storage sites by that time.

The IPCC Special Volume (IPCC, 2005) suggested that the economic potential of carbon dioxide capture and storage is in the range of 220-2200 Gt CO_2 until 2100. If it is assumed that an average project life is 50 years then this could be equivalent to thousands of Sleipners and many hundreds of Gorgons! In some ways it could be argued that Sleipner is a very atypical example of site characterization in that there was only limited information available on the site prior to injection.

In contrast, at the proposed Gorgon LNG project in Western Australia where it is intended to inject 3-4 million tonnes of CO_2 per annum, commencing in 2009-2010, characterization has been underway for several years. Gorgon may provide a more realistic example, the effort needed to adequately characterize the Barrow Island site, involving years of investigation, a 2500 page EIS and considerable cost.

Table 1. Estimates of Total Amounts of Geologically Stored CO_2 in Existing and Advanced Proposed Projects to 2015

PROJECT	COMMENCED	Anticipated amount injected by:		
		2006	2008	2010
Sleipner	1996	9MT	11MT	13MT
Weyburn	2000	5MT	9MT	12MT
In Salah	2004	2MT	5MT	7MT
Snohvit	2007	0	1MT	2MT
Gorgon	2010	0	0	0
Peterhead/ Miller	2009	0	0	1MT
California	2011	0	0	0
FutureGen	2012	0	0	0
Nagaoka	2002	10KT	10KT	10KT
Frio	2004	2KT	4KT	4KT
Ketzin/CO_2 store	2007	0	50KT	50KT
Otway	2007	0	100KT	100KT
Sleipner	1996	9MT	11MT	13MT
Weyburn	2000	5MT	9MT	12MT

In conclusion, we must develop clear protocols for site characterization that are fully fit for purpose as well as time and cost effective, without in any way jeopardizing health, safety and environmental standards or compromising social concerns. We must do this soon, if geological storage is to fully meet its potential to play a major role in mitigating anthropogenic CO_2 emissions to the atmosphere.

ACKNOWLEDGMENTS

I thank particularly Sally Benson for her contributions to this paper and to her coordination and leadership of IPCC Special Publication Chapter 5. I also thank the many talented researchers in CO2CRC for their support and their stimulating ideas.

REFERENCES

Hovorka, S.D., C. Doughty, and M.H Holtz, 2005: Testing Efficiency of Storage in the Subsurface: Frio Brine Pilot Experiment, Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), Vancouver, Canada. September 5-9, 2004, v.II, 1361-1366.

IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H.C. de Coninck, M. Loos, and L.A Meyer, (eds.)] Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

SITE SELECTION AND CHARACTERIZATION: GENERAL FRAMEWORK

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

GEOLOGIC FACTORS CONTROLLING CO_2 STORAGE CAPACITY AND PERMANENCE - TECHNIQUES AND CASE STUDIES BASED ON EXPERIENCE WITH HETEROGENEITY IN OIL AND GAS RESERVOIRS APPLIED TO CO_2 STORAGE

W. A. Ambrose, S. Lakshminarasimhan, M. H. Holtz, V. Núñez-López,
S. D. Hovorka, and I. Duncan

Gulf Coast Carbon Center
Bureau of Economic Geology
John A. and Katherine G. Jackson School of Geosciences
The University of Texas at Austin
University Station, Box X
Austin, Texas, 78713-8924, USA
e-mail: William.ambrose@beg.utexas.edu

INTRODUCTION

Detailed geologic characterization of subsurface formations is vital in understanding controls on CO_2 injectivity, migration, long-term storage, and to ensure that there will be no adverse impacts on the environment. A variety of structural and stratigraphic factors control geological heterogeneity, inferred to influence both sequestration capacity and effectiveness, as well as seal capacity (Doughty et al. 2001; Hovorka et al., 2004). Structural heterogeneity factors include faults, folds, and fracture intensity. Stratigraphic heterogeneity is primarily controlled by the geometry of depositional facies and sandbody continuity. Diagenesis also impacts heterogeneity.

This study focuses on the role of stratigraphic heterogeneity on reservoir geometry, permeability distribution, and recovery efficiency, with application to CO_2 sequestration. Two Oligocene oil and gas reservoirs in the Gulf Coast provide examples of the potential impact of facies variability on CO_2 sequestration. Seeligson Field is an example of major heterogeneity in fluvial systems, composed of discontinuous, channel-fill sandstones confined to narrow, sinuous belts encased in low-permeability mudstone. In contrast, barrier/strandplain deposits in West Ranch Field are homogeneous and continuous. Local areas of stratigraphic heterogeneity in West Ranch Field correspond to cross-cutting, lower-permeability and muddy tidal-inlet deposits that could influence both the capacity and effectiveness of CO_2 sequestration in analogous deposits.

GEOLOGIC HETEROGENEITY FACTORS

Several oil- and gas-reservoir characterization studies over the past 2 decades have demonstrated relationships between stratigraphic heterogeneity, internal reservoir architecture, and fluid flow (Galloway and Cheng, 1985; Tyler and Ambrose, 1985; Ambrose et al., 1995). Stratigraphic heterogeneity, which greatly controls permeability distribution, is indicative of the degree of interbedding between sandstones and mudstones, and in turn reflects the depositional setting. Stratigraphic heterogeneity exerts a major control on oil recovery efficiency. In a review of approximately 450 oil reservoirs in Texas, Tyler et al. (1984) demonstrated a relationship between depositional origin and recovery efficiency. For example, slope/basin reservoirs, which have a high degree of stratigraphic heterogeneity, display recovery efficiencies of <25%, whereas internally homogeneous barrier/strandplain and wave-dominated shoreface reservoirs commonly have recovery efficiencies of 50% or more.

Stratigraphic heterogeneity is also inferred to have an impact on both sequestration capacity and effectiveness. Sequestration capacity is the volume fraction of the subsurface available for CO_2 storage, which can be increased by stratigraphic heterogeneity. Numerical models described by Hovorka et al. (2004) suggest that in a homogenous rock volume, buoyant CO_2 flow paths may bypass much of the rock volume. In contrast, a heterogeneous rock volume disperses flow paths, resulting in a larger percentage of the rock volume being contacted by the injected CO_2. Sequestration *effectiveness*, defined as how much CO_2 will be sequestered for a given unit of time and space, can also be enhanced by heterogeneity. A given volume of CO_2 distributed over a larger rock volume may decrease leakage risk by shortening the continuous column of buoyant gas acting on a capillary seal and inhibiting seal failure (Hovorka et al., 2004).

Fluvial Reservoirs

Heterogeneity in fluvial systems occurs at several levels. Microscale heterogeneity occurs at the pore-throat level, whereas mesoscale heterogeneity in fluvial systems typically occurs as clay drapes within or above point-bar sandstones. Macroscale heterogeneity is a function of the connectivity of large-scale, channel-fill and overbank deposits. Connectivity is related to sediment load (Galloway, 1982). Sandy and coarse-grained, bedload fluvial systems typically contain well-connected channel-fill sandstone bodies deposited in wide sheets. In contrast, mixed load fluvial systems, which contain both sandy and muddy sediment, occur as meandering, sinuous river deposits with sand in lenticular, discontinuous point bars (Fig. 1).

Figure 1. Typical mixed-load fluvial system, with meander belts and point bar deposits occurring as lenticular, discontinuous sand bodies along the greatest point of curvature within meander loops. Example is the Trinity River in southeast Texas. Photograph by William Ambrose.

Heterogeneity in mixed load fluvial systems is typically higher than in bedload systems because individual channel-fill sandstones are poorly connected to each other and pinch out into muddy deposits. Middle Frio reservoirs in Seeligson Field in south Texas provide an example of discontinuous channel-fill sandstones confined to narrow belts between muddy floodplain deposits. Sandstone volumes in these types of systems for CO_2 sequestration may be limited, although the sequestration effectiveness may be enhanced by the great degree of sandstone/shale interbeds in channel-fill deposits and along channel-margin pinchouts (Fig. 2).

Barrier/Strandplain Reservoirs

Barrier/Strandplain reservoirs, particularly those deposited in a setting where wave processes were strong, contain well-sorted, continuous, sandy, and internally homogenous beach deposits. However, stratigraphic heterogeneity exists where beach deposits (barrier-core facies) are locally cross-cut by heterogeneous, shore-perpendicular tidal-inlet facies or where they pinch out landward into muddy backbarrier facies. The Oligocene Frio 41-A reservoir in West Ranch Field in southeast Texas is an example of a barrier/strandplain reservoir with a well-established relationship between barrier/strandplain facies architecture and permeability distribution (Galloway and Cheng, 1985). Barrier-core facies in the 41-A reservoir commonly have permeability values exceeding 2,000 md, whereas the cross-cutting tidal-inlet facies have permeability values ranging from <500 to 1,000 md (Fig. 3).

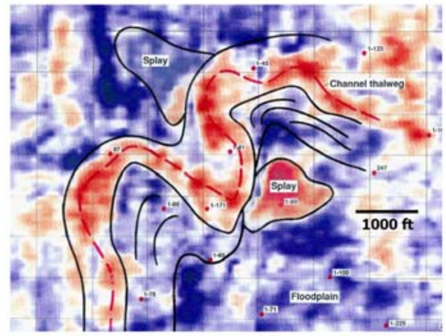


Figure 2. Fluvial sandstone geometry inferred from average amplitude map from 3-D seismic data, middle Frio (Oligocene) reservoirs in Seeligson Field, south Texas. Stratigraphic heterogeneity in these reservoirs is inferred to be high, resulting from bright-amplitude channel-fill sandstones confined to narrow, sinuous belts that pinch out into dim-amplitude, floodplain mudstones and variable-amplitude splay sandstones and siltstones. Modified from Ambrose et al. (1992).

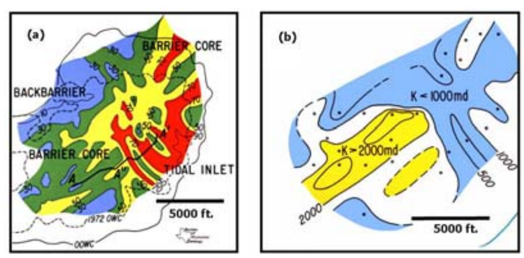


Figure 3. Relationship between (a) facies variability and (b) permeability structure in the Oligocene Frio 41-A reservoir in West Ranch Field. Modified from Galloway and Cheng (1985).

Injectivity of CO_2 in the relatively permeable and internally homogenous barrier core facies is inferred to be relatively high, where CO_2 flow paths may be dominated by buoyancy, initially bypassing much of the rock volume. Oil-production data indicate that the relatively homogeneous barrier core facies has been more efficiently drained during primary oil recovery, suggesting greater fluid mobility and more efficient transport of injected fluids (Godec, et al., 1989).

ACKNOWLEDGMENTS

The Gulf Coast Carbon Center, Bureau of Economic Geology acknowledges support of this research by BP America, Chevron, NRG, Entergy, KinderMorgan, Marathon, Schlumberger, Praxair, and the John A. and Katherine G. Jackson School of Geosciences.

REFERENCES

Ambrose, W. A., J. D. Grigsby, B. A. Hardage, R. P. Langford, L. A. Jirik, R. A. Levey, R. E. Collins, M. Sippel, W. E. Howard, and J. Vidal, *Secondary Gas Recovery: Targeted Technology Applications for Infield Reserve Growth in Fluvial Reservoirs in the Frio Formation, Seeligson Field, South Texas,* Topical Report GRI-92/0244, Gas Research Institute, Chicago, Illinois, 1992.

Ambrose, W. A., E. R. Ferrer, S. P. Dutton, F. P. Wang, A. Padron, W. Carrasquel, J. S. Yeh, and N. Tyler, *Production Optimization of Tide-Dominated Deltaic Reservoirs of the Lower Misoa Formation (Lower Eocene), LL-652 Area, Lagunillas Field, Lake Maracaibo, Venezuela,* Report of Investigations 226, Bureau of Economic Geology, The University of Texas at Austin, Austin, Texas, 1995.

Doughty, C. A., K. Pruess, S. M. Benson, S. D. Hovorka, and C. T. Green, *Capacity Investigation of Brine-Bearing Sands of the Frio Formation for Geologic Sequestration of* CO_2, Proceedings of the 1st National Conference on Carbon Sequestration, May 14-17, National Energy Technology Laboratory, Washington, D. C., 2001.

Galloway, W. E., *Depositional Architecture of Cenozoic Gulf Coastal Plain Fluvial Systems*, in Ethridge, F. G., and R. M. Flores, eds., Recent and Ancient Nonmarine Depositional Environments: Models for Exploration, Society of Economic Paleontologists and Mineralogists Special Publication 31, p. 127-155, Tulsa, Oklahoma, 1982.

Galloway, W. E., and E. S. Chang, *Reservoir Facies Architecture in a Microtidal Barrier System – Frio Formation, Texas Gulf Coast,* Report of Investigations 144, Bureau of Economic Geology, The University of Texas at Austin, Austin, Texas, 1985.

Godec, M. L., M. J. Parsley, D. Remson, K. S. McFall, N. Tyler, and W.A. Ambrose, *An Assessment of the Reserve Growth Potential of the Frio Barrier/Strandplain Play in Texas,* Topical Report prepared by ICF Resources Incorporated and the Bureau of Economic Geology for the U. S. Department of Energy/Office of Fossil Energy, contract nos. DE-ACO1-85FE60603 and DE-AC19-86BC14000, Washington, D. C., 1989.

Hovorka, S. D., C. Doughty, S. M. Benson, K. Pruess, and P. R. Knox, *The Impact of Geological Heterogeneity on* CO_2 *Storage in Brine Formations: a Case Study from the Texas Gulf Coast*, in Baines, S. J., and R. H. Worden, eds., Geological Storage of Carbon Dioxide, Geological Society of London Special Publication 233, p. 147-163, London, UK, 2004.

Tyler, N., W. E. Galloway, C. M. Garrett, Jr., and T. E. Ewing, *Oil Accumulation, Production Characteristics, and Targets for Additional Recovery in Major Oil Reservoirs of Texas,* Geologic Circular 84-2, Bureau of Economic Geology, The University of Texas at Austin, Austin, Texas, 1984.

Tyler, N., and W. A. Ambrose, *Facies Architecture and Production Characteristics of Strandplain Reservoirs in the Frio Formation, Texas,* Report of Investigations 146, Bureau of Economic Geology, The University of Texas at Austin, Austin, Texas, 1985.

RESERVOIR SEALS: HOW THEY WORK AND HOW TO CHOOSE A GOOD ONE

Charles A. Christopher, James Iliffe

BP Americas
501 Westlake Park Blvd
Houston, TX 77079 USA
e-mail: christca@bp.com

INTRODUCTION

Geological storage of carbon dioxide has been proposed as one method to prevent its entering the atmosphere. Because of the buoyancy of supercritical CO2 in the presence of formation water, the CO2 will have a tendency to rise. Reservoir seals are the entity that will prevent the CO2 from reentering the atmosphere.

RESERVOIR SEALS

All reservoir seals are permeable at some level. Their ability to seal depends on one of three sealing processes: Capillary, pressure, and permeability. Buoyancy forces cause some fluids to try to rise to the surface and thus place a pressure drop across the seal that is proportional to the density difference between the fluid in question and water and the height of the column of fluid.

Capillary entry pressure is inversely proportional to the pore throat radius– the smaller the pore throat, the greater the capillary entry pressure. Until the fluid overcomes the capillary entry pressure, no flow will occur. Lowering the interfacial tension between the fluid to be trapped and that in the pores of the seal will lower the pore entry pressure.

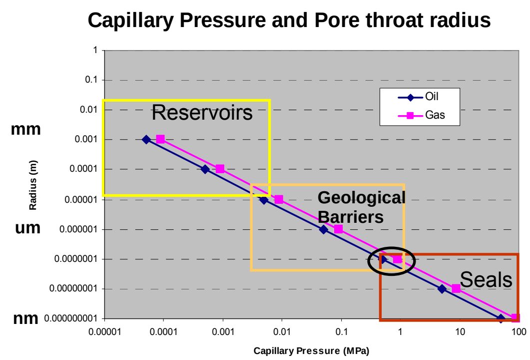
A pressure seal occurs where the buoyant fluid is held back by the wall of water flowing downwards through the pores due to a pressure potential – which can be considered to be an equivalent column of water – or "head". Capillary pressure alone is not enough to hold back the column of CO2 but combined with a downward head of water CO2 can be trapped.

Characteristics of a Good Seal

1) Petrophysically has small pore throats without large connected pores
2) Homogenous both vertically and laterally
3) Laterally continuous
4) Thick to reduce the number of pathways
5) Has no "bypass" systems (sand injection features, faults, etc.)
6) Water wet – to increase the capillary effects

Characteristics of a Poor Seal

1) Larger pore throats
2) Lithologically variable
3) Discontinuous layering
4) Thin beds
5) Fractured and faulted
6) Hydrocarbon wet



Will A Given Seal Hold More Gas, Oil, Or CO2?

Combining the buoyancy and interfacial tensions of the fluids against water, the calculations show that a pore throat of the following size is required to hold a column of 1,000 m of fluid:

- 19 nm – oil
- 14 nm – gas
- 10 nm – CO2

So, for the same length column, CO2 requires a better seal than oil or gas. Said another way, a given structure will hold less CO2 column height than oil or gas.

THE ROLE OF FAULTS

Some issues about the role of faults are under investigation by the petroleum systems community. Not every company has the same view of the role of faults but the following will show the experience of BP:

- What are the types of rocks that are faulted?
  - Soft, fine grained and unconsolidated
  - deform easily and are ductile
- Where fault throws are greater than sand thicknesses, they will smear some mudstone against sands thereby increasing their capil-

lary pressure. The "Shale Gauge Ratio" can be calculated.

- The more clay smeared a fault is the more capillary pressure the fault will have to a lateral sand across the fault.
- Faults do not play a significant conductive role for vertical migration of significant volumes
- Faults may be propped open by pore pressure but even this permeability is unlikely to provide efficient vertical conduits, and migration is just as efficient through topseals.
- Active faults will pump limited amount of fluid up them but this will not be significant.

Faults have been generally been considered to be a serious risk to CO2 storage but recent experience shows this may not be the case. Methods will be discussed which will allow faults to be analyzed.

CONCLUSIONS

- All seals have a threshold above which fluids will leak.
- Fine grained lithologies are essential for good seals.
- CO2 is lighter than oil so imparts more buoyancy pressure per unit.
- CO2 has lower interfacial tension than gas, so leaks easier than gas.
- The low permeability of fine grained rocks means that flow rates are extremely slow.
- Fluid flow UP faults may occur but at slow rates and at low volumes, flow ACROSS faults is much more likely.

THE ICE FRAMEWORK FOR SITE CHARACTERIZATION, AND A DESCRIPTION OF POTENTIAL DUE-DILIGENCE REQUIREMENTS

Julio Friedmann

Lawrence Livermore National Laboratory (LLNL)
P.O. Box 808
Livermore, California, 94550, U.S.A.
e-mail: friedmann2@llnl.gov

INTRODUCTION

The siting of geological storage projects requires a viable storage target. Three components of that storage system must be satisfied for an injection program to succeed and must be characterized in a site assessment: These are *injectivity*, *capacity*, and *effectiveness*, or ICE, and are defined as follows:

- *Injectivity* is the rate at which CO_2 injection may be sustained over fairly long intervals of time (months to years)
- *Capacity* is the total volume of potential CO_2 storage CO_2 at a site or in a formation.
- *Effectiveness* is the ability of the formation to store the injected CO_2 well beyond the lifetime of the project.

The vagueness of the definitions reflects the lack of legal or regulatory definition in many of the terms. Nonetheless, this framework provides a context in which to gather and analyze geological data, for consideration of regulatory due diligence, and as a useful foundation to decide upon site selection, site certification, and site decertification criteria.

ICE DEFINITIONS AND RELEVANT DATA

The simple definitions above provide limited insight. An expanded set of definitions herein helps to point to the data needed to provide insight into necessary site characteristics. These definitions are provided in the context of a reference plant; a 1000 MW coal-fired power plant with an 85% capacity factor and 90% capture injecting CO_2 for 50 years. Such a plant would produce over 6 million tons of CO_2/year, requiring the following ICE requirements:

- ~100,000 reservoir barrels/day CO_2
- ~2 billion reservoir barrels over 50 years
- High chance of effective storage well beyond those 50 years.

Injectivity, which is an effective rate term, may be described in various units (e.g., m^3/day/Pascal/m; barrels/day/psi/ft). This reveals some of the data required, including effective thickness (rock thickness, net:gross) over the injection footprint, local permeability, bulk connectivity, and down-hole pressure. Much of this data exists for oil and gas fields, but would be limited for other targets. However, conventional wells, geophysical surveys, and core analysis would be able to provide reasonable constraints for a project. The amount of data needed to constrain injectivity would vary by site, but it is highly unlikely that one well and a limited geological or geophysical survey could alone provide enough data to reduce the necessary risk. In many commercial applications, the degree of connectivity is not well understood for many years. It may not be practical to require years of study before siting a project, so empirical and theoretical approaches will be needed to provide additional information, and multiple scenarios should be considered.

The same will be likely of capacity estimation, which will be measured in units of volume (scf, barrels). A good estimate of capacity should also define the storage mechanisms involved. For example, site proponents should define the volume that would be stored as a dissolved phase, as a trapped residual phase, or as a trapped contiguous, buoyant phase (these terms will also affect effectiveness). While some data (thickness, porosity) are relatively easy to characterize with conventional tools, the effective volume is often difficult to predict because the effective rock volume depends on questions of reservoir heterogeneity. Moreover, it may be extremely difficult to predict the amount of residual trapping without extensive sampling and analysis. Since that may not be practical, analog and empirical data sets should be considered in defending capacity estimates.

Effectiveness is the trickiest term to define, but must rely on estimates of geomechanical, hydrodynamic, and seal integrity for the rock system, fault system, and well system (Figure 1). Some aspects of characterization (e.,g., Mohr failure criteria, capillary entry pressure) are straightforward. Some aspects are fairly straightforward but require a degree of geological sophistication (e.g., fault reactivation potential, in-situ stress tensor characterization). Some terms are extremely difficult to define (e.g., well behavior in 50-100 years) and cannot be unambiguously circumscribed in any reasonable operational context. However, there are relevant data sets (e.g., well completion records, wireline logs) that can provide a technical basis for assessing the likely degree of efficacy and safety, and relevant procedures (e.g., aeromagnetic surveys) that could serve as a component of due diligence in relation to unexpected and difficult to define phenomena.

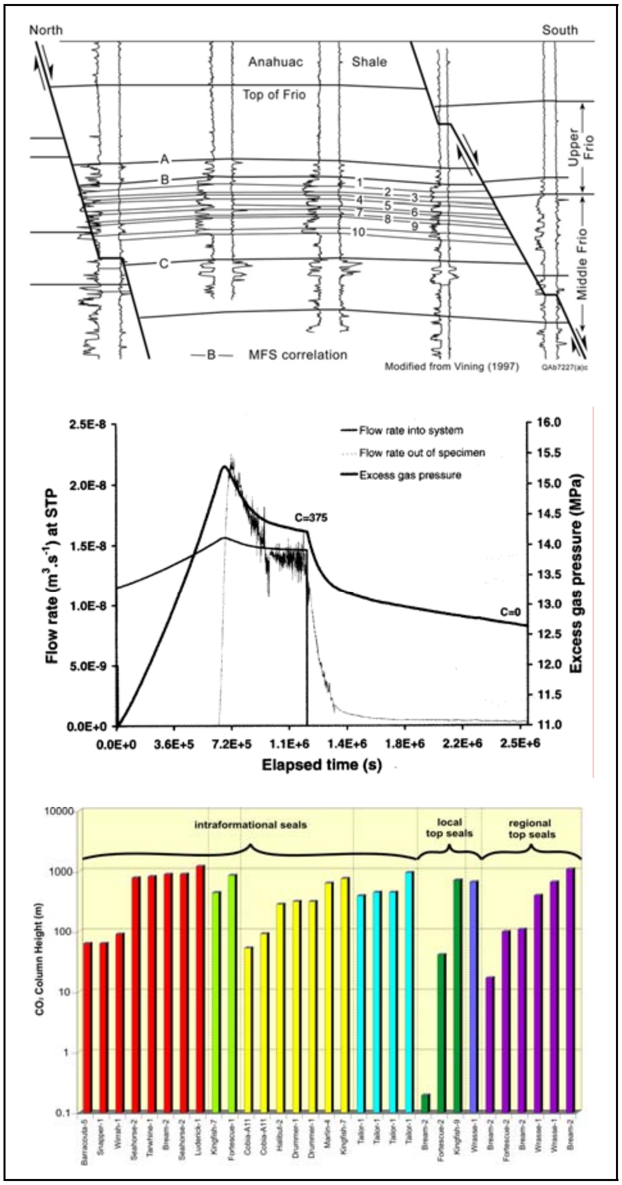


Figure 1. Some analyses available to characterize effectiveness. TOP: Well-log cross section showing thickness and extent of sealing facies (from Hovorka et al 2001). MIDDLE: examples of capillary entry pressure for a fine-grained mudstone (from Harrington and Horseman, 1999). BASE: Estimates of CO2 column height based on reservoir and seal characteristics (courtesy of CO2CRC).

POTENTIAL DUE DILIGENCE

Ideally, project site selection and certification for injection would involve detailed characterization given the geological variation in the shallow crust. In most cases, this will require new geological and geophysical data sets. The specifics will vary as a function of site, target class, and richness of local data. In that context, each target class can be considered in the ICE framework in terms of what might constitute due diligence for an evolving regulatory framework.

Depleted oil and gas fields

A depleted oil field is likely to have well, core, production, and perhaps seismic data that could be used to characterize ICE well in a fairly short time frame (order of months). If such data sets are available, no additional data may be required to characterize ICE. Conceivably, additional data (e.g., well-bore integrity analysis, capillary entry pressure data) may be required to satisfy regulators and stakeholders, chiefly in terms of effectiveness. Oil and gas fields will have an advantage regarding effectiveness in that the trap and function; however, greater due diligence may be needed in characterizing the fields in the well in terms of age, width of completion zones, and plugging history. For depleted hydrocarbon fields, the key issues may involve incremental costs necessary to ensure well or field integrity, and as such the due diligence may be straightforward and the burden relatively light.

Saline aquifers

In contrast, a saline aquifer project may have limited well data and lack core or seismic data altogether. Geological characterization of such a site may require new data to help constrain subsurface uncertainty, such as exploratory wells and new geophysical surveys. Injectivity may be readily constrained if it is already receiving injected fluids under the UIC; however, it is more likely that little will be known about the short or long term injectivity, and analog data may prove important. Similarly, the capacity may be a function of the hydrodynamic conditions and rely on residual phase trapping, both of which would require special analysis and might require broad hydrological characterization. Effectiveness would require (at a minimum) strong analog arguments on the seal rock's effectiveness (e.g., nearby hydrocarbon fields) but ideally would be defended or expanded based on new data collected from at least one exploratory well. For saline aquifers, key issues will involve appropriate mapping of potential permeability fast-paths out of the reservoir, accurate rendering of subsurface heterogeneity and uncertainty, and appropriate geomechanical characterization. However, existing science and technology exists and is well suited to defining ICE for all saline aquifer cases, and it is likely that the burden of proof would be manageable even in a cost-constrained environment.

Unmineable coal seams

Finally, unmineable coal seams pose substantial challenges in all three areas. While injectivity may be readily tested for CO2 storage in an unmineable coal seam initially, injectivity is time dependent due to coal swelling and plasticization. This may require some forward calculation to defend injectivity estimates. It may be more difficult to establish capacity and effectiveness. Although adsorption isotherms provide a basis for capacity estimates, it is not clear how much of the coal volume is accessible for storage. Effectiveness will be a function of the local stratigraphy, and many coal seams are interbedded or capped with permeable strata that do not seal. To define ICE for unmineable coal seams may prove daunting, and could conceivably involve characterization of cleat structure and geochemical/geomechanical response, accurate rendering of sealing architecture and leakage risk, and understanding transmissivity between fracture and matrix pore networks.

Cross-cutting issues

For these reasons, the regulatory framework will need to be tailored to the difference classes of sites and target types. Accordingly, the threshold for validation will vary from class to class and site to site, and the due diligence necessary to select a site and certify it could vary greatly. The goal, however, should be to provide a scientific (ideally quantitative) basis for characterizing injectivity, capacity, and effectiveness.

In that context, it is likely that simulations will play a pivotal role. At a minimum, simulations of multiphase fluid flow will give estimates of injectivity at a given pressure, some basis for claiming capacity, and an injection footprint to define the area of effectiveness.

ACKNOWLEDGMENT

Thanks to Elizabeth Wilson, David Keith, John Bradshaw, Anhar Karimjee, Howard Herzog, Mike Defiguerido, Ernie Moniz, and John Deutch for discussions that helped to formulate this manuscript. This work was performed under the auspices of the U.S. Department of Energy by the Lawrence Livermore National Laboratory under contract W-7405-ENG-48.

REFERENCES

Hovorka, S. et al., 2001, Evaluation of Brine-Bearing Sands of the Frio Formation, Upper Texas Gulf Coast for Geological Sequestration of CO2, First National Conference on Carbon Sequestration, Washington, D.C.

Harrington, J.F., and Horseman, S.T., 1999, Gas transport properties of clays and mudrocks, *in*, A.C. Aplin et al (eds.), Muds and Mudstones: Physical and Fluid Flow properties, Geol. Soc.
Special Publication 158, 107-124

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

MEASURING AND MODELING FOR SITE CHARACTERIZATION A GLOBAL APPROACH

Laurent Jammes[1], Dat Vu-Hoang[2], Ollivier Faivre[2], T.S. Ramakrishnan[3], Mahmut Sengul[1]

[1]Schlumberger Carbon Services
Le Palatin, 1 Cours du Triangle
92936 La Defense Cedex, France
e-mails: jammes1@la-defense.oilfield.slb.com, sengul@abu-dhabi.oilfield.slb.com

[2]Schlumberger Riboud Product Center
1 Rue Becquerel
92142 Clamart Cedex, France
e-mails: dvuhoang@clamart.oilfield.slb.com, ofaivre@clamart.oilfield.slb.com

[3]Schlumberger Doll Research
36, Old Quarry Road
Ridgefield, CT, 06877-4108,USA
e-mail: tsramakrishnan@ridgefield.oilfield.slb.com

INTRODUCTION

Operationally CO2 Sequestration projects can be evaluated in three phases, pre-operation, field development & operations and post injection. Site Characterization is the main task of the pre-operation phase, which follows the selection of candidate sites, as shown on Figure 1. The initial screening will use coarse criteria such as proximity to source, type of storage, average permeability and porosity, total volume. The aim of the characterization phase will be to assess the potential storage performance (with regard to capacity, injectivity, integrity) and to provide the needed information to simulate the sequestration process. Detailed risk evaluation will follow, examples of which are the potential to contaminate shallower formations, release of CO_2 to the surface and loss of integrity of the reservoir. This paper proposes an integrated methodology to address these two objectives

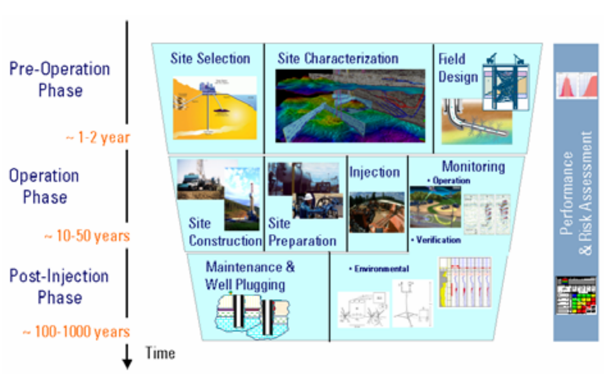


Figure 1: A CO_2 Storage Project

Site Characterization phase will start with an initial task where all data about the targeted storage reservoir and its environment would be collected and audited. A first pass analysis will allow identifying missing information, and a measurements campaign will follow.

Representative static and dynamic models of the reservoir and its overburden will be built and used to simulate the CO_2 injection performance and predict the short- and long-term fate of the CO_2. These models will form the bases for a first pass risk analysis.

Performance and Risk Assessment will be used, in conjunction with modeling studies, to design the optimum injection and monitoring systems.

This general methodology is displayed on Figure 2.

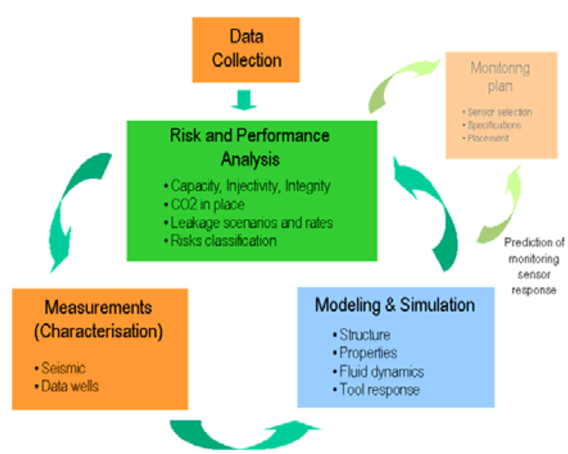


Figure 2: General methodology for site characterization

DATA AUDIT AND COLLECTION

A preliminary phase will consist in collecting and auditing all available data and information related to the potential storage site. This can vary greatly depending on the storage type: depleted oil or gas fields are usually well characterized while aquifers will lack of description. Usually in the data collection phase the following objectives are pursued:

- Determine what information is available, which of these may be utilized for characterizing the storage performance and safety (well completion data, information on wells, production history if storage in a depleted reservoir). Catalog the data for further site characterization (static and dynamic storage model)
- Determine if site characterization is possible with existing data. Identify the areas of uncertainties that can impose operational long term of higher and lower risk due to inadequate data.
- Define new set of data to be acquired to reduce these risks
- Define a scope of work and project timing for completing the site characterization

The available data will be collected and entered into a data repository system for easy access, display and further analysis.

MEASURING FOR CHARACTERIZATION

Based on the previous analysis, the need for additional measurements for site characterization will be identified and a measurement program launched. This may necessitate in drilling additional wells and further seismic campaigns.

Geology & Geophysics

Regional field geology, initial information available from hydrogeology, oil and gas exploration could be a good starting document for screening and preliminary characterization study. Existing seismic data in the area may be inadequate to provide a detailed characterization of both the trap and overburden formations, as well as a suitable baseline survey for further 4D monitoring.

Mapping of small-scale features and properties in the subsurface requires much higher resolution than it is usually demanded. Careful choices of recording parameters and processing flows are very important. Multi-fold data, accuracy and repeatability of the measurements to obtain the best signal to noise ratio, frequency content of the source, bandwidth, and the ability to combine long record lengths with high sampling rates, allow enhancing the data resolution. Finally, recording multi-component should be envisaged, as S-waves can provide valuable insights in the nature of subsurface lithology, pore-saturating fluids and fracture density and orientation.

Surface seismic surveys should be supplemented by well/VSP (Vertical Seismic Profile) data.

Fractures and traps play an important part in the reservoir characterization. Studies of high-resolution borehole images allow classifying observed zones as anticlines, stratigraphic traps, salt domes and fault trapping. Strike and dip may be obtained from recorded data, essentially translating a sinusoidal feature on the borehole surface. Electrical or acoustic images translate open fractures as a sharp contrasting sinusoid against the background. Conductive fractures tend to show a conductive anomaly, and a healed fracture is often non conductive. A detailed analysis of the electrical resistivity at the indicated fracture is often used to estimate the fracture aperture (Luthi, 1998)

Petrophysics & Mineralogy

Well log data such as the GR, density, porosity and resistivity logs facilitate identifying stratigraphic boundaries and quantifying reservoir thickness. Additionally petrophysical properties such as the primary and secondary porosity, the clay content, the fluid saturation and lithology may be estimated fairly reliably. A reservoir zoning is then carried out, based on log responses that depend of petrophysical parameters such as porosity, permeability and fluid saturation. The exact determination of the principal minerals and possibly of the accessory ones is necessary, since any error in mineral type can lead to significant errors in the calculation of porosities and saturation. For examples radioactive minerals such as micas, feldspars or phosphates may be confused with clays.

Due to chemical reaction between the acidic fluid that is formed after the injection of CO_2, and the reservoir rock, mineral dissolution, secondary carbonate minerals and clays are formed. Gunter et al (1993, 1997), suggests that siliclastic reservoirs are likely to be the most reactive type of reservoir, with alumina-silicate minerals (feldspars) breaking down to form kaolinite and carbonates. Limestones in contrast undergo dissolution. A detailed mineralogy of the cap rock and the reservoir is therefore needed. Elemental spectroscopy logging that acquires the elemental yields from some of the main elements found in the subsurface such as H, Cl, Si, Ca, Fe, S, K, Gd and Ti with oxide closure model allow an accurate mineral estimates (Herron et al 1996)

Geomechanics

Central to managing an injection project is maintaining reservoir integrity. A good measure of the fracture pressure is essential. Additionally, a controlled fracture may have to propagate through the stratum of interest, without damaging the sealing potential. Direct estimates of these geomechanical properties are possible through mini injection formation testing. In order to estimate in-situ stresses, acoustic and density logging provide elastic moduli. In conjuction with borehole images for identifying tensile fractures along with breakouts, an estimate of the minimum and maximum stresses may be obtained

Fluid and Transport Properties

For fluid flow modeling purposes, it is desirable to know the downhole properties of the injected CO_2. To that effect measurements of the fluid pressure and temperature as well as that of permeability are necessary. Thermodynamic modeling of brine- CO_2 systems are reasonably understood. Therefore a compositional simulation may be carried out provided relative permeabilities, capillary pressures, and permeabilities are available. Permeability estimates from either magnetic resonance or Stoneley waves will have to calibrated with either core data or formation tests. Relative permeabilities may be approximately evaluated through array resistivity logging, and then confirmed with zonal production tests or some reference core data.

Well Integrity

Provided that safe operational procedures are respected during the injection phase, so as not to compromise the rock integrity and the fault stability, the main remaining risk has to do with the deterioration of the well completion components in the presence of CO_2. Casing corrosion monitoring with calipers, EM tools and Ultrasonic Imaging tools for cement bond monitoring are useful in this regard. It will probably be necessary to develop CO_2 resistant cement both for seepage prevention and abandonment

Table 1. Measurement Techniques for Site Characterization

Measurement Technique	Reservoir Structure & Geology	Petrophysics & Mineralogy	Geomechanics	Fluid & Transport Properties	Storage Integrity
Geophysical techniques	Seismic, VSP		Seismic, VSP		
Logging	Dipmeters Imagers	Density Porosity Resistivity Spectroscopy	Density Sonic Imagers Caliper	Permeability (NMR, Resistivity)	Cement properties (Sonic, Ultrasonic) Casing corrosion (Ultrasonic, EM)
Coring & Sampling	Core analysis	Core analysis	Core analysis	Core analysis Pressure, Temp. Permeability Fluid composition	
Well(s) Testing			Fracture pressure	Injectivity	Fault transmissibility

MODELING

Once the properties of the storage and its environment have been fully characterized through measurements, a set of 3D models, with the ultimate objectives, to predict quantitatively the behavior of the storage under CO_2 injection are generated. This general workflow is shown on the Figure 3 below. It is convenient to distinguish two main phases:

- The construction of a static model for the reservoir and its overburden (structure, rock and fluid properties), including a description of shallower aquifers when they exist.
- The construction of a dynamic predictive model to simulate the injection of CO_2 and its effects on the reservoir and the cap-rock

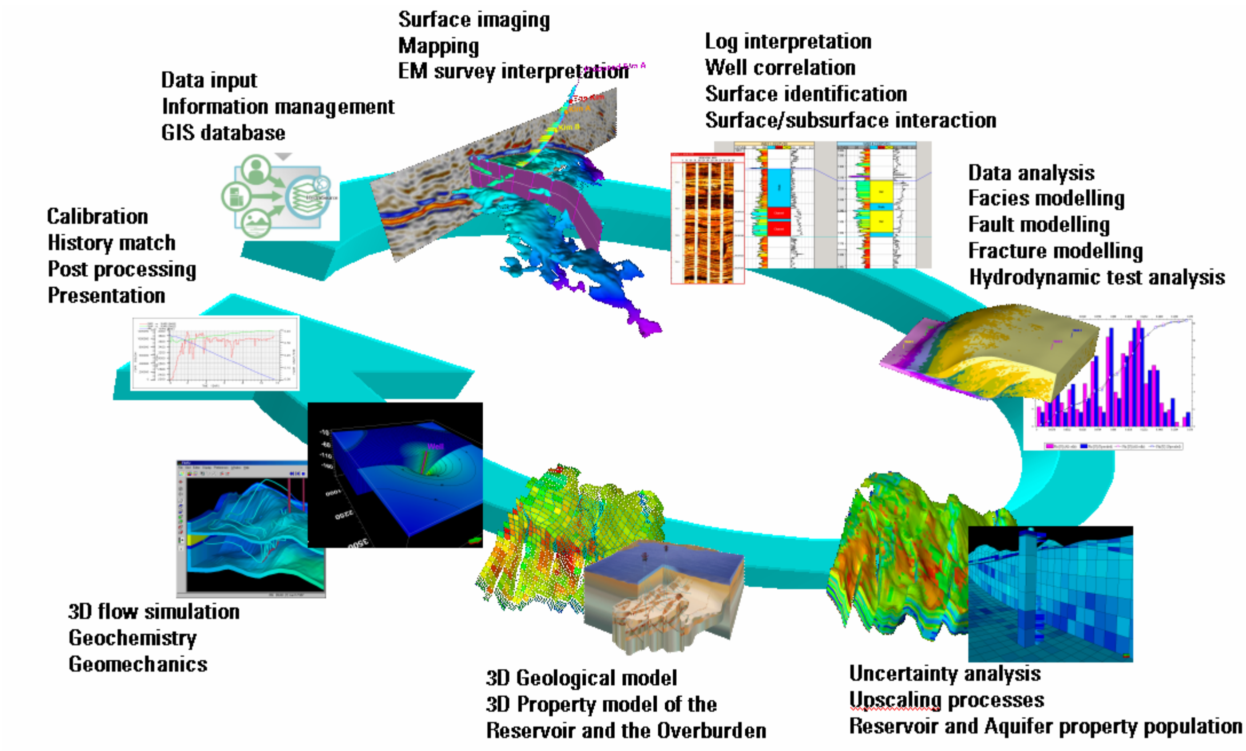


Figure 3 Reservoir and Overburden Modeling Workflow

Building a Static Model

The aim of the static model is to build as a detailed description of the reservoir as the measurements will allow. To that purpose "baseline" data acquired prior to the CO_2 injection will be used. A great emphasis will be put on the reservoir and its sealing horizons, with assessment of the layers above the storage due to possible CO_2 migration upwards. The static model will include a stratigraphic interpretation from surface seismic, results from well log correlations and interpretations. The geologist will add the fault and fracture characteristics and possibly results from hydrological tests. These are of great importance when CO2 is injected in aquifers. Should seismic data be of quality, fault and fracture detection could also be attempted through a novel approach called Ant Tracking and volume segmentation. Populating the model is then done through the use of geostatistical techniques. Reservoir engineers subsequently attempt to upscale these properties through simulations using flow models.

The Dynamic Model

Once a structural model is available and populated with petrophysical properties, a dynamic model is built to simulate the injection of CO_2, its displacement in the reservoir, and its interactions with other reservoir fluid and the matrix. For long-term simulation, a full-fledged compositional model is necessary. This will include phase equilibria of CO_2, various ionic components both from the dissolved salt components and those caused by CO_2 dissolution, and water. .Efficient and accurate numerical algorithms for a large range of temperature and pressure to carry out these calculations is important. In the long-term CO_2 sequestration induces slow mineralogical reactions within the reservoir. Major uncertainties affecting mineral dissolution / precipitation simulations are related to the simplified primary assemblage used in modeling whereas results are strongly dependent on rock composition (Xu et al. 2003, Gaus et al. 2004). This problem is enhanced by the lack of kinetic data since these invariably are slow reactions.

A geomechanics module that features the three dimensional elastoplastic stress equations should be combined within a reservoir simulator to equilibrate stresses with pore-pressure at the reservoir scale. This simulation tool will allow evaluating stress changes associated to CO_2 injection, in order to establish operational limits and pressures for the injection program that will not compromise the integrity of the over- and under-burden, the stability of the faults or the injection efficiency.

Thermal modeling should be included to evaluate the effect of temperature changes associated with CO_2 injection causing thermally induced stresses and fracturing.

Model Calibration

Although the utmost care had been taken in the building of the dynamic model, through a tight integration of all the available data, chances are that it still may not be a perfect mirror image of the subsurface. It is only through refining/calibrating the model so as to have a good match between the model prediction and the monitoring data, that a reliable model can be produced. This approach had been successfully applied to the Sleipner project, where the model was calibrated/fine tuned to achieve history matching (S. Holloway and al. 2004)

CONCLUSION

Through a tight integration of all the available relevant data, a geological model of the reservoir and the overburden zone has been constructed. A dynamic model was then built to simulate the CO_2 injection and its movement within the reservoir.

Prior to qualification of this model for future performance prediction, it needs to be calibrated with data from pilot wells and time-lapse measurements. The challenge is to increase the prediction power of the flow simulation.

Adequately placed and completed CO_2 injection wells and continuous monitoring of the integrity and capacity of the storage environment can achieve safe field operations

Adequate reservoir characterization and multi domain data integration in a simulation environment is the basis of a successful CO_2 projects site selection.

REFERENCES

Gunter W.D., Perkins E.H. and Mc Cann T.J., Aquifer disposal of CO_2 rich gases: reaction design for added capacity. Energy Consrv. Mgmnt, 34, 941-948, 1993

Gunter W.D., Wiwchar B. and Perkins E.H., Aquifer disposal of CO_2-rich greenhouse gases: extension of the time scale of experiment for CO_2 sequestration reactions by geochemical modeling. Mineralogy and Petrology, 59, 121-140, 1997

Herron S.L, Herron M.M, Quantitative Lithology: An Application for Open and Cased Hole Spectroscopy. Trans., SPWLA 37th Ann. Log Sym., New Orleans, 1996, Paper E

Holloway S., Chadwick A., Lindeberg E., Czernichowski-Lauriol I., Arts R., Best Practice Manual from SACS- Saline Aquifer CO_2 Storage Project, Statoil Research Center, 2004

Luthi S.M., Width Determination of Fractures Intersecting a Borehole, U.S. Patent Application Serial Number 252,958, filed October 1998

EXPERIENCE WITH SITE SCREENING AND SELECTION FOR CO2 STORAGE

Donald A. Seeburger

Chevron Energy Technology Company
6001 Bollinger Canyon Rd. D2324
San Ramon, CA 94583-2324 USA
e-mail: dase@chevron.com

INTRODUCTION

Many technical and non-technical issues must be addressed in the CO2 storage site selection process. Geological, geotechnical, regulatory, facility, economic and community factors must be considered. Site selection for CO2 storage is constrained in many ways. Constraints include the volume of CO2 to be stored, regulatory requirements relating to storage and other economic ventures that may be impacted, ownership or concession interests, economic viability, and operational and monitoring issues. A typical workflow is as follows:

1. Assess EOR and other usage options in the region.
2. Identify regional seals in the stratigraphic column
3. Identify potential storage sites
4. Assess storage site characteristics against project requirements and constraints
5. Determine economic characteristics of the potential sites
6. Estimate the remaining work to be done and the cost for that work in order to bring the sites to the decision point for final choice and regulatory approval
7. Ensure, to the extent possible, that the site and storage process will qualify for whatever credits and financial incentives that may be available

The site or sites that come to the fore through this workflow can then be submitted for greater evaluation, if required. The sites can then be considered for the regulatory and management approval process.

Experience with projects in Canada and Australia form the basis for the comments discussed.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

SITE CHARACTERIZATION NEEDS FROM A RISK ASSESSMENT PERSPECTIVE

M.J. Stenhouse, W. Zhou, and R. Arthur

Monitor Scientific LLC
3900 S. Wadsworth Blvd. #555
Denver, Colorado 80235, USA
e-mail: mstenhouse@monitorsci.com

INTRODUCTION

Risk assessment (RA) is likely to be the method used to assure stakeholders of the long-term safety of a geologic CO2 storage project. It is also likely to be part of the formal process in seeking regulatory approval for such project. As such, information and data from the characterization of a potential site for CO2 storage provide key input that feeds into RA modeling calculations. Although much of the site characterization (SC) work is carried out in advance of CO2 injection, and earlier than the RA modeling, the latter can be used to guide SC needs. This paper describes ways in which this can be achieved, based on the authors' experience in Phase 1 of the IEA Weyburn CO2 Monitoring and Storage Project. This extended abstract is restricted to key SC input.

For geologic CO2 storage projects, RA is concerned with predicting the likelihood of some potential harm, either to human health and safety, or to the environment (ecosystem) (HS&E impacts). For such harm to occur, CO2 must reach the surface/near-surface environment. Thus, it is important to identify all pathways along which CO2 can move and ultimately reach the surface/near-surface. Furthermore, the potential harm that can occur will be linked to the rate at which CO2 reaches the potential target, i.e., CO2 flux. This is a key focus of RA predictive modeling.

RA METHODOLOGY

One of the principal methods used in RA is scenario analysis. Using this approach, possible ways in which the storage system (reservoir plus surroundings; see Figure 1) may evolve are evaluated. Typically, this leads to a central or reference scenario that describes the expected evolution of the storage site. However, because of uncertainties associated with defining how the site will evolve, alternative ways of describing the future evolution are also considered, i.e., alternative scenarios and scenario variants.

Scenarios are supported by a consideration of features, events and processes (FEPs), which together describe the storage system and its possible evolution. One set of FEPs relates to the storage system itself, while other FEPs, primarily discrete events, do not relate to the storage system itself, but can act on the system to influence its evolution; for example, an earthquake occurring some time in the future may affect storage integrity.

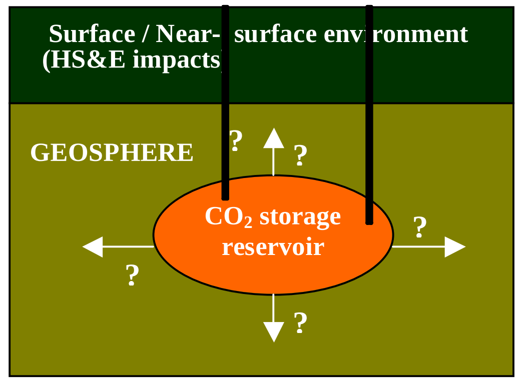


Figure 1. Representation of geologic CO2 storage system ("?" = possible CO2 transport).

Besides being used simply to describe the storage system and its evolution, FEPs play an important role in scenario analysis. They identify those features and processes that need to be considered when modeling the integrity of the storage system, specifically the potential movement of CO2 away from the CO2 reservoir into the surrounding formations and perhaps upwards to the surface or near-surface environment. Although these FEPs typically identify individual features and processes, they can still be used to provide top-level (management) oversight. *FEPs can also be used to guide SC needs.*

SPECIFIC SC INPUTS

Table 1 summarizes the important SC inputs used to support RA modeling predictions. Input can be incorporated *directly* into the modeling, such as specific data; or used *indirectly* to support RA conclusions. It is assumed here that some preliminary SC has been carried out to avoid proximity to other resources such as independent oil&gas fields, or coal or minerals, any of which may lead to future human intrusion.

Conceptual Model Input

A key stage in RA modeling is to develop a model of the system, a representation of the natural system but one that allows a mathematical treatment of the key processes associated with CO2 movement. In terms of geologic CO2 storage, this conceptual model would be expected to reflect at the very least the geometry of the storage reservoir and surrounding geology, i.e., stratigraphy. The depth of the reservoir, together with pressure and distribution, will determine the initial thermodynamic properties of CO2, in particular phase behavior. For certain types of reservoir, the shape of the top may cause individual pockets of supercritical CO2 to form, thereby affecting the nature of the upward driving force (buoyancy) and how it is modeled.

Table 1. Basic SC input for RA needs.

RA Needs	Basic SC Input
Conceptual model	Stratigraphy; reservoir geometry; preferential pathways, including wellbores; aquifer flows directions and rate)
Transport properties relating to CO2 movement	Petrophysical properties (porosities, permeabilities; heterogeneities) of different formations including sealing system, and other features (faults/fracture zones)
CO2 phase behavior	Pressure and temperature distributions of formations
Geochemical data	Rock-water chemistries that might promote reaction with dissolved CO2
Wellbore data (time-dependent transport properties)	Distributions, depth, age (initial seal characterization); field input on degradation of seals, casing (?)
HS&E impacts	Aquifer chemistry (trace metals)

Spatial Domain

The extent of the lateral area to be modeled will be dictated to a large extent by characterization of the principal groundwater regime(s). This will generally require good knowledge of the regional hydrogeology in order to provide a useful interpretation of aquifer movement in the vicinity of the site. Vertical extent is linked to key aquifers above and below the reservoir.

Preferential Pathways

RA is concerned with the identification of potential pathways and their transport properties, being of key importance to possible CO2 migration to the surface/near-surface environment. Such pathways may be natural (geological) or man-made. Examples of natural fast pathways include transmissive faults or major fracture zones. Thus, SC should seek to identify and characterize faults and fracture zones in the vicinity of a storage reservoir, and determine their relationship (connectivity) with the neighboring geology.

Since abandoned wells represent a potentially direct route from reservoir depth to the surface, SC must address abandoned wells. Characterization of abandoned wells should include geographic location, depth of penetration and knowledge of age and abandonment status. Thereafter, degradation rates of wellbore components (seals, metal casing, interfaces) and how they affect overall transport properties are of primary interest to RA but this information is unlikely to be provided by SC. Rather, relevant data on degradation state and hydraulic quality of seals will probably be provided by laboratory or (ideally) field testing.

Resistance to CO2 Movement

Reservoir Sealing System Characterization

The caprock, or upper sealing system of the reservoir, being the first line of defence, should be characterized in as much detail as possible in order to provide key input such as entry/capillary pressure. Pinchout of this sealing system, if it exists, needs to be identified. In addition, rock mineralogy will be important in determining to what extent CO2 is likely to react with the seal.

Identification of Hydraulic Units

Beyond the reservoir sealing system, those petrophysical properties that relate to the hydraulic integrity of different formations will determine how far CO2 moves from its reservoir and how quickly. Such properties include at a minimum porosity and permeability, which can be estimated relatively easily, and ideally capillary pressure vs. relative permeability relationship, which is more difficult to establish. Separate hydraulic units can be classified in terms of aquitards (low permeability, resistant to CO2 movement) or aquifers (relatively high permeability). In addition, the presence and nature of unconformities, depending on their specific properties, can act as a barrier (such as the thick clay formation above the reservoir at Weyburn), or can provide a preferred pathway.

The possibility of undetected features can be examined via alternative scenarios, where the resolution of the characterization techniques can be used to identify the largest feature (fault) that can be undetected.

Finally, geochemical data, in particular rock-water chemistries, feed into geochemical modeling of CO2 interactions. Closer to the surface, data on aquifer chemistry will help determine the potential for HS&E impacts as a result of CO2 leakage into drinking water sources.

Processes Affecting CO2 Movement

A range of processes and their individual properties will govern whether CO2 remains in its storage reservoir or is able to move away, possibly at a rate that can be hazardous. These processes can be subdivided conveniently into thermal, hydrogeological, mechanical, and chemical (abbreviated as THMC processes, which also encompass geothermal, geomechanical etc.), although this subdivision does not preclude coupling between/among processes. Again, in terms of RA and modeling predictions, the key processes are those that relate directly to the possible movement of CO2, either as a free phase or in solution.

RA-SC Relationship

RA modeling is an iterative process, providing feedback to the various sources of input information and data, for example, on gaps in data that need to be filled via additional SC work.

Importantly, documentation describing how individual FEPs are treated in the modeling, whether explicitly or implicitly, provides transparency in the RA process. Furthermore, the FEPs can be used to identify specific linkages between SC and RA.

CONCLUSIONS

RA relies heavily on SC input and, as such, should be used to guide exactly what information and data are collected during SC that are important to RA, as well as what information is irrelevant. Part of the RA process, the identification of FEPs, can be used to provide traceability and transparency by linking SC input to the modeling.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

SITE CHARACTERIZATION OF CCS: GEOMECHANICAL ASPECTS

Koji Yamamoto

Mizuho Information and Research Institute
3-1 Kanda Nishiki-cho
Chiyoda-ku, Tokyo 101-0054, Japan
e-mail: koji.yamamoto@gene.mizuho-ir.co.jp

INTRODUCTION

In the past decades, the petroleum industry has learnt that the reservoir response to hydrocarbon production and EOR jobs are dynamic process, and hydraulic characters of reservoirs change dramatically by the variation of pore pressure. Wellbore instability, productivity/injectivity change, non-linear response of fractured reservoirs, and surface subsidence are some examples of such dynamic characters.

In this paper, dynamic phenomena that may be caused by CO_2 injection and related geomechanical information are discussed for site characterization of CO_2 storage sites.

GEOMECHANICAL EFFECT ON THE CO_2 INJECTION AND STORAGE

Geomechanical parameters

Stress states (magnitudes and axes of three principal stresses), pore pressure, and elasticity and strength of formation rocks are the major parameters of geomechanics. Beside them, hydraulic characters such as permeability and porosity of the formation (rock matrix and fault/fracture) are important for CO_2 sequestration operation. Such hydraulic parameters are structure sensitive. For example, faults and fractures are dominant fluid path in many formations.

In the conventional reservoir mechanics model, a reservoir is assumed to be a rigid or elastic media, and hydraulic parameters of it are basically not or weakly affected by the pressure change. However, real geomaterials show complex and non-linear behavior by the pore pressure change, and such phenomena alter the hydraulic characters of the formation significantly.

It is important that such non-linear processes are irreversible. In the cases of CO_2 storage in EOR site or depleted hydrocarbon reservoirs, it is believed that fluid can be stored until the pressure reaches the original value, and the storable fluid volume is almost same as the produced hydrocarbon in in-situ condition. However, the non-linear and irreversible response of a reservoir rock can reduce the safety limit of the pressure, injectivity, and storage volume.

Failure modes and hydraulic characters

Three different modes of the rock failure lead to the following hydraulic character change. The relationship of stress condition and the failure modes is summarized in the Mohr diagram in Fig.1.

Tensile failure

Basically, when pore pressure exceeds the sum of minimum principal stress and tensile strength of rock, a fracture is created and propagates. In an industrial term, the borehole pressure that causes fluid loss from a well is called as “fracture gradient,” and this value represents the minimum principal stress in the most cases. Fracture creation makes new fluid path and increases the permeability significantly.

Shear failure

According to the Mohr-Coulomb failure criterion, shear failure of rocks happens when the difference between maximum and minimum principal stresses increases or effective stress is reduced due to the pore pressure increases.

A well-consolidated dense granular material shows a character of positive dilatancy, or porosity and permeability increase, with shear failure. On the other hand, the porosity and the permeability characters with the loading are opposite in loose porous materials. Also in fractured or faulted materials, shear motion between the discontinuous planes increases the permeability.

In a hard rock, the change is positive direction (increment of permeability). However, soft materials show more complicated processes. An example of strain curves under tri-axial loading on a carbonate rock is shown in Fig.2. In the figure, volumetric strain that is related to the permeability has three different regimes (elastic, negative dilatancy, and positive dilatancy) with loading condition.

In fractures and faults, pressure increment can cause shear motion in the discontinuous plane due to the reduction of friction between two surfaces, and the motion affect the permeability. In many hydrocarbon and geothermal fields, fault/fracture motions due to pressure change and subsequent hydraulic character change are observed through surface displacement, acoustic emission signals, and pressure measurement

(Ito and Zoback, 2000, Wiprut and Zoback, 2000). A natural CO_2 migration case inducing fault motion and earthquakes were observed (Miller et al. 2004).

When the stress state on the fracture/fault plane is close to the Mohr's failure envelope, the condition is called as "critically stressed," and small increment of the pore pressure easily change the permeability. The strength of rock mass is involved in the character of this permeability change.

Compressional failure

In underconsolidated loose sediments or rocks with high porosity and weak grains such as chalk and diatomite, the pressure drop and mean effective stress increment causes compaction of the material and reduction of porosity and permeability. Large-scale phenomena cause subsidence of surface above oil reservoirs (Settari, 2000). Also, local compaction around a borehole reduces injectivity of fluid from the well.

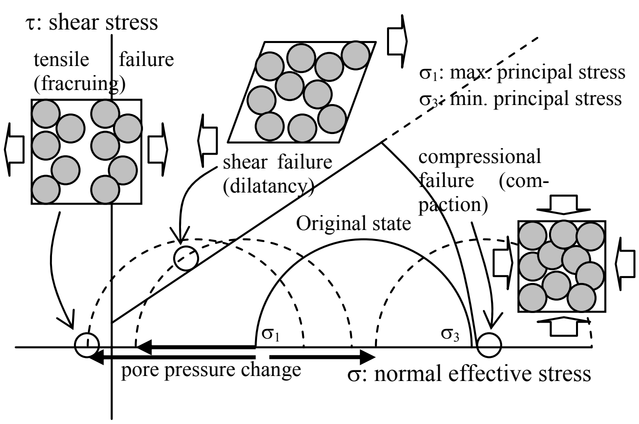


Figure 1. Stress states and failure mode.

DATA ACQUISITION AND MONITORING FOR GEOMECHANICS

Fault and fracture characterization

Information of large-scale discontinuity such as major faults can be found by seismic survey, but smaller features that are also important as fluid path should be investigated during drilling phase. Also, their hydraulic features should be characterized during injection.

The important features of such discontinuity are

A) Fracture system; dip angle and azimuth, and density of each fracture set, and connectivity between each set,
B) "Criticalness" of the discontinuity (relationship of fracture dip angle and azimuth, stress state and pore pressure),
C) Permeability in the original state,
D) Internal condition of the discontinuity such as existence of fault clay, and
E) Strength of rock mass, clay content, and chemical reactivity.

Hydraulic character change due to the shear motion is difficult to predict, but in many cases, it is reasonable to assume that shear motion increase the fault permeability due to the dilatancy.

To know such characters, the data of borehole image logs, small scale injection test, and pressure history analysis of injection operation are useful.

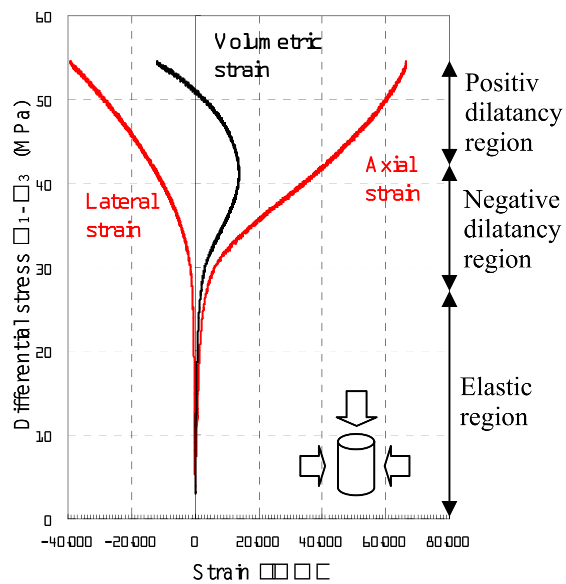


Figure 2. Strain and permeability curves during tri-axial loading on a carbonate rock. (*courtesy of JOGMEC-TRC*)

Stress states

We can know the fracture gradient (minimum principal stress) from the leak-off test record at each casing shoe, fluid loss data, and PWD (pressure while drilling) logs. More accurately, extended leaf-off test (ELOT, XLOT) or a mini-frac should be done in both reservoir and seal formations of the storage site.

Because no single method can give the whole of necessary information of the stress, other elements should be evaluated through the integrated approach of several scales from macroscopic geology, tectnostratigraphy and seismic activities, to the microscopic borehole loggings and core analyses.

Rock strength and failure behavior

It is difficult to obtain the mechanical character of the rock by geophysical methods, thus core testings are usually necessary. Tri-axial and compaction tests are the standard methods. Permeability measurement is during loading is preferable for our purposes. However, core can give the data of a single point, and difficult to assume that result represent the general condition throughout the reservoir.

Usually, porosity, density, mineralogy such as clay content and clay types, and elastic wave velocities (P and S waves) are important indexes for the characterization of rock mass.

Monitoring

Geomechanical condition change due to CO_2 injection is monitored through the following techniques:

Table 1. Data acquisition and monitoring items for Geomechanics in whole project

Planning phase	
Geological and tectno-stratigraphical information	Stress regime, max. horizontal stress orientation
Focal mechanism of seismic activities	Stress regime
Seismic survey	Reservoir structure and major faults
Drilling phase	
Fluid loss record, PWD	Min. Principal stress
Leak-off test, ELOT, mini-frac	Min. Principal stress
Density log	Vertical stress
Borehole imager tool	Stress axes, magnitude of anisotropy, faults, natural fractures
Dipole sonic tool	Elasticity, stress axes, magnitude of anisotropy
Core samples for strength measurement (tri-axial, compaction)	Strength and failure behavior
Core samples for stress measurement (ASR, DSCA, AE)	Stress axes and magnitude of anisotropy
Injection phase	
Pressure response to the injection	Dynamic response of reservoir
Acoustic emission	Rock failure, fault and fracture reactivation
Seismic survey	Fluid distribution in reservoir (heterogeneity)
Surface/subsurface deformation using tilt meter, GPS, SAR, radio active markers, etc.	Dynamic response of reservoir
Post-injection phase	
Fluid monitoring in surface/subsurface	Seepage path
Seismic survey	Fluid distribution in reservoir
Surface/subsurface deformation using tilt meter, GPS, SAR, etc.	Dynamic response of reservoir

Pressure analysis

Pressure analyses of the well test and CO_2 injection are the basic method to understand the hydraulic characters of the reservoir. Rapid change of such character suggests some nonlinear phenomena due to a geomechanical reason.

Acoustic emission

This technology is useful to understand the dynamic response of the reservoir. The technique gives the information of rock failure and shear motion of the fractures. Those signals are emitted at arbitrary timing of injection and post-injection periods, and then permanent type sensors should be valuable.

Deformations

Surface and subsurface deformation monitoring using tilt meter, radio active source, GPS, SAR (Synthetic Aperture Radar) is also useful. Some of these techniques give an opportunity of long term monitoring after the project finished.

The data acquisition and monitoring techniques are summarized in Table 1.

CONCLUSION

Characteristics of discontinuous structures (fractures and faults), stress states, and failure processes caused by pore pressure change have dominant role on the dynamic change of hydraulic parameters of reservoir and seal structures in a storage site. The failures of the formation cause the potential risk of injection difficulties and leakage. Irreversible behavior of the formation is important for EOR and depleted hydrocarbon reservoirs.

Because the mechanical characters of reservoirs are difficult to evaluate in advance of site selection, intensive data acquisition during whole process of a field development such as drilling, hydrocarbon production, and CO_2 injection are necessary, as well as analyses of the obtained information.

On the other hand the geomechanical information is often unintentionally taken during drilling and hydrocarbon production. Therefore, good record, reporting, and communication with the drilling and production engineers is a key of the safe and stable CO_2 storage.

ACKNOWLEDGEMENT

The author would like to acknowledge Prof. Koide of Waseda University and Prof. Matsuoka of Kyoto University for the valuable discussions.

REFERENCES

Ito, T. and Zoback, M.D., Fracture Permeability and In Situ Stress to 7 km Depth in the KTB Scientific Drillhole, *Geophys. Res. Lett.*, *27*, 1045-1048, 2000.

Miller, S.A., C. Colletini, L. Charaluce, M. Cocco, M. Barchi and B.J.P. Kaus, Aftershocks driven by a high-pressure CO_2 source at depth. *Nature*. 427, 724-727, 2004.

Settari, A., Reservoir Compaction, *JPT*, *54*(*8*), 62-69, 2002.

Wiprut, D. and M. D. Zoback, Fault reactivation and fluid flow along a previously dormant normal fault in the northern North Sea, *Geology*, *28*, 595-598, 2000.

SITE CHARACTERIZATION METHODS

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

ESTIMATION OF FIELD-SCALE RELATIVE PERMEABILITY FROM PRESSURE TRANSIENT TESTS

Sally M. Benson and Christine Doughty

Earth Sciences Division
Lawrence Berkeley Laboratory
Berkeley, California
e-mail: smbenson@lbl.gov

INTRODUCTION

Relative permeability curves are one of the most important factors controlling the migration of CO_2 in subsurface environments. Typically, relative permeability curves are determined in the laboratory from tests on small core samples. These relative permeability curves are then used in numerical simulators to predict how CO_2 behaves in the subsurface. How to upscale these measurements from the core scale to the reservoir scale is one of the major challenges facing accurate performance prediction. This paper explores the feasibility of using either analytical solutions or numerical simulation to estimate field-scale relative permeability functions for CO_2 – brine systems from reservoir scale pressure transient tests.

As part of the Frio Brine Pilot, downhole pressure transient measurements were obtained from both the injection well and observation well throughout the injection and recovery phases of the test (Hovorka et al., 2006). The test took place over 12 days, with 4 separate injection periods. The injection rate was about 2.5 l/s. Breakthrough of CO_2 at the observation well occurred approximately 51 hours after injection started. The pumping rate and pressure drawdown and buildup data are shown in Figures 1 and 2. Independent measurements of the intrinsic permeability were available from single phase pumping and injection tests. Thus, the pressure transients obtained during CO_2 injection to the brine formation are a sensitive indicator of relative permeability.

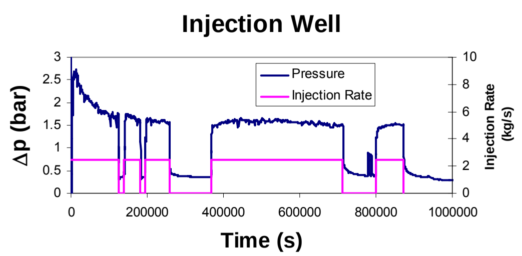


Figure 1. Injection rates and pressure buildup in the injection well.

ANALYTICAL APPROACH

The analytical approach used to interpret these data was based on the approach described by Benson (1984) and Benson et al., 1987. Fundamentally, as shown below, this approach formulates an approximate analytical solution for pressure transients by recognizing that the pressure buildup can be calculated as the sum of two terms, a steady state solution for the region inside of the moving CO_2 front and a transient solution outside the front.

$$\Delta p(r_w,t) = \Delta p_{s.s.}(r_w,t) + \Delta p_t(r_f,t)$$

$$\Delta p_{s.s.}(r_w,t) = \frac{q_{CO_2}}{2\pi kh} \int_{r_w}^{r_f} \frac{f_{CO_2}(r,t)}{\rho_{CO_2}(r,t)} \frac{\mu_{CO_2}(r,t)}{k_{r_{CO_2}}(r,t)} \frac{dr}{r}$$

$$\Delta p_t(r_f,t) = \frac{q_{CO_2}\mu_w}{4\pi kh\bar{\rho}_{CO_2}} Ei\left(\frac{r_f^2\phi\mu_w c_t}{4kt}\right)$$

For a simple system that neglects formation heterogeneity and gravitational override, the solution to this can be expressed as:

$$\Delta p_{s.s.}(r_w) = \frac{q_{CO_2}\bar{\mu}_{CO_2}}{2\pi\bar{\rho}_{CO_2}kh}\left[\ln\frac{r_f}{r_w} + \left(\left.\frac{f_{CO_2}}{k_{r_{CO_2}}}\right|_{r_f} - 1\right)\cdot\left(1 - \frac{r_w}{r_f - r_w}\ln\frac{r_f}{r_w}\right)\right]$$

$$\Delta p_t(r_f,t) = \frac{q_{CO_2}\mu_w}{4\pi\bar{\rho}_{CO_2}kh}\left[\ln\frac{kt}{\phi\mu_w c_t r_f^2} + .80907\right]$$

and $r_{s_{CO_2}} = \sqrt{\frac{Qt}{\pi\phi h}\left.\frac{\partial f_{CO_2}}{\partial s_{CO_2}}\right|_{s_{CO_2}}}$

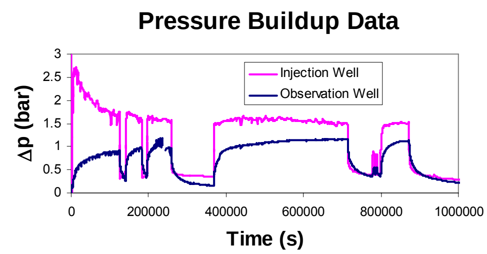


Figure 2. Comparison between the pressure buildup in the injection and observation wells.

To invert the pressure transient data for the purpose of estimating relative permeability curves the following procedure was used.

1. Estimate $\left.\frac{df_g}{ds_g}\right|_{s_{gf}}$ by the breakthrough time of CO_2 at the observation well, where $\left.\frac{df_g}{ds_g}\right|_{s_{gf}}$ is the derivative of the fractional gas flow curve at the CO_2 front.

2. Estimate $\left.\frac{f_g}{k_{rg}}\right|_{s_{gf}}$ by history matching the magnitude of the pressure buildup data, where $\left.\frac{f_g}{k_{rg}}\right|_{s_{gf}}$ is the ratio between the fractional flow of gas and the relative permeability to gas at the CO_2 front.

3. Knowing $\left.\frac{df_g}{ds_g}\right|_{s_{gf}}$ and $\left.\frac{f_g}{k_{rg}}\right|_{s_{gf}}$, it is then possible to determine s_{rg} if the relative permeability to gas is assumed to be of the form

$$k_{rg} = (1 - s^{*2})(1 - s^*)^2$$

where

$$s^* = \frac{s_l - s_{lr}}{1 - s_{lr} - s_{gr}}$$

Injection during the 10 day period resulted in primary drainage of brine from the pore space. Consequently, s_{gr} was assumed to be 0 for the purposes of this analysis. Therefore, the only remaining independent parameter is s_{rl}. Therefore, by history matching the pressure transient data, s_{rl} can be determined, and hence, the drainage relative permeability curves.

The match between the calculated and measured pressure for the observation well is shown in Figure 3. A similarly good match is obtained for the latter part of the injection well pressure data. However, the early time transients appear to be influenced by a high skin factor that decreased with time. The relative permeability to CO_2 obtained by using this procedure is shown in Figure 4.

Interestingly, this analysis suggests that the residual liquid saturation is about 0.6 to 0.7. This extremely high value is not consistent with the much lower values that would be expected for high permeability sediments such as the Frio Formation (~ 2 D).

The most likely explanation for the high values is that both heterogeneity and gravity have been neglected in this treatment of the solution. Both of these factors reduce the fraction of the reservoir swept by CO_2, thus creating the appearance of high residual liquid saturations. To confirm this explanation, numerical simulations of the test were conducted and compared to the results obtained using the analytical approach outlined above.

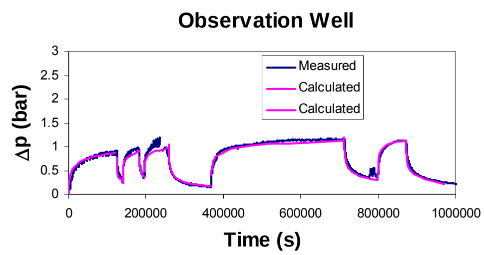


Figure 3. Match between the calculated and measured pressure buildup at the observation well.

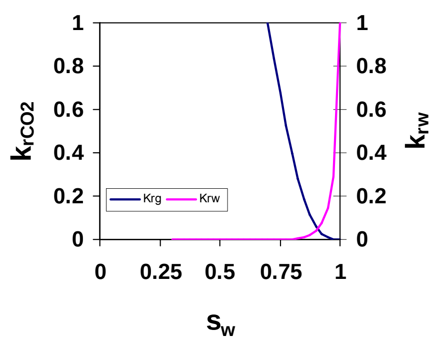


Figure 4. Relative permeability curves obtained from history matching the pressure transient data.

NUMERICAL ANALYSIS

One and two dimensional radial simulations of the injection test were carried out using the simulator TOUGH2. TOUGH2 accounts for the presence of multiple fluid phases, gravity driven flow, and dissolution of CO_2 in brine – all of which are likely to be important for this test. One dimensional radial simulations that neglected gravity and heterogeneity resulted in the same large values of residual liquid saturation that were obtained from the analytical approach described above. Two-dimensional radial simulations that included detailed stratigraphy (available from well logs) and gravitational forces were able to provide much for realistic values for the residual liquid saturation (0.2 to 0.3). The comparison between these numerical and analytical approaches confirm that heterogeneity and gravity both limit access of CO_2 to the reservoir, creating poor sweep efficiency. The poor sweep efficiency is manifested as a high residual liquid saturation in simple one dimensional analytical and numerical models.

CONCLUSIONS

Interpretation of pressure transient data provides important information regarding migration of CO_2 in the subsurface, and in particular, relative permeability curves. Interpretation however, is complex, being strongly influenced by the presence of heterogeneity and gravity override. This work suggests that if these factors are neglected, unexpectedly high values of residual liquid saturation will result. Moreover, it is likely that the larger the scale of the test, the larger this effect will be.

Pressure transient data can be interpreted using numerical simulators which include both the effects of gravity and heterogeneity. Using this approach, some information can be gained about relative permeability parameters. However, the large number of variables created when heterogeneity is introduced into the simulation render unique determination of relative permeability parameters difficult.

Clearly this is a situation where the well-known issues of up-scaling and mesh-refinement play an important role in the outcome of the analysis. This begs the question whether or not these field-scale relative permeability measurements can provide insight into effective approaches for up-scaling – and provide data sets to validate up-scaling approaches. The ability to simultaneously match pressure transients and multi-phase displacement data would be a good test of up-scaling approaches for relative permeability in heterogeneous environments with gravity override.

ACKNOWLEDGMENT

The authors would like to thank Sandia Technologies for collecting excellent pressure transient data, Susan Hovorka for leading the Frio Brine Pilot, and Larry Myer for coordinating LBNL's efforts. This work was part of the GEO-SEQ project supported by DOE's Office of Fossil Energy through the National Energy Technology Laboratory. Thanks are due to Charlie Byrer, Karen Cohen and Scott Klara for continued support of the GEO-SEQ program. This work was funded under DOE Contract No. DE-AC03-76SF00098.

REFERENCES

S.M. Benson (1984) "Analysis of Injection Tests in Liquid-Dominated Geothermal Reservoirs," *M. S. Thesis, University of California, Berkeley*; Report No. LBL-17953, Lawrence Berkeley National Laboratory, Berkeley, California.

S.M. Benson, J.S. Daggett, E. Iglesias, V. Arellano, and J. Ortiz-Ramirez (1987) "Analysis of Thermally Induced Permeability Enhancement in Geothermal Injection Wells," *Proceedings of the 12th Annual Workshop, Geothermal Reservoir Engineering*, January 20-22, 1987, Stanford, California; Report No. LBL-23022, Lawrence Berkeley National Laboratory, Berkeley, California.

Hovorka, S., et al., 2006. Measuring the Permanence of CO_2 Storage in Saline Formations: the Frio Experiment. *Environmental Geosciences*, V. 13, No. 2 (June 2006), pp 1-17.

IN-SITU BOREHOLE SEISMIC MONITORING OF INJECTED CO2 AT THE FRIO SITE

Thomas M. Daley and Valeri A. Korneev

Lawrence Berkeley National Laboratory, Earth Science Division
1 Cyclotron Rd,
Berkeley, Ca, 94720
e-mail: tmdaley@lbl.gov, vakorneev@lbl.gov

INTRODUCTION

The U.S. Dept. of Energy funded Frio Brine Pilot provided an opportunity to test borehole seismic monitoring techniques in a saline formation in south-east Texas. A relatively small amount of CO_2 was injected (about 1600 tons) into a thin injection interval (about 6 m thick at 1500 m depth). Designed tests included time-lapse vertical seismic profile (VSP) and crosswell surveys which investigated the detectability of CO_2 with surface-to-borehole and borehole-to-borehole measurement.

DATA ACQUISITION

Two time-lapse borehole geophysical surveys were acquired at the Frio site, a vertical seismic profile (VSP) and a crosswell seismic survey. A VSP uses surface sources with borehole sensors, while a crosswell survey uses borehole sources and sensors. Both surveys had baseline, pre-injection, data acquisition in July of 2004 and post injection data acquisition in late Nov., 2004 (approximately 1.5 months post injection). The VSP was intended to detect changes in seismic properties on the scale of 10's - 100's of meters around the injection well, while the crosswell survey was designed to detect changes between the injection and monitoring wells on the scale of 2 - 10 meters.

Both surveys used an 80-level, 3-component borehole geophone string with 7.6 m (25 ft.) spacing. The crosswell survey had 5 moves of the sensor string to acquire data at 1.5 m (5 ft.) spacing for both sensor and source. The crosswell source was an orbital vibrator (Daley and Cox, 2001) which generates both P- and S-waves, allowing imaging of compressional and shear properties, respectively. The VSP source was explosive shots at surface sites reoccupied after injection. Initial processing and analysis of the VSP data has provided measurement of seismic reflection amplitude changes on 3 azimuths, northwest, north and northeast of the injection well.

VSP AND CROSSWELL RESULTS

A large change in VSP reflection amplitude (about 70%) from the Frio zone was observed and the results were compared favorably with flow modeling predictions of saturation (Figure 1). The difference in VSP response for each azimuth of acquisition indicates subsurface heterogeneity affecting saturation.

The crosswell data provided very good P- and S-wave tomographic images. The time-lapse tomographic image mapped large changes in P-wave velocity (up to 30%), with well defined boundaries, due to the CO_2 plume (Figure 2). The S-wave tomogram shows no measurable change except at the injection well near the perforations.

The results of both VSP and crosswell demonstrate that CO2 injected in brine reservoirs can be spatially located with borehole seismic techniques. Estimates of CO2 saturation from the seismic response are difficult due to complex rock physics which require site dependent models usually obtained from laboratory core studies.

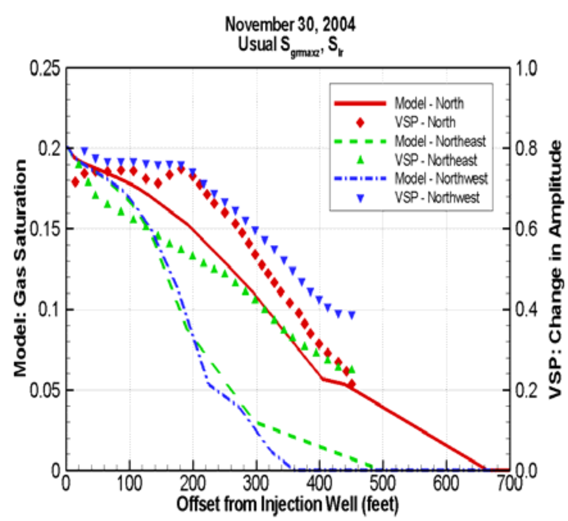


Figure 1. Change in VSP reflection amplitude (symbols), as a function of offset from injection well, for each of three azimuths, along with modeled gas saturation (lines)along the same azimuths. Gas saturation modeling courtesy of C. Doughty.

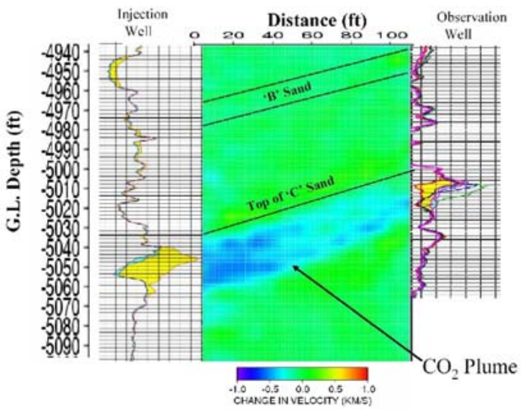


Figure 2. Crosswell tomogram showing the change in seismic velocity within the reservoir due to CO2 injection, along with pulsed neutron logs showing changes measured at the boreholes.

NEW MONITORING METHODOLOGIES

Having successfully applied VSP and crosswell imaging techniques, we investigated the data acquired at the Frio site for application of new methodologies. One promising potential application is the monitoring of acoustic signals for the purpose of characterizing out-of-casing fluid flow. While seismic sensors are deployed in the borehole, background 'noise' can be continuously monitored. Both recent and older studies suggest the possibility of multi-phase fluid flow detection using noise spectra in the 0-5 KHz range (McKinley, et al, 1972; Wang, et al., 1999). Although, noise studies were not initially planned for the Frio CO2 injection experiment we later included noise analysis as it potentially contained useful information.

Seismic noise in fluid-filled boreholes is primarily represented by vertically propagating tube waves. Tube waves have low attenuation and their velocities are usually below 1500 m/s. Tube wave velocities are sensitive to rock properties behind the casing and to the quality of casing contact with rock formation. Figure 3 shows noise amplitudes along the injection well at different frequencies for pre- and post-injection surveys. Notable changes are observed at 4950 ft and 5050 ft. The 4950 ft interval shows decreasing amplitude as frequency becomes higher, corresponding to a two-phase flow pattern. The amplitude distribution for the injection interval shows the highest peak at intermediate frequencies possibly indicating presence of both one-phase and two phase flows. This interpretation could be more conclusive if higher frequencies were recorded in the data (at least up to 2 KHz). Currently traces have frequencies up to 420 Hz. Analysis of acoustic 'noise' due to fluid flow could be a potential method of monitoring the bonding between casing and the formation. If proven robust, such measurements can give locations of weak zones behind casing. permanent emplacement of seismic sensors behind casing is a proposed method for obtaining continuous noise monitoring as well as time-lapse VSP and crosswell data.

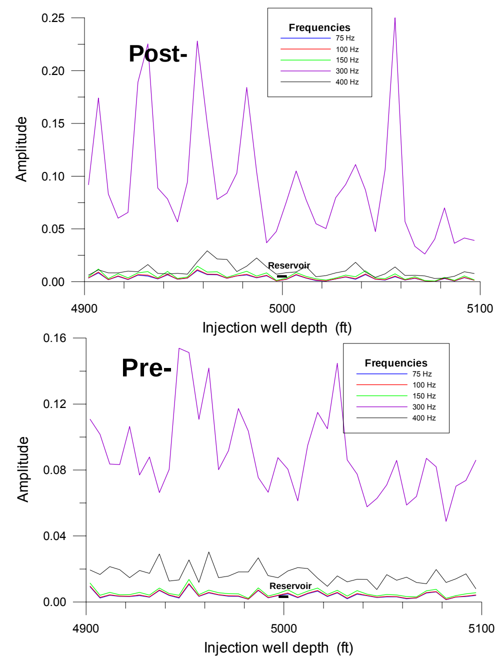


Figure 3. Noise amplitudes along the injection well at different frequencies for pre- (bottom panels) and post- (upper panels) injection surveys for 4900-5100 ft depth interval.

SUMMARY

Borehole seismic acquisition at the Frio site provided in-situ estimates of the spatial distribution of injected CO2, with high resolution between injection and monitoring wells (crosswell), and at larger distances, on different azimuths (VSP). These results demonstrate the applicability of seismic monitoring to CO2 storage in saline reservoirs.

Noise monitoring methodologies were investigated using the borehole emplaced seismic sensors. Intriguing results indicate that seismic sensors can be used to detect and monitor fluid flow in the near wellbore region.

The combined usefulness of active source surveys (VSP or crosswell) and acoustic monitoring point to the need for permanently emplaced seismic sensors to monitor CO2 sequestration.

REFERENCES

Daley, T.M. and Cox, D. *Orbital vibrator seismic source for simultaneous P- and S-wave crosswell acquisition*, Geophysics, 66, 1471-1480, 2001.

Wang, J, van der Spek, A. Georgi, D.T. and D. Chace, *Characterizing sound generated by multi-phase flow*, Society of Petroleum Engineers, Annual Meeting paper SPE 56794. 1999.

McKinley, R.M., Bower, F.M., and R.C. Rumble, *The structure and interpretation of noise from flow behind cemented casing*, Society of Petroleum Engineers, Annual Meeting paper SPE 3999, 1972.

ACKNOWLEDGMENT

This work was supported by the GEO-SEQ project, the National Energy Technology Laboratory, U.S. Department of Energy, under Contract No. DE-AC02-05CH11231. Thanks to Paulsson Geophysical for support of sensor deployment, Don Lippert and Rob Trautz for help with data acquisition, John Peterson for tomographic inversion and Chris Doughty for discussion and flow modeling.

SITE CHARACTERIZATION FOR CO_2 GEOLOGIC STORAGE AND VICE VERSA - THE FRIO BRINE PILOT AS A CASE STUDY

Christine Doughty

Earth Sciences Division
Lawrence Berkeley National Laboratory
Berkeley, California, USA 94720
e-mail: cadoughty@lbl.gov

INTRODUCTION

Careful site characterization is critical for successful geologic sequestration of CO_2, especially for sequestration in brine-bearing formations that have not been previously used for other purposes. Traditional site characterization techniques such as geophysical imaging, well logging, core analyses, interference well testing, and tracer testing are all valuable. However, the injection and monitoring of CO_2 itself provides a wealth of additional information. Rather than considering a rigid chronology in which CO_2 sequestration occurs only after site characterization is complete, we recommend that CO_2 injection and monitoring be an integral part of the site-characterization process.

The advantages of this approach are numerous. The obvious benefit of CO_2 injection is to provide information on multi-phase flow properties, which cannot be obtained from traditional site-characterization techniques that examine single-phase conditions. Additionally, the low density and viscosity of CO_2 compared to brine causes the two components to flow through the subsurface differently, potentially revealing distinct features of the geology. Finally, to understand sequestered CO_2 behavior in the subsurface, there is no substitute for studying the movement of CO_2 directly.

Making CO_2 injection part of site characterization has practical benefits as well. The infrastructure for surface handling of CO_2 (compression, heating, local storage) can be developed, the CO_2 injection process can be debugged, and monitoring techniques can be field-tested. Prior to actual sequestration, small amounts of CO_2 may be trucked in. Later, monitoring accompanying the actual sequestration operations may be used to continually refine and improve understanding of CO_2 behavior in the subsurface.

RECOMMENDED SITE CHARACTERIZATON ACTIVITIES

Site characterization must address two issues: the ability to put a large quantity of CO_2 into the subsurface, and the ability to keep it there for a long time. CO_2 injection requires adequate permeability, which can be assessed by well logs, core analyses, and single-well and interference pump tests. CO_2 storage requires adequate connected porosity, which can be assessed by core analyses and tracer tests. Immobilizing CO_2 in the subsurface for long-term geologic sequestration can be accomplished by four primary mechanisms: (1) *Structural trapping*: buoyant free-phase CO_2 is trapped beneath low-permeability layers or faults or in anticline structures. Knowledge of regional geology, geophysical imaging, and well logs provide this information. (2) *Mobility trapping*: multi-phase flow processes immobilize free-phase CO_2. Multi-phase flow behavior of CO_2 and brine provides the best direct information for mobility trapping, but in its absence information from oil/brine systems may be helpful. (3) *Dissolution trapping*: CO_2 dissolves in brine and is no longer buoyant. Brine composition, which may be obtained by collecting undisturbed fluid samples, is needed to quantify CO_2 dissolution. (4) *Mineral trapping*: CO_2 reacts with rock minerals to form carbonate compounds. Mineral compositions and distributions, which may be obtained from core samples, are needed to quantify CO_2/mineral chemical reactions.

Development and application of a numerical model concurrently with site characterization can be used for designing tests, predicting test outcomes to assess the current state of knowledge, and comparing model results to field observations to calibrate unknown parameters and to incorporate new features.

CASE STUDY - THE FRIO BRINE PILOT

At the Frio brine pilot, conducted at the South Liberty field near Houston, Texas, 1600 metric tons of CO_2 were injected over a period of 10 days into a steeply dipping sand layer at a depth of 1500 m. At this depth, free-phase CO_2 is supercritical. The sand layer is on the flank of a salt dome, and laterally compartmentalized by sub-vertical faults. The pilot employed one injection well and one observation well, each perforated over 6 m in the upper portion of the 23-m thick sand. The two wells are separated laterally by about 30 m, with the injection well downdip of the observation well (Hovorka et al., 2006). Historical oil production at depths around 2400 m provides structural information about the site. Site characterization activities for the Frio brine pilot are summarized in Table 1.

Table 1. Site characterization activities at the Frio brine pilot.

Activity	Monitoring	Information obtained
Review existing data related to historical oil production	3D seismic Wireline logs in regionally distributed wells	Structure of sand and shale layers surrounding salt dome Compartmentalization into fault blocks
Well log analysis	Wireline logs in injection and observation wells	Identify target sand layer and overlying shale caprock Extent, continuity, and variability of layers Using literature correlations, estimate permeability, porosity, relative permeability parameters
Core analysis from newly drilled injection well	Porosity Permeability Mercury intrusion	Calibrate well-log estimates of porosity Calibrate well-log estimates of permeability Capillary pressure/saturation relationship
Interference well test	Pressure transients	Confirm inter-well connectivity Flow properties of lateral boundaries Field-scale permeability Estimates of pressure increase during CO_2 injection
Aqueous-phase tracer test	Fluorescein break-through curve (BTC)	Single-phase dispersivity Porosity-thickness product of sand layer
CO_2 injection	Pressure transients CO_2 arrival at observation well RST (reservoir simulation tool) Cross-well seismic VSP (vertical seismic profile)	Two-phase flow properties Average CO_2 saturation between wells CO_2 saturation profiles at injection and observation wells CO_2 distribution between injection and observation wells CO_2 distribution updip of observation well
Two-phase tracer test (concurrent with CO_2 injection)	Two-phase tracer BTC	Two-phase dispersivity Evolution of CO_2 saturation distribution with time

Numerical modeling was used to help determine parameters of the CO_2 injection, and to design the site-characterization well test and tracer test (Doughty, 2005). As field work proceeded, model results were compared to field data, and the model was modified to incorporate new information.

Figure 1 illustrates single-phase site-characterization activities, specifically, an interference well test and a doublet tracer test (Trautz et al., 2005). The well test confirms core-scale permeability measurements on the order of 2 Darcies, and modeling suggests that a small fault within the main fault block should not be considered a closed boundary. The maximum pressure increases seen in the injection and observation wells may be used for equipment design and to ensure regulatory compliance during CO_2 injection. Matching the tracer test with a streamline model produces a small single-phase dispersivity and a large porosity-thickness product, implying that the sand is highly homogeneous and that the effective sand thickness between the injection and observation wells is greater than the 5.5 m inferred from well logs.

Figure 2 shows a time series of RST logs at the injection and observation wells, along with the corresponding model results for CO_2 saturation. The wireline reservoir saturation tool (RST) uses pulsed neutron capture to determine changing brine saturation as brine is displaced by CO_2 (Sakurai et al., 2005). The magnitude of CO_2 saturation provides constraints on two-phase flow properties, whereas the depth at which CO_2 appears provides valuable insights into geology. At the injection well, CO_2 extends below the perforated interval, suggesting that a thin marker bed located just below the perforations does not have nearly as low a permeability as inferred from well logs. In the observation well, CO_2 arrives almost 1 m shallower than predicted by the model, suggesting that a low-permeability layer identified just above the perforations in both wells may not be continuous. These findings are consistent with the large sand-layer thickness inferred from the single-phase tracer test, but only the CO_2 injection provides specific information about how this greater thickness arises.

Figure 3 compares vertical seismic profile (VSP) results for the far-field CO_2 distribution two months after CO_2 injection with model results. The change in amplitude of the seismic response is plotted as a function of offset from the injection well, along three azimuthal angles (Daley et al., 2005). We do not have a quantitative relationship between VSP change in amplitude and CO_2 saturation, so the vertical axes of the plot are adjusted to align these two quantities close to the injection well. Figure 3 shows good agreement between model and VSP in the updip direction (N), but the VSP indicates that the plume has moved farther than the model predicts to the NE and NW. In fact, the plume has moved as far to the NW as it has to the N, suggesting that either our notion of the true dip direction is inaccurate, or that there is significant heterogeneity or anisotropy in the permeability distribution beyond the immediate vicinity of the wells.

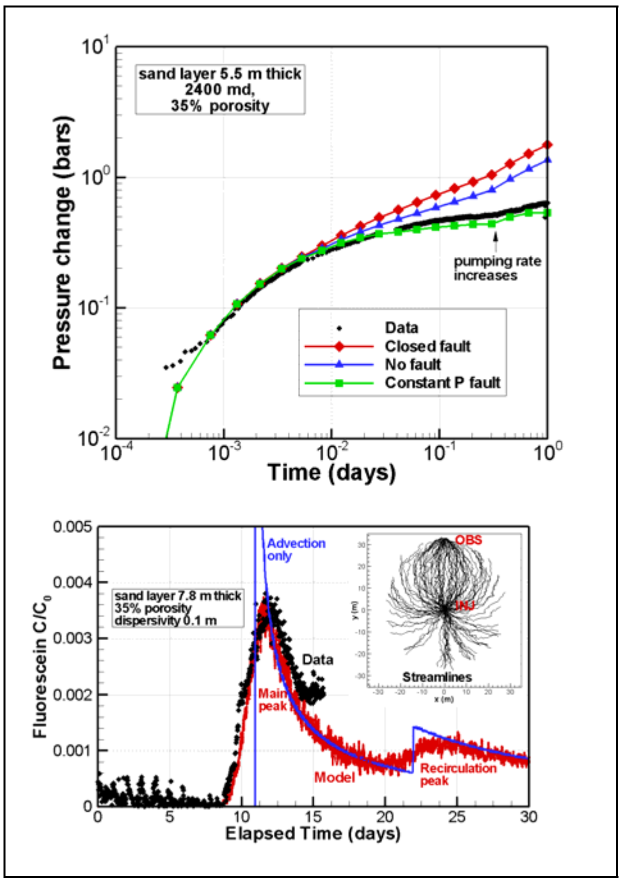


Figure 1. Top frame: Observation-well pressure transient during interference well test and model results considering three different boundary conditions for a small fault near the wells. Bottom frame: Tracer test data and results of a streamline model.

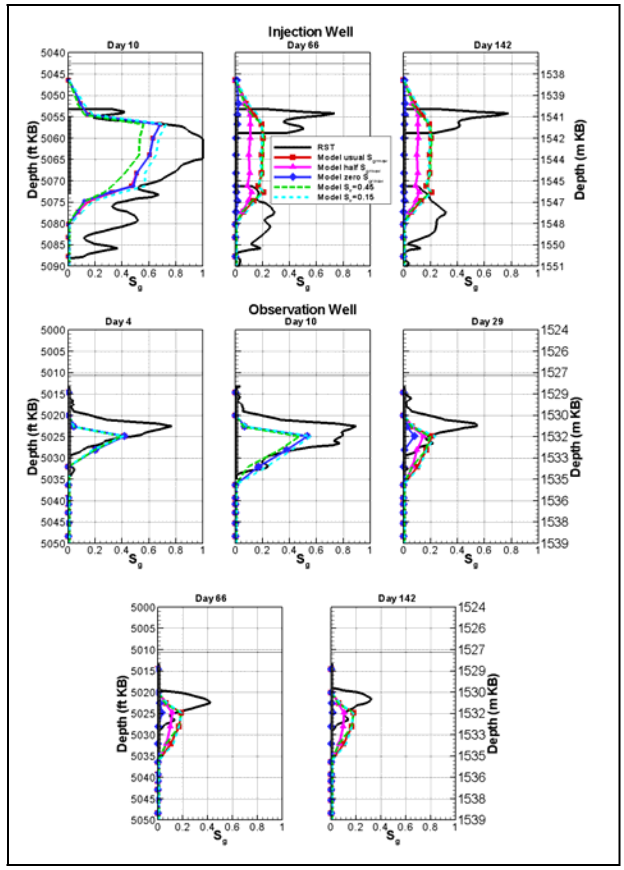


Figure 2. CO_2 saturation profiles inferred from RST logs in the injection well (top row) and in the observation well (bottom two rows). The injection period is days 0-10. Late-time profiles in both wells are less quantitative, due to well workovers conducted following the end of the injection period. Model results considering different two-phase flow parameters are also shown.

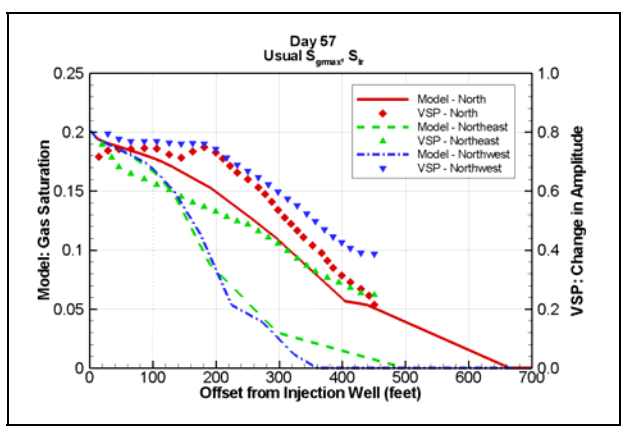


Figure 3. Comparison of VSP and model results for far-field CO_2 distribution.

ACKNOWLEDGMENT

Data provided by and stimulating discussions with members of the Frio brine pilot team are gratefully acknowledged, as is the review of this abstract by Curt Oldenburg. This work was supported by the Assistant Secretary for Fossil Energy, Office of Coal and Power Systems, through the National Energy Technology Laboratory, of the U.S. Department of Energy under Contract No. DE-AC02-05CH1123.

REFERENCES

Daley, T.M., L.R. Myer, E.L. Majer, J.E. Peterson, 2005, Acquisition of time-lapse, 6-component, P- and S-wave, crosswell seismic survey with orbital vibrator and of time-lapse VSP for CO_2 injection monitoring, presented at 75th annual International Meeting of the Society of Exploration Geophysicists, Houston TX, Nov. 2005.

Doughty, C., Flow modeling for CO2 sequestration: The Frio brine pilot, presented at AGU Fall Meeting, San Francisco, CA, December, 2005.

Hovorka, S.D. S.M. Benson, C. Doughty, B.M. Freifeld, S. Sakurai, T.M. Daley, Y.K. Kharaka, M.H. Holtz, R.C. Trautz, H.S. Nance, L.R. Meyer, K.K. Knauss, Measuring permanence of CO_2 storage in saline formations – The Frio experiment, *Environmental Geosciences*, in press, 2006.

Sakurai, S., T.S. Ramakrishnan, A. Boyd, N. Mueller, and S.D. Hovorka, Monitoring saturation changes of CO_2 sequestration: Petrophysical support of the Frio brine pilot experiment, presented at Society of Petrophysicists and Well Log Engineers 46th Annual Logging Symposium, New Orleans, LA, 2005.

Trautz, R.C., B.M. Freifeld, and C. Doughty, Comparison of single and multiphase tracer tests results from the Frio CO_2 pilot study, Dayton Texas, presented at National Environmental Technology Laboratory Fourth Annual Conference on Carbon Capture and Sequestration, Alexandria, VA, May 2-5, 2005.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

DETECTING FAULTS IN THE CAPROCK USING SEISMIC IMAGING

Lianjie Huang and Michael Fehler

Los Alamos National Laboratory
Geophysics Group, Mail Stop D443
Los Alamos, NM 87545, USA
e-mail: ljh@lanl.gov, fehler@lanl.gov

SUMMARY

Evaluation of the integrity of the caprock is important for selecting sites for safe geological carbon sequestration. We investigate the capability of seismic migration imaging for detecting faults in the caprock. Synthetic surface-reflection datasets used for this study were generated using a finite-difference wave-equation scheme for a complex model that contains three faults with different steep angles. We conduct wave-equation migrations of the datasets using different velocity models to study the effects of velocity inaccuracy on detecting faults. The imaging results show that the faults can be clearly imaged if they are illuminated and the velocity model is reasonably accurate. We demonstrate that relatively high-frequency data are needed to obtain high-resolution images of faults. Seismic migration imaging using surface reflection data has the potential to detect faults in the caprock over a large area.

INTRODUCTION

To ensure safe geological carbon sequestration, it is necessary to characterize the integrity of the caprock over very large areas (Tang et al., 2001). Faults are known to act as seals separating distinct geological units and to provide conduits with high permeability. However, faults can become activated and leak when pore pressure is elevated (Wiprut and Zoback, 2000, 2002). The leakage of CO_2 from the injection zone through faults in the caprock could make geological carbon sequestration unsafe. Depleted oil reservoirs are likely to be the first category of geologic formation where CO_2 is injected for sequestration on a large scale, if geologic sequestration proves feasible (Koscek, 2002). However, most depleted oil/gas reservoirs were poorly imaged because of limited imaging capability decades ago. During the last decade or so, significant advances have been made in developing improved seismic migration imaging methods. Advanced seismic migration imaging using surface reflection data has the potential to detect faults in the caprock and evaluate the integrity of the caprock.

The impedance contrasts across a fault can be weak and the structures of the caprock can be complex, which present great challenges for seismic migration to obtain high-resolution images of faults. Wave-equation migration can generally handle complex structures better than ray-based Kirchhoff migration (Fehler and Huang, 2002). The method has been successfully used for imaging complex structures beneath salt bodies (Huang et al., 2005). The image resolution of wave-equation migration could also be higher than that of ray-based Kirchhoff migration (Fehler et al., 2005). In this paper, we investigate the capability of wave-equation migration for detecting faults in the caprock.

We conducted migrations of synthetic datasets for a complex model containing three faults with different steep angles using a wave-equation migration scheme (Huang and Fehler, 2000; Huang et al., 2005). We first used exploding-reflector datasets to avoid the illumination effects on migration. We investigated the effects of frequency and velocity on the capability for detecting faults. Finally, we compared the migration image obtained from an exploding-reflector dataset with that obtained from a common-shot dataset, showing that limited illuminated apertures could reduce the capability of migration imaging for detecting faults.

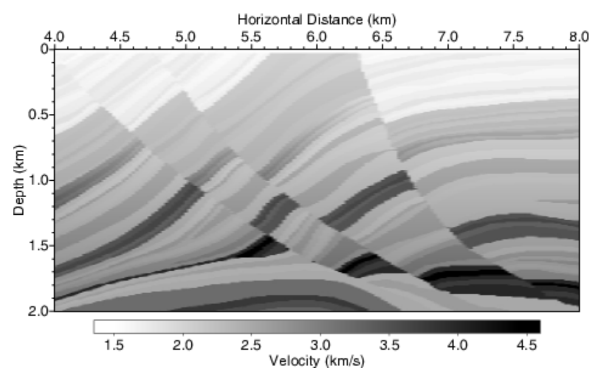


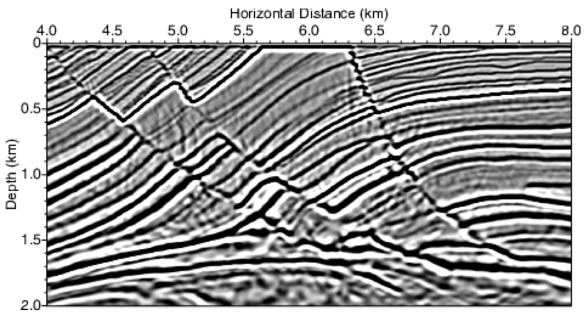
Figure 1. Marmousi model containing three faults with different steep angles.

IMAGING FAULTS USING WAVE-EQUATION MIGRATION

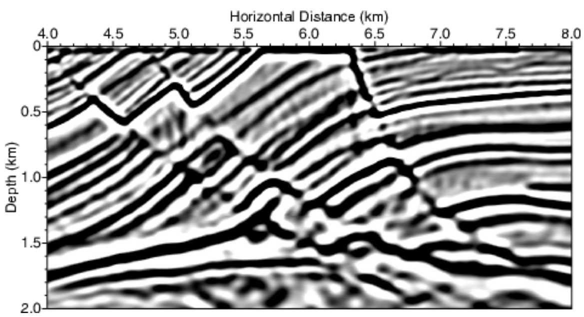
We generated exploding-reflector datasets for a complex model using a finite-difference wave-equation scheme. We investigated the capability of wave-equation migration to detect faults in a complex Marmousi model that contains three faults with different steep angles (Figure 1). The structure of the model is complex, and the faults break through many layers. The impedance contrasts are high in some sections of the faults, but low in some other sections. We generated two exploding-reflector datasets with central frequencies of 15Hz and 30Hz and recorded data on the surface of the model. We used the globally optimized Fourier finite-difference method to migrate the datasets (Huang and Fehler, 2000).

Migrations of Exploding-Reflector Datasets

Figure 2 shows migration images of exploding-reflector datasets with different central frequencies. The model was defined on a grid with a grid spacing of 4 m. The images of the faults in (a) are better defined than those in (b), demonstrating that high-frequency surface reflection data may be needed for imaging faults.



(a) The central frequency of the dataset is 30Hz.



(b) The central frequency of the dataset is 15Hz.

Figure 2. Migration images of exploding-reflector datasets, clearly showing high-resolution images of the three faults in (a), but a reduced resolution in (b).

Migration with Inaccurate Velocity Models

Velocity analysis may not be able to produce an accurate velocity model for migration imaging. We conducted migrations of the exploding-reflector dataset with a central frequency of 30 Hz using different velocity models that are either higher or lower than the correct velocities. Figure 3 is an image obtained using a velocity model in which velocities are 10 percent higher than the correct values. It shows that the faults are not well imaged, making it difficult to identify the faults. We found that when the velocities are within 5 percent of the correct values, the faults can still be reasonably well imaged.

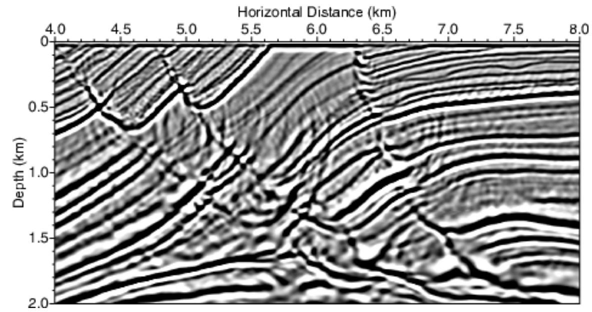


Figure 3. Migration image of an exploding-reflector dataset using a velocity model that is 10 percent higher than the correct one, showing that the images of the faults are significantly deteriorated.

Migration of a Common-Shot Dataset

Next, we migrated a synthetic common-shot surface-reflection dataset. The dataset contains 240 common-shot gathers with a shot spacing of 25 m and a receiver spacing of 25 m. The minimum and maximum receiver offsets are 200 m and 2575 m, respectively. The model used was defined on a grid with a horizontal grid spacing of 25 m and a vertical grid spacing of 4 m. Figure 4 is the wave-equation migration image, demonstrating that some portions of the faults cannot be imaged due to limited illumination apertures.

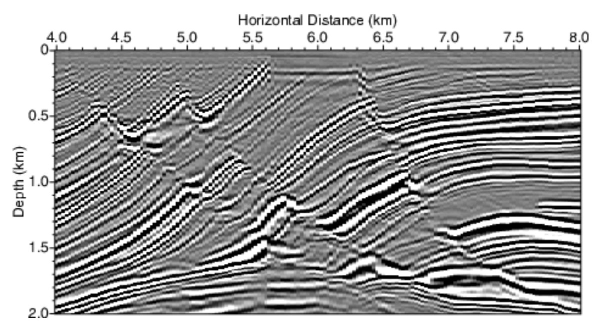


Figure 4. Prestack migration image of a synthetic common-shot dataset. Some portions of images of the faults cannot be imaged as clearly as those in Figure 1.

CONCLUSIONS

We have demonstrated that wave-equation migration can accurately image faults in the caprock. Relatively high-frequency data are needed to obtain high-resolution images of faults. Large errors in velocity analysis could lead to inaccurate images of faults. To obtain high-quality images of faults, receivers must be distributed over a relatively long range so as to be able to record signals reflected from steep faults.

ACKNOWLEDGMENT

This work was supported by the U.S. Department of Energy through contract W-7405-ENG-36 to Los Alamos National Laboratory.

REFERENCES

Fehler, M. C. and L. Huang, Modern imaging using seismic reflection data, *Annu. Rev. Earth Planet. Sci*., 30, 259-284, 2002.

Fehler, M. C., L. Huang, R.-S. Wu, and X.-B. Xie, *Seismic imaging resolution: Numerical investigation of role of migration imaging operator*, in Expanded Abstracts, 75th Annual International SEG Meeting, 1870-1873, 2005.

Kovscek, A. R., Screening criteria for CO_2 storage in oil reservoirs, *Petroleum Science and Technology*, 20, 841-866, 2002.

Huang, L. and M. C. Fehler, *Globally optimized Fourier finite-difference migration method*, in Expanded Abstracts, 70th Annual International SEG Meeting, 802-805, 2000.

Huang, L., M. C. Fehler, Z. Li, and P. Schultz, *3D common-shot depth imaging with an optimized Fourier finite-difference scheme*, in Expanded Abstracts, 75th Annual International SEG Meeting, 1854-1857, 2005.

Tang, C-F., S. M. Benson, B. Kobelski, and R. Smith, *Scientific considerations related to regulation development for CO_2 sequestration in brine formations*, in Proceedings of the First National Conference on Carbon Sequestration, 2001.

Wiprut, D. and M. Zoback, Fault reactivation and fluid flow along a previously dormant normal fault in the northern North Sea, *Geology*, 28, 595-598, 2000.

Wiprut, D. and M. Zoback, Fault reactivation, leakage potential, and hydrocarbon column heights in the northern North Sea, in *Hydrocarbon Seal Quantification*, Koestler, A. G. and R. Hunsdale, Eds., Elseveir, 2002.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

NEW APPROACHES FOR TRANSIENT TESTING AND LONG-TERM PRESSURE MONITORING OF LOW-PERMEABILITY CAPROCKS

Srikanta Mishra[1], John F. Pickens[1], and Jacques Delay[2]

[1]INTERA Inc.
9111A Research Blvd
Austin, Texas, 78758, USA
e-mail: smishra@intera.com; jpickens@intera.com

[2]ANDRA
Route Departmental 960
55290 Bure, France
e-mail: jacques.delay@andra.fr

INTRODUCTION

Sequestration of anthropogenic CO_2 in deep saline aquifers is one of the many strategies under consideration for stabilization of greenhouse gas emissions. Such a strategy would involve the injection of supercritical CO_2 into porous and permeable formations. Under ideal conditions, the injected supercritical CO_2 would displace pore fluids and permanently remain trapped by a low-permeability caprock overlying the disposal horizon. It thus becomes necessary to determine the sealing potential and related hydrologic characteristics of the caprock as part of site characterization studies at potential CO_2 sequestration sites.

The well hydraulics of coupled formations – where crossflow occurs between a primary aquifer (or reservoir) and a secondary unit – have been extensively studied in groundwater hydrology (e.g., Hantush, 1964) and petroleum engineering (e.g., Streltsova, 1988). The emphasis in such studies has been on the determination of the leakage potential of the secondary unit. Witherspoon et al. (1967) studied the related problem of gas storage in aquifers and developed a variety of approaches for characterizing caprocks under conditions of both large and small leakage. Moench (1985) developed solutions for transient flow to finite diameter wells in aquifers with semi-confining storative layers and concluded that wellbore storage effects may completely mask the effects of leakage from over/underlying formations.

In this paper, we revisit the leaky aquifer problem from two main perspectives. First, we explore solutions with a constant pressure inner boundary condition (i.e., flow to a constant drawdown well). The motivation here is to avoid wellbore storage effects that come into play under constant rate flow testing as noted by Moench (1985). Second, we restrict our solution space to caprocks with permeabilities significantly lower than the aquifer – as would be expected in candidates for geologic sequestration. This is similar to some of the cases considered by Witherspoon et al. (1967) for aquifer gas storage. The other issue discussed in this paper is the experience from the field of nuclear waste disposal with the use of wireless telemetry based long-term pressure monitoring devices in low-permeability formations.

CONSTANT DRAWDOWN TESTING

Following Hantush (1964), we study the case of flow to a permeable aquifer overlain by a low-permeability semi-confining layer (caprock). Flow in the aquifer is assumed to be strictly radial toward the well, whereas flow in the overlying caprock is assumed to be strictly vertical toward the aquifer. The bottom of the aquifer is assumed to be a no-flow boundary, as is the top of the caprock. A well fully penetrates the aquifer and produces under constant drawdown conditions. The usual assumptions of homogeneous and isotropic properties, uniform initial conditions, infinite lateral extent, etc., are assumed to be valid. The equations governing pressure diffusion through the aquifer and caprock have been presented in detail by Hantush (1964) and will not be repeated here for reasons of brevity. The problem is solved using the method of Laplace transformation as follows:

$$\bar{s}(r,p) = s_w \left\{ \frac{K_0(\lambda r)}{pK_o(\lambda r_w)} \right\} \tag{1}$$

where $\bar{s}$ denotes the Laplace transformation of the drawdown at any radial distance r ; p is the Laplace space variable ; K_o is the Bessel function of second kind and order zero, s_w is the constant drawdown imposed at the well with radius r_w ; and λ is a term representing the degree of hydraulic interaction between the aquifer and the caprock,

$$\lambda^2 = \frac{p}{\eta} + \left(\frac{K'}{Kbb'} \right) \left\{ b' \sqrt{\frac{p}{\eta'}} \tanh\left(b' \sqrt{\frac{p}{\eta'}} \right) \right\} \tag{2}$$

Here η = (K/S_s) is the hydraulic diffusivity of the aquifer with K the hydraulic conductivity and S_s the specific storage, b is the thickness of the aquifer; and the primed superscripts denote the corresponding quantities for the caprock. The flow rate to the well in Laplace space is given by:

$$\overline{q}(r_w,p) = -2\pi Kb\left(r\frac{\partial\overline{s}}{\partial r}\right)_{r_w} = 2\pi Kbs_w\left\{\frac{\lambda r_w\,K_1(\lambda r_w)}{pK_o(\lambda r_w)}\right\} \quad (3)$$

where K_1 is the Bessel function of the second kind of order one. Finally, the Laplace transformed drawdown in the caprock, $\overline{s}_1$, is given by:

$$\overline{s}_1(z,r,p) = \overline{s}(r,p)\left\{Sinh\left((b'-z)\sqrt{\frac{p}{\eta'}}\right)\right\}\Big/\left\{Sinh\left(b'\sqrt{\frac{p}{\eta'}}\right)\right\} \quad (4)$$

where z is the upward vertical distance from the aquifer-caprock interface. Although these solutions can be found in Hantush (1964), an examination of the aquifer and caprock responses under constant drawdown flow conditions (and their corresponding interpretive equations) do not appear to have been discussed in the literature. These analyses are presented next.

Eq. (1)-(4) have been numerically inverted using the Stehfest algorithm for the following parameters: $K = 10^{-5}$ m/s, $K' = 10^{-10}$ m/s, $S_s = 10^{-6}$ 1/m, $S_s' = 10^{-7}$ 1/m, $b = 100$ m, $b' = 10$ m, $s_w = 7$ m, and $r_w = 0.1$ m. In the aquifer, drawdown responses are evaluated at r = 5, 50 and 250 m; and in the caprock, drawdown responses are evaluated at the same radial distances for $z = 5$ m.

Figure 1(a) shows a log-log graph of the aquifer drawdown history at the 3 radial locations of interest. As expected, the drawdown curves show a Theis-type behavior with little or no pressure support from vertical leakage because of the low-permeability of the caprock. Also shown therein is the temporal evolution in the well flow rate, which exhibits the typical Jacob-Lohman type response.

For a confined aquifer under constant drawdown well flow conditions, Mishra and Guyonnet (1992) have shown that if the drawdown in the aquifer at any given time is divided by the well flow rate at that time, the normalized quantity plots as a straight-line versus the logarithm of time, with the slope being inversely proportional to transmissivity. Following the same logic, rate-normalized drawdown data extracted from Figure 1(a) at t = 0.1 d, 1 d, 10 d and 100 d for r = 5 m, 50 m and 250 m are plotted against scaled time (t/r^2) in Figure 1(b). The resulting semi-log straight line has a slope that is less than 2% different from the value calculated using the input transmissivity value. Thus, the rate-normalized drawdown analysis, i.e., a generalized Cooper-Jacob analysis, can also be considered a useful tool for the determination of aquifer transmissivity in aquifers with a low-permeability caprock.

The drawdown response in the caprock, shown in Figure 2(a), does not reveal any distinct features other than the expected pressure attenuation at early times and pressure equilibration with the aquifer at late times. More insight is obtained by plotting the ratio of the caprock and aquifer drawdowns, at the same radial location and at the same time. Figure 2(b) shows this normalized plot for r = 50 m, which exhibits a strong diffusional S-shape characteristic. As suggested by Eq. (4), the caprock is actively responding to transients in the aquifer in the form of 1-D pressure diffusion. Figure 2(b) contains normalized caprock drawdown responses generated using 3 different values of diffusivity. It appears that a nonlinear parameter estimation approach to matching caprock drawdown data to Eq. (4) would produce an estimate of the caprock diffusivity. An independent knowledge of the caprock specific storage would however be required to evaluate the vertical permeability for the caprock.

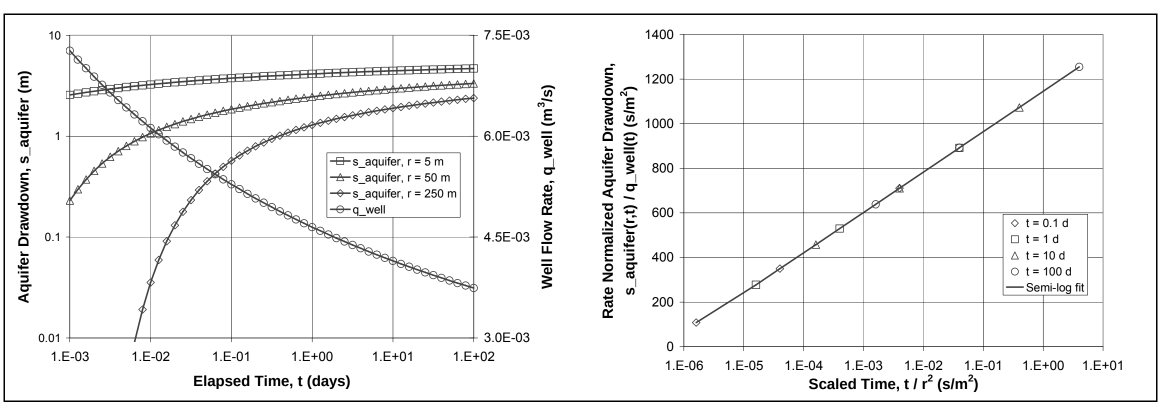


Figure 1. Time history of aquifer drawdown and well flow rate (a, left panel), and rate-normalized drawdown versus scaled time (b, right panel).

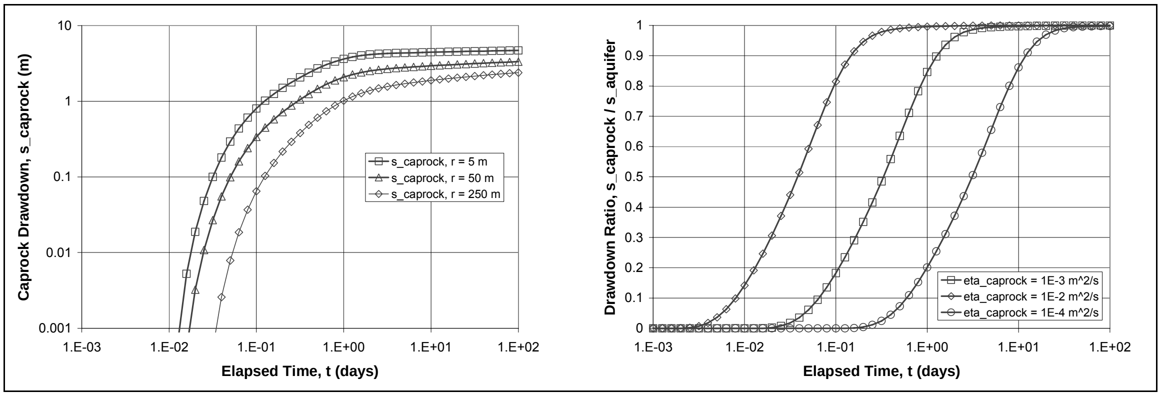


Figure 2 Time history of caprock drawdown (a, left panel), and diffusional nature of ratio of caprock to aquifer drawdown at r = 50 m (b, right panel).

LONG-TERM PRESSURE MONITORING

Accurate measurement of subsurface pressures is an important consideration in the characterization of potential nuclear waste repository sites, and for that matter, any geologic disposal site. Typical problems linked to long-term measurements include: long test durations necessitated by the low-permeability of the host rock, preserving test zone isolation (cables or tubes connected to ground can cause potential leaks), and ensuring that the sensor will not fail or drift during the measurement period. To this end, the French national radioactive waste disposal agency, ANDRA, has developed and implemented the Electromagnetic Pressure Gauge (EPG) concept (Andra, 2003). The EPG tool is installed permanently below a grout-inflated packer and borehole cement plug. Data are transmitted from the EPG using wireless electromagnetic (EM) transmission, avoiding the use of cables. Wireless EM has been used in the oil industry for many years.

Figure 3 shows a typical well completion plan for EPG placement in the ANDRA program. The overall EPG setup includes a battery powered surface transceiver linked to satellite transmission with the permanent gauge buried at ~440 m in the potential repository horizon. Electromagnetic transmission allows a wireless bidirectional link between the downhole gauge and the surface transceiver. Low frequency waves propagate first from the gauge to the bottom of the casing using the formation as a transmission medium then to the surface using the casing as a long transmission guide.

The EPG consists of a pressure quartz sensor with reliability proven in oil field applications, timer for power consumption optimization, bidirectional EM transmitter allowing 4 data rates (5 per hour, 1 per hour, 1 per day, 1 per week), and two lithium batteries with high energetic densities and low self-discharge characteristics.

In the ANDRA program, the EPGs have proven to be very successful in monitoring to determine undisturbed formation pressures in very low permeability environments (~K = 10^{-13} m/s). They hold promise for monitoring pressures within low-permeability caprocks during pre-injection testing as well as during the injection period in CO2 sequestration projects.

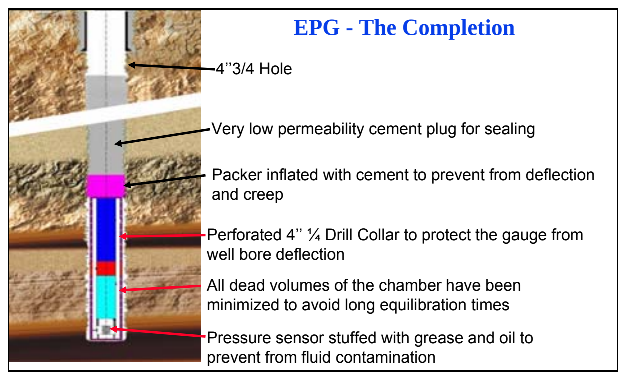


Figure 3. Typical well completion plan for EPG placement.

CONCLUSIONS

- Constant drawdown aquifer testing is a useful strategy for characterizing both aquifers and their overlying low-permeability caprocks.
- Rate-normalized drawdown analysis can be utilized for graphical determination of aquifer transmissivity.
- Nonlinear regression analysis on caprock drawdown data can be used for determining caprock diffusivity.
- The EPG tool, based on wireless telemetry, is a promising tool for pressure monitoring of low-permeability caprocks.

REFERENCES

ANDRA, *Mesures de pression dans les argillites du Callavo-Oxfordien : synthese des resultats obtenus dans le forage EST 107 et EST 103*, Agence nationale pour la gestion des decherts radioactifs, Bure, France, 2003.

Hantush, M.S., Hydraulics of wells, in *Advances in Hydroscience*, vol. 1, V.T. Chow (Ed.), pp. 281-432, Academic Press, New York, 1964.

Mishra, S. and D. Guyonnet, Analysis of observation-well response during constant-head testing, *Ground Water*, 30(3), 345-350, 1992.

Moench, A.F., Transient flow to a large-diameter well in an aquifer with storative semi-confining layers, *Water Resources Research*, 21(8), 1121-1131, 1985.

Streltsova, T.D., *Well Testing in Heterogeneous Formations*, 413 pp, John Wiley and Sons, New York, 1988.

Witherspoon, P.A., I. Javandel, S.P. Neuman and R.A. Freeze, , *Interpretation of Aquifer Gas Storage Conditions from Water Pumping Tests*, Monograph for Project NS-38, 235 pp, American Gas Association, New York, 1967.

CO2 INJECTION TO ROCK SPECIMENS AND ITS RESISTIVITY MEASUREMENTS

K. Onishi, Y. Ishikawa, Y. Yamada, and T. Matsuoka

Kyoto University
Yoshida-Honmachi, Sakyo-ku
Kyoto, 606-8501, Japan
e-mail: onishi@kumst.kyoto-u.ac.jp

INTRODUCTION

It is desired to develop the technique halting global warming by reducing CO_2 emission, which is considered the main cause for the global warming. The CO_2 is easy to be retrieved in industrial plants, such as a thermal power plant, and CO_2 sequestration technologies have a high degree of expectation to realize the technique reducing CO_2 emissions. The technique injecting gas into the ground can be diverted from the technique of EOR, which has been established yet, and it means that the geological sequestration has a high possibility to realization.

The method of CO_2 sequestration is considered the way to inject into production wells in EOR, isolate into old oil fields, and store into aquifer. This study aims to develop the method monitoring the retention stability of CO_2 in aquifer.

The confirmation of long-term stability is essential to realize the CO_2 sequestration into aquifer. The test injecting CO_2 into rock cores obtained from injection wells is effective to surely clarify the behavior of CO_2 injected into aquifer. Also, it is important to know basic data such as the level of physicality change due to the displacement of pore liquid from formation water to CO_2 for the development of the method monitoring underground structures after the injection of CO_2. The CO_2 injection test using local rock cores is effective for the latter case, too.

We experiment to observe the phenomenon of a rock core injected with CO_2 in a pressure vessel same as underground conditions. It is considered that the seismic measurement using supersonic transducers or measuring resistivity distribution using electrodes is a useful method for the nondestructive measurement of pore-fluid distribution of a rock core in a pressure vessel. Some positive results of the seismic measurement were reported (Xue and Ohsumi, 2004). This study developed the method measuring resistivity distribution. Because CO_2 is a bad conductor, the bulk resistivity of a rock will increase when the pore fluid converts from formation water to CO_2. The electric exploration is a reasonable method than the elastic wave exploration for monitoring CO_2 in actual fields and the technique is expected to be developed.

EXPERIMENTAL METHOD AND PROCESS

A pressure vessel, which uses oil as a medium adding confining pressure, was adopted for making high pressure conditions below underground. Syringe pump was used to inject stably high pressure fluid. The diagram of a whole system is shown in Fig.1.

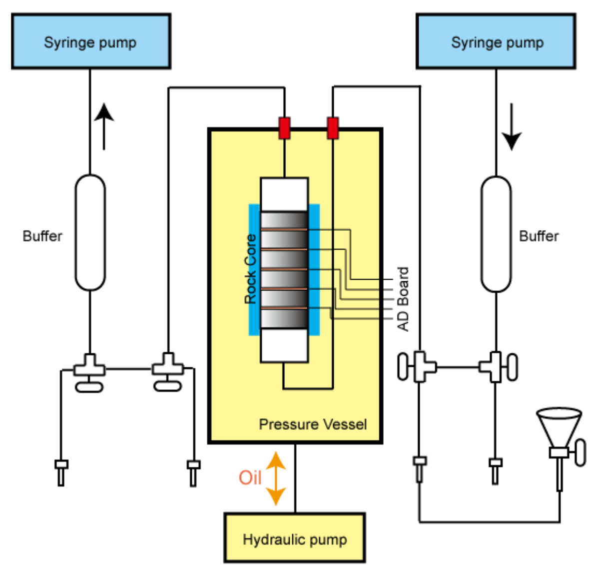


Figure 1. Diagram of the experiment system.

Berea sand stones of 5cm in diameter and 12cm in height were used as a rock sample. The penetration rate of the specimens is 150md. Round and reticulated loading electrodes were set on the both ends of the sample and seven ring measuring electrodes were set on the side of the sample at the 1.5cm interval. Electric potentials at the measuring electrodes were measured and the resistivity between electrodes was calculated. KCL solution of 1.0 ohm-meter was prepared as simulated formation water. The end faces of rock samples are composed of the special piece for making homogeneous inflow and outflow. The middle of the flow lines in a pressure vessel are composed of short tubes with electric insulation and the rock core is electrically isolated from the external portion. The side wall of the rock samples is covered with waterproof bond and silicon rubber of about 1cm thickness and separated from the confining fluid area.

The resistivity values of a same rock sample were measured under the three conditions of temperature and pressure. Each condition of temperature and pressure is shown in Table 1. Each condition corresponds to gas, liquid and super critical phase of carbon dioxide.

Table 1. Conditions of temperature and pressure in injection measurements.

Phase	Pore Pressure (MPa)	Temperature (deg C)
Gas	3.0	15.5-17.6
Liquid	10.0	17.5-18.0
Super Critical	10.0	37-38

EXPERIMENTAL RESULTS

The graphs of resistivity variations calculated from the experimental results are shown in Fig.2. The increase of resistivity in conjunction with the volume of injected CO_2 is observed in all conditions, which are gas, liquid and super critical phase. Also, the increase of resistivity is stopped over a specific amount of injected CO_2. Compared with the resistivity of gas, liquid and super critical phase, the increasing speed of resistivity is fast, when liquid or super critical CO_2 is injected.

Finally, using Archie's equation, we calculated replacement ratios of CO_2 from the resistivity data. The estimated replacement ratios suit to the replacement ratios calculated from actual evacuated volumes after the experiments (Fig.3). This indicates that the method measuring resistivity is able to estimate the replacement ratio with high accuracy.

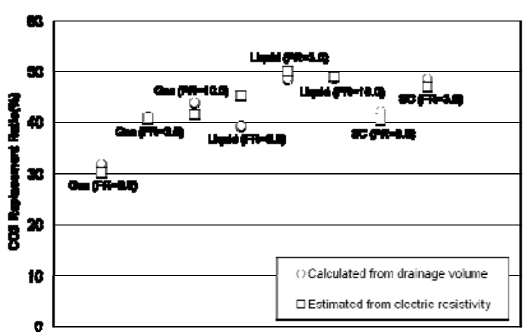


Figure 3. Replacement ratios estimated from the resistivity data and calculated from actual volumes evacuated from the rock core. FR means 'Flow Rate' and the unit is 'ml/min'. SC means 'Super Critical' phase.

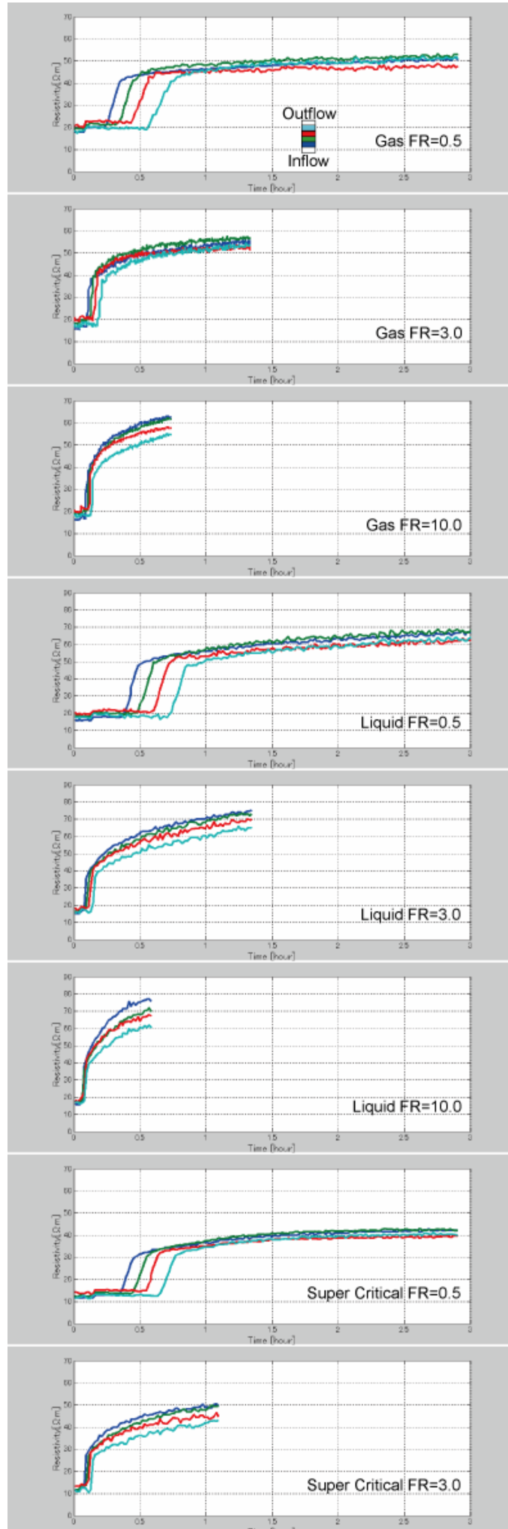


Figure 2. Resistivity variations of a rock sample injected with CO_2. FR means 'Flow Rate' and the unit is 'ml/min'.

CONCLUSIONS

It is required to establish the method analyzing CO_2 behavior injected into aquifer for estimating the long-term stability of CO_2 sequestration. The analysis of CO_2 behavior injected in rock samples is effective to develop the in-situ monitoring method. Thus, we measured electric resistivity variations of rock samples injected with CO_2, which was in the phase of gas, liquid and super critical, in a pressure vessel. In the result, the increases of resistivity with the CO_2 injection were measured. Therefore, it is considered that the condition of CO_2 sequestration can be observed using electric exploration. Also, the differences of velocity and range of CO_2 seepage in the phase of gas, liquid or super critical were found. In the future, we will test other observing conditions, such as rock types, injection flow rate, temperature, pressure, electrode intervals and so on, and will develop the system monitoring CO_2 behavior using this resistivity measurement.

REFERENCES

Xue, Z., and T. Ohsumi, *Seismic wave monitoring of CO_2 migration in water-saturated porous sandstone*, Geophysical Exploration, 35, 25-32, 2004.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

SITE CHARACTERIZATION USING JOINT RECONSTRUCTIONS OF DISPARATE DATA TYPES

Abelardo Ramirez, Julio Friedmann, Kathy Dyer, Roger Aines

Lawrence Livermore National Laboratory (LLNL),
P.O. Box 808
Livermore, California, 94550, U.S.A.
e-mail: ramirez3@llnl.gov

INTRODUCTION

Potential CO_2 reservoirs are often geologically complex and possible leakage pathways such as those created. Reservoir heterogeneity can affect injectivity, storage capacity, and trapping rate. Similarly, discontinuous caprocks and faults can create risk of CO2 leakage. The characteristics of potential CO_2 reservoirs need to be well understood to increase confidence in injection project success. Reservoir site characterization will likely involve the collection and integration of multiple geological, geophysical, and geochemical data sets. We have developed a computational tool to more realistically render lithologic models using multiple geological and geophysical techniques. Importantly, the approach formally and quantitatively integrates available data and provides a strict measure of probability and uncertainty in the subsurface. The method will characterize solution uncertainties whether they stem from unknown reservoir properties, measurement error, or poor sensitivity of geophysical techniques.

METHODOLOGY

The tool uses statistical theory and geophysical forward models to compute images of the subsurface reservoirs. It produces images that are consistent with disparate data types such as geostatistical trends of formation layers, geophysical logs, and surface or cross-borehole geophysical measurements. Joint reconstruction of these data results in subsurface models that are more realistic than those obtained conventionally. Our reconstruction method uses Bayesian inference, a probabilistic approach that combines observed data, geophysical forward models, and prior knowledge (e.g., geostatistical trends of layer correlation lengths, thicknesses and juxtaposition tendencies). The result is a sample of the distribution of likely lithology models that are consistent with the data collected. The method uses a Markov Chain Monte Carlo (MCMC) technique to sample the space of possible lithology models, including the shape, location and continuity of layers. Figure 1 shows a schematic diagram of the MCMC approach used for this study.

The approach that generates random lithology models (bottom of Figure 1) uses a geostatistical model to generate the "prior" spatial distribution of physical properties (resistivity, density, etc.) during each iteration in the MCMC process. Given that geophysical properties (such as electrical resistivity) tend to correlate with lithology or facies (rock categories with distinctive characteristics), we have employed a categorical geostatistical simulation approach. The model space is defined to consist of those combinations of voxel-level lithologic categories that are consistent with our prior spatial distribution. The main advantages of this approach are: (1) data are often categorical (e.g. lithologic descriptions), (2) geologic insight on the spatial characteristics of geologic systems (e.g., facies models) can be exploited, and (3) a very large proportion of the information known about the system can be represented very compactly using only a few lithologic categories.

The stochastic simulation code "TSIM" is used to propose random lithology models that honor prior data) TSIM (Carle, 1996; Carle et al., 1998) is a geostatistical simulation code that accurately honors the spatial variability model for multiple lithology problems. Each realization exhibits a similar pattern of spatial variability that is consistent with borehole data and geologic descriptions of the site. TSIM honors "hard" data, such as lithologic data at boreholes. "Soft" data, such as electrical resistivity logs, cone penetrometer data, or other forms of indirect data can also be used; in these cases, the relationship between the measured parameter and lithology is somewhat uncertain.

Additional capabilities of this approach are:

- Realizations can be generated that are similar to previous realization, as required by the MCMC algorithm.
- Prior knowledge of "nonstationarity" of lithology placement, e.g. information indicating that a certain lithology is more likely to occur in a certain area, can be considered.

MCMC is a proven technique that uses a random-walk type procedure to sample possible outcomes given all available data. A key advantage of the MCMC approach is that it automatically identifies alternative models that are consistent with all available data, and ranks them according to their posterior probabilities and associated confidences. In most geophysical applications, the inverse problem is substantially under-constrained and ill-posed. Thus, the search for a solution that is unique and possesses a high degree of confidence is generally impossible. Our approach makes use of prior information to sufficiently reduce the size of the space of feasible solutions in order to mitigate ill-posedness. The approach identifies competing models when the available information isn't sufficient to definitively identify a single optimal model. Another strength is that it can be used to jointly invert disparate data types such as those described earlier. The method also provides quantitative measures of the uncertainty of a generated estimate. Additional details of this approach can be found in Ramirez et al., 2005.

RESULTS

We have conducted a numerical experiment where disparate data types were used to infer the most likely lithologic model. The numerical model is based on a well-characterized site located at DOE's Savannah River Site (near Aiken South Carolina). At this site the lithology is known along a distal well, geophysical borehole logs are available and the overall geostatistical trends are well understood on the basis of core and outcrop studies. The site contains sand, silt and clay layers with minor gravel.

Using TSIM, we generated random lithologic realization that honored the core log and geostatistical trend data. One realization is shown in Figure 1 (top frame). The location of the distal well where the lithology is known is shown as a dark line along the right hand side of the figure. One realization, chosen as random, was designated as the "true" model (Fig.1, left frame, bottom row). Cross-well electrical resistivity data were calculated for electrodes located within a pair of wells (shown as small squares in Figure 1).

All the data (core logs from the distal well, cross well electrical resistivity data and geostatistical trends) were used to guide the search. The unknowns were the location and spatial trends of the lithologies within the domain. The results of the MCMC search are shown in the bottom row of Figure 1 as probability images. These images indicate the most likely location for each soil type. Note that there is reasonably good agreement between the probability images and the "true" model shown on the lower left corner of Figure1. The "true" model consists mainly of sand with a few thin clay and silt layers. The probability image corresponding to sand (white-yellow image, bottom row of Fig. 1) is mostly bright yellow; i.e. there is a high probability of sand at most locations. The white-blue and white-green images indicate the probabilities that clay and silt are present (respectively). These locations are also in good agreement with clay and silt locations in the "true model". Importantly, the study resulted in a new and more representative reservoir model that better explained the distribution of the contaminant plume.

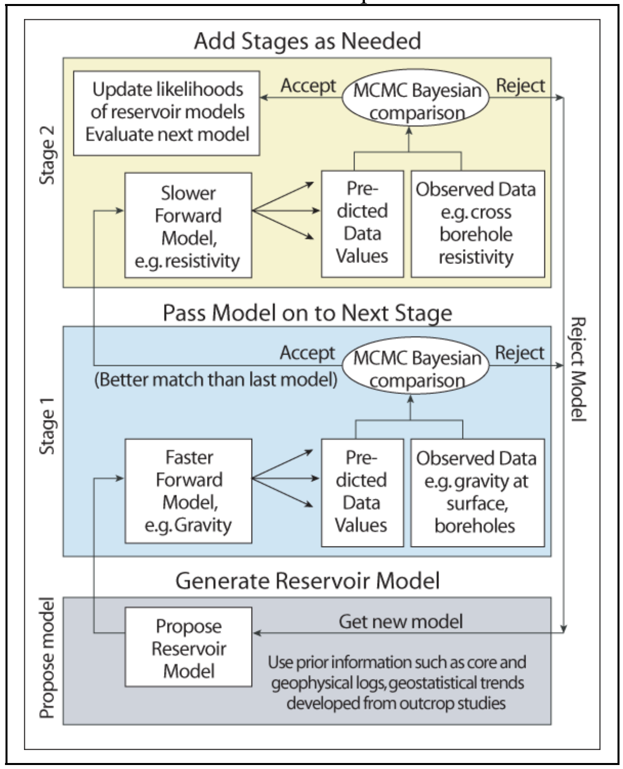


Figure 1. Schematic diagram of the MCMC approach used.

Figure 3 schematically illustrates how "soft" information such as a geophysical log can be incorporated with other data to further constrain the TSIM algorithm. Our approach establishes confidence levels for given lithology types. The left side of the figure shows an electric borehole log from the site. The vertical blue, green and yellow bands indicate the range of resistivity values associated with clay, silt and sand materials. These ranges were determined on the basis of expert judgement but can also be determined based on core studies or Bayesian time series analysis. Suppose that the resistivity curve is near the middle of the resistivity range for a silt (green band); a high confidence level would be assigned in this case because that is likely to be silt. Thus, the confidence level for silt at this depth would be 1.0 and 0.0 for silt and clay. If the resistivity falls along the edge between the green and yellow bands, we are quite confident that material at that location is not clay, but cannot decide whether it is sand or silt. In this case, the confidence level for clay would be 0.0, 0.5 for sand and 0.5 for silt. The rest of the electric log curve would be analyzed in similar ways. The diagram on the right side of Figure 3 schematically shows the confidence levels assigned to each lithology type based on the electric log data. The width of the colored section indicates the confidence level that each lithology (indicated by color) is present. The height of each section indicates the depth range associated with the confidence levels. This type of "soft" conditioning allows many kinds of data to be incorporated in the analysis. For example, results of geochemical or mineralogical analysis, other types of geophysical well logs, and the results of hydrologic pumping tests could be incorporated in this manner.

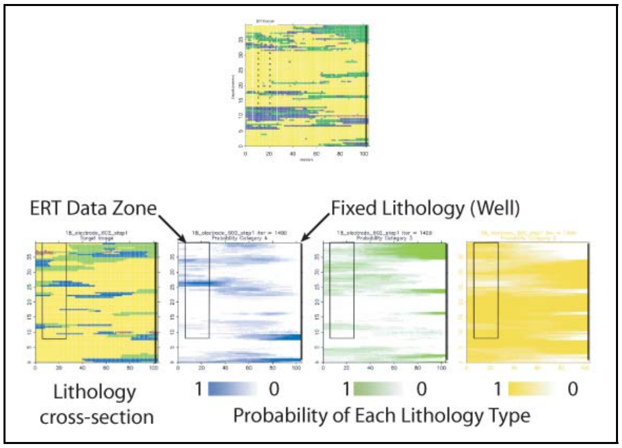


Figure 2. The top frame shows one realization of lithology. The bottom left frame shows the "true model. The remaining bottom frames show the probability that clay (white-blue image), silt (white-green image) and sand (white-yellow image) is present.

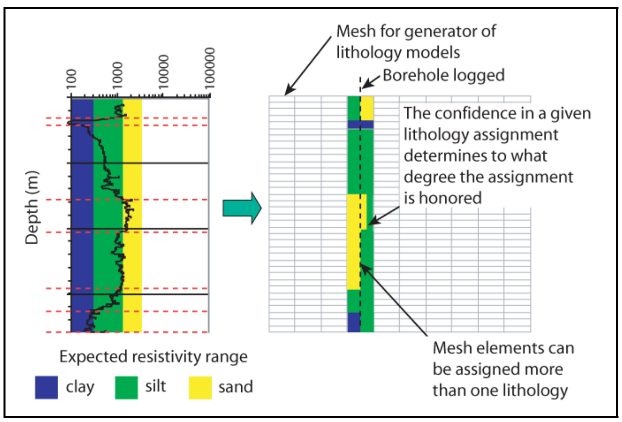


Figure 3. Schematic diagram showing how "soft" data such as a resistivity log (left side) is converted to lithology probabilities (right side of the diagram).

ACKNOWLEDGMENT

We wish to acknowledge the contributions of LLNL colleagues W. Hanley, S. Carle, R. Glaser and R. Newmark. This work was funded by the Laboratory Directed Research and Development Program at Lawrence Livermore National Laboratory. This work was performed under the auspices of the U.S. Department of Energy by the Lawrence Livermore National Laboratory under contract W-7405-ENG-48.

REFERENCES

Carle, S.F. (1996) *A Transition Probability-Based Approach to Geostatistical Characterization of Hydrostratigraphic Architecture*. Ph.D. dissertation, Department of Land, Air and Water resources, University of California, Davis.

Carle, S.F., Labolle, E.M., Weissmann, G.S., Van Brocklin, D, Fogg, G.E., 1998, Geostatistical simulation of hydrofacies architecture, a transition probability/Markov approach: in Fraser, GS; Davis, JM, *Hydrogeologic Models of Sedimentary Aquifers, Concepts in Hydrogeology and Environmental Geology* No. 1, SEPM (Society for Sedimentary Geology) Special Publication, p. 147-170.

Ramirez, A. L., J.J. Nitao, W.G. Hanley, R.D. Aines, R.E. Glaser, S.K. Sengupta, K.M. Dyer, T.L. Hickling, W.D. Daily, 2005, Stochastic Inversion of Electrical Resistivity Changes Using a Markov Chain, Monte Carlo Approach, *Journal of Geophysical Research,* vol 110, B02101, doi:10.1029/2004JB003449.

APPLICATION OF CUTTING EDGE 3-D SEISMIC ATTRIBUTE TECHNOLOGY TO THE ASSESSMENT OF GEOLOGICAL RESERVOIRS FOR CO_2 SEQUESTRATION

E.C. Sullivan[1], K, J. Marfurt[2], F.J. Hilterman[2], S. Nissen[3], and G. Goloshubin[2]

[1]Battelle/Pacific Northwest National Laboratories
Richland WA 99352
e-mail: Charlotte.Sullivan@pnl.gov

[2]Allied Geophysical Laboratories
University of Houston
Houston TX 77004-5006

[3]Kansas Geological Survey
University of Kansas
Lawrence KS 66047

INTRODUCTION

Seismic attribute technology is a standard reservoir characterization component for assessment of hydrocarbon seals, reservoir heterogeneity and compartmentalization; and for the quantification of gas reservoir storage, saturations, deliverability, product loss, and movement of reservoir fluids through time. The geologic sequestration of large quantities of CO_2 must additionally address differences in the behavior and trapping mechanisms of CO_2 in underground formations. These requirements demand more rigorous, seismic-scale quantification of reservoir properties, as well as the development of technology for more quantitative 4-D seismic monitoring of fluid movement.

The aim of collaborative seismic attribute research at the University of Houston Allied Geophysical Laboratories (AGL) and the University of Kansas is to develop seismic technology and workflows for assessing structural integrity and reservoir heterogeneity of geological reservoirs for CO_2 sequestration. Our research emphasizes reservoirs in coal-producing or emission-producing regions (Wyoming, Kansas, Illinois, and Ohio) that represent a diversity of geology and porosity/permeability systems. Specific objectives are to: 1) integrate new spectral decomposition and multi-trace seismic attributes to address problems in imaging small scale (<10 m) structural and stratigraphic features, 2) test and calibrate new frequency- and angle-dependent seismic attributes and target-oriented processing for the quantification of reservoir porosity, permeability, and fluid saturations, and 3) validate newly developed methods with field-based petrophysical and engineering data. In this paper, we review our new seismic attribute-based technologies and illustrate the application to a variety of reservoir types that may be suitable for CO_2 sequestration.

IMAGING SMALL SCALE FEATURES

In contrast to conventional amplitude extractions, geometric (multi-trace) attributes are a direct measure of *changes in seismic texture*. These robust attributes facilitate the recognition of irregular geologic features by avoiding the need to pre-interpret horizons and by enhancing subseismic lateral variations in reflectivity. Geometric attributes include the well-established coherence measures, coupled with recent developments in spectrally limited estimates of volumetric curvature and coherent energy gradients. Coherence measures the lateral changes in waveform, and as such is often sensitive to small faults (<10 m) and to similar lateral scale changes in stratigraphy, such as channels and sinkholes. Components of reflector curvature, including the most negative, most positive, Gaussian curvature and related shape indices, are complementary to coherence measures. These attributes are particularly helpful when combined with azimuth and mapped to color (Figure 1), or when combined with spectral decomposition, which is designed to enhance *vertical* changes in reflectivity (Partyka et al. 1999).

Recent AGL volumetric attribute work in black shales and carbonates of the Fort Worth Basin includes investigating the following: azimuthally limiting seismic volumes to improve lateral resolution (Jyosyula, 2004); the sensitivity of volumetric curvature attributes to delineate cracks and flexures (al-Dossary et al., 2003; 2006), and the relation between volumetric attributes and hydraulically propagated fractures (Simon, 2005). In studies of reservoirs on the Central Basin Platform of West Texas, Blumentritt et al. (2006) demonstrated the relation between models of stresses associated with polyphase deformation and the lineaments in curvature volumes. Other recent applications of geometric attributes to illuminate and map subseismic features include prediction of azimuth of greatest probability of open fractures and non sealing faults (Figure 2) in a deep

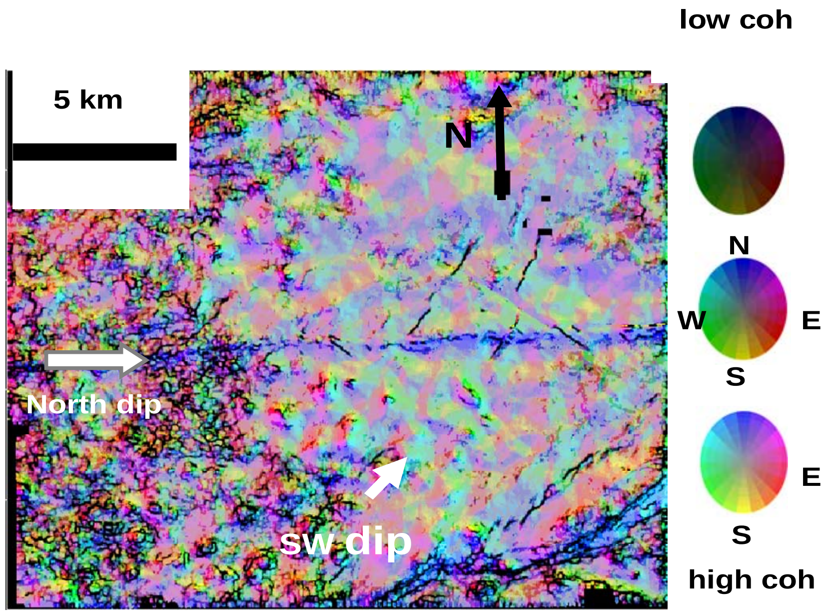


Figure 1. Multi-attribute time slice from a Fort Worth Basin 3-D survey. This attribute volume combines coherence, dip and azimuth through hue, light and saturation. This combination of attributes clearly delineates the large (700 m) collapse features in the southwest, as well as north dip along a fault crossing the center of view, and broad wavelength folds and compaction features that have southeast and southwest dip.

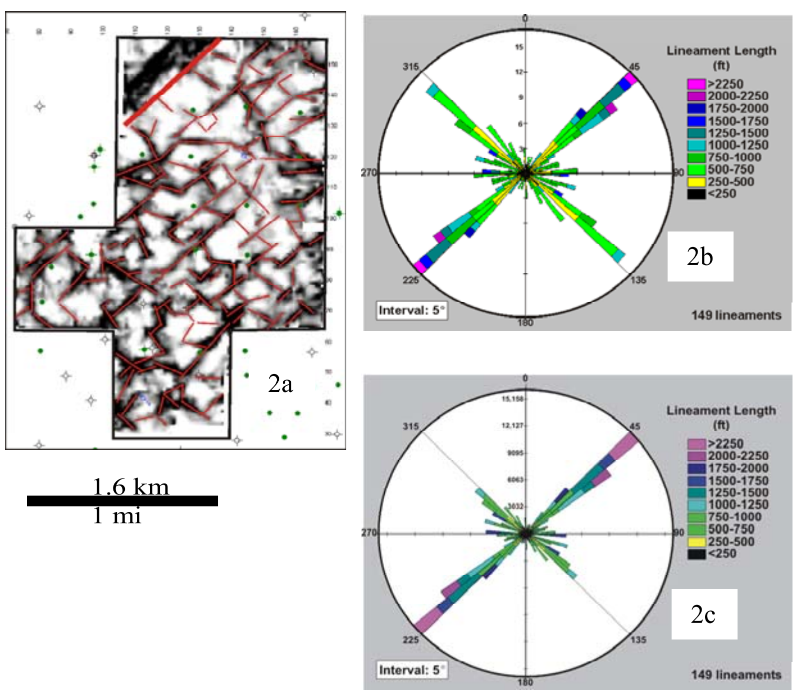


Figure 2. Interpretation of seismic lineaments in the Most Negative curvature volume along the base of a Mississippian deep saline formation in Kansas. Rose diagrams show (b) frequency (number of lineaments) vs. azimuth and (c) length of all lineaments vs. azimuth. Correlations between fluid production and distance to lineaments show that the northeast-trending lineaments represent barriers to fluid flow and that the northwest-trending lineaments represent open faults and joints. (After Nissen et al., 2004).

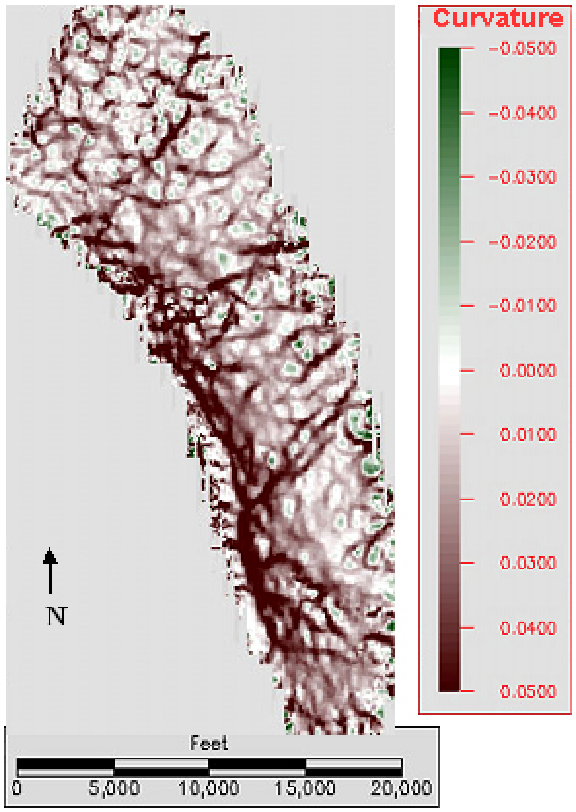


Figure 3. Short wavelength, Most Positive curvature attribute horizon extraction along the top of the Tensleep Formation, Teapot Dome Field Wyoming. Red indicates high positive (anticlinal) curvature, gray indicates low curvature, and green indicates areas with negative (synclinal) curvature. The west side o the field is bounded by a reverse fault, and several smaller NE-SW faults cross the field. f

saline formation (Nissen et al., 2004), and discrimination between karst and tectonic collapse features (Sullivan et al., 2006). The relation of volumetric curvature to in-situ stress is being calibrated with image log data at Teapot Dome (Figure 3) and elsewhere, and will be used to constrain reservoir-scale fracture modeling.

Although reflector curvature calculated from outcrop and from discrete interpreted seismic horizons is well correlated to fracture intensity (Hart, et al., 2002; and Bergbauer et al., 2003), the AGL researchers appear to be the first to publish and calibrate curvature for 3-D data volumes. *These attributes have the potential to image features related to fractures and non-sealing faults that may compromise seal integrity of CO_2 storage reservoirs, but which cannot be detected with other methods.* In addition, volume-based estimates are of particular value for interpreting low signal-to-noise reservoir heterogeneity, characteristic of mixed coal-sand lithologies common in many areas that are candidates for CO_2 sequestration.

TOWARD QUANTIFICATION OF POROSITY, PERMEABILITY, AND SATURATIONS

Recently acquired data from seismic field experiments and physical modeling exhibit amplitude losses that are dependent on the incident angle and frequency. The observed amplitude loss is explained by recent wave-propagation theory (Pride et al., 2003), which indicates that new frequency and angle dependent attributes are promising tools for more quantitatively imaging reservoir structure and estimating reservoir porosity and permeability.

Laboratory and field examples show superior reservoir imaging capabilities with low-frequency seismic components that are normally filtered out in conventional data processing. Physical modeling experiments (Goloshubin et al., 2002), using three different portions of a sandstone layer saturated with different fluids verified that the oil-saturated sandstone is more visible at very low (~5 kHz) frequencies, whereas water- and air-saturated sandstones are well detected at 15 kHz and 50 kHz, respectively. These observations cannot be explained by tuning effects.

The experiments of Goloshubin et al. (2002) have been verified by multiple field tests, where hydrocarbon zones were undetected with conventional seismic, but were identified using analysis of low frequency data. The low value of the quality factor Q for the low frequency waves is a characteristic feature of permeable fluid-bearing layers (Korneev et al., 2004). Goloshubin et al. (2001) and Korneev et al. (2004) analyzed VSP data recorded at a natural gas storage field in Indiana, where due to gas injection in the summer and withdrawal in the winter, the reservoir fluid changed seasonally. They were able to distinguish a low frequency, water-saturation signature from the gas-saturation signature. *These observations have important implications for monitoring fluid movement in CO_2 storage reservoirs.*

The calibration of seismic frequency-dependent reflectivity measurements to reservoir properties is based on the assumption that robust amplitudes are obtained for individual frequency components of the propagating wavelet. However, the frequency content of the seismic wavelet is distorted by conventional data processing with normal move out (NMO) providing the most significant distortion. With the introduction of anisotropic NMO processing, the wavelet frequency content on the very far-offset trace can be almost one-half that of the normal-incident wavelet. This is not an acceptable condition when calibrating loss mechanisms to reservoir properties as a function of frequency. Hilterman and Van Schuyver (2003) developed an innovative processing technique that does migration without NMO corrections, followed by a target-oriented NMO correction. This improved processing will facilitate progress in the quantification of frequency attributes.

ACKNOWLEDGMENT

Funding was provided the AGL; State of Texas ATP Grants 2001, 2003; DOE Grants DE-FC26-04NT15504, DE-PS26-04NT15450-2A, DE-PS26-05NT42472-07; and the Petroleum Research Fund.

REFERENCES

Al-Dossary, S., and K. J. Marfurt, 3-D volumetric multispectral estimates of reflector curvature and rotation, *Geophysics*, 2006, *in press.*

Al-Dossary, S., and K. J. Marfurt, Fracture-preserving smoothing, *73rd Annual International Meeting Society of Exploration Geophysicists, Expanded Abstracts*, 378-381, 2003.

Bergbauer, S., T. Mukerji, and P. Hennings, Improving curvature analyses of deformed horizons using scale-dependent filtering techniques, *AAPG Bulletin, 87*, 1255-1272, 2003.

Blumentritt, C. H., K. J. Marfurt, and E. C. Sullivan, Volume-based curvature computations illuminate fracture orientations, lower-mid Paleozoic, Central Basin Platform, West Texas, *Geophysics*, 2006, *in press*.

Goloshubin, G., T. Daley, and V. Korneev, Seismic low-frequency effects in gas reservoir monitoring VSP data, *71st Annual International Meeting Society of Exploration Geophysicists, Expanded Abstracts,* 1693-1696, 2001.

Goloshubin, G., V. Korneev, and V. Vingalov, Seismic low-frequency effects from oil-saturated reservoir zones, *72nd Annual International Meeting Society of Exploration Geophysicists, Expanded Abstracts,* 1813-1816, 2002.

Hart, B.S., R. A. Pearson, and G. C. Rawling, 3-D Seismic horizon-based approaches to fracture swarm sweet spot definition in tight-gas reservoirs, *The Leading Edge, 21*, 28-35, 2002.

Hilterman, F. and C. van Schuyver, Seismic wide-angle processing to avoid NMO stretch, *73rd Annual International Meeting Society of Exploration Geophysicists, Expanded Abstracts*, 215-218, 2003.

Jyosyula, S., *Azimuthally dependent Seismic attribute analysis*, unpublished M. S. Thesis, University of Houston, 2004.

Korneev, V. A., G. M. Goloshubin, T. M. Daley, and D. B. Silin, Seismic low-frequency effects in monitoring fluid-saturated reservoirs, *Geophysics, 69*, 522-532, 2004.

Nissen, S. E., K. J. Marfurt, and T. J. Carr, *Identifying subtle fracture trends in the Mississippian Saline Aquifer Unit using new 3-D seismic attributes,* Kansas Geological Survey Open File 2004-56, http://www.kgs.ku.edu/PRS/publication/2004/2004-56/, 2004.

Partyka, G., J. Gridley, and J. A. Lopez, Interpretational applications of spectral decomposition in reservoir characterization, *The Leading Edge, 18*, 353-360, 1999.

Pride, S.R., J.M. Harris, D.L. Johnson, L. Mateeva, K.T. Nihei, R.L. Nowack, J.W. Rector, H. Spetzler, R. Wu, T. Yamomoto, J.G. Berryman, M. Fehler, Permeability dependence of seismic amplitudes, *The Leading Edge, 22*, 518-525, 2003.

Simon, Y., *Stress and fracture characterization in a shale reservoir, North Texas, using correlation between new seismic attributes and well data,* unpublished M. S. Thesis, University of Houston, 2005.

Sullivan, E.C., K. M. Marfurt, A. Lacazette, and M. Ammerman, Application of new seismic attributes to collapse chimneys in the Fort Worth Basin, *Geophysics*, 2006, *in press*.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

USE OF INSTANTANEOUS FREQUENCY TO MAP POROSITY IN A SILURIAN AGE REEF IN NORTHERN MICHIGAN BASIN IN PREPARATION FOR CO2 INJECTION

Brian Toelle, Larry Pekot

Schlumberger Data & Consulting Services
1310 Commerce Dr.
Pittsburgh, PA. 15725 USA
e-mail: toelle1@slb.com, Lpekot@slb.com

INTRODUCTION

The Charlton 30/31 Oil Field is located in Otsego County, Michigan in the north central Michigan Basin. This field is one of several hundred similar Silurian age reef structures that stretch across this part of the state.

This field is the subject of a new CO_2 injection EOR project and has the benefit of receiving US Department of Energy support to perform 4D seismic surveying and numerical simulation in order to closely monitor the progress of the flood. This paper describes results from the first 3D seismic survey and numerical modeling of the field. CO_2 injection has recently begun.

PROJECT DESCRIPTION

The Charlton 30/31 reef, like other reefs in the play, developed within the stratigraphic unit historically referred to as the Niagaran Brown. This unit has recently been renamed the Guelph formation. The field covers 300 acres with a structural closure of approximately 300 feet. Charlton 30/31 was discovered by Shell in 1974 and has produced 2.6 million of its estimated 7 million barrels of oil initially in place. A total of 6 production wells were drilled, all during the 1970s. The reservoir could be characterized as a low porosity, low permeability limestone matrix with irregular dolomitized intervals providing a secondary network of higher porosity and permeability which controls fluid flow throughout the reservoir. Gravity segregation/gravity drainage effects are apparent as a depletion mechanism in the field. Primary production essentially ended in 1997 and the field was shut in. Today, four of the original wells have been restored to operable condition in preparation for CO_2 flood operations.

The source of the CO_2 for the project is anthropogenic. Gas production from the stratigraphically shallower Antrim shale formation results in the production of CO_2 as a byproduct. The Antrim, as a desorption-controlled reservoir, produces with a slowly increasing CO_2 cut. The gas must be processed and the CO_2 removed in order to meet pipeline quality specifications. The vast majority of the excess CO_2 is rejected to the atmosphere. These two producing trends, the Guelph and the Antrim shale coexist in the area, see Figure #1. Co2 flooding was tried on two smaller fields in the area during the 1990's, which had some success. Therefore, compression and pipeline facilities already exist to carry CO_2 to the oil fields, but a lack of capital has hindered large-scale development.

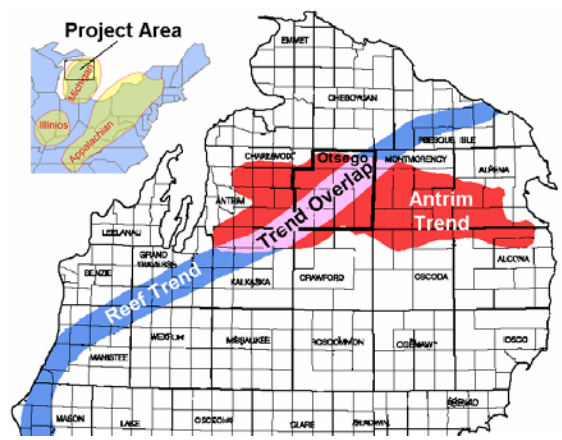


Figure 1. Project area location and location of Antrim Shale and the Northern Niagaran Reef Trend.

Recently Core Energy, a Michigan-based oil and gas exploration and development company, assumed operation of certain oil assets and the mothballed CO_2 delivery system. Core selected the Charlton 30/31 field to begin a new generation of enhanced oil recovery (EOR) projects using CO_2 from the Antrim shale.

In connection with the project, Schlumberger Data & Consulting Services has obtained a grant from the US Department of Energy in order to monitor the flooding of this reef. A 4D seismic survey is planned over this field during first few years of this CO_2 flood. The first 3D of this 4D seismic survey was acquired in March of 2004. This survey covered 2.5 square miles, and resulted in an 82.5 by 82.5 foot bin spacing. Five pounds of dynamite supplied the energy source and the resulting processed volume had a sample rate of 1 millisecond.

Basic geophysical analyses were performed on this 3D survey. These included wavelet extraction and analysis, well to seismic tie generation, and basic horizon interpretation. The results of one of the well to the seismic ties are shown in Figure #2. A good

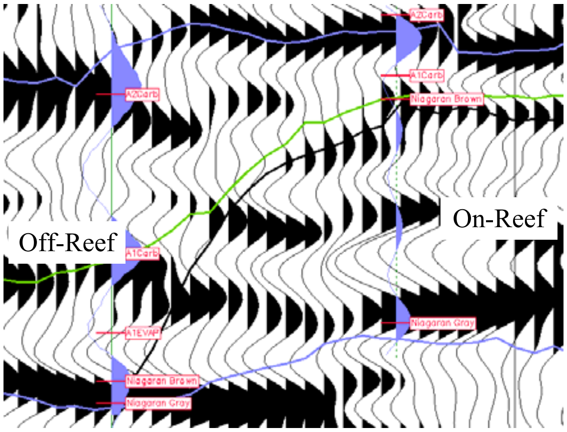


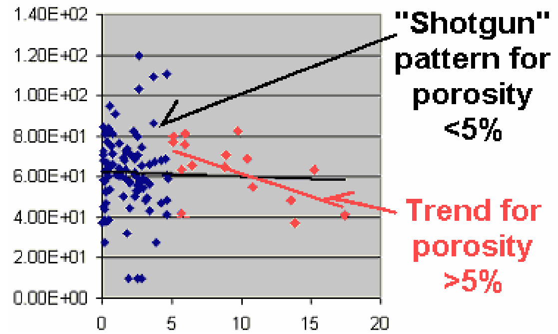
Figure 2. Example of well to seismic ties generated to identify reef and non-reef facies.

correlation between the synthetic seismograms and the base 3-D was established.

In addition to the basic interpretation, a number of seismic attributes were extracted from the 3-D volume and seismic attribute analysis was conducted. In order to relate the various seismic attributes to the porosity values obtained by the well logs, time slices at 2 ms intervals were converted to depth using velocities established during the well to seismic ties. The log porosity values were averaged within the interval bounded by these 2 ms depthed time slices. These averaged porosity log values were then compared with each of the seismic attributes extracted from the seismic volume along the well bore locations.

An analysis of these attributes suggests a potential correlation between instantaneous frequency and porosity values greater than 5%. This relationship, although not well-defined, may be usable in helping to characterize these types of reservoirs. Graph #1 illustrates this relationship for all data pairs within this reef. A "shotgun pattern" exists for all porosity values less than 5%. However, a correlation can be seen for values above 5%. The porosity / frequency pairs suggesting this relationship have been designated in Graph #1.

The relationship shown in this graph has been used to generate a porosity volume for the reef. Instantaneous frequency values from the time slices between the 2 millisecond bounding surfaces were used to influence the gridding other the log porosity values. The resulting porosity volume was tested in the field reservoir simulation and a good history match of the 25-year production history was obtained. The simulation results indicated that while this porosity distribution was reasonable, the overall pore volume was too high and had to be reduced. Reductions to porosity, and by inference permeability, were systematically made to lower porosity grid cells in which the seismically derived porosity may have been overestimated. The history-matched simulation has been used to test several of Core Energy's injection/ production scenarios and refine their preferred option. Additional drilling options have also been investigated.



Graph 1. In reef log porosity values from all wells versus instantaneous frequency values.

CONCLUSIONS

The results of the history matched reservoir simulation support the relationship suggested in Graph #1. A relationship between lower instantaneous frequency and higher porosity exists in rocks with porosity values greater than 5%. Unfortunately, lower instantaneous frequencies can also be found in rocks with less than 5% porosity. When the relationship shown in Graph #1 is applied to the entire reef, rocks with porosities lower than 5% are artificially boosted to higher porosity values.

This resulted in the overestimated pore volume for the reef as indicated by the reservoir simulation. Additional work is being conducted in an attempt to distinguish the lower porosity zones from the higher porosity zones. This work will include comparing additional seismic attributes with the low instantaneous frequency zones. At least one well has also been planned to test a low instantaneous frequency zone in a nearby reef as part of this project.

The implications of this work has the potential for a broad impact in the area of carbonate reservoir characterization. The ability to locate higher porosity reservoir rock prior to drilling would be a major benefit when planning CO_2 sequestration projects as well as Enhanced Oil Recovery projects.

REFERENCES

Ferdinand, Kevin, The Integration of Seismic Attributes and Rock Properties for Mapping Porosity Thickness in the Heterogeneous Grayburg Carbonate Reservoir, Corrigan Cowden Unit West Texas, *AAPG Annual Meeting,* March 10-13, 2002 Houston, Texas

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

AN EVALUATION OF HELICOPTER AND GROUND METHODS FOR LOCATING EXISTING WELLS

Garret Veloski and Richard Hammack

U.S. Dept. of Energy, National Energy Technology Laboratory
626 Cochrans Mill Rd.
Pittsburgh, PA 15236 USA
e-mail: veloski@netl.doe.gov

INTRODUCTION

Prior to the injection of CO_2 into geological formations, either for enhanced oil recovery or for CO_2 sequestration, it is necessary to locate wells that perforate the target formation and are within the radius of influence for planned injection wells. Locating and plugging wells is necessary because improperly plugged well bores provide the most rapid route for CO_2 escape to the surface. This paper describes the implementation and evaluation of helicopter and ground-based well detection strategies at a 100-year old oilfield in Wyoming where a CO_2 flood is planned.

Previous researchers have shown that ground and airborne magnetometry can detect steel-cased wells. This investigation's purpose is to evaluate contemporary helicopter and ground-based magnetometer surveying systems for their ability to accurately locate wells, particularly wells in old oilfields where casing may be of varying length, diameter, and extent of corrosion. Further, the study intends to evaluate the ability of magnetometry to discriminate between well casing and other oilfield infrastructure such as metal pipelines, tanks, derrick anchors etc. An expected outcome of the study is the optimization of survey design (line spacing and direction; flight altitude in the case of airborne surveys etc.).

Not all wells can be located with magnetometry. Early wells had wood casing that exhibits no magnetic signature. Moreover, subeconomic wells may have had the steel casing pulled either for use elsewhere or for its scrap value. Therefore, a new detection strategy was needed for wells with no casing or non-magnetic casing. Leaking wells (both uncased and cased) as well as deep-seated fracture zones can be located by sensing volatile components from sedimentary strata that have migrated to the earth's surface via these pathways. Anomalous concentrations of light hydrocarbons, radon, or radon daughters on the surface can be indicative of leakage zones, either fracture zones or leaking oil and gas wells. The sensitivity of airborne remote sensing methods has dramatically increased in recent years.

New, more sensitive sensing techniques now may allow leaking wells and other conduits for gas migration to be found based on the airborne detection of anomalous concentrations of these substances. Further, airborne techniques allow larger geographical areas to be evaluated more quickly and inexpensively than ground-based searching. This is especially useful when evaluating large fields, where the ability to find and plug well bores prior to CO_2 injection translates to a more efficient deployment of resources at a sequestration or enhanced oil recovery (EOR) site.

SURVEY DESCRIPTION

Helicopter and ground surveys were conducted using magnetic and methane sensors on a one square mile area within the Salt Creek Oilfield near Midwest, Wyoming, USA. The Salt Creek Oilfield has been in continuous production for almost 100 years and is estimated to contain more than 3500 wells. Available databases indicate that there are 129 well locations in the 1 square mile study area. Salt Creek Oilfield is currently operated by Anadarko Petroleum Inc.

Airborne Surveys

Total magnetic field intensity data were obtained using boom-mounted cesium magnetometers (Fugro Airborne Survey's Midas II system) on opposite sides of the helicopter (Fig. 1). Helicopter methane surveys were conducted at the same time as magnetic surveys using the ALPIS differential absorption lidar sensor built by LaSen, Inc. (Fig 1). Airborne surveys

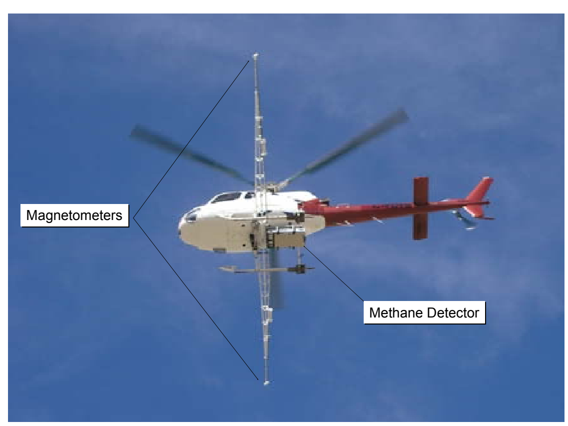


Figure 1. Helicopter with magnetic and methane sensors.

were flown at headings 90º to the prevailing wind direction to intercept methane plumes. Magnetic and methane surveys were flown at 50-m altitude. A magnetic only survey was flown at 35-m altitude. Line spacing was 25 m for all helicopter surveys.

Ground Surveys

Ground surveys were conducted using a 4-wheel drive, utility vehicle with boom-mounted, cesium magnetic sensors and an Apogee CH_4, CO_2, and HC sensor (Fig. 2). Ground surveys with 10-m line spacing were conducted on about 10% of the study area.

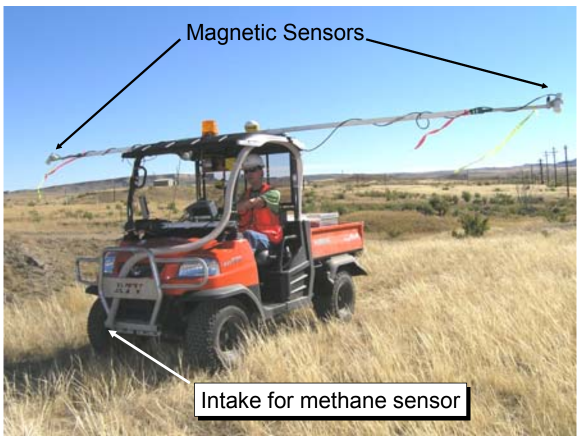


Figure 2. Utility vehicle used for ground magnetic and methane surveys.

RESULTS AND CONCLUSIONS

Helicopter surveys with two boom-mounted magnetic sensors located 120 wells within the test area including 34 magnetic monopole features interpreted as wells that were not in available company databases (Fig. 3). However, 10 locations in the well database exhibited no magnetic well signature. At present, it has not been determined if the "no detects" are invalid well locations, wells where the casing has been pulled, or simply missed wells. The ground magnetic survey of the test area generally corroborated the helicopter well locations but identified one additional well that was not detected by the helicopter survey.

This study found that better results were obtained when helicopter magnetic surveys were flown at an altitude of 35 m rather than 50 m. These results were expected. For surveys flown at higher altitudes, the magnetic anomalies are broader and less intense, which would result in a larger area for the ground search.

Helicopter, methane-sensing surveys using the ALPIS sensor detected four methane plumes within the study area and numerous lesser methane anomalies. Methane sources were located by tracing the plume to its origin in an up-wind direction. Locations determined in this manner were within 20 m of the actual source. The four most substantial methane leaks were at well heads, pipelines, and separation facilities and were quickly repaired when identified. At present, not all sources of the more subtle ALPIS methane anomalies have been investigated. However, one ALPIS anomaly is at a pumping unit where the Apogee LDS system detected 4 ppm methane at ground level. It is remarkable that a 4 ppm methane plume could be detected from a helicopter at 50-m altitude. However, the concentration and thickness of the methane plume in the atmosphere between the ground and the helicopter (which would affect detectability) is not known.

Ground methane surveys with the Apogee LDS detected numerous methane sources originating from pumping units. The observation that methane anomalies were commonly associated with older pumping units was made but not investigated. If this observation is correct, the Apogee LDS may provide an effective means of determining when maintenance is needed on pumping units.

The helicopter magnetic surveys have aided Anadarko Petroleum's effort to locate and re-plug, as necessary, all wells before their planned CO_2 flood of parts of the Salt Creek Oilfield. The survey has provided the location of numerous wells that were not in available databases. However, Anadarko needs the reassurance that all wells have been detected by the helicopter magnetic survey. Comparison of magnetic anomalies with database well locations indicates that some wells may have been missed. Also, there is a problem with the resolution of closely spaced wells. Future work will determine if wells were missed and why. Information from this study will be used to improve the design of future surveys.

The airborne and ground methane surveys alerted Anadarko to leaking pipelines and well heads, which were quickly repaired once identified. The results of this study make a strong case for routine methane (and possibly CO_2) surveillance in oil and gas fields.

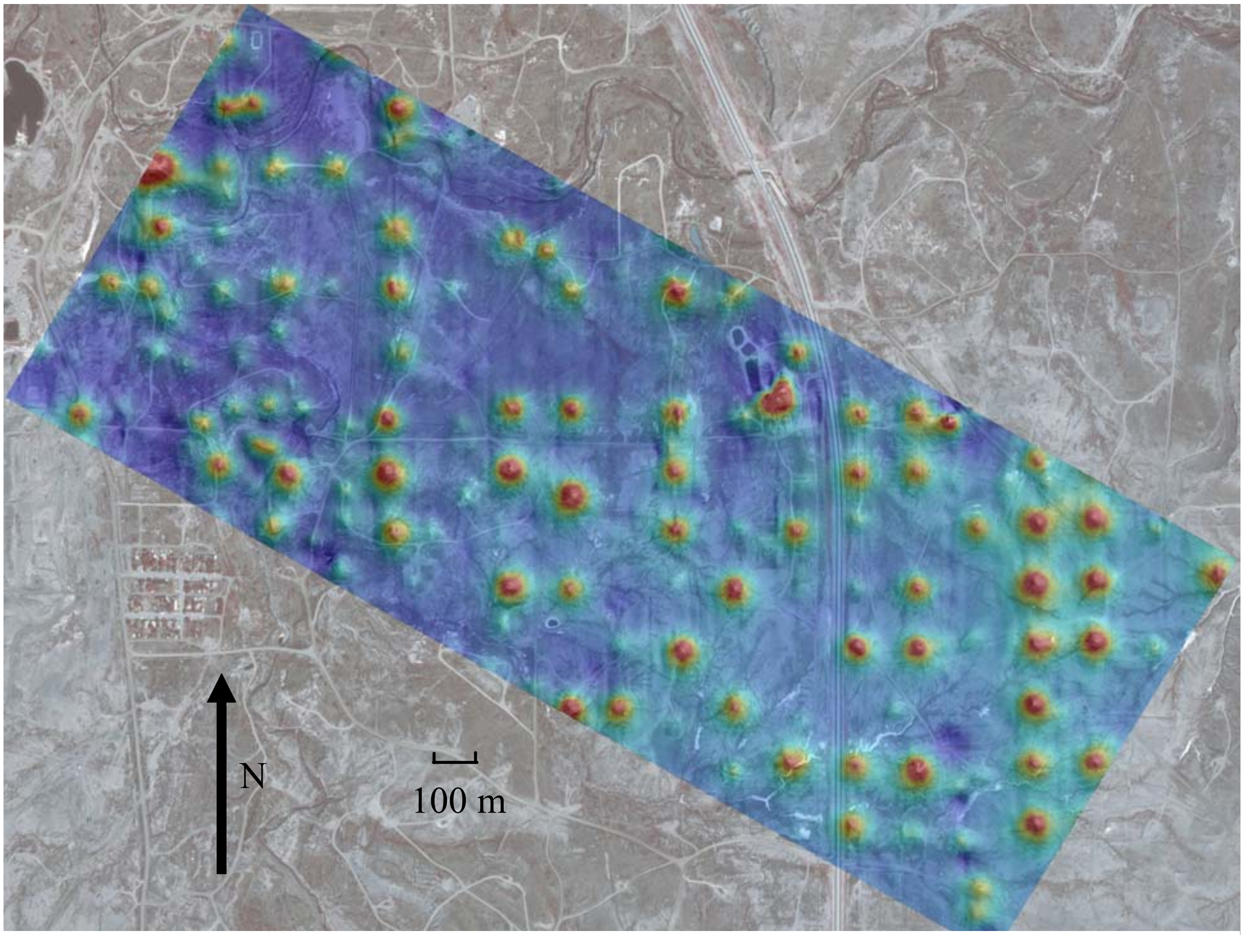


Figure 3. Helicopter magnetic data from study area plotted as color-scale, hill-shaded images. Wells (warm-colored dimples) can be identified by their distinctive monopole signature.

REGIONAL-SCALE SITE SELECTION

EVALUATION OF THE POTENTIAL FOR CO_2 STORAGE IN UNMINABLE COAL BEDS AND SELECTION OF LARGE-CAPACITY AREAS IN THE ALBERTA BASIN, CANADA

Stefan Bachu

Alberta Energy and Utilities Board
4999-98th Avenue
Edmonton, AB, T6B 2X3, Canada
e-mail: Stefan.Bachu@gov.ab.ca

INTRODUCTION

Carbon dioxide capture and geological storage is a means for reducing anthropogenic CO_2 emissions into the atmosphere that is immediately available and technologically feasible and that is particularly suited for the Province of Alberta as a result of its land location, geology and CO_2 emissions profile. Storage of CO_2 in coal seams, concurrent with methane production, is one of the possible means of CO_2 geological storage. Currently, Alberta is the province with the largest CO_2 emissions in Canada at more than 230 $MtCO_2$/year, with most of the emissions originating in large stationary sources such as coal-fired power plants, oil sands plants, refineries, bitumen and heavy oil upgraders, and cement plants. The government of Alberta has committed to reduce by 2020 the greenhouse gas emission intensity to half of the 1990 level, and, consequently, work is underway in the province for the assessment and identification of large potential CO_2 sinks, with a focus on enhanced oil recovery (CO_2-EOR) and enhanced coalbed methane recovery (ECBMR) because these means of CO_2 storage would inherently increase oil and gas production, thus contributing to the security and stability of energy resources in North America. The work reported here is the result of the assessment of the potential for CO_2 storage in coal beds and identification of the areas with the largest potential in terms of capacity and location.

COAL CHARACTERISTICS

Cretaceous-Tertiary strata in Alberta contain eight coal zones, of which three coal zones, Mannville in the Lower Cretaceous Mannville Group, Drumheller in the Upper Cretaceous Horseshoe Canyon Formation, and Ardley in the Upper Cretaceous - Tertiary Scollard Formation, have been identified for assessing their capacity for CO_2 storage on the basis of their thickness and potential for coalbed methane.

The Mannville coals are found at depths that range from ~500 m in the northeast to more than 3000 m in the southwest, and vary in thickness between less than 1 m and 16 m. Pressures vary from 3.2 MPa to ~30 MPa, while temperatures vary from ~16^{o}C to ~125^{o}C. Water salinity is high, varying from more than 2,500 mg/l in the shallowest northeast to more than 130,000 mg/l in central Alberta.

The Drumheller coals of the Horseshoe Canyon Formation are found at depths that vary from ~40 m at outcrop beneath Quaternary sediments, to ~1900 m in the west. Coal thickness varies between ~1 m over most of the area where these coals are present, to 35 m in the east at shallow depth near outcrop. These coals are severely underpressured as a result of post-glacial rebound, with pressures reaching only ~17 MPa. Pressures are up to 6 MPa less than hydrostatic, and these low pressures affect the adsorption capacity of these coals. Temperatures vary between 8^{o}C and more than 60^{o}C. Water salinity is low, less than 2,000 mg/l, in recharge areas near outcrop, and reaches more than 15,000 mg/l in areas of severe underpressuring in the center of the coal zone.

The Ardley Coal Zone dips southwestward, with depth varying between a few metres under the Quaternary drift at outcrop at the top of the bedrock in the east, to 1160 m in the west. The cumulative coal thickness varies between less than 1 m and 25 m. Pressures in the Ardley Coal Zone are generally hydrostatic, increasing with depth, similarly with temperatures that reach close to 30^{o}C. The water in the Ardley coals is of meteoric origin and has low salinity, generally less than 1,000 mg/l.

Very few data exist about coal permeability, which decreases significantly with the effective stress exerted on these coals. Since the latter increases with depth, coal permeability displays a decrease with depth from several darcies in very shallow coals (less than 100 m deep) to a few millidarcies and less for coals several hundred metres deep. The direction of coal cleats is aligned with that of minimum horizontal stress in the basin and is generally perpendicular to the Rocky Mountain deformation front. Numerous coal fields exist along the outcrop of Ardley and Horseshoe Canyon coal zones.

APPROACH

Regions suitable for CO_2 storage in each of these three coal zones have been defined on the basis of depth. Coals shallower than 300 m have been considered not suitable for CO_2 storage either because they may serve as aquifers or be in contact with aquifers used for potable groundwater resources, or because they may be mined at some time in the future and they should not be sterilized. For each coal zone, the maximum depth of the coal suitable for CO_2 storage was established as the depth at which CO_2 at in situ pressure and temperature conditions would change phase from gaseous to dense fluid (liquid or supercritical), because of the plasticization properties of non-gaseous CO_2 that lead to permeability loss. In addition, deep coals have low permeability to start with, and the presence of CO_2 further decreases coal permeability as a result of swelling. Low or loss of permeability affects CO_2 injectivity and coalbed methane producibility. Thus, for each coal zone a region of intermediate depth, greater than 300 m but, as it happens, less than 800-900 m, has been identified that is suitable for CO_2 storage.

RESULTS

The theoretical CO_2 storage capacity in the respective region of suitability was estimated for each coal zone on the basis of CO_2 adsorption isotherms measured on coal samples, taking into account the moisture and ash content of these coals. The CO_2 theoretical storage capacity varies from ~20 $ktCO_2/km^2$ in the areas of thin coals to 1,260 $ktCO_2/km^2$ in areas of thick coals, for a total of approximately 20 $GtCO_2$. This represents the ultimate storage capacity limit that would be attained if there would be no other gases present in the coal or they would be completely replaced by CO_2, and if all the coals in the suitable regions will be accessed by CO_2. A recovery factor of less than 100% and a completion factor less than 50% reduce the theoretical storage capacity to an effective storage capacity of only 6.4 $GtCO_2$ for the three coal zones. The suitable regions will not be used for CO_2 storage in their entirety, however, because it will be uneconomic to build the necessary infrastructure for areas with low storage capacity per unit surface. Considering that it is economic to build the necessary infrastructure for CO_2 storage only in areas with effective CO_2 storage capacity greater than 200 $ktCO_2/km^2$, then the CO_2 storage capacity in coal beds in Alberta is greatly reduced further to a practical capacity of only ~850 $MtCO_2$.

There are no suitable target areas with high CO_2 storage capacity in the Mannville Coal Zone. In addition, the Mannville coals would make poor candidates for CO_2 storage because of their depth, low permeability, elevated salinity of formation water that would be produced, the presence of oil and gas reservoirs in this stratigraphic interval that could be contaminated by leaked CO_2, and the absence of major CO_2 sources and potential CO_2 sinks within close distance. In regard to the Drumheller Coal Zone of the Horseshoe Canyon Formation, there are only a few very small areas with high capacity northwest and east-southeast of Calgary. The practical CO_2 storage capacity in these areas is 55 $MtCO_2$. These areas are located in the agricultural heartland of Alberta and CO_2 storage with coalbed methane production may raise conflicts with land use. The Drumheller coals in these regions are relatively shallow (very close to 300 m depth). Carbon dioxide stored in these coals will likely sterilize shallow coal resources that may become economic for mining at some time in the future, and any leaked CO_2 from these coals will likely contaminate groundwater resources in these agricultural regions.

In contrast to the Mannville and Drumheller coal zones, the Ardley Coal Zone has a much larger practical capacity for CO_2 storage of ~800 $MtCO_2$ in an area of ~3,330 km^2 in western Alberta located in forested lands which are less likely to become the object of land-use conflicts. The low salinity of water in the Ardley coals adds the advantage that produced water does not have to be treated and it is possible that it could even be discharged at surface if regulatory requirements are being met. There are no oil or gas reservoirs in stratigraphic vicinity of Ardley coals that may be contaminated, but there are many large potential CO_2 sinks in deeper oil and gas reservoirs in the area. Large stationary CO_2 emitters are located within close distance and infrastructure built to bring CO_2 from large CO_2 sources in the Edmonton – Lake Wabamun region located in central Alberta will be economic given the large number of potential CO_2 sinks in western Alberta. Given the high coalbed methane potential of the Ardley coals, CO_2 could be used in enhanced coalbed methane, but also in oil and gas recovery operations, thus producing additional oil and gas that would significantly increase the economics of CO_2 storage operations.

CONCLUSIONS

Although the Cretaceous-Tertiary sedimentary succession in the Alberta basin contains eight coal zones, only two of them, Drumheller and Ardley, have the potential for CO_2 storage as assessed on the basis of coal thickness, depth, and in-situ temperature and pressure. The practical CO_2 storage capacity in these coals is estimated to be in the order of 850 $MtCO_2$, with most of it being found in the Ardley Coal Zone in western Alberta. Identification of specific sites for implementation of CO_2 storage should be based on detailed geological characterization and testing of the coals.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

SITE SELECTION FOR CO_2 STORAGE IN DEEP AQUIFERS OF THE PARIS BASIN - FRANCE

Didier Bonijoly[1], Frank Hanot[1], Christian Robelin[1], Olivier Serrano[1], Etienne Brosse[2], Pascal Houel[2], Charles Naville[2], Christophe Rigollet [3], Taoufik Manai[4], Patrick Renoux[4]

[1]BRGM
BP6009, 45060, Orléans cedex 2, France
e-mail: d.bonijoly@brgm.fr

[2]IFP
1 & 4, avenue de Bois-Préau
92852 Rueil-Malmaison Cedex – France

[3]GdF
BP 33, 93 211 Saint Denis-La Plaine Cedex

[4]Geostock Sarl
7, rue E. et A. Peugeot
92563 RUEIL-MALMAISON Cedex

INTRODUCTION

In 2003, the French Ministry of Industry decided to support research dedicated to CO_2 storage in depleted reservoirs and deep saline aquifers. In response to this initiative, the major French oil and gas companies, producers of industrial gas products, boiler manufacturers, research institutes and research laboratories gathered together to form a Research Consortium. The main objectives were to be in a position, by the end of 2009, to implement the first CO_2 injection pilot that could prefigure industrial storage in France (Brosse, 2005) and support the development of France's technological capacity. In 2006, the financial support of this activity has been relayed by assistance from the National Research Agency (ANR).

Concerning the selection of favourable areas for CO_2 storage in geological reservoirs, the GESTCO results (Bonijoly and coll., 2003) demonstrated the interest of the Paris basin where two major reservoirs are overlain at depth: the Dogger reservoir (carbonated reef barrier) and the Triassic reservoir (silico-clastic sandstones).

In each of these reservoirs, oil fields have been discovered in the south-east of Paris and are productive where traps occur.

The Research Consortium decided to investigate more in detail this regional area (Figure 1), where geological information is plentiful, and where, additionally, a source of pure CO_2 (ca. 480 $kt.yr^{-1}$) is immediately available for a pilot project

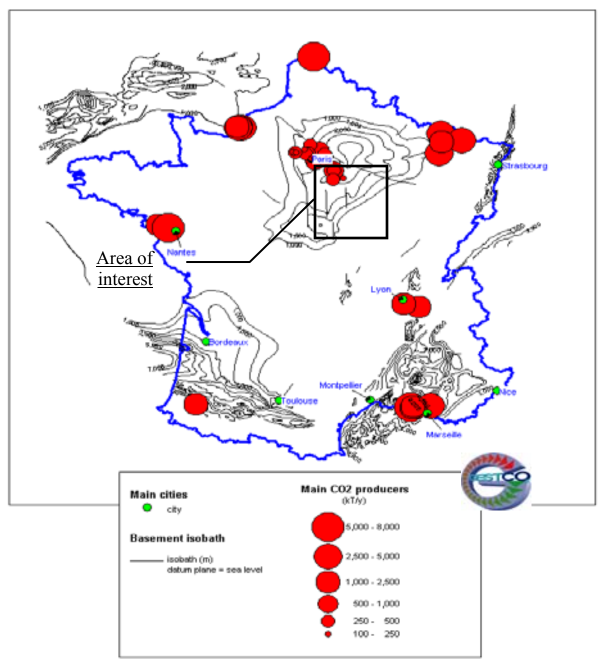


Figure 1. Main CO_2 producers and main sedimentary basins in France

METHODOLOGY

The methodology adopted for selecting the future site and defining a relevant program for the pilot is driven by the need to explore any technical aspect of CO_2 storage in this specific context and by the necessity to pave the way for obtaining storage authorisation. For this, French regulations state that information must be produced concerning the items summarised in Table 1.

Table 1. Work-packages of the PICOREF project

Storage capacity assessment	Selection of favourable areas for CO_2 storage in geological reservoirs
Reservoir injectivity	Source to sink matching
Reservoir injectivity	Guaranty of reservoir integrity and its cap rock Development of methods and design of dedicated tools. Improvement tools for modelling the short- and long-term behaviour of the system. Development of risk–assessment scenarios.

For each item above, the following methodology is applied (Table 2):

Table 2. Methodology (PICOREF project)

➢ Description of technical operations	✓ Existing regulations
➢ Characterisation of phenomena involved	✓ Lack of regulations
➢ Risk assessment ➢ Tools and methodology for control	✓ Documentation required by French administration
➢ Remediation actions in the event of an accident	✓ Responsibilities of each actor

PRELIMINARY RESULTS

The characterisation of the reservoir and cap-rock geometry was based on the reprocessing of onshore seismic profiles (880 km) acquired during the last three decades. Specific processing was carried out so as to increase the quality of results. In particular, the necessary static corrections were applied to correct the effect of the superficial Tertiary formations and the lateral variation of sonic speed in the Mesozoic Chalk (13-layer model).

Six regional transects were laid out and have allowed the construction of a geometric model. The increase in quality was so important that internal reservoir structures were identified (prograding wedges).

Two targets are identified in the initial area of interest: an oil trap associated with one of the major faults in the Paris basin (the Saint Martin de Bossenay fault) and a flat block where the two aquifers seem to occur without any faults.

In parallel, basin geology and sedimentological studies were carried out to increase the knowledge on the nature of the cap rocks and reservoirs (borehole logs) and the facies variations within the Dogger reservoir (logs and outcrops).

The main results issued from these studies concern:

- the continuity of impermeable cap rocks over each reservoir (Dogger limestones and Triassic sandstones),
- the confinement of Triassic sandstone reservoirs without any water outlet,
- the complexity of grainstone distribution in the Dogger carbonates,
- the identification of five reservoir layers within the Dogger limestones:
    - ✓ the grainstones of the “Dalle Nacrée” Formation (A-B reservoirs), clearly controlled by sedimentological parameters (intertidal sigmoidal megaripples), deposited in a coastal environment,
    - ✓ the mudstones of the “Comblanchien” Formation (C-D reservoirs), controlled by the succession of complex events of dolomitisation and de-dolomitisation,
    - ✓ the grainstones of the “Oolithe blanche” Formation, controlled by the paleogeography of the reef barrier and by carbonate diagenesis (de-dolomitisation).

CONCLUSION

Research studies carried out for the selection of a CO_2 storage sites in the Paris basin has allowed the elaboration of a methodological work-flow, able to address the site evaluation for a CO_2 storage pilot project. It is based on integrated geological and geophysical studies that provide access to the reservoir properties, and the key points for assessment of CO_2 storage capacity in onshore sedimentary basins.

The following work will serve during the reservoir characterisation phase in order to assess the CO_2 storage capacity, to model the reservoir behaviour in response to injection and to size the injection pilot.

ACKNOWLEDGMENTS

The Research Consortium thanks particularly TOTAL E&P for its support and the supply for original data.

REFERENCES

Bonijoly D. and coll., *Feasibility of CO_2 storage in geothermal reservoirs – example of the Paris basin – France*, Geological storage of CO_2 from combustion of fossil fuel – European Union Fifth Programme for Research and Development – Project no. ENK6-CT-1999-00010, 2003

Brosse, E., PICOREF, a French R&D Programme on CO_2 Geological storage, *Greenhouse Issues*, no. 77, 5-7, 2005.

STORAGE-CAPACITY ASSESSMENT FOR CO2 CAPTURED FROM FCB POWER PLANTS IN FRANCE – AQUIFER STORAGE vs ECBM RECOVERY

Didier Bonijoly [1], Zbigniew Pokryszka[2], Brunello Jean Marie[3]

[1]BRGM
BP6009, 45060, Orléans cedex 2, France
e-mail: d.bonijoly@brgm.fr

[2]INERIS
BP2, 60550, Verneuil-en-Halatte, France

[3]SNET
2 rue Jacques Daguerre
92565 Rueil Malmaison, France

INTRODUCTION

The present study consists of a global assessment of CO_2 storage capacity in France, in order to provide the main CO_2 producers with solutions for eliminating their ultimate industrial process products, and to help the French Government respect its commitments in terms of GHG reduction. It aims to study the technical and economic feasibility of CO_2 storage produced by coal-fired FCB power plants. Two options are considered (1) storage in deep aquifers and (2) storage in deep coal seams combined with ECBM recovery, for two FCB power plants owned by the SNET company: the Emile Huchet power plant (125 MWe) located in northern France (Lorraine), and the Gardanne power plant (250 MWe) in southern France (Provence).

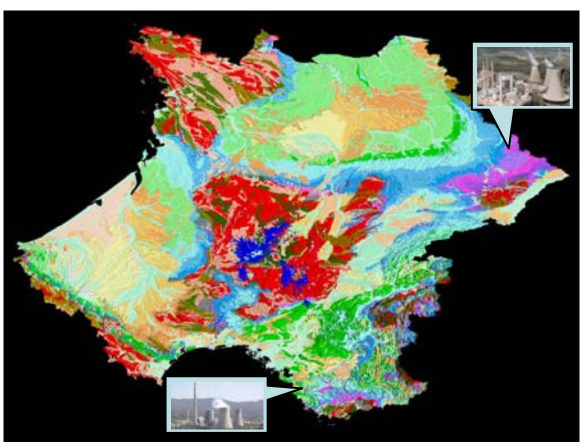


Fig 1: Location of the SNET power plants – Emile Huchet power plant in the NE of France, Gardanne power plant in the SE of France

GEOLOGICAL CONTEXT OF THE PLANTS

The Emile Huchet plant lies within one of the major Carboniferous coal basins in France (Lorraine Coal Basin). Composed of very thick formations (more than 5000 m), the most productive unit is of Westphalian age and includes more than 100 coal seams of which the thickness varies from a few centimetres to more than 4 m. Exploitation affects less than 50% of the basin surface accessible for mining and was concentrated between a depth of 300 and 1200 m. The basin is folded (NE-SW) and faulted (NE-SW and NW-SE). The coal formations are overlain by a thick impermeable Permian formation separating them from one of the major Triassic aquifers exploited on a regional scale (Robelin, 2004; Nguyen-Thé and Vaute 2005).

The Gardanne plant lies within the Mesozoic Arc coal basin (Gonzalez, 2005) composed of alternating marls and limestones (Late Cretaceous). At the base of these lacustrine deposits, eight coal seams are interlayered with lacustrine limestones. The thickness of the seams varies from 0.7 to 2.6 m. The deepest and thickest seam was mined until the 1990's (Grande mine). The Late Cretaceous formations are overlain by thick argillaceous and gypsum formations (100 to 200 m) that isolate the coal formation from the surface.

MAIN RESULTS

The present study underlines the very small quantity of data available on these basins outside the exploited zones. This data scarcity is a major drawback because it strongly reduces the confidence ascribable to the achieved results.

Concerning the *Lorraine coal basin*, one of the most unexpected results is that within this several-thousand-meter-thick succession (more than 5000 m), no truly permeable formations seem to exist that could resemble an aquifer and into which CO_2 could be injected. The few permeability values available

(5.10^{-10}m.s^{-1}) are crippling because they predict a very poor injectivity into the ground. Moreover, the very low porosity (about 5.8%) means that only a very limited volume of CO_2 could be stored (5 Mt, Table 1; 6% storage, assumption GESTCO, 5th PCRD).

Table 1 Assessment of CO_2 storage capacity for the Tittreling formation (sandstones and conglomerates)

Section (m)	Semi-permeable form. vol (m^3)	porosity (m^3)	Mt CO_2 (6% useful volume)
global	8,234,000,000	477,572,000	13.329
0-500	562,000,000	32,596,000	0.196
500-1000	4,960,000,000	287,680,000	6.904
1000-1500	2,244,000,000	130,152,000	5.154
1500-2000	468,000,000	27,144,000	1.075
>2000			

However, the high volume of coal still in place between 500 and 1500 m in the Vernejoul - Saint Avold– Hombourg area, considered gassy and unmineable by conventional methods, underlines the interest of this basin for the possible production of coal gas. The recovery of methane by injecting CO_2 (ECBM) could be a solution of economic interest.

In addition to the production of an energy resource whose price is forecast to increase significantly, ECBM recovery could contribute to the reduction of greenhouse gas emissions because the estimated storage capacity (more than 34 Mt of CO_2, Table 2) would suffice for a significant portion of the CO_2 emitted by the Emile Huchet plant (3.5 Mt of CO_2 per annum), i.e. a storage capacity of approximately 10 years.

Table 2: Assessment of CO_2 storage capacity in various coal seams

Section (m)	formation	Coal mass (t)	CO_2ads (Mt) 30% available	CO_2poro (Mt) 30% available
500-1000	LAUDR	348,691,200	8.285	0.38
	FORB	103,395,600	2.457	0.11
	GRAS1	56,628,000	1.345	0.06
	GRAS2	77,746,500	1.847	0.09
			13.934	0.645
1000-1500	LAUDR	378,892,800	9.002	0.63
	FORB	296,049,600	7.034	0.49
	GRAS1	63,148,800	1.500	0.10
	GRAS2	49,666,500	1.180	0.08
			18.717	1.300

The Arc basin presents highly favourable conditions in terms of deposits and containment. The basin is flat (monoclinal) with a thick impermeable overburden. The estimated volume of lignite between 500 and 1500 m is about 720 Mt in the studied area (288 km²), which would enable the storage of more than 28 Mt of CO_2, corresponding to 12 years of production for a power plant such as Gardanne.

However, as is the case for the Lorraine coal basin, methane recovery combined with CO_2 storage would make this type of operation highly profitable. Although containment of the coal seams seems geologically satisfactory, it remains to be proven that no communication is possible with the underlying karstic aquifers One aspect that needs more investigation concerns the possibility of the leakage of acid water via faults or fractures, which could reactivate the old karst and pollute the upper aquifers that are exploited near the Arc basin (Moulin, 2005).

CONCLUSION

The first assessment of CO_2 storage capacity dedicated to the reduction of GHG produced by coal-fired power plants in France demonstrates the interest of ECBM recovery combined with CO_2 injection. The storage capacities available are compatible with the volumes of CO_2 produced by the plants. The possibility of increasing the CO_2 storage volume by injection into permeable formations only seems feasible for the Gardanne power plant, although the impact on the underlying aquifers remains to be evaluated.

REFERENCES

Bonijoly, D. and coll., *Faisibility of CO2 storage in geothermal reservoirs – example of the Paris basin – France*, Geological storage if CO2 from combustion of fossil fuel – European Union Fifth Programme for Research and Development – Project n° ENK6-CT-1999-00010.

Gonzalez, G., *Etude de faisabilité d'un pilote de sequestration du CO2 pour les centrales thermiques au charbon – Bassin de l'Arc*, Final Report BRGM/RP53703-FR, BRGM ed., 2005.

Moulin, M., *Faisabilité technique du stockage géologique du CO2 dans le bassin de l'Arc – Aspects hydrogéologiques*, Final Report BRGM/RP53858-FR, BRGM ed., 2005.

Nguyen-Thé, D., Vaute L., *Elements d'hydrogéologie sur la zone de Vernejouls, Saint Avold, Hombourg*, Final Report BRGM/RP53858-FR, BRGM ed., 2005.

Robelin, C., *Etude de faisabilité d'in pilote de sequestration du CO2 pour les centrales thermiques au charbon – Bassin houiller lorrain*, Final Report BRGM/RP53943-FR, BRGM ed., 2004.

DELINEATION OF DEEP SALINE AQUIFERS IN GANGA BASIN FOR CARBON DIOXIDE SEQUESTRATION

D K Chadha

Global Hydrogeological Solutions
G-66, Vikas Puri
Delhi-110018, India
e-mail: dkchadha27@rediffmail.com

INTRODUCTION

India covers 2.4 percent of the total world's surface area, i.e. 3.28 million square km with almost one-fifth of the world's total population. India is among the top ten emitters of carbon dioxide ranking fifth in the list. The total carbon dioxide emissions in India has increased from 560 MT in 1990 to 706 MT in 1994 and to 1069 MT in 2000 and is projected to be 4588 MT in 2025. About 40% (i.e. 395 MT) of the emissions is from eighty one thermal power plants across the country. Carbon dioxide emissions vary significantly in the different sectors; maximum emissions are from the electricity and heat-generating sector, followed by the manufacturing and construction industries. Other major sectors contributing to the CO_2 emissions are transport, other energy industries, residential, and others (including industrial waste fugitive emissions, non-renewable municipal waste etc.).

In order to tackle the emissions, many methodologies are being undertaken including different geological formations as one such option. India acquires good potential of saline aquifers in different geological formations but it is quite substantial in the Ganga basin, which can be made use of in sequestering the carbon dioxide.

CARBON DIOXIDE EMISSIONS

The major contributors of the carbon dioxide are the thermal power plants. The power plants located in the Ganga basin are spread in 8 states i.e. Rajasthan, Madhya Pradesh, Uttar Pradesh, Haryana, Delhi, Bihar, Punjab and Himachal Pradesh. The corresponding number of power plants in these states is, Bihar-2, Delhi - 3, Haryana - 2, Madhya Pradesh - 3, Punjab - 3, Rajasthan - 6 and Uttar Pradesh - 7. The power and coal usage statistics at the thermal power plants in different states is given in Table 1.

The carbon dioxide emissions from the power plants in the study area is 260 gigagrams/day, therefore the area around these power plants have been investigated.

Table1. Power and coal usage statistics at the thermal power plants in different states

State	Installed capacity of power stations (MW/day)	Generation (MW/day)	Carbon Dioxide emissions (giga-grams/day)	Million KWH per day (MU)
Bihar	530	105	6.943	2.75
Delhi	1117.8	700	21.578	19.76
Haryana	815	493	14.464	12.70
Madhya Pradesh	4243	3819	83.287	87.54
Punjab	2120	1565	37.464	39.46
Rajasthan	1350	1372	31.903	32.25
Uttar Pradesh	8961	7203	169.613	179

DEEP SALINE AQUIFERS OF INDIA

The major geological formations in Indian continent are Deccan Basalt, Granitic group of Rocks, Indo-Gangetic basin, which constitute the major aquifers in India (Figure 1).

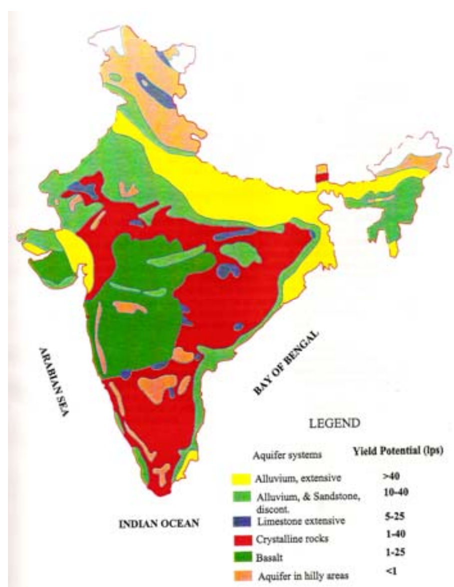


Figure 1 Major aquifers of India

The deep saline aquifers are present in different geological formations as revealed by exploratory drillings for the delineation of deep aquifer zones. The distribution of inland saline aquifers is given in Figure 2.

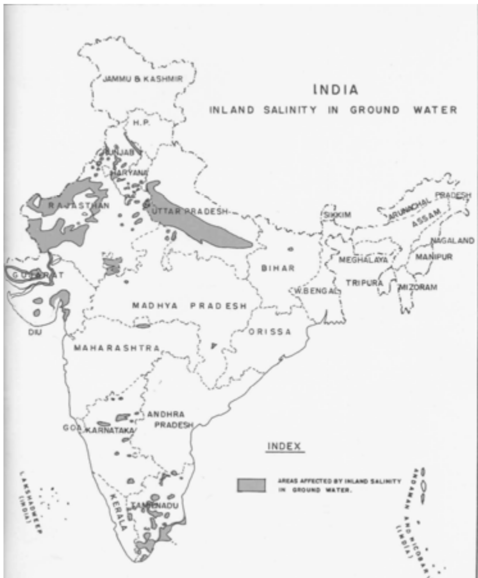


Figure 2. Distribution of Saline Aquifers

EXPLORATION FOR DEEP SALINE AQUIFERS

In the identified inland salinity areas, exploration for identification of deep saline aquifers was carried out. In Gujarat, exploration for deep saline aquifer was carried out upto 621 m bgl. The exploration indicated the presence of thick saline aquifers in the basalt and Precambrian shale formations, and the aquifers are under free flowing artesian conditions. In the arid areas of Rajasthan, the exploration shows the presence of saline aquifers in about 1,00,000 Sq Km and the salinity increase with depth. The exploration upto 610 m indicated the presence of granular zones with high salinity.

Similarly in the Kutch region (coastal Gujarat), the saline aquifers were encountered at different depths and they continue upto the explored depth of 458 m bgl with the EC value of 10,000-μ siemens/cm. In southern coastal areas of Tamil Nadu, the tertiary sandstone and the alluvial formation encompass deep saline aquifer zones in an area of 65 Sq Km.

GANGA BASIN

The exploratory drilling and geophysical logging shows the presence of deep saline aquifers but they are more prominent in the states of Rajasthan (100620 Sq Km), Haryana (9166 Sq Km), Punjab (3500 Sq Km), Gujarat (28600 Sq Km), Uttar Pradesh (25770 Sq Km), and Madhya Pradesh (1000 Sq Km).

In the Ganga Basin, the saline aquifers are present in its western extension almost running for 342 Km from Meerut to Rasalpur (Figure 3). The highly saline aquifers at all depths are present in an area of 8,600 Sq Km in Meerut and Agra districts. In the Meerut district, the saline aquifers have been traced upto 600 m bgl. The geophysical logs of 172 boreholes in the study area shows the thickness of saline aquifers ranging from 30 to 300 m indicating the presence of thick granular zones.

The deep saline aquifers are now being delineated with deep resistivity survey to estimate the thickness of saline aquifer zones at different depths to comprehend the possibility of sequestration of carbon dioxide emission from the power plants located in the area. It is observed that carbon dioxide sequestration other than the deep aquifers of the Ganga Basin may not be cost effective and feasible because of the strategic locations of the power plants and the logistic reasons.

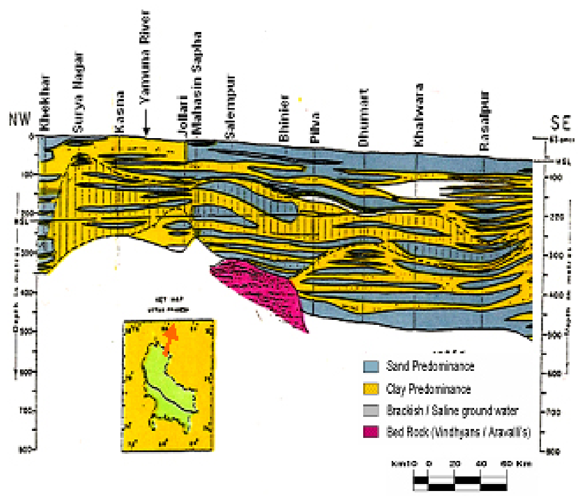


Figure 3. Disposition of saline aquifers in parts of Ganga Basin

ACKNOWLEDGMENT

Thanks are due to the assistance provided by Nidhi Sarin in preparation of this document.

REFERENCES

Chadha, D.K., S.P.Sinha Ray, *Inland Ground Water Salinity in India,* Central Ground Water Board, Ministry of Water Recourses, Government of India.

IEA Statistics, *CO_2 Emissions from Fuel Combustion (1971-2003),* International Energy Agency.

SITE SCREENING AND ASSESSMENT FOR TESTING GEOLOGICAL SEQUESTRATION IN THE ILLINOIS BASIN: A DOE PHASE II REGIONAL PARTNERSHIP PROGRAM

Robert J. Finley and Scott M. Frailey

Illinois State Geological Survey
615 E. Peabody Drive
Champaign, Il 61820
e-mail: finley@isgs.uiuc.edu

INTRODUCTION

The Midwest Geological Sequestration Consortium (MGSC) was initiated as a Phase I Department of Energy (DOE) Regional Carbon Sequestration Partnership in October 2003, and continued as a Phase II effort beginning in October 2005. MGSC's focus is on geological carbon sequestration potential in the Illinois Basin of Illinois, southwestern Indiana, and western Kentucky, USA. MGSC is led by the Illinois State Geological Survey with the collaboration of the Indiana and Kentucky Geological Surveys and a group of additional subcontractors.

GEOLOGICAL FRAMEWORK

The Illinois Basin contains deep coal seams, mature oil reservoirs, and deep, brine-filled formations that offer potential carbon dioxide (CO_2) storage capacity. A sequestration fairway has been defined in southeastern Illinois and southwestern Indiana that likely offers the best potential for sequestration based on the distribution of coal seams, the presence of most of the larger oil fields, and geological structures that could store CO_2 in brine-filled formations. These target sinks have been mapped at various scales, both regionally and site-specifically.

COAL SEAM SEQUESTRTION

The opportunity to sequester CO_2 in coals judged unminable (i.e., less likely to be mined in comparison to shallower, thicker coal seams) is based on both technical and economic considerations and would be supported by production of methane displaced from the coal seams. Maps of coal seam extent, thickness, and depth were completed for seven seams across the Illinois Basin. Unminable seams were judged those <107 cm (42 in) thick and/or at depths of >305 m (1,000 ft). The COMET reservoir simulator was used to assess CO_2 enhanced coalbed methane recovery and CO_2 sequestration storage factors for three depth intervals with gas content and petrophysical properties representative of Basin coals. Low, middle, and high estimates were made of the recovery and storage factors for seven seams. The middle estimate indicated that 190 million m^3 of coalbed methane was recoverable and 3.6 billion tonnes of CO_2 would be retained across all seams.

Initial Phase II efforts have focused on selecting a site for a multiwell coal seam test, consisting of (ideally) an injector, observation wells, and producing wells. A field test was carried out in well drilled to a deeper oil reservoir test wherein coal was cored and a drill stem of a 1.4 m (4.5ft) thick Herrin No.6 coal at about 327 m (1,080 ft) depth along the deep axis of the Illinois Basin. The successful drill stem test recovered 84.1 m (276 ft) of 100 g/l (100,000 ppm) water which indicated that this coal should have sufficient bulk permeability for consideration as a test site. One coal seam sequestration test will be carried out in Phase II.

MATURE OIL RESERVOIR STORAGE

Enhanced Oil Recovery (EOR) offers the most important economic offset to the costs associated with carbon sequestration in the Illinois Basin. To assess this potential, basin-wide assessments were made of the original-oil-in-place, potential CO_2 stored volume, the EOR resource and its geographic distribution, miscible vs. immiscible recovery mechanisms, and daily EOR injection rate as a measure of CO_2 demand. To assess the incremental oil recovery and associated CO_2 storage potential, parts of nine reservoirs were studied representing two sandstones and one carbonate (three reservoirs each) that account for >70 percent of the Basin's oil production. Reservoir properties such as permeability and porosity were assessed and structure and thickness defined. The oil reservoirs studies included deterministic and geostatistical geologic modeling and compositional reservoir simulation using Geographics, Isatis, and VIP (Landmark) software.

While miscible flooding recovers more incremental oil, many of the Basin's reservoirs are at too low a pressure to reach miscible conditions. Although immiscible flooding would store less CO_2 per barrel of oil produced than miscible flooding, the many immiscible reservoirs in the Basin suggest the importance of testing this process as well. Eighty-one fields were defined each with >3.97 million m^3 (25 million barrels) OOIP which would form significant EOR and storage targets.

Phase II EOR testing will consist of four field tests. The simplest will be a single well inject/soak/produce test. Another test will consist of converting a water injection well to a CO_2 injection well, most likely in a stratigraphically or structurally constrained setting where good material balance between injected and produced fluids has already been established. In the third and fourth tests, new CO_2 injection wells will be drilled to establish a well-defined pattern of an injector and producing wells. A portfolio of 36 potential candidates from 10 companies is now being screened for these four tests based on geological, engineering, and site criteria. For example, those reservoirs that have undergone a successful waterflood might be better candidates for an EOR project given that the operator has a good understanding of fluid flow in the reservoir and the pressure in the reservoir has been maintained such that large volumes of CO_2 would not be required to reach miscible conditions.

Using the current reservoir pressure and temperature and the density of the crude oil, the 36 nominated fields were classified into general miscibility categories of immiscible-gas, immiscible-liquid, and miscible. The inject-soak pilot is the first EOR pilot planned. Immiscible-gas conditions are optimal for this type of CO_2 EOR so that the injected CO_2 does not displace oil from the well. Twelve of the 36 reservoirs were identified as inject-soak candidates. Six of these were given higher ranking based on the Basin-wide representation of the geologic formation, the degree of pressure depletion, and the proximity of the reservoir pressure and temperature to the saturation line and critical point of pure CO_2. Geologic and reservoir models will be developed for each of these to identify the optimal inject-soak pilot site.

SALINE RESERVOIR STORAGE

The primary saline reservoir storage target in the Illinois Basin is the Mt. Simon Sandstone; a secondary saline reservoir target is the St. Peter Sandstone. In far northern Illinois it is a fresh water aquifer but farther into the Basin it rapidly becomes saline and in some locations is used for natural gas storage. These natural gas storage fields have provided significant data for Mt. Simon reservoir characterization down to a depth of about 1,200 m (4,000 ft) including the opportunity to use geostatistical techniques to develop a multilayer porosity and permeability model to demonstrate the impact of reservoir heterogeneity on buoyant supercritical CO_2. Mt. Simon field testing may be considered down to a depth of about 3,000 m (~10,000 ft) but increasing drilling, casing and other costs may argue for testing at depths closer to ~2,000 m (~6,600 ft).

One field pilot test of saline reservoir sequestration is proposed as part of Phase II. Screening with 2D seismic data has been a first step toward determining a field test site, and two sites were shot in summer, 2005. Data from one site has shown terminating seismic reflectors that may indicate that the Mt. Simon is thin or absent over a preexisting basement high on which it was deposited or onlapped. At another site, the Mt. Simon is relatively deep and the injected volume of CO_2 would be difficult to geophysically monitor. Any conclusions reached based on 2D data would be confirmed with 3D seismic before a site was selected for this pilot study.

Using closed structures for initial sequestration testing in saline reservoirs would seem prudent until more experience is gained with reactions between injected CO_2 and the host formation. Thus, a number of oil field structures are being assessed for their deeper Mt. Simon and St. Peter storage capacity. Further, monitoring of shallower oil reservoirs where production already has a significant water cut may be an excellent way to monitor for any possible leakage through changes in water chemistry.

ACKNOWLEDGMENT

The Midwest Regional Sequestration Consortium is funded by the U.S. Department of Energy, National Energy Technology Laboratory, by the Illinois Office of Coal Development, Illinois Department of Commerce and Economic Opportunity, and by the geological surveys of Illinois, Indiana, and Kentucky.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

REGIONAL CHARACTERISATION OF A MAJOR STORAGE SYSTEM: GIPPSLAND BASIN, SOUTHEAST AUSTRALIA

Catherine M. Gibson-Poole[1,2], Lotte Svendsen[1,2], James Underschultz[1,3], Maxwell N. Watson[1,2], Jonathan Ennis-King[1,4], Peter J. van Ruth[1,2], Emma J. Nelson[2], Richard F. Daniel[1,2] and Yildiray Cinar[1,5]

[1]CRC for Greenhouse Gas Technologies (CO2CRC)

[2]Australian School of Petroleum
The University of Adelaide
Adelaide, SA 5005, Australia

[3]CSIRO Petroleum
PO Box 1130
Bentley, WA 6102, Australia.

[4]CSIRO Petroleum
Private Bag 10
Clayton South, VIC 3169, Australia

[5]School of Petroleum Engineering
The University of New South Wales
Sydney, NSW 2052, Australia
e-mail: cgibsonp@asp.adelaide.edu.au

INTRODUCTION

Much of the electricity for the State of Victoria, southeast Australia, is generated from power stations fuelled by the extensive brown coal resources of the Latrobe Valley. Whilst this is a cheap source of energy, there is increasing concern over the contribution of greenhouse gases to the atmosphere from fossil fuel combustion. Thus, geological storage of carbon dioxide (CO_2) is being investigated by the Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) as a possible method for storing the very large volumes of CO_2 emissions from the Latrobe Valley area.

The ideal sink for this large source of CO_2 is the neighbouring offshore Gippsland Basin (Figure 1), which is one of Australia's premier hydrocarbon provinces and has been producing since the 1960s. The depletion and decommissioning of some of the major oil fields is likely to coincide with the need for storage for anticipated CO_2 sources from new coal developments in the Latrobe Valley. Enhanced oil recovery using CO_2 is not being considered for the oil fields at present, since primary recoveries are already very high.

A recent study has focused on storage of CO_2 emitted from the use of new coal developments in the area, which are planned to be Carbon Capture and Storage (CCS) compatible. A storage capacity of about 50 million tonnes per year (Mt/y) for a minimum 40-year injection period is required, which provides a significant challenge of scale not previously considered. One single site will not be able to accommodate a source of this magnitude individually, so a regional solution must be found. To meet this challenge, several individual storage sites within the offshore Gippsland Basin will need to be utilised both sequentially and simultaneously.

GEOLOGICAL SETTING

The reservoir intervals are interbedded sandstones, shales and coals of the Paleocene-Eocene upper Latrobe Group. The sediments were deposited in alluvial plain, coastal plain, shoreface and shelf depositional environments along wave-dominated shorelines. The Gurnard Formation at the top of the Latrobe Group is a condensed, glauconitic marine shelf deposit, and is anticipated to act as either a low quality reservoir or a seal depending on the location. The Latrobe Group sediments are tilted structurally upwards to the east and are progressively truncated by the Latrobe Unconformity, a major basin-wide angular unconformity separating the reservoir intervals of the Latrobe Group from the overlying Seaspray Group. The fine-grained sediments of the Lakes Entrance Formation at the base of the Seaspray Group were deposited in shelf, slope and basinal depositional environments, and act as the regional seal.

REGIONAL-SCALE MIGRATION PATHWAYS

An analysis of the likely migration pathways at the top Latrobe Group (base regional seal) identified two main trends: (1) migration from a basin centre location via the northern gas fields of Marlin, Snapper and Barracouta, and (2) migration via the southern oil fields of Fortescue, Kingfish and Bream (Figure 1).

It is envisaged that individual sites from along these two trends would be used sequentially, ramping up the volume of CO_2 stored to 50 Mt/y but timed such that existing hydrocarbon assets are not compromised.

INJECTION SCENARIOS

Taking into consideration techno-economic constraints such as depletion schedules (i.e. oil before gas), a rollout plan of injection sites was devised. The first site to potentially be utilised is the Kingfish Field area. This oil field is anticipated to be depleted within the period 2015–2025 and thus available for CO_2 storage. The injection scenario assumes 15 Mt/y injection for a 40-year period, starting in the year 2015. The second site is the Fortescue Field area, also for 15 Mt/y for 40 years, commencing in 2022. The third site is the basin centre and northern gas fields trend (Marlin, Snapper, Barracouta), which assumes an injection scenario of 20 Mt/y for 40 years commencing in 2030.

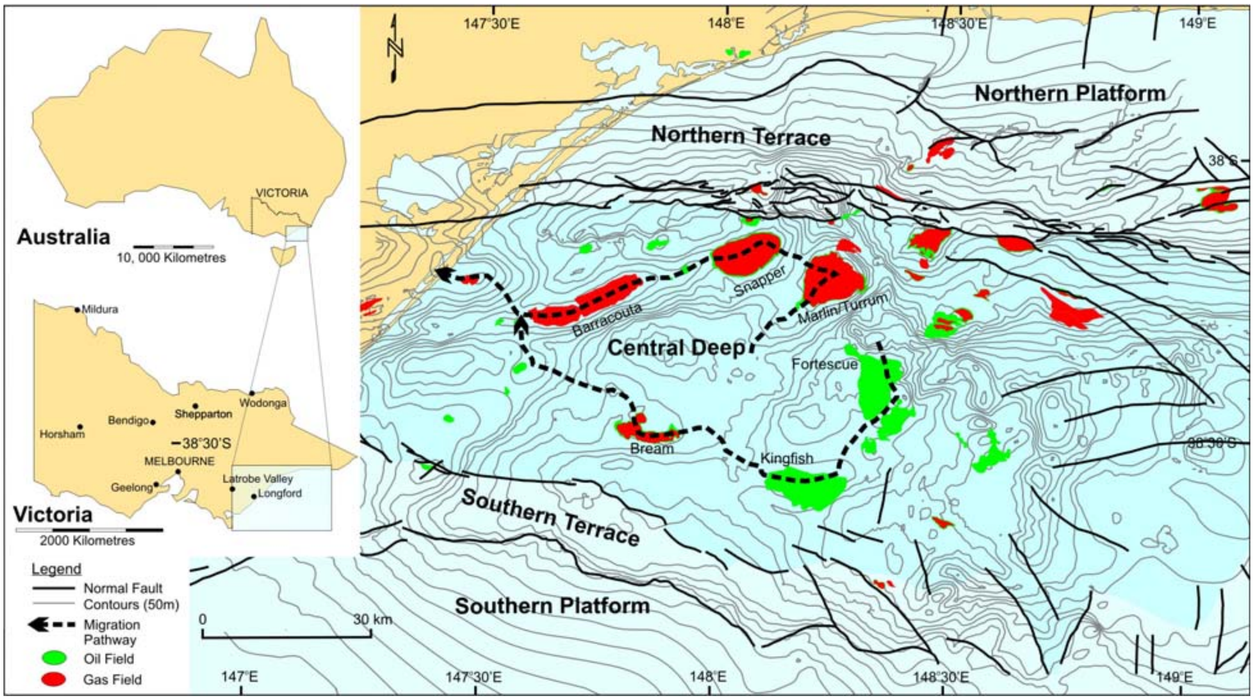


Figure 1. Location map of the Gippsland Basin, southeast Australia, showing key tectonic elements and existing oil and gas accumulations. The depth structure contours of the top Latrobe Group (base regional seal) are shown, and potential CO_2 migration pathways are indicated.

For the Kingfish and Fortescue field areas, the concept involves CO_2 injection deep beneath the main oil accumulations (>500 m deeper), within the intra-Latrobe Group stratigraphy. For the basin centre site, injection is within the top Latrobe Group stratigraphy (same interval as the hydrocarbons), but significantly downdip from the existing gas accumulations. The CO_2 injection and storage strategies proposed are intended to provide a time delay before the depleted hydrocarbon assets are reached, to increase the potential storage capacity by accessing greater pore space and to take advantage of several trapping mechanisms (residual, dissolution, mineral and structural trapping).

DETAILED CHARACTERISATION

The subsurface behaviour of CO_2 is influenced by many variables, including reservoir and seal structure, stratigraphic architecture, reservoir heterogeneity, relative permeability, faults/fractures, pressure/temperature conditions, mineralogical composition of the rock framework, and hydrodynamics and geochemistry of the *in situ* formation fluids. Therefore, accurate appraisal of a potential CO_2 storage site requires detailed reservoir and seal characterisation, 3-D geological modelling, numerical flow simulation, economic modelling, and risk and uncertainty analysis (Gibson-Poole et al., 2005) (Figure 2).

The detailed geological characterisation concluded that the reservoirs are of sufficient quality to allow injection. At the Kingfish and Fortescue field areas, the complex intra-Latrobe Group stratigraphy would provide baffles and intraformational seals that would hinder and slow the migration of the CO_2, thus allowing other trapping mechanisms such as residual gas trapping and dissolution to take effect. An assessment of the regional seal determined that the Lakes Entrance Formation has sufficient seal capacity to successfully retain the CO_2.

A geochemical evaluation of the likely CO_2-water-rock interactions revealed that mineral reactions in the low-reactive reservoir units are unlikely to occur during the short-term (injection period), thus the injectivity of the reservoir units would not be compromised. However, mineral reactions are possible in the low permeability Gurnard Formation at the top of the Latrobe Group, which would provide mineralogical storage of CO_2.

The geomechanical assessment established that there is some potential for fault reactivation, thus pore pressure increases would need to be carefully monitored. However, most of the faults present are not in the predicted immediate CO_2 migration pathways and most do not cut the top seal.

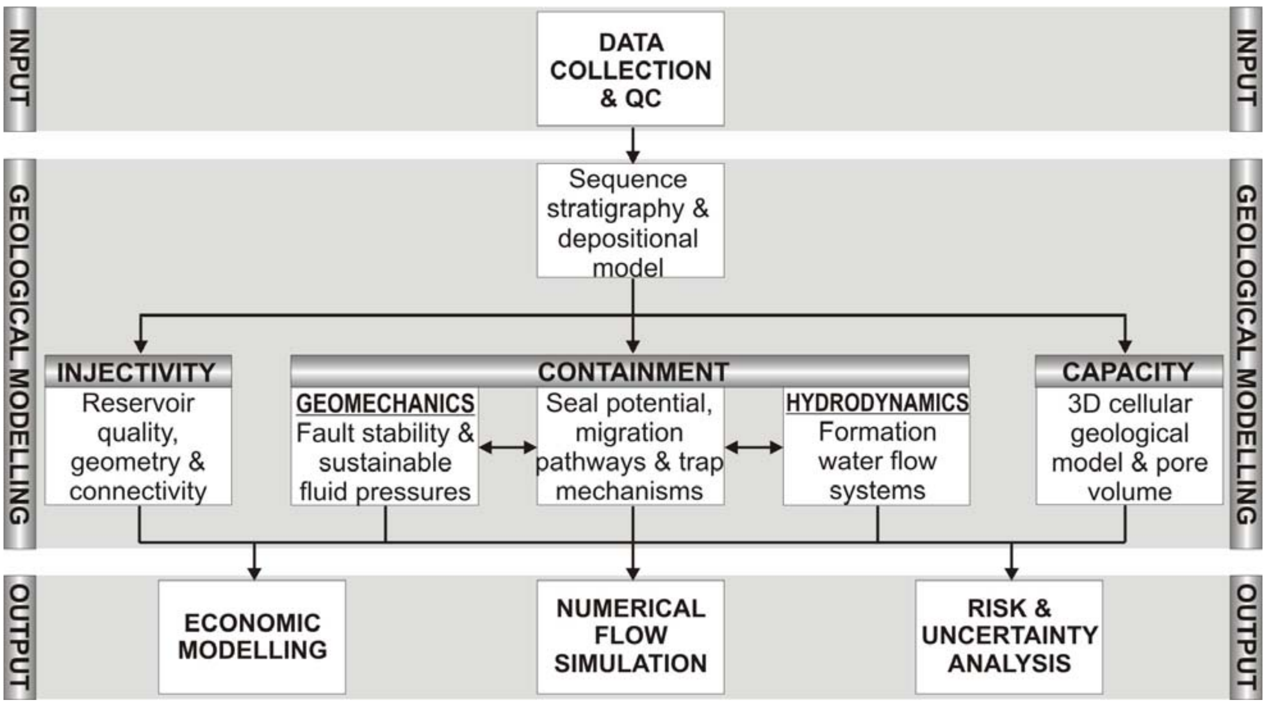


Figure 2. Workflow for CO_2 geological storage assessment (after Gibson-Poole et al., 2005).

A review of the hydrodynamic flow regime determined that the formation water flow has been affected by hydrocarbon production in the region. At the basin centre site, the hydrodynamic flow is likely to have little effect due to the significant structural gradient. However, in the Kingfish Field area the locally steepened hydraulic gradient opposes the expected buoyancy-driven migration direction and may positively impact on the predicted migration direction and containment of CO_2 in the short-term (10s to 100s of years).

Numerical flow simulation models were constructed from depth-converted seismic surfaces and the porosity-permeability characteristics of the intersecting wells. Shale distributions were modelled either by means of reduced vertical permeability or by object modelling to reflect the stratigraphic complexity. The numerical simulations indicate that it is feasible to inject 15–20 Mt/y into the Latrobe Group reservoirs. Sensitivity studies conducted on short-term (25–40 years) numerical simulations determined that permeability and the fracture pressure affect the maximum injection rate of CO_2 that can be achieved. An increase in the number of injection wells can compensate for this effect. The long-term (post-injection to 2,000 years) numerical simulations verified that the first arrival of CO_2 at the hydrocarbon-producing areas is decades after injection commences (i.e. after planned decommissioning of the Kingfish and Marlin Fields) and that a deep injection strategy results in greater CO_2 storage via residual gas saturation.

CONCLUSIONS

There are several features to the offshore Gippsland Basin that make it particularly favourable for CO_2 storage. These include: a complex stratigraphic architecture that provides baffles which slow vertical migration and increase residual gas trapping; non-reactive reservoir units that have high injectivity; a thin, suitably reactive, low permeability marginal reservoir just below the regional seal to provide additional mineral trapping; several depleted oil fields that provide storage capacity coupled with a transient flow regime that enhances containment, and; long migration pathways beneath a competent regional seal. This study has shown that the Gippsland Basin has sufficient capacity to store very large volumes of CO_2. It may provide a solution to the problem of substantially reducing greenhouse gas emissions from the use of new coal developments in the Latrobe Valley.

REFERENCES

Gibson-Poole, C.M., R.S. Root, S.C. Lang, J.E. Streit, A.L. Hennig, C.J. Otto, and J.R. Underschultz, Conducting comprehensive analyses of potential sites for geological CO_2 storage, In: E.S. Rubin, D.W. Keith & C.F. Gilboy (Eds.) *Greenhouse Gas Control Technologies: Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, Vol. I,* 673-681, 2005.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

ASSESSING AND EXPANDING CO_2 STORAGE CAPACITY IN DEPLETED AND NEAR-DEPLETED OIL RESERVOIRS

Vello A. Kuuskraa and George J. Koperna

Advanced Resources International, Inc.
4501 Fairfax Drive, Suite 910
Arlington, VA 22203 USA
vkuuskraa@adv-res.com and gkoperna@adv-res.com

INTRODUCTION

The United States, like many other parts of the world, has many large, mature oil reservoirs that are near the end of their economically productive lives. Numerous factors make these oil reservoirs ideal candidates for storing CO_2.

1. Established Trap. An oil reservoir has accumulated and held fluids for millions of years, thus providing confidence in the integrity of the reservoir seal and the permanence of the fluid trap. As such, CO_2 injected into an oil reservoir, as long as the injected CO_2 volumes do not exceed the spill-point, will likely remain "permanently" trapped and stored.

2. Value-Added Products. When the geological and oil property conditions are favorable, injecting CO_2 into a depleted or near-depleted oil reservoir can mobilize and recover a significant portion of the oil left behind after traditional primary and secondary oil recovery. This could provide revenues to offset some or all of the costs of storing CO_2.

3. Existing Infrastructure. In many cases, particularly for oil reservoirs that have been drilled with injection wells and have established waterflooding facilities, much of the essential infrastructure already exists for injecting and storing CO_2. As such, the initial capital requirements for establishing the CO_2 storage facility could be considerably lower than constructing an alternative CO_2 storage option.

KEY ISSUES

Given the many compelling reasons for using depleted and near-depleted oil reservoirs for CO_2 storage, the paper addresses the following topics:

1. What set of procedures would help one to rigorously assess CO_2 storage capacity?

2. What set of essential reservoir and fluid properties govern CO_2 storage capacity?

3. How would one identify oil reservoirs with potential for significant "value-added" oil production?

4. What steps could be taken to maximize the CO_2 storage capacity of oil reservoirs?

SUMMARY OF RECENT WORK

Advanced Resources International, in support of the Oil Technology Program, Office of Fossil Energy, U.S. Department of Energy, is completing a series of studies (including ten "basin reports") that address the above four questions.

1. Data Base. The studies are founded on a detailed reservoir data base of over 1,500 large (>50 MMBbls of OOIP) oil reservoirs, accounting for about two-thirds of the oil production/proved reserves in the U.S. These reservoirs are located in 22 of the oil producing states plus offshore Louisiana, as shown on Figure 1.

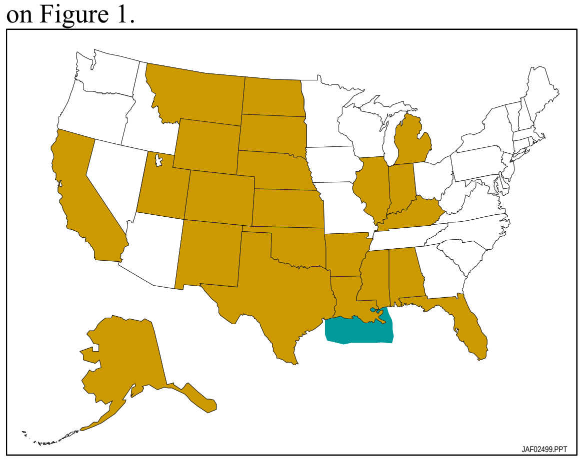


Figure 1. Oil Producing States Assessed for CO_2-EOR and CO_2 Storage Capacity.

2. Reservoir Modeling. With the data base in hand, the oil recovery and CO_2 storage capacity for each reservoir has been calculated under "state-of-the-art" CO_2-EOR and CO_2-storage technology using a streamline reservoir simulator (CO_2 PROPHET).

3. Alternative CO_2-EOR and CO_2 Storage Technology Options. Currently, the Advanced Resources studies are examining a set of "Next Generation" CO_2-EOR technologies that would lead to maximizing CO_2 storage in oil reservoirs. These alternative technologies involve using: (1) innovative flood designs and wells; (2) mobility control agents; (3) larger volumes of CO_2 injection; and, (4) real-time flood performance diagnostics and controls.

The information in this paper draws extensively on this on-going work.

CASE STUDY: MAXIMIZING CO_2 STORAGE

1. Production History. The Wellman Field (Wolfcamp), discovered in 1950 and located in West Texas, serves as one example of how innovative CO_2-EOR design can be used to maximize CO_2 storage while pursuing "value-added" oil recovery. The Wolfcamp reservoir in this field is a limestone reef of Permian age and holds 126 MMBbls of original oil in-place.

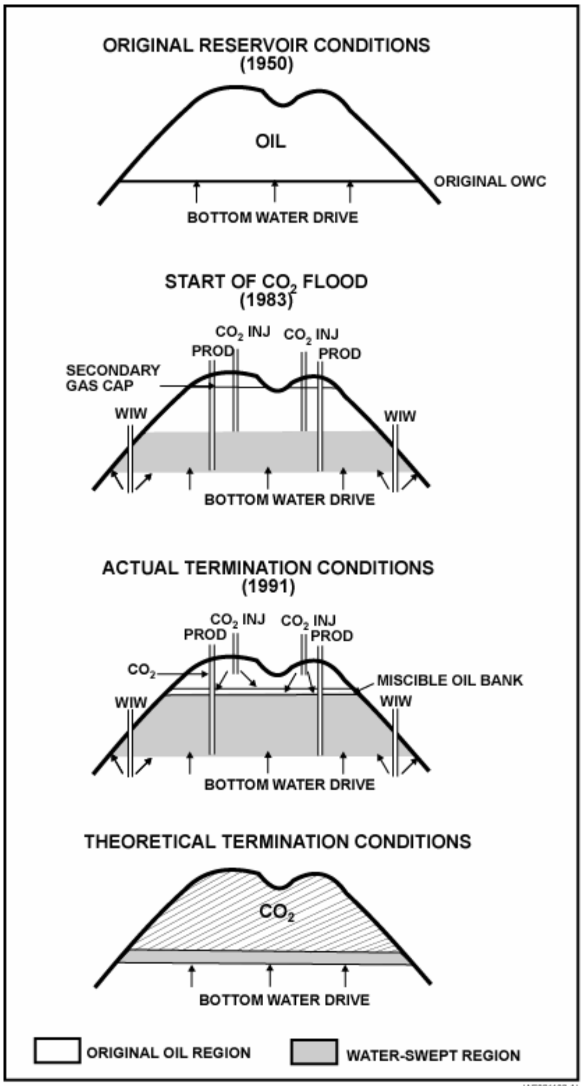


Figure 2. Migration of the Oil/Water Zone.

Primary oil production recovered 41.8 MMBbls, or 33.2% of the OOIP. During this time the oil/water contact rose 220 ft. from its original depth. Secondary oil recovery began in 1979 raising cumulative oil recovery to 55 MMBbls (43.7% of OOIP) by 1983. During secondary recovery, the oil/water contact rose another 160 ft, to a total of 380 ft. above the original oil/water contact.

Figure 2 illustrates the migration of the oil/water zone through the primary, secondary, and tertiary oil recovery phases.

2. CO_2-EOR Design and Results. Gravity-stable CO_2 injection was initiated in late 1983 and stopped in 1991, after injecting 23 Bcf (1.2 million tons) of CO_2. The gravity-stable CO_2 flood was prematurely terminated due to problems with sufficient access to CO_2. At the end of the CO_2 flood, the Wellman Field (Wolfcamp) had recovered a total of 69.2 MMBbls of which 3.5 MMBbls came from CO_2-EOR.

The operator estimated that if the CO_2 flood had continued as designed, ultimate oil recovery from the CO_2-EOR flood would have been 21 MMBbls, or 16.7% of OOIP. In addition, if the wells in this field had been deepened to fully produce the oil bank, an additional 7.5 million barrels of oil could have been produced. This would have raised tertiary oil recovery to 28.5 MMBbls or 22.7% OOIP, leading to storage of 185 Bcf (10 million tons) of CO_2.

TECHNCIAL POTENTIAL FOR STORING CO_2: GULF COAST OIL RESERVOIRS

Based on the work for one of the "basin reports" - - the Gulf Coast "basin study" - - the CO_2 storage potential in reservoirs favorable for CO_2-EOR in this area is as follows, Table 1:

- The technical potential for CO_2 storage (in oil reservoirs that would provide some level of "value added" revenues) is equal to 33,300 Bcf or 1,760 million metric tons.
- Introduction of "next generation" CO_2-EOR and CO_2-EOR storage technologies, such as discussed in the case study, could increase the CO_2 storage volumes to 48,700 Bcf or 2,580 million metric tons.
- Continued injection of CO_2 after the conclusion of the CO_2-EOR project would substantially increase CO_2 storage in these Gulf Coast oil reservoirs.

Table 1. Maximizing CO_2 Storage in Gulf Coast Oil Reservoirs

	Large Oil Reservoirs Data Base		Oil Recovery and CO_2 Storage (All Reservoirs)			
			"State-of-the-Art"		"Next Generation"	
	Reservoirs #	OOIP (MMBbls)	Recoverable Resource (MMBbls)	CO_2 Storage (Bcf)	Recoverable Resource (MMBbls)	CO_2 Storage (Bcf)
• Alabama/Florida	27	2,400	570	2,600	1,200*	3,900*
• Mississippi	34	3,000	840	3,700	1,300	4,700
• Louisiana (onshore)	178	20,400	5,490	27,000	12,020	40,100
– Data Base Total	239	25,800	-	-	-	-
– Extrapolated Total		44,400	6,900	33,300	14,550	48,700
(Million Tonnes)				(1,760)		(2,580)

**Estimated from Louisiana and Mississippi data.*

JAF26048.DOC

OPPORTUNITIES FOR CO_2 GEOLOGICAL STORAGE IN CENTRAL COAL BASIN (NORTHERN SPAIN)

Jorge Loredo, Pablo Cienfuegos, and Fernando Pendás

University of Oviedo
E.T.S. Ingenieros de Minas
Independencia 13
33004 Oviedo, Spain
e-mail: jloredoe@uniovi.es

INTRODUCTION

In order to reduce net CO_2 emissions to the atmosphere, the geological storage by capturing from major stationary sources and injecting it into suitable deep rock formations provides a powerful way. Geological storage of anthropogenic CO_2 was already proposed in the 1970's (Marchetti, 1977), but little studies were done until the early 1990's when research groups began to work seriously on the matter (Holloway and Savage, 1993; Bachu et al., 1994). Currently, many projects are under operation and study in many sedimentary basins of the world and the perspectives for development are very promising. The geological storage of CO_2 can play a key role in the transit from the conventional technologies with fossil fuels to the hydrogen technology and other clean sources of energy.

Asturias, in northern Spain, is the site of a big industry. Thermoelectric plants of soft coal and anthracite with an installed total power of 5,624 Mw remain the largest source of CO_2 emissions, representing the 60 % of total emissions. CO_2 yearly emissions of the whole of the Asturian thermoelectric plants exceed 18 Mt and together with the emissions from steel industry (6 Mt CO_2) and cement industry (2.12 Mt CO_2) constitutes the main sources generating CO_2 emissions. The CO_2 emissions in Asturias represent the 8% of total CO_2 emissions in Spain, whereas population represents only 2.60% and GDP the 2.27%.

In this context, until the development of renewable energy plants with H_2 as source of energy, the CO_2 geological sequestration can help to reduce the emissions to the environment of the new plants of coal and natural gas combined cycle.

GEOLOGY AND HYDROGEOLOGY

Asturias Central Coal Basin constitutes the biggest productive carboniferous area of the Iberian Peninsula, with an extension bigger than 1500 km^2. It is intensively deformed and fractured and affected by two generations or folding phases, which originate great synclines and anticlines forming a typical structure of domes and basins. The intense tectonic deformation conditions that the 50% of the coal beds show dip higher than 60º. To the northern, the coal basin is covered by Permo-Mesozoic and Tertiary sediments, whereas to the southern limits with a great tectonic accident: the León fault. To the west, the limit is constituted by the basal overthrust of the Aramo Unit and to the east overlaps over the Región del Manto del Ponga.

It can be considered two main hydrogeological basins in the area: the Nalón and Caudal basins. The Caudal basin extends in the form of fan in the South-occidental part of the Central Coal Basin, The Nalón basin has a more longitudinal form with a clear disposition Southeast-Northwest; all of its tributaries are very short and they meet the Nalón River in a perpendicular way. They can be considered multibed type aquifer, where the materials forming the stratigraphic series are characterized by very low porosity and permeability. Primary permeability of not fractured rocks is lower than 10^{-7} m/seg. Permeability of fractured rock massif is $5{\cdot}10^{-6}$ to $1{\cdot}10^{-6}$ m/seg. The functioning of the multibed aquifer system is deeply altered by the mine works. Central Coal Basin is characterised by important rates of pluviometry and infiltration. Furthermore the fracturation associated to mining operations gives that in the environment of the mines, the rocky massif drains in a great part towards the inside of the mine voids.

According to regional geology, the options for CO_2 geological sequestration in Asturias are deep saline aquifers and unexploited coal beds.

CO2 SEQUESTRATION IN AQUIFERS

Asturias has a Palaeozoic sedimentary basin which counts on carbonated and silicoclastic aquifer formations constituting potential reservoirs of great thickness and good caprocks in Carboniferous and Devonian materials. In relation to the geological sequestration in deep saline aquifers, it can be considered two areas of interest: the synclinal structure of La Camocha in La Sobia-Bodón Unit, and a synclinorium structure in Central Coal Basin Unit.

La Camocha synclinal structure is covered by permo-triassic sediments, whereas the nucleus is constituted by Upper Carboniferous sediments that have been object of an intense mining on the last 75 years. Aquifers of interest in this area are the Mountain Limestone with 1,500 metre thick, good characteristics of porosity (1-2%) and permeability, and the reef Muniello Limestone of 150-200 metres thick. The aquifer recharge is from the very complex tectonic zone of the Ventaniella fault, and the syncline borders.

The synclinorium structure in Central Coal Basin Unit is open in the nucleus to Upper Carboniferous levels in tights anticline and syncline structures objects of an intense mining on the last two centuries. The aquifers of interest are: the Mountain limestones with 200 to 300 metres thick. They are mudstone of low porosity and permeability, which acquire more favourable conditions by dolomitization and fracturation. The aquifer recharge has place in its eastern border and water circulation is superficial from the watershed of the Nalón and Aller riverbeds, and deep with unloading by diffuse circulation through the carboniferous series.

CO2 SEQUESTRATION IN COAL BEDS

CO_2 sequestration in coal beds goes in parallel to the coalbed methane industry. Geological variables are very important for selection of CO_2 storage sites in coal beds. The theoretical estimation of CO_2 storage in coal beds has been made under the hypothesis that the substitution relation between methane and carbon dioxide is 1:2 supposing that coal bed is completely saturated in gas. As storage capacity is related to gas content, the methodology used for CO_2 storage estimation is similar to used for CBM resources CBM (m^3) = $\rho \cdot S \cdot e_m \cdot G$ where:

ρ = Average coal density (1.6 t/m^3 has been considered for all coal beds).
e_m= Coal bed thickness (m)
S = Average coal bed surface (m^2).
G = Average methane content (m^3/t).

For CO2 storage estimation, the division of Central Coal Basin in zones of established in the National Inventory of Coal Resources, has been considered: North Zone, West Zone, La Justa Zone, and Centre Zone.

In the north zone, coal reserves up to 800 m depth are evaluated in 1,240 Mt., and accumulated coal bed thickness is 57 m. Average content in volatiles is 30 %, indicating that the evolution grade is moderate. For coals without ashes gas content is 3.88 to 9.35 m3/t. Capacity for CO_2 storage has been evaluated in 12.47 Mt CO_2.

In the west zone, coal reserves up to 800 m depth are evaluated in 769 Mt. Accumulated coal bed thickness is 15 m. Average content in volatiles is 30 %, indicating that the evolution grade is moderate. For coals without ashes, gas content is 3.79 to 9.89 m3/t. Capacity for CO_2 storage has been evaluated in 4.22 Mt CO_2.

Coal reserves up to 800 m depth in La Justa zone are 134 Mt, with an accumulated coal bed thickness comprised between 11 and 15 m. Average content in volatiles is 32 - 37 %, indicating bituminous coals with high volatiles degree. For coals without ashes, gas content is 8.2 m3/t. Capacity for CO2 storage has been evaluated in 6.26 Mt CO_2.

In the centre zone, coal reserves up to 800 m depth are 570 Mt., and accumulated coal bed thickness is 26 m. Volatiles content is 22 - 32 %, indicating that the evolution grade is moderate with coals from bituminous to sub-bituminous. For coals without ashes, gas content is 5.6 to 10.81 m3/t. Capacity for CO2 storage has been evaluated in 7.39 Mt CO_2.

CONCLUSIONS

Deep saline aquifers seem to be the most attractive objectives for CO_2 geological storage projects in Asturias. Since the emissions of the thermoelectric plants suppose 18 Mt CO_2 and each million ton CO_2 supposes a flow of 40 l/s, the injection of the CO_2 emissions from the thermoelectric plants supposes a flow of 800 l/s, figure which is attainable, given the extraordinary potential for CO2 storage of aquifers in this area.

The possibility for CO_2 sequestration in coal beds is modest and associated to the CBM commercial exploitation. It has been estimated in 30 Mt CO_2 that is equivalent to 1 year of emissions. However, if will be devoted about the 10 % of these emissions to the enhanced recovery of CBM, it could be obtained an important reduction of the CO_2 emissions in the next decade, furthermore than an special benefit by the increase on the performance in a 20 to 30 % to the typical extraction of CBM.

Finally, it is necessary to have in mind that the feasibility of CO_2 geological storage in Asturias apart of technical factors will depend on price of CO_2 ton, legal conditioning and possibility to apply emission rights to projects.

REFERENCES

Bachu, S., W.G. Wunter, and E.H. Perkins. (1994). Aquifer disposal of CO2: hydrodynamic and mineral trapping, Energy Conversion Management, 35 (4), 269-279.

Holloway, S. and D. Savage, The potential for aquifer disposal of carbon dioxide in the UK. *Energy Conversion and Management, 34 (9-11),* 925-932. 1993.

Marchetti, C., On geoengineering and the CO2 problem. *Climatic Change, 1,* 59-68. 1977.

CHARACTERIZATION OF POTENTIAL STORAGE SITES IN THE WEST COAST STATES

Larry Myer[1], Cameron Downey[2], John Clinkenbeard[2], Steven Thomas[3], Scott Stevens[4], Sally Benson[5], Henry Zheng[6], Howard Herzog[6], and Jon Price[7]

[1]PIER Program
California Energy Commission
Sacramento, CA

[2] California Geological Survey
Sacramento, CA

[3]Golder Associates
Redmond, WA

[4]Advanced Resources International, Inc. (ARI)
Arlington, VA

[5]Earth Sciences Division
Lawrence Berkeley National Laboratory

[6]MIT Lab for Energy and Environment
Cambridge, MA

[7]Nevada Bureau of Mines and Geology
Reno, NV

An initial assessment of the potential for geologic storage of CO_2 in the West Coast states was carried out as part of Phase I of the WESTCARB project. This work included a review of 104 sedimentary basins in California, an initial characterization of sedimentary basins and deep coal seams for sequestration in Washington and Oregon, assessments of oil and gas reservoirs in California, and assessment of sedimentary basins in Nevada.

The work focused on sedimentary basins as the initial most-promising targets for geologic sequestration. The approach for various states has followed similar steps: First, the extent (area) of the basins was determined and entered into a GIS layer. Baseline data was then collected, and preliminary screening conducted, using such criteria as the presence of porous sediments, depth, and restricted access, resulting in a list of basins for which more detailed data on geologic properties were obtained. Priority was given to basins in which there are potential value-added benefits from enhanced oil recovery (EOR), enhanced gas recovery (EGR), and enhanced coal bed methane recovery (ECBM). Data from reservoirs in these basins form the bulk of the characterization data. The third step entailed evaluating CO_2 storage capacity. Ultimately, the characterization data is integrated with source and transportation data to evaluate economics and develop supply curves for regional source/sink options.

In California, the screening process excluded basins from further consideration on the basis of lack of sufficient depth (<800 m), lack of porous or permeable rocks, or lack of identifiable seals. (Basins underlying national parks and military installations are also excluded from further consideration.) Of the 104 basins evaluated to date, 77 have been excluded for one of the reasons listed above. In conjunction with this effort, the California Geological Survey (CGS) prepared depth-to-basement and sandstone isopach maps for major sedimentary basins for which geophysical or well log data were available.

The oil and gas reservoirs in California were assessed by compiling and analyzing published state data, including discovery date and well, deepest well and depth, well locations, field area, cumulative production, base of freshwater, and specific physical rock and fluid properties for each producing, idle, or abandoned zone within each field. Results are being used to screen fields for CO_2 storage potential and identify depleted or abandoned fields for CO_2 EOR or sequestration opportunities.

In Nevada, the minimum basin depth criterion was taken as 1000 m (3300 ft) due to a generally higher geothermal gradient in the Basin and Range province. An approach to account for the proximity of potential sinks to faults and mineral and geothermal resources was developed, and a conceptual model for saline formations and oil and gas reservoirs was created.

In Oregon and Washington, information on coal formations as potential sinks was compiled, as was data on the overall geology of sedimentary basins. For coal, available data on coal rank, per cent methane saturation, and sorbtive capacity were compiled in addition to other reservoir properties.

The Phase I assessment shows that are excellent geologic storage opportunities in the WESTCARB region in each of the major technology areas: saline formations, oil and gas reservoirs, and coal beds.

California offers outstanding opportunities because of large capacity and the potential of value-added benefits from EOR and EGR. Figure 1 is a map of the sedimentary basins in California, showing those basins which passed preliminary screening, oil and gas fields, and large point sources. Of the 27 basins which met the screening criteria, the most promising are the larger Cenozoic marine basins, including the San Joaquin, Sacramento, Los Angeles, Ventura, and Salinas basins, followed by the smaller Eel River, La Honda, Cuyama, Livermore, and Orinda marine basins. Favorable attributes of these basins include 1) geographic diversity; 2) thick sedimentary fill with multiple porous and permeable aquifers and hydrocarbon reservoirs; 3) thick, laterally persistent marine shale seals; 4) locally abundant geological, petrophysical, and fluid data from oil and gas operations; and 5) numerous abandoned or mature oil and gas fields which might be reactivated for CO_2 sequestration or benefit from CO_2 enhanced recovery operations. Our estimate of the storage capacity of saline formations in the ten largest basins in California ranges from about 150 to about 500 Gt of CO_2, depending on assumptions about the fraction of the formations used and the fraction of the pore volume filled with separate-phase CO_2 (Figure 2). The low end of this range would provide sufficient capacity for storing over 1,000 years of utility and industrial sector emissions at the current emission rates.

The first sequestration targets are likely to be oil reservoirs where CO_2 EOR will help offset overall capture and storage costs. In California, most oil reservoirs are found in the San Joaquin Basin, Los Angeles Basin, and southern coastal basins. Estimates made by WESTCARB investigators yielded a potential CO_2-EOR storage of 3.4 Gt, based on a screening of reservoirs using depth, an API gravity cutoff, and cumulative oil produced. Capacity estimates will be further refined in Phase II.

There are abundant gas reservoirs in the Sacramento Basin, including Rio Vista, the largest onshore gas field in California, and has produced over 9.3×10^{10} m^3 (3.3 Tcf) of natural gas since 1936. The cumulative production from gas reservoirs (screened by depth) suggests a CO_2 storage capacity of 1.7 Gt.

In Oregon and Washington, the most promising near term sedimentary basin targets are found in the Coastal Ranges and Puget-Willamette Lowlands geomorphic provinces, though several interior basins may also be important because of the location of large emission sources (Figure 3). The Coastal Ranges and Puget-Willamette Lowlands provinces are the home of a major Tertiary sedimentary belt of basins characterized by up to 20,000 feet of Tertiary sedimentary rocks deposited in embayments and shallow seas. The Willapa Hills basin is the most promising Coastal Range Basin for hydrocarbon development, and, therefore CO_2 storage, because of the deep-water sandstones, thick shales and claystones, and anticlinal traps. Of particular interest in the Puget-Willamette Lowlands is the Puget Trough Basin, which contains up to 3,700 feet of unconsolidated sediments overlying up to 10,000 feet of Tertiary sedimentary rocks. The Puget Trough Basin also contains deep coal formations, which are sequestration targets and may have potential for ECBM. The amount of unmineable coal in the Puget Sound basin was estimated to be over 70 billion tons, with a CO_2 storage potential of 2.8 Gt.

In Oregon, the Astoria-Nehalem Basin is of significance because it contains the only economically productive gas filed in Oregon (known as the Mist Gas Field), which occupies an area of about five square miles and was first produced from in 1979. The basin geology is complex due to the extensive folding and faulting. Of key importance is gas-producing Clark & Wilson (C&W) Sandstone which is overlain by a thick shale unit. The C&W sandstones have porosities up to 39% and permeabiliites from 1 – 1,400 md.

In Nevada, many small basins were identified, but there is generally a paucity of information on the structure and properties of these sediments. Assessments of their suitability and of the potential for mineral storage techniques using mafic rock will be carried out in Phase II.

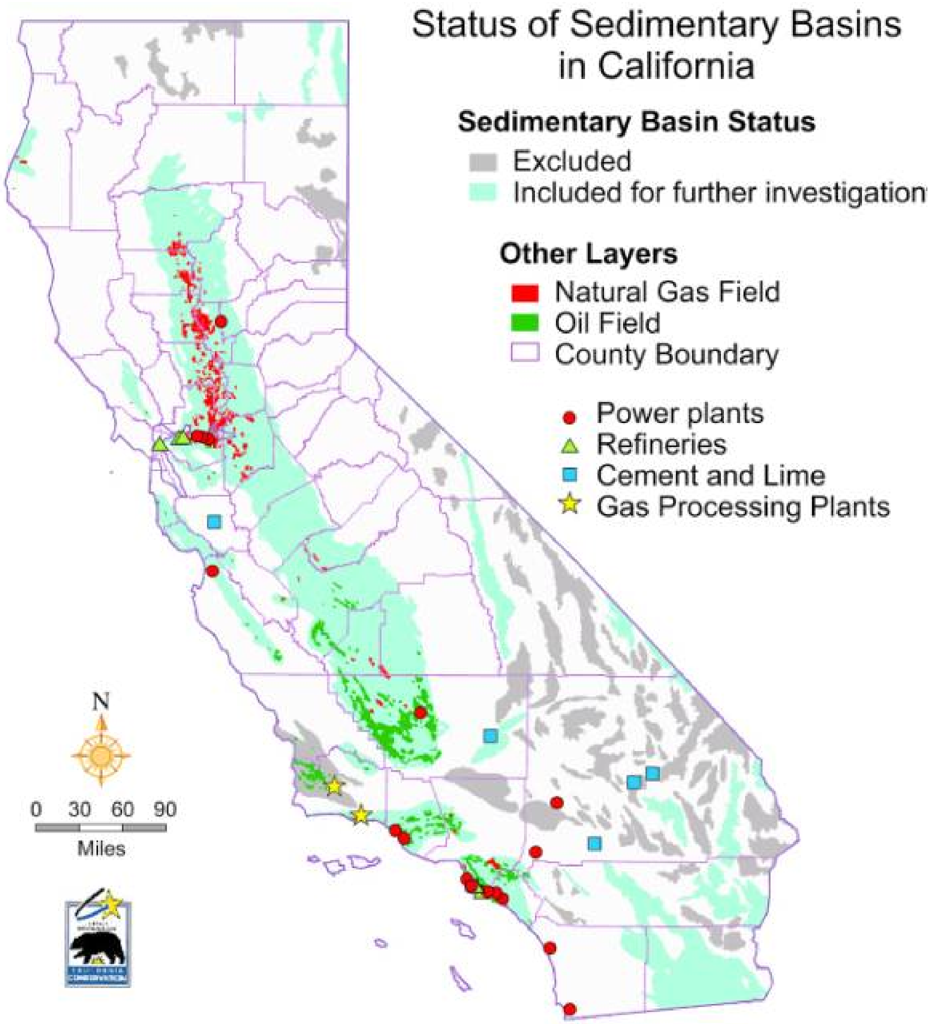


Figure 1. California sedimentary basins, oil and gas fields, and industrial CO_2 emissions sources.

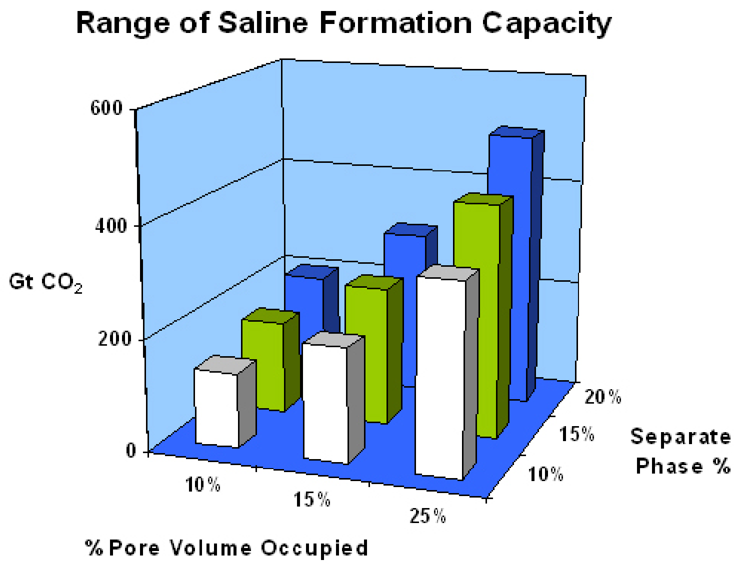


Figure 2. Total sequestration capacity of saline formations in ten largest basins in California

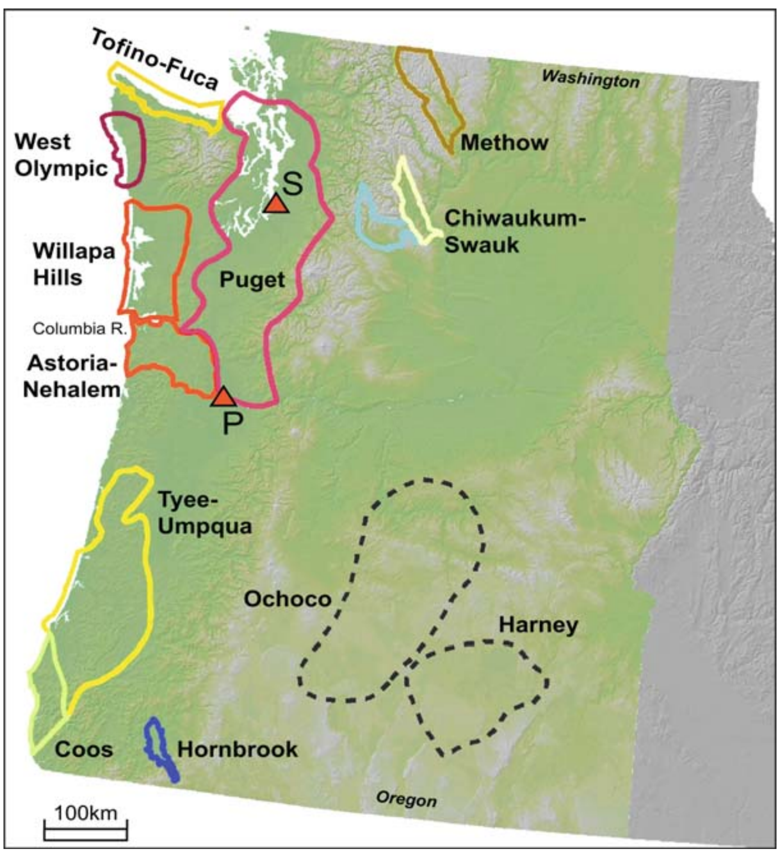


Figure 3. Sedimentary basins in Oregon and Washington

MIDWEST REGIONAL CARBON SEQUESTRATION PARTNERSHIP, PRELIMINARY ASSESSMENT OF POTENTIAL CO_2 STORAGE RESERVOIRS AND CONFINEMENT, CINCINNATI ARCH SITE

J. Rupp[1], W. Solano[1], S. Greb[2], L. Wickstrom[3], and N. Gupta[4]

[1] Indiana Geological Survey
611 N. Walnut Grove
Bloomington, IN 47405
e-mail: rupp@indiana.edu

[2] Kentucky Geological Survey
Mining and Minerals Building
Lexington, KY 40506
e-mail: greb@uky.edu

[3] Ohio Division of Geological Survey
2045 Morse Rd., Bldg. C1
Columbus, OH 43229
e-mail: larry.wickstrom@dnr.state.oh.us

[4] Battelle Memorial Institute
505 King Ave.
Columbus, OH 43201
e-mail: gupta@battelle.org

INTRODUCTION

The Indiana, Kentucky, and Ohio Geological Surveys, working under the auspices of the Midwest Regional Carbon Sequestration Partnership (MRCSP), completed a preliminary report on the feasibility of geological sequestration as a carbon management strategy for a large coal-fired power-generation facility. This proposed Cincinnati Arch field demonstration project is planned as part of MRCSP's Phase II sequestration evaluation within the Regional Partnership. Broad structural arches in which deep Paleozoic strata rise to near the surface are a major part of the geology of the MRCSP region. Also, structural arches underlie many of the CO_2 sources in the region. Understanding the feasibility for sequestration in these situations as compared to deeper, basinal configurations is important for regional CO_2 sequestration assessment.

The objective of this feasibility study is to provide a preliminary assessment of known geologic characteristics of the region surrounding the site. An area within a radius of approximately 50 miles of the site was included in the study. The primary purpose of the assessment was to determine the presence, configuration, and characteristics of potential reservoirs and confining strata.

If the Cincinnati Arch site is chosen as a pilot injection site by the MRCSP, a detailed geological and geophysical evaluation program, including the acquisition of new site-specific information will follow this preliminary assessment. This information will be used as the basis for other tasks to be completed by the MRCSP including: developing a field work plan; assessing site-specific data acquisition needs (seismic profiles, seismic monitoring, acquisition of available commercial data, test borings, etc.); design of the injection well, monitoring plan, and reservoir simulations; and the acquisition of an underground injection permit.

PRELIMINARY ASSESSMENT

The three state geological surveys worked cooperatively to integrate subsurface data unique to their states into a combined analysis that includes a stratigraphic model, structure and isopach maps, and geologic cross sections. The principal sources of the deep subsurface information in the study area were obtained from deep wells drilled for oil and gas exploration. Data from water wells, and shallow oil and gas wells, were also used for interpreting the near-surface geology. Rock and water samples, along with geophysical logs obtained from deep boreholes, were analyzed to obtain information on the lithologies, petrophysical characteristics, and bulk water-chemistry of the intervals that were penetrated. Three small, shallow gas storage fields in Knox carbonates are located in the study region, and subsurface logs and field histories were also evaluated as part of this investigation. Although no reflection seismic data were available within the study area, such data are available outside of the study region and are used to define the major deep structures in the region.

The general location of the study area is along the Ohio River at the junction of northern Kentucky and southeast Indiana, southwest of Cincinnati, Ohio (Figure 1). The study area was assessed on two fundamentally different scales: 1) the regional context (a 50-mile radius) and 2) the "area of review" (approximately a 2-mile radius). The area of review is the immediate vicinity of the site that may be affected by small-scale injection testing.

GEOLOGICAL SETTING

The regional geology of the area is characterized by an essentially undeformed sequence of lower Paleozoic (Cambrian through Ordovician) sedimentary rocks overlying a late Proterozoic sequence of mixed intrusive igneous and metasedimentary rocks that comprise the Precambrian basement complex. The overall tectonic context is that of the stable interior of the craton, while the regional structural setting is that of a north-south trending antiform, the Cincinnati Arch, which gently dips to the east into the Appalachian Basin and to the west into the Eastern Interior (Illinois) Basin. The Paleozoic sedimentary column is dominated by carbonate rocks (predominately dolomites at depth and limestones at and near the surface) and subordinate amounts of shales, sandstones, and siltstones. Paleozoic strata rise in elevation towards the crest of the arch, and post-middle(?) Ordovician strata were influenced by structural movement on the arch. Pre-Paleozoic sediments also exist along the Cincinnati Arch. The arch is underlain by the East Continent Rift Basin, a Proterozoic rift complex, which approximately parallels the trend of the arch, with several possible branches westward from the crest of the arch. This rift basin is filled with basalts and sedimentary rocks of the Middle Run Formation (Drahovzal et al., 1992). Because Middle Run strata were deposited prior to the formation of the Cincinnati Arch they do not show the same dips and structural configuration as overlying Paleozoic strata.

The evaluation of the Paleozoic and Proterozoic stratigraphy focused on three intervals (in descending order): 1) dolomite, limestone, and shales units of the uppermost Cambrian through middle Ordovician that could potentially serve as a confining unit, 2) the primary target reservoir rocks of the upper Cambrian Mount Simon Sandstone, and 3) the underlying potential reservoir rocks and seals of the Precambrian Middle Run Formation.

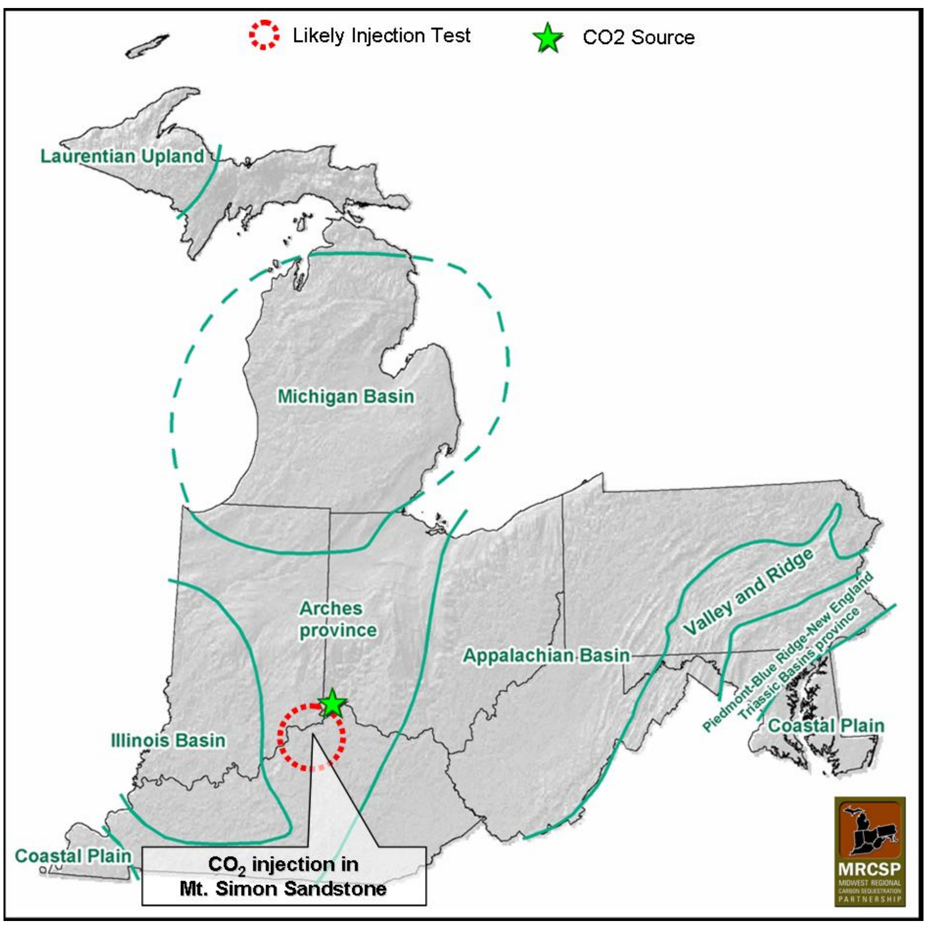


Figure 1. General location of the Cincinnati Arch project site

The subsurface data were interpreted to portray the general structural and thickness configurations of these three rock sequences. Structure maps were constructed for the following horizons (in descending stratigraphic order): Black River Group, Knox Supergroup, Eau Claire Formation, Mount Simon Sandstone, and the Precambrian basement complex. Thickness maps were constructed for the following stratigraphic intervals: Black River to Knox, Knox to Eau Claire, Eau Claire to Mount Simon, and Mount Simon to Precambrian basement (or top of the Middle Run where it is projected to occur). Additionally an attempt was made to map the thickness of the Middle Run based on potential field and seismic data outside the study region.

A review of all available geologic literature, maps, and data available for the area was conducted including regional reports and reservoir test data, as well as drill cuttings, and rock core information. The two most critical sources of previously constructed regional subsurface evaluations were the Phase I study of the MRCSP and the report compiled by the Cincinnati Arch Consortium (Drahovzal et al., 1992).

PRELIMINARY FINDINGS

Essential conclusions based on the examination of these data include:

1) As at many sites on interbasinal arches in the MRCSP region, many of the upper Paleozoic strata are too shallow or eroded to function as potential reservoir targets. The Cambrian Mount Simon Sandstone is located below 2,500 feet at the study site and is the candidate primary target for injection along this arch.

2) A significantly thick (300–400 ft) section of Mount Simon Sandstone is projected to exist at the site that could serve as a reservoir for injected CO_2. The top of this section is at a depth of approximately 3,700 feet, well below the depth necessary for maintaining CO_2 in a supercritical state (> ~2,400 feet in this region). Site-specific porosity and permeability data are not available for the sandstone at the study site at this time.

3) A thick sequence of dense carbonate and argillaceous rock (basal Knox, Davis Formation. and Eau Claire) directly overlies the Mount Simon at the study site. The combined thickness of these units exceeds 1,000 feet. Vertical permeability values below 0.01 millidarcies have been determined for core samples from this sequence in adjoining wells, so the interval should function as an effective confining unit.

4) Small gas storage fields have used porosity zones within the upper Knox carbonates in the study region. These porosity zones appear to be laterally confined, and are too shallow for supercritical injection at the study site. More than 1,000 feet of relatively impermeable dolomite occur between the potential porosity intervals in the upper Knox and the Mount Simon at the study site.

5) The structural setting of this site lies slightly downdip to the west of the axial trace of the Cincinnati Arch. The position of this trace changes with depth, migrating to the east with depth. No localized closure for structural entrapment is apparent from the existing data, but deep structures associated with the East Continent Rift Basin may occur.

6) There has been only one previous injection test in the Mount Simon in the study region. A waste disposal well in the vicinity of Louisville, Kentucky, located approximately 75 miles downdip from the study site. The well encountered tight sand within the Mount Simon and had to use alternate porosity zones in the overlying Knox Supergroup for an injection interval. While the Mount Simon may not be a homogenous, highly porous, and permeable sandstone as it is in the northern part of the MRCSP region, analyses of a well within 8 miles of the study site indicate that the porosity within the Mount Simon Sandstone interval increases with depth proportionally to a decrease in interbeds of silt and shaly siltstone.

7) Projections from seismic analyses outside of the study region indicate that the Proterozoic East Continent Rift Basin and Middle Run Formation should underlie the study site. Permeable sandstones have been encountered in the Middle Run in other areas and might exist beneath the Mount Simon. This is significant because, while the Mount Simon overlies impermeable crystalline basement in other areas of the region, here an additional interval may exist for injection in this part of MRCSP region.

8) Based on analyses of recovered brines and log analyses, the base of the underground source of drinking water (USDW) (<10,000 ppm total dissolved solids (TDS)) is located stratigraphically within the upper portion of the Knox carbonate sequence generally at depths of 2,000 or more feet beneath the surface. Although there is no direct measurement data at depth near the study site, calculations from geophysical logs in a nearby well confirm this distribution.

9) Most of the water for public use near the study site is from the Ohio River and Ohio River alluvium. Few wells are drilled into the bedrock, and salt water is found at depths greater than 100 feet below the level of the principal valley bottoms in

upland areas around the study site, such that there should be little risk of impact from an injection project. Some salt springs are known at the surface in the region, including the famous spring at Big Bone Lick State Park. Total TDS of springs on the arch are below maximum contaminant level (MCL), but the presence of local salt licks indicates the possibility of slow migration of deep, basinal saline waters out of the basins onto the crest of the arch; this migration influenced regional mineralization and may be important for understanding and modeling deep-water chemistry.

10) Significant unknowns remain regarding the potential for the rock sequence present at this site to accept and confine significant volumes of injected CO_2. Fundamental details that remain unknown include:

    a. Permeability and porosity of the Mount Simon or potential, deeper, Middle Run reservoirs;
    b. Compatibility of the mineralogical content of the potential reservoir and confining rock sequence with CO_2;
    c. Interactivity of CO_2 with the ambient brines within the reservoir;
    d. Predominant sequestration mechanism (dissolution/displacement/mineralization);
    e. Migration pathways and ultimate fate of the injectant.

Immediately following the completion of this preliminary feasibility study of the site, a program will be initiated that will assess the new data needs and acquisition procedures in order to address these unknowns. Details of the data acquisition associated with a drilling program (rock core and cuttings data, water samples, and pressure data) will be determined as well as pre-drilling acquisition of geophysical data (including reflection seismic information).

REFERENCES

Drahovzal, J.A., Harris, D.C., Wickstrom, L.H., Walker, D., Baranoski, M.T., Keith, B.D., and Furer, L.C., The East Continent Rift Basin: A New Discovery: edited by D.C. Harris for the Cincinnati Arch Consortium, *Indiana Geological Survey Special Report 52*, 25 p., 10 fig., 1992.

POTENTIAL FOR GEOLOGIC STORAGE OF CARBON DIOXIDE FROM COAL-FIRED ELECTRICAL GENERATING STATIONS IN ARIZONA, USA

Dennis H. Shirley, Edwin H. McGavock, and Errol L. Montgomery

Errol L. Montgomery & Associates, Inc.
1550 E. Prince Rd.
Tucson, AZ 85719, USA
e-mail: dshirley@elmontgomery.com

Large coal-fired electrical generating stations are presently operating at four sites in northeastern Arizona. The combined carbon dioxide (CO_2) discharge at these stations in year 2000 was approximately 42 million tons. Where favorable geologic and hydrologic conditions occur, CO_2 from existing and future Arizona generating stations might be captured for long-term storage in subsurface geologic reservoirs.

Favorable hydrologic conditions for subsurface storage include occurrence of sufficient hydraulic confining head above the top of a target reservoir to exceed critical pressure of liquid CO_2; this required hydraulic confining head is about 800 meters. Required volume for a target reservoir is less where CO_2 would be stored as a super-critical liquid, and more where CO_2 would be stored as a compressed gas. Favorable hydraulic conditions also include occurrence of saline groundwater in target reservoirs. Naturally occurring groundwater in target reservoirs under pre-injection conditions should contain total dissolved solids of no less than 10,000 mg/L (milligrams per liter) or approximately one-third of salinity of sea water. Favorable geologic conditions include occurrence of porous and permeable geologic units, such as sandstone strata, to comprise storage reservoirs; and occurrence of poorly permeable geologic units, such as mudstone or shale strata, capping a potential reservoir.

Opportunities for subsurface storage of CO_2 may be classified with respect to regional geologic conditions. Arizona occupies parts of two geologic provinces: the northeast half of the state is in the Colorado Plateau Geologic Province. This province is a high plateau region where landforms are dominated by buttes, mesas, deeply incised canyons, and volcanic peaks. Much of the Colorado Plateau is underlain by a thick sequence of nearly flat-lying sedimentary strata interrupted at places by faults and gentle folds. The existing coal-fired generating stations and the extensive Navajo and Hopi Indian Reservations occur in the Colorado Plateau Geologic Province. The southwest half of the state is in the Basin and Range Geologic Province. This province consists of broad desert basins bounded by precipitous mountain blocks. The basins in the Basin and Range Province comprise tectonically depressed troughs and have been filled to depths of 1,000 meters or more with materials eroded from the mountain blocks. This province includes the large cities of Phoenix and Tucson and more than 70 percent of Arizona's population. The northwest trending mountainous area of the Central Highlands transition zone occurs between the two provinces, is characterized chiefly by occurrence of igneous and metamorphic rocks, and has little potential for geologic storage. Locations of the provinces and of large coal-fired electrical generating stations in Arizona are shown on Figure 1.

Favorable geologic and hydrologic conditions for storage of CO_2 occur in selected areas of the Colorado Plateau province in Arizona. The most favorable physical conditions occur in the Black Mesa basin beneath the Navajo and Hopi Indian reservations. There, potential storage reservoirs in geologic formations of Mississippian through Permian age are overlain by Mesozoic strata containing numerous confining beds. In order of increasing depth and age, porous and permeable geologic formations include strata of the Navajo Sandstone, Coconino and De Chelly Sandstones, Esplanade member of the Supai Formation and Cedar Mesa Sandstone member of the Cutler Formation, Redwall Limestone, Temple Butte Limestone, Martin Formation, and Tapeats Sandstone. These geologic formations together with mudstone strata that serve as overlying capping or confining units are summarized in Table 1. A principal confining seal is the Triassic Chinle Formation, about 300-500 meters thick, and present in much of northeastern Arizona. Potentially favorable areas for geologic storage also occur about 50-90 kilometers southeast of Page, Arizona, near Kaibito, and in the area east from Holbrook and south of Interstate 40. In the Kaibito area, deep storage reservoirs and confining seals are present, but water quality in the Permian and older reservoir rocks is unknown. Potential storage areas south from Interstate 40 have a Permian Coconino Sandstone reservoir, containing very saline groundwater, and a confining seal of Chinle Formation. Heads in the Coconino Sandstone reservoir, however, are often less than 400 meters, requiring CO_2 to be stored in a gaseous phase.

Table 1. Geologic Reservoirs and Seals in Colorado Plateau Province, Arizona

Geologic Unit	*Age*	*Thickness (meters)*	*Description*	*Remarks*
Carmel Fm.	Jurassic	20-80	Claystone and sandstone	Confining bed beneath Black Mesa
Navajo SS.	Jurassic & Triassic	30-300	Fine to med.-grained eolian sandstone; porosity 25-30%	Potential reservoir beneath Black Mesa but groundwater contains <1,000 TDS
Kayenta, Wingate, Moenave Fms.	Triassic	200-250	Mudstone, siltstone, and sandstone	Primarily serve as confining beds in S. Black Mesa area
Chinle Formation	Triassic	100-400	Primarily bentonitic mudstone; some sandstone and conglomerate	Excellent confining seal in much of NE Arizona
Moenkopi Formation	Triassic	30-100	Siltstone and sandstone	Not considered an effective confining seal
Coconino – DeChelly Sandstones	Permian	100-300	Fine to med.-grained eolian sandstone	A major potential reservoir in much of NE Arizona; groundwater contains >10,000 TDS in 8,000 km^2 of southern Black Mesa area
Hermit Shale – Organ Rock mem. of Cutler Fm.	Permian	30-100	Primarily siltstone with sandstone lenses	Confining seal in Grand Canyon-Black Mesa area
Esplanade mem. of Supai Fm. – Cedar Mesa mem. of Cutler Fm.	Permian	20-200	Permeable sandstone with siltstone facies	Potential reservoir; not present in SE part of area shown on Figures 2 and 3
Lower Supai Fm.	Pennsylvanian	100-250	Siltstone, sandstone, and limestone; extensive halite beds in SE Black Mesa basin	Acts as both confining seal and potential CO_2 reservoir
Redwall Limestone, Temple Butte Limestone, and Martin Formation	Mississippi & Devonian	150-300	Primarily limestone and dolomite; cavernous in Grand Canyon area	Potential reservoir; not present in SE part of area shown on Figures 2 and 3
Tapeats Sandstone	Cambrian	50-80	Feldspathic, micaceous sandstone	Potential CO_2 reservoir

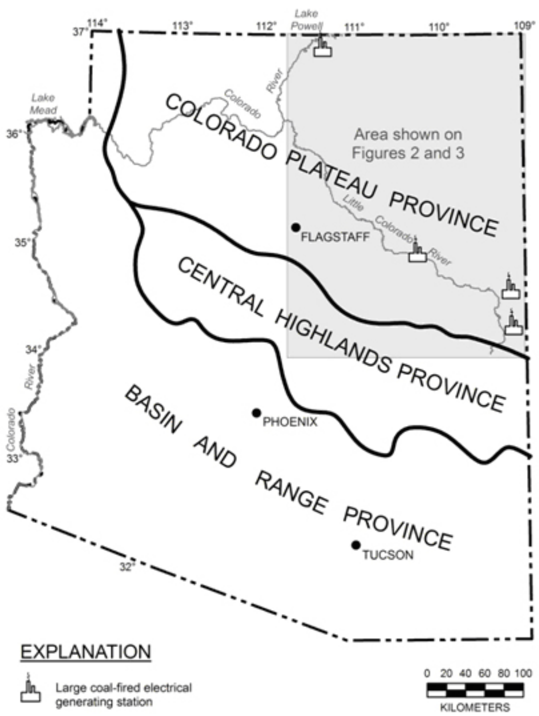


Figure 1. Arizona geologic provinces.

The Coconino and De Chelly Sandstones are stratigraphic equivalents, range in thickness from about 100 to 300 meters, and crop out or occur in the subsurface at most locations in northeast Arizona. Beneath Black Mesa, permeability and porosity of the sandstone is reported to be small, and total dissolved solids are reported to be about 750 mg/L. The most favorable and extensive targets for sequestration of compressed gaseous CO_2 from existing generating stations in the Arizona section of the Plateau Province are believed to occur in these geologic formations. Beneath and south of Black Mesa to approximately the location of the Little Colorado River, the unit is confined by the overlying Chinle Formation. The strata have a gentle northeast dip. Pattern of thickness of the Chinle Formation confining unit is shown on Figure 2. Hydraulic head above the top of the sandstones ranges from approximately 30 to 500 meters north of the Little Colorado River and is about 750 to 1,000 meters beneath Black Mesa; pattern of hydraulic head is shown on Figure 3. Saline groundwater with total dissolved solids concentrations more than 10,000 mg/l occurs north from the Little Colorado River in an area of about 8,000 square kilometers; this saline groundwater area is shown on Figure 3.

The floors of the large basins in the Basin and Range Geologic province are usually underlain by coarse-grained sand and gravel units to depths of 100 meters or more. Beneath the coarse-grained units, in the central parts of most of the large basins, thick sequences of fine-grained mudstones and evaporites occur. The evaporite deposits include gypsum and halite. The fine-grained units may comprise useful confining units, and at places overlie extensive permeable sand and gravel units. Saline groundwater conditions occur at depth in selected basins. Although the lower Colorado River basin area north and south of Yuma, Arizona is included in the Basin and Range Province, this area is not typical of Basin and Range stratigraphic sequence and structural geological conditions. Here, the basin-filling deposits are much thicker and consist of a combination of marine and non-marine strata. This area has been tectonically depressed during the late Cenozoic. These relations may provide favorable areas for geologic storage.

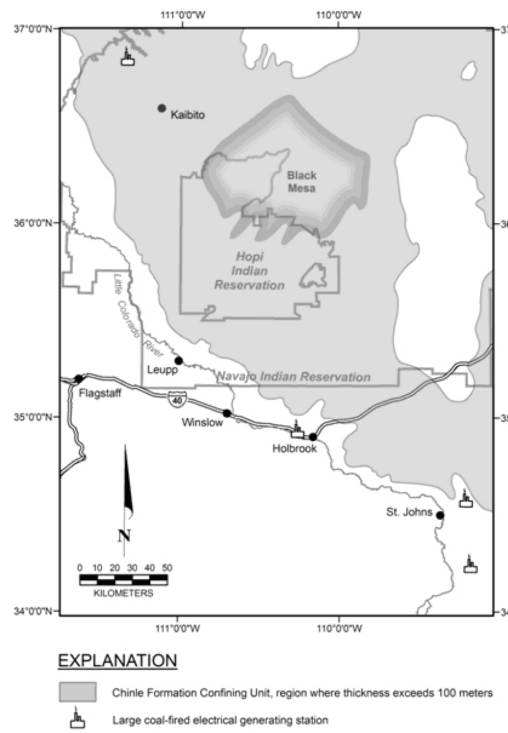


Figure 2. Aerial distribution of Chinle Formation.

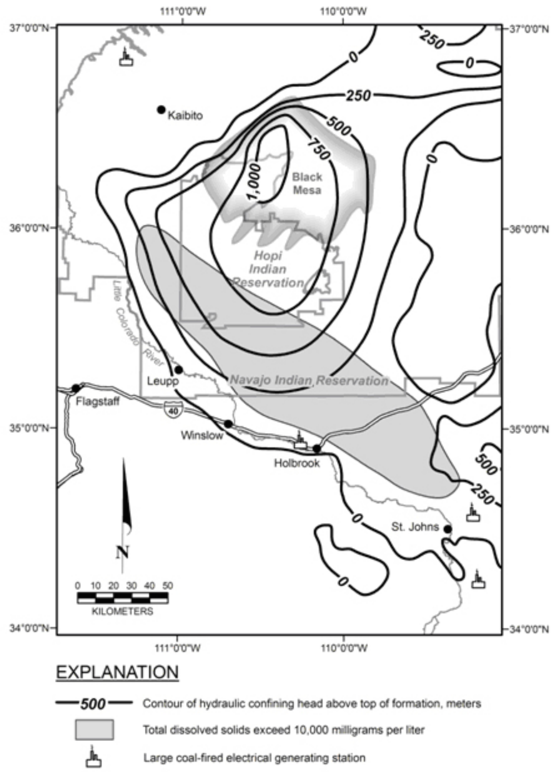


Figure 3. Hydraulic confining head and total dissolved solids in Coconino-DeChelly sandstones.

SITE CHARACTERIZATION CASE STUDIES

GEOLOGICAL CHARACTERIZATION OF THE WEYBURN FIELD FOR GEOLOGICAL STORAGE OF CO2

Rick Chalaturnyk[1] and Steve Whittaker[2]

[1]University of Alberta
Department of Civil and Environmental Engineering
Edmonton, Alberta T6G 2W2, Canada
e-mail: rjchalaturnyk@ualberta.ca

[2] Saskatchewan Industry and Resources
2103-11th Avenue
Regina, Saskatchewan S4P 3V7, Canada
e-mail: swhittaker@ir.gov.sk.ca

INTRODUCTION

The IEA GHG (International Energy Agency, Greenhouse Gas R&D Programme) Weyburn CO_2 Monitoring and Storage Project (Weyburn Project) , coordinated through the Petroleum Technology Research Centre in Regina, Saskatchewan, was initiated to study the potential for geological storage of CO_2 in a depleting oil field in southeastern Saskatchewan and to investigate methods of monitoring the movement of CO_2 in the subsurface to: 1) enhance the effectiveness of the miscible flood, 2) determine the potential of the reservoir to serve as a vessel for long-term (*ca.* 5,000 years) storage of the anthropogenic CO_2, and 3) to determine the economic feasibility of long-term storage. Phase I of the Weyburn Project began in July 2000 and was completed in September 2004. Phase II, potentially the final phase, of the Weyburn Project was officially launched late in 2005.

This extended abstract summarizes the findings from the Geological Characterization work completed in Phase I of the Weyburn Project. The complete summary report for the project (Wilson and Monea, 2004) is available for download.

GEOLOGICAL INVESTIGATION

The Geological Characterization theme of the Weyburn Project was one of the largest and most diverse aspects of the study. The overall goal was to evaluate the geological integrity of the Weyburn Oil Pool and the surrounding geosphere for storing injected CO_2 for hundreds to thousands of years. This involved providing a regional geological dataset in which other, more detailed, studies may be placed. The regional geological mapping was performed from the Precambrian surface to ground surface across a region 200 x 200 km centred on the Weyburn Field. This area included much of southeastern Saskatchewan and portions of northwestern North Dakota and northeastern Montana (Figure 1).

The Weyburn reservoir, in the Midale Beds of the Mississippian Charles Formation, is at an average depth of 1.5 km and includes an upper dolostone unit, the Marly, with an average thickness of about 6 m, and a lower limestone unit, the Vuggy, that averages around 15 m in thickness. The Vuggy contains porous grainstones developed along a carbonate shoal which form good-quality reservoir, and low porosity mudstones, interpreted to represent intershoal deposits that are of poor reservoir quality. Most oil production from the Weyburn Pool prior to the CO_2 -miscible flood was from the Vuggy shoal regions. CO_2 is currently being injected into the Marly dolostones to access residual oil, although the CO_2 is moving through both the Marly and Vuggy. The upper seals to the reservoir are the Midale Evaporite, a highly competent sedimentary anhydrite layer ranging in thickness from one to more than 10 m, and a diagenetic zone in which Midale carbonates have been extensively altered and anhydritized resulting in virtually complete porosity occlusion. This diagenetically altered zone occurs at the up-dip portion of the Midale Beds immediately subjacent the regional Sub-Mesozoic Unconformity.

Above the Sub-Mesozoic Unconformity are the relatively impermeable beds of the Triassic Lower Watrous Member that serve as a regionally extensive aquitard across much of southern Saskatchewan. In fact the shaly, anhydritic siltstones of the Lower Watrous Member, or redbeds, arguably form the most important trap for hydrocarbon accumulation in the northern Williston Basin. The Watrous redbeds separate a deep hydrogeological system, which includes the Midale reservoir and essentially all Paleozoic strata, from intermediate and shallow hydrogeological systems. Intermediate (around 1000 to 300 m depth) and shallow systems are much less saline, and have higher permeabilities and faster flowing formation waters than the deep hydrogeological system. Hydrogeological data indicate no evidence for flow across the Lower Watrous Member between the deep and intermediate systems, thus, the Midale Beds are effectively hydraulically isolated from shallower strata. The Watrous aquitard, therefore, is an excellent regional seal for CO_2 injected into the Midale Beds.

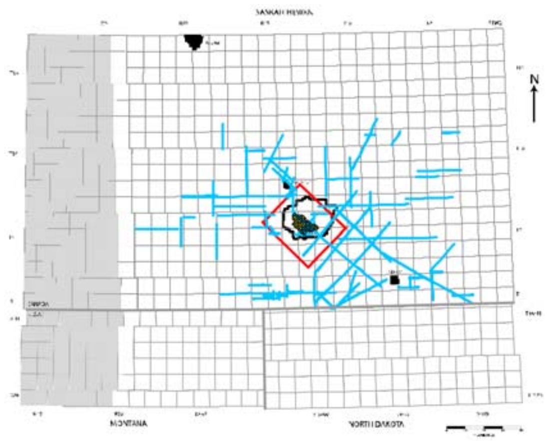


Figure 1. Map of the regional study area in the Weyburn Project. The shaded area along the west indicates an extension of the study area in which some hydrogeological mapping was performed. The geological model was constructed for the region outlined by the red rectangle around the Weyburn Field. The area of CO_2-flooding is depicted as the gridded region within the western portion of the field. The locations of 2-D seismic lines analyzed in the study are shown in blue.

The Midale aquifer has low flow velocities (<1 m/yr) and mainly horizontally oriented flow which favours hydrodynamic trapping of CO_2 thereby reducing the effectiveness of formation-water acting as a transport agent for CO_2. The Weyburn Pool occurs within a tectonically quiescent region. Although large-scale regional fractures and faults are present in the larger region, most faults observed are mainly localized disturbances without recognizable offset. Regionally extensive faults that may occur within the vicinity of the Weyburn Pool also exhibit limited offset and have not compromised hydrocarbon retention for the past 50 million years. Therefore, such faults are considered to be closed and likely do not represent fast pathways for CO_2 movement within the subsurface.

A detailed 3-D geological model was constructed using the data obtained from the above studies. This model includes the geometry of the geological formations grouped into hydrostratigraphic units. Each hydrostratigraphic unit represents a rock package that acts mainly as an aquifer or as an aquitard (Figure 2). In the model, the units are populated with data such as porosity, permeability, salinity, temperature, pressure, and additional information where available. Also included in the model is a projected fault plane, the Souris Valley Fault, identified in this study. The depth of the model extends from ground surface to the base of the Tilston Beds, and the areal extent is 10 km beyond the limits of the CO_2 flood as described previously. This model served as the foundation for detailed numerical risk and performance assessment.

Additional studies contemplated in Phase II of the Weyburn Project include determining the nature of regional and smaller-scale faults with respect to their likelihood of serving as preferential pathways for CO_2 migration, the petrophysical character of shales and their ability to serve as seals to CO_2, detailed hydrogeological modeling, and improving on the geological models through increased petrophysical and geostatistical property attribution beyond the reservoir itself.

MECHANICAL EARTH MODEL

In order to understand the evolution of the Weyburn system under EOR-CO_2 storage conditions, a mechanical earth model was developed over the stratigraphic column for the Weyburn system. A mechanical earth model is a logical compilation of relevant information about earth stresses and rock mechanical properties based on geomechanical studies and geological, geophysical and reservoir engineering models.

For geological storage, an important element of the model is whether conductive features exist within the caprock. A detailed review of the information and evidence available indicates that there are not conducting fractures in the caprock. In the past, however, conductive fractures did exist (Cioppa, 2003) and supports the mechanism of fracturing proposed by Burrowes (2001) and synthesized by Moreno et al. (2004) to help explain the widespread presence of fractures in the basin.

In-Situ Stress

Unfortunately the information available about in-situ stress for the Weyburn field is rather poor and some of the information available is of doubtful quality. Figure 3 summarizes most of the information available. For the direction of maximum and minimum horizontal stress, breakouts from nearby wells including information from the Midale field (McLellan et al., 1992), as well as some results from an anelastic strain recovery from the Midale field were utilized. The directions were compared with the natural fractures azimuths measured in core studies in the Weyburn and Midale field. The breakouts that show a small azimuth are from poor quality measurements, while the directions from breakouts measured in the Midale field, anelastic strain recovery and the directions from natural fracture sets coincide. Consequently the azimuth of the maximum horizontal stress is around 40-50°, while the minimum horizontal stress has an azimuth of 130-140°. The vertical in-situ stress was obtained from density logs, with an average unit weight of 24 kN/m. The magnitude of the horizontal stresses is difficult to establish because of the lack of measurements. Measurements from Regina (McLennan et al., 1986), and the Midale field seem to indicated a stress gradient of 18 kN/m, where the low values from the Midale field are apparently due to depletion of the reservoir.

Mechanical Properties

The mechanical properties are evaluated from the Manville aquifer down to the Frobisher beds. The Manville formation was chosen as an upper limit because of its large flow velocity, where any CO_2 leaking through the overburden would likely be carried away laterally by this aquifer. The dynamic elastic properties are evaluated using dipole sonic logs that were run in five different wells. Figure 3 shows the values for dynamic and static Young's modulus, and Poisson's ratio for the different formations. There is a clear contrast between the young formations post-Mississippian and the older pre-Mississippian formations, with the shaly Jurassic age Watrous Formation as a transition formation perhaps due to the presence of dolomitic and anhydritic cements.

Information about strength properties is rather poor and other than limited triaxial testing carried out on the Three Fingers Formation, which is the transition formation between the Marly and the Midale Evaporite, there is no information available. Utilizing a large constitutive behavior database on Anhydrites (Pfeifle and Hansen, 1998), it is postulated that anhydrite caprocks within the Weyburn field possess excellent mechanical properties, especially with increasing anhydrite content, and the Midale Evaporite within the Weyburn field has contents of anhydrite in excess of 90% in the upper zones of the formation. Consequently, it is concluded that the Weyburn field anhydrite will serve as a competent caprock, even though it displays brittle behavior during shear failure which made lead to the development of conductive fractures if shear failure occurs during CO_2 injection.

SUMMARY

Detailed geological characterization was performed to assess the geosphere encompassing the Weyburn Pool area regarding its suitability for long-term geological storage of CO_2. The characterization included regional and detailed geological mapping, hydrogeological studies, regional geophysical investigations including seismic and HRAM, and remotely sensed imagery studies. A detailed 3-D geological model was constructed from much of these data for use in numerical risk and performance assessment. The results from these and other studies conducted as part of the IEA Weyburn Project indicate that up to 23 MT CO_2 will remain in the reservoir at the end of EOR operations and that this CO_2, which otherwise would be vented to atmosphere, will remain securely stored within the geosphere for more than 5,000 years. Investigations into the geological characterization of the region and rigorous numerical modeling have each indicated that the Weyburn Pool is a highly suitable location for long-term geological storage of CO_2.

REFERENCES

Burrowes, G., Investigating CO_2 storage potential of carbonate rocks during tertiary recovery from a billion barrel oil field, Weyburn, Saskatchewan: Part 2 – reservoir geology; in *Summary of Investigations 2001, Volume 1, Saskatchewan Geological Survey, Sask. Energy Mines, Misc. Rep. 2001-4.1*, p64-71, 2001.

Wilson, M. and Monea, M., IEA GHG Weyburn CO_2 Monitoring and Storage Project Summary Report 2000-2004; *Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, Volume III*, Vancouver, 2004. http://www.ptrc.ca/access/Uploads/Summary_Report_2000_2004.pdf (accessed 28 February, 2005)

Cioppa, M.T., Magnetic evidence for the nature and timing of fluid migration in the Watrous Formation, Williston Basin, Canada: a preliminary study. *Journal of Geochemical Exploration, Vol. 78-79*: p. 349-354, 2003

Moreno, F.J., R.J. Chalaturnyk, and J.A. Jimenez. Methodology for assessing integrity of bounding seals (wells and caprock) for geological storage of CO2. *Proceedings 7th International Conference on Greenhouse Gas Control Technologies,* Vol. 1, Elsevier, London, 2004.

McLellan, P.J., K.H. Lawrence, and K.W. Cormier, A multiple-zone acid stimulation treatment of a horizontal well, Midale, Saskatchewan. *Journal of Canadian Petroleum Technology,* 1992. 31 (4): p. 71-82, 1992.

McLennan, J.D., H.S. Hasegawa, J.-C. Roegiers, and A.M. Jessop, Hydraulic fracturing experiment at the University of Regina Campus. *Canadian Geotechnical Journal, Vol. 23*, pp. 548-555, 1986.

Pfeifle, T.W. and F.D. Hansen, Database of Mechanical and Hydrological Properties of WIPP Anhydrite Derived from Laboratory-Scale Experiments. *Sandia National Laboratories.* 74 p., 1998.

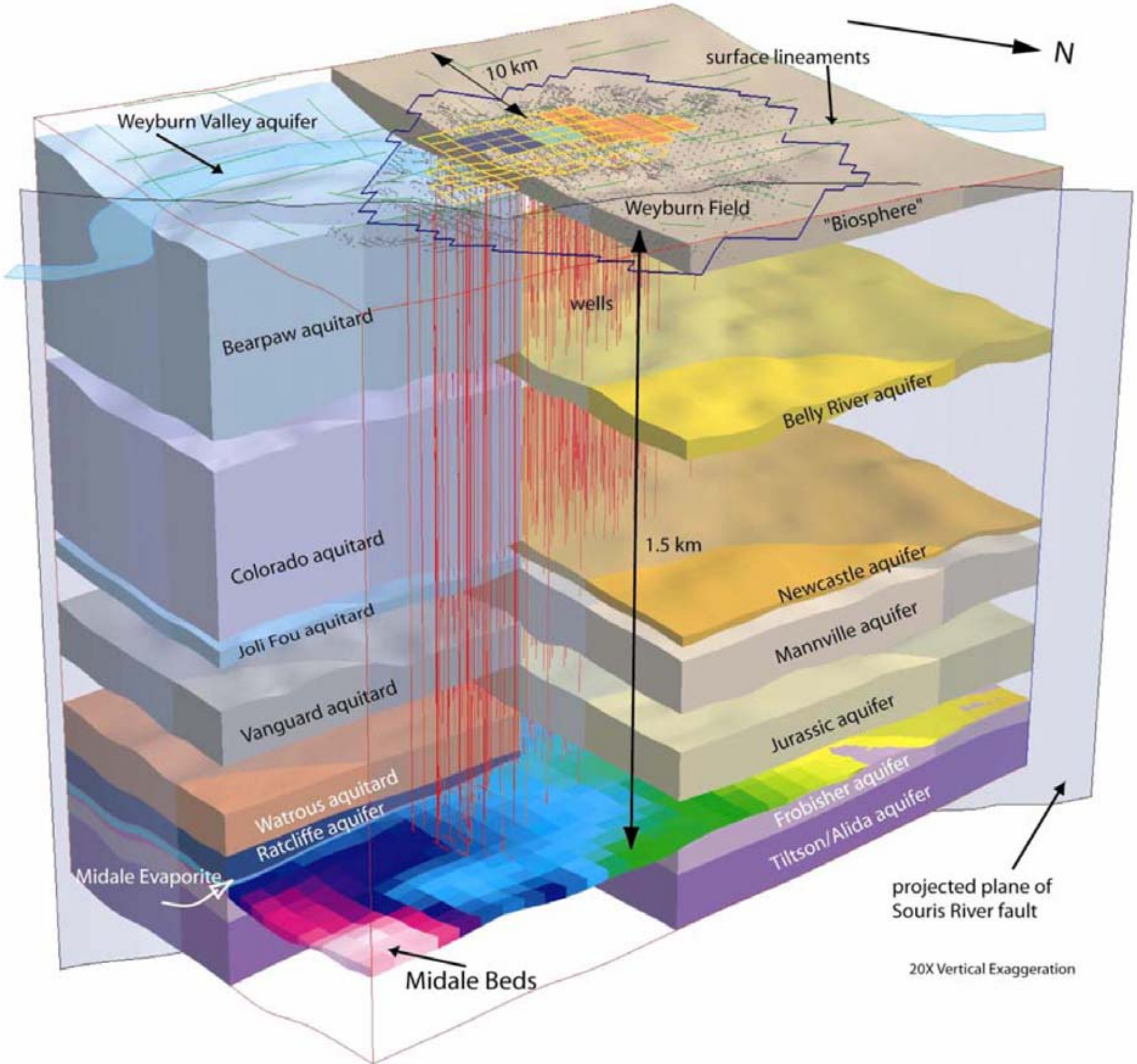


Figure 2. Cutaway block diagram of the geological model developed for the Weyburn Project. The model depicts the major hydrostratigraphic units; on the left are aquitards and on the right are aquifers. The yellow grid on the ground surface indicates the area planned for CO_2 injection, with field areas already undergoing CO_2-flooding shown as filled colours. Lineaments identified from satellite images and airphotos are presented as green lines on the surface, and the location of the shallow Weyburn Valley aquifer is also shown. The colour variations in the Midale Beds represent variations in salinity within this aquifer.

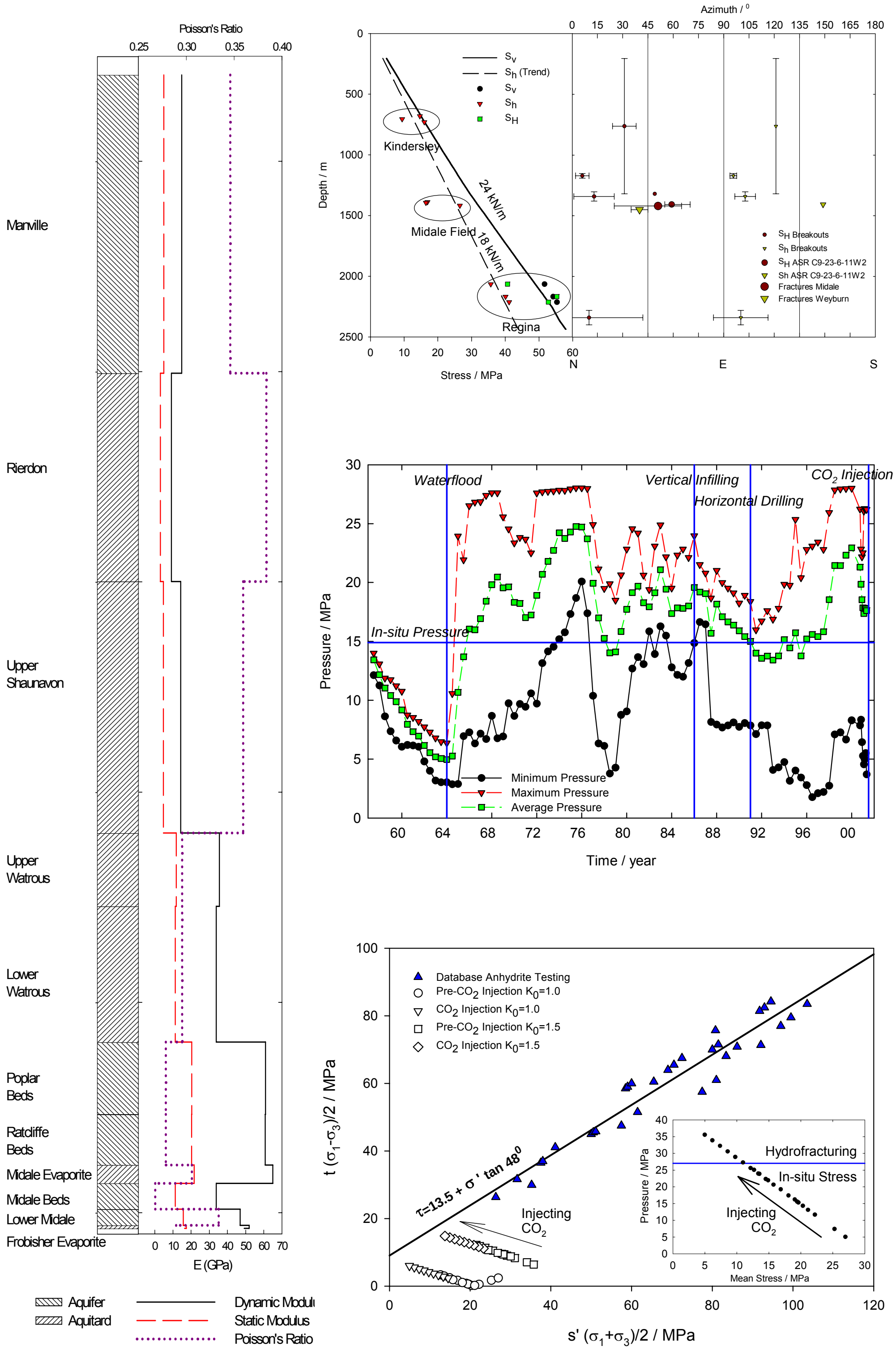


Figure 3. Summaries of mechanical earth model results.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

GEOMECHANICAL SITE CHARACTERIZATION TO CONSTRAIN CO2 INJECTION FEASIBILITY: TEAPOT DOME EOR PILOT

Laura Chiaramonte[1], Mark Zoback[1], Julio Friedmann[2] and Vicki Stamp[3]

[1]Department of Geophysics, Stanford University
Stanford, CA, 94305-2215, USA
e-mail: chiarlau@pangea.stanford.edu

[2]Lawrence Livermore National Laboratory (LLNL)

[3]Rocky Mountain Oilfield Testing Center (RMOTC)

INTRODUCTION

We investigate the effects of CO_2 sequestration on fault stability and seal integrity in the Teapot Dome oil field, Wyoming, with the objective of making predictions about the potential risk of CO_2 leakage along critically stressed fractures and faults.

We know that CO_2 injection into reservoirs creates a transient stress field that in many cases could potentially bring fractures and faults to their critical point. Inducing slip on pre-existing faults, or extending natural fractures could affect seal integrity.

Teapot Dome is an elongated, asymmetrical basement-cored anticline with a north-northeast axis (Figure 1). It is part of the Salt Creek structural trend, located in the southwestern edge of the Powder River Basin.

The target reservoir is the Pennsylvanian Tensleep Formation which in this area consists of interdune deposits, such as eolian sandstones, sabkha carbonates, evaporates (mostly anhydrite), and extensive beds of very low permeability dolomicrites. The average porosity of the Fm. is 10 %, ranging from 5 – 20 %, and the average permeability is 30 mD, ranging from 10 – 100 mD. The average net thickness is 50 ft. It is a reservoir with a strong aquifer drive, showing a reservoir pressure of 2350 psi and a temperature of 190 deg F.

The reservoir is trapped against a NE-SW fault to the north (3-way closure trap) and covers an area of approximately 1.2 km^2 (Figure 2).

The Opeche Shale plus the anhydrite of the Minnekahta Member of the Permian Goose Egg Formation is the regional seal of the Tensleep Fm. throughout Wyoming, and a major unconformity is

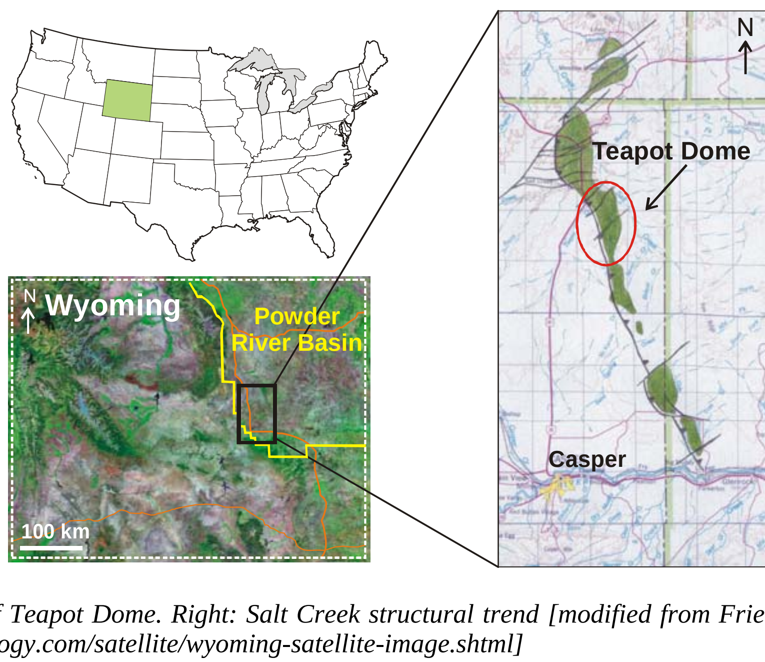


Figure 1: Location of Teapot Dome. Right: Salt Creek structural trend [modified from Friedmann et al., 2004b & http://geology.com/satellite/wyoming-satellite-image.shtml]

found in between both formations. From the study of the 48-X-28 core, the only Teapot Dome well where the cap-rock has been cored, a detailed characterization showed the structure of the caprock consisting of a very tight cemented paleosoil interval overlying the weathering surface on top of the Tensleep Fm (due to the unconformity) followed by the Opeche Shale member, and the anhydrite on top of it (M. Milliken, personal communication).

Present day stress directions documented from well bore breakouts and induced fracture analysis performed in well 67-1-X-10 (Milliken and Koespell, 2002) established the maximum horizontal stress direction as N75ºW (105º Az). These data are taken as preliminary and a careful interpretation of the FMI logs is being performed as part of the work proposed here (Figure 2).

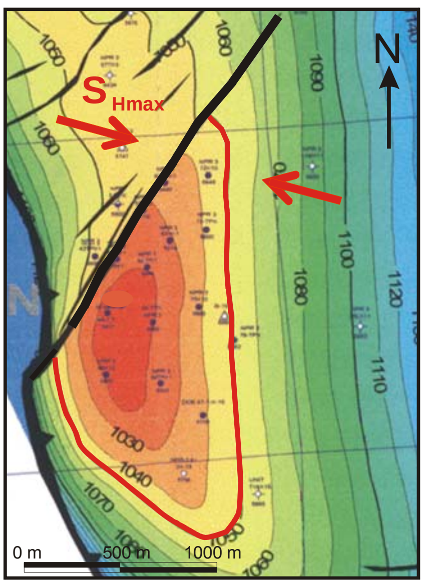


Figure 2: Time structure map of Tensleep Formation showing approximated oil contact area (red line) and S_{Hmax} orientation.

METHODOLOGY

Oil reservoirs have promising expectations as storage locations for CO_2 due to the fact that if hydrocarbons have been trapped for geological periods of times imply the presence of an effective trap and seal. The starting point of this study is to analyze whether past production may have adversely affected the seal of the reservoir.

Therefore, in the context of the initial trap and seal mechanisms, we will assess whether the effects of production have compromised reservoir seal capacity.

The study utilized data already present within the field, such as FMI and microresistivity logs, production data, downhole pressure information, and fracture orientations derived from well logs and cores. The geometry of the faults and reservoir targets are defined by wells and 3D seismic.

After establishing a comprehensive geomechanical model, we will provide quantitative estimates of the pore pressure at which faults will slip (or pressures at which hydraulic fracturing of the cap rock would occur). To build this geomechanical model we will use observations of wellbore breakouts, drilling induced fractures, leak-off or mini-frac tests and other available geophysical data (Zoback *et al*, 2003).

To define the reservoir model of the Tensleep Fm. we will characterize the geology analyzing seismic (Figure 3), log, outcrop, core and image log data. Geostatistics will be used to provide reasonable spatial variations of geologic and hydrologic properties to be considered.

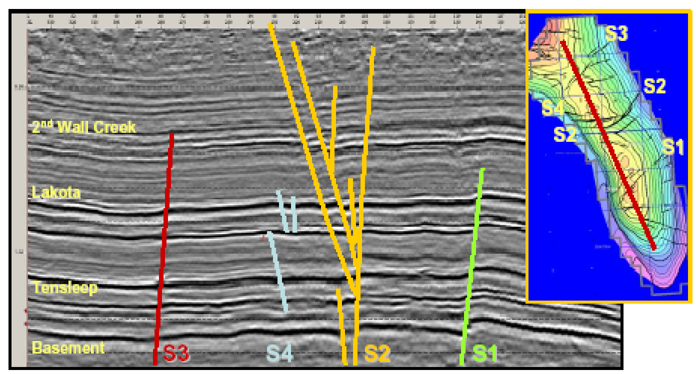


Figure 3: NW-SE cross section through Teapot Dome (left). Depth-structure map on the 2nd Wall Creek Sandstone [Friedmann et al., 2004a]

CONCLUSIONS

Taking advantage of Teapot Dome's unique characteristics that make it an ideal laboratory for studying CO_2 sequestration in a mature oil reservoir, we will develop a workflow to asses the feasibility of a CO_2 Sequestration- EOR pilot. In the context of the initial trap and seal mechanisms, we will assess the effects of past production on reservoir seal capacity, and in the context of a comprehensive geomechanical model, provide quantitative estimates of the pore pressure at which faults slip (or the hydraulic fracturing of the cap rock would occur). Through reservoir simulation, with the geomechanical and geological characterization as input, we will develop numerical models of pressure and CO_2 saturation as well and estimate the likelihood that faults of particular orientations might be reactivated and predict possible migration pathways for CO_2.

ACKNOWLEDGMENTS

We thank the Stanford University Global Climate and Energy Project for funding this project and Mark Milliken and Brian Black from RMOTC.

REFERENCES

Friedmann, S. J., V. Stamp, and D. Nummedal, Prediction, execution, and mitigation of an engineered leak at the Teapot Dome field experimental facility (NGCSTS-1): *Proposal to CO_2 Capture Project 2 (CCP2)*, 2004a.

Friedmann, S.J., T. McCutcheon, D., Nummedal, M., Milliken, V.R., Stamp, and R., Klusman, Goals and configuration of an induced leakage experiment at Teapot Dome, WY, *NETL 3rd Annual Carbon Sequestration Conference Proceedings, Alexandria, VA, Exchange Monitor Publications,* 2004b.

Milliken, M. and R. Koepsell,, Imaging Technology offers enhanced interpretation of Teapot Dome reservoirs: *Wyoming Geological Association 2003 Field Guidebook*. 2002

Zoback, M.D., C.A.Barton, M.Brudy, D.A.Castillo, T.Finkbeiner, B.R.Grollimund, D.B. Moos, P.Peska, C.D. Ward, and D.J. Wiprut, Determination of stress orientation and magnitude in deep wells, *Int. J. of Rock Mechanics and Mining* 40, 1049-1076, 2003.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

CHARACTERIZATION OF GREATER ANETH FIELD, PARADOX BASIN, UTAH, FOR SEQUESTRATION: INFLUENCE OF RISK AND MITIGATION REQUIREMENTS ON MONITORING STRATEGIES

Thomas C. Chidsey, Jr.[1], Richard G. Allis[1], Brian McPherson[2], Jason Heath[2], Stephen E. Malkewicz[3], and Wilson Groen[4]

[1]Utah Geological Survey
Salt Lake City, Utah

[2]New Mexico Institute of Mining & Technology
Socorro, New Mexico

[3]Resolute Natural Resources
Denver, Colorado

[4]Navajo Nation Oil & Gas Company, Inc.
Window Rock, Arizona

ABSTRACT

Greater Aneth oil field, Utah's largest oil producer, was discovered in 1956 and has produced over 440 million barrels of oil. Located in the Paradox Basin of southeastern Utah, Greater Aneth is a stratigraphic trap, with fractures and minor faults. Because it represents an archetype of a mature western U.S. oil field, Greater Aneth was selected to demonstrate combined enhanced oil recovery (EOR) and carbon dioxide sequestration under the auspices of the Southwest Regional Partnership on Carbon Sequestration, sponsored by the U.S. Department of Energy. This field testing and detailed characterization of Greater Aneth field, which is currently underway, will demonstrate the efficacy of the most promising sequestration technologies (including monitoring-mitigation-verification [MMV] and risk mitigation approaches) and infrastructure concepts, and identify regulatory gaps to reduce or offset greenhouse gas emissions in the region.

The Paradox Basin is located mainly in southeastern Utah and southwestern Colorado with small portions in northeastern Arizona and northwestern New Mexico (figure 1). The Paradox Basin is an elongate, northwest-southeast-trending, evaporitic basin that predominantly developed during the Pennsylvanian, about 330 to 310 million years ago. Deposition in the basin resulted in a thick cyclical sequence of carbonates, evaporites, and organic-rich shale.

The most prolific oil- and gas-producing reservoir in the Paradox Basin is the Pennsylvanian (Desmoinesian) Paradox Formation. The Paradox has produced over 500 million barrels of oil from over a hundred fields. Most Paradox oil production comes from stratigraphic traps in the Blanding sub-basin and Aneth platform (figure 1) that locally contain algal-mound and other carbonate facies buildups in the southern part of the basin. Facies changes and extensive diagenesis have created complex reservoir heterogeneity within these two diverse zones, and they likely contain significant undrained oil reserves that could be produced by injecting CO_2 as part of EOR programs.

The two main producing zones of the Paradox Formation are informally named the Ismay and the Desert Creek. The Ismay zone is dominantly limestone comprising equant buildups of phylloid-algal material with locally variable small-scale subfacies and capped by anhydrite. The Ismay produces oil from fields in the southern Blanding sub-basin. The Desert Creek zone is dominantly dolomite comprising regional, nearshore, shoreline trends with highly aligned, linear facies tracts. The Desert Creek produces oil in fields in the central Blanding sub-basin and the Aneth platform. Both the Ismay and Desert Creek buildups generally trend northwest-southeast. The source of the oil is several black, organic-rich shale units within the Paradox Formation. Paradox Formation shale, halite, and anhydrite serve as vertical reservoir seals; lateral seals are permeability barriers created by unfractured, off-mound (non-buildup) mudstone and wackestone.

The primary reservoir at Greater Aneth field is the Desert Creek zone of the Paradox Formation, consisting of limestone (algal boundstone/bafflestone, and oolitic, peloidal, and skeltal grainstone and packstone) and finely crystalline dolomite. The Desert Creek at Greater Aneth was deposited in a warm, shallow sea as a horseshoe-shaped buildup of reef-like mounds (figure 2) composed of the green algae *Ivanovia* capped by banks of oolitic sands, similar to the present-day Bahama open-marine, carbonate-shelf system. The thickness of the Desert Creek in the Aneth Unit is about 60 m, with an average of 15 m containing 10% porosity and permeability ranging from 3 to 30 millidarcies. The productive field area

is 195 km^2 and there are currently 635 active wells. The oil has an API gravity of 42° and is low in sulfur content. The original reservoir drive mechanisms were solution gas and fluid expansion.

Greater Aneth field is divided into four units (figure 2). After years of declining production following 23 years of waterflooding, a CO_2 flood program was initiated in the McElmo Creek Unit in 1985 and continues to the present. The technique applied is water alternating with gas, or WAG, requiring water injectors (30), WAG injectors (65), water supply wells (9), and oil producers (90). The injected CO_2 is also produced and reinjected into the reservoir. As a result of the WAG program, oil production increased from 4000 barrels of oil per day to 26,000 barrels per day in 1998; however, oil production has declined since then. Over 180 billion cubic feet of CO_2 has been injected into the Desert Creek zone in the unit. Although this figure includes cycled gas, the exact fate of this CO_2 is poorly understood – it is unclear whether some of it has leaked into other intervals or to the surface, changed the mineral components of the reservoir, caused extensive damage to the well casing, etc.

The Aneth Unit in the northwestern part of Greater Aneth field (figure 2) has not had significant CO_2 injection and therefore provides an opportunity to inject a relatively large volume of CO_2 from a nearby pipeline, and to extensively monitor the effects of injection from reservoir to surface. Thus, the Southwest Regional Partnership field demonstration will take place in the 66-km^2 Aneth Unit, operated by Resolute Natural Resources and Navajo Nation Oil & Gas Co., Inc. The Desert Creek zone in the unit is divided into two subzones: a lower interval predominantly composed of algal-mound facies and an upper interval composed of oolitic-peloidal facies (figure 3). These subzones create a west-northwest-trending reservoir buildup (figure 2) overlain and vertically sealed by the Gothic shale of the Paradox Formation (figure 3). Most oil has been produced from the lower Desert Creek interval with much of the remaining oil in place confined in the less permeable, heterogeneous upper interval. Production has declined approximately 50% in the unit over the past 20 years in spite of waterflood and horizontal drilling projects. However, the Aneth Unit has produed over 149 million barrels of the estimated 450 million barrels of oil in place – a 33% recovery rate from the heterogeneous reservoir. The large amount of remaining oil, combined with the nearby CO_2 pipeline, makes the Aneth Unit ideal to demonstrate both CO_2 storage capabilty and EOR of further oil reserves by flooding the upper Desert Creek reservoir with the CO_2. This process may force the now-mobilized oil from the upper Desert Creek interval into the more permeable, higher porosity lower Desert Creek interval where it will be easier to produce and ultimately provide greater storage capacity for the injected CO_2.

The Southwest Partnership will conduct extensive monitoring to track the movement and fate of injected CO_2 for risk mitigation and optimization of MMV protocols (including a suite of direct techniques [direct CO_2 flux measurements] and indirect techniques [such as seismic methods]). Effective outreach and communication are additional critical goals of the test. The demonstration will help determine what monitoring data are needed for facilitating risk assessment and designing mitigation plans. The demonstration will also identify spatial and temporal “gaps” in the monitoring data. MMV design will depend on baseline MMV measurements and detailed reservoir models based on extensive geological characterization. The planned CO_2 flood will begin in mid-2007, at the rate of about 150,000 tons per year for 3.5 years (400 tons/day [25 MMCFGD]) as conditions permit.

REFERENCES

Harr, C.L., 1996, Paradox oil and gas potential of the Ute Mountain Ute Indian Reservation, *in* Huffman, A.C., Jr., Lund, W.R., and Godwin, L.H., editors, Geology of the Paradox Basin: Utah Geological Association Publication 25, p. 13-28.

Peterson, J.A., 1992, Aneth field – U.S.A., Paradox Basin, Utah, *in* Foster, N.H., and Beaumont, E.A., editors, Stratigraphic traps III: American Association of Petroleum Geologists Treatise of Petroleum Geology – Atlas of Oil and Gas Fields, p. 41-82.

Peterson, J.A., and Ohlen, H.R., 1963, Pennsylvanian shelf carbonates, Paradox Basin, *in* Bass, R.O., and Sharps, S.L., editors, Shelf carbonates of the Paradox Basin: Four Corners Geological Society Guidebook, p. 65-79.

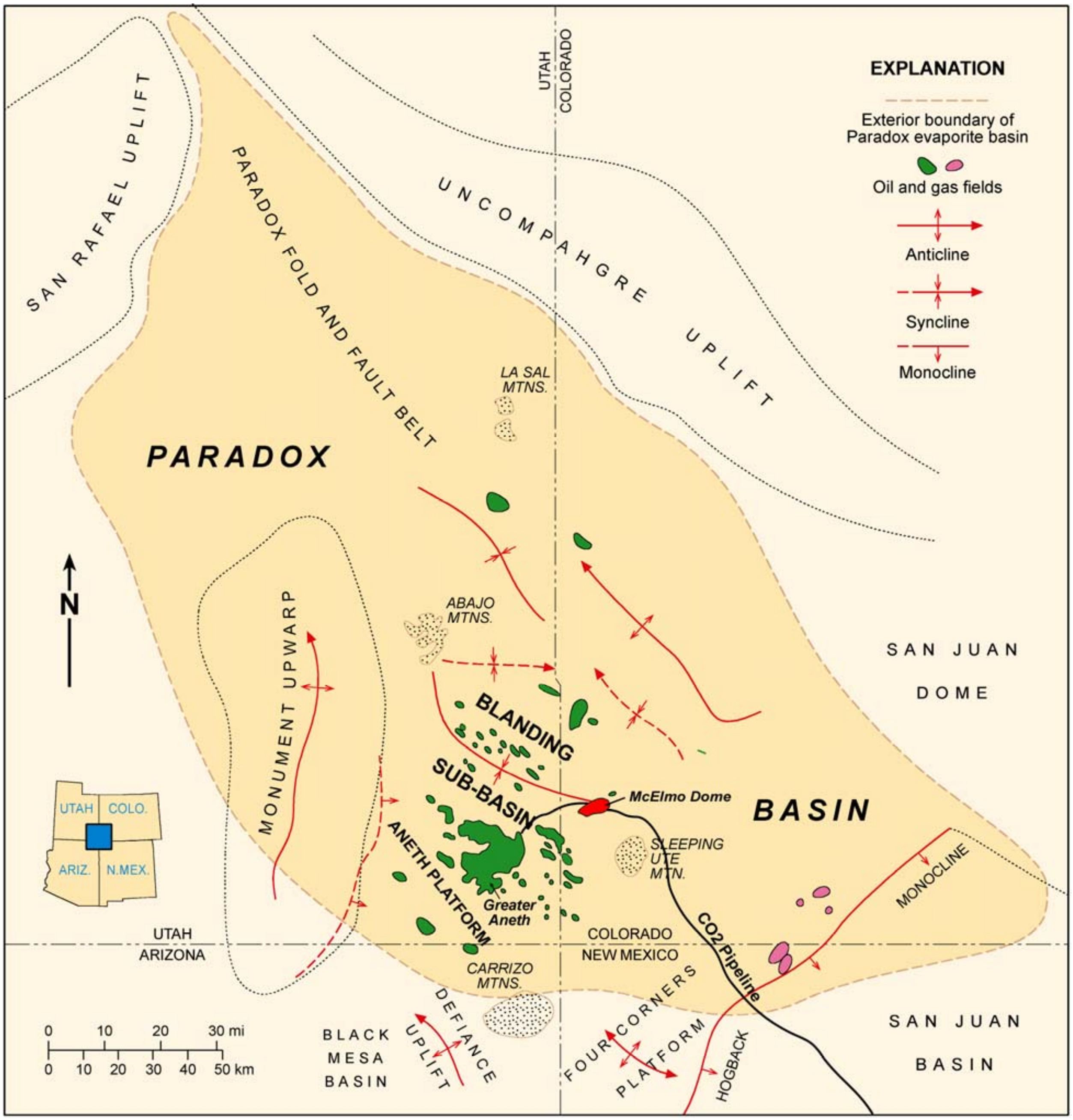


Figure 1. Location map of the Paradox Basin, Utah, Colorado, Arizona, and New Mexico showing major producing oil and gas fields, the Paradox fold and fault belt, Blanding sub-basin, and Aneth platform as well as surrounding Laramide basins and uplifts (modified from Harr, 1996).

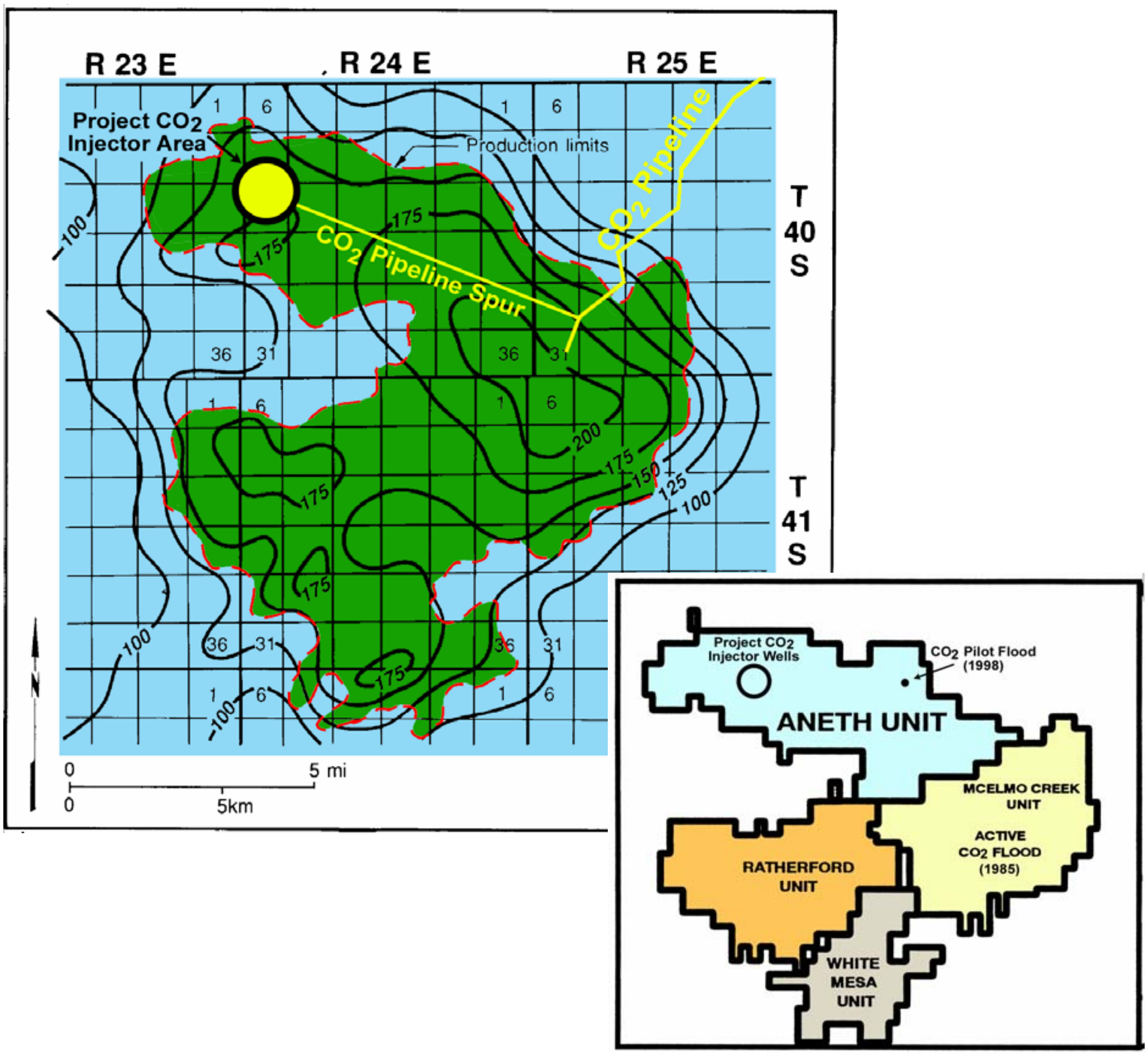


Figure 2. Generalized thickness map of the Desert Creek zone, demonstration site, and CO2 pipeline, Greater Aneth field, San Juan County, Utah; contour interval = 25 feet. Modified from Peterson and Ohlen (1963). Inset shows units within Greater Aneth field.

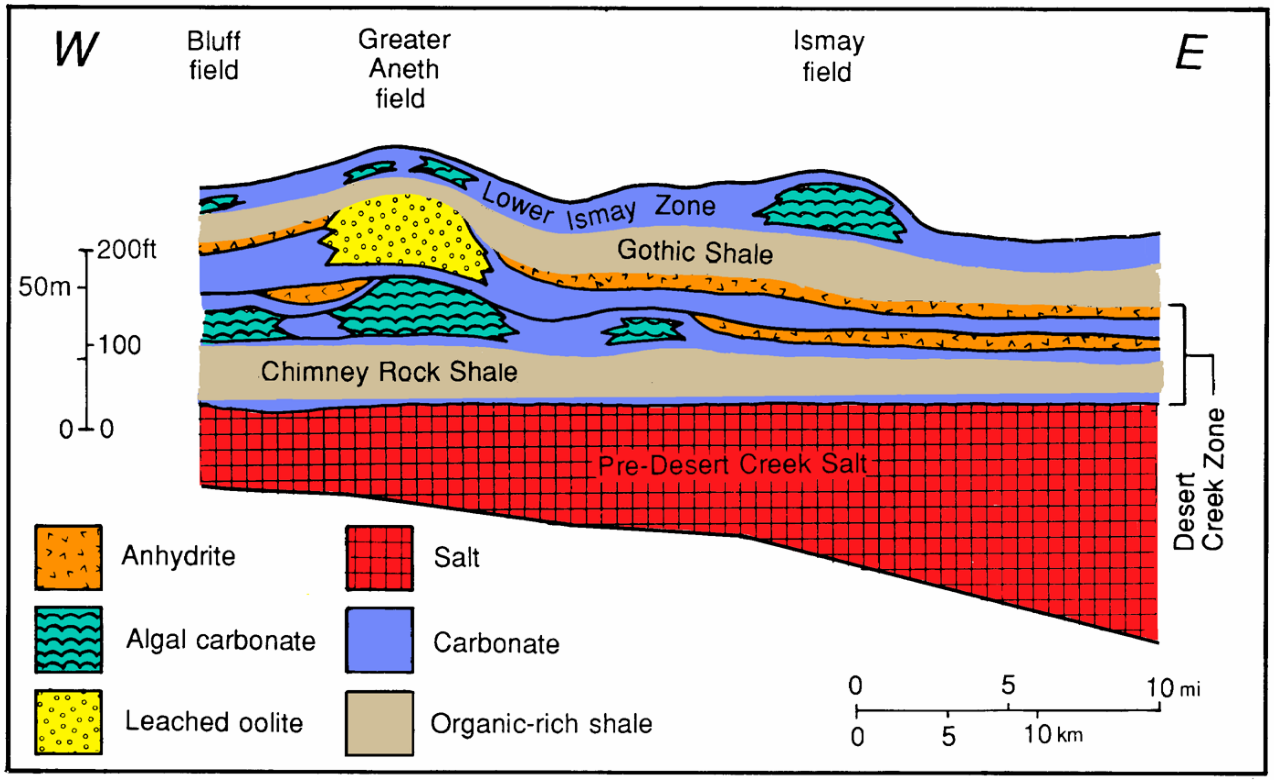


Figure 3. Diagrammatic lithofacies cross section, Greater Aneth field, southeastern Utah. Datum is base of the Desert Creek zone of the Paradox Formation (modified after Peterson, 1992).

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

DETAILED GEOLOGICAL SITE CHARACTERIZATION OF A CO_2 STORAGE SITE: OTWAY BASIN PILOT PROJECT, AUSTRALIA

Peter J. Cook and Sandeep Sharma

Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)
GPO Box 463
Canberra, ACT, 2601, Australia
e-mail: pjcook@co2crc.com.au, ssharma@co2crc.com.au

BACKGROUND

Australia contributes less than 2% of total global emissions of CO_2 but is one of the world's highest per capita emitters of CO_2, because it has an energy intensive economy and because the overwhelming majority of its electricity is generated from coal. This presents a challenge but also offers the opportunity to mitigate emissions from major stationary sources such as power stations.

The Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC) and its predecessor (APCRC) have been working on the characterization of Australian sites for the geological storage (geosequestration) of CO_2 since 1999. Initially the approach taken was to undertake continent-wide regional characterization (both onshore and offshore) in order to identify Australia's overall storage resource. As part of this exercise, more than 100 areas/regions were assessed, of which approximately two-thirds were found to be potentially viable although detailed studies were only undertaken at four locations.

Subsequently the characterization of sites focused on key areas with major stationary emission sources (Figure 1). Work in the Perth Basin is summarized in this volume by Dance & Tyson (2006); Preliminary investigations have been completed in southeast Queensland and the Sydney Basin but there is more work to be done, particularly in looking at the options for storage in low permeability systems in eastern Australia. The Latrobe Valley/Gippsland Basin characterization considered in this volume in some detail by Gibson-Poole et al (2006) and also by Gibson-Poole et al (2005) provides an excellent example of the sort of preliminary study that will be required for large scale commercial activities.

THE OTWAY BASIN PROJECT

In 2004 an opportunity was identified in the Otway Basin of southern Australia (Fig.1) to research and demonstrate geosequestration at a commercially significant scale. The onshore Otway Basin has many naturally occurring high CO_2 gas accumulations and a number of depleted gas fields in close proximity. This allowed a proposal for a large-scale Pilot Project to be developed (Fig. 2). The US$23 million research project will involve producing CO_2 and methane gas from an existing well, processing the gas to

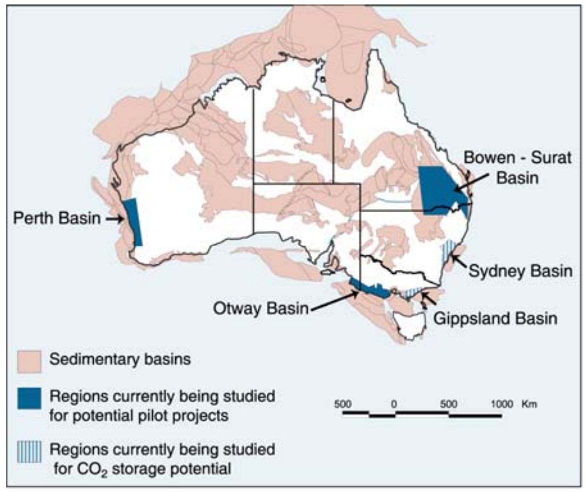


Figure 1. Regions currently being studied for potential pilot projects or for determination of likely CO_2 storage potential.

separate out and generate a stream of supercritical CO_2, which will be transported 2-3 kms by pipeline and then injected into a nearby depleted natural gas field for long-term storage. A new injection well will be drilled downdip from an existing well (which will become a monitoring well) in the depleted field and approximately 100,000 tonnes of CO_2 will to be injected over two years (Fig. 3). The CO_2 will be injected into the Late Cretaceous Waarre C Sandstone at a depth of about 2000 metres, within the depleted Naylor Gas Field. The Waarre is overlain by a regional seal, the Belfast Mudstone.

CO2CRC Pilot Project Ltd is now the holder of two petroleum tenements (PPL11 and PPL13) and will be the Operator of the CO_2 gas well, the pipeline and the injection activities (Fig. 2). It will also be responsible for abandonment and any remediation of the site. Abandonment will be based on meeting a number of Key Performance Indicators which will be agreed with the Environment Protection Agency (EPA Victoria) prior to commencement of injection. Detailed site characterization is an essential component of site selection, risk management, monitoring activities and identification of the right KPIs.

GEOLOGICAL CHARACTERIZATION

Detailed site characterization, geological modeling and reservoir simulations have been undertaken for the Otway Project. An extensive monitoring and verification (M&V) program will be conducted throughout the injection phase and will continue for several years following cessation of injection in order to verify the behaviour of the CO_2 in the subsurface.

The site has been very comprehensively characterized using a range of techniques aimed at understanding:

- The geological structure, properties and heterogeneities.
- The orientation and stress distribution in the bounding faults and the potential of leakage.
- The behaviour of the injected CO_2 in the Waarre C Formation.
- The long term storage mechanisms.
- Sensitivities of different modeling techniques and responses.

The past gas production of the Naylor Gas Field and other nearby fields provided geological data which was used for the creation of detailed geological models, which were in turn used for fluid flow simulation. Several geological realisations were considered and peer reviewed as part of the process of selecting the most likely case. The geological model will be further validated once existing wells are re-logged and as data from new wells becomes available. 3D seismic on a 20m by 20m grid was available and the model was constructed using PETREL software.

Depth-converted faults and horizons were used as the framework for the reservoir model and the interpreted depositional model (regressive braided fluvial deposits). The final Petrel reservoir model is high resolution, with approximately 100,000 cells on a 20mx20m grid and a cell thickness of 1-4m. Volumetrics were performed and the injection volumes proposed minimize risk of going beyond spill point.

A number of faults are present in the vicinity of the proposed injection and therefore geomechanical analysis was undertaken using rock strength, in-situ stress data, etc., in order to assess fault and reservoir strength. This will be used as a basis for developing an injection scenario and a monitoring scheme during the injection phase to ensure that significant pore pressure build up does not occur. Once a new well is available, geomechanical risking will be undertaken to provide estimates of fracture pressure, thus providing upper limits on injection volumes and rates.

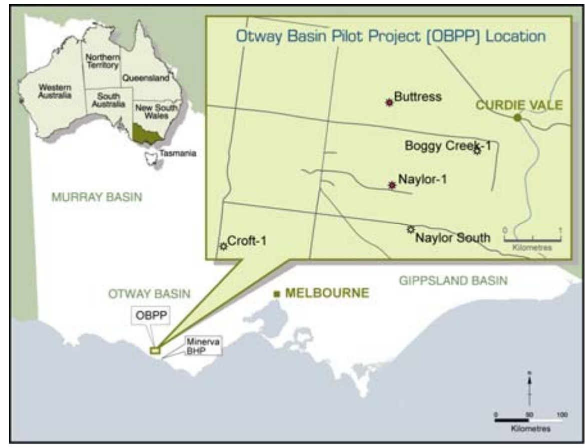


Figure 2. Proposed location of the Otway Basin Pilot Project.

There are some uncertainties because information on rock properties is only available from two wells in this particular structure. Confidence in the chosen model and the properties comes from analyzing the nearby wells, recognizing that there is a variation in properties given the nature of the depositional environment. As such, there is a high degree of confidence that it will be possible to inject 3 million standard cubic feet per day of CO_2 for at least 18 months. One of the uncertainties yet to be resolved is the current height of the gas-water contact; the results of monitoring this in the observation well will determine the ultimate location for the new well. Better information on the geometry of the top surface of the storage formation will also help to determine the migration rate and direction of the CO_2 with greater precision.

Numerical simulations of multiphase flow in a porous media were carried out using Eclipse and TOUGH2, and various injector locations were modelled. For an injector location at 280m from the observation well, it is estimated that breakthrough will be in around 6 months for the high permeability case (1000 mD) and in around 9 months if the permeability was lower at 250 mD.

The distribution of remaining methane in the field will also be important to monitoring and therefore modeling was also undertaken on likely vertical and lateral changes in the relative distribution of CO_2 and methane.

The potential for leakage up through a fault zone into the overlying Parratte Formation (an aquifer above the seal) was also comprehensively modelled as part of site characterization. The models are strongly indicative that were any free CO_2 to leak in this way, it would dissolve in the deeper saline and brackish aquifers and not go beyond. At present the deepest of the used fresh water aquifer is approximately 1 km shallower than the injection zone. There is very high confidence that the injected CO_2 will never reach this aquifer or any other useable aquifer.

CONCLUSIONS

A comprehensive approach has been adapted to geological characterization, of the site for the Otway Basin Pilot Project. The focus of the characterization has been the Waarre Formation, the intended injection formation. The characterization has involved the collection of geological, production and other regionally relevant data and the construction of static and dynamic models. Some of current data gaps produce some uncertainties in the modeling outputs. However, these uncertainties will be addressed to a significant degree with new and site specific data, when the additional logs are recorded in the existing Naylor-1 well and drilling of a new injection well has been undertaken.

Nonetheless at this stage we can conclude the following:

- Storage Capacity – the intended reservoir will safely contain the volumes envisaged to be injected (up to 100,000 tonnes of CO_2).
- Containment – the reservoir seal is robust and will contain the CO_2 injected.
- Injectivity – the storage reservoir has enough porosity and permeability to be able to accept the injected CO_2 at rates forecast (3 million scfpd).
- The selected site has the major advantage of being onshore rather than offshore, allowing the project research teams to test and further refine the extensive monitoring and verification techniques at a more accessible location. It is also close to a major source of CO_2 and is an excellent site logistically.
- The site is well-characterized. More work will further reduce uncertainties and refine the monitoring program, but is not expected to change the conclusion that this is an excellent site for demonstrating geological storage of CO_2 at significant scale.

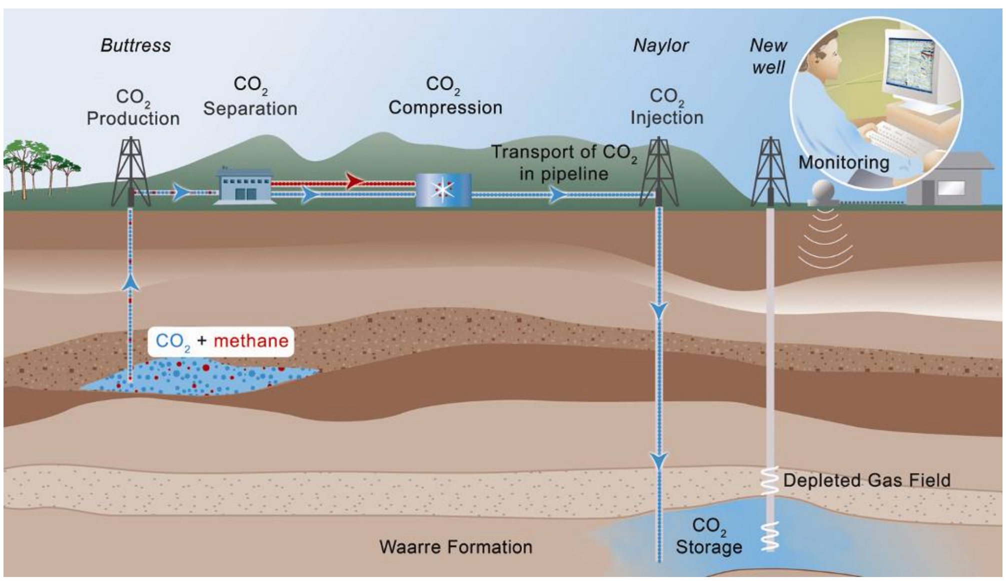


Figure 3. Schematic representation of the Otway Basin Pilot Project.

ACKNOWLEDGMENTS

Many people have contributed to the geological characterization of the project site. The geological and dynamic models have been built by Lynton Spencer and Josh Xu. We also thank Kevin Dodds, Jonathan Ennis-King, Allison Hennig, Frank La Pedalina, Lincoln Paterson, Ernie Perkins, Andy Rigg, Sandy Robinson, Don Sherlock, Linda Stalker, Peter van Ruth and Max Watson. We also thank the many organisations involved in the characterization work of the CO2CRC, including CSIRO, Geoscience Australia, The Australian of School of Petroleum, Adelaide, Curtin University and Schlumberger. We also thank the research organisations, universities, Australian and Victorian Governments and our industry for financial assistance. A full list of collaborating organisations is provided at www.co2crc.com.au.

REFERENCES

Cook, P.J., A. Rigg, and J. Bradshaw, 2000, Putting it back where it came from: is geological disposal of carbon dioxide an option for Australia., *The APPEA Journal*, 40,654-666.

Dance, Tess and S. Tyson, 2006, Regional Reservoir Characterization of the Gage Sandstone, Perth Basin: Issues of Scale. *Proceedings CO2SC Symposium 2006*, Lawrence Berkeley National Laboratory.

Gibson-Poole, C.M., R.S. Root, S.C. Lang, J.E. Streit, A.L. Hennig, C.J. Otto, and J.R. Underschultz, 2005: Conducting Comprehensive Analyses of Potential Sites for Geological CO_2 Storage, In: Rubin, E.S., Keith, D.W., & Gilboy, C.F., (Eds.) *Greenhouse Gas Control Technologies: Proceedings of 7th International Conference on Greenhouse Gas Control Technologies*, Vol. 1, 673-681.

Gibson-Poole, C.M., L. Svendsen, J. Underschultz, M.N. Watson, J. Ennis-King, P.J. van Ruth, E.J. Nelson, R.F. Daniel, and Y. Cinar, 2006, Regional Characterization of a Major Storage System: Gippsland Basin, Southeast Australia, Proceedings, CO2SC Symposium 2006, Lawrence Berkeley Laboratories, Berkeley, California.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

RESERVOIR CHARACTERIZATION OF THE GAGE SANDSTONE, PERTH BASIN

Tess Dance[1] and Stephen Tyson[2]

[1]Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC)
Geoscience Australia, GPO Box 378
Canberra, ACT 2601, Australia.

[2]Geo Visual Systems Pty. Ltd., Coogee, NSW, Australia.
e-mail: tess.dance@ga.gov.au

INTRODUCTION

The Southern Perth Basin is considered prospective for the geological storage of carbon dioxide (Bradshaw et al., 2001). As part of a major CO2CRC integrated site assessment, researchers at Geoscience Australia have identified potential reservoirs in the offshore portion of the basin (Fig. 1). The Gage Sandstone, lying directly beneath the South Perth Shale, appears to be the most prospective, with thick permeable sands proximal to emission sources (Causebrook et al., in press).

In order to gain a better understanding of the Gage Sandstone and its capacity to store CO_2, several geological models were constructed for input into a reservoir simulation. During the modeling process major challenges were faced when trying to strike a balance between including small-scale details that were known to exist in the reservoir that would impact on the behavior of the injected CO_2, and keeping the file size of the geological models within reasonable limits for simulation.

The aim of building the three dimensional geological models of the Gage Sandstone is to address key questions related to reservoir heterogeneity and storage capacity. Firstly, through simulation we hope to understand potential injectivity given the average parameters of porosity, permeability and reservoir pressure. This will give us a better understanding of rates of injection and design requirements of potential injectors.

Similarly, once the CO_2 has been injected we need to accurately predict its behavior and possible migration pathways. By modeling short and long term migration times of CO_2 through the reservoir, we can better estimate dissolution rates and the site's potential for mineral trapping. Moreover, by modeling all likely migration pathways we will determine whether CO_2 will flow to regions of high risk, such as faults or areas of low sealing capacity.

Finally, through modeling multiple realizations of every likely facies distribution, we will be able to establish the range between minimum and maximum storage capacity. This will indicate if the reservoir will have the means to store volumes of CO_2 close to that of existing and proposed future sources. Thus we can then determine if the storage solution will meet our aims of significantly reducing local emissions over a long period of time.

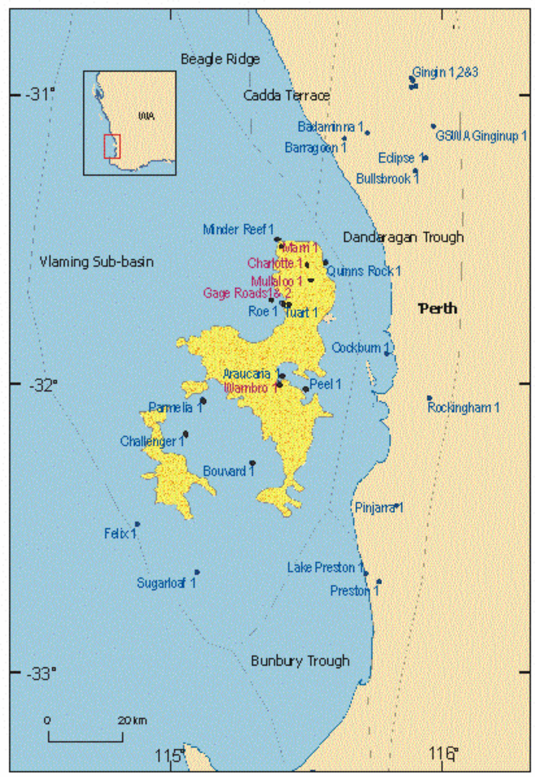


Figure 1. Location of exploration wells and the extent of the Gage Sandstone (yellow) within the Vlamming Sub-basin, offshore Perth, Western Australia. Only six wells, which are shown in red, penetrated the reservoir, these provided the basis for characterization and modeling.

GEOLOGICAL CHARACTERIZATION

The first step in characterizing the Gage Sandstone was to examine the cores and well logs to determine the type of environment the sediments were deposited in. Numerous sedimentary structures were observed in a ten meter core from Warnbro-1. These included erosional bases, fining-up sequences, dish structures, rip-up clasts, dewatering features, planar laminations, traces of cross ripple laminations, and flame structures (Fig. 2). By far the most prevailing feature of Core-1 is the episodic gradation from coarse sands to fine muds, known as normal graded bedding (Boggs, 1995), and fine parallel laminae composed of mud, clay and silt. These features indicate the sediments were transported by turbidity currents and were likely to be deposited in stacked lobes at the mouths of channels on the basin floor. These channels and lobes have been classified in terms of a submarine fan model which is consistent with the basin stratigraphic framework at the time of deposition of the Gage Sandstone.

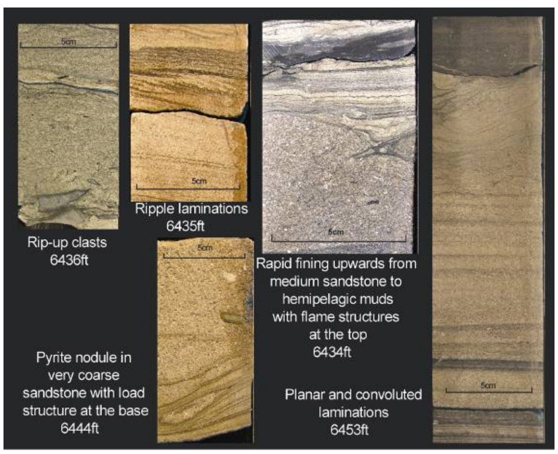


Figure 2. Examples of sedimentary structures of the Gage Sandstone consistent with high density turbidity currents transporting and depositing both fine and coarse-grained sediments. The graded bedding and repeated layering is common in basin floor fan facies.

IMPLICATIONS FOR RESERVOIR QUALITY

Research then focused on finding suitable conceptual models for guiding the construction of the larger Gage Sandstone model. The model proposed is a system of sandy channels and lobes that entered the basin through several confined, steep valleys at the head of the fans, then spread broadly on the basin floor terminating into suprafan lobes that are laterally extensive up to tens of kilometers across (Shanmugam and Moiola, 1991). Within this system, four main facies components were identified each with different reservoir potential (Fig. 3).

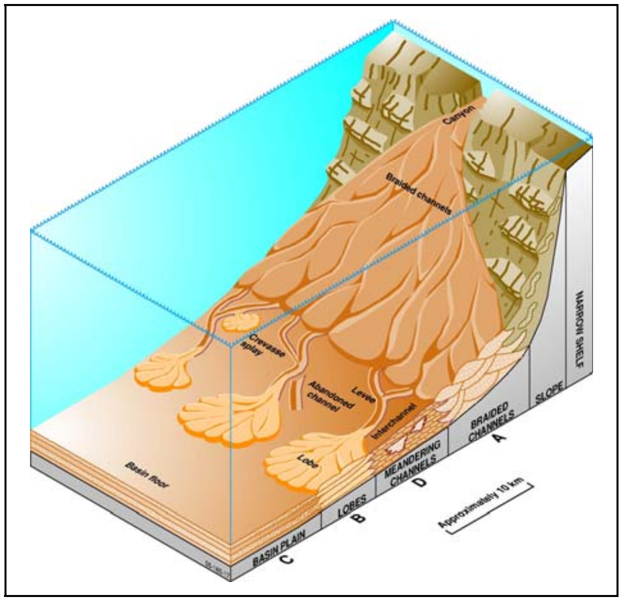


Figure 3. Model of an active margin fan system of channels and lobes termed "Suprafan lobes" (modified from Shanmaugam et.al. 1988). The various facies components (A, B, C, and D) are described in table 1 with summaries of reservoir quality.

INTERMEDIATE SCALE MODELS

In order to capture the ratios of directional permeabilities of the various facies, several intermediate models were constructed. The aim was to improve understanding of likely vertical and horizontal pathways for CO_2 at a 100 m-10 km scale. Stochastic models of objects representing braided suprafan, depositional lobes, basin plain, and meandering submarine channels and levees were constructed using Petrel^{TM} software. Models were populated using known averages from Gage Sandstone petrophysical logs and relative core data values using sedimentary facies as the constraining property. Sensitivity analysis was then conducted to determine effective values for Kx, Ky, and Kz. These effective permeabilities could then be used directly in reservoir simulations and thus reduce the errors associated with upscaling in the modeling workflow.

SITE SCALE SIMULATION

To investigate the potential of a large hydrodynamic storage site in the southern portion of the basin a coarse scale geological model was constructed (Fig. 4) incorporating the results from the intermediate facies models. The number of cells did not exceed 200,000 making it practical for running multiple simulations. CO2CRC researchers are currently building several more intermediate models to produce a library of facies scenarios that can be applied to future site investigations.

Table 1. Each different lobe model within the sub-marine fan system has notably different reservoir geometry. This has implications for storage of CO_2 within the Gage Sandstone so it is important to include this detail in the larger basin scale model.

Fan lobe models	Character	Connectivity	Net to gross	Reservoir Quality.
(A) Braided Suprafan Lobes	Vertically and laterally stacked channel sand bodies, generally uninterrupted by mudstone beds.	Good lateral and vertical communication	High 80-90%	Excellent
(B) Depositional Lobes	Interbedded sandstones and mudstones with characteristic thickening-upward cycles.	Good lateral connectivity in all directions, moderate vertical communication due to layering.	50-80%	Good
(C) Basin Plain	Mudstone with the occasional laterally extensive but thin sand layer.	Very Poor vertical communication and isolated sheet sands.	Low <10%	Poor
(D) Meandering Channels	Lenticular sand bodies of channels and levees in Fanlobes	Highly anisotropic. Poor sand body connectivity	10-50%	Moderate

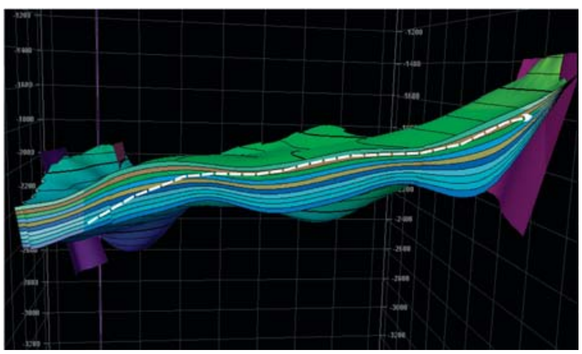


Figure 4. Geological Model of the southern portion of the Gage reservoir where the most likely injection site is located. Injection is proposed down dip with a long migration pathway to the east.

REFERENCES

Bradshaw, J., B. Bradshaw, L. Spenser, P. Wilson, G. Simon, and Makie, V., 2001. Uei 60 - Geological Carbon Dioxide Sequestration in the Perth Basin, GEODISC: Project 1 Regional analysis Stage Three Basins and Emissions mapping. *GEODISC report 1-2001-006.*

Boggs, S. Jr., 1995. Principles of Sedimentology and Stratigraphy. Pretince Hall. Ch. 3, p. 69-73.

Bouma, A.H, J.M. Coleman, and DSDP Leg 96 Shipboard Scientists, 1985. Mississippi fan: Leg 96 Program and Principal Results, in Bouma A.H., Normack W.R., and Barnes N.E., eds. *Submarine Fans and Related Turbidite Systems:* New York, Springer-Verlag, p. 247-252.

Causebrook R., K. Bale, and T. Dance *in press.* Southern Perth Basin Site Investigation and Geological model for Storage of Carbon Dioxide. Research Program 1.1- Technologies for Assessing Sites for CO_2 Storage. CO2CRC Report.

Mutti, E., 1977. Distinctive Thin-bedded Turbidite Facies and Related Depositional Environments in the Eocene Hecho Group. *Sedimentology*, v.24, p. 107-131.

Shanmugam, G. and R.J. Moiola, 1991 Types of Submarine Fan Lobes: Models and Implications. *The American Association of Petroleum Geologists Bulletin* v. 75, No.1 January 1991, p. 156-179.

Shanmugam, G. and R.J. Moiola, 1988 Submarine Fans: Characteristics, Models, Classification, and Reservoir Potential. *Earth-science Reviews*. v. 24, p. 383-428.

Walker, R.G., 1978 Deep-water Sandstone Facies and Ancient Submarine Fans: Models for Exploration for Stratigraphic Traps. *The American Association of Petroleum Geologists Bulletin* v. 62, p. 932-966.

SITE CHARACTERIZATION OF FLUVIAL, INCISED-VALLEY DEPOSITS

Peter Frykman[1], Kim Zink-Jørgensen[1], Niels Bech[1], Ben Norden[2], Andrea Förster[2] & Michael Larsen[1]

[1]GEUS - Geological Survey of Denmark and Greenland
Øster Voldgade 10
Copenhagen, 1350 K, Denmark
e-mail: pfr@geus.dk

[2]GFZ - GeoForschungsZentrum, Potsdam, Germany

INTRODUCTION

The CO_2SINK integrated project, supported under the FP/6 framework by the EU commission and industry, is part of a European research program that aims to investigate the potential of geological storage of CO_2. The project is targeted at research on monitoring of CO_2 that will be injected into a saline aquifer near the town of Ketzin, about 25 km west of Berlin (Germany). Prior to this experimental injection a baseline survey of the site and the target reservoir is performed, and a detailed risk assessment is made to ensure that the experiment can be conducted safely.
One focus of the baseline study has been on the reservoir rocks in the Upper Triassic Stuttgart Formation, which are fluviatile sandstone bodies whose dimensions and spatial extent remain a matter of exploration. The sedimentary setting is interpreted as being a system of incised-valley deposits, where channel belts have formed by amalgamation of individual fluvial channels. The channels are incised into floodplain-facies or playa-type facies sediments, possibly including some levee deposits and overbank crevasse splays.

Because data about the reservoir section are limited to few wells, geostatistical methods were used for the construction of a reservoir model and the evaluation of its uncertainty. Parameters from analogue sequences were used as an additional input into the conceptual model.

The reservoir model has been used to simulate the migration and fate of the injected CO_2 with a commercial flow simulator (ECLIPSE).

THE RESERVOIR SYSTEM AT KETZIN

From exploration in the larger Ketzin area it is known that good quality sandstone reservoirs exist in the Upper Triassic section. The Ktzi 163/69 borehole has encountered the target reservoir and provides core and well-logging data. The Stuttgart Formation is lithologically heterogeneous: it is made up of muddy flood-plain-facies rocks of poor reservoir quality alternating with sandy string-facies rocks of good reservoir properties that may attain several tens of meters thick where subchannels are stacked. The sandstones consist of varying amounts of quartz, feldspar, and rock fragments, classifying them as graywacke (Beutler and Häusser, 1982). They are fine-grained to medium-grained, well sorted, and often poorly cemented. Cements comprise silicates and clay as well as sometimes also anhydrite (Beutler et al., 1999). The sandstones have an average porosity of 23%. The permeability determined in hydraulic well tests ranges between 500 and 1000 mD. The temperature of the reservoir in the Ktzi 163/69 well is 33–36°C at a depth of 600-700m. This is also the depth interval in which the reservoir sandstones are expected at the CO_2SINK injection drilling site. Formation pressure at 700 m depth is supposed to range between 70 and 75 bar.

GEOLOGICAL RESERVOIR MODEL

The FLUVSIM program (Deutsch and Tran, 2002) has been used for the geostatistical modeling of the reservoir architecture between and beyond well control. It exploits the advantages of a hierarchical object-based modeling scheme. The geostatistical input to the stochastic modeling is derived from conceptual models of the sedimentological architecture of the Stuttgart Fm. (Beutler and Häusser, 1982, Beutler, pers. com.) as well as from regional facies maps of northeast Germany (Beutler, 2002).

The program operates with a background matrix of non-channel facies and generates objects of channel facies in the matrix (see Fig. 1).

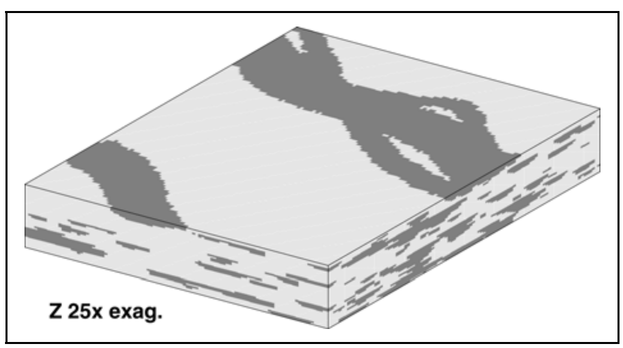


Figure 1. A realization of the geostatistical model of a fluvial system with channel belts in an area of 10x10 km. The total thickness of 80 m is exaggerated 25 x in this plot.

The program honors the primary borehole data with channel/non-channel facies supplemented by different types of secondary information, such as a vertical proportion curve to account for vertical trends in net/gross ratio (sand/clay ratio), and spatial variations in channel-sand frequency given as a spatial proportion map. The vertical proportion curve is mainly guided by the well data within the site area, but also accounting for general information about the sequence from other wells outside the area. The spatial proportion map is based on an interpretation of the structural evolution of the area indicating lateral bounds for the incised valley.

The modeling has not included the facies of levee deposits or crevasse-splay/overbank deposits.

The sand channel input parameters are derived from analogue outcrop data and conceptual models. The geometry parameters have been assigned to channel belts that can be considered to consist of amalgamated individual channels. The orientation of these channel belts ranges between 15° and 20°. The sinuosity is described by a channel amplitude of 100–500 m and a wavelength of 5,000–9,000 m; the channel belt widths range between 100 and 1,600 m combined with channel sand thickness between 1 and 8 m.

One example of a realization of the FLUVSIM modeling is given in Fig. 1. It shows the sinuosity of the wide channel belts and the partial amalgamation of the channel belt sands. The 3-D connectivity can be investigated and will show the vertical connectivity that is important for the CO_2 migration.

The spatial distribution of the channel sand and resulting net/gross ratio is shown in Fig. 2. The low net/gross ratio at the western and eastern margins is guided by the bounds set for the incised valley. An assemblage of this and other realizations can be used to investigate the expectations for net/gross ratio variability at planned well locations and thereby to establish a risk assessment for the future development of the injection facilities at the site.

To use the geological reservoir model for CO_2 propagation modeling, the channel sand has been assigned a permeability distribution with a mean of 500 mD (10–1000 mD), and the flood-plain rock has been assigned a permeability distribution with a mean of 20 mD (1–35 mD), see Fig. 3. The latter permeability is somewhat higher than that seen in measured data, but takes into account that clean mudstone might include some sand/silt stringers from levees or overbank sediments. The vertical-to-horizontal permeability ratio (kv/kh) is set to 0.33 everywhere to account for small-scale layering.

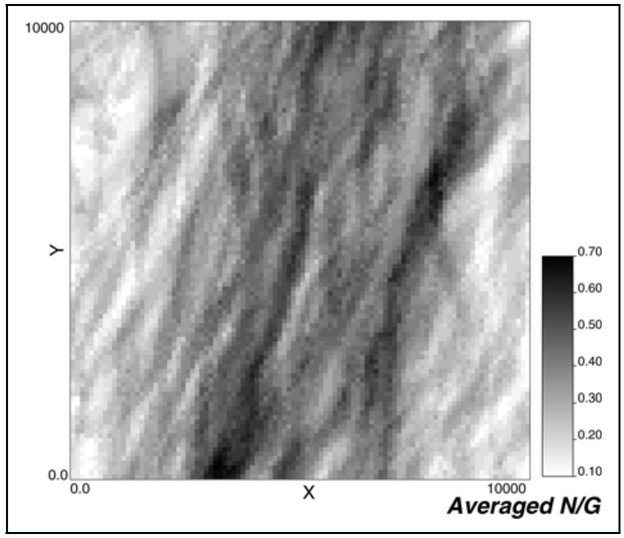


Figure 2. Map of the site area of 10x10 km showing the spatial variation of the net/gross ratio when the full model (80 m thick) is averaged. The main direction NNE-SSW for the channel belts is reflected, as well as the lateral bounds for the incised valley at the western and eastern margins.

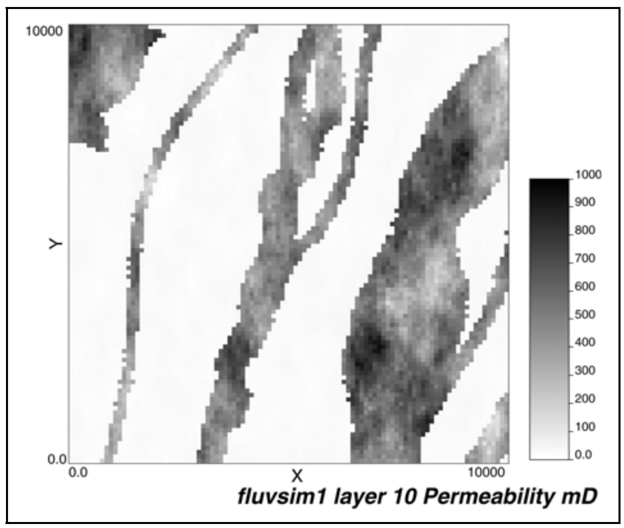


Figure 3. A single layer in the geostatistical model with permeability distribution incorporated. The patchy distribution of the permeability is obtained by merging the channel belt model with an unconditional sequential Gaussian simulation of a permeability field.

DYNAMIC RESERVOIR MODEL

A major focus of this early modeling work was to evaluate the propagation and maximum extension of injected CO_2 in the subsurface and its migration path. For this purpose the ECLIPSE 100 reservoir simulation program was employed by attributing brine and CO_2 properties to the simulator's oil and gas phases, respectively. The phase behavior is described by black-oil PVT (pressure-volume-temperature) tables. These describe the CO_2 density and viscosity as a function of pressure and temperature, CO_2 solubility in water and brine as a function of salinity, the density of brine, and its viscosity. The diffusion of CO_2 in water has been neglected in the present calculations, as its effect is negligible during the time span considered (20 years).

FUTURE WORK

This initial site characterization is used to model probable reservoir conditions and thereby scenarios for the CO_2 migration in the reservoir section. As more data become available, the modeling scheme allows an easy update and gradual reduction of the uncertainty.

REFERENCES

Beutler, G., and I. Häusser, 1982, Über den Schilfsandstein in der DDR: Zeitschrift für Geologische Wissenschaften, v. 10, p. 511–525.

Beutler, G., N. Hauschke, and E. Nitsch, 1999, Faziesentwicklung des Keupers im Germanischen Becken, in N. Hauschke, V. Wilde, Trias, eine ganz andere Welt: München, Verlag Dr. Friedrich Pfeil, p. 129–173.

Beutler, G., 2002, Keuper – Mächtigkeit und Lithofazies des Schilfsandsteins, in W. Stackebrandt, and V. Manhenke, Atlas zur Geologie von Brandenburg im Maßstab 1:1,000000: Kleinmachnow, Landesamt für Geowissenschaften und Rohstoffe Brandenburg, Germany, p. 62–63.

Deutsch, C. V., and T. T. Tran, 2002, FLUVSIM: a program for object-based stochastic modeling of fluvial depositional systems: Computers & Geosciences, v. 28, no. 3, p. 525–535.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

GEOLOGICAL SITE CHARACTERIZATION OF THE NEARLY DEPLETED K12-B GAS FIELD, OFFSHORE THE NETHERLANDS

C.R. Geel[1], R.J. Arts[1], R.M.H.E. van Eijs[1], E. Kreft[1], J. Hartman[2], D. D'Hoore[2]

[1]TNO Built Environment & Geosciences
PO Box 80015
3508 TA Utrecht, The Netherlands
e-mail: kees.geel@tno.nl

[2]Gaz de France Production Nederland B.V.
PO Box 474
2700 AL Zoetermeer, The Netherlands

INTRODUCTION

The EU-sponsored CASTOR project and Dutch government-sponsored CATO project aim to develop and validate all of the innovative technologies needed to capture CO_2 at the post-combustion stage and store CO_2. One of CATO/CASTOR's sub-projects studies the storage of CO_2 in the nearly depleted K12-B gas field, offshore The Netherlands. A second goal is to achieve enhanced gas recovery through the CO_2 injection.

This paper describes the geological characterization of the reservoir and overlying cap rock.

THE K12-B GAS FIELD

The K12-B gas field is located in the Dutch sector of the North Sea, some 100 km northwest of Amsterdam (Figure 1). It has been producing from 1987 onwards and is currently operated by Gaz de France Production Nederland B.V.

The K12-B structure was discovered in 1981 by the K12-6 exploration well. Gas production started in 1987. The gas contains 13% CO_2 which is removed at the production platform

Gas production is from the Upper Slochteren Formation, Rotliegend, of Permian age. The reservoir lies at a depth of approximately 3800 meters below mean sea level, and the temperature is about 128 ºC. The K12-B field has produced 12 BCM of gas, about 90% of the initial gas in place. The initial reservoir pressure of 400 bar has presently dropped to 40 bar.

Although the site has clearly proven itself already in terms of gas storage capacity and seal efficiency, it was deemed necessary to characterize reservoir and cap rock for CO_2 injection.

RESERVOIR CHARACTERIZATION

In order to build a reservoir model that accurately predicts injected CO_2 flow behavior within the reservoir, several reservoir-geological issues were addressed. Heterogeneities due to sedimentary structures, diagenesis, and faulting were studied and quantified where possible.

Sedimentary facies

Sedimentary heterogeneities include a complex interfingering of high-perm (300-500 mD) aeolian facies, low-perm fluvial facies (5-30 mD), and mud-flat facies that act as vertical permeability barriers. It is most likely that the several meters thick aeolian streaks, which form about 11% of the gross rock volume will act as conduits for the CO_2. The lateral extent of individual streaks is estimated to be no more than a few hundred meters. Shale streaks comprise 16% of the volume and fall into two categories. A minority has a field-wide extent, while most of the shale streaks can not be correlated across more than two or wells, corresponding to a lateral extent of a few hundred meters.

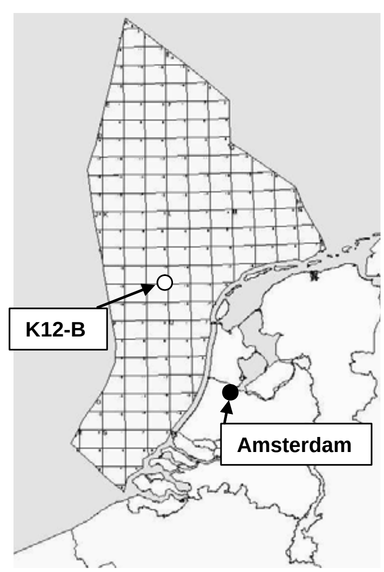


Figure 1. Location of the K12-B Gas Field, offshore The Netherlands.

Diagenesis

Diagenesis is considered to be the main controlling factor for fluid flow. Its influence is demonstrated in three different ways:

1. Several phases of diagenetic processes resulted in the formation of autigenic illite, kaolinite, and carbonate cements, which at places effectively block vertical flow through the reservoir. These diagenetic zones seem to be confined to the shale streaks.
2. Most fault zones are completely cemented, as testified by one well that penetrates a fault, and by the virgin pressures encountered in undrained fault compartments.
3. Permeability and porosity are much lower in the water-bearing zone below the gas column which can be attributed to the presence of diagenetic cement.

Faulting

The K12-B field consists of a number of tilted fault blocks which are not or only slightly in pressure communication. All faults are normal faults with moderate throws (10-100 meters), apart from the main boundary fault which has a throw of 500-900 meters. None of the faults reach the top of the overlying salt seal; the salt acts an effective absorber of the faults below the Zechstein.

Geocellular model

A 3D geocellular model was built according to the seismic interpretation of the Top Rotliegend and information on the well tops from the eight K12-B wells (Figure 2). Well logs for porosity, permeability, and original water saturation were used to populate the geocellular models. 3D reservoir properties were generated in accordance with the heterogeneities discussed above. In order to retain the heterogeneity, a finely layered model was built with a vertical resolution of 1-2 meters.

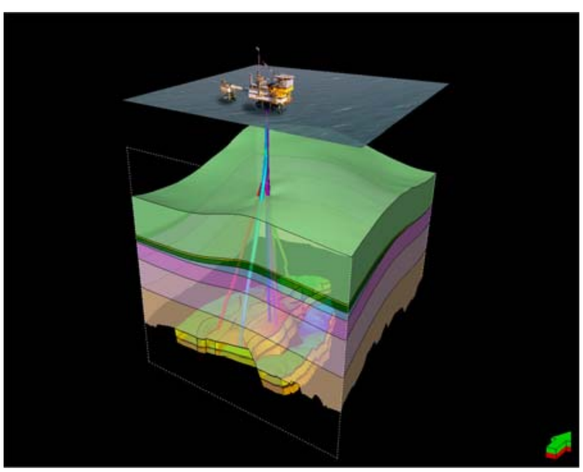


Figure 2: 3D perspective view of the Petrel model of the K12-B field and its overburden. Tertiary strata were omitted from the drawing for the sake of clarity.

The 3D geocellular model served as a basis for fluid flow simulations, both for gas production and CO_2 injection.

SEAL CHARACTERIZATION

The top seal of the K12-B reservoir is provided by the Zechstein Group which consists of a thick evaporatic sequence dominated by rock salt. This sequence thickens towards the north as a result of structural deformation. One of the objectives of the seal characterization was to distinguish and map the different salt minerals. There are no cores of the Zechstein Group in this area and neither any age data. Therefore correlation was purely based on log response.
Evaporite lithology was estimated from the gamma-ray and sonic log to enhance the visual correlation. Based on those two logs, the following minerals could be identified with reasonable confidence: Shale, Halite, Dolomite, Anhydrite, Polyhalite, Carnallite, and Bishoffite (Figure 3).

The correlation of the Zechstein Group could only be made on a large scale due to the moderate structural deformation of the salts. Seismic cross sections demonstrate possible detailed correlation for the lower part and upper part of the Zechstein Group only. This observation is confirmed by the well logs, where the thick halite layer in the middle part of the Zechstein Group could not be subdivided. Therefore the Zechstein Group was divided into only three units: Lower, Middle, and Upper. The Lower Unit is dominated by a calcareous bottom sequence. The upper part of this sequence is formed by a thick layer of nearly pure rock salt. This rock salt layer thickens from 75 meters in the southwestern part of the field to more than 450 meters in the northeast. The top of the Lower unit can be recognized by a sharp transition of a thick rock salt sequence to a unit with an alteration of clays, halite and carnallite. This Middle Unit contains carnallite and polyhalite layers having a maximum thickness of 10 meters. Bischoffite is present in thin layers (up to 2 meters). The top of the Middle Unit is marked by a pronounced anhydrite layer. The Upper Unit is dominated by the rock salt. Carnallite layers occur in the upper part of the unit while clay layers are abundant in the lower part but these are restricted to the southern part of the area.

DISCUSSION AND CONCLUSION

The main conclusion of this study is that the K12-B gasfield is suitable for storage of CO_2. The reservoir has obviously proven itself already with respect to gas storage capacity and sealing efficiency. However, the pressure drop of 400 bar to 40 bar due to the gas production over the last two decades required a careful re-evaluation of the sealing capacity and the injectivity of the reservoir. The results were positive:

diagenetic effects have mainly lowered the vertical permeability, which is positive to retain CO_2. The faults present in the reservoir all seem to be well cemented and sealing. Moreover, none of the faults reach the top of the overlying (salt) seal. The Zechstein salt appears to be a perfect seal.

ACKNOWLEDGEMENTS

The authors are grateful to the EU and the Dutch government for funding this research through respectively the CASTOR and CATO projects.

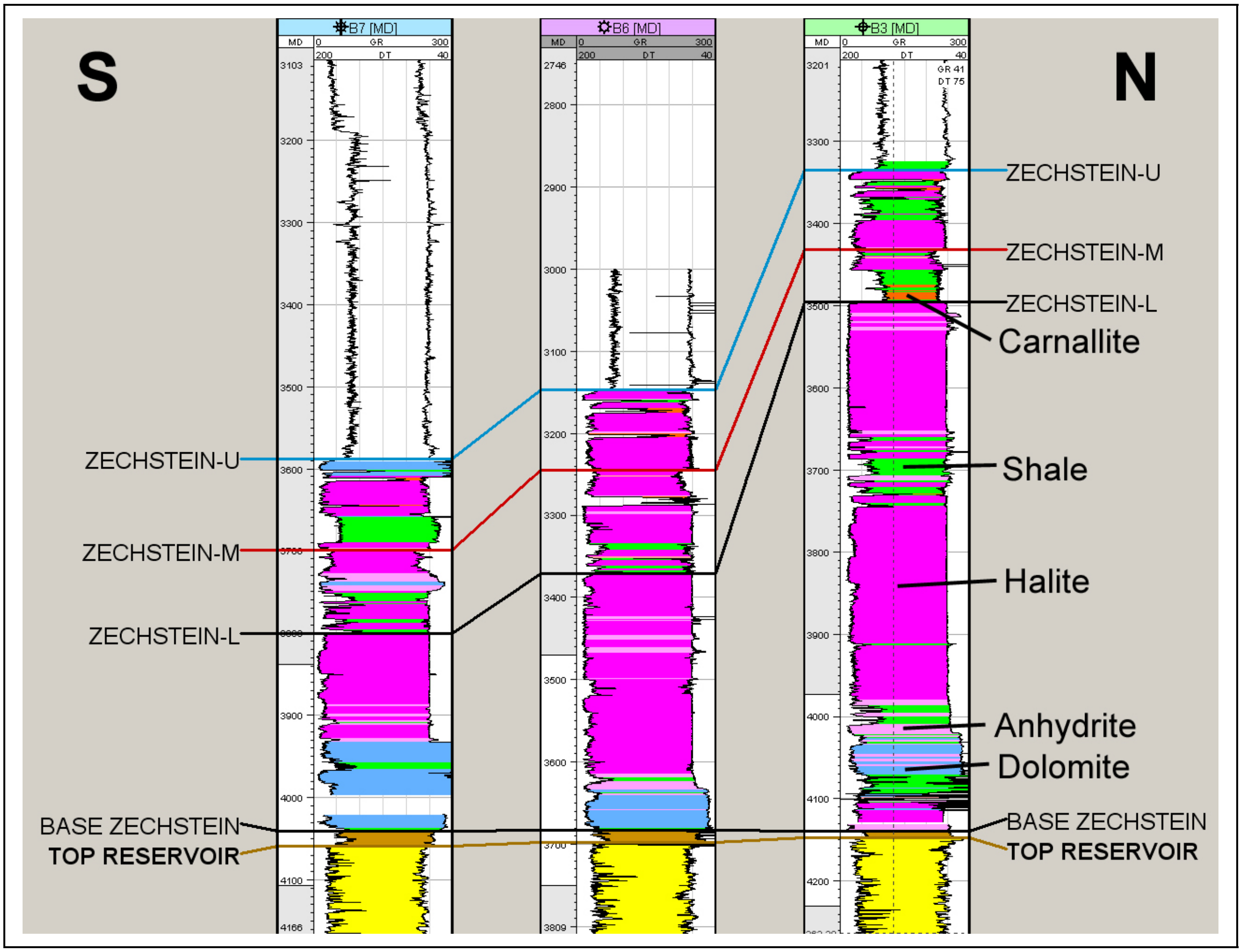


Figure 3 Well correlation of the Zechstein Group which forms the top seal of the Slochteren Sst of the K12B field. Average well spacing is 1600 m.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

SUBSURFACE CHARACTERIZATION OF CO_2 SEQUESTRATION SITES—EXAMPLE FROM A CARBONATE REEF SETTING

Mark H. Holtz[1], Rebecca C. Smyth[1], Brian McPherson[2], Weonshik Han[2]

[1]The University of Texas at Austin, Bureau of Economic Geology
University Station Box X
Austin, Texas, 78713, USA
e-mail: mark.holtz@beg.utexas.edu

[2]New Mexico Institute of Mining and Technology

INTRODUCTION

Several sequential steps lead to proper and complete characterization of the subsurface in which geologic sequestration takes place (Fig. 1).

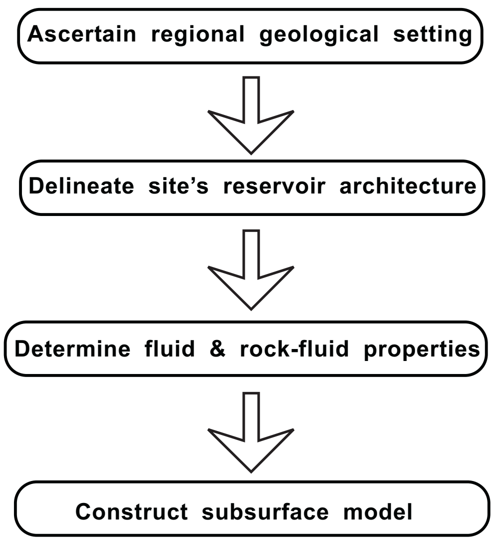


Figure 1. Work flow for subsurface site characterization consists of four basic steps, which result in integration of data into a functional model.

The first step, to ascertain the regional geological setting, allows determination of analogous sites and development of regional stratigraphy, which serves as the platform for the rest of the characterization. The next step is to delineate the site's geologic architecture by making detailed chronostratigraphic correlations of maximum flooding surfaces, depositional facies relationships and diagenetic overprints and determining spatial positioning of fault planes. Then fluid and rock-fluid properties are determined and characterized in the context of geologic architecture, in order to determine which properties are stratigraphically or depositional-facies dependent. The final task is to construct a subsurface model and run fluid-flow simulations. A 3D geocelluar model allows greatest integration of geological and engineering information. Dynamic simulations are used to calculate the volume of potential CO_2 sequestered.

We will illustrate this characterization process with our in-process study of the sequestration capacity of the SACROC and Claytonville reservoirs of the Midland Basin, West Texas.

REGIONAL GEOLOGIC SETTING

The SACROC oil field unit and the Claytonville Canyon Lime reservoir produce from Pennsylvanian-age strata. The SACROC oil field unit, the main part of Kelly-Snyder field, lies along a trend of fields and was described by Galloway et al. (1983) as the Horseshoe Atoll Play. The Claytonville Canyon Lime reservoir lies east of SACROC in the Pennsylvanian Reef/Bank Play. This play trends north-south along the east edge of the Midland Basin and follows the paleo-Strawn and Canyon shelf edges (Fig. 2). Both produce from Strawn- and Canyon-age carbonate reefs. The SACROC unit, however, represents an isolated platform depositional environment whereas Claytonville is described as a ramp depositional environment, because it is connected to the eastern shelf. Depositional facies found in the Pennsylvanian Reef/Bank Play resemble those of the Horseshoe Atoll, although they have a different geologic trend. Producing carbonates in both fields are draped by thick Wolfcamp shales that act as the reservoir seal.

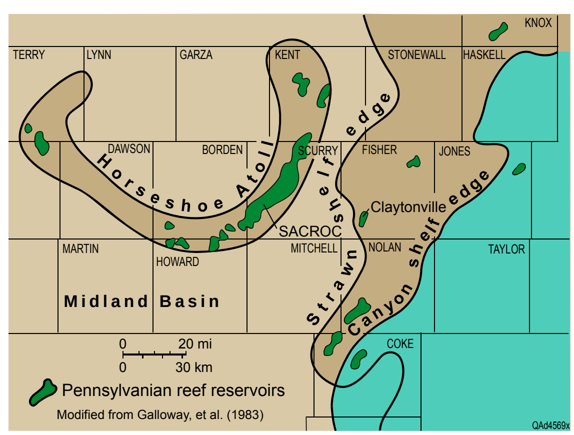


Figure 2. The SACROC unit is located along the West Texas Horseshoe Atoll trend and Claytonville field along the Strawn Formation shelf edge.

RESERVOIR ARCHITECTURE

Claytonville field is a northeast-southwest-trending anticline that consists of four localized structural highs. The structure, approximately 5 miles long and ¾ mile wide, reflects depositional topography and consists of reef buildups with facies of interbedded pellet, crinoid, algal, and intraclast grainstones and boundstones.

The oil-bearing zone is a 500- to 1,000-ft-thick series of carbonate reef facies. Facies include crinoid wackestones, skeletal packstones and grainstones, karst breccia, and debris breccia. A typical upward- shoaling cycle consists of lower-energy crinoid wackestones at the base, followed by higher-energy skeletal and ooid packstones and grainstones, and capped by thin karst breccia. These cycles can be five to tens of feet thick. Debris breccia are likely to lie at the edges of the reef complexes.

The carbonates contain both primary and secondary porosity. Crinoid wackestones have primary intercrystalline porosity, as well as fracture and vuggy secondary porosity. Vuggy pores can be lined with dog-tooth calcite. Intercrystalline, vuggy, and fracture pore types can be present spatially within wackystones. Wackestones can also be solely intercrystalline forming lower permeability zones. Skeletal packstones and grainstones are dominated by intergranular pores. In core they exhibit mottling of darker and lighter colors which may indicate diagenetic alteration. The thin karst breccias are well cemented, and they display mainly intercrystalline pores.

Overlying strata

The entire section overlying the productive oil zone is Permian-age strata. Permian strata include cyclic shallow-water ramp carbonates sequences bracketed by cycle-base shales, and evaporate tops. The cycles contain tight carbonate mud-dominated zones and interbedded siltstones. Sandstones are typically found interbedded with these carbonates. In these sequences the sandstones are most porous when they represent marine environments. The carbonate mudstones and Evaporite beds are tight.

FLUID AND ROCK-FLUID PROPERTIES

Initial fluid properties offer insight into how fluids will flow in the subsurface and how they will interact with CO_2. The key is to understand how fluid properties will change with changes in subsurface pressure and whether their initial character is dependent on stratigraphy and/or depth.

The Claytonville (Canyon lime) oil field was discovered in January 1952 in Fisher County, Texas. By 1958 50 producing wells had been drilled in the field over approximately 3,360 acres, followed by limited water injection starting in 1960, which is thought to have been successful in maintaining reservoir pressure. In 1975 gas injection occurred in the northeastern part of the field for a short period of time. By the end of 2003, the reservoir had produced nearly 66 million barrels of oil, and it continued to have 21 producing wells with an annual rate of 90 thousand barrels, or an average of 11.7 STB/day.

The oil residing in the field is of high quality. Oil API gravity is 42. At an original reservoir pressure of 2,335 psi, the oil was slightly undersaturated, so there was no original gas cap. Some free gas was most likely released into the reservoir during initial production, as seen by increasing producing gas:oil ratios. After water injection and possible bottom water drive stopped pressure depletion in the 1960's, these gas:oil ratios dropped and stabilized. A possible secondary gas cap is thought to have developed in the northeast structural high. The character of this oil makes this reservoir a good candidate for CO_2 enhanced oil recovery.

Oil reservoir porosity and permeability are relatively low. Porosity averages 5 percent, and permeability is in the 10-md range. Pore types include vugs, interparticle, intercrystalline, and fractures. Because the relationship between porosity and permeability is dependent on the pore type, it can be quite variable. Although storage and flow capacity is low, the reservoir has been interpreted to be in fairly good vertical and horizontal communication, based on the consistency of bottom-hole pressure measurements.

GROUNDWATER STUDY

Analysis of groundwater above two Permian Basin oil fields (SACROC Unit and Claytonville field) near Snyder, Texas, will determine if impacts of 30 years of CO_2 injection can be detected. CO_2 flooding for enhanced oil recovery (EOR) has been active at SACROC in Scurry County since 1972. Approximately 13.5 million tons per year ($MtCO_2$/yr) is injected, with withdrawal/recycling amounting to about 7 $MtCO_2$/yr. It is estimated that the site has accumulated more than 55 $MtCO_2$; however, no rigorous investigation has been undertaken to confirm that CO_2 is trapped in the subsurface. Assessment of groundwater for leakage signal is one approach to assessing the effectiveness of the SACROC reservoir and engineered system in retaining CO_2.

Methods for groundwater study will include (1) examination of existing analyses of saline to freshwater samples collected within an eight-county area encompassing SACROC and Claytonville; (2) additional groundwater sampling for analysis of major and minor element chemistry plus field-measured pH, alkalinity, temperature, stable isotopic ratios of hydrogen (D/H), oxygen ($^{18}O/^{16}O$), and carbon ($^{13}C/^{12}C$); and (3) geochemical equilibrium and flow-path modeling. The objective of this groundwater study is to look for potential impacts on shallow groundwater from as a result of long term deep CO_2 injection.

SUBSURFACE MODELING

Constructing a subsurface model through integration of reservoir architecture with rock-fluid properties is the critical step in subsurface site characterization and forms the basis for testing and interpreting the reservoir architecture correlation. The outcome of this integration becomes the working model on which EOR and sequestration strategies are based. The goal is to determine which geological architectural elements are controlling fluid-flow movement, thus defining the subsurface framework compartments and flow units.

From the development of a 3D geocelluar model, simulations of fluid-flow and rock-fluid interactions can be made. For our West Texas carbonate reef setting, fluid-flow simulations will be done to determine the best method for CO_2 EOR, and coupled process modeling will investigate the total system including preliminary estimates of CO2 storage capacity. The model is also used to aid in identification of areas that warrant closer examination with respect to risk criteria, especially those areas with data of least certainty.

ACKNOWLEDGMENT

This work is a subset of the Southwest Regional Partnership on Carbon Sequestration Phase 2 studies funded by the Department of Energy (DOE) in cooperation with industry and government partners. A special thanks to Charles Kerens and F. J. Lucia for help and insight. Kinder Morgan, the company sponsor, deserves special recognition, along with Steve Guillot and Mike Hirl, for their support.

REFERENCE

Galloway, W. E., and others 1983, Oil Atlas of Major Texas Reservoirs: The University of Texas at Austin, Bureau of Economic Geology, 163 p.

REGIONAL SCREENING, SELECTION AND GEOLOGICAL CHARACTERIZATION OF THE SALINE AQUIFER STRUCTURE "SCHWEINRICH", A POSSIBLE CO_2-STORAGE SITE FOR A LARGE LIGNITE-FIRED POWER PLANT IN EAST GERMANY

Robert Meyer[1], Franz May[1], Christian Müller[1] and Christian Bernstone[2]

[1]Bundesanstalt für Geowissenschaften und Rohstoffe (BGR)
Stilleweg 2
D-30655 Hannover, Germany

[2]Vattenfall
Jämtlandsgatan 99
16287 Stockholm, Sweden

e-mail: robert.meyer@bgr.de; Franz.May@bgr.de; christian.bernstone@vattenfall.com

INTRODUCTION

In order to reduce greenhouse gas emissions, options for CO_2 storage are currently investigated in many countries in interdisciplinary research programs. The EU supported CO2STORE research and development project investigates new off-shore and on-land long-term carbon dioxide storage opportunities in extensive saline aquifers. Within the German case study "Schwarze Pumpe", a regional site screening was accomplished and several candidate storage sites have been identified in North-East Germany. Subsequent to a ranking considering different criteria, the anticlinal structure "Schweinrich" has been selected and investigated in order to evaluate its capability for safe long term CO_2 storage. Contributing project partners are BGR (Germany), NITG-TNO (Netherlands), BRGM (France) and Vattenfall Utveckling AB (Sweden).

The main target of this pre-feasibility study was to find a single storage site (structural closure), likely capable to take in the total amount of CO_2 produced by a modern, lignite fired power plant. Exemplarily, the power plant "Schwarze Pumpe" (a modern, lignite fired power plant operated by Vattenfall) with an output of about 400 Mt CO_2 during an expected operation lifetime of about 40 years, is used as a representative CO_2 source. Because of economical reasons, CO_2 transport by pipeline should be limited to transport distance up to about 300 km.

SITE SCREENING AND SITE SELECTION

Suitable saline aquifers of regional extent are located in the North-German basin, part of the Southern Permian Basin. Due to the limited transport distance the screening area for site selection was restricted to the eastern part of the North German basin, covering an area of about 40,000 km^2 (Figure 1). The structural geological framework as well as the Mesozoic and Caenozoic strata are well known from oil and gas explorations (1950´s to 70´s) and geothermal surveys (80´s).

This sedimentary basin holds several Mesozoic sandstone aquifers (Lower and Upper Triassic, Lower and Middle Jurassic and Lower Cretaceous). Between 1000 and 4000 m depth, these aquifers contain brines of 100 to 400 g/l dissolved solids.

The site screening and site identification has been accomplished by mapping the regional occurrence and relevant properties of saline aquifer formations: depth: 900 to 4000 m, thickness of reservoir rocks > 20 m, presence of cap rock formations, substitution of sandstone facies by fine clastic sediments.

Based on these maps suitable sites have been selected according to a set of criteria. Critical selection criteria that excluded unsuitable structures from further consideration were

- Storage capacity > 400 Mt CO_2
- presence of tectonically little disturbed closed storage structure
- transport distance of more than 300 km
- conflicts with existing use

A ranking of 27 structures identified in Northeast Germany has been performed (Figure 2) according to the above mentioned and additional important criteria:

- thickness of reservoir > 20 m
- reservoir porosity > 20%
- cap rock properties
- presence of reserve aquifer
- site connection to pipeline tracks
- salinity > 100 g/l
- presence of wells drilled through the cap rocks
- data availability (pre-exploration)

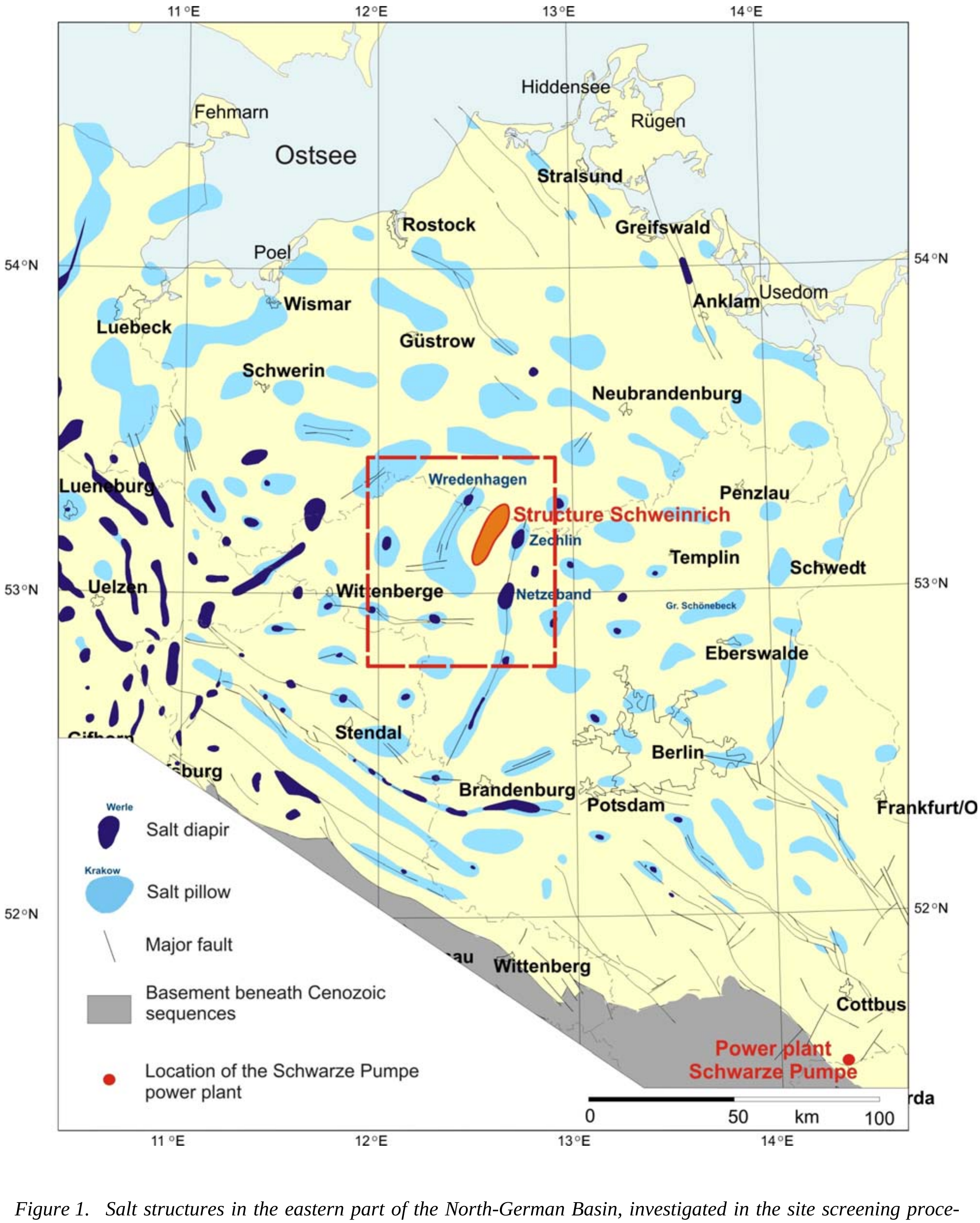


Figure 1. Salt structures in the eastern part of the North-German Basin, investigated in the site screening procedure. The location of both, the "Schwarze Pumpe" power plant and the structure "Schweinrich" relative to the distribution of salt structures (indicating the distribution of potential aquifer storage structures) and basement topography are displayed. The red frame indicates the area considered in the site characterisation process.

Additional, in the pre-feasibility phase less important site selection criteria were

- presence and kind of protected areas
- landscape picture
- population density

The structure "Schweinrich", some 250 km NW of the "Schwarze Pumpe" has been selected as the most suitable candidate site in this case study.

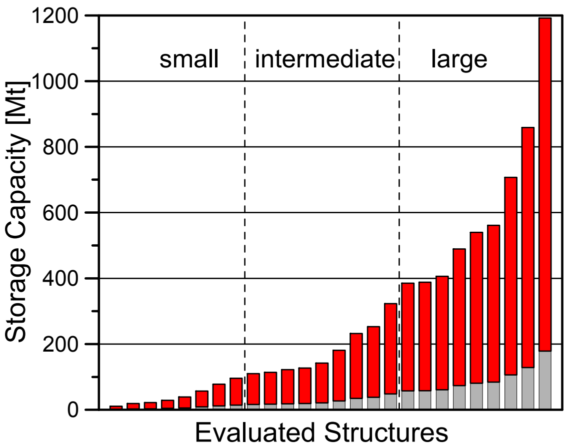


Figure 2. Estimated CO_2 storage capacities for candidate sites in the Northeastern German Basin based on a storage efficiency of 6 to 40%, sorted by increasing capacity and subdivided into categories of small (< 100 Mt), intermediate (100 to ~400 Mt), and large (> ~400 Mt) storage capacities.

SITE CHARACTERISATION

The depth of the reservoir was mapped from existing 2D seismic data. Thickness and lithology of the reservoir and the overlying cap rock were interpreted using information from nearby wells that also used as reference points to calibrate the seismic data. Petrophysical properties of the reservoir have been derived from wireline log interpretation and well correlations. The structural maps were used to derive the geometrical model for fluid-dynamical reservoir simulations.

The selected candidate site "Schweinrich" is a passive anticlinal structure (turtle structure) located between two salt diapirs (Figure 3). The target reservoirs are two sandstone sequences of the Lower Jurassic and the Upper Triassic, located in more than 1,300 m depth. The cumulative gross thickness of both reservoirs ranges between 270 and 380 m. The entire reservoir is overlain by thick Jurassic clay formations of several decametres thickness. The structural closure covers an area of some 100 km².

The site characterisation of the structure Schweinrich comprised:

- the geological survey of the structural closure and the surrounding areas, likely affected by CO_2
- the mineralogical and geochemical characterisation of reservoir and cap rock samples from wells
- numerical modeling to predict geochemical processes induced by CO_2 storage
- the creation of a 3D geological model
- numerical simulation of the fluid movement within the reservoir during the injection phase and the following 10,000 a
- an interdisciplinary safety assessment (impact to human health, safety and environment)

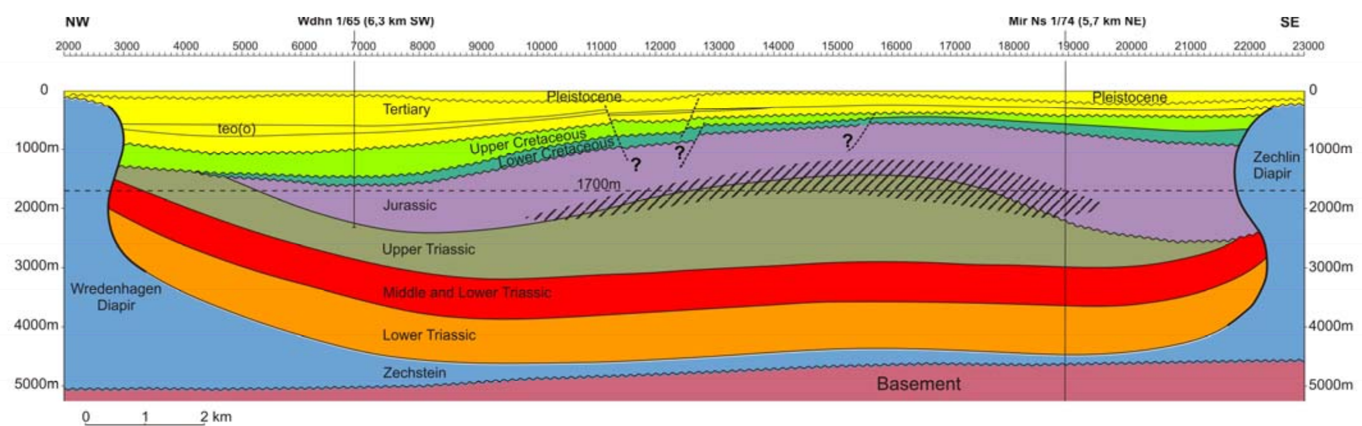


Figure 3. Cross section of the passive anticlinal structure Schweinrich between two salt diapirs. The hatched area indicates the reservoir and storage position. The faults in the overburden of the structure are not definitely confirmed.

CONCLUSIONS

A sufficiently large area extending beyond the preferred transport distance has been screened. Several prospective formations were mapped and a few dozens of structures have been evaluated. Eight structures fulfilling principle site requirements were ranked according to additional site selection criteria.

A first site characterisation based on existing data and numerical modeling of physic-chemical processes during and after CO_2 injection gave supportive evidence of the suitability of the selected site. The pre-feasibility study also revealed the lack of essential data and processes that could be critical for a future CO_2 storage. Apart from exploration wells and seismics any true feasibility study would need to incorporate a wider region surrounding the storage site in order to answer principal questions about salt water displacement and pressure build-up in the aquifer
.

COMPREHENSIVE CHARACTERIZATION OF A POTENTIAL SITE FOR CO_2 GEOLOGICAL STORAGE IN CENTRAL ALBERTA, CANADA

K. Michael, S. Bachu, B.E. Buschkuehle, K. Haug, M. Grobe, and A.T. Lytviak

Alberta Geological Survey/Alberta Energy and Utilities Board
4th Floor, 4999-98 Avenue
Edmonton, AB, T6B 2X3, Canada
e-mail: Karsten.Michael@gov.ab.ca

INTRODUCTION

Geological storage of CO_2 in deep saline aquifers is an option for significantly reducing emissions into the atmosphere. The Wabamun Lake area southwest of Edmonton in central Alberta (Figure 1) was identified as a potential site for future large-scale CO_2 injection for a variety of favorable conditions. Several large industrial CO_2 point sources are located in the vicinity, resulting in short transportation distances of the captured gas.

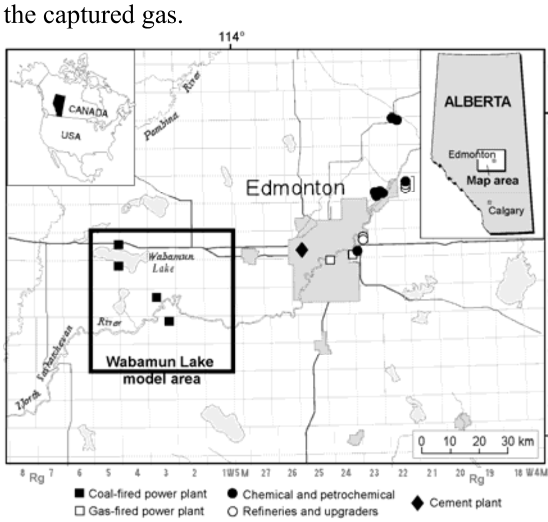


Figure 1. Location of the Wabamun Lake study area in Alberta, Canada. The study area covers 5 x 5 townships, which is equivalent to 900 square miles or 2500 km^2.

Various deep saline formations that have sufficient capacity to accept and store large volumes of CO_2 in supercritical phase exist at the appropriate depth and are overlain by thick confining shale units. Most importantly, a wealth of data exists (i.e., stratigraphy, rock properties, mineralogy, fluid composition, formation pressure, information about well completions), which was collected by the petroleum industry and submitted to the provincial regulatory agency, the Alberta Energy and Utilities Board. For these reasons, the Wabamun Lake area is an ideal location for the comprehensive characterization of a CO_2 storage site and for analyzing the potential risks associated with such an operation. In addition, this comprehensive data set offers the opportunity to test and to benchmark various models for predicting the performance of sites for CO_2 geological storage and the long-term fate of the injected CO_2.

GEOLOGY AND HYDROSTRATIGRAPHY

Overlying the Precambrian basement, the sedimentary succession in the Wabamun Lake area has a maximum thickness of up to 3000 m. It consists at its base of passive margin sediments, including evaporites and marine carbonates and shales of Cambrian to Jurassic age. The upper part is formed mainly by coarse to fine siliciclastic that were deposited in the Rocky Mountain foreland basin during the Cretaceous to present period. Due to pre-Cretaceous erosion, Mississippian carbonates subrop below Lower Cretaceous sandstones in the northeastern part of the study area. The sedimentary succession dips gently towards the southwest with a slope of 9 m/km (Figure 2). There are no known major faults in the area.

Figure 2 shows the general stratigraphy in the Wabamun Lake area along a dip cross section. Typically, sandstones and carbonates are aquifers, whereas shales and evaporites form aquitards. The sedimentary succession is subdivided by two thick aquitards, the Woodbend Group shales and the Colorado Group shales, into three main hydrostratigraphic groups: a) the Cambrian-Middle Devonian, b) the Upper Devonian-Lower Cretaceous, and c) the post-Colorado. Each major hydrostratigraphic group contains several aquifers and intervening aquitards. Some units also host hydrocarbon reservoirs and oil and gas production occurs mainly from the Banff Formation, the Lower Mannville Group, the Viking Formation, the Cardium Formation and the Basal Belly River Group (Figure 2).

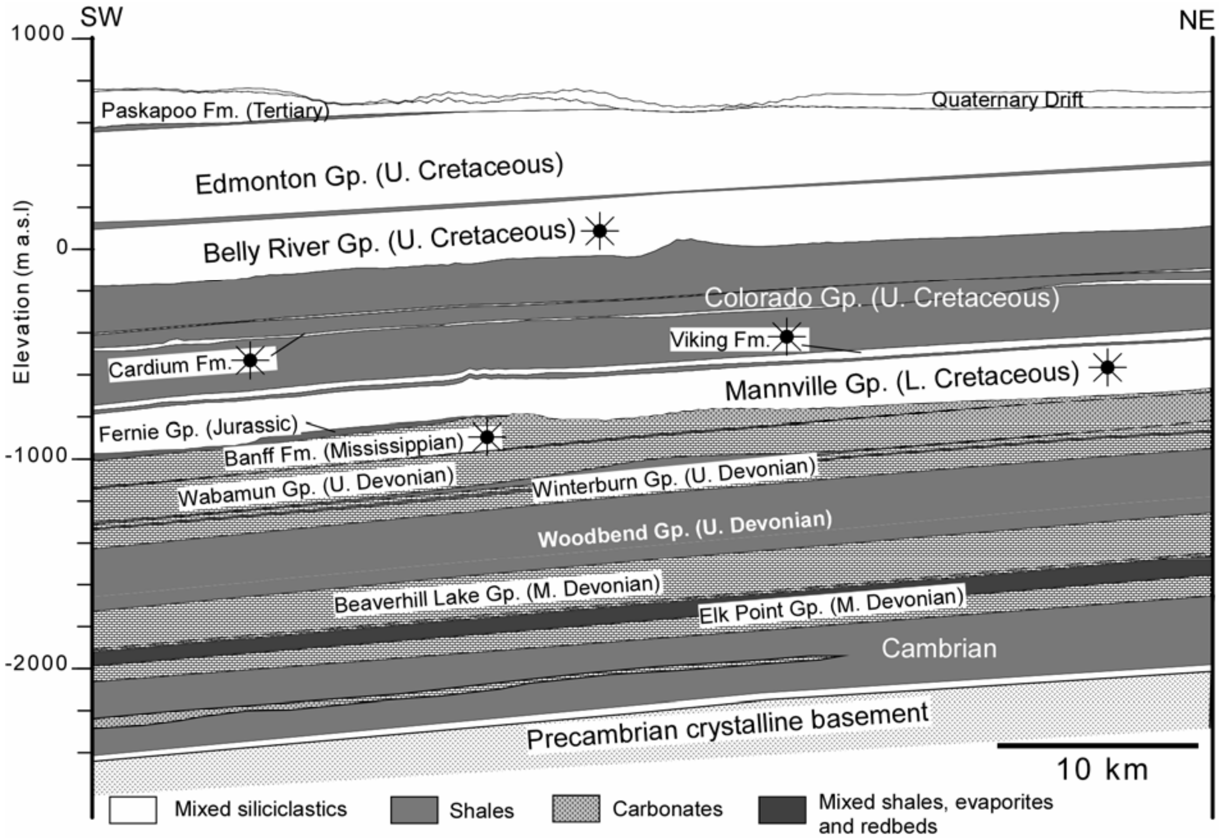


Figure 2. Dip cross section through the sedimentary succession in the Wabamun Lake area, Alberta, Canada, showing the general stratigraphy and lithology distribution.

FORMATION FLUIDS

Three different pressure regimes govern the flow of formation fluids in the Wabamun Lake area. The lower part of the succession, from the Cambrian to the Lower Cretaceous Viking aquifer, is underpressured, with pressures ranging from 28 MPa at 3000 m to 6.5 MPa at 1000 m depth. Exceptions are overpressured "Deep-basin style" hydrocarbon accumulations in the Lower Mannville and Cardium aquifers, which are hydrocarbon-saturated areas in the respective aquifer located downdip of the water leg. The shallow aquifers in the upper succession above the Colorado Gp. shales aquitard are normally to slightly sub-hydrostatically pressured, and formation water flow is driven by the topography in the Wabamun Lake area. The salinity of formation water generally increases with depth, reaching 10 g/l in the Basal Belly River aquifer. All aquifers below the top of the Lea Park shales contain brines with salinity values above 20 g/l and up to 170 g/l in the Upper Devonian aquifers. No data exist for the Middle Devonian to Cambrian aquifers in the Wabamun Lake area, but regional-scale studies indicate salinity of formation waters of up to 300 g/l (Bachu, 1999; Anfort et al. 2001).

DATA SOURCES, TYPES AND QUALITY

Approximately 1400 wells have been drilled in the Wabamun Lake area for hydrocarbon exploration and exploitation. Data collected by the petroleum industry in Alberta are submitted to the Alberta Energy and Utilities Board (EUB), including drill cores that are stored at the EUB's Core Research Centre. Generally, data abundance decreases with depth, and testing and sampling occurred in aquifer units and reservoir rocks, predominantly in the hydrocarbon-bearing units (Table 1). The following data are digitally stored in databases at the Alberta Geological Survey and were used in this study.

General Well Information

For each borehole, records exist of the geographic location, the surface elevation, the total depth, the various operational dates, and the well status. In most cases, information exists on the casing, completion and cement types and their location in the borehole. Production volumes and rates are available for producing wells.

Table 1. Count of selected parameters that were collected in the various aquifer units.

	Number of wells with:			
Aquifer	Strat.	DST	Chem.	Core
Belly River	503	49	45	7
Cardium	861	6	2	183
Viking	845	26	18	4
Mannville	882	37	43	257
Nordegg (Jur.)	212	6	3	17
Banff	779	20	15	81
Wabamun	82	4	12	4
Nisku (Winterb.)	39	6	18	14
Slave Point	14	-	-	-
Keg River	3	-	-	-
Pika (Cambrian)	1	-	-	-
Basal Sandstone	1	-	-	-

Stratigraphic Picks

In more than 1000 wells, the stratigraphy was picked and reported by the geologist in charge using geophysical logs. The accuracy and resolution in the picks dataset varies as a result of different methods and geological interpretation by various geologists. Therefore, consistency of the stratigraphic framework was established by confirming the correct stratigraphic succession within each individual well, as well as ensuring lateral consistency for individual horizons. Data that caused stratigraphic inversions or anomalies in mapped surfaces were individually checked and either corrected or removed from the data set.

Drillstem Test Data

Drillstem tests (DSTs) are performed by the petroleum industry to determine pressure and permeability in potential reservoir units. Formation pressures and permeability values are determined from DST results using a Horner plot analysis. The data were allocated to the respective aquifers and were culled for erroneous tests, including production influence (Michael and Bachu, 2002).

Formation Water Composition

Samples of formation water are taken from DSTs or during well production. The typical chemical analysis includes major ion and total dissolved solids (TDS) concentrations, pH, temperature, density and resistivity. After assigning the chemical analyses to their respective hydrostratigraphic unit, erroneous analyses were removed using methods presented by Hitchon and Brulotte (1994).

Core Analyses

Drill cores were taken in many wells and core analyses exist for selected intervals in approximately 550 wells, mainly in reservoir rocks. In addition to lithological description, parameters typically measured on core plugs are porosity, permeability and grain density. In addition, relative permeability tests for supercritical CO_2 displacing brine were conducted on selected carbonate, sandstone and shale core samples (Bennion and Bachu, 2005).

Mineralogy

A mineralogical assessment was performed on core samples from potential injection horizons. Polished thin sections were prepared for mineralogical analysis by electron microprobe. Powdered samples were analyzed by XRD, X-Ray Fluorescence (XRF), and Inductively-Coupled Plasma Mass Spectrometry. The computer code LPNORM (Caritat et al., 1994) was used to perform a normative analysis from the chemical analysis to obtain a normative mineralogical composition.

CONCLUSIONS

Favorable geological conditions, infrastructure, and comprehensive data holdings make Alberta and specifically the Wabamun Lake area southwest of Edmonton an ideal location for a detailed study and characterization of future CO_2 storage sites. Several deep saline aquifers are located at the appropriate depth at which CO_2 can be stored as a supercritical, dense fluid. They are confined by one or more thick, low-permeability aquitards, preventing upward leakage of injected CO_2. The Banff to Cardium aquifers are currently producing hydrocarbons and could be considered for CO_2 enhanced oil or gas production. In contrast, the absence of hydrocarbon occurrences in the Cambrian to Devonian succession and the presence of additional overlying aquitards make aquifers in this stratigraphic interval good candidates for long-term CO_2 storage.

REFERENCES

Anfort, S.J., S. Bachu, and L.R. Bentley, Regional-scale hydrogeology of the Upper Devonian-Lower Cretaceous sedimentary succession, south-central Alberta Basin, Canada, *American Association of Petroleum Geologists Bulletin, 85*, 637-660, 2001.

Bachu, S., Flow systems in the Alberta Basin: Patterns, types and driving mechanisms, *Bulletin of Canadian Petroleum Geology*, *47*, 455-474, 1999.

Bennion, B. and S. Bachu, Relative permeability characteristics for supercritical CO_2 displacing water in a variety of potential sequestration zones in the western Canada Sedimentary Basin, *Paper SPE*

95547, presented at the 2005 SPE Annual Technical Conference in Dallas, TX, 9-12 October, 2005.

de Caritat, P., J. Bloch and I.E. Hutcheon, LPNORM: A linear programming normative analysis code, *Computers & Geosciences, 20*, 313-347, 1994.

Hitchon, B. and M. Brulotte, Culling criteria for "standard" formation water analyses, *Applied Geochemistry*, *9*, 637-645, 1994.

Michael, K. and S. Bachu, Origin, chemistry and flow of formation waters in the Mississippian - Jurassic sedimentary succession in the west - central part of the Alberta Basin, Canada, *Marine and Petroleum Geology*, *19*, 289-306, 2002.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

CASABLANCA OFFSHORE FIELD, A DEPLETED KARSTIC OIL RESERVOIR FOR GEOLOGICAL STORAGE OF CO2

Virginie Mignot[1], Yann Le Gallo[1], Jean-Claude Lecomte[1], Tristan Euzen[1], Tomas Vallaure[2], Juan Mallo[2]

[1] Institut Français du Pétrole (IFP), 1&4, avenue de Bois-Préau
92 852 Rueil-Malmaison, France

[2] REPSOLYPF, Madrid, Spain Organization
e-mail: Yann.le.gallo@ifp.fr, J.Claude.Lecomte@ifp.fr, Tristan.Euzen@ifp.fr, tvallaurea@repsolypf.com

INTRODUCTION

A main objective of the CASTOR European project is to contribute to the feasibility and acceptance of the concept of geological storage of CO_2 and to validate this concept on real sites. The aim of this project is precisely to develop and apply a methodology for the selection and the secure management of storage sites by improving assessment methods, defining acceptance criteria, and developing a strategy for safety-focused, cost-effective site monitoring. This paper focuses on one of the four field cases studied in CASTOR. Casablanca oil field, operated by Repsol-YPF is located in the Mediterranean sea on the East coast of Spain, 43 km from Tarragona. The field was discovered in 1975 by Chevron. Its production started in 1977. Casablanca cumulative production is 143 MBbbls as of August 2005. Since the oil production is declining and the economic limit of the field will be reached in the next few years, REPSOL-YPF is evaluating the possibility of using this field for storage of 0.5·Mt of CO_2 per year produced by its Tarragona refinery (20% of refinery's total yearly production).

The study of the Casablanca field case in the CASTOR project has been divided into several phases: geological study, reservoir modeling, performance of CO_2 injection, wells integrity and long term behavior of the CO_2 in the subsurface. This paper addresses the first two steps of the study with special emphasis on the work methodology and it presents the techniques which will be used for CO2 injection simulation.

BRIEF DESCRIPTION OF THE CASABLANCA FIELD

Casablanca oil field is located on the South-East flank of one of the sub-basins (Tarragona trough) of an aborted rift, the Valencia Trough, formed during the Early Miocene opening of the Mediterranean Sea. Casablanca reservoir consists of Upper Jurassic-Lower Cretaceous limestone and dolomite. These platform carbonates were uplifted and intensively karstified and fractured during the Paleogene compression, with local karst rejuvenation during an Early-Middle Miocene rifting event. Finally, reservoir underwent extensive hydrothermal corrosion and dolomitization during its burial history. This evolution led to the formation of a very heterogeneous porous network related to the complex interaction between subaerial karstification, fracturation, hydrothermal processes.

The amount of precise geological information for such an heterogeneous reservoir is scarce. Half of the wells are completed only in the top of the reservoir. The seismic is poor quality because it is a highly fractured karst. The reservoir is underlain by a really strong aquifer which maintained the pressure during all the production at almost initial pressure. A specificity of the reservoir is its relatively high temperature, 152°C and low GOR 26.7 m^3/m^3.

METHODOLOGY USED TO BUILD A RESERVOIR MODEL OF THE CASABLANCA RESERVOIR

Due to the scarcity of data and to the complexity of the porous network, it has not been possible so far to construct a detailed static geological model. Consequently, the proposed methodology was to build a simplified reservoir model and to refine it iteratively by introducing new geological features, in order to better fit the well production history. Once the model has been considered sufficiently accurate, scenarios of CO_2 injection have been simulated to investigate CO_2 placement in the reservoir.

FIRST RESERVOIR MODEL

The geological data used for the model were the top (structural) and bottom (OWC) surfaces of the reservoir. In this first approach, the highly fractured reservoir has been considered as having the behavior of an homogeneous equivalent reservoir. A stratigraphic layering with an average dip angle of 2 degrees was subsequently added, based on biostratigraphical data. This first homogeneous layered reservoir model has enabled history matching of some of the production wells but not all of them. However, it has also shown that it has not been possible to reproduce the sharp and fast entry on a few wells or the odd behavior of some others.

IMPROVEMENT OF THE RESERVOIR MODEL

One explanation for the sharp and fast water production in some wells and difficulty to match their production is the probable existence of fractures corridors (swarms) located not far from these wells. Outcrop studies along the Spanish coast have also shown the presence of polygonal fractures arrangement at different scales in similar karstic formations. Those fractures are principally located in low topographic points and could be associated with paleo drainage area. Fractures described previously have been represented by high permeability sectors in the reservoir model.

Another explanation for the odd behavior of Casablanca wells is the heterogeneities of petrophysical properties in the Casablanca field. Strata markers have been determined from a petrophysical study on several wells and four strata with localized porosity values have been defined.

To refine the petrophysical heterogeneities, a workflow with two IFP tools COUGAR™ and CONDOR has been used. COUGAR™ uses the experimental design approach to determine the key parameters. CONDOR makes oriented automatic history matching. This workflow using these two tools is the main part of the study because it has allowed matching the production history of all wells and determining petrophysical properties heterogeneities in the reservoir model.

CO_2 INJECTION, THE FUTURE STEP

The reservoir model described above was built assuming a Black-Oil representation. Modeling of CO_2 injection requires a compositional representation of the fluid thermodynamics since CO_2 can dissolve both in water and oil.

The reservoir model has been transferred in a research IFP software called COORES. This software is used to simulate CO2 injection with a compositional PVT modeling.

A main interest of the modeling of CO_2 injection will be to comprehend its behavior in the reservoir and the influence of structural locations of injection and production wells and perforations location in the reservoir to determine the best injection mode.

Finally in a next step, the model to which seal will be added, will be used to study the long term behavior of the CO_2.

CONCLUSION

The study of Casablanca field case for CO_2 storage is of major interest for several reasons: offshore reservoir, “fractured” carbonate reservoir, complex karstic geology and diagenetical evolution of carbonate reservoir, depleted oil reservoir at end of production, huge aquifer maintaining the pressure, ... Considering the heterogeneity of the reservoir and the specificity of the data required to assess CO_2 relationships with host rock and fluids at the reservoir, the available data is somewhat insufficient thus, a simplified methodology has been followed to build a consistent reservoir model. This model has been used to study CO_2 injection scenarios and will be used for long term behavior assessment in the next future. The full study will ascertain the ability of this field to be used as a safe geological CO_2 storage.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

SITE CHARACTERIZATION: LESSONS LEARNED FROM A CO_2 SEQUESTRATION FIELD DEMONSTRATION AT THE WEST PEARL QUEEN SITE

Rajesh Pawar[1], John Lorenz[2], Charles Byrer[3]

[1] Los Alamos National Laboratory
MS T003
Los Alamos, New Mexico, 87545, USA
e-mail: rajesh@lanl.gov

[2] Sandia National Laboratories
MS 0750
Albuquerque, New Mexico, 87185, USA
e-mail: jcloren@snl.gov

[3] National Energy Technology Laboratory
MS C04
Morgantown, West Virginia, 26507, USA
e-mail: charles.byrer@netl.doe.gov

INTRODUCTION

Successful implementation of geologic carbon dioxide (CO_2) storage will require detailed characterization of storage reservoirs. Characterization would be necessary to maximize reservoir storage potential, to develop effective monitoring plans and to ensure long-term effectiveness. Geologic reservoirs are inherently heterogeneous. Adequate representation of reservoir heterogeneity to accurately predict reservoir fluid-flow behaviour is a classic problem, one that has been studied for a long time in hydrology and petroleum engineering. The overall economics of geologic CO_2 storage technology may limit the quality and quantity of characterization data collected. This makes it extremely important to determine what type of data should be collected, how much data should be collected and where should it be collected.
The different types of geologic reservoirs currently being proposed for CO_2 storage, include, deep saline aquifers, depleted oil/gas reservoirs, and deep unmineable coal seams. One of the major advantages of depleted oil reservoirs is extensive, publicly available characterization data. But it is important to critically evaluate the available data and to understand how much insight the data really provides into the flow dynamics of the reservoir. In this paper we talk about some of the lessons learned during a CO_2 sequestration field demonstration project in a depleted oil reservoir. The project is funded by the U.S. Department of Energy and is one of the very first field demonstration projects in the U.S. and the world. The central part of the project is injection of about 2100 tons of CO_2 in a depleted, sandstone oil reservoir. The field-injection is combined with monitoring techniques, numerical simulations and laboratory experiments to characterize the fluid flow behavior of the reservoir. The ultimate goal of the project is to understand reservoir response to CO_2 injection, to predict migration of CO_2 within the reservoir, and to assess the ability of geophysical techniques to monitor the process.

PROJECT SUMMARY

The field experiment took place in the west Pearl Queen field, which is owned and operated by the Strata Production Company (SPC) of Roswell, New Mexico. The field is located near Hobbs, New Mexico (Figure 1).

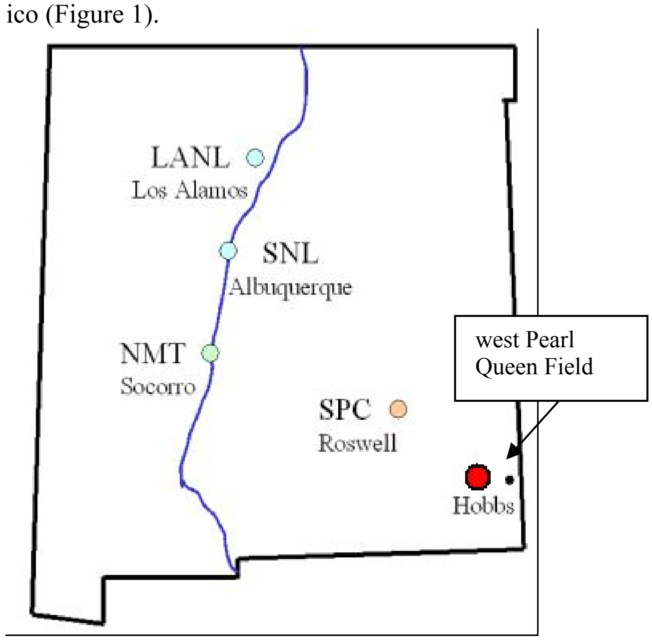


Figure 1. Location of west Pearl Queen Field, New Mexico, US.

The field was first produced in 1984 and had produced about 250,000 barrels of oil until the beginning of this project. All of the production from the field had been solely through primary recovery operations, which made the field an attractive field site for a CO_2

sequestration experiment. There have been five wells drilled in the field. Of the five wells, only one well has been on active production prior to the beginning of this project. One of the shut-in wells was used for injecting CO_2 during the experiment, while the active production well was used as the monitoring well. The monitoring and the injection wells were approximately 1300 feet apart.

The project consisted of three phases. In Phase I, pre-injection characterization activities were performed to understand the geology of the reservoir, to determine potential response of reservoir to CO_2 injection and to characterize migration of CO_2 in the reservoir. The characterization activities included geologic characterization based on available data, laboratory experiments to characterize multi-phase flow characteristics of reservoir rock and numerical simulations of fluid flow in the reservoir.

Phase II consisted of acquisition of a high-resolution, 3-dimensional, 9-component surface seismic survey and injection of 2100 tons of CO_2.

Phase III included post-injection soaking of CO_2 in the reservoir for six months by shutting-in the injection well, acquisition of another high-resolution surface seismic survey, production of CO_2 from the injection well and activities to monitor migration of CO_2. Phase III also includes integration of the field and laboratory experimental data, numerical simulation results and monitoring observations.

PRE-INJECTION CHARACTERIZATION

As mentioned earlier, pre-injection characterization data was based on available legacy data. The legacy data was typical data collected in oil industry and included logs such as Density Porosity, Neutron Porosity, Gamma Ray and Resistivity. In addition to the log data, core analyses data were available from a core from the field. The core data included measurements on porosity and permeability. In addition to the legacy data, other data were collected during pre-injection characterization phase of this project. These included outcrop data and a two-dimensional cross-well velocity tomogram. Note that the 3-dimensional surface seismic survey interpretations were not available during the pre-injection characterization analysis.

The above-mentioned data were used to interpret the geology of the reservoir. Log analyses indicated the reservoir to be made up of three distinct layers. Log data also indicated the layers to be fairly continuous between the wells. A geologic model for the reservoir was created based on the log, core and outcrop data. A reservoir fluid flow model was created based on the geologic model and was subsequently used to perform a history match. An estimate for the initial reservoir pressure was available, but no measurements for recent values of reservoir pressure were available. The pressure was estimated based on historic reservoir performance, reservoir gas production and recent field fluid (oil/water/gas) production rates.

The reservoir flow model was used to match the historic oil, gas and water production data as well as the estimated reservoir pressure. The history-matched model was subsequently used to perform simulations of CO_2 injection in order to determine feasible CO_2 injection rates, to predict migration of injected CO_2 and to simulate production of CO_2 after the soak period. Understanding migration of CO_2 in the reservoir was necessary to determine the time of arrival of injected CO_2 at the monitoring well. Results of the numerical simulations indicated that CO_2 could be injected at a rate of 100 tons/day without exceeding the regulatory bottom hole pressure constraint (2900 psi at the depth of 4500 feet). The simulations also predicted that injected CO_2 would travel up to the proposed monitoring well within six months after the injection.

FIELD EXPERIMENT

Figure 2 shows the data on injection rate and surface injection pressure during the field experiment.

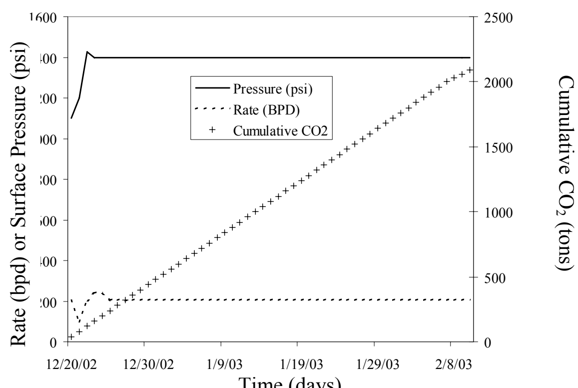


Figure 2. Rate and pressure observed during CO_2 injection field experiment.

As can be seen from the figure, during the field experiment CO_2 was injected at a constant rate of 40 tons/day at a constant surface injection pressure of 1400 psi. The injection rate could not be increased beyond this value. This is because it was estimated that the surface pressure of 1400 psi translated into a bottom hole pressure of approximately 2900 psi. Increasing the injection rate would have required increasing the surface injection pressure, which would have resulted in exceeding the regulatory bottom hole pressure constraint.

After injecting approximately 2100 tons of CO_2, the injection well was shut-in for six months for post-injection soak. At the end of the soak period both the injection and monitoring wells were opened to production and multiple gas samples were collected from both the wells at regular intervals. The compositions of produced gas were analysed to monitor migration of CO_2 between the injection and monitor wells. Figure 3 shows the composition of gas samples from the monitor well.

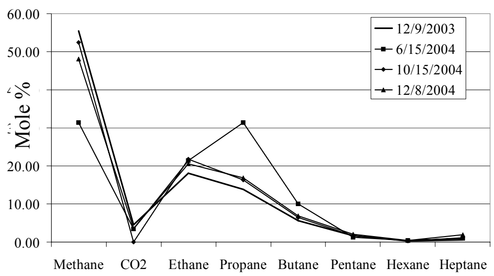


Figure 3. Composition of gas collected from monitor well.

As can be seen from the figure, the gas produced from the monitor well has very low amount of CO_2 indicating that even after a year the injected CO_2 had not reached the monitor well.

OBSERVATIONS

The field experiment observations were significantly different than the pre-injection characterization predictions. Both the injection and production (during post-soak production) rates were significantly lower than the rate estimated based on pre-injection characterization. In addition, the prediction related to post-injection migration of CO_2 was significantly different than the field observation.

During Phase III of the project additional characterization data became available. This data included information on reservoir geology and structure based on the interpretation of 3-dimensional surface seismic data. The reservoir structure interpreted from the seismic data was significantly different than the earlier interpretation based on the log data. In addition, the reservoir pressure measured during the field experiment was significantly higher than the earlier estimates.

This project clearly demonstrates the need for effective characterization. Effective characterization will require evaluation of available data, identification of required additional data as well as collection of data from multiple sources. Designing optimum and effective monitoring strategies will require detailed understanding of migration behaviour of injected CO2 in any reservoir.

ACKNOWLEDGMENT

This work was funded by the U.S. Department of Energy. Other contributors to the project include Bruce Stubbs of Pecos Petroleum Engineering, Roswell, NM; Reid Grigg of Petroleum Recovery Research Center, New Mexico Institute of Mining & Technology, Socorro, NM; and Robert Benson of Colorado School of Mines, Golden, CO. We would also like to acknowledge Mark Murphy of Strata Production Company, Roswell, NM.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

GEOMECHANICALLY CONSTRAINED SIMULATION OF CO_2 SEQUESTRATION AND ENHANCED METHANE RECOVERY IN COALBEDS OF THE POWDER RIVER BASIN, WYOMING

Hannah E. Ross and Mark D. Zoback

Department of Geophysics
Stanford University
Stanford, CA, 94305-2215, USA
e-mail: hemiller@pangea.stanford.edu

INTRODUCTION

CO_2 sequestration in coalbeds has been proposed as technology to reduce greenhouse gas concentrations in the atmosphere. Coalbeds are an appealing geological environment for CO_2 sequestration because CO_2 is held in the coal as an adsorbed phase, and the cost of sequestration can be offset by enhanced coalbed methane recovery (ECBM).

In order to examine the feasibility of sequestering CO_2 in sub-bituminous coalbeds of the Powder River Basin (PRB), Wyoming (Figure 1), we have carried out a geological and geomechanical reservoir characterization study and preliminary flow simulations.

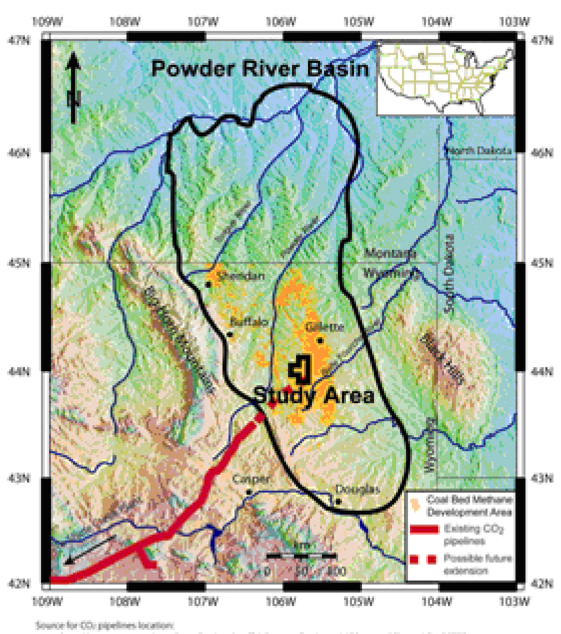


Figure 1. Location map of the Powder River Basin, Wyoming, and our study area.

The PRB was chosen as our study area because the basin is the location of the fastest growing natural gas play in the USA, mostly from the development of coalbed methane (CBM); the state of Wyoming contains a number of point sources for the capture of CO_2, and has a CO_2 pipeline network with a proposed extension to the edge of the PRB; and extensive work has been carried out to categorize fracture growth in PRB coals from water enhancement practices conducted by CBM operators.

RESERVOIR CHARACTERIZATION

We have focused our study on the Big George coal, part of the Wyodak-Anderson coal zone of the Tongue River Member. The Tongue River Member of the Palaeocene Fort Union Formation is the primary coal-bearing unit of the PRB. The average depth of the Big George coal is 335m and it varies in thickness from 14 to 62m.

Water enhancement tests and gamma ray logs have been used to characterize the Big George coal in our study area. Gamma ray logs gave us the depth and thickness of the coal, and water enhancement tests were analyzed to determine the direction of hydraulic fracture propagation in the coal. Water enhancement tests are used by CBM operators in the PRB to connect the CBM wells to the natural coalbed fracture network. In some areas the hydraulic fractures are found to propagate vertically, whereas in others they grow horizontally (Colmenares and Zoback, in review). Knowing where vertical hydraulic fractures will form in the coal is especially important when choosing a site for CO_2 sequestration because hydraulic fractures that propagate vertically may penetrate the overlying strata creating potential leakage conduits for CO_2.

Using gamma ray logs from actively producing CBM wells we have built our 3D model in an area of the PRB where the least principle stress (S_3) is equal to the overburden stress, resulting in horizontal hydraulic fractures (if hydraulic fractures are created). In our model area the Big George coal is approximately 16m thick and ranges in depth from 315-360m, with a slight dip to the west (Figure 2). We have currently run simulations on a 5-spot well pattern with 80-acre well spacing.

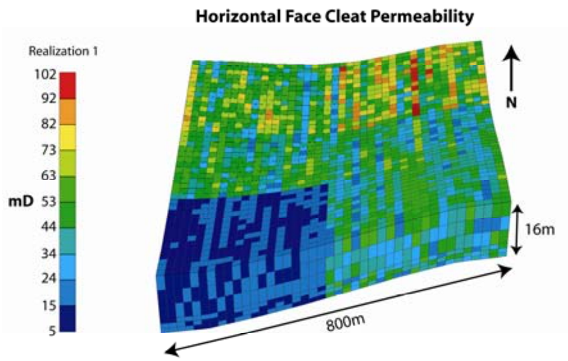


Figure 2. Our 3D model and the horizontal face cleat permeability distribution of realization 1.

We used sequential Gaussian simulation and simple kriging to populate our 3D model with multiple cleat and matrix permeability and porosity realizations. Our initial permeability and porosity values came from the literature and we have further constrained the cleat permeability and porosity values through history-matching production data from the CBM wells used to build our 3D model (Figure 2).

PRELIMINARY SIMULATION RESULTS

Preliminary simulations were run with and without coal matrix shrinkage and swelling, and with and without horizontal hydraulic fractures placed at the base of the injection well. We used adsorption isotherms specific to the PRB, and because we did not want to fracture the coalbed we ran our simulations with a maximum bottom hole pressure (BHP) in the injector below S_3. This ensured that the pressure in the cleats did not exceed 6200 kPa, the fracture pressure in this area (S_3). For the first 5 years of simulation we produced CBM with no CO_2 injection to deplete our model by the same amount of CH_4 depletion that has occurred in our study area. CO_2 was then injected for variable amounts of time.

We found that coal matrix swelling (or stress dependent permeability) resulted in a reduction in CO_2 injectivity, and that gravity and buoyancy were the major driving forces behind gas flow within the coal. Gravity and buoyancy caused the gas to migrate upwards at first and then along the top of the coal, which reduced gas sweep efficiency and sequestration. Hydraulically fracturing the coal close to its base increased gas sweep efficiency and mitigated the negative effect of permeability reduction on injection rate due to coal matrix swelling.

In addition, we have run a small sensitivity analysis on the cleat permeability. Doubling the permeability increased CH_4 production and CO_2 injectivity. However, CO_2 breakthrough occurred earlier than in the base case and a larger volume of CO_2 was produced. Halving the permeability reduced CH_4 production and the CO_2 injection rate, but meant that CO_2 breakthrough occurred much later than in the base case and was almost negligible.

CONCLUSIONS AND FUTURE WORK

Utilizing geophysical and geological data from the PRB we developed a 3D model of the Big George coal and used geostatistical techniques to populate our model with coal cleat and matrix permeability and porosity realizations. Initial results from fluid flow simulations show that gravity and buoyancy drive gas migration and matrix swelling reduces gas injectivity. However, placing a horizontal hydraulic fracture at the base of the injection well helps to overcome this negative effect of matrix swelling on injection rates. Further sensitivity analyses will be run on various parameters, including flowing BHP, permeability, cleat spacing and orientation, and matrix shrinkage and swelling parameters.

ACKNOWLEDGMENTS

We thank the Stanford University Global Climate and Energy Project for funding this project.

REFERENCES

Colmenares, L. B. and M. D. Zoback, Hydraulic fracturing and wellbore completion of coalbed methane (CBM) wells in the Powder River Basin, Wyoming: Implications for water and gas production, *American Association of Petroleum Geologists Bulletin*, in review.

SITE CHARACTERIZATION FOR GEOMECHANICAL AND FLOW MODELING AT WEST PEARL QUEEN PILOT SITE

Hema Siriwardane, Grant S. Bromhal, Thomas Wilson, and Duane H. Smith

National Energy Technology Laboratory, U.S. Department of Energy
and
West Virginia University
Morgantown, West Virginia 26506, USA

e-mail: hema.siriwardane@mail.wvu.edu, grant.bromhal@netl.doe.gov

INTRODUCTION

Geologic sequestration has been identified as one of the methods for disposal of carbon dioxide (CO_2) rather than venting it to the atmosphere. Sequestration in coal-seams, saline aquifers, and depleted oil reservoirs are some of the options that have been identified for geologic sequestration. For sequestration to be successful, technologies must be developed to help predict where the CO_2 migrates within the subsurface and to ensure that it does not return to the atmosphere. This paper addresses some of the issues dealing with computational modeling of coupled flow behavior and geomechanical response at the West Pearl Queen pilot site, which is a depleted oil reservoir.

SITE DESCRIPTION

The West Pearl Queen field is located in New Mexico in the Permian basin. In the field study at this site, the carbon dioxide was injected to the Shattuck sandstone layer, which is located at a depth of about 4,500 feet. This sandstone layer has a thickness of about 50 feet. There has been significant oil recovery from this sandstone layer in the area where the pilot sequestration test was conducted. It has been reported that the Shattuck formation consists of sandstones, silt stones, and sandy siltstones (Westrich, 2001). The permeability of the Shattuck formation has been reported to be in the range of 30 to 500 md (Mazzullo, 1988).

The West Pearl Queen field is considered a depleted oil reservoir. Since 1984, nearly quarter of a million barrels of oil has been produced at this site (Westrich, 2001). Engineering properties such as elastic modulus, Poisson's ratio, porosity, permeability, and layer thicknesses were estimated on the basis of available geologic data. The geologic column (stratification) used in the study was determined from the available well log and core data.

CARBON DIOXIDE INJECTION

The field experiment was started in 2002 and completed in 2003. Details of the pilot scale test are given elsewhere (Westrich, 2001; Pawar et al. 2001; Pawar et al., 2003) and only a summary is given in this section.

Injection pressure (bottom hole): 2,900 psi
Duration of injection: 53 days
Total CO_2 injection: 2,090 tons
Reservoir pressure after the injection: 1,700 psi

NUMERICAL MODELING

The geomechanical response was modeled by considering a coupled flow-deformation formulation based on the theory of linear poroelasticity (Biot, 1941). The numerical model was based on the finite element method. The injection of CO_2 in the porous medium was modeled by assuming single-phase flow (e.g., no capillary pressure or relative permeability). The deformation of the rock formation was modeled by assuming linear elastic properties. Computations were carried out by considering the injection as an axisymmetric problem.

The initial geostatic stresses were computed by using known values of densities for the rock layers. The injection was simulated by prescribing the bottom hole injection pressure as a boundary condition. The permeability of the reservoir was selected so that it took 53 days to inject about 2,090 tons of CO_2, corresponding to the actual field case. The computed injection volume for the assumed conditions is given below.

Model prediction of injection volume: 2,095 tons
Measured injection volume: 2090 tons

The injection was terminated after 53 days. The simulation of fluid flow-deformation was continued for 97 days beyond the termination of injection. Computed surface deflections are shown in Figure 1.

As can be seen from this figure, the surface displacements drop slightly after the completion of injection. This seems to be caused by the continued flow of fluids into the reservoir due to the pressure gradient that exists after the completion of injection.

Computed vertical displacements in the rock formation are shown in Figure 2. As could be seen from this figure, surface displacements spread over a large area outside the injection well. While these displacements are very small, they may be useful in indirect estimates of the CO_2 plume underground.

RESULTS AND DISCUSSION

The results from the coupled flow-deformation analysis of the CO_2 injection at West Pearl Queen site indicate that the ground surface deforms during and after the injection. While the magnitude of the ground deformations in this pilot test are very small, the results show the possibility of heaving of the ground depending upon the amount of CO_2 injection. It also shows that ground deformations and the surface slopes, which may be measured by tilt meters, could be used as an indirect method for monitoring of the CO_2 plume propagation.

As could be seen from the Figure 1, the surface deformations drop rapidly after the termination of CO_2 injection. The permeability and elastic properties of the geologic formations would have a significant influence on the reservoir response after the injection. The analysis did not consider the influence of natural fractures that may exist in the reservoir. The pressure decline data as well as measured surface deformations could be used to adjust the engineering parameters used in the analysis.

Figure 2 shows that computed displacements near the Shattuck sandstone layer are much higher than the surface displacements. Figure 3 shows computed values of pore pressure increase in the reservoir and surrounding layers. Underground measurements such as tilt meter measurements could be very useful during the monitoring phase. Also, fluid pressure measurements at observation wells within the reservoir and/or surrounding permeable formations could provide information useful to identifying the extent of the CO_2 plume within the reservoir, as well as potential leakage pathways. Indirect measurements such as the ones discussed in this paper and a comprehensive site characterization will improve the accuracy of predictive models.

In this example, the engineering properties used in the analysis were inferred from limited available data. As such, the magnitudes of deformation may not be very accurate. Accurate geologic characterization of the sequestration site and determination of engineering properties are important issues for the reliability of model predictions. Therefore, a comprehensive effort on site characterization should be undertaken at any potential CO_2 sequestration site. Field monitoring of surface deformations and slopes together with underground measurements such as the pore pressure can be useful in fine-tuning computational models.

REFERENCES

Biot, M. A., General theory of three-dimensional consolidation, *J. Appl. Phys.*, 12, 1941.

Mazzullo, S. J. and A. M. Reid, The Pennsylvanian Permian boundary in shelf areas of the North Platform of the Midland Basin, *West Texas Geological Society Bulletin,* Vol 27, 1988.

Pawar, R. J., D. Zhang, B. Stubbs, and H. R. Westrich, *Preliminary geologic modeling and flow simulation study of CO_2 sequestration in a depleted oil reservoir,* Proceedings of the first national Conference on Carbon Sequestration, Washington DC, 2001.

Pawar, R.J., N. Warpinski, B. Stubbs, and D. Zhang, *Numerical Modeling of CO_2 Sequestration in a Depleted Oil Reservoir*, Proceedings of the 2nd Annual Conference on Carbon Sequestration, Alexandria, VA, May 5-8, 2003.

Westrich, H. R., *Sequestration of CO_2 in a depleted oil reservoir: an overview,* Proceedings of the first national conference on carbon sequestration, Washington DC, 2001.

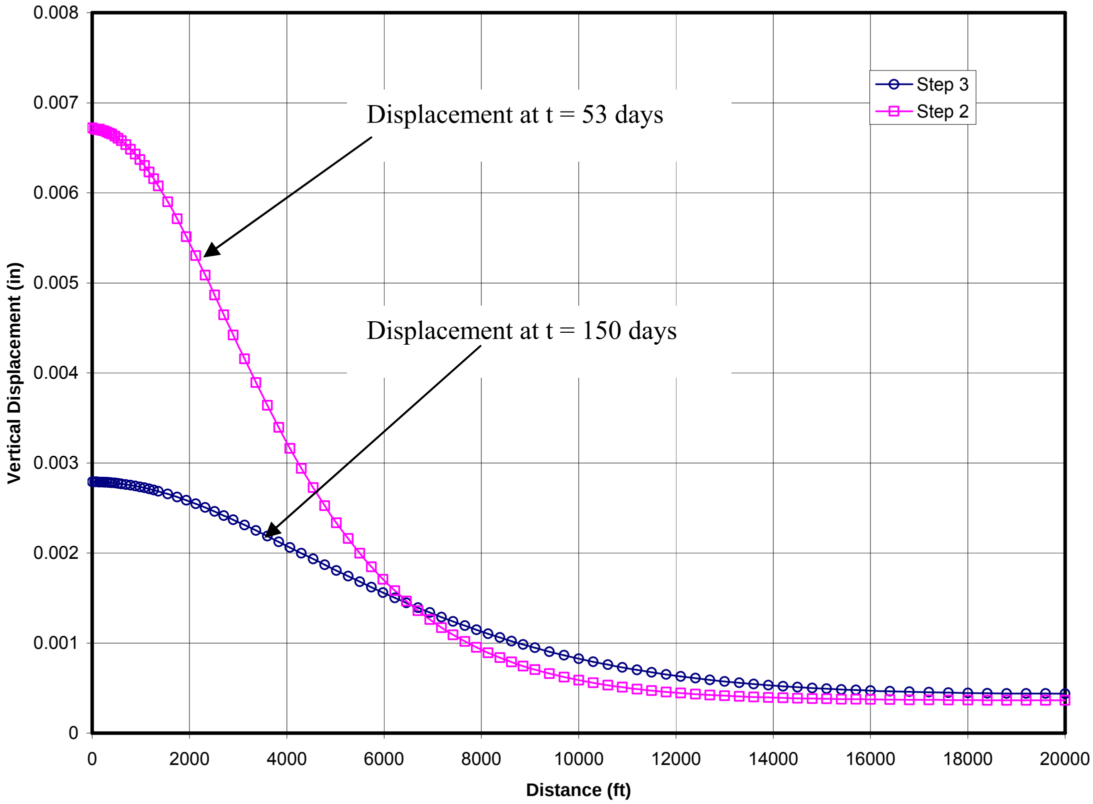


Figure 1: Computed surface displacements.

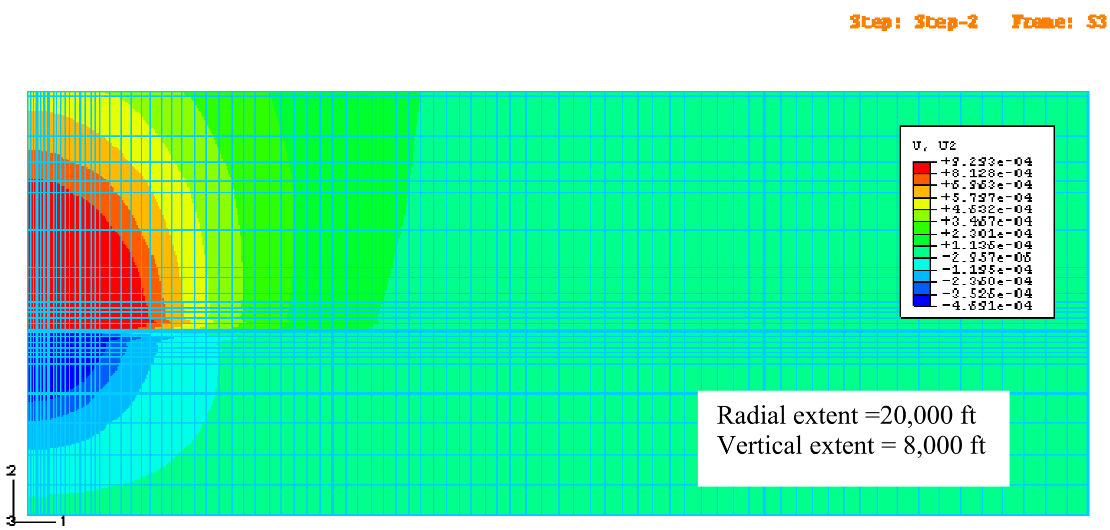


Figure 2: Computed Vertical Displacements after 53 days.

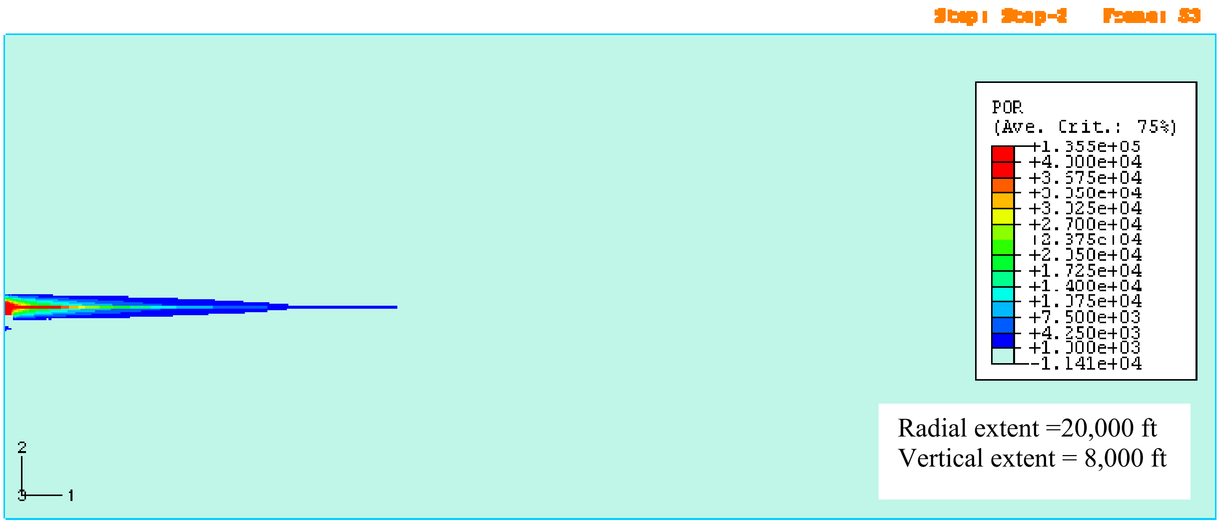


Figure 3: Computed pores pressure distribution at 53 days.

RESULTS OBTAINED FROM RECONNAISSANCE-LEVEL AND DETAILED RESERVOIR CHARACTERIZATION METHODS UTILIZED FOR DETERMINING HYDRAULIC PROPERTY DISTRIBUTION CHARACTERISTICS AT MOUNTAINEER AEP #1

F.A. Spane[1], P.D. Thorne[1], N. Gupta[2], P. Jagucki[2], T.S. Ramakrishnan[3], and N. Mueller[3]

[1]Battelle/Pacific Northwest National Laboratories
Richland, WA
e-mail: frank.spane@pnl.gov

[2]Battelle Memorial Institute
505 King Ave.
Columbus, Ohio 43201

[3]Schlumberger-Doll Research
Ridgefield, CT

INTRODUCTION

The Ohio River Valley CO_2 Storage Project is a collaborative effort to investigate the potential of reservoirs for sequestering CO_2 on both site-specific and regional basis. As a part of this effort, a 9,000+ ft deep test well was drilled in 2003 at American Electric Company's (AEP) 1,300 MW Mountaineer Power Plant located in the Appalachian Basin region along Ohio River in West Virginia. Following drilling and well completion, a systematic reservoir characterization program was initiated that included determining the permeability distribution within the open-borehole section (6,285 to 9,190 ft), and within identified candidate reservoir formations (e.g., Rose Run Formation). The characterization methods have varying scales of investigation and resolution. Specifically, the permeability characterization methods utilized included standard hydraulic testing (composite open borehole and isolated interval/straddle-packer tests), continuous wireline logging, and laboratory tests of selected core samples. The results of the investigations were used to evaluate and quantify injection potential and are being used to assess feasibility of several options for a possible future CO_2 injection field-demonstration phase at the site. This paper compares the results obtained from the various reconnaissance-level and detailed characterization techniques, as they relate in determining the vertical distribution of hydraulic properties within Mountaineer AEP #1. This is an important aspect in assessing the CO_2 storage potential of the site.

RECONNAISSANCE METHODS

Reconnaissance-level characterization methods are used to identify major productive zones and determine the general distribution of transmissivity within the open-borehole section, utilizing either direct or indirect measurement techniques. Reconnaissance-level methods employed at AEP #1 include dynamic fluid-logging during pumping, composite borehole/single-packer hydrologic tests, and nuclear magnetic resonance (NMR) wireline logging.

Dynamic Fluid-Logging

For this test method, formation water was continuously withdrawn from the borehole utilizing an air-lift technique that effectively lowered the fluid column to a depth of ~530 ft below land surface. The lowering of the fluid column lowers the fluid pressure within the borehole, which in turn induces flow of formation water into the borehole from surrounding productive reservoirs. When this test is conducted under constant-drawdown conditions, the slow decline in flowrate over time can be analyzed using standard hydrologic test methods (e.g., Jacob and Lohman 1952) for determining the composite transmissivity of the open borehole section. In addition, pressure buildup recovery following termination of the test can be analyzed using standard analysis methods (e.g., Earlougher 1977).

During the air-lifting, a combined wireline full-bore spinner flowmeter and fluid temperature sonde was repeatedly lowered and raised at a constant logging speed for measuring fluid inflow characteristics over the duration of the test. Prior to air-lift testing, fluid logging was conducted to survey existing vertical flow conditions within the borehole under ambient/static conditions. Establishing the ambient profile prior to testing provides a baseline for comparison with results obtained under dynamic pumping conditions.

Selected results from the dynamic fluid-logging (flowmeter and fluid temperature) are shown in Figure 1. Although observed flowrates were near the resolution and sensitivity limits of the commercial flowmeter used, several consistent patterns are exhibited for the two surveys as they relate to fluid inflow and inferred permeability distribution: 1) relatively little formation fluid inflow into the borehole (inferred low permeability) below a depth of 8,320 ft; 2) significant fluid inflow/outflow zones within the Copper Ridge (8,175 to 8,320 ft) and Rose Run (7,755 to 7,870 ft) Formations; and 3) dispersed zones of fluid inflow within the Beekmantown

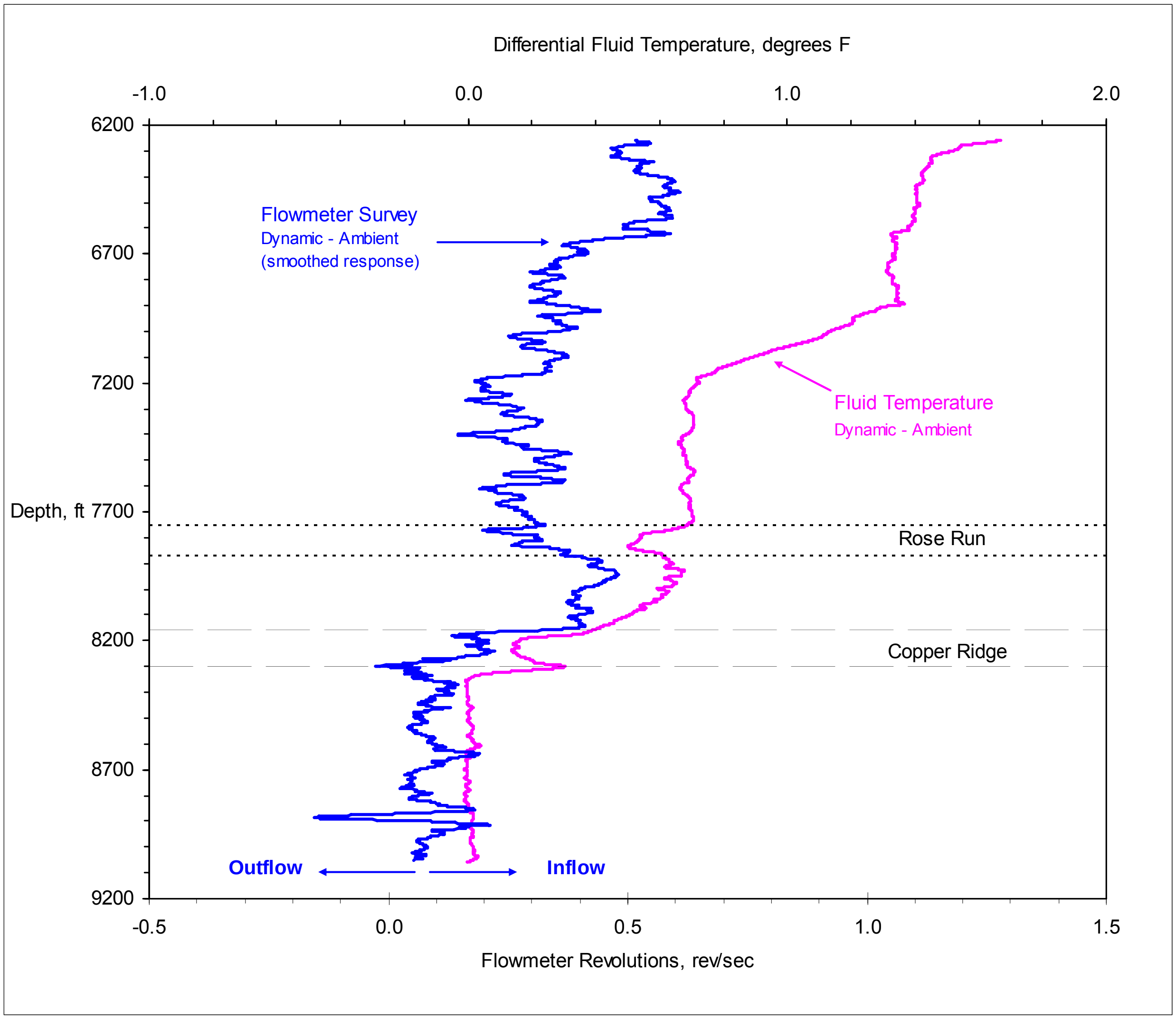


Figure 1. Comparison of Fluid-Dynamic Flowmeter and Fluid Temperature Surveys

Formation above ~7,175 ft. Analysis of the decline in flowrate during the 5-hr air-lift test provided an estimate of composite transmissivity (T) for the entire open borehole section of 7.9 ft^2/day (note: 1 ft^2/day equals ~0.37 darcy-ft).

Single-Packer Tests

For these tests, a single-packer test system was utilized to test progressively larger sections of the open borehole. The primary objective of this testing was to rapidly extend hydraulic property characterization over large open borehole sections, thereby, developing a relative profile of the distribution of transmissivity. Three open borehole sections were characterized using single-packer tests: Zone 1 = 8,068 to 9,190 ft (T = 3.4 ft^2/day); Zone 2 = 7,279 to 9,190 ft (T = 5.8 ft^2/day); and Zone 3 = 6,285 to 9,190 ft (T = 7.6 ft^2/day). The composite transmissivity values determined for the three sequentially larger open borehole sections were determined utilizing standard slug/drillstem (DST) type analysis methods (e.g., Earlougher (1977).

CMR Wireline Logging

The CMR[1] (Combinable Magnetic Resonance) is a borehole wireline logging survey that makes continuous pulse-echo NMR measurements of the subsurface formation. As discussed in Kenyon et al. (1995), these measurements are sensitive to the presence of hydrogen nuclei contained within formation pore spaces and their transverse magnetization decay, which in turn can be used to estimate in-situ formation permeability, especially when a single fluid saturates the pore space. The characterized pore-size

[1] Trademark of Schlumberger.

information is unique to NMR logging devices, and it can be used to distinguish between the presence of small pores reflecting low permeability or larger pores with generally higher permeabilities. The scale or depth of CMR characterization is, however, limited to a few centimeters into the surrounding formation, with about 15 centimeters vertical resolution.

Although CMR logging has a limited area-of-investigation, when combined with standard hydrologic testing having larger-scales of investigation, an optimized methodology for hydrologic characterization over the entire open borehole can be realized. In this application, the CMR provides a continuous measurement of hydrologic properties, and its results can be used to identify zones for detailed hydraulic characterization, which in turn, can be used to calibrate the CMR logs to provide a more accurate, continuous log of hydrologic properties. Figure 2 shows the permeability results obtained from the CMR log, which were converted to a CMR summation transmissivity profile. Also shown in the figure are the average transmissivity determinations from the three composite, open borehole single-packer tests. As shown, the summation CMR transmissivity values compare reasonably well with composite average transmissivity values over the depth intervals investigated by the single-packer tests. This relative correspondence between methods of different investigative scale, lends credence to the continuous vertical distribution depicted by the CMR over the entire open borehole section.

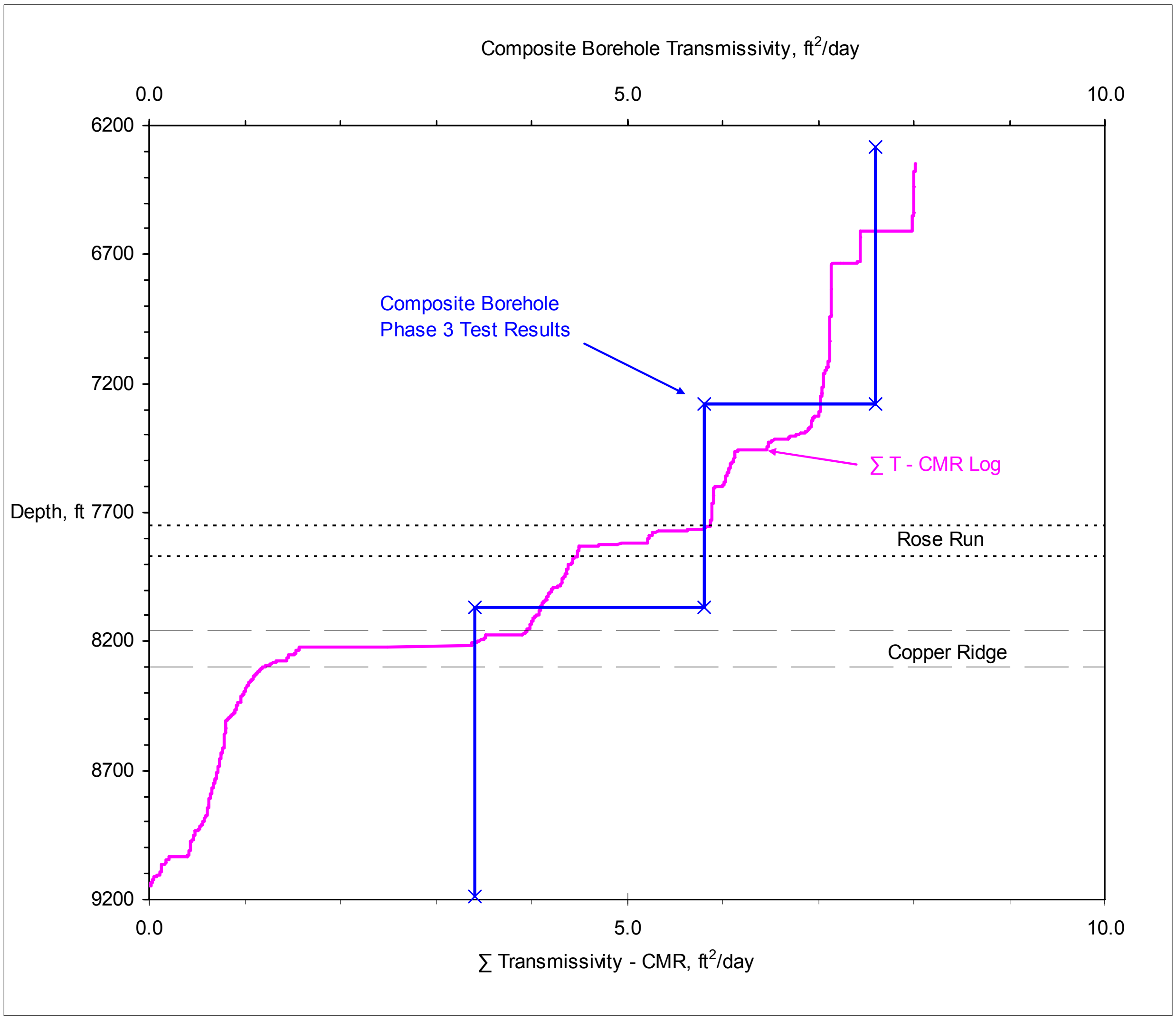


Figure 2. Comparison of Converted CMR Summation Transmissivity Log and Single-Packer Composite Borehole Transmissivities

DETAILED CHARACTERIZATION METHODS

Detailed characterization tests include those methods for quantitatively determining the hydraulic properties of candidate reservoir zones previously identified using reconnaissance-level open-borehole tests. Detailed characterization level methods utilized at AEP #1 include straddle-packer hydraulic tests and laboratory permeability measurements of selected core samples.

Straddle-Packer Tests

Detailed characterization testing includes straddle-packer tests of isolated selected candidate reservoir horizons utilizing a suite of hydrologic methods including slug/DST, constant-pressure/drawdown, and constant-rate pumping and injection tests. The primary objectives for detailed characterization testing were to: provide quantitative hydrologic characterization information of selected, isolated reservoir formations including the determination of: hydraulic/storage properties, threshold fracture pressures, and static formation pressure conditions and collection of representative formation fluid hydrochemistry samples. Currently, two reservoir formations at AEP #1 (the Rose Run and Copper Ridge Formations) were isolated with straddle packers and characterized utilizing these detailed test methods. Good correspondence for test zone transmissivity calculations (within ± 15%) was obtained between the various test characterization methods for the respective test reservoirs. Based on these results, two candidate storage reservoirs appear to possess 55 to 60% of the total open borehole composite transmissivity.

Laboratory Core Permeability Measurements

Although laboratory tests can provide detailed measurements of permeability for recovered core samples, the derived permeability characterization information has a degree of uncertainty as it pertains to formation representativeness (small core sample size), and can be limited in application by needing to know a priori the exact drill depth sections for core sample collection. Based on previous regional hydrogeologic information, three stratigraphic horizons were identified for continuous core recovery. In all, seven sections totaling about 300 ft of 3-in.-diameter rock core were collected from three coring campaigns, within the Maryville and Rose Run, and just above the Beekmantown Formation. Augmenting this vertical core sequence, 23 discrete sidewall cores were also collected from several identified injection and caprock zones utilizing wireline tools. The general permeability profile for the three vertically cored sequences was determined first in the laboratory utilizing Perm-Profile scanning technology (Core Labs) and is based on gas pressure decay through a probe. The generated permeability profile was then used to select specific reservoir core-sections for more quantitative permeability measurements using standard laboratory core-cell techniques.

Figure 3 shows a comparison of the converted permeability (hydraulic conductivity) vertical distribution profile within the Rose Run Formation,
as determined by the laboratory core probe scan and CMR. Additionally, the average hydraulic conductivity calculation derived from straddle-packer tests for the Rose Run Formation (based on a composite productive sandstone section of 35 ft) is also shown. As indicated, a reasonably close correspondence in permeability distribution profiles was obtained for the laboratory core probe scan and CMR survey. Additionally, the calculated converted core probe summation transmissivity (≈0.9 ft^2/day) for the entire Rose Run compares well with the average transmissivity from straddle packer tests (0.78 ft^2/day) for this reservoir formation. This agreement between methods of different investigative scale, lends credence to the continuous vertical distribution of permeability depicted by the laboratory core scan and CMR survey over the entire reservoir section.

ACKNOWLEDGMENTS

The sponsors, project managers, and stewards for the Mountaineer/Ohio River Valley CO_2 Storage Project include the U.S. Department of Energy's National Energy Technology Laboratory (Charles Byrer); American Electric Power (Dale Heydlauff, Michael Mudd); BP (Charles Christopher); The Ohio Coal Development Office of the Ohio Air Quality Development Authority (Jackie Bird); and Schlumberger (T.S. Ramakrishnan), Battelle, and it's Pacific Northwest Division. Authors also wish to acknowledge the technical and logistical support for field effort by Joel Sminchak, Danielle Meggyesy, and Bruce Sass of Battelle, and AEP's Mountaineer Plant staff.

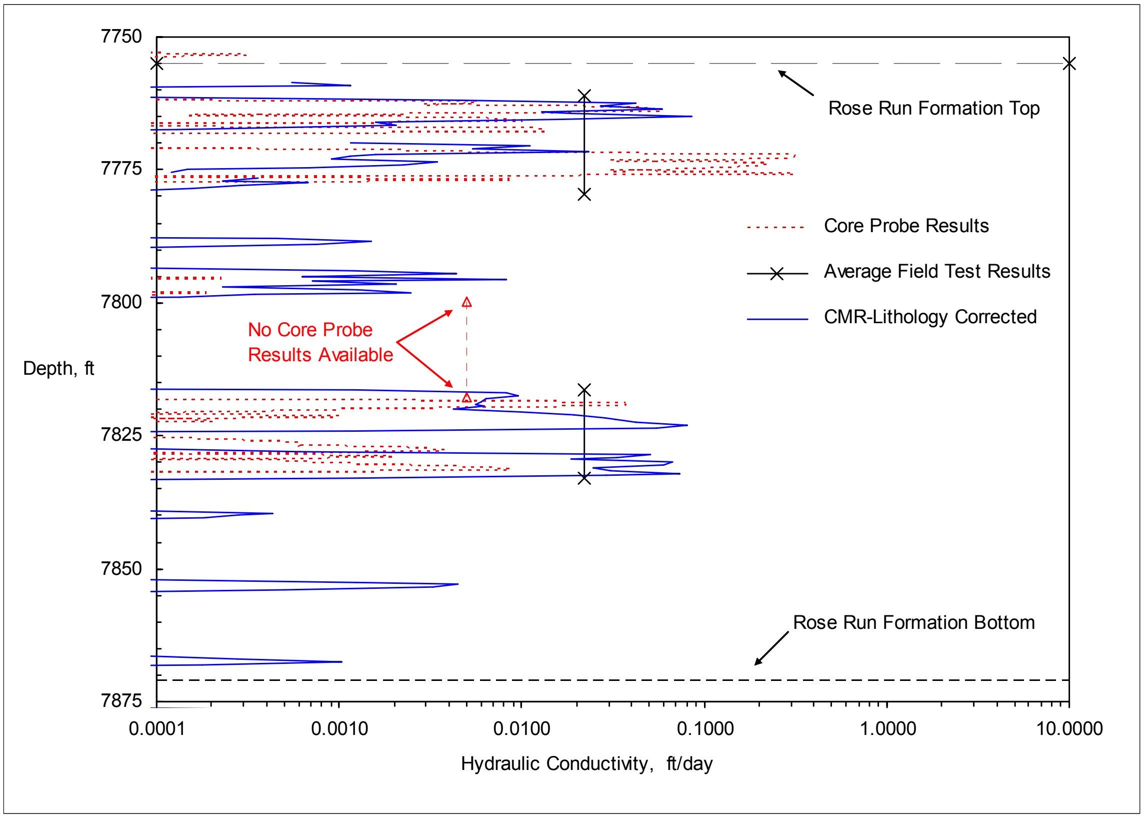


Figure 3. Comparison of Converted Core Probe and CMR Hydraulic Conductivity Vertical Profile Plots within the Rose Run Formation

REFERENCES

Earlougher, R., Jr. *Advances in well test analysis*, Monograph, Vol. 5, Society Petroleum Engineers, Richardson, Texas, 1977.

Jacob, C. and S. Lohman. Non-steady flow to a well of constant drawdown in an extensive aquifer, *Transactions American Geophysical Union*, 14, 446-460, 1952.

Kenyon, W., R. Kleinberg, C. Straley, G. Gubelin, and C. Morriss. Nuclear magnetic resonance imaging – technology for the 21st century, *Oilfield Review*, 7(3), 19-33, 1995.

LEAKAGE FROM STORAGE FORMATIONS: PATHWAYS, EFFECTS, AND IMPLICATIONS FOR SITE CHARACTERIZATION

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

IMPLICATIONS OF ABANDONED WELLS FOR SITE SELECTION

Michael A. Celia[1], Dmitri Kavetski[1], Jan M. Nordbotten[1,2], Stefan Bachu[3], and Sarah Gasda[1]

[1]Department of Civil and Environmental Engineering
Princeton University
Princeton, NJ 08544 USA
e-mail: celia@princeton.edu

[2]Department of Mathematics
University of Bergen
Bergen, Norway

[3]Alberta Energy and Utilities Board
Edmonton, Alberta, Canada

INTRODUCTION AND OVERVIEW

In mature sedimentary basins, especially in North America, the century-long history of oil and gas exploration and production has resulted in millions of wells being drilled. Many of these wells are abandoned. Because these basins are likely targets for CO_2 storage projects, the possibility of CO_2 leakage along existing wells is an important part of any risk assessment study.

From a computational point of view, this problem of fluid flow and leakage is highly demanding. For some locations in North America, plumes of injected CO_2 will encounter potentially large numbers of existing wells, each of which needs to be included in the mathematical description of the problem. In addition, because vertical migration of CO_2 is a central feature of the leakage problem, multiple geological formations need to be included in the vertical description of the subsurface. Computational limitations make it virtually impossible to run traditional numerical simulators that need to spatially resolve hundreds of wells while including perhaps 10 geological layers in the vertical and covering domains on the order of 1,000 km^2. The computational constraints are essentially prohibitive when the high degree of uncertainty associated with the hydraulic characteristics (and often even location) of the existing wells is considered. Since the precise leakage pathways are poorly understood, a probabilistic analysis is necessary to estimate the likelihood of leakage and the confidence limits on these predictions given some assumptions about the statistical distribution of the well properties. Considering the strong nonlinearity of the system with respect to its (highly uncertain) hydraulic properties, the use of Monte Carlo methods becomes necessary. Since Monte Carlo analysis requires multiple (hundreds or thousands of) runs with different system properties sampled from *a priori* distributions, general numerical algorithms for multiphase flow (such as ECLIPSE, TOUGH2 or DynaFlow), which can take weeks or months of computing time for a single leakage scenario with a dozen wells and a few geological layers, are unsuitable for such risk assessment.

In order to carry out realistic Monte Carlo risk assessment, we are developing a novel semi-analytical model for computationally fast estimation of CO_2 migration. Unlike general numerical multiphase flow models, which discretize the domain and solve for pressures and saturations at each grid point, the new model specifically focuses on the wells as the dominant transport mechanism and derives an approximation of the general multiphase equations specifically adapted to the scenario of homogeneous horizontal aquifers separated by impervious aquitards and perforated by permeable wells. A central component of the methodology is a model of radial CO_2 plumes developing around injection and leaky wells.

Figure 1 below shows a schematic of the system modeled by the semi-analytical approach. In general, any well may leak CO_2 to the overlying formations, with the flowrates denoted by $Q_i^j(t)$ and the amounts of mass by $M_i^j(t)$, where i indexes the wells and j indexes the layers (see Figure 1). The shape of all plumes and the pressures at all well locations in all layers are computed using a semi-analytical approximation based on plume self-similarity. The magnitude of leakage in each well segment is proportional to the pressure gradient across the aquitard and is computed using a Darcy-type equation and depends strongly on its assigned properties (effective flow area and permeability). The plume masses are then updated using a time stepping algorithm.

Major assumptions in this semi-analytical model include radial symmetry of the CO_2 plumes in all formations, spatial homogeneity of every layer, impervious caprock formations, and horizontal formation layering with vertical wells. We also assume vertical equilibrium of the CO_2 plumes and ignore capillary pressure and thermal effects. An effective Darcy-type

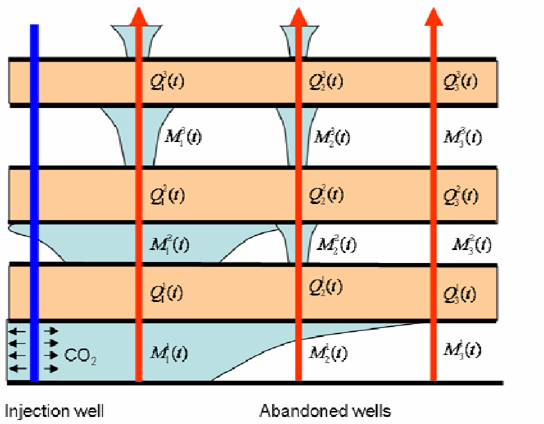


Figure 1. Schematic of injection and leakage, including leakage plumes and multiple layers.

permeability is used to calculate flows in the abandoned wells. The model includes modules to simulate the evolution of injection (and leakage) plumes in each layer, near-well upconing effects associated with well inflows, and a module that simulates redistribution after injection ceases.

The Monte Carlo analysis of potential leakage requires assumptions to be made regarding the permeability of the well segments in the aquitards (which we believe to be the dominant source of uncertainty in the system). As an initial approximation, we assume that the distribution of the logarithm of the permeability is bi-modal Gaussian, with peaks at 10^{-20} m^2 and 10^{-16} m^2 and that the permeabilities in different well segments are completely uncorrelated. The first peak of the distribution corresponds to the mean permeability for cement that is well-formed and properly emplaced (10^{-20} m^2), while the second peak corresponds to degraded cement. While this chosen value is probably much too low for severely degraded cement, we have used it in our first calculations to illustrate how the semi-analytical solutions behave and to show the kinds of information they provide. Clearly, the identification of appropriate probability distributions of effective permeabilities along all segments of existing wells is a critical and difficult task. Given the lack of reliable data in this respect, we emphasize again that the results presented below are intended as a demonstration of the general capabilities of the methodology and should not be taken as actual predictions for any existing or planned injection scenario.

RESULTS

Below we show a few results to demonstrate the capabilities of the model we have developed. We have used the hydrogeological data from the Wabamun Lake formation in Alberta, Canada, with approximately 500 existing wells in an area of about 30 x 30 km. The model includes 7 permeable layers in the vertical, separated by impervious layers. Thicknesses and flow parameters for each layer are taken from data provided by the Alberta Geological Survey (Bachu, personal communication, 2006).

Figure 2 shows the plume masses predicted by the semi-analytical model to have accumulated in the aquifer overlying the injection formation after 32 years of injection.

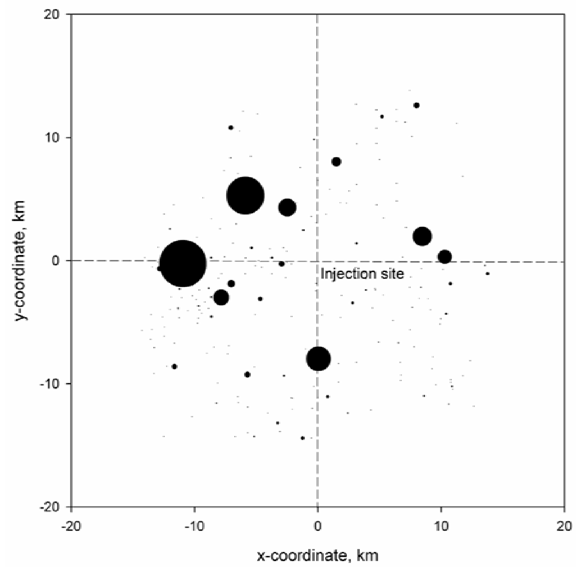


Figure 2. Plume migration in the layer above the injection formation after 32 years of injection. The xy axes denote the spatial domain, centered on the injection site. The plumes are indicated by circles scaled by the plume size.

It can be seen that the injection plume has encountered a large number of wells. However, because leakage is controlled by the well permeability, the majority of resulting plumes in the layer above the injection layer are small. Several larger plumes arise around wells with higher permeability. Also note that, for a single realization, the magnitude of the leakage depends primarily on the well permeability, with the distance from the injection site being of secondary importance.

The Monte Carlo results presented here are based on 600 independent realizations of the well permeability field described by the bi-Gaussian distribution. From these simulations, we can determine output statistics, including statistics related to well leakage. Figure 3 shows a histogram of leakage statistics, in terms of cumulative mass that has leaked from the injection formation after 32 years. These results indicate that we can reasonably expect the total mass of CO_2 above the injection formation (summing over all the well segments in this layer) to range between 0.3%

and 10% of the total injected mass, with the value of about 2% being most likely. It is this kind of uncertainty estimates that are currently impossible to obtain using traditional numerical models, due to computational limitations. Here we generated 600 realizations in approximately a week, running on 4 desktop CPUs. Note that the computational runtime is strongly proportional to the well permeabilities and to the ratio of well permeabilities in adjacent vertical segments. We are carrying out numerical analysis to understand this dependence and further improve the efficiency and robustness of the model.

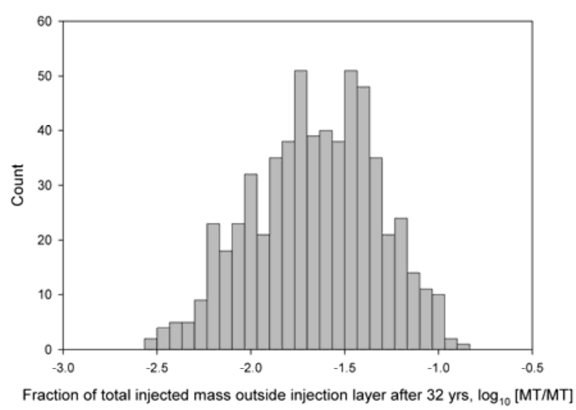


Figure 3. Leakage statistics (after 32 years of injection).

SUMMARY AND CONCLUSIONS

We have developed a semi-analytical model that captures many of the essentially physics of injection and leakage along wells. The model includes multiple leaky wells, and multiple formation layers in the vertical. The simplified calculations involved in this model allow for large numbers of simulations to be completed in reasonable times, and therefore allows Monte Carlo analysis to estimate the uncertainty in leakage predictions arising from incomplete knowledge of the properties of the system.

While the model is currently able to produce the kinds of results we have presented herein, there remain several important components that require additional work. These include more physically-based estimation of saturations in the wells, improved numerical algorithms for the nonlinear differential-algebraic equations that arise in the semi-analytical formulation, and a new hybrid approach that allows traditional numerical solutions in the injection layer to be coupled with semi-analytical leakage solutions for the overlying formations. These and other modifications continue to be motivated by the need to quantify uncertainty in risk analyses of CO_2 injection.

ACKNOWLEDGMENTS

This work was supported in part by BP and Ford Motor Company through funding provided to the Carbon Mitigation Initiative at Princeton.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

WELL INTEGRITY IN CO_2 ENVIRONMENTS: PERFORMANCE, RISK, AND TECHNOLOGIES

Bruno Gerard[1], Richard Frenette[1], Laurent Auge[1,]
Veronique Barlet-Gouedard[2], Jean Desroches[2], Laurent Jammes[3]

[1]OXAND
36 bis, avenue Franklin Roosevelt
77210 Avon, France
e-mail: richard.frenette@oxand.com, bruno.gerard@oxand.com, laurent.auge@oxand.com

[2]Schlumberger Riboud Product Center
1 Rue Henri Becquerel,
92142 Clamart Cedex, France
e-mail: vbarlet@clamart.oilfield.slb.com, jdesroches@clamart.oilfield.slb.com

[3]Schlumberger Carbon Services
Le Palatin 1, 1 cours du triangle
92936 La Defense Cedex, France
e-mail: jammes1@la-defense.oilfield.slb.com

INTRODUCTION

One of the major issues associated with CO_2 geological storage is the control of the seal integrity over very long timescales: leakage could not only defeat the purpose of storage but also badly affect human health or the environment.

Leakage through wells is one of the major preoccupations when storing CO_2 in depleted oil or gas reservoirs. Indeed, many wells have been drilled in these areas, which may be plugged and abandoned, closed or still active (producers). Old well locations are sometimes not even known with precision. As for new wells, it is critical to ensure that they do not compromise the long-term integrity of the storage.
When CO_2 dissolves in water-rich surroundings, it creates an acidic environment detrimental to completion long-term integrity. Zonal isolation may be lost, due to degradation of cement or casing corrosion, with preferential channels for carbon dioxide migration into shallower formations or even back to surface.

This paper introduces a global methodology to address long-term well integrity issues for CO_2 storage (Figure 1).

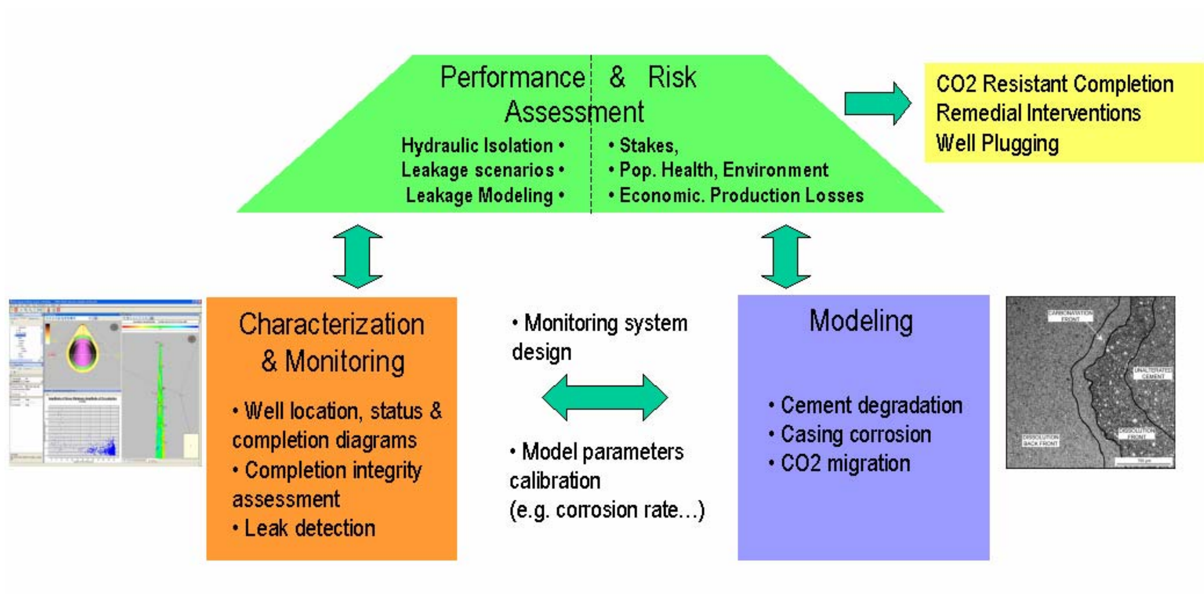


Figure 1: General methodology for Performance & Risk analysis

The Performance & Risk Assessment approach consists in: (i) a characterization of the sealing integrity with time: Performance, (ii) an analysis of the Risks associated to well leakage: aquifer contamination and CO_2 release.

Quantitative estimations of leakage rates versus time, at any point of the completion, are made possible by modeling material degradation and simulating CO_2 transport throughout the completion. Model parameters are calibrated, for example using time-lapse logging measurements, such as cement bond or casing corrosion logs.

Risks associated with leakage are classified as a function of their criticality. The weakest components can be identified from scenario analysis and sensitivity studies, which then support a mitigation strategy. This strategy comprises well completion repair and specific monitoring options.

For new well construction, an initial assessment of performance and risks allows designing the optimum well trajectory, and selecting the optimum materials for long-term integrity. Similarly, at the closure phase, the plugging material will be designed to ensure the long-term integrity of the well.

PERFORMANCE & RISK ASSESSMENT

A Performance & Risk analysis requires several steps illustrated in Figure 2:

- The first task consists in identifying all required functions (confinement, production, access…) expected from the system as well as all components (wells with their completion, formation layers, surface facilities…) necessary to achieve these functions.
- The second task consists in identifying all processes (material degradation, internal/production and external stresses, etc.) that can compromise the well integrity and thus its functional purpose. From these, all the possible leakage scenarios are constructed.
- For each scenario, fluid-flow and degradation models are used to estimate leakage rates versus time, with associated uncertainties. These well flow models use boundary conditions provided by a reservoir simulator providing CO_2 saturation and pressure. Model parameters, such as corrosion rates and cement degradation can be calibrated through laboratory tests, including accelerated testing and time-lapse well integrity monitoring measurements.
- Risks are identified in relation with leakage scenarios, and categorized as a function of their criticality (probability versus severity). Estimation of leakage rates through quantitative models enables linking risk to the failure of a specific component, for example using sensitivity analysis. Appropriate (proactive, reactive, predictive) actions can then be taken to mitigate the highest risks.

Although focused on leakage through wells, this Performance and Risk analysis can be easily extended to deal with all possible storage integrity issues (wells, cap-rock and faults).

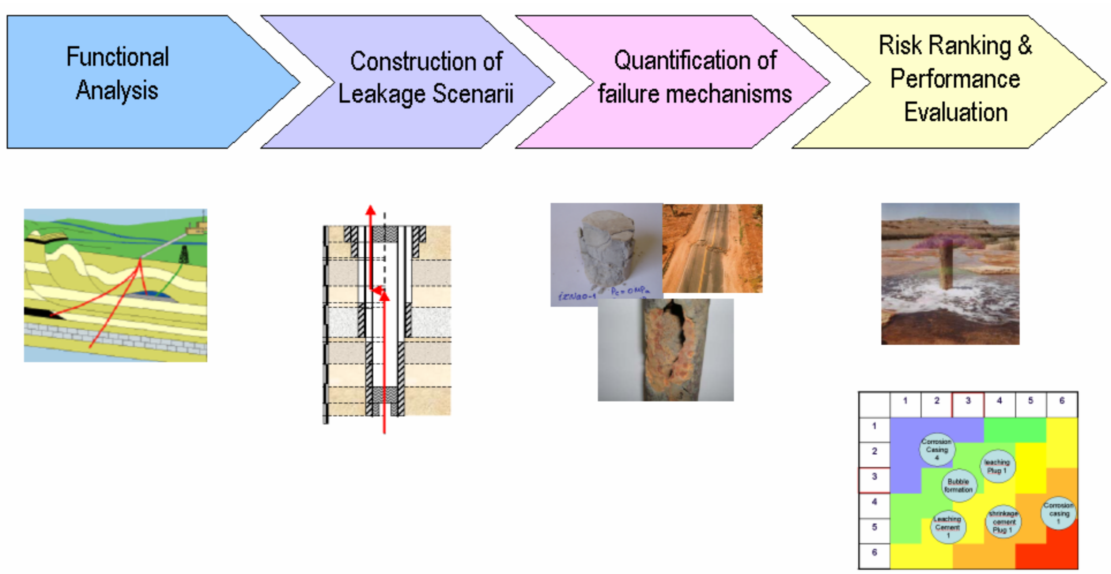


Figure 2: Performance & Risk Analysis for Well Integrity

MODELLING

As discussed in the previous section, quantitative models are of paramount importance for:

1) estimating correctly the criticality of risks versus time by computing leakage rates in critical locations and

2) linking these risks to a change in component properties that affect most the transport of CO_2 through the completion.

Two different kinds of alteration models are currently in use:

- The first model is focused on the quality of the interfaces. It allows predicting the occurrence of micro-annulus or cracks in the cement sheath due to pressure and temperature variations experienced by the system. The computation accounts for formation (reservoir, cap rock or overburden), cement and casing mechanical properties.
- The second model deals with the evolution of cement and casing properties under CO_2 aggression. The deterioration of well completion components (cement chemical attack, casing corrosion) can be modeled over long periods (1,000 to 10,000 years), with estimations of changes in corresponding properties, such as porosity and permeability.

A hydrodynamics model is then used to simulate the fluid flow through the various components of the completion, along the wellbore trajectory, for each CO_2 migration scenario. Resulting CO_2 fluxes are computed at any point of interest, for instance in a shallower aquifer, or at surface.

The optimum monitoring strategy is derived from this analysis. If possible, sensors are placed in critical locations, in order to detect as early as possible component failure or leakage routes, before any irreversible damage or serious hazard can occur.

WELL COMPLETION CHARACTERIZATION & MONITORING

Once critical risks and critical scenarii have been defined, refined well completion characterization is used to enhance the precision of the prediction, and hence strengthen the risk mitigation strategy. Furthermore, during the life of the storage, monitoring is used to assess regularly the performance of the system.

Completion integrity is commonly assessed and monitored using logging tools. Cement quality and cement bonding is usually characterized using sonic and ultrasonic tools, The latter technique, together with electromagnetic sensing or caliper measurements, provides a measurement of casing thickness and corrosion.

For example, the new generation of ultrasonic tools combines a standard pulse-echo technique with a flexural wave attenuation measurement. This additional measurement can provide a characterization of the formation / cement interface (Zeroug, 2005). Those tools offer a precise characterization of the casing thickness and shape. Combined with electromagnetic remote field eddy current sensing, they enable to differentiate between internal and external corrosion. Localized defect detection through focused devices allows early prevention of leakage through the inside of the casing. Measurement complementarities (in terms of depth of investigation and probing technique) are exploited to provide a full diagnosis of the completion integrity, from the internal side of the casing to the near well-bore region.

Monitoring of the completion integrity will be supplemented by detecting leaks through various strategies, depending on the most likely leakage scenarii. Because well access can be an issue, a combination of techniques is considered, like pressure measurements in the annulus, analysis of formation fluids in aquifers above the reservoir through monitoring wells and surface CO_2 sensors.

WELL TECHNOLOGIES – CONSTRUCTION AND PLUGGING

Finally, the analysis of Performance & Risks allows taking various decisions on well construction materials (CO_2-resistant materials for completions exposed to aggressive environments), well repair operations or plugging system design for well closure. The choice of technologies is directly guided by the risk and sensitivity analysis.

Conventional materials used for well isolation are Portland-based cement systems, which present the advantage to be low cost and efficient for oil & gas operations. However, the durability of these materials is known to be limited in time, especially in acidic environments. CO_2 reacts with calcium hydroxide formed from hydrated calcium silicate phases. However, the increase of molar volume associated with cement carbonation and leading to a decrease in porosity and permeability is not the ultimate stage of the CO_2 reaction. Indeed, precipitation & dissolution of carbonates compete, because of the low pH environment, and conventional cement significantly degrades with time. Such mechanisms have been fully characterized through laboratory testing and are documented in Barlet et al. (2006).

New cement systems have been developed, which show much better resistance in CO_2 environments, for a wide range of slurry densities. Using these materials for cementing will allow maintaining zonal isolation over very long timescales.

In CO_2 storage conditions, well integrity will be regularly checked across the injection interval, the cap rock and even shallower zones. Adequate remedial operation must be concurrently developed to re-establish zonal isolation when a leakage path has been detected. For instance, squeeze jobs will allow repairing any faulty primary cement job. Advanced cement systems having a better resistance to CO_2 than most other squeeze cement formulations are under development.

New cementing materials and repair procedures should be complemented by a review and adaptation of standard plugging-and-abandonment (P&A) procedures, which vary according to local regulations. At present, there is no specific abandonment procedure for "CO_2" wells. Depending on the criticality of the plug, different materials and different placement methods can be used. As for materials, one can choose between regular cement, new plug materials combining flexibility with extension (see for example Nagelhout, 2005) or long-term durable material that is thermodynamically stable in the CO_2 environment. Concerning the placement of the plug, standard plug placement can be considered or, if deemed necessary by the criticality of the plug, the casing and cement can be milled all the way to the formation before placing a cement plug directly in contact with the formation.

ACKNOWLEDGEMENTS

The authors would like to thank. N. Aimard and S. Crépin of TOTAL for the fruitful discussions and input they had on the methodology presented herein.

REFERENCES

Barlet-Gouédard, V., G. Rimmelé, B. Goffé, O. Porcherie and T.S. Ramakrishnan, *Mitigation strategies for the risk of CO_2 migration through wellbores*, SPE paper 98924, Proc. of the 2006 IADC/SPE Drilling Conference, Miami, Florida, 21-23 February 2006.

Houdu, E., L. Augé, R. Frenette, B. Gérard, B. Capra, *Les transferts en site profond*, Compte-rendus des 7e Journées d'Etude sur les Milieux Poreux. pp. 196-197. Bordeaux, France, Octobre 2005.

Nagelhout, A.C.G., M.G.R. Bosma, P.J. Mul, G.G. Krol, J.F.G. van Velzen, J.S. Joldersma, S.G. James, B. Dargaud, G.J.R. Schreuder and F. Théry, *Laboratory and field validation of a sealant system for critical plug*, SPE Paper 97347, Proc. of the 2005 SPE/IADC Middle East Drilling Technology Conference, Dubai, UAE, 12-14 September 2005.

S. Zeroug, R. van Kuijk, B. Froelich, M. Allouche, S. Bose, J. Le Calvez, V. Shoepf and A. Pagnin, Schlumberger and D. Miller, *A Novel Ultrasonic Cased-Hole Imager for Enhanced Cement Evaluation and Cement Sheath Calipering*, Proc. of the IPTC (International Petroleum Technology Conference), Doha, Qatar, 21-23 November 2005.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

DEVELOPMENT OF A GEOCHEMICAL CODE TO ASSESS CEMENT REACTIVITY IN CO2/BRINE MIXTURES

Bruno Huet, Richard Fuller, Jean Prevost, George Scherer

Department of Civil and Environmental Engineering,
Princeton University
Princeton NJ 08544
Phone: +1 609 258 1619
e-mail: bhuet@Princeton.edu, rcfuller@Princeton.edu, prevost@Princeton.edu, scherer@Princeton.edu

INTRODUCTION

This work aims at modeling well-bore leakage of carbon dioxide (CO_2) from sequestration reservoirs. The leakage of CO_2 is a function of the geometry of the low permeability path and boundary conditions. However, the CO_2 flow can also be strongly influenced by the chemical reactivity of cement leading either to the sealing or to the widening of the annulus. Thus, a multiphase transport model that aims at assessing CO_2 leakage along high permeability paths must account for the reactivity of the porous environment. Therefore a geochemical module must be integrated. This study presents preliminary results of the coupling of a geochemical module with a transport module. Simulation of chemical degradation of cement paste (CEM I) in pure deionized water are presented.

Geochemical module

The geochemistry part of the code assumes local chemical equilibrium. This assumption is valid as long as reaction kinetics are much faster than diffusion kinetics. It takes into account the reactivity of cement, i.e. both mineral solid phase changes, such calcium carbonate formation from portlandite, and carbonic acid dissolution within the interstitial solution.

The equilibrium conditions in terms of aqueous concentrations and mineral assemblage are computed through the resolution of two sets of non-linear equations. The first one describes the homogeneous chemistry, inside the aqueous phase (Eq. 1). The second one governs equilibrium between solid phases and the aqueous phase (Eq. 2).

$$TotC_k^0 - \sum_{i=1}^{N_{sp}} \nu_{ki} \cdot \frac{K_{f\,i}}{\gamma_i} \prod_{j=1}^{N_c} \left(\gamma_j . C_j^0\right)^{\nu_{ij}} = 0 \quad , \quad k \in \{1, N_c\}$$

Eq. 1

$$\sum_{j=1}^{N_c} \nu_{ij} \left(Log(\gamma_j) + Log\left(C_j^0 + \sum_{k=1}^{M} \nu_{jk}\, \Delta S_k \right)\right) + Log(K_{f\,i}) = 0 \quad , i \in \{1, M\}$$

Eq. 2

where N_c, N_{sp} and M are respectively the number of basis components, aqueous species and minerals considered, K_{fi} is the formation constant of an aqueous species or mineral, γ_j are the activity coefficients, ν_{ij} are the stoichiometric coefficients, C_j^0 are the concentrations of aqueous basis components, and ΔS_k are the amounts of minerals that react to satisfy equilibrium.

The description of those equations and the need for a relevant choice of basis components may be found elsewhere [1, 2]. The solution of each equation (Eq. 1 and Eq. 2) is performed using the well-known Newton-Raphson iterative scheme. Two other iteration procedures have been added. The first one identifies the basis components in the aqueous phase. As a result an aqueous species component may be switched into a basis component and inversely. The criterion for switching is that the concentration of a basis component must be ten times smaller than that of the corresponding aqueous species (e.g. $c_{CO_3^{2-}} \le 0.1 c_{HCO_3^-}$). As a consequence of the basis switch the log$K$ value of minerals and aqueous species are corrected in order to match the new set of basis components.

The second procedure aims at finding the solid phases that should precipitate to satisfy partial equilibrium. In the end, this routine gives the number and nature of solids in equilibrium within the mineral assemblage. Given an initial composition of an aqueous solution, the saturation indices of minerals are calculated. First the algorithm deals with the precipitation of minerals. The mineral with the highest saturation index (SI) precipitates. This procedure is repeated in succession for every mineral whose SI is greater than zero. Then this scheme is repeated for every mineral that is undersaturated (SI<0), beginning with the minerals with the lowest saturation indices. An alternative procedure is to check after each mineral precipitation whether the SI of every mineral precipitated remains ≥ 0. If not, those minerals are partially or completely dissolved to satisfy equilibrium. In the latter case the mineral is removed from the mineral assemblage.

Those two iterative procedures are solved in succession to avoid divergence of the global solution. First the homogeneous chemistry is solved and then the heterogeneous chemistry. This iterative procedure is repeated as long as the two sets of equations have not simultaneously converged to the same concentrations of the basis components, based upon an adaptable tolerance threshold.

The set of basis components, aqueous species and minerals representative for the studied chemical system is given in Table 2. Portlandite, jennite, ettringite and calcium monosulfoaluminate form the characteristic mineral assemblage of a hydrated Portland cement (CEM I). All the other phases are likely to form during the carbonation process of the cement. Calcite is the most stable calcium carbonate phase in the temperature and pressure ranges which are likely to be found within a well. Calcium tricarboaluminate, calcium monocarboaluminate and calcium hemicarboaluminate are AFt and AFm phases that are likely to form by substitution of sulfate ions by carbonate ions. Although experimental study of AFt and AFm, substituted by SO_4^{2-}, CO_3^{2-} or OH^-, indicates solid solution formation [1], pure phases are only considered in this work. Finally in highly carbonated concrete, amorphous silica (silica gel), amorphous alumina and gypsum are the most stable phase. The log$K$ value of each mineral is subject to variation from one reference to another. In this work, we chose the log$K$ values of aqueous species and minerals given by an extensive European report on cement chemical behavior in various aggressive aqueous environments [1].

Transport module

The transport equation solved in this work is the one introduced by Samson et al. [1, 2]. It takes account of the effects of diffusion, electrical coupling between ions and chemical activities on transport kinetics (Eq. 3):

$$\frac{\partial\left(\theta C_i^0\right)}{\partial t}-\frac{\partial}{\partial x}\left(\begin{array}{l}\theta D_i \dfrac{\partial C_i^0}{\partial x}+\theta C_i^0 \dfrac{D_i z_i F}{RT}\dfrac{\partial \psi}{\partial x}\\ +\theta D_i C_i^0 \dfrac{\partial \ln \gamma_i}{\partial x}+D_i C_i^0 \dfrac{\partial \theta}{\partial x}\end{array}\right)$$
$$, i \in \{1, N_{sp}\}$$

Eq. 3

where θ is the porosity, D_i the diffusion coefficient of aqueous species i , z_i the valence number of aqueous species i, F the faraday constant, R the perfect gas constant, T the temperature and ψ the electrical potential. An electrical potential appears to maintain electroneutrality in the bulk solution when each aqueous species diffuses with different diffusion rate. According to Poisson's equation (Eq. 4), the electrical potential value is calculated in every mesh to account for electrical coupling.

$$\tau \frac{d}{dx}\left(\theta \frac{d\psi}{dx}\right)+\frac{F}{\varepsilon}\theta\left(\sum_{i=1}^{N} z_i C_i^0\right)=0$$

Eq. 4

As a result of mineral dissolution and formation, porosity varies. The feedback on transport properties is evaluated since the effective diffusion coefficient value depends on porosity.

First Results

The code is currently under development. Therefore the capacity and robustness of the code were evaluated in the case of the well documented degradation behavior of cement in pure deionized water [4].

The initial chemistry is fixed by the mineral assemblage (portlandite, jennite, calcium monosulfoaluminate and ettringite) and by the alkali content (Na^+ and K^+). The porosity value is 0.522 and the effective diffusion coefficients of aqueous species are in the range of 10^{-12} m^2/s. The thickness of the cement paste sample is 2 cm. The concentration profiles are given after a real time of 10 days.

Figure shows the concentration profiles of Na^+, K^+ and OH^-. The loss of those ions induces a large decrease of the pH in the degraded zone, which shifts the equilibrium of all minerals. The Ca^{2+} concentration, which is fixed by portlandite solubility, increases (Figure), leading to an increase of calcium leaching and portlandite dissolution (Figure). The decrease in pH and sulfate concentrations shifts the equilibrium of Aft and AFm phases toward calcium monosulfoaluminate dissolution and ettringite precipitation. The dissolution of portlandite and the conversion of calcium monosulfoaluminate into ettringite are consistent with the experimental results presented in the European report [4].

The geochemical module of the code is still under development. First, the robustness of the code needs still to be evaluated over longer degradation period that leads to further mineral degradation. Results will be validated by comparison with experimental results and other 1D one-phase reactive transport models. Secondly, modeling results must be assessed in the case of chemical degradation by CO2 saturated brine.

Future developments of the code could be the implementation of 1) a solid solution model for the thermodynamic description of mineral equilibrium and 2) a kinetic control of heterogeneous reactions. Improving the description of the CSH and AFt and AFm dissolution may give more accurate results concerning the mineral zoning of a degraded cement paste. This zoning depends also on reaction kinetics of heterogeneous reactions.

REFERENCES

[1] J. Westall, "Chemical Equilibrium including adsorption on charged surfaces" American Chemical Society, Advanced Chemistry Series,1980, 189, 33-44

[2] F.M Morel and J.G. Hering, "principles and applications of aquatic chemistry", John Wiley & Sons, Inc, 1993, ISBN 0-471-54896-0

[3] H. Pöllmann, H.-J. Kuzel, R. Wenda, "Solid solution of ettringites, Part I: Incorporation of OH- and CO32-, in 3CaO.Al2O3.3CaSO4.32H2O", Cement and Concrete Research, 1990, 20, 941-947.

[4] Revertegat, Adenot, Glasser, Damidot, Stronach, Richet, Wu, "Theoretical and experimental study of degradation mechanisms of cement in the repository environment", Rapport Européen, Contrat CCE N° FI 2W-CT.90-0035, 1997

[5] E. Samson, J. Marchand, "Numerical solution of the extended Nernst-Planck model", Journal of Colloid and Interface Science, 1999, 215, 1-8.

[6] E. Samson, J. Marchand, K.A. Snyder, J.J. Beaudouin, "Modeling ion and fluid transport in unsaturated cement systems in isothermal conditions", Cement and Concrete Research, 2005, 35, 141-153.

Table 1: Initial basis components, aqueous species and minerals considered for the simulation.

Initial basis components	
H_2O, H^+, Ca^{2+}, SiO_2^0, $Al(OH)_4^-$, SO_4^{2-}, CO_3^{2-}, Na^+, K^+, Cl^-	
Aqueous species	
$Ca(OH)^+$, $Ca(OH)_2^0$, $CaCO_3^0$, $CaHCO_3^+$, $CaSO_4^0$, $CaCl^+$, $CaCl_2^0$, Al^{3+}, $Al(OH)_2^+$, $AlOH^{2+}$, CO_2^0, HCO_3^-, $H_2SiO_4^{2-}$, $HSiO_3^-$, $Al(SO_4)^{2-}$, $AlSO_4^+$	
Minerals	
Name	*Chemical formula*
Portlandite	$Ca(OH)_2 \Leftrightarrow Ca^{2+} + 2\ OH^-$
Jennite	$9CaO.6SiO_2.12H_2O \Leftrightarrow$ $9\ Ca^{2+} + 6\ SiO_2^0 + 18\ OH^- + 2\ H_2O$
Tobermorite	$5CaO.6SiO_2.12H_2O \Leftrightarrow$ $5\ Ca^{2+} + 6\ SiO_2^0 + 10\ OH^- + ½\ H_2O$
Ettringite (AFt)	$3CaO.Al_2O_3.3CaSO_4.32H_2O \Leftrightarrow$ $6\ Ca^{2+} + 2\ Al(OH)_4^- + 3\ SO_4^{2-} + 4\ OH^- + 26\ H_2O$
Monosulfoaluminate (AFm)	$3CaO.Al_2O_3.\ CaSO_4.12H_2O \Leftrightarrow$ $4\ Ca^{2+} + 2\ Al(OH)_4^- + SO_4^{2-} + 4\ OH^- + 6\ H_2O$
Calcite	$CaCO_3(s) \Leftrightarrow Ca^{2+} + CO_3^{2-}$
Hemicarboaluminate	$3CaO.Al2O3.½\ CaCO3.½CaO.11.5H2O \Leftrightarrow$ $4\ Ca^{2+} + 2\ Al(OH)^{4-} + ½\ CO_3^{2-} + 4\ OH^- + 5.5\ H_2O$
Monocarboaluminate (AFm)	$3CaO.Al_2O_3.CaCO_3.12H_2O \Leftrightarrow$ $4\ Ca^{2+} + 2\ Al(OH)_4^- + CO_3^{2-} + 4\ OH^- + 6\ H_2O$
Tricarboaluminate (AFt)	$3CaO.Al_2O_3.3CaCO_3.32H_2O \Leftrightarrow$ $6\ Ca^{2+} + 2\ Al(OH)_4^- + 3\ CO_3^{2-} + 4\ OH^- + 26\ H_2O$
Gypsum	$CaSO_4.2H_2O \Leftrightarrow Ca^{2+} + SO_4^{2-} + 2\ H_2O$
Amorphous alumina	$Al_2O_3 + 2\ OH- + 3H_2O \Leftrightarrow 2\ Al(OH)4-$
Amorphous silica	$SiO_2\ (s) \Leftrightarrow SiO_2^0$

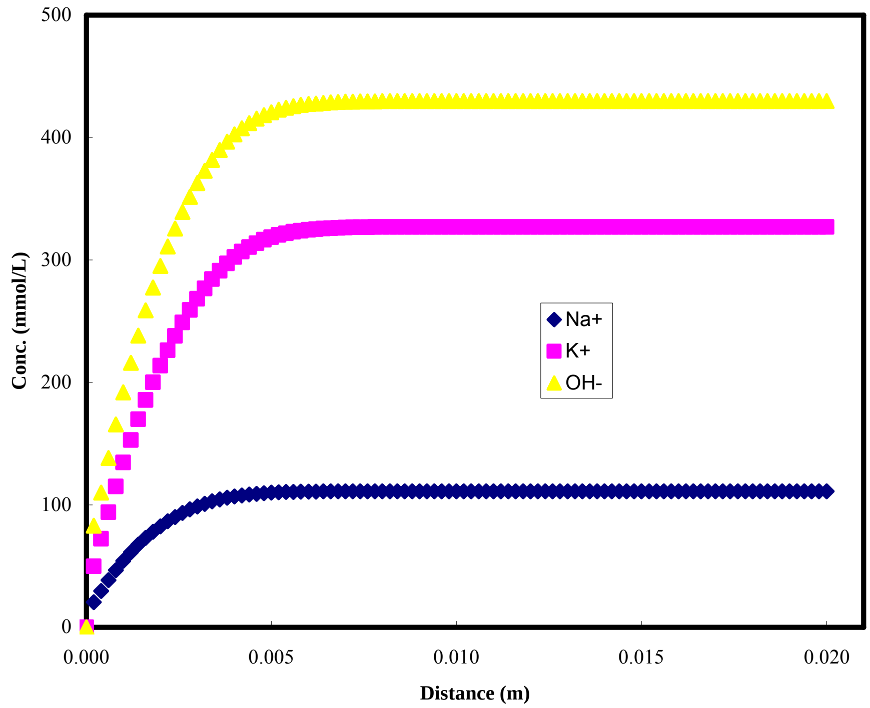


Figure 1: Na^+, K^+ and OH^- concentration profile within Portland cement after degradation in pure deionized water

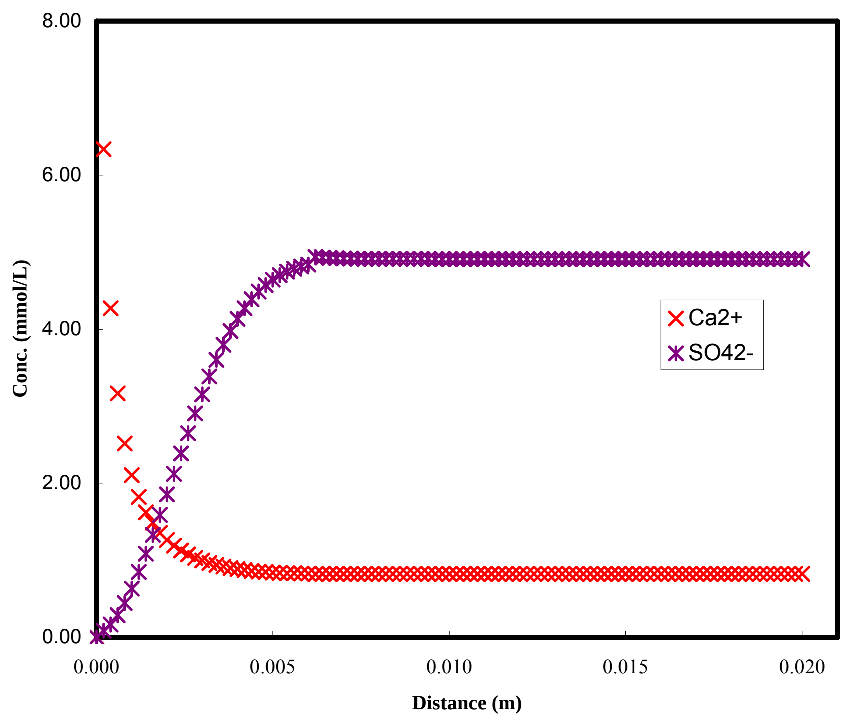


Figure 2 Ca^{2+} and SO_4^{2-} concentration profile within Portland cement after degradation in pure deionized water

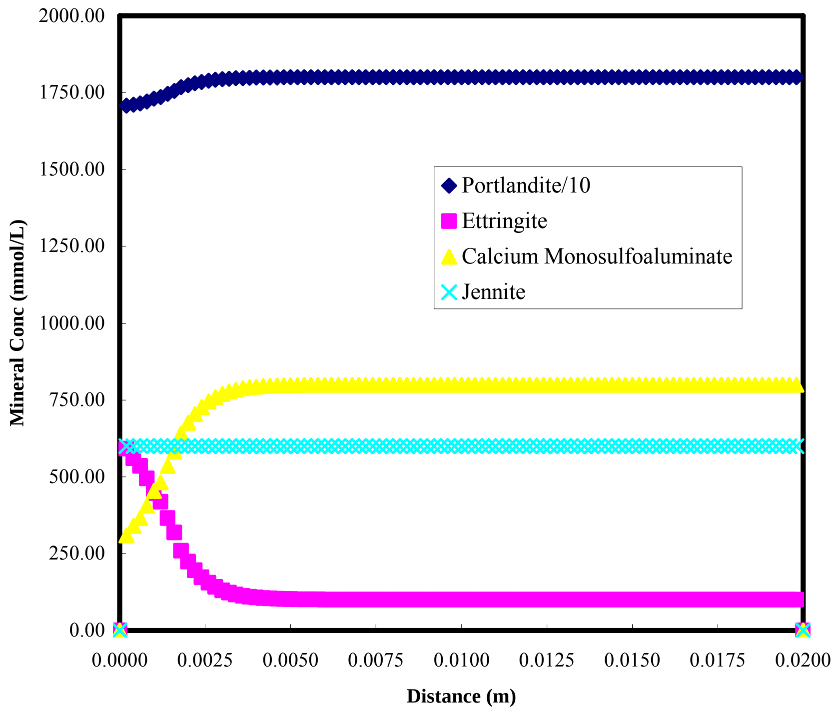


Figure 3: Mineral profile within Portland cement after degradation in pure deionized water.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

SURFACE GAS MEASUREMENTS AND RELATED STUDIES FOR THE CHARACTERISATION AND MONITORING OF GEOLOGICAL CO_2 STORAGE SITES: EXPERIENCES AT WEYBURN AND IN SALAH

D. G. Jones[1], S. E. Beaubien[2], A. Annunziatellis[2], J.-C. Baubron[3], G. Braibant[3], C. Cardellini[4], D. Cinti[3], J. R. Davis[1], C. Scheib[1], S. Lombardi[2], K. Michel[3], N. Morgantini[4], L. Penner[5], F. Quattrocchi[4], M. H. Strutt[1], N. Voltattorni[4]

[1]British Geological Survey
Keyworth
Nottingham, NG12 5GG, UK
e-mail: dgj@bgs.ac.uk

[2]University of Rome "La Sapienza"
Department of Earth Sciences, P. le Aldo Moro 5, 00185 Rome, Italy
e-mail: salvatore.lombardi@uniroma1.it, stanley.beaubien@uniroma1.it

[3]Bureau de Recherches Géologiques et Minières
3 Avenue Claude Guillemin
B.P. 6009, 45060 ORLEANS Cedex, France
e-mail: K.Michel@brgm.fr

[4]Istituto Nazionale di Geofisica e Vulcanologia
Via di Vigna Murata 605, 00143, Rome, Italy
e-mail: quattrocchi@ingv.it

[5]J. D. Mollard and Associates Limited
2002 Victoria Avenue, 810 Avord Tower, Regina, Sasketchewan, S4P 0R7, Canada
e-mail: penner@jdmollard.com

INTRODUCTION

Geological storage of CO_2 is one route to reducing greenhouse gas emissions to the atmosphere and thus mitigating the extent of global warming. Near surface gas geochemistry data have the potential to provide the ultimate indication of escape of injected gas from a CO_2 storage scheme into the atmosphere and are important to allay possible public concerns over geological CO_2 storage.

We have been involved in surface gas studies in relation to two CO_2 storage projects at Weyburn, Canada and In Salah, Algeria. The projects are at different stages of development and have points in common but also significant differences. We draw on our experiences at these sites and other related studies to make more general observations on soil gas monitoring for such projects.

BACKGROUND

Since late 2000, the petroleum company EnCana has been injecting liquefied CO_2 recovered from a coal-gasification plant in South Dakota (USA) into the mature oil reservoir near Weyburn (Saskatchewan, Canada) as a tertiary Enhanced Oil Recovery (EOR) method (e.g. White et al, 2004). During this process it is estimated that 20 million tonnes of CO_2 will eventually remain in the reservoir after the field is finally decommissioned, storing the man-made CO_2 at a depth of about 1500 m in a proven trapped reservoir; in this case a Mississippian carbonate reservoir with evaporite seals. The Weyburn EOR project was a combined N American and European effort under the International Energy Agency Greenhouse Gas Research and Development Programme. Weyburn is a real-life field laboratory to study the behavior and migration of injected CO_2 using a wide range of monitoring techniques, with the final goal being to determine the eventual safety of geological storage of greenhouse gases. Over the period from 2001 to 2003 a multidisciplinary European project studied many aspects of the Weyburn project, including near-surface geochemical monitoring of possible leakages to the atmosphere of the injected gas (Riding and Rochelle, 2005). This 'soil gas' research involved four field campaigns and the collection of a large and unique data set. It has continued in 2004 and 2005 with proposals for its continuation in Phase 2 of the Weyburn project.

The climatic conditions at Weyburn are continental with marked seasonal temperature differences. Weyburn has widespread vegetation cover typical of mixed arable and pastoral prairie farmland.

The In Salah Gas project in Algeria (Riddiford et al, 2005) is operated by a consortium of Sonartrach, BP and Statoil. The Krechba reservoir is the most northerly field, discovered in 1956 with production starting in 2004. Gas is produced from a Carboniferous sandstone reservoir at a depth of about 1850 m. The reservoir is capped by Carboniferous mudstones that are overlain unconformably by a mixed Cretaceous sequence of mostly sandstones and mudstones with thin evaporites. Gas is currently produced from four wells at Krechba. Carbon dioxide is removed from the produced gas in an amine stripping plant that leaves less than 0.3 % CO_2 in the final gas for sale. The CO_2 is re-injected into the flanks of the reservoir, below the gas-water contact, via three horizontal injection wells. Like Weyburn, In Salah is being used for an international research project studying a wide range of aspects of geological CO_2 storage. This is being funded in part by BP and through a proposed European project, 'CO_2Remove' that is expected to start in 2006. Research at In Salah is therefore at a much more preliminary stage than that at Weyburn.

The climate at Krechba is arid with very sparse surface vegetation for most of the year. However, in common with other parts of the Sahara, when rain does fall, there is a brief period of intense vegetation growth.

METHODS

A baseline soil gas survey was carried out at Weyburn in 2001 close to the start of injection of CO_2. This has been followed by annual surveys, conducted at different times of the year, providing information also on seasonal variability.

Clearly the gas of principal interest is CO_2. However, CO_2 is highly soluble and can be consumed via acid-base reactions, and thus its movement (if any) might be attenuated over the short (geologically) monitoring period. Moreover, interpretation of CO_2 data is complicated by the fact that this gas is produced by metabolic reactions, both via soil microbes and plant roots. Because of these possible sources and sinks of CO_2, a large suite of other soil gas species was studied. These might help define possible flow paths that CO_2 may follow in the future or the origin of the present CO_2 anomalies. They include less reactive gases associated with the reservoir, which could be used as tracers of deep flow (e.g. He, Rn and CH_4), and gases that might be involved in shallow biological reactions (e.g. O_2, CH_4 and C_2H_4).

Soil gas concentrations and fluxes were measured initially over a wide area grid (360 points at 200 m spacing). This included field measurements, field laboratory measurements and the collection of samples for laboratory analysis. Results from the grid were used to locate more detailed profiles with, typically, 50-60 measurements 25 m apart. Sites on these profiles were then chosen for the emplacement of continuous radon monitors. These provided a more detailed appreciation of seasonal changes and of the gas flow regime and rates at a depth (2 m) where biogenic effects are much reduced.

Since 2003, additional investigations have been made. The focus of these has been on potential pathways for gas migration, including abandoned wells and lineaments that might reflect faulting, dissolution-related fracturing or thinning of the reservoir seal. A background site, of similar nature to the oilfield, but away from the main zone of production and CO_2 injection, has also been examined.

Soil gas studies at In Salah are so far restricted to an initial feasibility study. This evaluated the use of standard soil gas concentration and flux measurement techniques at the site and provided a limited set of baseline measurements. The work covered 6 different sites: the 3 injection wells, the original 1956 discovery well, a site over the crest of the reservoir and a background site to the west, away from the CO_2 injection zone.

Based on the initial results, plans are being drawn up for a more comprehensive baseline set of measurements and for longer term monitoring of surface gases.

RESULTS

The data so far obtained at Weyburn (e.g. Jones and Beaubien, 2005) do not give any clear indication of surface release of injected CO_2. Both soil gas CO_2 concentrations and flux were slightly higher in 2004 than in 2003 at all study sites, including the background site away from the oilfield. They were, however, well within the range of values over the four years of monitoring and far less than those measured during the initial summer campaign. The difference between 2003 and 2004 is consistent with the warmer and wetter conditions in autumn 2004, compared to 2003, and the fact that the harvest was later in 2004. The results continue to support the interpretation that CO_2 distribution is due to near-surface biological processes. This is backed up by data for other gas species; O_2 shows an inverse correlation to CO_2, suggesting its consumption as CO_2 is produced, whilst N_2 levels are constant, implying no dilution by CO_2 from depth; CH_4 was lower in 2004 than 2003, which can be explained by increased microbial consumption under the wetter soil conditions and reduced downward diffusion from the atmosphere; in contrast the abiotic gases Rn and thoron show relatively constant values over all four years.

CO_2 and Rn distributions on the main grid have been quite consistent from year to year with many CO_2 highs related to low-lying marshy ground with abundant vegetation. Again this supports biogenic CO_2

production. Carbon dioxide flux measurements are less consistent spatially, but this can be explained by changes in water content and land use from year to year as well as flux variations due to diurnal and atmospheric pressure effects. Hydrocarbon gases show similar spatial patterns between species for a given year but anomalies do not match from year to year. This may, in part, be due to the very low levels encountered. As higher levels are often seen above oilfields, and have been used as an exploration tool, this may suggest either a very efficient seal on the reservoir or de-pressuring due to oil extraction that has reduced gas seepage or caused small fractures to close. As CO_2 injection has the potential to re-pressurize the field, this may change in the future.

As in 2003, the gas concentrations at the completely abandoned well on the main grid were generally much lower than at the suspended well which lies to the north of the grid. Values at the latter were similar to those on the nearby horizontal profiles and probably reflect different soil type and moisture conditions. No consistent anomalies were seen at either well that might indicate gas leakage.

Horizontal profiles on the grid have produced similar results each year. Higher concentrations of CO_2 correlate well with CO_2 flux (and lower O_2) and sometimes correspond to Rn and Tn highs. They are typically associated with depressions, or near to surface water, and appear to be shallow features where organic matter and water foster higher biogenic CO_2 production. In some cases they match air photo lineaments that could be glacial features or, possibly, surface expressions of deeper faulting.

Profiles across a river lineament, that may be the surface expression of a fault, also have given consistent data for the two years they have been sampled. Helium anomalies were again seen at the SE end of one profile in 2004, as in 2003. They suggest migration of gas from depth. However, no He anomalies were seen when the traverse was extended to the SE and some of the original points repeated. Gamma spectrometry revealed changes in ground composition sub-parallel to the lineament. Further investigation of the He anomalies was carried out in 2005 and a continuous Rn monitor installed.

Long term monitoring of radon has provided modeled gas flow rates of up to 28 cm h^{-1}, but much lower rates were seen at some sites where gas migration is purely by diffusion rather than advection. Calculated CO_2 fluxes at 2 m depth were 10 to 20 times lower than at surface, indicating the potential for monitoring releases at this sort of depth where biological processes are greatly subdued. Short-term (few hour) pulses of increased gas concentration have been seen at two sites since July 2003. They suggest transient pressure phenomena near-surface that may be linked to changes in the reservoir conditions at depth. Radon accumulation during the winter months, and rapid decreases in the spring, indicate frozen ground, locally impeding upward gas migration during the coldest months.

Ground conditions at In Salah were very different to those at Weyburn (Jones and Annunziatellis, 2004). It was difficult to use standard soil gas probes as the rocky ground made it hard to find sites where the hollow steel probes could be inserted to their full depth of 90 cm. Also, because the ground was so dry and permeable, dilution of the soil gas by atmospheric air was significant. This dilution was variable, making meaningful data harder to both acquire and interpret, but could be overcome by deeper sampling. This is probably best achieved by lining shallow boreholes with small diameter tubing to set up a network of easily sampled monitoring points.

Measured concentrations of all gases (except O_2 and N_2) were very low. Initial indications suggest CO_2 concentrations provide a very low background against which to monitor possible leakage of gas to surface. Thus it is likely to be much easier to detect than at Weyburn. Other gas values were also very low. However, methane concentrations, although very low, were higher than expected and suggest possible low-level diffuse leakage from the reservoir or another geological source. Helium anomalies were also observed that indicate the migration of gas from depth. Carbon dioxide flux measurements proved to be easy to make and are very rapid. Where the flux could be measured it was extremely low, which also makes it far more likely that leakage of CO_2 from the reservoir could be detected. The presence of significant values of methane also suggests the possibility of making flux measurements for methane, which could provide a very useful additional indication of gas escape related to the reservoir.

DISCUSSION AND CONCLUSIONS

Experience at Weyburn, In Salah and elsewhere can be used to consider more generic requirements of surface gas monitoring at geological CO_2 storage sites.

It is important to have a baseline set of measurements, ideally before any injection of CO_2. This provides a yardstick against which to compare subsequent results and is useful to demonstrate that any later measurements are no different to the pre-injection values. It is also valuable to have information on seasonal variations in gas concentrations and fluxes for the same reason.

The timing of soil gas monitoring is an important consideration. We have found at Weyburn that the fall is the best compromise; biological activity is reduced after the harvest and access to fields is not a problem as the growing crop has been removed. At other sites winter sampling has been advocated (Klusman, 2005) because biogenic gas production should be at a minimum in this season. Weyburn, however, can experience extremely low winter temperatures (-30 C or below) and the ground can be deeply frozen, impeding the flow of gas, observed in some of the Rn monitoring probes. At In Salah, winter is probably the best time for sampling but, owing to the general lack of vegetation, timing is probably far less critical.

Consideration has to be given to the conflicting demands of area coverage, to avoid missing a leak because of too low a density of observations, and making detailed, precise and accurate measurements adequate to demonstrate that the leaking gas is coming from depth. The time and resources available are an additional factor. The ideal would be a very rapid method, able to cover large areas quickly with a very low detection limit and high precision. However, this is currently not possible. The best compromise appears to be using rapid field methods to define broad scale features and targeted more detailed investigations with more accurate, precise laboratory methods with lower detection limits. These include GC-MS analysis of gases and isotope studies, such as C isotopes in CO_2 and CH_4. However, even with these techniques it may still be difficult to demonstrate unequivocally that a leak has occurred. Artificial tracers added to the injected gas may be one way to overcome this problem and could reveal short-term connections between reservoir and surface. As indicated earlier, the much lower background gas concentrations and fluxes at In Salah should mean that it is much easier to identify leakage there than is the case in more temperate settings where biogenic gases are much more prevalent.

In identifying sites for more detailed investigation it is important to consider the local geology, in order to target places where there is a greater likelihood of gas escape. For example, at both Weyburn and In Salah there are no mapped surface faults but re-examination of seismic data, and lineament analysis of air photo and satellite imagery, has been undertaken (or is planned) in an attempt to map features that may represent faulting, fracturing or thinning of seals. At other sites this information may already exist. Boreholes also represent a potential line of weakness and have been targeted in soil gas studies. Some emphasis has been given to abandoned wells, particularly older ones where the cements used on completion may have degraded.

A weakness of soil gas surveys is the lack of temporal data; leakage could be missed because of the timing of the survey and the discontinuous or time-limited nature of the release. This can be addressed by installing continuous gas monitors. These may be buried, such as the radon probes used at Weyburn, or surface mounted. Such instruments also provide valuable data on seasonal changes in gas concentration and flux and, when modeled using meteorological data collected at the same time, can be used to estimate total mass transfer rates to the atmosphere and whether flow is advective or diffusive. The advantage of burial is that there is no surface equipment that could be stolen or vandalized and they can be used in arable farmland as they are below plowing depths. They are also designed to run on batteries so require no external power source. Surface equipment may allow more sensors to be used and data can be transmitted to a remote location.

ACKNOWLEDGMENTS

Work at Weyburn was funded by the European Commission, the UK Department of Trade and Industry, the Petroleum Technology Research Centre, Regina, Canada and our institutions. BP funded In Salah studies. We would also like to thank Encana and In Salah Gas for their help.

REFERENCES

Jones, D. and Annunziatellis, A.. *Soil gas feasibility study at In Salah, Algeria*. Report, CR/04/260, British Geological Survey, Keyworth, Nottingham, UK, 2004

Jones, D. and Beaubien, S. *Continued soil gas monitoring at the Weyburn Unit in 2004*. Report COAL R288, DTI/Pub URN 05/1261, Department of Trade and Industry, London, 2005.

Klusman, R. Baseline studies of surface gas exchange and soil gas composition in preparation for CO2 sequestration research: Teapot Dome, Wyoming, *AAPG Bulletin*, 89, 981-1003, 2005

Riddiford, F., Wright, I., Bishop, C., Espie, T. and Tourquoi, A. *Monitoring geological storage: the In Salah Gas CO_2 storage project*. 1353-1359 in: *Greenhouse Gas Control Technologies*, Wilson, W., Morris, T., Gale, J. and Thambimuthu, K. Eds. Elsevier, Amsterdam, 2005.

Riding, J. and Rochelle, C. *The IEA Weyburn CO_2 Monitoring And Storage Project – Final Report Of The European Research Team*. Report COAL R275, DTI/Pub URN 05/513, Department of Trade and Industry, London, 2005

White, D J, Burrowes, G, Davis, T, Hajnal, Z, Hirsche, K, Hutcheon, I, Majer, E, Rostron, B and Whittaker, S.. Greenhouse gas sequestration in abandoned oil reservoirs: The International Energy Agency Weyburn pilot project. *GSA Today*, *14*, 4-10, 2004

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

CAPILLARITY TRAPPING IN THE OVERBURDEN AS A DEFENSE-IN-DEPTH MECHANISM AGAINST LEAKAGE FROM CO2 STORAGE SITES: THE CASE OF THE TERTIARY TEXAS GULF COAST

Jean-Philippe Nicot, Srivatsan Lakshminarasimhan, and Susan D. Hovorka

Gulf Coast Carbon Center, Bureau of Economic Geology
Jackson School of Geosciences, The University of Texas at Austin
Austin, TX, 78713, USA
e-mail: jp.nicot@beg.utexas.edu

INTRODUCTION

Trapping of carbon dioxide (CO_2) in the subsurface can be classified into four main categories: (1) mineral trapping, when CO_2 is captured in cements within the rock matrix; (2) solubility trapping, when CO_2 dissolves into water; (3) hydrodynamic trapping, when CO_2 accumulates in traps; and (4) capillary trapping. The last category includes the trail of residual saturation left behind by a moving plume. This paper presents a methodology to (1) better quantify storage capacity, (2) investigate the behavior of CO_2 leaking from the storage formation, and (3) explore the role of heterogeneity in containing leakage from the main storage area. We are using the particularly favorable attenuation processes of the Gulf Coast as an example.

Potential subsurface storage sites in sedimentary basins fall into a large range of geological heterogeneity. The 300+ meter-thick marine Utsira Sand of Miocene age at the Sleipner site has been interpreted as a relatively homogeneous graben fill of fine sand with very thin but laterally extensive intercalations of a shaly nature and overlain by several massive shales (Chadwick et al., 2004). On the contrary, the Gulf Coast area displays a high level of heterogeneity.

DESCRIPTION OF TRAPS IN THE TEXAS GULF COAST

The general geology of the Tertiary and Quaternary succession in the Texas Gulf Coast can be summarized in a simple model. It consists of a thick wedge (10's of kilometers) of alternating sandy and clayey layers resulting from the deposition by rivers of their sediments in deltas and farther out in the ocean in multiple, offlapping cycles that record deltaic and shoreface progradation. The process, resulting in fluvial, deltaic, barrier bar/strandplain, and slope/basin depositional systems such as those of the modern Mississippi River and smaller, coastal rivers, is still active today. Despite a general gentle dip toward the Gulf of Mexico, local geometry of the layers does include numerous structural traps, owing to the activity of growth faults and radial faults around salt domes and to the deformation near diapirs. Growth faults, resulting from sediment loading on unstable substrates, periodically develop. Intermittent movement along these growth faults has accommodated accumulation of enormous masses of sediments. Hydrocarbon traps occur in areas where these sediments have been tilted or deformed within anticlinal structures bounded by growth faults. Deformation of strata above the kilometer-thick Jurassic Louann salt layer has resulted in a contrast in types of structural traps. In the northern section of the Texas Gulf Coast, salt movement has been focused around piercement diapirs, resulting in numerous and complex traps associated with locally steeply dipping strata. Farther south, regionally aligned reservoirs in the Corpus Christi area are more commonly created by structural and stratigraphic traps along growth faults. This contrast in trap style is visible on a map of oil and gas well surface locations, which are clustered around salt domes in the Houston area and more spread out elsewhere.

Within the range of buoyancy of most hydrocarbons (more than oil, less than gas), CO_2 introduced for storage will most likely follow pathways similar to those of hydrocarbons and accumulate in similar traps. If the injected volume is larger than the capacity of the first encountered trap, CO_2 will spill and continue to flow upward until it reaches another trap, leaving behind a trail of CO_2 at residual saturation (traps are fully saturated with CO_2 with water at residual saturation) (Figure 1). Earlier we mapped traps on the basis of a contour map of the top of the Frio (Figure 2 and Nicot et *al.*, 2006). A significant number of individual traps have an area smaller than 5 square miles although some are very large covering tens of square miles. The associated capacity is, in most cases, less than 10 millions tons of CO_2.

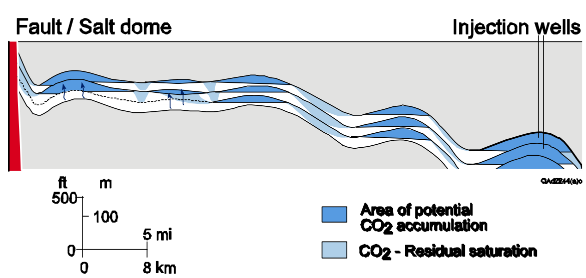


Figure 1. CO_2 travel path and trapping mechanisms

Traps are generally limited in volume by the limited lateral extend of the growth fault (Figure 2). Injecting more CO_2 into the trap will result into the spilling of an additional volume at the edges of the trap from which it will move to the next trap leading to a process that can be described as "fill and spill".

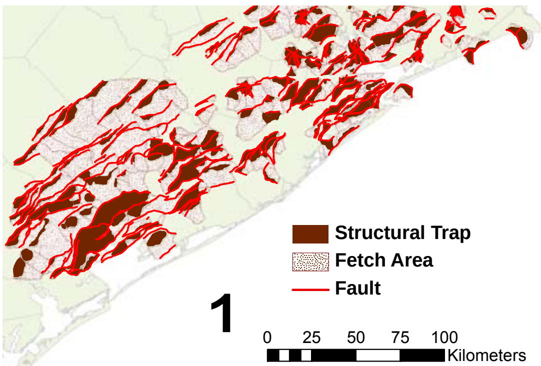


Figure 2. CO2 traps on top of the Frio. Areas not mapped eventually lead to a salt diapir.

WHY RELY ON CAPILLARY TRAPPING

Relying on capillary trapping will work well if the two other avenues for leakage, wells and faults, can be shown to impact the behavior of the storage site only minimally.

Approximately 140,000 known wells are in the Tertiary section of the Gulf Coast between Corpus Christi and Houston. About 30% are plugged and abandoned wells with plugging records available in electronic form from the Texas Railroad Commission (RRC). The remainder are either wells still in operation or wells with no records or records available only in microfilm or paper form. Well density can be extremely high around salt domes, hundreds or even thousands of wells per square kilometer (1 km^2 ~250 acres).

Following Warner et al. (1997), the RRC well dataset can be sorted into four classes: post-1983, 1983–1967, 1967–1935, and pre-1935, arranged in decreasing order of reliability relative to leakage. Warner et *al*. (1997) also stated that there is a high probability that post-1967 wells have been properly plugged. However, the insurance of a good plugging job does not guarantee the integrity of the well relative to CO_2. Cement plugs in well bores are always going to be a point of weakness in sequestration. Even wells abandoned at current standards cannot be guaranteed leak-free in the long term. The mitigating factor in the Gulf Coast area is that open wells may benefit from their natural tendency to heave and close (Clark et al., 2003). In any case, restricting the injection to a depth of 10,000 ft or lower will increase the likelihood of having a comprehensive list of all wells possibly impacted (Figure 3).

Growth faults are typically limited to the formation that they impact and generally do not extend to the surface.

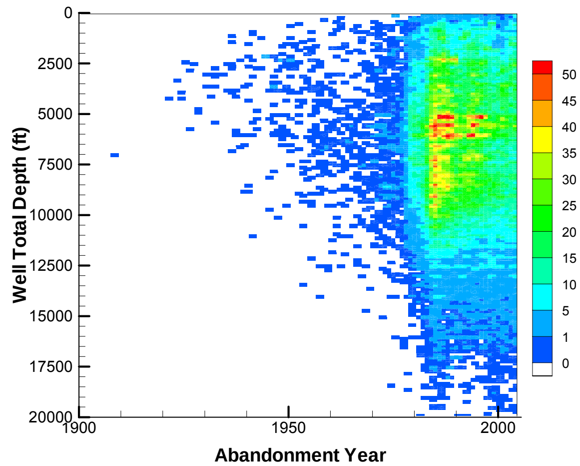


Figure 3. Well total depth distribution (Texas RRC districts 2, 3, and 4. Key is in number of fields / year / 100 ft)

IS CAPILLARY TRAPPING EFFICIENT?

Leakage mechanisms are in essence identical to a "fill-and-spill" operational method in which multiple individual traps are successively filled. It can thus be argued that no leakage of stored CO_2 as such will occur until the plume has reached the base of the usable quality water. Capillary trapping as a leakage control mechanism will be acceptable only if the contacted volume is large enough to absorb a significant mass of the leaking plume. The question of the migration mode, between the end-members of a wide diffuse spreading and of a localized fingering/channeling, remains open although all indicators point to a limited role for fingering. A scaling analysis suggests that the aspect ratio a of the plume is mainly function of the permeability ratio and of the dip angle θ:

$$a = \frac{z_0}{x_0} \sim \frac{k_z}{k_x} \cot \theta$$

Permeability ratios are relatively well known at the core level (Holtz, 2003) and represent an upper bound to the permeability ratio at the reservoir scale because fractures are not commonly described in Texas Gulf Coast reservoirs. Residual saturation in the Gulf Coast formations as a function of the porosity is also known (Holtz, 2005). Knowledge of (1) trap geometry and spatial arrangement, (2) permeability and porosity distributions and their empirical functional relationship with gas residual saturation, and (3) leaking plume shape will allow quantification of the capacity of Gulf Coast formations to absorb the "spill" part of plume migration. Preliminary results show that capillary trapping is very efficient in the short term in controlling CO_2 leakage to USDW.

ACKNOWLEDGMENT

The Gulf Coast Carbon Center, Bureau of Economic Geology acknowledges support of this research by industry partners and the John A. and Katherine G. Jackson School of Geosciences.

REFERENCES

Chadwick, R. A., P. Zweigel, U. Gregersen, G. A. Kirby, S. Holloway, and P. N. Johannessen. 2004. Geological reservoir characterization of a CO2 storage site: The Utsira Sand, Sleipner, Northern North Sea. *Energy* 29:1371-1381.

Clark, J. E., D. K. Bonura, P. W. Papadeas, and R. R. McGowen. 2003. Gulf Coast borehole closure test well near Orange, Texas. in *Proceedings of Second International Symposium on Underground Injection Science and Technology*, October 22-23, 2003. Lawrence Berkeley National Laboratory, Berkeley, CA.

Holtz, M. H., 2003, Pore-scale influences on saline aquifer CO2 sequestration (abs.): *American Association of Petroleum Geologists Annual Convention, Salt Lake City, UT*, May 11-14, v. 12, p. A79.

Holtz, M. H., 2005. *Reservoir characterization applying residual gas saturation modeling, example from the Starfak T1 reservoir, Middle Miocene Gulf of Mexico*. Master's Thesis, The University of Texas at Austin, 111 pp.

Nicot, J.-P., S. D. Hovorka, P. R. Knox, and T. Naing, 2006, Area of review: how large is large enough for carbon storage? in *Proceedings of the 2006 UIC Conference of the Groundwater Protection Council, Austin, Texas*, January 23-25, Abstract 17.

Warner, D. L., L. Koederitz, and R. C. Laudon, 1997. *Application of an area-of-review (AOR) concept to the East Texas Field and other selected Texas oilfields*: University of Missouri-Rolla, Final Report for U.S. Department of Energy Grant No DE-FG22-94MT-94002, 402p.

HYPERSPECTRAL GEOBOTANICAL REMOTE SENSING FOR CO2 STORAGE MONITORING

William L. Pickles, Wendy A. Cover

University of California
Lawrence Livermore National Laboratory and University of California Santa Cruz
7000 East Ave L644
Livermore CA 94550 USA
e-mail: pickles1@llnl.gov

ABSTRACT

We have developed an airborne remote sensing method for detection and wide area mapping of elevated soil CO2 concentrations that might be leaking up from an underground storage formation. The method uses high resolution hyperspectral imagery to detect and map the effects of elevated CO2 soil concentrations on the roots of the local plants. The method also detects subtle or hidden faulting systems which localize the CO2 pathways to the surface. Elevated CO2 soil concentrations deprive the plant root systems of oxygen which is essential for a healthy plant. Excessive soil CO2 concentrations are observed to significantly affect local plant health, and hence plant species distributions. It also directly affects animal ecologies particularly for burrowing animals. At higher soil CO2 concentration levels humans can be affected if they lie on the ground as they may do while camping or if they enter a building or a depression where CO2 escaping from the soil can collect. These effects were studied in a previous remote sensing research program at Mammoth Mountain CA USA , as part of the DOE geothermal resource exploration program. This earlier research showed that subtle hidden faults can be mapped using the spectral signatures of altered minerals and of plant species and health distributions. Mapping hidden faults is important because these highly localized pathways are the conduits for potentially significant CO2 leaks from deep underground formations.

The detection and discrimination methods we are developing uses advanced airborne reflected light hyperspectral imagery. The spatial resolutions are 1 to 3 meters and 128 band to 225 wavelength resolution in the visible and near infrared. We also are using the newly available "Quickbird" satellite imagery that has spatial resolutions of 0.6 meter for panchromatic images and 2.4 meters for multispectral). We have two commercial providers of the hyperspectral imagery acquisitions, so that eventually the ongoing surveillance of CO2 storage fields can be contracted for commercially. This research project is a collaboration between two University of California campuses, Lawrence Livermore National Laboratory (LLNL) and UC Santa Cruz (UCSC) and HyVista Corp in Sydney Australia. In this project we had a commercial provider acquire airborne hyperspectral visible and near infrared reflected light imagery of the Rangely CO enhanced oil recovery field and the and surrounding areas in August 2002. . The images were analyzed using several of the methods available in the suite of tools in the "ENVI" commercial hyperspectral image processing software to create highly detailed maps of soil types, plant coverages, plant health, local ecologies or habitats, water conditions, and manmade objects throughout the entire Rangely Oil field and surrounding areas. The results were verified during a field trip to Rangely CO in August 2003. These maps establish an environmental and ecological baseline against which any future CO2 leakage effects on the plants, plant habitats, soils and water conditions can be detected and verified. We have also seen signatures that may be subtle hidden faults. If confirmed these faults might provide pathways for upward CO2 migration if that occurred at any time during the future.

We have found an unexpected result, that is potentially very important to the task of monitoring for CO2 that has leaked to within the plant root depths near the surface. The spectral angle mapper technique contained in the ENVI program has picked out finely detailed mapping of areas with complicated shapes that are adjacent to each other . Some of these areas are found to occur across the entire Rangely oil field and into the surrounding areas. During the field trip in August 2003, these areas were determined to be characterized by having a specific and different narrow range of percentage admixtures of two or three plant types and soil types. They are habitats or localized ecologies. Any large amounts of CO2 reaching the root depth near the surface would begin to modify the shapes of the habitats. These habitat changes will be easy to detect by repeat imaging of the area. The modification of the habitat shapes and charateristics that would be caused by Increased soil CO2 concentartions is probably more detectable in our hyperspectral imaging method than detecting individual plant stress directly. The plants in these high desert regions are well adapted to the dry environment and do not necessarily appear healthy on the outside when they are actually quite healthy. They can appear as having desicated surfaces while they are alive and well and doing things like controlling there intra-plant spacing. This is a well known adaptive action taken by Creosote bushes for example. Research into

our these high desert habitats would respond to elevated CO_2 soil concentrations has not been reported in the literature. A research effort that will establish what CO_2 soil concentration levels produce observable changes in these habitat shapes is needed.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

ON LEAKAGE FROM GEOLOGIC STORAGE RESERVOIRS OF CO_2

Karsten Pruess

Lawrence Berkeley National Laboratory
Berkeley, CA 94720, U.S.A.
Email: K_Pruess@lbl.gov

INTRODUCTION

Large amounts of CO_2 would need to be injected underground to achieve a significant reduction of atmospheric emissions. The large areal extent expected for CO_2 plumes makes it likely that caprock imperfections will be encountered, such as fault zones or fractures, which may allow some CO_2 to escape from the primary storage reservoir. Leakage of CO_2 could also occur along wellbores.

Concerns with escape of CO_2 from a primary geologic storage reservoir include (1) acidification of groundwater resources, (2) asphyxiation hazard when leaking CO_2 is discharged at the land surface, (3) increase in atmospheric concentrations of CO_2, and (4) damage from a high-energy, eruptive discharge (if such discharge is physically possible). In order to gain public acceptance for geologic storage as a viable technology for reducing atmospheric emissions of CO_2, it is necessary to address these issues and demonstrate that CO_2 can be injected and stored safely in geologic formations.

MECHANISMS AND ISSUES FOR LOSS OF CO_2 FROM STORAGE

The nature of CO_2 leakage behavior will depend on properties of the geologic formations, primarily their permeability structure, and on the thermodynamic and transport properties of CO_2 as well as other fluids with which it may interact in the subsurface. At typical temperature and pressure conditions in the shallow crust (depth < 5 km), CO_2 is less dense than water, and therefore is buoyant in most subsurface environments. In geologic formations that are suitable for CO_2 storage, CO_2 would normally be contained beneath a caprock of low absolute permeability with "significant" gas entry pressure. Upward migration of CO_2 will occur whenever appropriate (sub-)vertical permeability is available, and/or when the capillary entry pressure of the caprock is exceeded.

It is obvious that leakage from geologic storage reservoirs for CO_2 must not exceed a "small" fraction of total inventory, in order not to defeat the main objective of geologic sequestration, namely, to keep greenhouse gases out of the atmosphere. A general consensus appears to be building in the technical community that storage losses should not exceed 0.1 % of inventory per year in order to be acceptable (Pacala, 2003; Hepple and Benson, 2003; Ha-Duong and Keith, 2003).

Leakage along pre-existing wells that may be improperly plugged, or whose cements may corrode, constitutes perhaps the most likely scenario for loss of CO_2 from storage. Celia and co-workers have developed a stochastic approach to estimate leakage risk in an environment where the number of wells is too large, and their locations and flow properties too uncertain, to permit mechanistic modeling (Celia et al., 2005; Nordbotten et al., 2004). Celia et al. conceptualize wellbore flow as Darcian, which will be satisfactory for wells that provide relatively "small" flow pathways, but is not applicable to flow behavior in open-hole sections. Flow in a few open holes could contribute more to total CO_2 leakage than a multitude of slightly leaky wellbores, and approaches are needed to quantify and mitigate associated risks.

After a discharge of CO_2 is initiated it may be subject to "self-enhancement," due to the smaller density and greater mobility (smaller viscosity) of CO_2. Self-enhancement may also occur from geochemically and geomechanically coupled processes, when migrating CO_2 dissolves caprock minerals and causes movement along faults, increasing their permeability.

NUMERICAL SIMULATIONS

Here we briefly summarize results of numerical simulation studies for leakage and discharge scenarios that have demonstrated self-enhancement. All discharge scenarios we have investigated so far have shown self-limiting features as well.

CO2 Migration along a Fault

Fig. 1 shows a schematic model of a fault zone, along with simulation results for CO_2 discharge through this fault. The fault initially contains water in a normal geothermal gradient of 30 ˚C/km with a land surface temperature of 15 ˚C, in hydrostatic equilibrium. CO_2 discharge is initiated by injecting CO_2 at an overpressure of approximately 10 bar in a portion of the fault at 710 m depth. The numerical simulation includes two- and three-phase flow of an aqueous phase and liquid and gaseous CO_2 phases in the fault, as well as conductive heat transfer with the wall rocks that are assumed impermeable (Pruess, 2005).

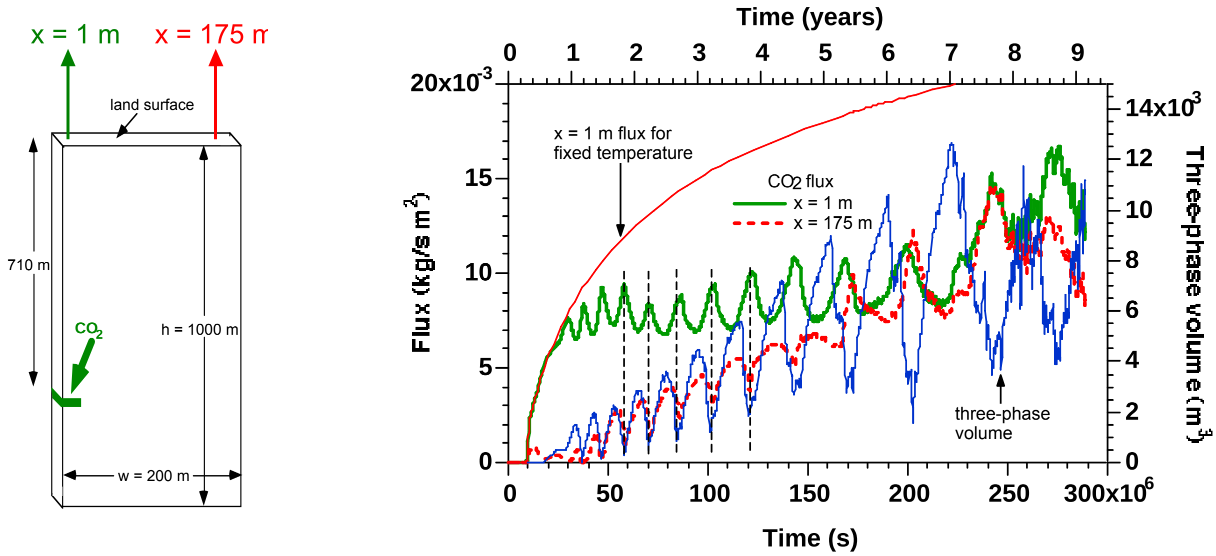


Figure 1. CO_2 leakage along a fault zone (from Pruess, 2005). A schematic model of a fault zone is shown on the left. The right panel gives temporal variation of CO_2 leakage fluxes at two different positions at the land surface. Total flow system volume with three-phase conditions is also shown.

We find strong cooling due to the Joule-Thomson effect as rising CO_2 expands (Katz and Lee, 1990). Additional temperature decline occurs when liquid CO_2 boils into gas. The simulations show persistent flow cycling with increasing and decreasing leakage rates after a period of initial growth. No non-monotonic behavior is observed when flow system temperatures are held constant at their initial values. The cyclic behavior is explained in terms of varying fluid phase composition, due to heat transfer limitations, giving rise to an interplay between self-enhancing and self-limiting features.

<u>Discharge of Water/CO_2 Mixture from a Well</u>

We present preliminary simulation results for the discharge of CO_2-laden water from a well. A wellbore of 20 cm diameter extending to 250 m depth is subjected to inflow of water with 3.5 % CO_2 by weight (Fig. 2), which is slightly below the CO_2 solubility limit for prevailing temperature and pressure conditions at 250 m depth. The well discharges to atmospheric conditions of (T, P) = (15 ˚C, 1.013 bar). As rising fluid encounters lower pressures, CO_2 exsolves and two-phase conditions develop. In order to model two-phase flow in the wellbore, we incorporated the "drift flux" model of Zuber and Findlay (1965) into our TOUGH2 simulator (Pruess, 2004). Fig. 2 shows the simulated discharge behavior for a constant aqueous phase injection rate of 0.2 kg/s at the base of the well. In our simulation the water initially in the well is CO_2-free, and discharge rate is constant for an initial time period, until CO_2 exsolution effects come into play. Subsequently the discharge goes through regular cyclic variations with a period of approximately 1600 s,

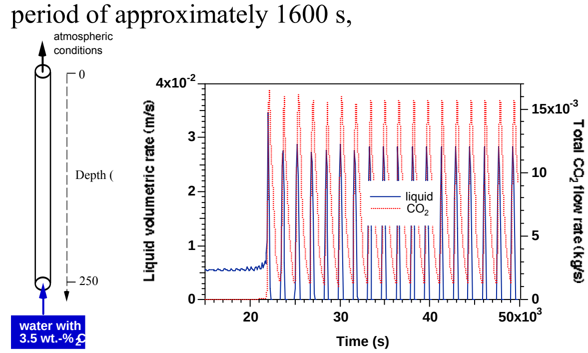


Figure 2. Discharge of a water-CO_2 mixture from a well. The wellbore model is shown on the left, while the right panel shows simulated discharge rates from the well.

i.e., the well behaves as a geyser. The geysering is due to an interplay between different flow velocities for gas and liquid, and associated changes in the average density of the two-phase mixture as CO_2 gas exsolves. Discharge is enhanced by CO_2 gas coming out of solution, but the preferential upflow of CO_2 also depletes the fluid of gas. This produces alternate cycles of self-enhancement and self-limitation.

In natural systems CO_2 venting usually occurs in a diffuse manner, but there are "cold" geysers that are driven by the energy released when high-pressure CO_2 expands, such as the Crystal Geyser in Utah (Shipton et al., 2004).

"PNEUMATIC" ERUPTION?

The mechanical energy of compression accumulated in a CO_2 storage reservoir is very large, equivalent to approximately 1 megatonne of TNT for storing the CO_2 generated by a coal fired plant of 1,000 MW electric power capacity over a period of 30 years (Pruess, 2006). If just a small fraction of this energy could be discharged in localized fashion over a short period of time, this would generate very serious consequences. In the volcanological literature, the possibility of a "pneumatic" eruption has been suggested (Giggenbach et al., 1991; Browne and Lawless, 2001; Benson et al., 2002). In contrast to the well known hydrothermal or "phreatic" eruptions, which are powered by the thermal energy stored in an accumulation of hot water, pneumatic eruptions are presumed to be driven solely by the mechanical energy stored in an accumulation of non-condensible gas, without substantial contributions from thermal energy. Pneumatic eruptions remain hypothetical at this time, but substantial CO_2 release events have been reported from CO_2-enhanced oil recovery projects, where CO_2 breakthrough occurred at production wells (Skinner, 2003). All of the CO_2 discharge scenarios we have investigated so far have shown self-limiting features that prevented an eruptive release.

Eruptive discharge of CO_2 from geologic storage, if it is at all physically possible, may be a "low probability–large consequence" type of event. Although such events may not qualify as "high risk" in formal risk analysis, experience has shown that the public is extremely reluctant to accept technologies that have a potential for accidents with large consequences, even if the probability of such accidents may be exceedingly low. A thorough evaluation of the possibility of high-energy discharges would be useful for demonstrating the technical feasibility of storing CO_2 in geologic reservoirs, and achieving public acceptance of the technology.

CONCLUDING REMARKS

CO_2 leakage from man-made storage reservoirs can occur through a variety of mechanisms. A credible analysis of associated risks must be based on a sound understanding of the underlying physical and chemical processes, and on an adequate characterization of potential leakage pathways. Naturally leaky CO_2 reservoirs provide ideal settings for studying the behavior of CO_2 in the subsurface over the large space and time scales required for CO_2 storage. Studies of natural CO_2 discharges in the Colorado Plateau region have documented extensive mineral deposition, yet many CO_2 vents and springs do not self-seal, and persist for thousands of years (Evans et al., 2004). These observations are consistent with recent findings from reactive chemical transport modeling (Gherardi et al., 2005).

Studies of the physics and chemistry of CO_2 leakage behavior to date have been quite limited. Popular news media have made reference to the lethal CO_2 bursts at Lakes Monoun (Sigurdsson et al., 1987) and Nyos (Tazieff, 1991) to suggest that geologic storage of CO_2 may be dangerous. The mechanisms that released major CO_2 accumulations at these lakes cannot be replicated in subsurface storage reservoirs; yet concerns raised by these eruptions may seriously impede public acceptance of geologic storage of CO_2. Focused research efforts are needed to provide a rational basis for assessing risks associated with geologic storage of CO_2, and to gain assurance that a high-energy, eruptive discharge is not possible.

ACKNOWLEDGMENT

The author acknowledges helpful discussions with John Apps and Jens Birkholzer. Thanks are due to Chin-Fu Tsang for a careful review of the manuscript and the suggestion of improvements. This work was supported by the Zero Emission Research and Technology project (ZERT) under Contract No. DE-AC02-05CH11231 with the U.S. Department of Energy.

REFERENCES

Benson, S., R. Hepple, J. Apps, C.-F. Tsang, and M. Lippmann, *Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geological Formations*, Report LBNL-51170, Lawrence Berkeley National Laboratory, Berkeley, Calif., 2002.

Browne, P.R.L. and J.V. Lawless. Characteristics of Hydrothermal Eruptions, with Examples from New Zealand and Elsewhere, *Earth-Scienc Rev.,* Vol. 52, pp. 299–331, 2001.

Celia, M., S. Bachu, J.M. Nordbotten, S.E. Gasda and H.K. Dahle. Quantitative Estimation of CO_2 Leakage from Geological Storage: Analytical Models, Numerical Models, and Data Needs, *Proceedings, 7th International Conference on Greenhouse Gas Control Technologies, 5–9 September 2004, Vancouver, Canada,* pp. 663–671, Elsevier Ltd., 2005.

Evans, J.P., J.Heath, Z.K. Shipton, P.T. Kolesar, B. Dockrill, A. Williams, D. Kirchner, T.E. Lachmar and S.T. Nelson. Natural Leaking CO_2-charged Systems as Analogs for Geologic Sequestration Sites, paper presented at Third Annual Conference on Carbon Capture and Sequestration, Alexandria, VA, May 2004.

Gherardi, F., T. Xu and K. Pruess. Coupled Hydrodynamic-Geochemical Modelling of CO_2-Driven Water-Rock Interactions into Sealed and Fractured Caprock Formations, paper presented at Geoitalia 2005, 5th Italian Forum of Earth Sciences, Spoleto/Italy, September 21-23, 2005.

Giggenbach, W.F., Y. Sano, and H.U. Schmincke. CO_2-rich Gases from Lakes Nyos and Monoun, Cameroon; Lacher See, Germany; Dieng, Indonesia, and Mt. Gambier, Australia – Variations on a Common Theme, *J. Volcanol. Geotherm. Res.,* Vol. 45, pp. 311–323, 1991.

Ha-Duong, M. and D.W. Keith. Carbon Storage: The Economic Efficiency of Storing CO_2 in Leaky Reservoirs, *Clean Techn Environ Policy,* Vol. 5, pp. 181–189, DOI 10.1007/s10098-003-0213-z, 2003.

Hepple, R.P. and S. Benson. Implications of Surface Seepage on the Effectiveness of Geologic Storage of Carbon Dioxide as a Climate Change Mitigation Strategy, in: J. Gale and Y. Kaya (eds.), *Greenhouse Gas Control Technologies,* pp. 261–266, Elsevier Science, Ltd., Amsterdam, The Netherlands, 2003.

Katz, D.L. and R.L. Lee. *Natural Gas Engineering,* McGraw-Hill Publ. Comp., New York, NY 1990.

Nordbotten, J.M., M.A. Celia and S. Bachu. Analytical Solutions for Leakage Rates through Abandoned Wells, *Water Resour. Res.,* Vol. 40, W04204, doi:10.1029/2003WR002997, 2004.

Pacala, S.W. Global Constraints on Reservoir Leakage, in: J. Gale and Y. Kaya (eds.), *Greenhouse Gas Control Technologies,* pp. 267–272, Elsevier Science, Ltd., Amsterdam, The Netherlands, 2003.

Pruess, K. The TOUGH Codes—A Family of Simulation Tools for Multiphase Flow and Transport Processes in Permeable Media, *Vadose Zone J.,* Vol. 3, pp. 738–746, 2004.

Pruess, K. Numerical Studies of Fluid Leakage from a Geologic Disposal Reservoir for CO_2 Show Self-Limiting Feedback between Fluid Flow and Heat Transfer, *Geophys. Res. Lett.,* Vol. 32, No. 14, L14404, doi:10.1029/2005GL023250, July 2005.

Pruess, K. On CO_2 Behavior in the Subsurface, Following Leakage from a Geologic Storage Reservoir, Lawrence Berkeley National Laboratory Report LBNL-59628, February 2006.

Shipton, Z.K., J.P. Evans, D. Kirschner, P.T. Kolesar, A.P. Williams and J. Heath. Analysis of CO2 Leakage through 'Low-permeability' Faults from Natural Reservoirs in the Colorado Plateau, East-central Utah, in: S.J. Baines and R.H. Worden (eds.), *Geological Storage of Carbon Dioxide,* Geological Society, London, Special Publications, Vol. 233, pp. 43–58, London, England, 2004.

Sigurdsson, H., J.D. Devine, F.M. Tchoua, T.S. Presser, M.K.W. Pringle, and W.C. Evans. Origin of the Lethal Gas Burst from Lake Monoun, Cameroon, *J. Volcanol. Geotherm. Res.,* Vol. 31, pp. 1–16, 1987.

Skinner, L. CO_2 Blowouts: An Emerging Problem, *World Oil,* Vol. 224, No., 1, 2003.

Tazieff, H. Mechanism of the Nyos Carbon Dioxide Disaster and of so-called Phreatic Steam Eruptions, *J. Volcanol. Geotherm. Res.,* Vol. 391, pp. 109–116, 1991.

Zuber, N. and J.A. Findlay. Average Volumetric Concentration in Two-Phase Flow Systems, *J. Heat Transfer, Trans. ASME,* Vol. 87, No. 4, pp. 453–468, 1965.

DEGRADATION OF WELLBORE CEMENT DUE TO CO_2 INJECTION-EFFECTS OF PRESSURE AND TEMPERATURE

Brian R. Strazisar and Barbara G. Kutchko

U.S. Department of Energy
National Energy Technology Laboratory
P.O. Box 10940
Pittsburgh, PA 15236-0940, USA
e-mail: brian.strazisar@netl.doe.gov

INTRODUCTION

Geologic carbon sequestration involves injection of large quantities of carbon dioxide (CO_2) into geologic formations such as depleted or active oil and gas reservoirs, unmineable coalseams, or deep saline aquifers. A significant issue with geologic sequestration is the verification of long term storage by identifying and monitoring "leaks and other deterioration of storage integrity over time."(US DOE, 2004) The majority of locations that are being considered for CO_2 injection are in areas that have a history of oil, natural gas, and/or coalbed methane production. This is due to value added opportunities such as enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) recovery. Also, since oil and gas reservoirs have stored these resources underground for millions of years, there is less uncertainty as to the possibility for permanent storage. There is also a greater knowledge base for saline aquifers that lie either above or below oil and gas reservoirs due to well logging and exploration activities. As a result of human activity, these formations are typically punctured by a significant number of wells, from both exploration and production. No matter how impermeable an overlying caprock is, the sealing integrity may be compromised by the drilling of wells. Well bores represent the most likely route for leakage of CO_2 from geologic carbon sequestration.

When production wells are completed, they are normally lined with steel casing. A low permeability cement is then set into the annular space surrounding the casing in order to prevent the flow of fluids along the annulus. Abandoned wells are typically sealed with cement plugs intended to block vertical migration of fluids. In both cases, the permeability and integrity of the cement will determine how effective it is in preventing leakage through the annulus surrounding a well's casing. Cement must be able to maintain its properties over lengthy exposure to reservoir conditions. In the case of carbon sequestration, the conditions include exposure to carbonated water at increased pressure and decreased pH.

In order to understand well cement integrity, several issues must be addressed through research. Dry CO_2 is a relatively inert gas that is not expected to degrade materials. However, when CO_2 is dissolved into the aqueous phase, carbonic acid is formed, leading to a significant lowering of pH. Calcium hydroxide ($Ca(OH)_2$) is a key component in hardened cement that buffers the pH of pore water, protecting the steel casing from corrosion. However, $Ca(OH)_2$ readily reacts with carbonic acid to form highly soluble calcium bicarbonate (Bruckdorfer, 1986):

$$Ca(OH)_{2\,(s)} + 2\,H_2CO_{3\,(aq)} \rightarrow Ca(HCO_3)_{2\,(aq)} + 2\,H_2O$$

This reaction is in essence a neutralization of acid in the aqueous phase by the $Ca(OH)_2$ dissolution. In addition, carbonic acid reacts with calcium silicate hydrate (C-S-H) which gives cement its structural properties including strength and low permeability, leaving behind an amorphous silica phase that is weaker and has a lower molar volume than the C-S-H. These reactions lead to a greater porosity and permeability in the cement, allowing further penetration of the attacking acid solution into the cement.

EXPERIMENTAL

In order to study the degradation of cement, a series of high-pressure, high-temperature experiments were conducted to expose the cement to CO_2 under sequestration conditions. The temperatures and pressures represent sequestration conditions at a depth of approximately 1300 m. The experiments were carried out in reactor vessels capable of reaching sequestration temperatures and pressures.

The cement was prepared using Class H mixed using a water-to-cement (w/c) ratio of 0.38. All cement samples were mixed according to API specifications (API, 1997). Cement samples were cast in the form of cylinders by placing the mix into cylindrical plastic molds, sealed and placed into 1% NaCl solution bath. The cement was removed from the molds after three days and placed back into the solution bath and was cured for a total of 28 days.
Following the 28 day cure, each cement sample was exposed to the same experimental sequestration conditions to evaluate the effect of CO_2 exposure. The cement was placed in the reactor vessels filled half full with a 1% NaCl solution bath. Each sample was only partially submerged in the solution so that exposure to both CO_2-saturatued brine and water-saturated CO_2 (headspace) could be studied. Both situations

are relevant to sequestration. The vessels were pressurized to 4400 psi with CO_2 and heated to a temperature of 50˚C.

The cylindrical cement samples were removed from the reactor vessels after 9 days and cut using a standard isomet rock saw with diamond blade into slices approximately 1 cm thick. In order to preserve sample integrity, a hydrocarbon lubricating fluid was used in place of water at all times in order to avoid any dissolution or washing away of water-soluble phases present in the cement. The cement was polished according to standard polishing techniques.

Scanning electron microscopy (SEM) coupled with energy dispersive spectroscopy (EDS) was used in order to determine how the cement responded to the continuous exposure to CO_2 rich fluid under simulated injection conditions. The analysis of the cement samples included the depth of penetration as well as changes in the cement chemistry and structure (chemical and physical changes to the cement).

RESULTS AND DISCUSSION

A sample SEM image of an exposed cement sample is shown in Figure 1. All experiments showed a similar general trend with an inner "ring" of decreased porosity followed by a region of increased porosity and dramatically reduced strength. The inner ring is likely due to acid attack of the cement followed by precipitation of calcium carbonate. Subsequent attack leads to bicarbonate formation and dissolution in the outer ring. Unhydrated cement grains which appear bright in the unreacted portion of the cement (left side of Figure 1) have turned dark in the outer "ring" due to decalcification leaving amorphous silica.

Experiments showed a significant difference in degradation dynamics based on curing conditions as shown in Table 1. Sample 2 (high p and T cure) had the smallest degree of penetration of the reaction front, and also showed the most symmetric attack. This is likely due to the fact that $Ca(OH)_2$ crystals are smaller and therefore more homogeneously distributed throughout the solid matrix of the cement. This is evidently an effect of both pressure and temperature, as samples 3 and 4 were both more resistant to attack than sample 1, but both were intermediate between samples 1 and 2 in depth of penetration.

Comparison was also made between the submerged and non-submerged portions of the CO_2 samples over longer time periods. Although initially, the depth of penetration was similar in both top and bottom portions of the samples, the portion of samples in the CO_2 phase had highly asymmetrical reaction fronts. (Figure 2) In addition, this portion showed very little

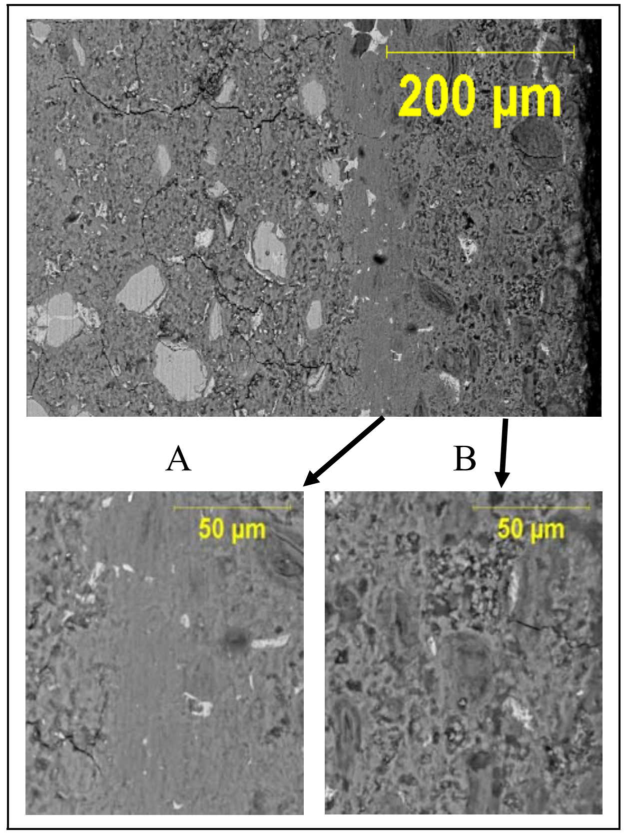


Figure 1. Sample SEM images of degraded cement sample. Top image shows overview of reaction zones including A) low porosity region due to carbonation and B) high porosity region due to bicarbonation and dissolution.

Table 1. Extent of Acid Attack on Cement Samples after Nine Days Exposure in CO_2-Saturated Aqueous Phase Related to Curing Conditions

Sample #	Temperature	Pressure	Depth of attack
1	ambient	ambient	590 µm
2	50˚C	4400 psi	220 µm
3	ambient	4400 psi	445 µm
4	50˚C	ambient	440 µm

further progression of the reaction fronts after the initial nine-day experiment, while the cement in the aqueous phase showed further penetration. Long term experiments are still a work in progress and will be described in more detail in future communications.

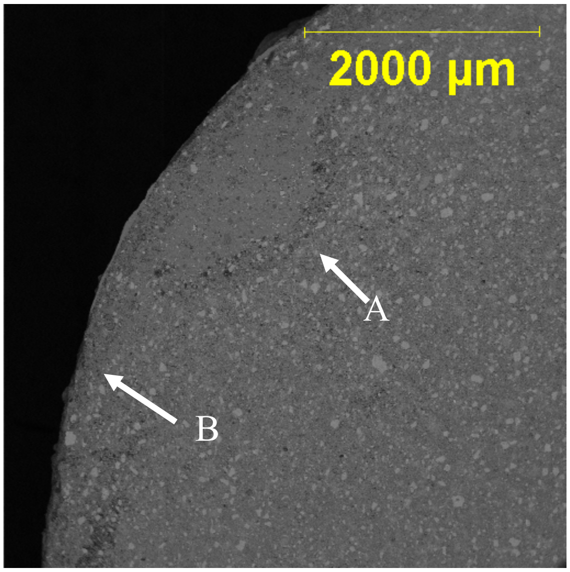


Figure 2. SEM image of cement from top portion of sample (exposed to water-saturated CO_2 in headspace). The highly asymmetrical reaction front penetrates deeply at "A" and is very shallow at "B".

REFERENCES

API. *API Recommended Practice 10B.* Washington DC.: American Petroleum Institute, 1997.

Bruckdorfer R. A., "Carbon Dioxide Corrosion in Oilwell Cements" *Report No. 15176* Society of Petroleum Engineers, Richardson, TX, 1986.

U.S. Department of Energy, "Carbon Sequestration Technology Roadmap and Program Plan - 2004" National Energy Technology Laboratory, Pittsburgh, PA and Morgantown, WV, 2004.

NEAR-SURFACE MONITORING OF GEOLOGIC CARBON SEQUESTRATION

Brian R. Strazisar, Arthur W. Wells, J. Rodney Diehl

U.S. Department of Energy
National Energy Technology Laboratory
P.O. Box 10940
Pittsburgh, PA 15236-0940, USA
e-mail: brian.strazisar@netl.doe.gov

INTRODUCTION

In order to evaluate the success or failure of a CO_2 storage operation, it is important to monitor injection sites to detect CO_2 released at the surface. The U.S. Department of Energy has placed a high priority on the development of inexpensive, effective methods to measure, monitor, and verify long term sequestration of CO_2 in geological sinks. It is expected that monitoring by well established methods will be required for future full-scale geologic sequestration activities. Monitoring the leakage of CO_2 is a challenging task, due to the small expected concentrations above a leaking reservoir as well as the relatively large background of CO_2 present in the atmosphere. Another complication is the fact that CO_2 continually diffuses from the soil into the atmosphere due to plant and microbial respiration. Any leak of CO_2 from a reservoir would have to be differentiated from these other processes.

EXPERIMENTAL

The measurement, monitoring and verification (MMV) work at NETL, is collectively referred to as SEQURE technologies, and has as its goal, providing a set of complementary surface and near-surface monitoring techniques that can reliably evaluate leakage from geologic sequestration sites. Field projects include, geophysical surveys of the site, tracer additions to the injected CO_2 with soil-gas monitoring, at the part-per-quadrillion level, for the presence of tracers, monitoring for changes in shallow water aquifer chemistry characteristic of CO_2 infusion, and direct CO_2 flux monitoring at the surface. Pilot sequestration test sites have included EOR and saline aquifer sites. In addition to field work, we are also investigating the modeling, and testing of tracer/CO_2 interactions with reservoir and overlying strata, and with well-bore cements to evaluate long term leakage potential, and transport mechanisms. We have benefited from the long term participation from Professor Thomas Wilson of WVU in geophysical surveys, and of Professor Henry Rauch of WVU in shallow water aquifer chemistry studies at field sites.

Evaluation of surface and subsurface geophysics, especially the location of fault zones and other features with near-surface expression, is conducted prior to developing a monitoring protocol. This is accomplished by combining remote sensing with ground based measurements. This work employs analysis of remote sensing images of the earth's surface taken at several different wavelengths: these views include optical, near infrared, thermal infrared and radar regions, along with aerial photography. Imagery is examined for the presence of anomalous linear features (lineaments) that might be associated with vertical fracture zones. Ground-truthing of suspected fracture zones is undertaken using terrain conductivity, and ground penetrating radar. Additional information can be obtained by extending VSP seismic studies and well logging data to the surface.

The matrix design for the monitoring grid is determined from the geophysical surveys and remote sensing work described above. Perfluorocyclohydrocarbon tracer compounds are injected into the CO_2 as 12 hour slugs of 500 mls from a syringe pump at the well-head. The soil-gas monitoring holes are made of steel pipe, detachable-head penetrometers (Figure 1) that are driven into the soil to a depth of one meter. Sorbent packets (called CATs) are used to collect the tracers and are placed into the monitoring holes as a series of sample sets, before, during and after CO_2 injection. Monitoring is designed to look for leakage at the injection well, and at other active and capped wells as well as other potential sources of leakage the CO_2 plume is expected to reach. The area in the vicinity of the injection well is monitored for low levels of microseepage from the sequestration reservoir.

Shallow soil gas samples are also taken at each location and analysed for CO_2 and methane. Methane has been closely associated with leakage of CO_2 from deep sources. In particular, sequestration in coal-seams is known to liberate methane gas, a phenomenon that could lead to value added enhanced coalbed methane production (ECBM). Its measurement is useful in any location where fossil fuel resources are present (Klusman, 2003). Previous studies have shown that methane measurements in soil gas can be useful for identifying CO_2 leakage due to its very low background. Also important to identifying the source of CO_2 in soil gas is the ratio of stable carbon isotopes. The isotope ratio $\delta^{13}C$ can be used to distinguish leaking CO_2 from atmospheric contamination as well as the biological background.

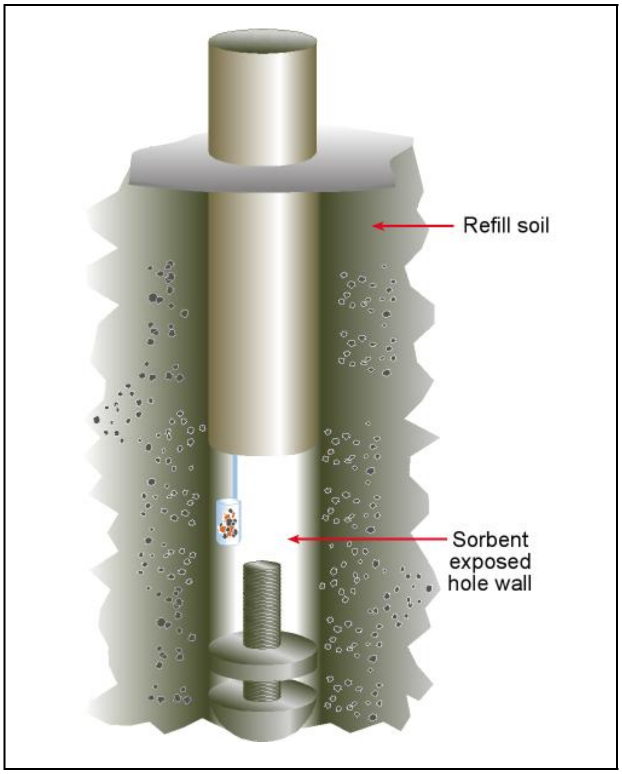


Figure 1: Schematic of detachable head penetrometer used for long term sampling of soil gases for perfluorocarbon tracers

Soil gas CO_2 fluxes are measured directly using an accumulation chamber equipped with an infrared spectrometer. The chamber is sealed to the soil surface, and the rate of increase in CO_2 concentration is measured in real time. In most cases there is a positive flux for CO_2 at the soil surface due to baseline biological activity. Leakage from a deep reservoir would be detected as an increase in flux above the background levels, and can be verified by supporting data from the other techniques. In particular, a shift in stable isotope ratio from that of the biological background toward that of the deep source is an indication of leakage to the surface.

Previous studies of soil gas have also shown that CO_2 concentration is often correlated with radon concentration in the soil. This is because CO_2 may pick up radon as it seeps to the surface, serving as a carrier gas. Due to its radioactivity and relatively low background, radon is more easily detected than CO_2. Therefore, it is also useful to detect radon in soil gas as another indicator of CO_2 leakage.

The chemistry of surface well water is monitored for characteristic changes resulting from the leakage of CO_2 or methane during injection. Both field and laboratory analytical procedures are implemented. Other measurements include well headspace sampling and analysis, water level changes, and monitoring for tracers in well water samples.

FIELD RESULTS

The technologies discussed here have been applied in to two field sequestration pilot projects over the last few years. At the West Pearl Queen pilot injection, the perfluorocarbon tracer technology and geophysical analysis were employed. The results are summarized in Figure 2. A plume of tracers was detected in the northwest direction from the injection site corresponding to less than 0.01% of the total CO_2 injected. The plume followed the general directional trend of faulting in the area and was nearly opposite of the prevailing wind current. This indicates that contamination of soil gas with tracer from the surface was unlikely.

At the Frio pilot site, the full suite of NETL's SEQURE technologies was employed. This site proved to be challenging due to the warm, moist climate in Eastern Texas, as well as the high water table at the site. Biological activity was a greater source of background CO_2 here than at more arid locations. CO_2 fluxes were greater by over an order of magnitude than previous measurements in Colorado and Wyoming (Klusman, 2003; 2005). Soil gas sampling was often impossible due to soil saturation. Although CO_2 in soil gas was quite high, the isotope ratios indicated that biological sources dominated. However, tracer studies were successful in detecting a subtle plume of CO_2 at the Frio site.

Future projects will involve applying SEQURE technologies to future field projects including a larger scale sequestration pilots, and a near-surface monitoring experiment to measure well defined quantities of CO_2 flow to the surface.

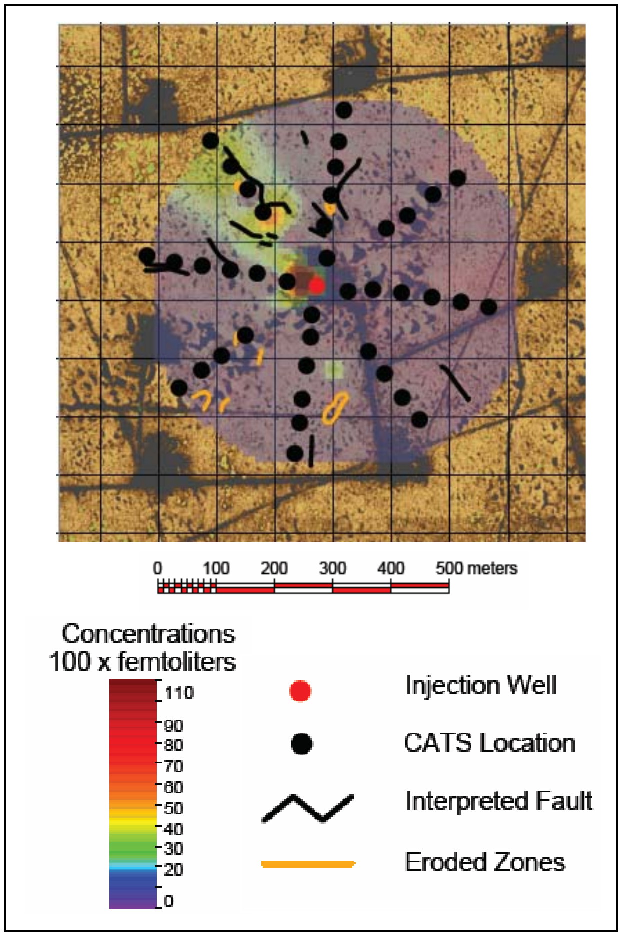


Figure 2. Results of tracer staudies at the West Pearl Queen pilot sequestration project. Tracers were detected in soil gas to the northwest of injection following the direction of faulting.

REFERENCES

Ball, T. K., D. G. Cameron, T. B. Colman, P. D. Roberts, Behavior Of Radon In The Geological Environment - A Review, *Quarterly Journal of Engineering Geology 24*, 169-182, 1991.

Klusman, R. W., Rate measurements and detection of gas microseepage to the atmosphere from an enhance oil recovery/sequestration project, Rangely, Colorado, USA, *Applied Geochemistry, 18,* 1825-1838, 2003.

Klusman, R.W., Baseline studies of surface gas exchange and soil-gas composition in preparation for CO2 sequestration research: Teapot Dome, Wyoming, *AAPG Bulletin, 89*, 981-1003, 2005.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

IMPORTANCE OF MINERALOGICAL DATA FOR GROUNDWATER QUALITY AFFECTED BY CO_2 LEAKAGE FROM STORAGE SITES

Tianfu Xu

Earth Sciences Division
Lawrence Berkeley National Laboratory
Berkeley, California 94506, USA
e-mail: Tianfu_Xu@lbl.gov

INTRODUCTION

Recently, geological storage of CO_2 has been extensively investigated. The impact of leakage from CO_2 storage reservoirs on groundwater quality is one of the concerns. Dissolution of CO_2 in groundwater results in a decrease in pH. Such acidic condition can affect the dissolution and sorption mechanisms of many minerals (Jaffe and Wang, 2004). Some heavy-metal-bearing minerals dissolve under acidic conditions. For example, galena (PbS) can dissolve and increase significantly Pb concentrations and diminish groundwater quality. If calcite is present in the rock, it can buffer the pH and decrease galena dissolution. Therefore, mineralogical composition and distribution in caprock, overlying aquifers, and along the leakage paths are important data that should be obtained from site characterization. Insight into which minerals and compounds are most important for groundwater quality can be obtained from reactive geochemical transport simulations. Here we present results of simulations using the code TOUGHREACT, whose physical and chemical process capabilities have been discussed by Xu et al. (2006). The simulator can be applied to one-, two-, or three-dimensional porous and fractured media with physical and chemical heterogeneity, and can accommodate any number of chemical species present in liquid, gas and solid phases.

PROBLEM SETUP

A 1-D system of 100 m length was used for studying water quality evolution along the flow path. The system was divided into 50 uniform grid blocks. We started from a Gulf Coast Frio sandstone, and with the mineralogical composition given in Table 1. Calcite and anhydrite are assumed to react at equilibrium. Other mineral reactions proceed under kinetic conditions. A general kinetic rate law accounting for multiple mechanisms was used. The boundary can be on the storage reservoir or on the leakage path. A separate CO_2 phase could exist in the CO_2 source zone. For purpose of water quality studies, we assumed CO_2 (a partial pressure of 100 bar), H_2S (1 bar) and SO_2 (10^{-4} bar) dissolve into 1 M NaCl brine. The resulting water with a pH of about 3, a dissolved inorganic carbon concentration of 1.54 mol/kg, and a dissolved sulfur of 0.15 mol/kg, was injected into the system. The water chemistry is assumed unchanged with time. A total of five simulations were performed using different combinations of pore velocity and mineralogical composition. Two pore water velocities were used, the higher case 10 and the lower case 0.1 m/yr. The first simulation used the higher velocity and mineral composition of Table 1 (base-case). Simulations 2 and 3 used a zero calcite abundance and double the calcite at Table 1. Simulation 4 used a lower velocity of 0.1 m/yr. Simulation 5 assumed Pb and Zn bearing minerals, galena and sphalerite, present in the rock with 1% volume fraction each. Changes in mineral abundances of calcite, galena and sphalerite are adjusted with abundance of quartz. An injected CO_2 stream often may contain other constituents such as NO_x and mercury. The rock adsorption capabilities on the flow path are important for the heavy-metal transport. These are beyond of the scope of this paper.

Table 1. List of Initial Mineral Volume Fractions and Possible Secondary Mineral Phases (Gulf Coast Frio Sandstone) Used for Reactive Transport Simulations

Mineral	Vol.% Of solid	A (cm^2/g)
Primary:		
Quartz	57.888	9.8
Kaolinite	2.015	151.6
Calcite	1.929	
Illite	0.954	151.6
Oligoclase	19.795	9.8
K-feldspar	8.179	9.8
Na-smectite	3.897	151.6
Chlorite	4.556	9.8
Hematite	0.497	12.9
Secondary:		
Anhydrite		
Magnesite		9.8
Dolomite		9.8
Low-albite		9.8
Siderite		9.8
Ankerite		9.8
Dawsonite		9.8
Ca-smectite		151.6
Alunite		9.8
Pyrite		12.9

RESULTS

Dissolution of calcite makes the pH increase from 3 to about 5 (Figure 1). The calcite dissolution is typically quite rapid, assumed at equilibrium, relative to the time frame being modeled. Therefore, a step increase in pH is observed. After 100 years, the front of calcite dissolution moves 40 m. After 240 years, calcite dissolves completely and a steady-state pH and concentration profile is formed, which is buffered by other mineral reactions. pH increases from 3 to about 3.8 at 100 m distance. A zero calcite abundance results in a pH profile similar to the curve at 300 yr. The double calcite simulation cause the dissolution and pH front slow by a factor of 2.

Results for a lower pore velocity of 0.1 m/yr, are shown in Figure 2. After 24,000 years, a steady state buffered by other mineral reactions is formed. pH is higher than the base case (4.4 over 3.8 at the outlet).

Galena and sphalerite dissolve in lower pH regions (Figure 3). Consequently, Pb concentration increases to about 4×10^{-6} mol/l (much higher than the action level of 7.25×10^{-8} mol/l reported by Wang and Jaffe (2004)), and Zn concentration increases to about 3×10^{-4} mol/l). Galena dissolution essentially occurs within 20 m of the CO_2 source. The simulation suggests that galena dissolution will not be a problem at distance greater than 20 m from the injection point. Therefore, data on mineral distribution along the flow path is important in addition to the mineral composition.

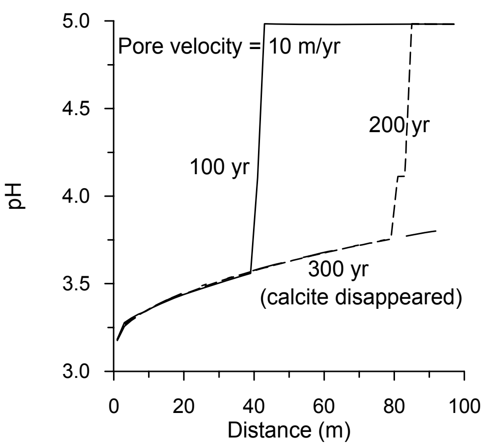


Figure 1. pH distribution at three different times for a pore velocity of 10 m/yr.

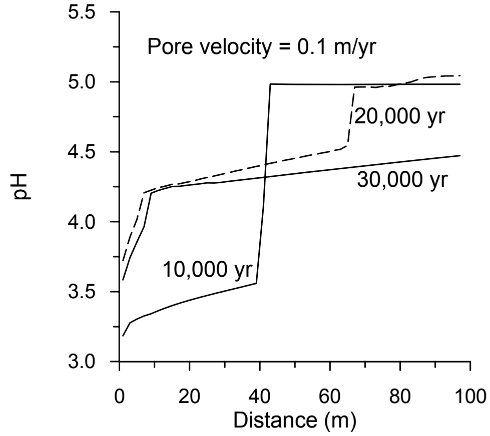


Figure 2. pH distribution at three different times for a lower pore velocity of 0.1 m/yr.

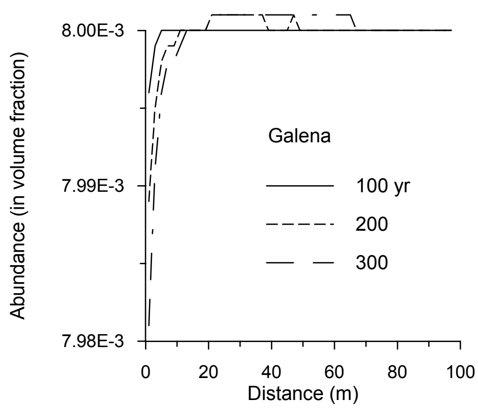


Figure 3. Abundance of galena (in volume fraction) at three different times for a pore velocity of 10 m/yr.

CONCLUSIONS

Mineralogical composition and distribution in the CO_2 leakage pathway and in overlying aquifers are important data for water quality evolution, and therefore should be an important part of CO_2 site characterization. If carbonate minerals such as calcite are present along the leakage pathway, they can buffer the pH to about 5. Other minerals can also buffer the pH but to lesser degree. Acidic conditions affect significantly the dissolution and sorption mechanisms of many minerals. For example, if galena is present in the low pH regions its dissolution causes Pb concentration to increase to about 4×10^{-6} mol/l, which is much higher than the action level of 7.25×10^{-8} mol/l (Wang and Jaffe, 2004).

ACKNOWLEDGMENT

We thank Curt Oldenburg and Guoxiang Zhang for reviews of the manuscript. This work was supported (1) partly by the U.S. Environmental Protection Agency, Office of Water and Office of Air and Radiation under an Interagency Agreement with the U.S. Department of Energy at the Lawrence Berkeley National Laboratory, and (2) partly by the Zero Emission Research and Technology project (ZERT), through Contract number DE-AC02-05CH11231.

REFERENCES

Wang, S., and P.R Jaffe, Dissolution of a mineral phase in potable aquifers due to CO2 releases from deep formations: effect of dissolution kinetics, Energy Conversion and Management, v. 45, 2833-2848, 2004.

Xu, T., E.L. Sonnenthal, N. Spycher, and K. Pruess, TOUGHREACT: A simulation program for non-isothermal multiphase reactive geochemical transport in variably saturated geologic media, Computer & Geoscience, v 32/2, 145-165, 2006.

FUNDAMENTAL PROCESSES AND TECHNICAL ISSUES RELATED TO SITE CHARACTERIZATION

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

EFFECTS OF IN-SITU CONDITIONS ON RELATIVE PERMEABILITY CHARACTERISTICS OF CO_2-BRINE SYSTEMS

Stefan Bachu[1] and Brant Bennion[2]

[1]Alberta Energy and Utilities Board
4999-98th Avenue
Edmonton, AB, T6B 2X3, Canada
e-mail: Stefan.Bachu@gov.ab.ca

[2]Hycal Energy Laboratories Ltd.
1338 A-36th Avenue NE
Calgary, AB, T2E 6T6, Canada
e-mail: brantb@hycal.com

INTRODUCTION

Carbon dioxide capture and storage (CCS) in deep underground formations is an emerging technology that is increasingly being considered for reducing greenhouse gas emissions to the atmosphere. Carbon dioxide geological storage is likely to occur first in depleted or abandoned oil and gas reservoirs; however, this will likely be inadequate on a global basis because hydrocarbon reservoirs are not present in many major CO_2 producing areas, they may have limited volumetric capacity, or may not be available until depletion of the existing hydrocarbon reserves. Deep saline aquifers provide a very large capacity for CO_2 storage that is immediately accessible, and, unlike oil and gas reservoirs or coal beds, they are found in all sedimentary basins. Proper understanding of the displacement character of CO_2-brine systems at in-situ conditions is essential in ascertaining CO_2 injectivity, migration and trapping in the pore space as a residual gas, and in assessing the suitability and safety of prospective CO_2 storage sites.

To date, no data have been published about the relative permeability and other displacement characteristics of CO_2-brine systems, which led the authors to commence a program of measuring these characteristics for sandstone, carbonate and shale formations in the Wabamun Lake area of central Alberta in western Canada, where four major coal-fired power plants produce more than 32 $MtCO_2$/year. The formations selected for testing are in general representative of the in-situ temperature, pressure, salinity, porosity and intercrystalline rock characteristics of deep saline aquifers in compacted on-shore North American sedimentary basins and elsewhere around the world. Descriptions of the equipment and procedures used to conduct the high-pressure air-mercury capillary pressure, interfacial tension (IFT) and relative permeability measurements at reservoir conditions were presented previously or will be presented at upcoming SPE meetings in a series of three related papers (Bennion and Bachu, 2005, 2006 a & b), together with detailed results that can be used in numerical simulations of CO_2 injection and storage processes both at this specific location and for similar operations planned elsewhere and around the world. Similarly, the geological setting and location of the wells with core samples used for measurements were presented in the first paper of the series. This paper presents rather a synthesis and interpretation of the results, pointing out to observed trends and to needs for future testing.

MAIN RESULTS

Ten sets of rock samples from three sandstone, one shale and three carbonate formations were analyzed in total. Seven samples (one from each formation) were analyzed at the respective in situ conditions of pressure, temperature and salinity of formation water. The other three samples (a sandstone and two carbonates) were analyzed at the same in-situ conditions as the first sample from the corresponding formation, to ascertain the effect of rock properties. For one sample, IFT and relative permeability measurements were performed also for a) the same salinity and lower pressure and temperature, and b) for freshwater at the same pressure and temperature, to ascertain the effect of these parameters on the displacement characteristics of CO_2-brine systems. Drainage relative-permeability measurements were performed on all samples and for the conditions described previously, but imbibition measurements were performed only for three of the systems: a sandstone, a shale and a carbonate. Thus, nine different IFT measurements, twelve drainage and three imbibition relative-permeability measurements were performed. Tables 1 and 2 present summaries of the in-situ conditions and IFT and relative permeability measurements, with the data listed stratigraphically in descending order.

The preliminary results of these measurements indicate the following.

1. The permeability to CO_2 at irreducible water saturation is approximately one seventh of that measured for brine at conditions of 100% brine satura-

tion (solid line in Figure 1). One of the cases of very low relative permeability to CO_2 at irreducible water saturation corresponds to gaseous CO_2 at low pressure and temperature. The second case is for a heterogeneous Cooking Lake Fm. carbonate sample which contains a significant amount of large vugular porosity that the authors feel has contributed to macroscopic channeling effects. This probably led to bypassing of a portion of the pore system, resulting in more extensive multiphase flow interference and a lower resulting endpoint relative permeability to CO_2. This appears to be a singular characteristic of the particular geometry of the pore system in this sample and is not apparent in the other more uniform and intergranular-dominated pore systems tested in the other nine samples. If these two samples are excluded, then the permeability to supercritical CO_2 at irreducible water saturation is about one fifth of that measured for brine (dashed line in Figure 1).

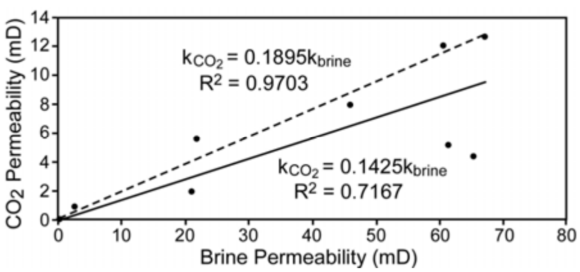


Figure 1. Relation between maximum permeability to CO_2 and permeability to brine at 100% saturation for various rock samples at in-situ conditions from the Wabamun Lake area, Alberta, Canada.

2. Irreducible brine saturation S_{gir} is in the order of 0.2-0.6.
3. Pore distribution and size affect absolute permeability, the shape and values of capillary pressure curves, and the characteristics and shape of relative-permeability curves.
4. The CO_2-brine IFT depends strongly on pressure, less so on temperature, and only slightly on brine salinity. IFT was found to decrease with increasing pressure, with increases in temperature and salinity having opposite effects on IFT; the effects of temperature and salinity on the IFT are likely due to CO_2 solubility and phase effects.

To confirm the observed trends of variation in IFT with pressure, temperature and salinity, a series of additional IFT measurements for CO_2-brine systems were performed for variable pressures at 41ºC and 75ºC that match the in-situ temperatures for some of the previous measurements. These measurements clearly show an asymptotic decrease in IFT with increasing pressure, and a significant increase in IFT with increasing temperature (Figure 2).

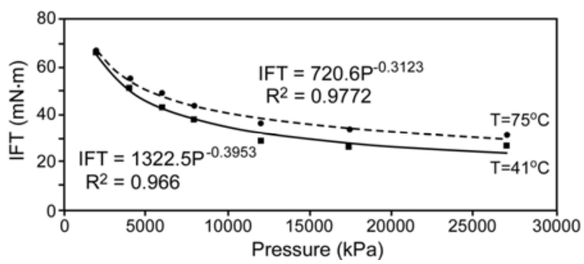


Figure 2. Variation with pressure of the interfacial tension between CO_2 and equilibrium brine for two different temperatures characteristic of the sedimentary column in the Wabamun Lake area, Alberta, Canada.

Table 1: In situ characteristics of rock samples from the Wabamun Lake area, Alberta basin, Canada.

Rock Sample & Formation	Lithology	Depth (m)	Pressure (kPa)	Temp (ºC)	Salinity (ppm)	Median Pore Size (microns)	Porosity (%)
Viking I	sandstone	1240	8,610	35	28,286	3.760	12.5
Viking II	sandstone	1344	8,610	35	28,286	10.763	19.8
Ellerslie	sandstone	1462	10,850	40	97,217	0.277	12.6
Wabamun I	carbonate	1355	11,920	41	144,304	8.760	14.8
Wabamun II	carbonate	1603	11,920	41	144,304	0.645	7.9
Calmar	shale	1566	12,250	43	129,688	0.006	3.9
Nisku I	carbonate	2050	17,400	56	136,817	0.066	9.7
Nisku II	carbonate	1953	17,400	56	136,817	4.327	10.4
Cooking Lake	carbonate	1893	15,400	55	233,417	15.860	9.9
Basal Cambrian	sandstone	2734	27,000	75	248,000	0.919	11.7

Table 2: Displacement characteristics for CO_2-brine systems at in situ conditions for rock samples from formations in the Wabamun Lake area, Alberta basin, Canada.

Rock Sample & Formation	IFT (mN·m)	K_{Brine} (mD)	$K_{r\,CO2}$	$S_{b\text{-}irr}$
Viking I	32.12	2.700	0.3319	0.558
Viking II	32.12	21.720	0.2638	0.423
Ellerslie	32.45	0.376	0.1156	0.659
Wabamun I	29.53	0.018	0.5289	0.595
Wabamun II	29,53	66.980	0.1883	0.569
Wabamun II, low T&P	49.24	61.160	0.0860	0.682
Wabamun II, S=0	28.89	60.640	0.1993	0.552
Calmar	27.60	0.00000294	0.1875	0.638
Nisku I	34.56	45.920	0.1768	0.330
Nisku II	34.56	21.020	0.0999	0.492
Cooking Lake	35.74	65.300	0.0685	0.476
Basal Cambrian	27.01	0.081	0.5446	0.294

CONCLUSIONS

The displacement of formation water by injected CO_2, the migration of CO_2 within the sedimentary structure, and the storage of CO_2 in the pore space at irreducible saturation depend on the displacement characteristics of CO_2-brine systems at in-situ conditions. Pore size and distribution affect absolute permeability and capillary pressure to CO_2, while interfacial tension between CO_2 and formation water decreases with increasing pressure and increases with increasing temperature and formation water salinity. Preliminary results on a limited data sample suggest that relative permeability to CO_2 at maximum saturation is approximately one seventh of the absolute permeability for brine, while the irreducible water saturation is in the order of 0.2-0.6.

The results suggest that, from a CO_2-storage capacity perspective, in general, deeper, higher pressure formations which have a more uniform porosity character provide more storage capacity for CO_2 based on the maximum obtainable saturation and effective CO_2 maximum relative permeability.

REFERENCES

Bennion, B., and S. Bachu, Relative permeability characteristics for CO_2 displacing water in a variety of potential sequestration zones in the Western Canada Sedimentary Basin, *Paper SPE 95547*, 15 p., presented at the 2005 SPE Technical Conference and Exhibition, Dallas, TX, October 9-12, 2005.

Bennion, B., and S. Bachu, The impact of interfacial tension and pore size distribution/capillary pressure character on CO_2 relative permeability at reservoir conditions in CO_2-brine systems, *Paper SPE 99325*, 10 p., to be presented at the SPE/DOE Fifteenth Symposium on Improved Oil Recovery, Tulsa, OK, USA, April 22-26, 2006a.

Bennion, B., and S. Bachu, Supercritical CO_2 and H_2S – brine drainage and imbibition relative permeability relationships for intercrystalline sandstone and carbonate formations, *Paper SPE 99326*, 13 p., to be presented at the SPE Europec/EAGE Annual Conference and Exhibition, Vienna, Austria, June 12–15, 2006b.

THERMO-KINETIC MODELING OF THE EVOLUTION OF THE CO_2-RICH WEYBURN BRINES AT THE RESERVOIR INFERRED CONDITIONS (P, T, WATER-GAS CHEMISTRY): FIRST RESULTS OF RESULTS OF A NEW APPROACH.

B. Cantucci[1,2], G. Montegrossi[3], O. Vaselli[1,3], L. Pizzino[2], F. Quattrocchi[2], N. Voltattorni[2]

[1]Dept. Earth Science
Univ. of Florence
Via La Pira 4, Florence, 50121, Italy

[2]INGV
Fluid Geochemistry Lab. Rome 1 Section
Via di Vigna Murata 605
Rome, 00143, Italy

[3]CNR – IGG
Via La Pira 4
Florence, 50121, Italy
e-mail: cantuccib@tiscali.it

INTRODUCTION

EnCana's CO_2 injection EOR project at Weyburn (Saskatchewan, Canada) is the focal point of a multi-faceted research program sponsored by IEA GHG R&D and numerous international industrial and government partners including the European Community (BGS, BRGM, INGV, GEUS and Quintessa Ltd. as research providers), to find co-optimization between "CO_2-EOR Production" and "CO_2-Geological Storage", addressed to environmental purposes, in the frame of the Kyoto Agreement Policies.

The Weyburn oil-pull is recovered from Midale Beds (at the depth of 1300-1500 m). This formation consists of Mississippian shallow marine carbonate-evaporites that can be subdivided into two units: i) the dolomitic "Marly" and ii) the underlying calcitic "Vuggy", sealed by an anhydrite cap-rock. Presently, around 3 billions mc of supercritical CO_2 have been injected into the "Phase A1" injection area that includes around 90 oil producers, 30 water injectors and 30 CO_2 injection wells, build up since September 2000. Canadian research providers, flanked by INGV, carried out a full geochemical monitoring program -approximately thrice yearly from pre-injection ("Baseline" trip, August 2000) to September 2004. The merged experimental data are the base of the present geochemical modeling, a theoretical model able to predict the evolution in time of the analytical data taking into account the amount of injected (5,000 ton/day) CO_2 being the main goal of the present study. Refinement of the geochemical data set and application of the proposed method to other Canadian sparse/non ultimate data is auspicial. In the past, assumptions and gap-acceptance have been made in the literature in the frame of the geochemical modeling of CO_2 geological storage, in order to reconstruct the reservoir conditions (pressure, pH, chemistry, and mineral assemblage). As most part of strategic geochemical parameters of deep fluids cannot always be measured in-situ and at low cost, this information as a whole must be computed by *a posteriori* procedure involving as input the experimental semi-reliable analytical data. On the other hand, only a repetitive/wide sampling scheduling of the oil fields following some spot baseline/step benchmark "Schlumberger" (or "U") in-situ sampling may be the correct bivalent approach. Despite the medium-quality experimental data-set available, in this work we propose a new approach to geochemical modeling in order to: i) reconstruct the in-situ reservoir chemical composition and evolution (including *p*H) and ii) evaluate the boundary conditions (e.g., growing the pressure as sum of n moles building up of pCO_2, pH_2S), necessary to implement the reaction path modeling. This is the starting point to assess the geochemical impact of CO_2 into the oil reservoir and, as main target, to quantify water-gas-rock reactions vs. time (i.e. 100 years or at the final equilibrium after 10 Ka).

RECONSTRUCTION OF THE IN-SITU RESERVOIR COMPOSITION (60 °C, 150 BARS)

Our geochemical modeling procedure is based on the available data, such as: a) bulk mineralogy of the Marly and Vuggy zones by a distinct step-by-step modeling; b) mean gas-cap composition at the well-heads and c) selected pre- and post-CO2 injection water samples from Vuggy and Marly, minimizing the effects of the past 30-years of water flooding in the oil field. The geochemical modeling has been performed by using the commercial code PRHEEQC (V2.11) Software Package; the in-situ reservoir composition was calculated by the chemical equilibrium among the various phases at reservoir temperature (62 °C) and pressure (150 bars) via thermodynamic corrections to the code database. Some solid phases, such as dawsonite, magnesite, epsomite and KAlSO4 were added and CO2 supercritical fugacity and solubility (Duan et alii, 1992; 2002, respectively) under reservoir conditions were considered; eventually, several kinetic rate equations (e.g. USGS open file report 2004-1068) were introduced. Successively, the “primitive brine” chemical composition of the pre-injection reservoir liquid phases for the Marly and Vuggy units was derived. The “primitive” composition was modeled by assuming the equilibrium condition for the mineral assemblage with respect to the water. A comparison between the chemical composition of the “primitive” brines with that measured before CO2 injection is shown in Figure 1. Since the process considered in this part of the model is substantially in equilibrium, there is a good agreement between the calculated and the measured values (Fig. 1).

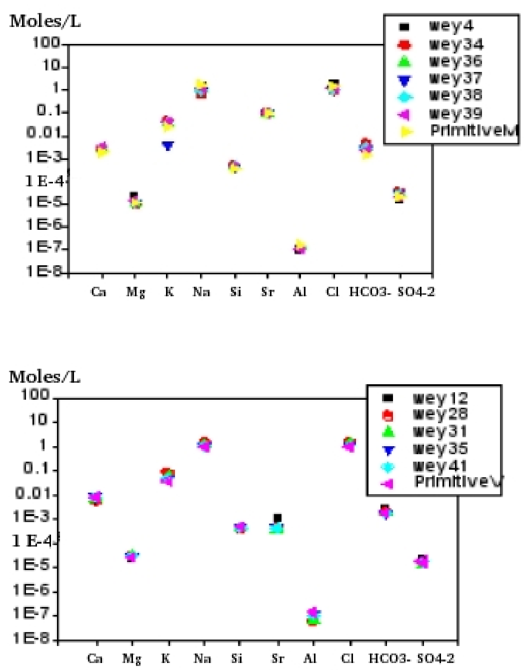


Figure 1. Comparison between “primitive”and pre-injection reservoir compositions of Marly (a) and Vuggy (b) waters.

An Inverse Modeling Simulation (IMS) calculated between the “primitive” water composition and the latest analytical data was carried out to calculate the amount of mass transfer of liquid, gas and solid phases that accounted for changes in the water chemistry between the 2000 and 2004 data-sets, to obtain an evaluation of the alteration induced in the reservoir by CO_2 injection.

KINETIC SIMULATION

We have also modeled the geochemical impact of CO_2 injection on Weyburn reservoir subjected to both local equilibrium and kinetically controlled reactions, adding proper mineral kinetic constants, equations and specific surfaces area (SA) in the data set. The whole set of mineralogical data, with respect to the SA and kinetics data source, is presented in Table 1, with secondary minerals whose formation is predicted. Data are presented for both Marly and Vuggy units of the Midale Beds, differentiated for their mineralogical composition. The selection of thermodynamic data was done in order to maintain an internal coherence of the whole data set, by selecting only thermo-chemical measurements and, when possible, values pertaining to the same research team, due to a high variability of the available data, e.g. dolomite Ksp (Sherman and Barak 2000). We avoided water/gas/rock ratios obtained by experimental runs often realized by using high unrealistic gas(CO_2)/rock ratios. Thermo-kinetic modeling of the evolution of the CO_2-rich Weyburn brines interacting with the host-rock minerals, performed over 100 years after injection, confirms that “solubility trapping” is prevailing in this early stage of CO_2 injection, differently with respect to the equilibrium conditions (>10 Ka), calculated by applying with the same method.

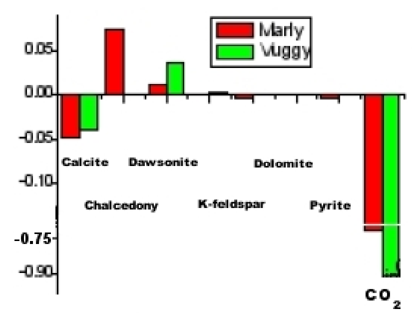


Figure 2. Comparison of the mineralogical changes at reservoir conditions (62 °C, 150 bars) due to CO_2 injection after 100 years of kinetic calculation.

Cross-correlation with the available experimental data are to be refined for the period 2000-2004 as well as validation of the proposed method is to be implemented and further constrained. The results of 100 years kinetic model for Marly (red) and Vuggy (green) units are shown in Figure 2. Slight dissolution of K-feldspar and kaolinite and precipitation of chalcedony occur, calcite tends to be dissolved as CO_2 solubilizes, whereas dolomite dissolution can be considered negligible. Dawsonite precipitates as secondary mineral. The solubility trap (short-term sequestration) gives an amount of dissolved CO_2 of 0.719 and 0.909 mol for Marly and Vuggy unit, respectively. The mineralogical trap, calculated as difference between dissolved and precipitated carbonate minerals, is -0.036 mol and –0.040 mol for Marly and Vuggy units, respectively.

Mineral phases	% w/w		Amount present mole/kgw		Specific surface area m^2/g		Source of kinetic rate data
	M	V	M	V	M	V	
Calcite	14.5	94	7.956	87.38	0.034	0.015	Plummer et alii, 1978
Chalcedony	0.5	0.5	0.438	0.74	0.038	0.015	Icenhower and Dove, 2000
Dolomite	80	3	51.29	3.25	0.105	0.014	Busemberg and Plummer, 1982
Celestite	0.25	-	0.109				Dove and Czank, 1995
Dawsonite*	-	-	-	-	0.140	0.019	Johnson et alii, 2001
Gypsum	3	0	0.829	-	0.003	-	Jeschke et alii, 2001
Anhidrite	-	2	-	1.516	-	0.013	Dove and Czank, 1995
Kaolinite	0.25	0	0.95	-	2.317	0.015	e.g. Ganor et alii, 1995
pyrite	0.5	0.5	0.58	0.99	0.012	0.008	McKibben and Barnes, 1986
K-feldspar	1	0.5	0.198	0.16	0.175	0.015	Sverdrup, 1990

Table 1. Mineralogical Composition of the Marly and Vuggy reservoirs used for the modeling, the specific surface area and the sources of kinetic rate data.

CONCLUSIONS

The Weyburn reservoir appears to be strongly modified by the daily injection of CO_2. The geochemical modeling approach coupled with a proper monitoring program seems to be the only way to assess the evolution of the geochemical impact in the Midale Beds Formation and to mitigate any CO_2 release.

REFERENCES

Busenberg, E., and Plummer, L. N., The kinetics of dissolution of dolomite in CO2-H2O systems at 1.5 to 65°C and 0 to 1 atm P(CO2), *Am. J. Sci., 282*, 45-78, 1982.

Dove, P. M. ,and Czank, C. A., Crystal chemical controls on the dissolution kinetics of the isostructural sulfates; celestite, anglesite and barite, *Geochim. Cosmochim. Acta, 59,*1907-1915, 1995.

Duan, Z., Moller, N., Weare, J.H., An equation of state fpr the CH4-CO2-H2O system: 1. Pure systems from 0° to 1000°C and 0 to 8000 bar, *Geochimica et Cosmochimica acta*, *56*, 2605-2617, 1992.

Duan, Z., and Sun, R., An improved model calculating CO2 solubility in pure water and aqueus NaCl solutions from 273 to 533 K and from 0 to 2000 bar, *Chemical Geology*, *193*, 257-271, 2003.

Ganor, J., Mogollón, J. L., and Lasaga, A. C., The effect of pH on kaolinite dissolution rates and on activation energy, *Geochim. Cosmochim. Acta, 59*, 1037-1052, 1995.

Incenhower, J. P., and Dove, P. M., The dissolution kinetics of amorphous silica into sodium chloride solutions: Effects of temperature and ionic strength. *Geochim. Cosmochim. Acta, 64,* 4193-4203, 2000.

Jeschke, A. A., Vosbeck, K., and Dreybrodt, W., Surface controlled dissolution rates of gypsum in aqueous solutions exhibit nonlinear dissolution kinetics. *Geochim. Cosmochim. Acta,* 65, 27-34, 2001

Johnson, J. W., Nitao, J. J., Steefel, C. I., and Knauss, K. G., Reactive transport modelling of geologic CO2 sequestration in saline aquifers: the influence of intra-aquifer shales and the relative effectiveness of structural, solubility, and mineral trapping during prograde and retrograde sequestration. *First National Conference on Carbon Sequestration.* May 14-17, 2001, Washington, D.C.

McKibben, M. A. and Barnes, H. L., Oxidation of pyrite in low temperature acidic solutions: Rate laws and surface textures, *Geochim. Cosmochim. Acta, 50*, 1509-1520, 1986.

Plummer, L.N., Wigley, T.M.L., and Parkhurst, D.L., The kinetics of calcite dissolution in CO2-water systems at 5-60 C and 0. 0-1.0 atm CO2, *American Journal of Science, 278*, 179-216, 1978.

Sherman, L.A., and Barak, P., Solubility and dissolution kinetics of dolomite in Ca-Mg-HCO3/CO3 solutions at 25°C and 0.1 MPa carbon dioxide, *Soil Sci. Soc. Am. J., 64,* 1959-1968, 2000.

Sverdrup, H. *The Kinetics of Base Cation Release Due to Chemical Weathering*. Lund University Press, Lund, Sweden, 1990.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

GEOCHEMICAL PROCESSES WITH IMPLICATIONS FOR SITE CHARACTERISATION

Isabelle Czernichowski-Lauriol, Pascal Audigane, Irina Gaus, Christophe Kervévan

BRGM (French Geological Survey)
BP6009, 45060, Orléans cedex 2, France
e-mail: i.czernichowski@brgm.fr

INTRODUCTION

The degree of reactivity between the injected CO_2 and the host rock formation may have significant consequences, either beneficial or deleterious, on injectivity, storage capacity, sealing efficiency, and long-term safety and stability (Czernichowski-Lauriol et al., 1996; Rochelle et al., 2004). This will depend on the nature and scale of the chemical reactions between CO_2 and its potential impurities with reservoir rocks, cap rocks and well completions. Geochemical reactions are highly site-specific and time-dependent. Appropriate site characterization is crucial to ensure site suitability for long-term storage.

INITIAL CHARACTERISATION: DATA ACQUISITION

Before being able to assess the potential impact of CO_2 storage, it is essential to rely on relevant data characterizing the initial geochemical status of both the host formation and the injected CO_2. This requires a phase of data acquisition before the injection starts that differs from the usual practice in hydrocarbon operations.

The following data should be acquired:
- properties of the solid phases (reservoir rock, cap rock, cement): mineralogical and chemical composition, specific surface areas;
- properties of the water phases: comprehensive analyses of reservoir and cap rock pore-waters;
- physical properties of reservoir and cap rock: pressure and temperature conditions, porosities, permeabilities, capillary entry pressure as well as diffusion rates in the case of cap rock;
- properties of the injected CO_2: exact composition of the CO_2 stream, CO_2 temperature, pressure and flow rate at the base of the injection well.

For a reliable and comprehensive characterization, a minimum amount of core and water samples should be collected and analyzed. At least one cap rock core sample, one reservoir core sample and one formation water sample should be carefully collected. Special attention has to be paid to the sampling techniques in order to get good quality samples.

Characterization should be further improved if lateral and vertical variations are suspected: rock heterogeneities and gradients of temperature, pressure and salinity may have a significant impact on the geochemical processes.

ADVANCED CHARACTERISATION: COMBINATION OF MODELLING AND OBSERVATIONS

Based on data acquired, advanced site characterization is needed to assess the geochemical impact of large-scale CO_2 storage. Geochemical reactions, which are induced by the dissolution of CO_2 into the pore-waters and the resulting pH decrease, are highly complex. They are the results of interdependent thermodynamic, kinetic, flow and transport processes and can occur in the bulk of the reservoir rock, cap rock and well cements, but can also be exacerbated in fractures. They increase the site CO_2 trapping potential due to dissolution of CO_2 in the formation water and possible formation of carbonate minerals (Table 1). Mineral reactions can result in modification of porosity and permeability, which can either hinder the actual injection of CO_2, or aid its migration out of the injection area. Note that the geomechanical consequences of the chemically-induced changes in fractures and bulk rock petrophysical properties also need to be assessed as they will have an effect on long term storage stability and security.

Table 1. Trapping mechanisms (Czernichowski-Lauriol et al., 2006).

> **Physical trapping**
- CO_2 ‘bubble’: dense supercritical CO_2 phase

> **Chemical trapping**
- Solubility trapping: CO_2(aq) or $H_2CO_3^0$
- Ionic trapping: HCO_3^-, $CaHCO_3^+$, $MgHCO_3^+$, $NaHCO_3^0$, …
- Mineral trapping: $CaCO_3$ (calcite), $CaMg(CO_3)_2$ (dolomite), $MgCO_3$ (magnesite), $FeCO_3$ (siderite), $NaAlCO_3(OH)_2$ (dawsonite), ...

Increasing importance with time

Geochemical impact assessment has to consider multiphase systems (brine, dense CO2, various minerals) with coupled time and space dependent processes. Due to this extreme complexity, investigations need to be carried out on a site-to-site basis according to best practices by combining numerical modeling and observations from laboratory experiments, field monitoring, and natural analogues (IEA-GHG, 2003; Czernichowski-Lauriol et al., 2006). Hence observations can be made at different spatial and temporal scales: from an individual sample scale to field scale, from hours to millions of years, from direct study of the selected injection site to indirect study through natural analogues. Constrained by these three types of observations, numerical models can make predictions from shorter to longer timescales, which is essential for assessing long-term geochemical processes associated with CO_2 storage.

PLEA FOR A RELIABLE SITE CHARACTERISATION: TWO EXAMPLES

CO_2 Solubility in Formation Waters

Particular attention has to be paid to the assessment of CO_2 solubility in formation waters. This is because the dissolution of CO_2 is the driving force of the geochemical reactions. Inaccurate assessment of CO_2 solubility may have important repercussions on the predictions of gravity-driven flow of the brine enriched with dissolved CO_2, pH changes, mineral reactions, and dissolution and mineral trapping. A reliable assessment of CO_2 solubility needs to be based on a comprehensive site pore-water analysis and on thermodynamic calculations that take into account the specific effects of the various electrolytes and the non-ideal behavior of the CO_2 supercritical phase. Consistent corrections of dissolved species activities, gas fugacities and influence of pressure on thermodynamic constants have to be applied in geochemical models calculations (Kervévan et al., 2005). Figure 1 illustrates the error on CO_2 solubility that may result from neglecting thermodynamic corrections and lack of consideration of precise fluid chemistry. Errors as high as 400% may be induced when neglecting fluid salinity and assuming CO_2 to be an ideal gas. Note that any impurity within the CO_2 would also have an important impact on CO_2 solubility.

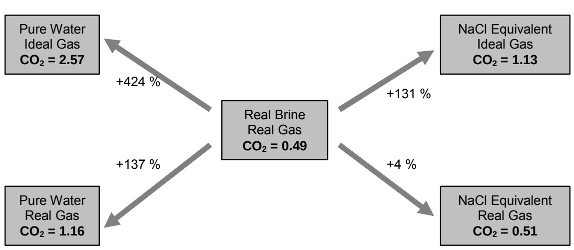


Figure 1. Summarising diagram of the relative weights of the various corrections applied to the calculation of CO_2 solubility (expressed in mol.(kg H_2O)$^{-1}$) for a 237 g.l^{-1} brine at 60 °C and 200 bar (Kervévan et al., 2005).

Geochemical Reactions in the Storage Reservoir

Classical geochemical modeling is not well suited for making realistic predictions about CO_2 fate in the reservoir and geochemical impact. Kinetic batch geochemical modeling allows identifying the main chemical reactions and making predictions of CO_2 solubility and changes in fluid chemistry and mineralogy with time. However, this type of modeling considers only closed systems and is of limited utility to predict the geochemical impact of CO_2 storage as hydrodynamics plays an important role. Dynamic modeling taking into account the geometry and main characteristics of the reservoir as well as the flow of supercritical CO_2 and brine, together with the geochemical reactions, is required. Only reactive-transport models can give quantitative estimates of mineral reactions and trapping mechanisms as a function of space and time. These models should be used and further developed for advanced reservoir characterization. Figures 2 and 3 show some results of a 2D reactive-transport modeling carried out with the TOUGHREACT code at the Sleipner site (Audigane et al., 2006; in preparation).

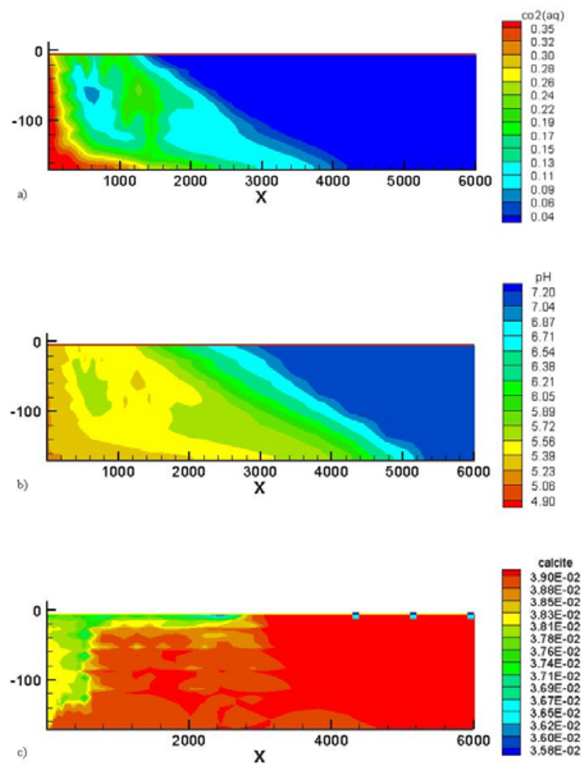


Figure 2. Results of 2D reactive-transport at Sleipner after 10000 years: a) dissolved CO_2, b) pH, c) calcite amounts (moles) (Audigane et al., 2005).

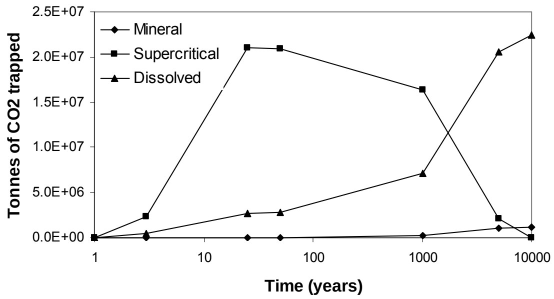


Figure 3. Results of 2D reactive-transport at Sleipner: relative weights of trapping mechanisms with time up to 10000 years (Audigane et al. 2006, in preparation).

CONCLUSION

Advanced geochemical site characterization requires close integration of laboratory, field and modeling studies. Key to this will be the acquisition of detailed quantitative data to underpin the modeling, and the construction of more complex models that can take into account a wider range of processes. Only through the repeated validation of models against laboratory and field data or observations from natural systems we will be able to reach a high degree of confidence in our understanding of the geochemical reactions caused by the underground storage of CO_2. This will be necessary if we are to satisfy the questions of the public and regulatory bodies.

REFERENCES

Audigane, P., I. Gaus, K. Pruess and T. Xu, Reactive transport modelling using TOUGHREACT for the long term CO_2 storage at Sleipner, North Sea, Fourth Annual Conference on Carbon Sequestration, Alexandria, VA, USA, May 2-5, 2005.

Audigane, P., I. Gaus, I. Czernichowski-Lauriol, K. Pruess and T. Xu, Two-dimensional reactive transport modelling of CO_2 injection in a saline aquifer at the Sleipner site (in preparation), 2006.

Czernichowski-Lauriol, I., B. Sanjuan, C. Rochelle, K. Bateman, J. Pearce and P. Blackwell, Analysis of the geochemical aspects of the underground disposal of CO_2: scientific and engineering aspects. In*: 'Deep Injection Disposal of Hazardous and Industrial Wastes, Scientific and Engineering Aspects'*, J.A. Apps and C.-F. Tsang (Eds), Academic Press, 1996.

Czernichowski-Lauriol, I., C. Rochelle, I. Gaus, M. Azaroual, J. Pearce and P. Durst, Geochemical interactions between CO_2, pore-waters and reservoir rocks: lessons learned from laboratory experiments, field studies and computer simulations, In: *Advances in the Geological Storage of Carbon Dioxide*, NATO Science Series: IV: Earth and Environmental Sciences, 65, Lombardi, S.; Altunina, L.K.; Beaubien, S.E. (Eds.), 157-174, Springer, 2006.

IEA-GHG, *Saline Aquifer CO_2 Storage project (SACS) Best Practise Manual*. Report Number PH4/21, 53 p, 2003.

Kervévan, C., M. Azaroual and P. Durst, Improvement of the calculation accuracy of acid gas solubility in deep reservoir brines: application to the geological storage of CO_2, *Oil & Gas Science and Technology – Rev. IFP, 60 (2)*, 357-379, 2005.

Rochelle, C.A., I. Czernichowski-Lauriol and A.E. Milodowski, The impact of chemical reactions on CO2 storage in geological formations: a brief review, In: *Geological Storage of Carbon Dioxide*, Baines S.J. and Worden R.H. (Eds.), Special Publication of the Geological Society of London, 233, 87-106, 2004.

REGIONAL-SCALE VARIABLE-DENSITY FLOW IN DEEP SALINE FORMATIONS IN THE MIDWESTERN UNITED STATES: IMPLICATIONS FOR LARGE SCALE GEOLOGIC CO_2 SEQUESTRATION

Neeraj Gupta[1] and Joel Sminchak[2]

Battelle
505 King Ave
Columbus Ohio 43201, USA
[1]phone: 614-424-3820; fax: 614-424-3667; e-mail: gupta@battelle.org
[2]phone: 614-424-7393; fax: 614-424-3667; e-mail: sminchak@battelle.org

INTRODUCTION

Regional groundwater flow patterns in the broad basins and arches of the Midwestern United States are primarily controlled by topographic forces, fluid-density related forces, and variations in hydraulic conductivity. Understanding the influence of fluid-density variations on regional groundwater flow patterns in deep saline rock formations is important to demonstrate permanent CO_2 sequestration when considering large scale storage, long-term potential for CO_2 migration, and changes in conditions in deep reservoirs. In this study, the sedimentary layers in the region are grouped into hydrostatic units that incorporate the fluid density, pressure, boundary conditions, and a conceptual variable density flow model for local, intermediate and regional-scale flow systems. Basal sandstone/Mt. Simon Sandstone layers are the primary focus due to there importance for waste disposal and potential for CO_2 storage, however, the model incorporates the entire sedimentary column as 11 layers. The Basal Sandstone is a regionally extensive unit at the base of the Paleozoic rock column and considered an excellent CO_2 sequestration target throughout most of the Midwest.

Several studies have addressed variable density flow in Midwestern regional basins (see Gupta and Bair, 1997 for details). Many studies incorporate spatial variations in fluid density indirectly using the concept of equivalent freshwater head to examine regional flow patterns, even thought the use of variable density head may be more appropriate. In addition, many computer models have been used to simulate the injection and migration of CO_2 on a site specific basis (Gupta et al, 2003; White, 2004; Pruess et al., 2002; Zweigel et al., 2000). These models generally focus on assessing injectivity, upward movement of CO_2, geochemical transformations, leakage through containment layers, and the effects of variable geology on CO_2 distribution. However, few models have considered regional flow in relation to large-scale CO_2 storage fields. When investigating full-scale storage or long-term fate, it is important to consider the potential for regional migration. To be effective across large regions, geologic storage will require storage of many gigatonnes of CO_2. CO_2 will tend to migrate upward along structural dip until it encounters some physical boundary, is trapped as residual levels in pore space, dissolves in formation waters, and/or is mineralized. Under large-scale scenarios, the possibility for either CO_2 to migrate to areas of concern or facilitate movement of saline waters into freshwater zones needs to be evaluated carefully, even though the presence and long-term stability of natural gas and natural CO_2 fields provides a suitable analogue for geologic storage concepts. In addition, regional flow trends will affect many of these processes.

VARIABLE DENSITY FLOW CONCEPTS

The qualities that make deep saline formations attractive for CO_2 storage also lead to several complicating factors when considering regional fluid flow. First off, they are very deep and have little, if any, economic value. Therefore, very few wells penetrate these formations and even fewer have high quality pressure and fluid data from drill stem tests (as shown in Figure 3 which shows fluid density samples from the Basal Sandstone). Consequently, researchers have a limited amount of data to analyze and some unreliable data may be present. The lack of pressure data is especially affects the reliability of the conceptual flow model and the boundary conditions that may be used in regional-scale models of flow and transport. Secondly, the rock formations are saturated with brines that vary in density with location and depth. To understand the regional pressure patterns, it is necessary to convert the data into variable density heads. It is not possible to assume that fluid density is the same for the entire depth interval at a sample location. Third, the deep sandstone formations are interlayered with low permeability layers. Presumably, most fluid flow will occur in the more permeable sandstones, but some degree of vertical flow is likely to occur due to permeability contrasts. Lastly, the setting is in mature basins where formation fluids have accumulated or been trapped over many millions of years. Consequently, some variations in pressure and density may be related to ancient events, rock digenesis, and slow leaching from the salt beds present locally in the region.

GEOLOGIC FRAMEWORK

Sequences of Paleozoic sedimentary rocks in the Midwestern United States exist as broad basins and arches approximately 1 to 7 km in thickness (Figures 1 and 2). These rocks overlie Precambrian igneous, metamorphic, and metasedimentary basement rock. Faults and fractures are variably developed in some areas of the regions, but extensive faulting and displacement is generally absent. Several deep saline sandstone formations have been identified with significant storage potential. Some of the sequestration targets are depleted oil and gas reservoirs, while many of the rocks are older Paleozoic rocks relatively free from oil and gas drilling. The Basal Sandstone is considered one of the most attractive storage targets because it is deep, saturated with highly concentrated brines, and present throughout most of the region. However, the formation does vary in thickness and character such that certain areas may be more suitable for storage. Other carbonate rocks, organic shales, and coal seams have also been identified as having significant sequestration potential. A diverse and extensive range of containment units are present around the sequestration targets. Most of the target storage units have lithologic or structural traps such that migration to the surface is very unlikely, but there is some uncertainty regarding flow patterns and the effects of large-scale storage.

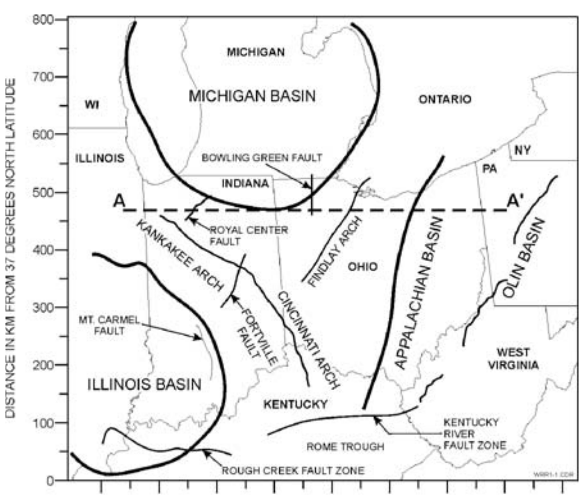


Figure 1. Map showing basins and arches in Midwestern United States.

PRESSURE AND GEOCHEMICAL DISTRIBUTIONS

Shut-in pressure data from the Basal Sandstone and other formations was compiled from hazardous waste injection wells, test wells, and oil and gas wells. Only about 20 reliable values are available for the Basal Sandstone, however, significantly greater amount of data are available from shallower units in the region. The entire database consisting of several thousand wells was used to develop the hydrostatic conceptual model and a variable density code was used to develop an understanding of the regional (deep), intermediate, and local (shallow) flow patterns. The differences in flow patterns determined from variable density heads versus the equivalent freshwater heads also were evaluated. Formation fluid density values from more than 1800 locations were also mapped, Figure 3 shows data from one of these layers, the Basal sandstone. Densities are close to freshwater in outcrop and subcrop areas in northern Illinois and Wisconsin and gradually become more saline in the Michigan and Appalachian basins. Examination of other Paleozoic units shows some fluid density reversals associated with Silurian Salina formation salt bed deposits. Combined with the typical permeability present in the Basal Sandstone, pressure distributions suggest a very slow fluid flow rate of less than 0.3 meters/year.

CONCLUSIONS AND IMPLICATIONS FOR GEOLOGIC CO_2 SEQUESTRATION

Fluid flow in deep saline formations in the Midwest U.S. is controlled by topography, geologic structure, permeability variations, and variable density. Flow in deeper basins appears to be influenced primarily by structures, while flow in the shallow layers is more controlled by gravitational forces and topography. Based on the variable density heads and boundary conditions the flow in the deeper layers is generally part of the regional and extremely slow flow paths, that are ideal for large-scale storage. Local variations in the deep patterns are observed in the model where thick salt beds are present. Variations in hydraulic conductivity appear to mainly influence the vertical flow component. Fluid density variations must be considered when evaluating flow, because pressure gradients may not be accurate when converted to equivalent freshwater heads.

The impact of large-scale CO_2 storage on the flow patterns in the deeper flow systems needs to be evaluated next. Existing fluid flow is less than 0.3 meter/year, so it is also unlikely that existing flow regime will cause any injected CO_2 to migrate. Specific areas of further study include the impact of locating multiple facilities on the regional pressures, mobilization of the saline waters, and any impact on the freshwater-brine interface where the storage is close to the freshwater zones. The challenges in meeting this objective include the lack of reliable pressure and permeability data, multiphase aspects of CO_2 storage and the regional nature of this problem that can require very large computer resources. It may be useful to conduct initial test cases using simplified single-phase assumptions before incorporating the multiphase effects.

REFERENCES

Gupta, N., and Bair, E.S. 1997. Variable-density flow in the mid-continent basins and arches region of the United States. Water Resources Research, Vol. 33, No. 8, p. 1785-1802

Gupta, N., B. M. Sass, S. Chattopadhyay, J. Sminchak, P. Wang, and T. Espie. 2004. Geologic storage of CO_2 from refining and chemical facilities in the Midwestern U.S., *Energy,* Vol. 29, No. 9-10: 1599-1609.

Pruess, K., Garcia, J., Kovscek, T., Oldenburg, C., Rutqvust, J., Steefel, C., and Xu, T., 2002, Inercomparison of numerical simulation codes for geological disposal of CO_2, LBNL-51813, p. 86

White, M., Gupta, N., Kelley, M., and Sminchak, J. 2005. Assessment of CO_2 injection at the Mountaineer Power Plant site using scalable numerical simulation. In: M. Wilson et al. (Eds.), Proceedings of the 7th Annual Conference on Greenhouse Gas Technology, Vancouver, Canada, September 5-9, 2004. Elsevier. Vol II-2, pp 2269-2272

Zweigel, P., Hamorg, M., Arts, R., Lothe, A., and Tommeras, A. 2000. Prediction of migration of CO_2 injected into an underground depository: Reservoir geology and migration modeling in the Sleipner case (North Sea). 5th International Conference on Greenhouse Gas Control Technologies, Cairns (Australia), August 2000

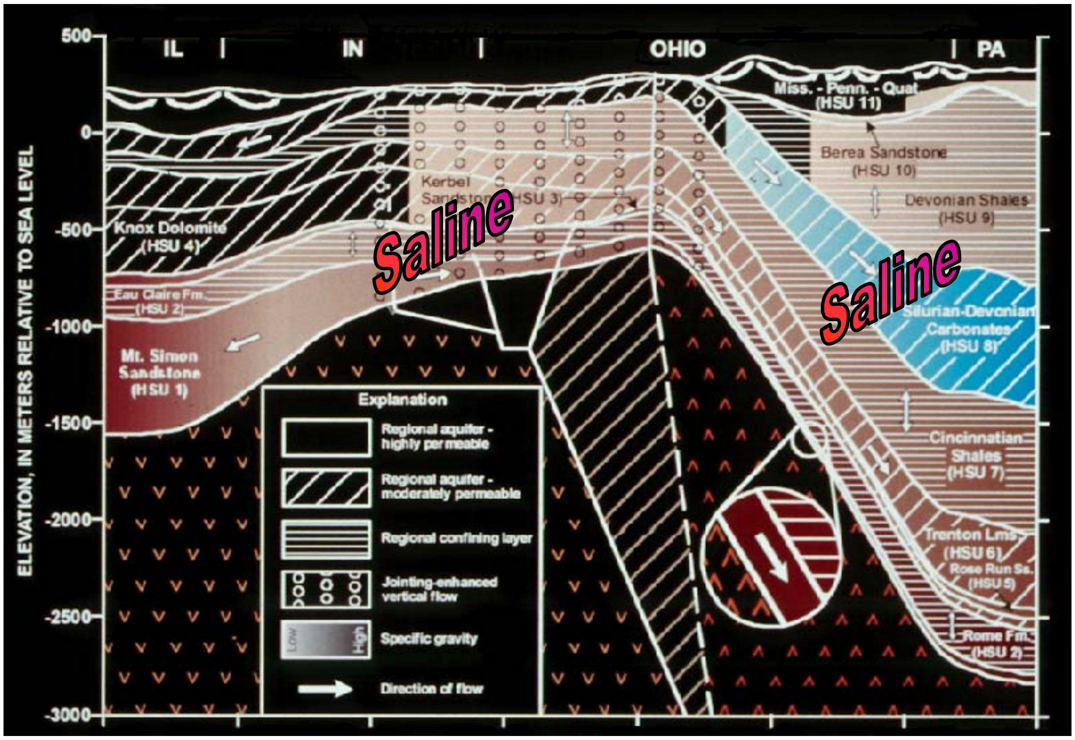


Figure 2. Generalized West-East cross section showing configuration of stratigraphic units and major tectonic features in the study area

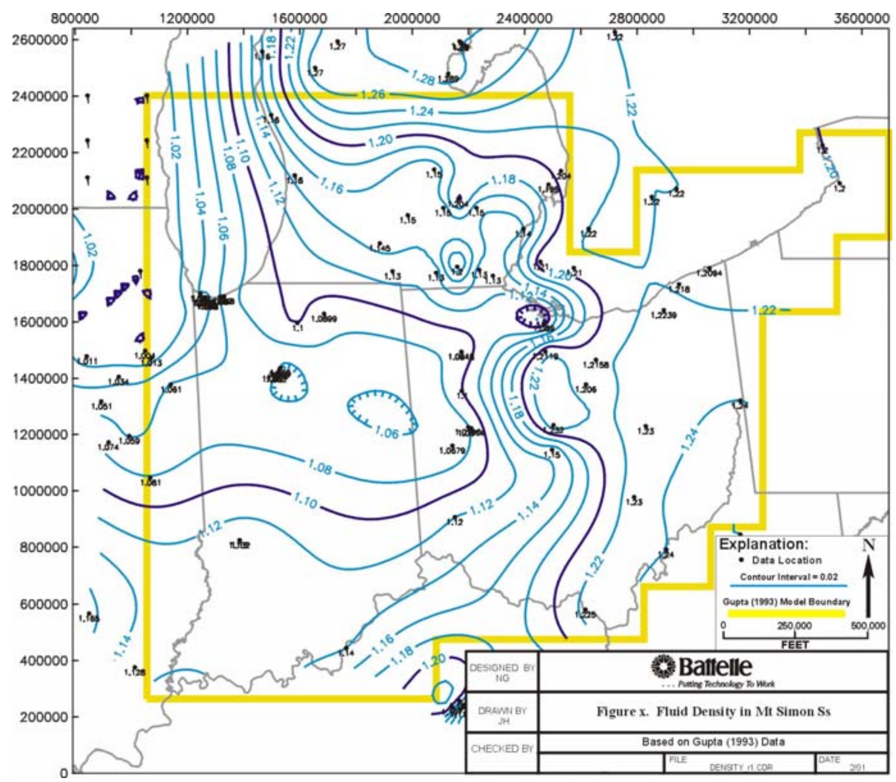


Figure 3. Map showing observed fluid density in Basal Sandstone/Mt.Simon Sandstone and the area of the regional model.

RESOLVING DENSITY FINGERING DURING CO_2 SEQUESTRATION: A CHALLENGE FOR RESERVOIR SIMULATION

M. A. Hesse, A. Riaz, and H. A. Tchelepi

Department of Petroleum Engineering, Stanford University
65 Green Earth Sciences Building
Stanford, CA, 94305, U.S.A.
e-mail: mhesse@stanford.edu

INTRODUCTION

CO_2-sequestration in deep geological formations has been suggested to reduce greenhouse gas emissions. At depth greater than 800 m, CO_2 forms an immiscible CO_2-rich vapor phase, and a small amount of CO_2 dissolves in the brine (van der Meer, 1992). The density of the CO_2-rich vapor phase is less than the density of the brine, but the density of the brine will increase with increasing CO_2 concentration (Ennis-King & Paterson, 2003). In addition to a hydrodynamic seal that prevents upward migration, other trapping mechanisms should either immobilize the CO_2 or eliminate its positive buoyancy, to ensure safe storage over long time scales. CO_2 dissolved into the brine is considered trapped, because the dense CO_2 saturated brine sinks to lower levels. Dissolution is also prerequisite for subsequent precipitation of CO_2 as carbonate minerals. In this paper we present recent results on the length and time scales and the rates of CO_2 dissolution. We also discuss the implication on site selection and the challenges this process poses for field scale simulation of CO_2 storage.

DISSOLUTION TRAPPING

The increase in brine density with increasing CO_2 saturation may lead to a gravitational instability in the diffusive boundary layer below the CO_2–brine interface (Lindeberg and Wessel-Berg, 1997). If the instability occurs, plumes of CO_2 saturated brine migrate downward and fresh unsaturated water is transported to the interface. The experiments of Yang and Gu (2005) show an increase of the CO_2 dissolution rate, due to convective transport. In the absence of convective transport dissolved CO_2 diffuses, and the dissolution rate decreases rapidly with time. It is therefore important to understand under which conditions convective transport occurs. This question has been addressed in several recent theoretical, numerical and experimental investigations.

Hydrodynamic Stability of Diffusive Boundary Layer

An analysis of the hydrodynamic stability of the diffusive boundary layer below the CO_2-brine interface determines the conditions for convective transport. This phenomenon has been investigated theoretically most recently by Ennis-King-Paterson (2003), Ennis-King et *al.* (2005), Xu et *al.* (2006), and Riaz et *al.* (2006). These theoretical results are based on the assumption of a homogeneous porous medium, a stationary impermeable CO_2-brine interface, and linearized governing equations. These linearized results are valid at early times, and need to be supplemented by full nonlinear numerical simulations at late times. The strength of the analytical approach is the unlimited spatial resolution, the physical insight, and the possibility to provide a benchmark for the numerical simulations.

Critical time t_c for the onset of convection: An important parameter for site characterization

The most important result of these studies is that the diffusive boundary layer needs to grow to a critical thickness before convection occurs. This introduces an important time scale, the critical time for the onset of convection t_c. Riaz et *al.* (2006) give the following expression

$$t_c = 146\frac{\phi\mu^2 D}{\left(Kg\Delta\rho\right)^2}$$

in terms of average aquifer parameters, that is valid for aquifers thicker than the penetration depth of the diffusive boundary layer $\delta_c = 24\mu D/(Kg\Delta\rho)$. Where ϕ is the porosity, μ is the viscosity of the brine, D is the dispersion coefficient, K is the permeability, g is the gravitational acceleration and $\Delta\rho$ is the density difference between the CO_2 saturated and the unsaturated brine. For potential storage aquifers the permeability may vary from 10^{-3} D to 3 D, and the critical times vary from a few days (t_c< 10 days) in a high permeability aquifer to a few thousands of years (t_c ~ 2000 years) in a low permermeability aquifer.
CO_2 dissolution will therefore be an important trapping mechanism in high permeability aquifers, where onset is essentially instantaneous, and the dissolution rate is high (see below). In low permeability aquifers dissolution trapping will not contribute significantly to the reduction of mobile CO_2 before the critical time, which may be several hundred years, and even after the onset of convection the dissolution rate will be low (see below).

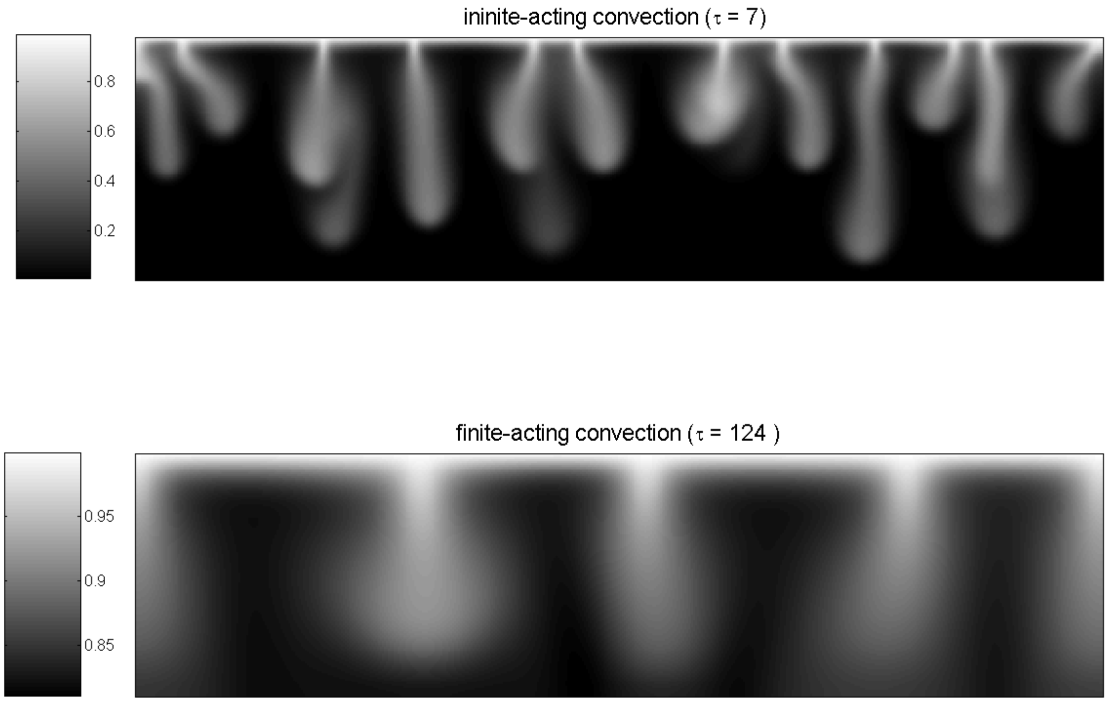


Figure 1: The instability leads to the formation of dense miscible plumes or fingers that transport CO_2 away from the interface. Contours show the non dimensional CO_2 concentration (C), note the different scales of the top and bottom figure. The domain is of unit height and the aspect ration is 4 by 1. The timescale $t^* = \phi\mu H/(K\Delta\rho g)$, can be used to obtain dimensional time from τ. The top figure shows the infinite-acting convection regime, and bottom shows the finite-acting convection regime (see text for explanation).

Critical wavelength λ_c of the instability:
A numerical challenge

The hydrodynamic stability analysis also gives information on the initial wavelength of the instability. This initial wavelength can be interpreted as the separation between convection cells or plumes at and shortly after the critical time. Riaz et *al.* (2006) give the following expression for the critical wavelength in an isotropic aquifer as

$$\lambda_c = \frac{2\pi\mu D}{0.07 K g \Delta\rho}.$$

In a high permeability aquifer (K~3 D) where dissolution is an important trapping mechanism, the critical wavelength is $\lambda_c \sim 0.3$ m.

To model this instability accurately with a numerical simulator, it is necessary to resolve this critical wavelength. Typical discretizations have grid blocks up to a 100 m wide and often 10 m thick. The instability we need to resolve requires a discretization that is 3 orders of magnitude finer than what is currently considered feasible. Lindeberg and Bergmo (2003) have shown that failure to resolve the small initial wavelength delays the onset of convection. For a 100 m by 100 m by 10 m grid and a high permeability aquifer they observed a delay in the onset of convection by two orders of magnitude.

DIRECT NUMERICAL SIMULATIONS

The linearized results presented above only describe the system at early times, we have performed numerical simulations to study the long term evolution (Figure 1). A high resolution spectral and compact finite difference method has been used to resolve the small length scales of the instability (Ruith and Meiburg 2000), and has been validated against theoretical results. The numerical simulations consider only single phase flow in the brine, and the density changes are modelled with a Boussinesq approximation.

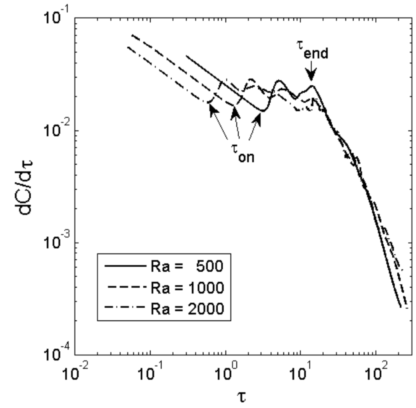


Figure 2: The non-dimensional dissolution rate as function of non-dimensional time, for different Ra-numbers. The onset time τ_{on} and the time at which vigorous convection ends τ_{end} are marked.

Ennis-King & Paterson (2003) have argued that equilibrium is established rapidly along the brine CO_2-vapour interface, and hence a Dirichlet boundary condition for the CO_2 concentration on the top of the domain is justified.

Long term evolution and dissolution rate

All numerical results shown below have been non-dimensionalized, and the governing parameter is the Rayleigh number ($Ra = \phi\mu HK^{-1}\Delta\rho^{-1}g^{-1}$). The concentration of CO_2 is defined as the mass-volume fraction $C_{CO2} = x_{CO2,b}\,\rho_b$, where $x_{CO2,b}$ is the mass fraction of CO_2 in brine and ρ_b is the density of the brine. This concentration has been normalized by the equilibrium concentration $C = C_{CO2}/C^{eq}_{CO2}$.

Three distinct mass transport regimes can be identified in the system described above. An initial period of diffusive transport is followed by rapid *infinite-acting* convective mass transport, superseded by a period of slow *finite-acting* convective transport. During infinite-acting convective transport the plumes of dense brine have not yet reached the bottom of the domain, and the convection is similar to that in a semi-infinite half-space. Finite-acting convection occurs after the plume tips have reached the bottom of the domain, and convection slows down significantly. (Figure 1)

The total rate of CO_2 dissolution (*dC/dt*), changes depending on the mass transport regime. In the diffusive regime the rate of solution trapping decreases with time as $dC/dt \propto t^{-1/2}$, before it becomes constant in the infinite acting convection regime $dC/dt \propto const.$, finally in the finite acing convection regime the rate of CO_2 dissolution decreases very rapidly with an exponent less than - *1/2*.

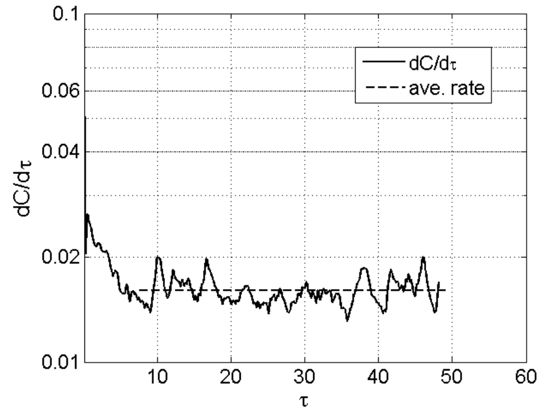


Figure 3: In the infinite-acting convection regieme, the non-dimensional dissolution rate dC/dt oscillates around a constant value.

The three mass transport regimes are separated by two important time scales, the *onset time* t_{on}, and the *ending time* t_{end} of infinite-acting convection. Both time scales can be identified in the flux profile as a function of time in Figure 2. The onset time is a strong function of the *Ra*, and is bounded below by the critical time. The onset time does not follow a simple scaling law for small *Ra* but is asymptotic to the critical time at large *Ra*. The end of the infinite-acting convection regime time is independent of Ra (Figure 3), and can be given in dimensional form as

$$t_{end} = 15\frac{\phi\mu H}{K\Delta\rho g}$$

Figure 3 shows that the dissolution rate during the infinite-acting convection regime oscillates around a constant value. Amplitudes and wavelengths of these oscillations decrease with increasing *Ra*, but the time average of the dissolution rate during infinite-acting convection is independent of the *Ra*. The two dimensional space time average of the mass dissolution rate of CO_2 per unit width, in the infinite-acting regime is given by

$$\frac{dM_{CO_2}}{dt} \approx 0.017\frac{K\Delta\rho g C^{eq}_{CO_2} L}{\phi\mu}$$

where M_{CO2} is the mass of dissolved CO_2. We see that the dissolution rate increases linearly with increasing permeability.

CONCLUSIONS

Theoretical and numerical results give the following scalings for important length and time scales and the dissolution rate as a function of the average aquifer permeability K:

1. The critical time for the onset of convection is proportional to K^{-2}.
2. The critical wavelength is proportional to K^{-1}.
3. The time until the plumes of CO_2 reach the bottom is proportional to K^{-1}.

4. The dissolution rate of CO_2 into the brine is proportional to K.

We conclude that dissolution of CO_2 into the brine will be an important trapping mechanism in high permeability aquifers, because convection starts early, and the dissolution rate is high. Current numerical techniques cannot resolve the small length scale of the instability at the field scale.

ACKNOWLEDGMENT

This research was supported by the Global Climate and Energy Project at Stanford University (GCEP).

REFERENCES

van der Meer L., G.,H., Investigations regarding the storage of carbon dioxide in aquifers in the Netherlands, *Energy Conservation and Management*, 33, 611-618

Lindeberg E., and D. Wessel-Berg, Vertical Convection in an aquifer column under a gas cap of CO_2, *Energy Conservation Management*, 38, SS 229-SS 234, 1997

Ennis-King, J., and L. Paterson, The Role of Convective Mixing in the Long Term Storage of Carbon Dioxide in Deep Saline Formations, *SPE 84388*, pp. 1-12, 2003

Yang, C. and Y. Gu, Accelerated Mass Transfer of CO_2 in Reservoir Brine Due to Density-Driven Natural Convection at High Pressures and Elevated Temperatures, *Industrial Engineering Chemical Research*, DOI: 10.1021/ie050497r, 2005.

Ennis-King, J., I. Preston, and L. Paterson, Onset of Convection in Anisotropic Porous Media Subject to a Rapid Change in Boundary Conditions, *Physics of Fluids*, 17 (084107), 2005

Xu, X., S. Chen, and D. Zhang, Convective Stability Analysis of the Long Term Storage of Carbon Dioxide in Deep Saline Aquifers, *Advances in Water Resources*, 29, pp. 397-407, 2006

Riaz, A., M. Hesse, and H. Tchelepi, Onset of Convection in a Gravitationally Unstable, Diffusive Boundary Layer in Porous Media, Journal of Fluid Mechanics, 548, 87-111, 2006

Lindeberg, E., and P. Bergmo, *Long Term Fate of CO_2 Injected into an Aquifer*, Greenhouse Gas Technologies, vol. 1, pp. 489-495, 2003

Ruith, M., and E. Meiburg, Miscible rectilinear displacements with gravity override. Part 1. Homogeneous Porous Medium, *Journal of Fluid Mechanics*, 420, p. 225, 2000

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

STREAMLINE BASED SIMULATION OF CO2 INJECTION IN SALINE AQUIFERS

Kristian Jessen and Franklin M Orr, Jr.

Stanford University
367 Panama Street, 065
Stanford, CA, 94305, USA
e-mail: krisj@stanford.edu

INTRODUCTION

Design and implementation of CO_2 sequestration projects in saline aquifers require, in part, a solid understanding of the key physics that determine distribution of the injected CO_2 within the target aquifer. This understanding then forms the basis for model formulation and development of simulation techniques appropriate for resolving the essential physics. In addition, a significant level of uncertainty exists as to the spatial distribution of rock properties. This, in turn, calls for development of simulation tools that are accurate and sufficiently efficient to be included in uncertainty estimation frameworks.

In this work we address the question of how to simulate the injection phase of CO_2 storage in saline aquifers at field scale accurately and efficiently. In these flow settings, we need to resolve the permeability heterogeneity of a given aquifer as well as adequately represent the interplay of gravity, capillary and viscous forces.

We demonstrate that compositional streamline simulation is an accurate method of predicting the movement of CO_2 in aquifers during the injection period. We describe how to handle the compositional effects (solubility of CO_2 in brine) in a very efficient manner based on look-up tables and explicit calculation of phase distributions and compositions followed by evaluation transport properties.

METHODOLOGY

The compositional streamline approach is compared to traditional finite difference/volume simulation techniques to evaluate computational efficiencies. Existing technology for simulating CO_2 injection in aquifers include

Conventional finite difference/volume simulation

- Compositional models:
  IMPES, Fully implicit (FIM) and
  Adaptive implicit (AIM)
- Black-Oil models:
  IMPES and FIM

Streamline based simulation

- Black-oil models : 3DSL

A large literature describes the development and application of streamline simulation to prediction of flow in three-dimensional heterogeneous reservoirs. See the papers of King and Datta-Gupta (1998) and Crane *et al.* (2000) for many references to the full range of work on streamlines. The use of compositional streamline simulation for gas injection processes was demonstrated by Thiele and coworkers (Thiele *et al.*, 1995 and 1997). Jessen and Orr (2002) showed how to combine the streamline approach with multicomponent analytical solutions for three-dimensional gas displacement problems, and Seto *et al.* (2003) applied that approach to the simulation of a gas condensate recovery process. Several investigators have shown that effects of gravity can be represented by operator splitting (Crane *et al.*, 2000; Jessen and Orr, 2004). Thus, there is considerable evidence that compositional streamline methods can be applied to describe the interaction of compositional effects associated with component transfers and dissolution that occur in CO_2 sequestration processes.

A comparison of compositional streamline simulations with equivalent black-oil formulations was initially performed to assess the efficiency and accuracy of existing technology relative to compositional streamline simulation. The comparison of the streamline approach with a black-oil finite volume approach was chosen due to the simplicity and efficiency of the black-oil models over finite volume compositional models.

COMPOSITIONAL EFFECTS

For given temperature, pressure and salinity, the solubility of CO_2 in the aquifer and the amount of water vapor that is present in a CO_2-rich gas phase in equilibrium with CO_2 saturated brine can be predicted by a standard equation of state (e.g. Peng-Robinson) using a non-symmetric binary interaction coefficient matrix. The densities and viscosities of the equilibrated phases can also be predicted quit accurately using an appropriate set of temperature dependent volume translation parameters.

Given that the system in question is a binary system, very efficient calculation of the phase behavior in compositional simulation can be performed using a K-factor lookup table generated prior to performing the streamline calculation. During the initialization of a given injection calculation, temperature, salinity and expected pressure range are estimated and a one dimensional table (pressure as independent variable) is generated for the equilibrium K-factors. During the actual simulation, phase mole fractions and compositions can be calculated explicitly given the pressure (K-factors) and an overall composition.

CALCULATION EXAMPLES

The lookup-table approach has been implemented in the compositional streamline simulator CSLS and tested for two three-dimensional cases:

Example A: 50x50x10= 25000 active blocks
Example B: 180x180x16=518400 active blocks

For comparison, equivalent black-oil simulations were performed using a commercial finite volume based simulator. In the black-oil approach, solubility of CO_2 in brine is modeled by a solution gas-brine ratio (Rs) from a differential liberation experiment simulated with the thermodynamic package of the compositional streamline simulator.

3D Calculation Example

To illustrate the efficiency of compositional streamline simulation, a 4500m by 4500m by 160m section of an aquifer was represented by a 180x180x16 computational grid (Example B). The permeability distribution of the aquifer in question is shown in Fig. 1.

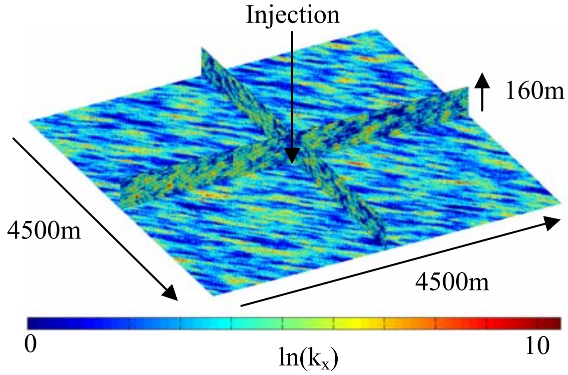


Figure 1: Permeability heterogeneity of aquifer

The average permeability is 100mD and the average porosity is 0.3. The initial pressure at the top of the aquifer is 90 bars, and CO_2 is injected at 150 bars in the center of the domain for 10 years corresponding to 2.5% of the aquifer pore volume. Fig. 2 compares the saturation distribution at the end of the injection period for the two simulation approaches. The two approaches are seen to be in good agreement.

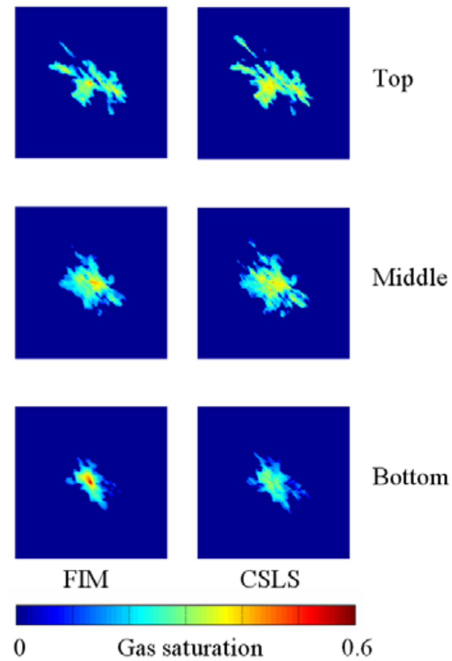


Figure 2: Distribution of gas after 10 years

In this setting, flow of the injected CO_2 is strongly affected by gravity and permeability heterogeneity. The injected CO_2 rises to the top of the formation where the flow of the plume is then restricted to high permeability zones.

The CPU time for the streamline simulation was 21 min whereas the time for running the equivalent black-oil simulation was 232 min. The modest computation time clearly demonstrates the potential of compositional streamline simulation for prediction of CO_2 injection in saline aquifers that allows for uncertainty assessment through multiple realizations of the model parameters in a reasonable time frame. An equivalent compositional finite difference calculation is not currently feasible due to the global time step restriction in IMPES models or the more diffusive nature of fully implicit (FIM) that may render the displacement calculations less accurate. These example computations demonstrate, therefore, that high resolution, three-dimensional, field-scale streamline simulations can be performed with quite reasonable computation times. A summary of CPU requirements for the investigated flow settings is given in Table 1.

Table 1: Comparison of CPU requirements: 2.8GHz

Model	N_{cells}	CSLS	FD-FIM	Ratio
A	25000	0.7 min	6 min	9
B	518400	21 min	232 min	11

DISCUSSION AND CONCLUSIONS

We have demonstrated that the proposed formulation is significantly less CPU intensive than existing methods for the flow settings typically encountered during the injection phase of CO_2 sequestration in saline aquifers. For larger scale problems with more than 500K active grid cells, the run times for the proposed formulation are more than an order of magnitude lower than those for conventional numerical approaches.

Effects of capillarity are not included in the streamline approach but can be included in conventional approaches. To gauge the impact of capillarity on CO_2 plume development, two black-oil simulations of Example A were performed. The results are shown in Fig.3.

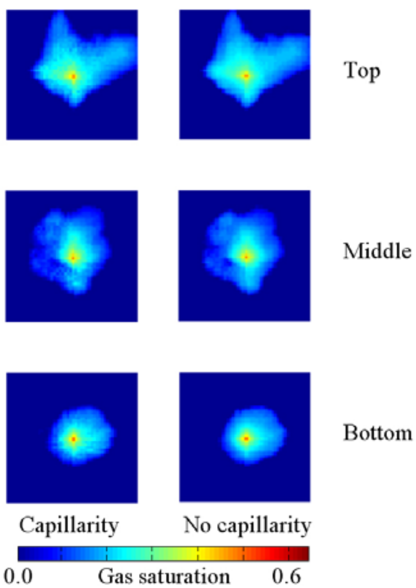


Figure 3: Effects of capillarity on CO_2 plume

Example A is a 2500m by 2500m by 100m section of an aquifer represented by a 50x50x10 computational grid. The average permeability of the aquifer is 90mD and the average porosity is 0.3. CO_2 was injected at a constant rate of 2000 Rm^3/day for a period of 3 years corresponding to ~5% of the pore volume.

Only marginal differences between the two simulations (good agreement with CSLS, not shown) are seen suggesting that gravity and viscous forces dominate the displacement process. This, in turn, suggests that capillarity may be neglected as in compositional streamline simulation for a range of sequestration projects. However, a more detailed study is required to fully understand and map out the limitations of the streamline approach for this type of displacements.

For post-injection time scales, where gravity-driven flows, diffusion of dissolved CO_2, residual trapping of CO_2 due to flow reversal and CO_2 saturation reduction as a result of additional dissolution, and geochemistry become important mechanisms determining the long term fate of injected CO_2, computational methods other than the streamline approach will be more appropriate.

Conclusions

Based on the results presented we conclude that

- Compositional streamline simulation has been demonstrated to be efficient and accurate for predicting the injection phase of CO_2 injection in saline aquifers.
- CPU requirements for the streamline approach are an order of magnitude less than fully implicit black-oil modeling. This speed-up factor is expected to increase with increasing size of aquifer model.
- Compositional streamline simulation is efficient enough to allow its use in uncertainty assessment frameworks in which a large number of realizations must be run within a reasonable timeframe.

REFERENCES

Crane, M., Bratvedt, F., Bratvedt, K., Childs, P. and Olufsen, R. A Fully Compositional Streamline Simulator, SPE 63156, SPE Annual Technical Conference and Exhibition, Dallas, TX, October 1-4, 2000.

Jessen, K. and Orr, F.M., Jr.: "Compositional Streamline Simulation," SPE 77379, SPE Annual Technical Conference and Exhibition, San Antonio, TX, September 29-October 2, 2002.

Jessen, K. and Orr, F.M., Jr.: "Gravity Segregation and Compositional Streamline Simulation," SPE 89448, SPE/DOE 14'th Symposium on Improved Oil Recovery, Tulsa, April 17-21, 2004.

King, M.J. and Datta-Gupta, A.: "Streamline Simulation: A Current Perspective," *In Situ*, 22 (1) (1998) 91-140.

Seto, C. J., Jessen, K., Orr, Jr., F. M.: "Compositional Streamline Simulation of Field Scale Condensate Vaporization by Gas Injection," SPE 79690, SPE Reservoir Simulation Symposium, Houston, TX, Feb. 3-5, 2003.Gerritsen et al (2005)

Thiele, M.R., Blunt, M.J., and Orr, F.M., Jr.: "Modeling Flow in Heterogeneous Media Using Streamlines—II," Compositional Displacements," In Situ, 19(4) (1995) 367-391.

Thiele, M.R., Batycky, R.P., and Blunt, M.J.: "A Streamline-Based 3D Field-Scale Compositional Simulator, SPE 38889, SPE Annual Technical Conference and Exhibition, San Antonio, TX, October 5-8, 1997.

ENVIRONMENTAL IMPLICATIONS OF TOXIC METALS AND DISSOLVED ORGANICS RELEASED AS A RESULT OF CO_2 INJECTION INTO THE FRIO FORMATION, TEXAS, USA

Y.K. Kharaka[1], D.R. Cole[2], J.J. Thordsen[1], E. Kakouros[1], S. Pfiffner[3], and S.D. Hovorka[4]

[1]U. S. Geological Survey
Menlo Park, CA 94025, USA
e-mail: ykharaka@usgs.gov

[2]Oak Ridge National Laboratory
Oak Ridge, TN 37831, USA

[3]Center for Biomarker Analysis
U. of Tennessee
Knoxville, TN 37932, USA

[4]Bureau of Economic Geology
University of Texas, Austin, TX 78713, USA

INTRODUCTION

Pore waters with salinities from ~5,000 to >300,000 mg/L total dissolved solids (TDS), in-situ temperatures of ~20^o to >150^{o}C and fluid pressures of ~100 to >1,000 bar, comprise approximately 20% by volume of sedimentary basins (Kharaka and Hanor, 2004). These formation waters are dominantly Na-Cl, Na-Cl-CH_3COO, or Na-Ca-Cl type, and commonly have significant amounts of dissolved gases, especially CH_4 and other hydrocarbons, but lesser amounts of the reactive gases CO_2 and H_2S. The geochemistry of basinal waters provides insight into their chemical evolution and into the economically important processes of petroleum and ore formation (Kharaka and Hanor, 2004).

Interest in the geochemistry of these waters has increased recently, because depleted petroleum fields and saline aquifers are being investigated as possible repositories for the storage of large amounts of anthropogenic CO_2 currently being released to the atmosphere. In geologic storage, CO_2 captured from fossil fuel-fired power plants may be stored in: 1) structural traps such as depleted petroleum reservoirs, primarily as supercritical immiscible fluid (hydrodynamic trapping); 2) formation water as $H_2CO_3^o$, HCO_3^- and other dissolved C-species (solution trapping); and/or 3) carbonate minerals, including calcite, magnesite, and siderite (mineral trapping) (Gunter et al., 1993; Hitchon, 1996).

Understanding gas-water-mineral interactions in sedimentary basins could facilitate the isolation of anthropogenic CO_2 in the subsurface for thousands of years, thus moderating rapid increases in concentrations of atmospheric CO_2 and mitigating global warming, arguably the most important environmental issue facing the world today (White et al., 2003). Because of economic benefits, it is likely that injection into depleted petroleum fields for enhanced oil recovery (EOR) will be the earliest method of CO_2 disposal. However, as the amount of CO_2 to be sequestered increases, deep saline aquifers will likely become preferred storage sites because of their huge potential capacity (estimated at 350-11,000 Gt of CO_2 worldwide) and advantageous locations close to the major CO_2 sources (Holloway, 1997; White et al., 2003). In addition to storage capacity and proximity to CO_2 sources, key environmental questions include the extent of CO_2 leakage related to the storage integrity, and the physical and chemical processes that are initiated by the injected CO_2 (Hepple and Benson, 2005; Kharaka et al., 2006).

In this summary, we discuss results from a US DOE funded multi-laboratory field experiment to investigate the potential for geologic storage of CO_2 in saline aquifers, emphasizing environmental implications of changes in fluid chemistry after injection. Approximately 1,600 metric tons of refinery CO_2 was injected during October 2004 into a 24-m sandstone zone of the Oligocene Frio Formation – an extensive regional petroleum and brine reservoir (Fig. 1) in the U. S. Gulf Coast (Hovorka et al., 2006). We obtained down-hole and surface samples of formation water and gas from both the injection and observation wells using a variety of sampling tools and methodologies. Samples were obtained from both wells before CO_2 injection for baseline data, during the injection to track its breakthrough and post-injection to investigate the 'residual' CO_2 (Hovorka et al., 2006) and its leakage into the overlying "B" sandstone section, and temporal changes in fluid composition (Kharaka et al., 2006).

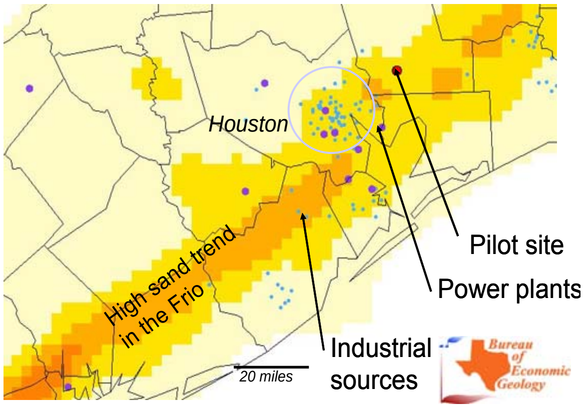


Figure 1- Location map of the many industrial sources of CO_2 and the high sand trend in the Frio Formation relative to the Frio pilot site near Houston, Texas (Modified from Hovorka, 2006).

REGIONAL SETTING AND METHODS

The Frio experimental site is located on the flank of a salt dome within the South Liberty oil field, near Dayton, Texas, a region of the Gulf Coast where industrial sources of CO_2 are abundant (Fig. 1). Oil wells in this field were drilled in 1950s, and produce from the Eocene Yegua Formation at depths of ~2900 m. An existing oil well, the Sun-Gulf-Humble Fee Tract 1, well #4, was recompleted and perforated in the Frio "C" sandstone at 1,528 -1,534 m for use as an observation borehole. About 30 m down-dip, a new CO_2 injection well was drilled and perforated also in Frio "C" at 1,541-1,546 m. Frio "C" is a poorly cemented subarkosic sandstone comprised dominantly of fine grained, moderately sorted quartz with minor amounts of illite/smectite, feldspar and calcite. The reworked fluvial sandstone has high mean porosity of 32% and permeability of 2-3 darcys. Situated immediately above the "C", the "B" sandstone has a ~4 m reworked fluvial sandstone bed at the top, but has more shale and siltstone beds, especially a ~7 m transgressive marine shale bed at the bottom. The regional barrier to CO_2 leakage, however, is expected to be the thick Miocene-Oligocene Anahuac Shale (Hovorka et al., 2006).

Approximately 1,600 tons of CO_2 were injected over a 10-day period while monitoring downhole T, P and fluid compositions in the observation borehole. Pre- and post-injection samples were obtained from both wells at ground level using gas lift, either N_2 gas or the injected CO_2; fluid samples were obtained also by swabbing the wells. Downhole sampling was carried out using evacuated Kuster samplers or the Schlumberger MDT syringe-like tool. During the CO_2 injection, intensive fluid sampling was carried out using a U- tube system (Freifeld et al., 2005) to track the arrival of CO_2. The drilling fluids were tagged with Rhodamine to allow for identification of pristine Frio brine. Water and gas samples collected using the U-tube and other tools were subjected to detailed field and laboratory chemical and isotope analyses described in Kharaka and Hanor (2004).

RESULTS AND DISCUSSION

Chemical analysis of brine and gas samples obtained from both wells prior to CO_2 injection show that the Frio water is a Na-Ca-Cl type, with a relatively constant salinity of 93,000±3,000 mg/L TDS. The brine has relatively high concentrations of Mg, and Ba, but low values for SO_4, HCO_3, DOC and organic acid anions (Kharaka et al., 2006). Careful measurements of the volumes of water and evolved gas obtained with downhole samplers show the pristine Frio brine to have 40-45 mM dissolved CH_4, which is close to saturation at reservoir conditions of 65°C and 150 bar (Spycher and Reed, 1988). Gas analysis show that CH_4 comprises 95±3 % of total gas, but dissolved CO_2 content of the gas is relatively low at ~0.3%; N_2 and C-2 and higher hydrocarbon gases comprise the remaining gas. This gas composition is similar to results showing that brines to depths > 6 km in the Gulf of Mexico basin are saturated with CH_4 and have low CO_2 fugacities (Hutcheon, 2000; Kharaka and Hanor, 2004).

During the CO_2 injection, October 4-14, 2004, more than 40 water samples were collected from the observation well. The electrical conductance (EC) exhibited a slight increase from a pre-injection value of ~120 mS/cm (at ~22 °C), whereas there were major changes in some parameters as the CO_2 reached the observation well, including a sharp drop in pH (from 6.5 to 5.7) and high increases in alkalinity (from100 to 3,000 mg/L as bicarbonate). Additionally, laboratory analyses showed major increases in dissolved Fe (from 30 to 1,100 mg/L) and Mn, (3-18 mg/L) (Fig. 2) and significant increases in the concentration of Ca. The most dramatic changes occurred at CO_2 breakthrough 52 hours after the start of injection, as shown also by on-site analysis of gas samples from the U-tube system when CO_2 concentrations increased from 0.3 to 3.6% of total gas (Freifeld et al., 2005). The CO_2 content of gas measured on site and in the laboratory then quickly increased, reaching values of up to ~97% of total gas, with CH_4 comprising the bulk of the remaining 3% (Kharaka et al., 2006).

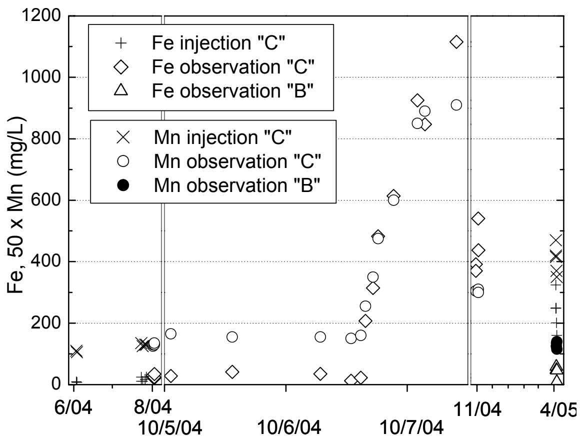


Figure 2- Concentrations of Fe and Mn in Frio brine from June, 2004 to April, 2005. Note the sharp increases in metal content during October 6, 2004, at the time of CO_2 breakthrough.

Results of geochemical modeling, using updated SOLMINEQ (Kharaka et al., 1988) indicate that the Frio brine in contact with the supercritical CO_2 would have a pH of about 3 at subsurface conditions, and this low pH causes the brine to become highly undersaturated with respect to carbonate, aluminosilicate and most other minerals present in the Frio Formation. Because mineral dissolution rates are generally higher by orders of magnitude at such low pH values (Palandri and Kharaka, 2004), the observed increases in concentrations of HCO_3 and Ca likely result from the rapid dissolution of calcite. The absence of Mg-concentration increases indicate insignificant dissolution of dolomite and magnesite.

The observed large increases in concentrations of Fe and equivalent bicarbonate could result from dissolution of siderite, but no siderite was observed in the retrieved core; they likely are caused by dissolution of the observed iron oxyhydroxides. There were also increases in the concentration of other metals, including Mn, Zn, Pb and Mo, which are generally associated (sorbed and coprecipitated) with iron oxyhydroxides. Rapid mineral dissolution could have important environmental impacts by mobilizing Fe and associated toxic components and creating pathways in the rock seals and well cements that could facilitate leakage of CO_2 and brine.

Microbial Populations and Organics

During the CO_2 injection, fluid samples were collected and analyzed to monitor microbial biodensity and community composition and to assess community stress. Membrane lipid biosignatures quantified were phospholipid fatty acids (PLFA) and quinones. Prior to CO_2 breakthrough, microbial biodensity averaged $7x10^6$ cells/L, whereas following breakthrough, biodensity averaged $4x10^7$ cells/L. Thus, CO_2 injection increased microbial biomass recovery by ~6 fold. Community composition prior to CO_2 breakthrough revealed a predominance of normal saturate and eukaryotic PLFA. After CO_2 breakthrough the proportions of monounsaturates and terminally branched saturates increased. Assessing community stress revealed that 40% and 82% of samples showed signs of stress before and after CO_2 breakthrough, respectively. Analysis of quinone composition provides an estimate of respiratory potential in the samples. Prior to CO_2 breakthrough ubiquinones dominated, whereas following breakthrough menaquinones dominated. This indicated a shift to more redox-reduced conditions. Hydrocarbons recovered during PLFA extraction were analyzed by GC-MS. Following CO2 breakthrough there was an increase in the type and amounts of hydrocarbons recovered.

Data on dissolved organics, with the exception of gases, were not initially emphasized, since there is no petroleum production from the Frio Formation at this site. The dissolved organic carbon (DOC) values obtained are expectedly low (1-5 mg/L) in the pristine Frio brine from both the “B” and the “C” sandstones. The DOC values obtained from the “C” sandstone during the CO_2 injection increased moderately to 5-6 mg/L; the values, however, increased unexpectedly by a factor of 100 on samples collected ~20 days after injection stopped (Fig. 3). The concentrations of organic acid anions and BTEX in these samples were low (<1 mg/L), but with formate, acetate, and toluene exhibiting higher values in the enriched DOC samples.

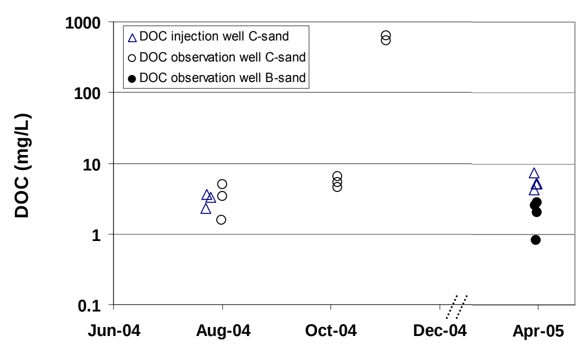


Figure 3- Concentration of dissolved organic carbon (DOC) in Frio brine. Note the extremely high values obtained on November, 2004, ~ 20 days after the end of CO_2 injection

Following the very high DOC values, we instituted a more detailed sampling protocol for 6- and 14-months after injection that included aliquots for oil and grease, and for detailed GC-MS analysis for volatile organic compounds (VOCs) and semi-VOCs. Results to date show all oil and grease values were below detection limit, and for samples from the “C” zone of the injection well, we obtained low levels of

VOCs (up to 30 ppb phenol) and semi-VOCs (30 ppb naphthalene), and only slightly elevated DOC values (4.5-7.5 mg/L) values (Fig. 3).

It is difficult to rule out contamination for the very high DOC values, but they likely represent a 'slug' of organic matter mobilized by the injected CO_2, as generally happens during EOR operations (Shiraki and Dunn, 2000). If this conclusion is supported by future studies, then mobilization of organics, including BTEX and other toxic organics from non oil-bearing aquifers, could have major implications for the environmental aspects of CO_2 storage and containment. The concern here is warranted as high values of toxic DOCs, including benzene, toluene (up to 60 mg/L for BTEX), phenols (<20 mg/L), and polyaromatic hydrocarbons (up to 10 mg/L for PAHs), have been reported in oil-field waters (Kharaka and Hanor, 2004).

ENVIRONMENTAL ISSUES OF CO2 STORAGE

Deep saline aquifers and depleted petroleum fields in sedimentary basins provide advantageous locations close to major CO_2 sources and huge potential capacity for the storage of large amounts of this GHG (Holloway, 2001). The Frio brine field test demonstrated the relatively straight forward method of CO_2 injection and its rapid transport to the observation well. Our field geochemical methodologies, especially measurements of pH, alkalinity and gas compositions (Freifeld et al., 2005) proved highly effective for tracking the injected CO_2. The tracking of CO_2 was later confirmed by laboratory determinations of dissolved Fe, Mn, and Ca, and isotopes, especially $\delta^{18}O$ values of brine and CO_2, and $\delta^{13}C$ values of DIC (dissolved inorganic carbon) and CO_2 (Kharaka et al., 2006).

The chemical data coupled with geochemical modeling indicate rapid dissolution of minerals, especially calcite and iron oxyhdroxides caused by low pH brine. This dissolution could have important environmental implications with regard to creating pathways in the rock seals and well cements that could facilitate leakage of CO_2 and brine. Maintaining reservoir integrity that limits CO_2 leakage to very low levels is essential to the success of injection operations (Hepple and Benson, 2005). Preventing brine migration into overlying drinking water supplies is equally important, because dissolution of minerals would mobilize Fe, Mn and other toxic metals, in addition to the chemicals in the pristine brine. Mobilization of organics, including BTEX, phenols and other toxic compounds, from this non oil-bearing aquifer would further compound the environmental severity of CO_2 and brine leakage.

Data on brine and gas compositions of samples from the "B" sandstone of the Frio Formation obtained ~6 months after the end of injection test are discussed in Kharaka et al. (2006). Preliminary and incomplete results on samples collected in January, 2006, ~14 months after the end of injection indicate no significant CO_2 leakage from the underlying "C" sandstone. This important result, together with additional changes in brine and gas compositions of fluids in the "C" sandstone is being investigated with more complete brine and gas analyses.

ACKNOWLEDGMENTS

We thank our colleagues G. Ambats, S. Nance, W. Evans, and B. Topping for their help with sampling and chemical analysis. We are grateful for logistical support from Dan Collins and others at Sandia Technologies, LLC. Financial support was provided by DOE-NETL (Karen Cohen, program coordinator).

REFERENCES

Freifeld, B.M., Trautz, R.C., Kharaka, Y.K., et al., 2005. The U-tube: A novel system for acquiring borehole fluid samples from a deep geologic CO_2 sequestration experiment. J. Geophys. Res., 110, B10203, 10.1029/2005JB003735.

Gunter, W.D., Perkins, E.H., and McCann, T.J., 1993. Aquifer disposal of CO_2-rich gases: reaction design for added capacity. *Ener.Convers. Mgmt.* 34, 941-948.

Hepple, R. P., and Benson, S. M., 2005. Geologic storage of carbon dioxide as a climate change mitigation strategy; performance requirements and the implications of surface seepage. Environmental Geology, v. 47, p. 576-585.

Hitchon, B. (Ed.), 1996. Aquifer Disposal of Carbon Dioxide. Geoscience Publishing Ltd., Sherwood Park, Alberta, Canada, 165 p.

Holloway, S., 1997. An overview of the underground disposal of carbon dioxide. *Energy Convers. Mgmt.*, 38, S193-S198.

Holloway, S., 2001. Storage of fossil fuel derived carbon dioxide beneath the surface of the earth. In: Annual Review of Energy and the Environment, v. 26, p.145–166.

Hovorka, S.D., Benson, S.M., Doughty, C.K., et al., 2006. Measuring permanence of CO_2 storage in saline formations – the Frio Experiment. Environ. Geosciences. In print.

Hutcheon I. 2000. Principles of diagenesis and what drives mineral change; chemical diagenesis. In *Fluids* *and basin evolution* (ed. K. Kyser), pp.93-114. Miner. Assoc.of Canada, Short Course # 28.

Kharaka, Y.K., and Hanor, J.S., 2004. *Deep fluid in the continents: I. Sedimentary basins,* in *Treatise on Geochemisty, v.5, Surface and Ground Water, Weathering, and Soils*, Elsevier, 499–540.

Kharaka, Y.K., Gunter W.D., Aggarwal P.K., Perkins E.H., and DeBraal J.D., 1988. SOLMINEQ.88: A computer program for geochemical modeling of water-rock interactions. U.S. Geological Survey Water Resources Invest. Rep. 88-4227.

Kharaka, Y.K., Cole, D.R.,Thordsen, J.J., Kakouros, E., and Nance, H.S., 2006. Gas-water-rock interactions in sedimentary basins: CO_2 sequestration in the Frio Formation, Texas, USA. Proc. Geofluids V, Windsor, Ontario, Canada.

Palandri, J.L., and Kharaka, Y.K, 2004. A compilation of rate parameters of water-mineral interaction kinetics for application to geochemical modeling: U.S. Geological Survey Water-Resources Investigations Rep. 04-1068, 70 p.

Spycher, N., and Pruess, K., 2005. CO_2-H_2O mixtures in the geological sequestration of CO_2. II. Partitioning in chloride brines at 12–100°C and up to 600 bar. Geochim. Cosmochim. Acta, 69, 3309-3320.

Shiraki, R., Dunn, T.L., 2000. Experimental Study on Water-Rock Interactions during CO2 Flooding in the Tensleep Formation, Wyoming, USA; *Applied Geochem.*, v. 15, p. 265-279.

White, C.M., Strazisar, B.R., Granite, E.J., Hoffman, J.S., and Pennline, H.W., 2003. Separation and capture of CO2 from large stationary sources and sequestration in geological formations—coalbeds and deep saline aquifers. *J. Air & Waste Manage. Assoc.* 53, 645–715.

MAN-MADE EARTHQUAKES AND THE IMPORTANCE OF ACCURATE SITE CHARACTERIZATIONS FOR CO_2 GEOLOGICAL STORAGE

Christian D. Klose

Lamont-Doherty Earth Observatory at Columbia University
Center for Hazards & Risk Research
P.O. Box 1000, 61 Route 9W
Palisades, NY 10964, U.S.A.
e-mail: cklose@ldeo.columbia.edu

INTRODUCTION

Man-made earthquakes are a partially hidden issue in both communities of earth engineers and seismologist. A common notion is that most man-made earthquakes are small and shallow. But, there are more than 70 known earthquakes published since the 1930s with magnitudes $4.5 < M_w < 7$ that were triggered by human actions. These earthquake magnitudes can not be considered as small but they are shallow. This extended abstract emphasizes briefly why most man-made earthquakes can nucleate very shallow in the crust and why accurate geological site characterizations are very important for CO_2 long-term storage in geological sinks.

DATA AND DISCUSSION

Geomechanical Pollution (GMP)

The amounts of CO_2 that would need to be injected in geological sinks such as deep saline aquifers to achieve a significant reduction of atmospheric emissions are very large. For example, a large 1000 Megawatt (MW) coal fired power plant emits approximately 30,000 t of CO_2 per day (Hitchon, 1996), 10 Mt per year, and hence approximately 0.3 Gt over a typical lifetime of 30 years. The resulting mass change of CO_2 injected underground in an area of 100 km^2 or more (Pruess, 2005) is enough to change the vertical in-situ stress by 0.01 MPa in a depth of 10 km (Figure 1). In addition, fluid pressure increases in excess of 0.1 MPa would extend over an area of more than 2,500 km^2 (Pruess, 2005) in shallow depth (<2.5km).

Observations have shown that a stress change of 0.01 MPa is enough to trigger earthquakes (Seeber et al., 1998; Harris et al., 1995; Steacy et al. 2005; Klose, 2006a). An induced shear stress change of at least 0.01 MPa might significantly destabilize a pre-existing fault under certain geological conditions. Anthropogenic fault destabilization, called *geomechanical pollution* (GMP), can trigger or induce earthquakes.

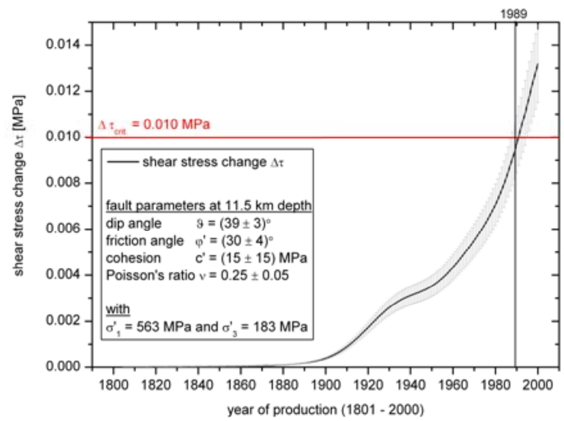


Figure 1. Simulation result shows a shear stress change in the Newcastle fault in 11.5 km depth, the hypocenter of the 1989 M5.6 Newcastle earthquake. Geomechanical pollution (GMP) has been caused by large-scale industrialization in an area of 2,400 km^2 since 1801 (3 Gt mass removals due to coal mining and water over-exploitation); it is still accelerating (Klose, 2006a). The simulation "predicts" an earthquake in 1991±4 years.

Man-made Earthquakes

Triggered seismicity are earthquakes ($M_w > 2.5$) caused by failure of larger rock mass discontinuities (m-km scale) due to a *normal* shear stress increase (shear failure following mass accumulations).

Induced seismicity describes micro-earthquakes ($M_w < 2.5$) caused by failure of intact rock or smaller rock mass discontinuities (mm-m scale) due to tension or an *abnormal* shear stress increase (hydro-fracturing following high-pressure injections).

Studies about man-made earthquakes that are thought to be triggered by human actions were mostly related to the poro-elastic behavior of the rock mass due to fluid flow e.g. induced by reservoir impounding (e.g. Gupta, 1992; Simpson 1992), oil/gas production (e.g. Grasso, 1992) or fluid injection (e.g. Healy et al., 1968; Raleigh et al. 1976, Knoll, 1990; Seeber et al., 1998). Such induced stress changes might destabilize only shallow faults in the uppermost part of the crust. Their influence in lower parts of the crust which are distant to the location of geoengineering activities seems to be small - in most cases. This could be an explanation why man-made earthquakes are shallow.

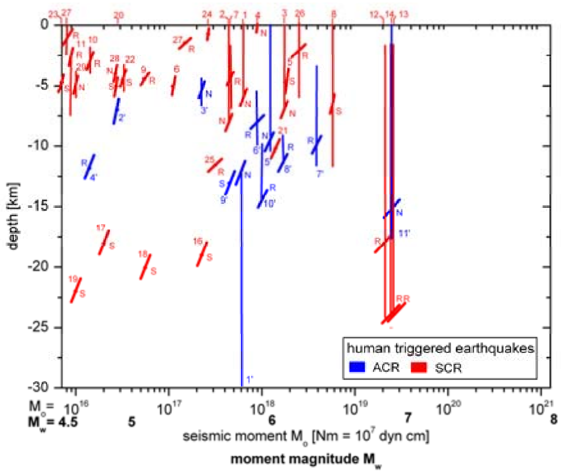


Figure 2. Depth distribution of human triggered earthquakes (m – mining, or – oil recovery, gr – gas recovery, d – dam, fi – fluid injection, q – quarry) in ACRs and SCRs. Vertical lines indicate depth range of rupture and the average moment per unit depth. The short segments indicate rupture dip and nucleation depth (R = reverse, S = strike-slip and N = normal) (Klose, 2006b): Australia: 25 Newcastle^{m}, 28 Ellalong^{m}, North-America: 9 Snipe field^{or}, 22 Perry^{fi}, 27 Cacoosing^{q}, 29 Trinidad^{fi}, India: 8 Koyna^{d}, 20 Bhatsa^{d}, 26 Killari^{d}, Africa: 1-4 Kariba^{d}, 16-19 Aswan^{d}, Europe 6 Monteynard^{d}, 7 Lacq^{gr}, 24 Völkers-hausen^{m}, Asia: 5 Xinfengjiang^{d}, 10 Staro Gronznenkoi^{or}, 11 Nurek^{d}, 12-14 Gazli^{gr}, 21Barsa-Gelmes-Vishka^{or} and North-America: 3' Denver RMA^{fi}, 4' Mc Naughton^{d}, 5' Oroville^{d}, 7' Coalinga^{or}, 8' Kettleman^{or}, 10' Whittier Narrows^{or}, Asia: 6' Srinagarind^{d}, Europe: 1' Kremasta^{d}, 2' Bajina Batsa^{d}, 9' Provadia^{m}, 11' Kozani–Grevena^{d}.

The possibility of earthquake triggering due to human actions would be negligible if the upper third of the crust (< 7-10 km) tends to be aseismic as active continental regions (ACRs) such as California, Turkey or Japan. But, most triggered earthquakes occur in stable continental regions (SCRs) such as many parts of America, Eurasia, Africa or Australia (Figure 2) although the natural seismicity in SCRs is much smaller than in ACRs. This phenomenon can be explained because a majority of natural SCR-earthquakes nucleate very shallow in the upper crust (< 7 km), where litho-static conditions (e.g. high differential in-situ stress) are more likely to be perturbed by human actions at the sub/surface (Klose and Seeber, 2006; Klose, 2006b). For example, 200 years large-scale industrialization triggered the 1989 M5.6 Newcastle earthquake in Australia (Figure 1) resulting in 3.5 billion U.S. dollars damage (1989 values). Many man-made earthquakes have magnitudes $M_w \approx$ 5-6 and occur statistically more often. They are likely to produce higher mesoseismal intensities and reach damage thresholds at lower magnitudes.

CONCLUSION

First, this article shows that many man-made earthquakes nucleate very shallow in the uppermost part of the crust within stable continental regions (SCRs) because natural SCR-seismogenesis is bimodal distributed (0-10 km and 20-30 km) with a very shallow upper crustal component. Second, human triggered earthquakes are not small. They reach magnitudes up to $M_w \approx 7$ although many devastating earthquakes have lower magnitudes such as the 1989 M5.6 Newcastle mainshock. This event resulted in 3.5 billion U.S. dollars damage (1989 values) and Australia's first and to date only fatalities with 13 deaths. These facts (human triggered earthquakes are shallow and can be strong) show that it should be of high priority to investigate, a priori, in field studies to assess accurate geological conditions in the vicinity of planned CO_2 injection sites.

ACKNOWLEDGMENT

Christian D. Klose expresses his gratitude to the German Science Foundation (DFG) which has been funding this study (KL 1833/1).

REFERENCES

Grasso, J.R., Mechanics of seismic instabilities induced by the recovery of hydrocarbons. *Pure and Applied Geophysics, 139*, 507-534, 1992.

Gupta, H.K., *Reservoir-Induced Earthquakes,* Elsevier, New York, 1992.

Harris, R. A., R. W. Simpson, and P. A. Reasenberg, Influence of static stress changes on earthquake locations in southern California, *Nature, 375*, 221-224, 1995.

Healy, J.H., Rubey, W.W., Griggs, D.T., and Raleigh, C.B., The Denver earthquakes, *Science, 161*, 1,301–1,310, 1968.

Hitchon, B., *Aquifer Disposal of Carbon Dioxide*, Geoscience, Sherwood Park, Alberta, Canada.

Klose, C.D. and Seeber, L., Shallow Seismicity in Stable Continental Regions (SCRs), (in publication process), Seismological Research Letters, 2006.

Klose, C.D., Large-scale industrialization can trigger catastrophic earthquakes, (in publication process), *Nature*, 2006a.

Klose, C.D., Are man-made earthquakes shallow and small?, (in publication process), *Earth and Planetary Science Letters*, 2006b.

Knoll, P., The fluid-induced tectonic rock burst of March 13, 1989 in Werra potash mining district of the GDR (first results). *Gerlands Breiträge zur Geophysik*, 99, 239-245, 1990.

Pruess K., Numerical studies of fluid leakage from a geologic disposal reservoir for CO2 show self-limiting feedback between fluid flow and heat transfer, *Geophysical Research Letters, 32*, 2005.

Raleigh C.B., J.H. Healy and J.D. Bredehoeft, An Experiment in Earthquake Control at Rangely, Colorado, *Science,* 191, 1230, 1976.

Seeber, L., J. G. Armbruster, W.-Y. Kim, N. Barstow and C. Scharnberger, The 1994 Cacoosing Valley earthquakes near Reading, Pennsylvania: A shallow rupture triggered by quarry unloading, *Journal of Geophysical Research, 103*, 24505-24521, 1998.

Simpson, D.W., A.A. Gharib and R.M. Kebeasy, Induced Seismicity and Changes in Water Level at Aswan Reservoir, Egypt, *Gerlands Breiträge zur Geophysik*, 191, 191-204, 1992.

Steacy, S., Gomberg, J., and Cocco, M., Introduction to special section: Stress transfer, earthquake triggering, and time-dependent seismic hazard, *Journal of Geophysical Research*, 110, 1-12, 2005.

MINERAL TRAPPING OF CO_2 IN GEOTHERMALLY USED AQUIFERS - REACTIVE TRANSPORT SIMULATION ON MULTIPLE SCALES

Michael Kühn and Christoph Clauser

RWTH Aachen University, Applied Geophysics
Lochnerstrasse 4-20
D-52056 Aachen, Germany
e-mail: m.kuehn@geophysik.rwth-aachen.de

INTRODUCTION

Costs for carbon dioxide (CO_2) sequestration into deep saline aquifers can be transformed into a benefit in combination with ecologically desirable geothermal heat or power production. The current "CO_2Trap" project aims to develop a scientifically and technically feasible new technology to achieve a safe and economically attractive long-term storage of CO_2 trapped in minerals (Kühn et al., 2005). Numerical models are applied to study injection of aqueous CO_2 into the subsurface and to quantify subsequent precipitation of calcite ($CaCO_3$) in potential geothermal reservoirs.

GEOTHERMICS AND CO_2 STORAGE

Exploitation of geothermal energy in Germany is mainly provided from deep sandstone aquifers. The common arrangement of boreholes is the well doublet, consisting of one well for hot water production and one well for cooled water re-injection. The cooled water is loaded with dissolved CO_2. After re-injection into the reservoir this cold water becomes enriched in calcium e.g. due to dissolution of anhydrite ($CaSO_4$). Subsequently CO_2 will react with the calcium ions to form and precipitate calcium carbonate. Following chemical reactions need to be considered with regard to CO_2 storage in geothermal reservoirs:

- Because the solubility of anhydrite increases with decreasing temperature, injecting cold water dissolves anhydrite in a growing region around the well: $CaSO_4 <=> Ca^{++} + SO_4^{--}$
- Before the re-injection, brines will be enriched with carbon dioxide generating carbonic acid: $CO_2 + H_2O <=> H_2CO_3 <=> H^+ + HCO_3^-$
- The favored reaction path, the transfer of anhydrite into calcite, leads to a surplus of acid: $CaSO_4 + H_2CO_3 <=> CaCO_3 + 2\ H^+ + SO_4^{--}$
- Alkalinity to buffer the reaction can be provided from rock forming minerals (e.g. oligoclase): $[NaAlSi_3O_8]_2[CaAl_2Si_2O_8] + 4\ H^+ + 10\ H_2O => 2\ Na^+ + Ca^{++} + 4\ H_4SiO_4 + 2\ Al_2Si_2O_5(OH)_4$

NUMERICAL SIMULATIONS

Numerical simulation is a means to quantify the entire process of CO_2 storage and provide deeper understanding of the detailed chemical processes. Simulations are performed on multiple scales, because as yet the combination of all scales from regional down to micro-scale is not feasible.

Programs SHEMAT (Clauser, 2003) and PHREEQC (Parkhurst and Appelo, 1999) have been applied for these simulations. SHEMAT provides two chemical modules: one is based on Pitzer's approach and the other one on the Debye-Hückel theory for ion activity calculations in highly saline brines and dilute solutions, respectively. PHREEQC is based on the Debye-Hückel theory. Although the Pitzer equations currently represent the most accurate approach for calculating ion activities in brines, aluminum is unfortunately not yet represented in the data set due to lacking Pitzer coefficients. Therefore, many rock forming minerals cannot be taken into account. For this reason we have applied both Pitzer equations (using SHEMAT) and Debye-Hückel theory (applying SHEMAT and PHREEQC) for the following simulations.

Batch reaction calculations

Using batch reaction calculations with PHREEQC we elaborate the thermodynamic background of the transformation of anhydrite into calcite.

The initial water composition and mineralogy was set according to chemical analyses of the brine and reservoir rock determined for the potential geothermal site at Stralsund (Kühn et al., 2002). In accordance with the technical process planned, the formation water has been cooled, enriched with CO_2, and brought into contact again with the reservoir minerals. Results demonstrate that weathering of plagioclase is a prerequisite for calcite precipitation. Without the buffering capacity of plagioclase no CO_2 can be bound. However, plagioclase dissolution itself is insufficient. For an increased rate of dissolution and in turn an increased buffering, a secondary siliceous phase, such as kaolinite, needs to be formed.

Because the initial calcium concentration of the brine is high, the additional and small increase resulting from dissolution of anhydrite does not affect the solubility product of calcite. However, anhydrite dissolution is important because its dissolution creates new pore space which balances the pore space reduction by the precipitation of calcite. The amount of calcite produced nearly equals the amount of anhydrite dissolved. Hence, for mass balance calculations the storage capacity of a geothermal reservoir can be estimated by its anhydrite amount.

Borehole-scale

Simulations on the borehole-scale confirm the viability of the transformation of anhydrite into calcite. The cooled, re-injected water spreads radially from the injection well. Due to its retrograde solubility, anhydrite is dissolved around the well. CO_2 was precipitated as calcite due to the increase of the calcium concentration in the water and the enrichment of the injected brine with CO_2.

The numerical simulations on the borehole-scale were performed with the chemical module of SHEMAT based on Pitzer's equations for highly saline solutions. As discussed above this excludes the study of buffering rock forming minerals like plagioclase. However, a sensitivity study was conducted defining varying pH values from 5 to 8 for the injected brine (imitated buffering). Results show that no calcite can be produced at a pH of 5 in contrast to pH values of 6, 7, and 8 when calcite is precipitated. The entire dissolution of anhydrite in a growing region around the well leads to a moving front of calcite. As soon as the calcium concentration of the water has decreased, due to a lack of dissolvable anhydrite, calcite starts to dissolve again and is transported away from the well.

Micro-scale

The numerical simulations on the micro-scale are generic experiments. The idea is that a certain volume of mineralized solution can only react with one mineral at a time because it can only be at one location at a time. In traditional reactive transport simulations a specific but averaged and homogenized mineral assemblage is considered for one model element or cell. Our model measures 1 cm by 3 cm and is discretized into 1 mm by 1 mm cells. Applying the mineral composition of the Stralsund location and based on a random distribution, model elements were assigned to specific minerals (quartz, plagioclase, K-feldspar, or anhydrite).

Two scenarios were considered on the micro-scale. The first one as described before with one mineral for each model cell. The second one was set up in a way that all initial mineral phases are available in each cell of the model (traditional approach). A comparison between the two scenarios reveals that the water composition finally is the same after its way through the rock assemblage. However, the resulting rock alteration assemblage shows significant differences between both models. The traditional scenario produces a planar and moving calcite reaction front. In the generic model the resulting calcite distribution is heterogeneous and seems to be permanent.

CONCLUSIONS

We demonstrate the feasibility of transforming anhydrite into calcite by thermodynamic modeling. The reaction proceeds at pH values higher than approximately 5.5. Buffering capacity (alkalinity) from the reservoir rock is necessary for the transformation of anhydrite into calcite. Although it turns out that anhydrite is not the major player from the chemical point of view, its dissolution with concurrent pore space increase is important to balance the pore space reduction by precipitation of calcite and secondary silicates in the geothermal reservoir. For further simulations it will be important to consider kinetic reactions and to study the porosity – permeability feedback.

Simulations on the micro-scale reveal that heterogeneity has important effects for the larger-scale and need to be studied in detail in the future.

ACKNOWLEDGMENT

The CO_2Trap project is part of the R&D-Programme GEOTECHNOLOGIEN funded by the German Ministry of Education and Research (BMBF) and German Research Foundation (DFG), Grant (03G0614A)

REFERENCES

Clauser, C. (ed), *Numerical Simulation of Reactive Flow in Hot Aquifers – SHEMAT and Processing SHEMAT*, Springer Publishers, Heidelberg-Berlin, 2003.

Kühn M., J. Bartels and J. Iffland, Predicting reservoir property trends under heat exploitation: Interaction between flow, heat transfer, transport, and chemical reactions in a deep aquifer at Stralsund, Germany. Geothermics, 31(6), 725-749, 2002.

Kühn, M., S. Asmus, R. Azzam, M. Back, A. Busch, H. Class, C. Clauser, A. Dengel, T. Dose, J. Ewers, R. Helmig, K. Jaeger, T. Kempka, B.M. Krooß, R. Littke, S. Peiffer, R. Schlüter, H. Stanjek, J. Strobel, K. Vosbeck, M. Waschbüsch, CO_2Trap – Development and Evaluation of Innovative Strategies for Mineral and Physical Trapping of CO2 in Geological Formations and of Long-Term Cap Rock Integrity. In: Stroink, L. (ed) *Investigation, Utilization and Protection of the Underground.* Geotechnologien Science Report 6, Koordinierungsbüro Geotechnologien, ISSN 1619-7399, 42-59, 2005.

Parkhurst, D.L. and C.A.J. Appelo, *User's guide to PHREEQC (version 2)--A computer program for speciation, batch-reaction, one-dimensional transport, and inverse geo-chemical calculations,* U.S. Geological Survey Water-Resources Investigations Report 99-4259, 1999.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

THERMO-HYDRO-CHEMICAL PERFORMANCE ASSESSMENT OF CO_2 STORAGE IN SALINE AQUIFER

Yann Le Gallo, Laurent Trenty, Anthony Michel, Teddy Parra

Institut Français du Pétrole (IFP)
1&4 avenue de Bois-Préau
92 852 Rueil-Malmaison, France
e-mail: Yann.Le-Gallo@ifp.fr

INTRODUCTION

Long-term CO_2 storage in aquifer may well be an interesting option to mitigate atmospheric CO2. However, detail site characterization must be carried out prior to any long-term storage. Key to performance assessment of such storage are the multiphase fluid flow simulators. Such simulators must account for permeability (intrinsic and relative) heterogeneities but also the pressure temperature effect on CO_2 as a free or trapped phase (supercritical or gaseous) or dissolved within the aquifer.

Given the time-scale of CO_2 storages in saline aquifers (over a 1000 years), several additional driving forces must be modeled, i.e., diffusion and dispersion within the aquifer and its geosphere (cap-rock and overburden), but also the role of pressure and temperature gradients both natural and induced during the injection process (short-term). Coupled to these hydrodynamical forces, geochemical and geomechanical influence should be carefully modeled to assess the long-term behavior of the CO_2 plume.

MODELING APPROACH

A 3-D 3-phase multi-component model, COORES, was built to assess the influence of different driving forces both hydrodynamics and geomechanics as well as geochemical on the CO_2 plume behavior during injection and storage (1000 years). Different coupling strategies were used to model these phenomena:

• pressure, temperature and diffusion are solved implicitly for better numerical stability. The PVT is describe either through an equation of state or tabulated partitioning factors. The diffusion is modeled through Fick's law. Finite volume approach is used to discretize the partial differential set of governing equations.

• geochemical reactions involve heterogeneous kinetically-controlled reactions between the host rock and the CO_2-rich aqueous phase which imply an sequential implicit coupling with fluid flow. The reaction source term in the mass balance governing equation can be expressed as

$$R_p^k = k_{reac}^k e^{-\frac{E_a}{RT}} \bullet S_{reac} \bullet \left[1-\left(\frac{Q_p^k}{K_{eq,p}^k}\right)^n\right]$$

The aqueous phase chemical reactions are assumed to be at equilibrium and no oxydo-reduction reaction is assumed.

• geomechanical influence is due to pressure and stress variations within and around the aquifer mainly during the injection phase. The stress changes may then alter the fluid flow parameters. To model these interactions, the hydro-mechanical equations is solved using a reservoir simulator in conjunction with a geomechanical simulator. The approach used exchange information between two dedicated software (ABAQUS and COORES) through a flexible interface allowing iterative or explicit coupling to update the pore volume. The reservoir grid is imbedded within the geomechanical grid that account for the geosphere stress change.

Geomechanical and geochemical variations induce porosity and permeability changes assuming different porosity-permeability laws such as Kozeny-Carman, Labrid or Fair-Hatch laws.

3-D CO_2 STORAGE IN AN HETEROGENEOUS SALINE AQUIFER

To illustrate the model capabilities, a 3-D saline aquifer is modeled (3000 x 6000 x 200 m) with about 50 000 grid blocks. The different sand bodies, with a permeability of 2500 mD and porosity of 35%, are separated by shale layers with permeability of about 10 mD and porosity of 10%. The mineralogy is derived from Nghiem et al (2004). The different mineral volume fractions are different in the shale, kaolinite and k-feldspar rich, and sand, quartz rich. The aquifer water is at equilibrium with the rocks. CO_2 is injected at a rate of 1Mt/y. The lateral boundaries of the model are at hydrostatic condition, the top and base boundary is assumed to be no-flow.

A phenomenological modeling of the storage shows that no significant geomechanical influence is expected since, during the CO_2 injection, pressure variation is negligible (c.a. 0.1 bar due to high permeability of the sand bodies). The influence of geochemistry is quite minor as well since no significant porosity and consequently permeability variation is computed over the whole storage life (1000 years).

As illustrated by the pH variations in Figure1, most of the geochemical change occurs within the CO_2-rich water region. This altered zone extend long after the CO_2 injection is finished since the CO_2-rich water migrate downward due to buoyancy. Figure 1 also illustrate the open lateral boundary condition (hydrostatic pressure) of the model as the CO_2-rich water spread over the top of the aquifer.

Due to the parallel kinetic reactions with different reaction rates, calcite mainly dissolves fairly rapidly in the reservoir (Figure 2) while illite mostly precipitates over long storage time (Figure 3). This behavior is consistent with Nghiem et al (2004). However, due to petrophysical and mineral heterogeneities between sand and shale, the mineral mole fraction variation is quite heterogeneous as shown in Figures 2 and 3 following the shale and sand layer distribution.

CONCLUSIONS

A new and efficient coupling approach is implemented to model reactive transport over CO_2 geological storage. The sequential implicit algorithm of COORES induce a CPU time overhead of about 65 % for the reactive transport modeling (7 minerals, 32 aqueous species and 8 chemical elements) with respect to the two-phase flow modeling (50000 grid blocks).

REFERENCES

Nghiem, L., P. Sammon, J. Grabenstetter and H. Ohkuma, Modeling CO_2 storage in aquifers with a fully-coupled geochemical EOS compositional simulator, SPE 89474, Proceedings of 14th SOE/DOE Symposium on Improved Oil Recovery, Tulsa, 2004

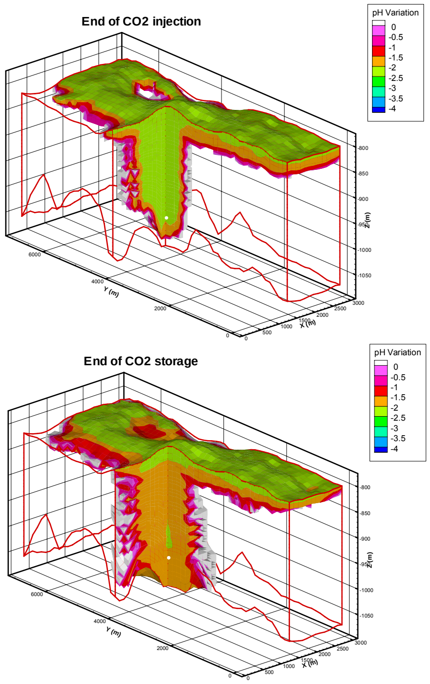


Figure 1. *pH variations at end of CO2 injection (50 years) above and at end of storage (1000 years) below. The white dot correspond to the injection point.*

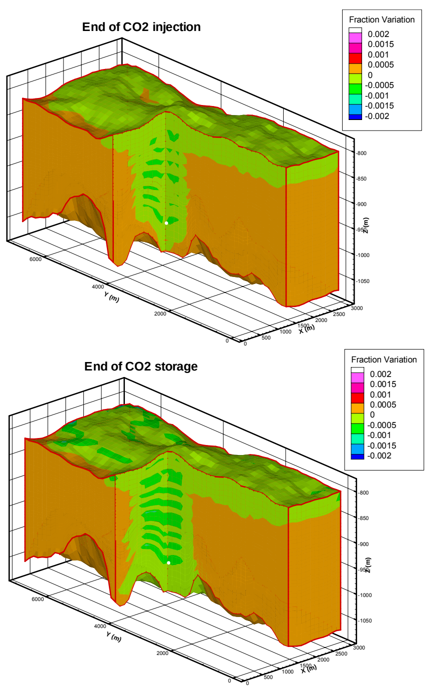


Figure 2. *Calcite volume fraction variations at end of CO2 injection (50 years) above and at end of storage (1000 years) below. The white dot correspond to the injection point*

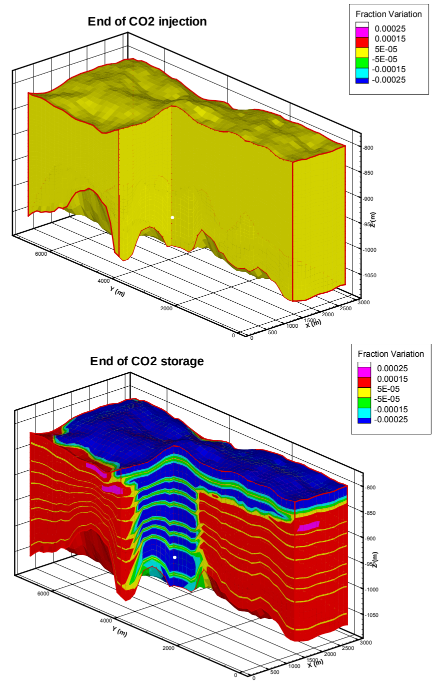


Figure 3. *Illite volume fraction variations at end of CO2 injection (50 years) above and at end of storage (1000 years) below. The white dot correspond to the injection poin*

HIGH RESOLUTION NUMERICAL INVESTIGATION OF CO_2 SEQUESTRATION IN GEOLOGIC MEDIA USING THE MASSIVELY PARALLEL COMPUTER CODE PFLOTRAN

Chuan Lu and Peter C. Lichtner

Los Alamos National Laboratory
Los Alamos, NM, 87545, USA
e-mail: clu@lanl.gov, lichtner@lanl.gov

INTRODUCTION

CO_2 sequestration (capture, separation, and long term storage) in various geologic media (such as depleted oil reservoirs, saline aquifers, oceanic sediments at different depths) is a possible solution to reduce green house gas emissions. The main risk associated with this process is the potential leakage during long-term storage. This may be caused by chemical reactions between acidized water and the geologic formation, leakage through abandoned wells etc. Density driven downward flow of CO_2 dissolved in formation waters plays an important role in reducing such risk, by enhancing the rate of dissolution of supercritical CO_2 into the aqueous phase through finger phenomena, and migration of CO_2 concentrated water deeper into the formation and away from the confining caprock and vicinities of wells (Ennis-King and Lincoln, 2003; Xu et al., 2005). Investigation of such processes can help better understand and predict the long-term behavior of injected CO_2 in aquifer formations and more significantly, the ultimate fate of CO_2 sequestered in deep geologic formations.

The computational effort necessary to carry out such an investigation for a realistic 3D field injection problem is enormous. The difficulties come primarily from three aspects. Length scales involved range from the size of the geologic formation itself, on the order of kilometers, to much smaller characteristic length scales of fingering phenomena on the order of meters on less to the chemical interactions that may be smaller than centimeters. Time scales range from thousands of years, to the relatively fast process involving chemical interactions on the order of days or less. Complex multicomponent heterogeneous chemical reactions and multiphase interactions involving phase transitions result in a highly coupled nonlinear system of equations. An efficient, massively parallel, high-resolution simulator is essential to resolve the complex behaviors of such systems.

In this study we utilize the PFLOTRAN simulator to investigate geologic sequestration of CO_2 (Lu and Lichtner, 2005). PFLOTRAN is a massively parallel 3D reservoir simulator for modeling subsurface multiphase (CO_2, H_2O), multicomponent reactive flow and transport based on continuum scale mass and energy conservation equations. The Span-Wagner (1996) equations of state are used for CO_2 with an efficient table-lookup scheme.

STRUCTURE OF PFLOTRAN

PFLOTRAN consists of two distinct modules PFLOW and PTRAN, which may be run in sequentially coupled or standalone mode. The code solves multiphase, multicomponent reactive flow and transport equations implemented within the PETSc framework for massively parallel computing architectures. The reactive transport equations describe multi-component chemical reactions within the formation involving aqueous speciation, and precipitation and dissolution of minerals including CO_2-bearing phases to describe aqueous and mineral CO_2 sequestration. PFLOW uses an efficient and modular mechanism to handle variable switching during phases transitions, bringing great flexibility in choosing the set of primary variables, addition of new EoS, mixing rules, etc. The assignment of primary variables for a simple two-phase supercritical CO_2 and water system is shown in Table 1.

Table 1. Primary variable assignment used in PFLOTRAN.

Phase condition	Primary variables		
Supercritical CO_2	p	T	X_{sc}^{CO2}
Aqueous	p	T	X_{w}^{CO2}
Two Phase	p	T	S_{sc}

The PETSc parallel scientific toolkit (Balay et al. 1997) is used to manage parallel data structures and MPI message passing, and its highly efficient Newton-Krylov solver framework is used to solve the nonlinear equations arising from a fully-implicit time stepping scheme based on domain decomposition. This allows simulations with hundreds of millions of degrees of freedom to be carried out—ideal for large-scale field applications involving multi-component chemistry. PFLOTRAN has been designed from the ground up with parallel scalability in mind, so it displays excellent scaling characteristics on modern supercomputers. The parallel efficiency is shown in Figure 1 for a modest sized problem running on MPP2 at PNNL/EMSL and Jaguar at ORNL. The benchmark was run on both the MPP2 cluster at PNNL/EMSL, a cluster of 1960 1.5 GHz Itanium 2 processors with Quadrics QsNe tII interconnect, and Jaguar, the 5200 Opteron processor Cray XT3 at ORNL/NCCS. PFLOW scales quite well on both machines, bottoming out at around 1024 processors on MPP2, and scaling exceptionally well on Jaguar, displaying linear speedup all the way up to 2048 processors, and still displaying modest speedup when going from there to 4096 processors. PTRAN scales similarly, which is not surprising because its computational structure is nearly identical to that of PFLOW.

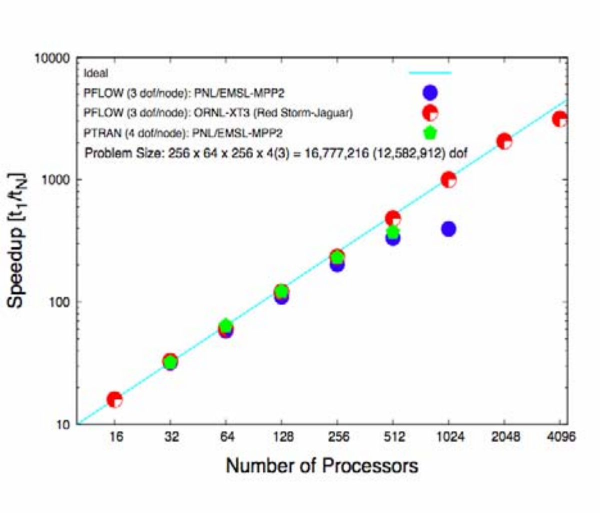


Figure 1. The performance of PFLOW and PTRAN running a single phase thermo-hydrologic bench mark problem on a 256 x 64 x 256 grid with three and four degrees of freedom per node, respectively (approximately 12.6 million degrees of freedom total).

APPLICATION TO CO_2 SEQUESTRATION

PFLOTRAN is applied to CO2 sequestration in a deep aquifer with the upper boundary of the domain at a depth of 2040 m. A 10 m thick caprock with low permeability overlies the aquifer at a depth of 10 m from the top of the domain. Injection of supercritical CO2 occurs at a depth of 35 m. Following injection the less dense supercritical CO2 phase rises rapidly until it reaches the relatively impermeable caprock producing large-scale convection cells. Two different mixing relations are considered for CO_2-H_2O: non-ideal mixing using the correlation derived by Garcia (2001) and ideal mixing. In the case of ideal mixing the density of the CO_2-H_2O mixture is always less than that of H_2O and density instability does not occur (Figure 2, bottom). For non-ideal mixing, however, the density of the mixture is greater than H_2O and instability results in complex fingering as shown in Figure 2 (top). In the case of ideal mixing the dissolved CO_2 remains concentrated beneath the caprock. However, when non-ideality mixing effects on the density are taken into account, buoyancy driven flow sets in leading to fingering and downward movement of the dissolved CO_2 and more rapid dissolution of the CO_2. These non-ideal effects arise because the partial molar volume of CO_2 in water is smaller than the molar volume of pure phase CO_2 (e.g., Garcia 2001).

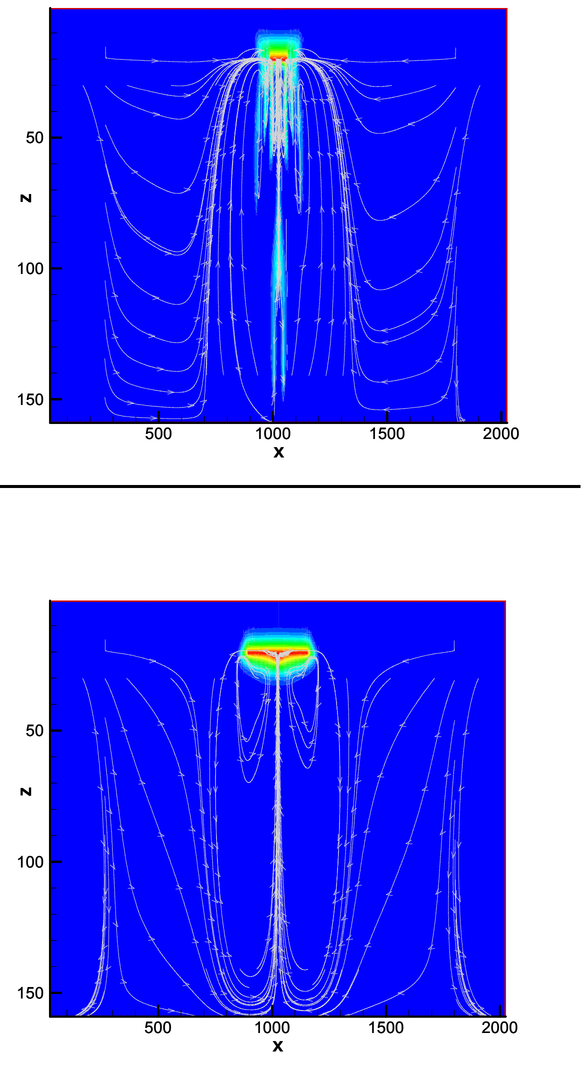


Figure 2. Mole fraction CO_2 after an elapsed time of 900 years for: (top) non-ideal mixture density taken from Garcia (2001), and (bottom) ideal mixing.

CONCLUSION

It appears essential to incorporate accurate estimates of the density of CO_2-H_2O mixtures for an accurate simulation of the behavior of the dissolved CO_2 plume. It should be noted that the relation provided by Garcia (2001) does not include pressure effects which can lead to additional uncertainty in the calculated results. Furthermore, the effects of salinity on the mixture density have not been considered in this work.

ACKNOWLEDGMENTS

We thank Bill Carey, Richard Mills, and Ioannis Tsimpanogiannis for helpful discussions during the course of this work. Calculations were carried out on the Pink supercomputer at LANL consisting of 2048 Intel Xeon, 2.4 GHz processors with a Myrinet interconnect.

REFERENCES

Balay, S., W.D. Gropp, L.C. McInnes and B.F. Smith, Efficient Management of Parallelism in Object Oriented Numerical Software Libraries, Modern Software Tools in Scientific Computing, Ed. E. Arge, A. M. Bruaset and H. P. Langtangen, 163-202, Birkhauser Press, 1997.

Ennis-King, J. and P. Lincoln, Role of convective mixing in the long-term storage of carbon dioxide in deep saline formations. In SPE Annual Technical Conference and Exhibition, Denver, CO, SPE 84344, 2003.

Garcia, J.E., Density of aqueous solutions of CO_2, LBNL Report 49023, Lawrence Berkeley National Laboratory, Berkeley, CA, 2001.

Lu, C., P.C. Lichtner, *PFLOTRAN: Massively Parallel 3-D Simulator for CO_2 Sequestration in Geologic Media*, FOURTH ANNUAL CONFERENCE ON CARBON CAPTURE AND SEQUESTRATION DOE/NETL, 2005.

Span, R. and W. Wagner, A new equation of state for carbon dioxide covering the fluid region from the triple-point temperature to 1100 K at pressures up to 800 MPa, Journal of Physical Chemical Reference Data, 25, 1509-1596, 1996.

Xu, X., S. Chen, and D. Zhang, Convective stability analysis of the long-term storage of carbon dioxide in deep saline aquifers, Advances in Water Resources, 29, 397-407, 2006.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

MODELING OF GEOMECHANICAL PROCESSES DURING INJECTION IN A MULTILAYERED RESERVOIR-CAPROCK SYSTEM AND IMPLICATIONS ON SITE CHARACTERIZATION

Jonny Rutqvist, Jens Birkholzer, and Chin-Fu Tsang

Lawrence Berkeley National Laboratory
Earth Science Division, MS 90-1116
Berkeley, CA, 947 20, USA
e-mail: jrutqvist@lbl.gov

INTRODUCTION

In this paper we present results of a numerical simulation of the potential for fault reactivation and hydraulic fracturing associated with CO_2 injection in a multilayered reservoir-caprock system, and discuss its implications on site characterization. The numerical simulation is performed using the coupled processes simulator TOUGH-FLAC (Rutqvist et al. 2002, Rutqvist and Tsang, 2003), and is an extension of earlier numerical studies of a single caprock system (Rutqvist and Tsang., 2002).

In this study, CO_2 is injected for 30 years in a 200 meter thick permeable saline water formation located at 1600 meters depth (Figure 1). The injection formation is overlaid by several layers of caprocks, which are intersected by a permeable fault zone allowing upward migration of the CO_2 within the multilayered system (see Table 1 for material properties). The potential for fault slip or fracturing are calculated, based on the time-dependent evolution and local distribution of fluid pressure and the three-dimensional stress field, including important poro-elastic stresses.

The numerical results are discussed with respect to the site-characterization strategy that would be recommended for evaluation of maximum sustainable injection pressure at an industrial CO_2 injection site.

SIMULATION RESULTS

Figures 2 and 3 present the main hydrological and geomechanical results. Figure 2a shows that CO_2 spreads within the storage formation, both upward and laterally, as significant flow is allowed through the permeable fault zones. At the end of the 30-year injection period, the downhole pressure has increased by 9 MPa to 25 MPa, which is well below the lithostatic stress at depth of the injection formation. (The lithostatic stress is about 35 MPa at the injection level, based on the weight of the overlying rock mass). Effective stress decreases as fluid pressure increases within the CO_2 storage zone (Figure 2b). By comparing contours for pressure and effective stresses in Figures 2a and b, it can be observed that the decrease in vertical effective stresses is approximately equal to the increase in fluid pressure, whereas the decrease in horizontal effective stress is much smaller. This difference in the magnitude of change in vertical and horizontal effective stresses is a result of injection induced poro-elastic stresses, which tend to provide additional confining (total) stresses in the horizontal direction.

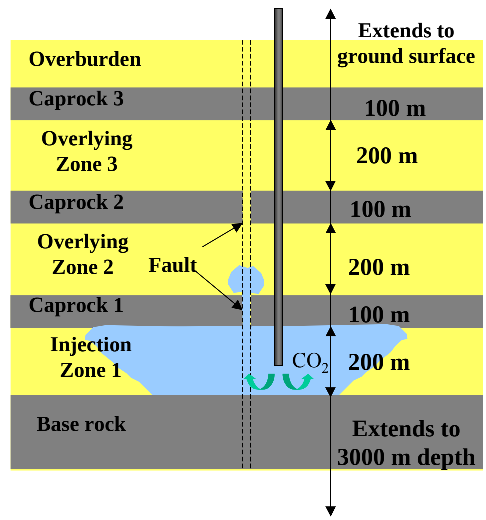
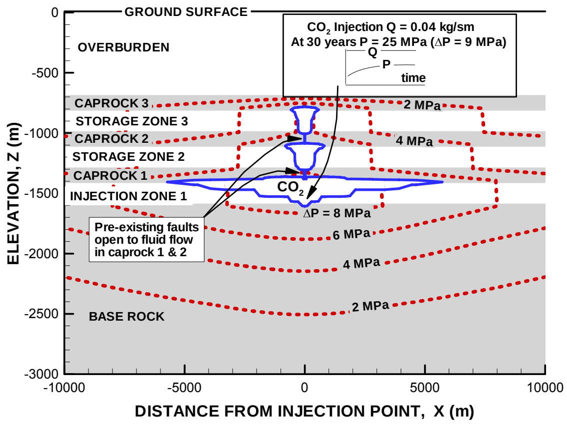


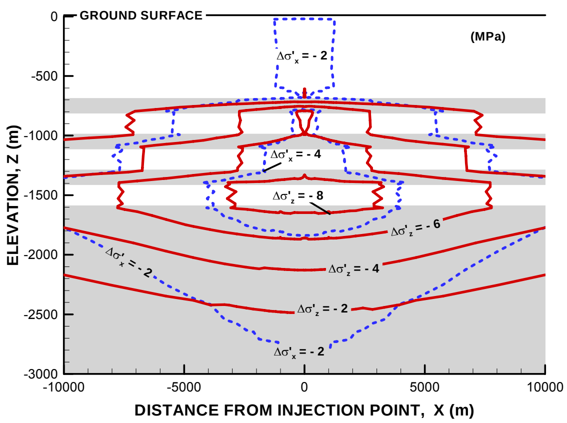
Figure 1. Model geometry for simulation of CO2 injection into a multilayered reservoir-caprock system.

Table 1. Rock properties

Property	Inject. Zone	Caps	Fault
Young's modulus, E (GPa)	5	5	2.5
Poisson's ratio, ν (-)	0.25	0.25	0.25
Saturated density, ρ_s (kg/m^3)	2260	2260	2260
Flow porosity, ϕ (-)	0.1	0.01	0.1
Permeability, k, (m^2)	1×10^{-13}	1×10^{-19}	1×10^{-14}
Residual CO_2 saturation (-)	0.05	0.05	0.05
Residual liquid saturation (-)	0.3	0.3	0.3
van Genuchten, P_0 (kPa)	19.9	621	0.9
van Genuchten, m (-)	0.457	0.457	0.457



(a)



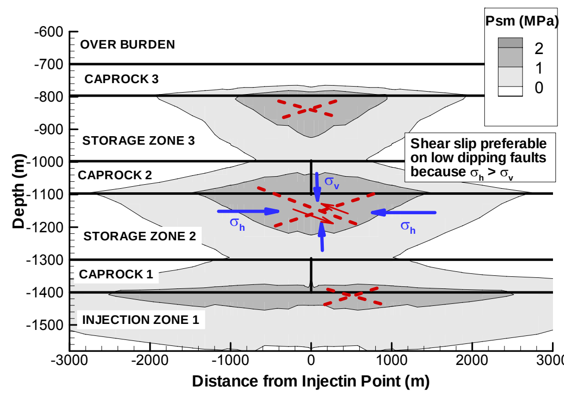
(b)

Figure 2. Simulated hydraulic and mechanical responses after 30 years of CO2 injection. (a) Spread of CO2-rich fluid and changes in fluid pressure. (b) Fluid pressure induced changes in vertical and horizontal effective stresses.

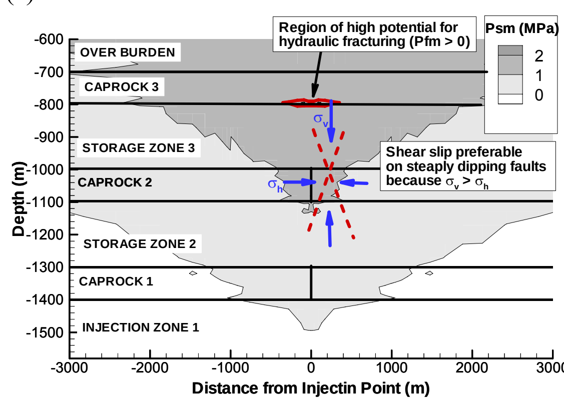
Figure 3 presents the potential for fault slip and hydraulic fracturing for two different anisotropic stress regimes—extensional stress regime and compressional stress regime. The results in Figure 3 are presented in terms of pressure margins to onset of shear slip or fracturing. These pressure margins are evaluated using failure criteria for fracturing and shear-slip adopting conservative rock mass strength parameters. Specifically, the pressure margin for fault-slip was calculated for arbitrarily oriented fractures, having zero cohesion and a static friction angle of 30°. A positive pressure margin implies that the local fluid pressure is above the critical pressure for onset of hydraulic fracturing of shear slip. In Figure 3, dark contours indicate areas of the highest potential for onset of shear slip.

The results in Figure 3 illustrate a complex distribution shear-slip potential and its dependency on the stress regime. An isotropic stress regime is most favorable for avoiding shear slip during injection (not shown). In the case of a compressional stress regime (Figure 3a), the shear slip is most likely to be initiated in subhorizontal fractures at the interface between the permeable formation layers and an overlying caprock. In the case of an extensional stress regime (Figure 3b), the shear slip is likely to occur in subvertical fractures in the upper aquifer and in the overburden rock. In addition, a high potential for hydraulic fracturing occurs in the case of an extensional stress regime at the lower parts of Caprock 3 (Figure 3b).

In this simulation the major vertical fault zone was open to fluid flow through Caprock 1 and 2, whereas it was sealed within Caprock 3. The results in Figure 3 indicates that this fault zone is much more likely to be reactivated to breach the seal of Caprock 3 in the case of an extensional stress regime, whereas it is unlikely in the case of a compressional stress regime.



(a)



(b)

Figure 3. Calculated pressure margin for shear slip under (a) compressional stress regime with $\sigma_{hi} = 1.5\sigma_{vi}$ and (b) extensional stress regime with $\sigma_{hi} = 0.7\sigma_{vi}$.(The one and only location for hydraulic fracturing is also indicated in (b).

IMPLICATIONS FOR SITE CHARACTERIZATION

The numerical results indicate that the coupled HM processes are quite complex and heterogeneous within the multilayered system and depend on the local evolution of fluid pressure and three-dimensional. Because of this complexity, a site-specific, coupled numerical analysis may be necessary for an accurate estimate of the maximum sustainable injection pressure at an industrial CO_2-injection site. Such coupled numerical modeling is associated with large data and model uncertainties, including uncertainties in location, orientation, and mechanical properties of pre-existing faults. Thus, the success and usefulness of such coupled numerical analysis is highly dependent on a comprehensive and accurate site characterization.

Our analysis shows that for evaluation of the maximum sustainable CO_2-injection pressure, it is essential to have a good estimate of the three-dimensional *in situ* stress. Thus it is not sufficient to determine estimate the lithostatic stress; the minimum principal stress is also an important parameter to characterize. Furthermore, the evolution of principal stresses (stress path) during injection should be evaluated and, if possible, monitored. Existing techniques for in situ stress measurements, e.g. hydraulic mini-frac tests, may be utilized for this purpose.

To be able to predict the evolution of stresses by coupled numerical modeling it is essential to have good estimates of the in situ mechanical and coupled hydraulic-mechanical properties. Mechanical properties of both the caprock and injection aquifer are required. If the deformation modulus of the cap rock and injection aquifer are very different, large vertical variation in poro-elastic stresses will occur, which in turn will increases shear stresses at the aquifer-caprock interfaces.

It might also be possible to estimate the evolution of the stress field by coupled hydraulic-mechanical back-analyzes against measured large-scale deformations monitored with tilt-meters during the injection. This would be possible if injection induced stresses are approximately proportional to the injection-induced deformations.

CONCLUSIONS

We have conducted a simulation study of hydromechanical processes during CO_2 injection into a faulted multilayer system. In this study, we focused on how the initial stress regime affects the potential for inducing irreversible mechanical changes in the system. The following general conclusions can be made related to the site characterization of industrial CO2 injection sites:

- The three-dimensional in situ stress field should be carefully characterized and monitored (if possible).
- Potential for fault reactivation and fracturing should be analyzed for the entire region affected by mechanical stress changes, which is generally more extensive than the region affected by fluid pressure (e.g in the overburden).
- The maximum sustainable injection pressure should be estimated using a site-specific coupled reservoir-geomechanical model that accounts for local evolutions of fluid pressure and the three-dimensional stress field.
- The mechanical and coupled hydrological-mechanical properties of various formations, including permeable formations and caprocks should be characterized.

ACKNOWLEDGMENT

We thank the U.S. Environmental Protection Agency, Office of Water and Office of Air and Radiation for funding this study under an Interagency Agreement with the U.S. Department of Energy at the Lawrence Berkeley National Laboratory, contract number DE-AC02-05CH11231.

REFERENCES

Rutqvist J., Wu Y-S., Tsang C-F., Bodvarsson G. A Modeling Approach for Analysis of Coupled Multiphase Fluid Flow, Heat Transfer, and Deformation in Fractured Porous Rock *Int J Rock mech Min Sc, 39,* 429-442, 2002.

Rutqvist, J. and C.-F. Tsang, A study of caprock hydromechanical changes associated with CO2-injection into a brine formation, *Environmental Geology*, *42*, 296-305, 2002.

Rutqvist J., and Tsang C.-F. TOUGH-FLAC: A numerical simulator for analysis of coupled thremal-hydrologic-mechanical processes in fractured and porous geological media under multi-phase flow conditions. Proceedings of the TOUGH symposium 2003, Lawrence Berkeley National Laboratory, Berkeley, May 12–14, 2003.

SCREENING AND CHARACTERIZATION TOOLS

PROTOTYPE NEAR-FIELD/GIS MODEL FOR SEQUESTERED-CO_2 RISK CHARACTERIZATION AND MANAGEMENT

Kenneth T. Bogen, Steven G. Homann, Frank J. Gouveia, and Lee A. Neher

University of California, Lawrence Livermore National Laboratory
Energy and Environment Directorate (Bogen L-396)
Livermore, CA 94550-9900 USA
e-mail: bogen@LLNL.gov

INTRODUCTION

Detecting unmapped abandoned wells remains a major carbon sequestration (CS) technology gap. Many ($>10^5$) abandoned wells are thought to lie in potential sequestration sites. For such wells, risk analysis to date has focused on aggregate long-term future impacts of seepage at rates < or << ~1 g m^2 d^{-1} on storage goals as sequestered plumes encroach upon wells with assumed distributions of seal ineffectiveness (Oldenburg and Unger, 2003; Saripali *et al.* 2003; Celia, 2005). However, unmapped abandoned wells include an unknown number without any effective seal at all, venting through which may dominate CO_2-loss scenarios. A model of such a well is Crystal Geyser (CG), a prospective oil well abandoned in the 1930s with no barrier installed after it encountered a natural CO_2 reservoir rather than oil (Baer and Rigby, 1978; Rinehart, 1980). CG demonstrates how an unimpeded conduit to the surface now regularly vents from 10^3 to $>10^4$ kg of CO_2 gas to the terrestrial surface (Figure 1). Unique field data recently gathered from Crystal Geyser (CG) in Utah (Gouveia *et al.* 2005) confirm that, although surface CO_2 concentrations resulting from CG-like eruptions would likely be safe in general, they could accumulate to pose lethal hazards under relatively rare meteorological and topographic (MT) conditions. This source of foreseeable risk needs to be managed if carbon sequestration is to be publicly accepted. To address this concern, we used CG field data to estimate the source term for a prototype model that identifies zones at relatively highly elevated risk for sequestered-CO_2 casualties. Such a model could be applied both to design and comply with future regulatory requirements to survey high-risk zones in each proposed sequestration site for improperly sealed wells.

DISPERSION MODEL

Basin topographies seriously limit turbulent mixing because they shelter the basin atmosphere from external winds, and because they enhance stable stratification through drainage flows and cold pool formation (Whiteman *et al.*, 2004). Basin and valley atmospheres are very poorly understood, partly because of deficiencies in model parameterizations, in particular for representing turbulence under stable stratification. Analysis of CG data disproved prior claims that eruptions were ≤12 h apart based on local anecdotal accounts (Shipton *et al.*, 2005), and instead indicates that after a CO_2 plume reaches an unimpeded well, an eruption of up to 40,000 kg CO_2 over a 2-h period could occur every 24-48 h. Accurate frequency monitoring EPIcode® Version 7.0 (a U.S. Department of Energy approved "Tool-box" Gaussian dispersion code, Homann Associates, Inc., www.epicode.com) was thus adapted to model this size CO_2 release, using realistic assumptions for a dense gas at wind speed (and wind direction variation) values ranging from 0.1 m/s ($\sigma_\theta = 25°$) to 5 m/s ($\sigma_\theta = 15°$), to assess the impact of basic terrain constraints on predicted downwind distance of potentially lethal ambient 5-min CO_2 concentrations (≥5% at a 1-m height). Results obtained indicate that potentially lethal hazards may arise for nearby prone individuals under low-wind conditions (e.g., campers sleeping at night), particularly if wellhead occlusion were to eliminate most or all vertical gas momentum and if the local terrain were to have basin-like features (Figure 2).

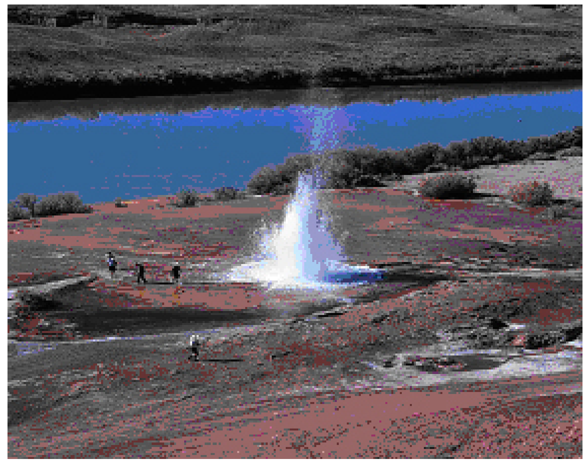


Figure 1. Crystal Geyser erupting

GIS TERRAIN-SPECIFIC RISK MODEL

An ArcGIS® 9.0 software (ESRI, Redlands, CA) program was developed to identify nearly flat basin-like terrain areas likely to present the greatest potential likelihood of serious hazard in the event of CO_2 release (Figure 3). Potentially hazardous areas

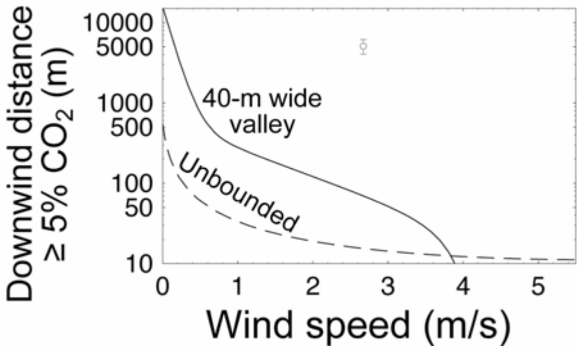


Figure 2. Downwind distance predicted to incur potentially lethal CO2 concentrations.

identified by the GIS algorithm can then be ranked by relative lethality risk using terrain-specific lethal-range information like that summarized in Figure 2. This prototype GIS/MT risk-indexing approach was applied to characterize CO_2 risk in one zone of a prospective U.S. sequestration site, using local wind speed, forestation and topographic data.

CONCLUSIONS

The prototype GIS/MT risk-indexing approach developed demonstrates a method to identify subzones within much larger (≥100-km^2) regions considered for potential CO_2 sequestration that are at relatively high risk conditional on both CO_2 efflux and simultaneous incidental occupation. This approach will greatly enhance the efficiency of detailed surveys for ineffectively sealed wells, by allowing the greatest survey resources to be focused on those subzones identified as harboring the greatest potential risk, analogous to a system previously developed to assess the potential air quality and visibility degradation caused by wildfires (Ferguson *et al*., 2003).

ACKNOWLEDGMENTS

This work was performed under the auspices of the U.S. Department of Energy by University of California, Lawrence Livermore National Laboratory under Contract W-7405-Eng-48, with support from the LLNL Carbon Management Program.

REFERENCES

Baer, J., and J.K. Rigby, Geology of the Crystal Geyser and environmental implications of its effluent, Grand County, Utah, *Utah Geol. 5*, 125-130, 1978.

Celia, M.A., ed., *Summary of Princeton Workshop on Geological Storage of CO2*, November 1-3, 2005, Princeton University, NJ, www.princeton.edu/~cmi/events/Workshop%20Summary%202005.pdf, 2005.

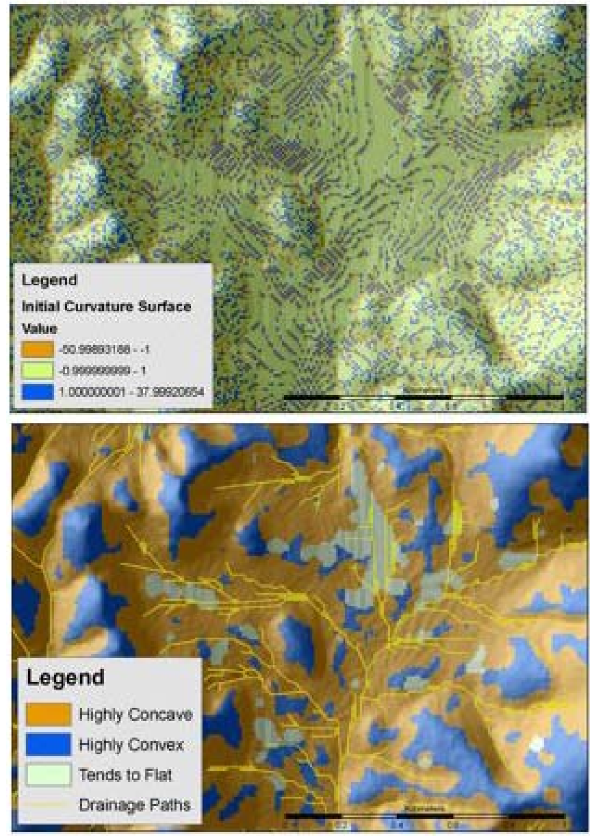


Figure 3. A GIS algorithm was used first to define surface curvature of realistic terrains (top), and then to identify corresponding potential CO2 hazard areas (bottom, light gray zones).

Ferguson, S.A., S.J. McKay, D.E. Nagel, T. Piepho, M.L. Rorig, C. Anderson, and L. Kellogg. *Assessing Values of Air Quality and Visibility at Risk From Wildland Fires*. U.S. Department of Agriculture, Forest Service, Pacific Northwest Station. PNW-RP-550, 2003.

Gouveia, F.J., M.R. Johnson, R.N. Leif, and S.J. Friedman. *Aerometric Measurement and Modeling of the Mass of CO_2 Esmissions from Crystal Geyser, Utah*, UCRL-TR-211870, Lawrence Livermore national Laboratory, Livermore, CA, 2005.

Klusman, R.W., A geochemical perspective and assessment of leakage potential for a mature carbon dioxide-enhanced oil recovery project as a prototype for carbon dioxide sequestration; Rangely field, Colorado. *AAPG Bull*., *87*, 1485-1507, 2003a.

Klusman, R.W., Rate measurements and detection of gas microseepage to the atmosphere from an enhanced oil recovery/sequestration project, Rangely, Colorado, USA. *Appl. Geochem., 18*, 1825-1838, 2003b.

Klusman, R.W., Evaluation of leakage potential from a carbon dioxide EOR/sequestration project. *Energy Conversion & Management, 44*, 1921-1940, 2003c.

Oldenburg, C.M., and A.J.A Unger, On leakage and seepage from geologic carbon sequestration sites: Unsaturated zone attenuation, *Vadose Zone J.*, *2*, 297-296, 2003.

Oldenburg, C.M., and A.J.A Unger, Coupled vadose zone and atmospheric surface-layer transport of CO_2 from geologic carbon sequestration sites, *Vadose Zone J., 3*, 848-857, 2004.

Rinehart, J.S., *Geysers and Geothermal Energy*. Springer-Verlag, New York, NY, 1980.

Saripali, P., N. Mahasenan, E.M. Cook, Risk and hazard assessment for projects involving the geologic sequestration of CO_2. In Gale, J.J. and Y. Kaya, eds., *Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies*, Elsevier, Oxford, UK, 2003.

Shipton, Z.K., J.P. Evans, B. Dockrill, J.E. Heath, A. Williams, D. Kirchner, and P.T. Kolesar, Natural leaking CO_2-charged systems as analogs for failed geologic sequestration reservoirs. In: Benson, : S. M., ed., *CCP results Volume 2 – Geologic Storage of Carbon Dioxide with Monitoring and Verification* Elsevier Science, Oxford, UK, 2005.

Whiteman, C.D., T. Haiden, B. Pospichal, S. Eisenbach, and R. Steinacker, Minimum temperatures, diurnal temperature ranges, and temperature inversions in limestone sinkholes of different sizes and shapes, *J. Appl. Meteorol.*, *43*, 1224-1236, 2004.

PROCEEDINGS, CO2SC Symposium 2006
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

BUILDING A MECHANICAL EARTH MODEL FOR STORAGE INTEGRITY

[1]Jean Desroches, [2]Laurent Jammes, and [2]Thomas Berard

[1] Schlumberger Riboud Product Center
1 Rue Henri Becquerel, BP 202
92142 Clamart Cedex, France
e-mail: jdesroches@clamart.oilfield.slb.com

[2]Schlumberger Carbon Services
Le Palatin 1, 1 cours du triangle
92936 La Defense Cedex, France
e-mail: jammes1@la-defense.oilfield.slb.com

INTRODUCTION

CO2 injected in a potential storage formation might leak if the injection operation compromises the integrity of the cap rock or leads to a reactivation of the faults that links the reservoir to the overburden.

Cap rock integrity under injection conditions can be impaired if a hydraulic fracture is generated from injecting wells and is not contained by the cap rock, or if changes in the state of stress in the cap rock leads to the formation of a fracture. The fracture initiation, propagation and containment in the formation are related to in-situ stresses, rock mechanical properties and the coupled pressure and thermal effects while injecting.

A fault may seal if deformation processes have created a membrane seal, or if it juxtaposes sealing rocks against aquifer/reservoir rocks, and the fault has not been reactivated subsequent to the fluid charging the trap. Rock mechanical properties, pore pressures, in-situ stresses and the stress evolvement under injection or depletion conditions control whether a fault can be reactivated or not, and therefore the risk of fault seal breach.

Geomechanics has been successfully applied in oil industry for decades. The newly developed wireline logging technologies such as DSI / MSIP (Dipole Shear Sonic Imager / Modular Sonic Imager Platform) or borehole imaging, completed with laboratory testing and drilling data such as leak-off tests, allow an accurate determination of rock mechanical properties and earth stresses, and therefore improve the capability of accurately predicting cap rock integrity and fault stability under injection condition.

In this paper, we will present how a complete and calibrated 3D Mechanical Earth Model is critical to establish operational limits for the injection program that will not compromise the integrity of the storage.

BUILDING A STATIC MECHANICAL EARTH MODEL

In order to be able to extrapolate the behavior of the storage in terms of cap rock integrity and fault stability, it is necessary to build a mechanical earth model that is fully representative of either the initial state of the storage or, at least, the current stage in case of the use of an existing hydrocarbon reservoir.

Building a 1D Static Mechanical Earth Model

The first step, in building a static Mechanical Earth Model, consists in building a series of static Well Mechanical Earth Models or 1D-MEMs. 1D-MEMs consist of the following properties evaluated along a well trajectory:

- Facies types
- Rock deformation properties (elastic moduli such as Young's modulus and Poisson ratio)
- Rock strength properties (Unconfined Compressive Strength, Friction Angle)
- Pore-Pressure and in-situ stresses

The process starts with analyzing available logs (compressional and shear slowness, density, calipers, porosity, GR (Gamma Ray), etc.) and other well data.

To ensure a good accuracy of 1D-MEM properties, the log-derived elastic moduli and rock strength properties often need to be calibrated against laboratory testing data under different confining pressures.

Direction and magnitudes of principal stresses are key parameters. Principal stress direction is generally derived from breakout orientations (image and caliper data), assuming one of the principal stresses to be vertical. In addition, drilling induced fractures identified from borehole images are used to determine principal stress directions, constrain the order of principal in-situ stresses in specific intervals along the well path, and establish limits for the magnitudes of principal horizontal stresses.

Data and model are validated and calibrated using the available drilling records (occurrence of kicks, mud losses, cutting analysis), as well as comparing the prediction of the formation failure modes with borehole images recorded while drilling.

This methodology has been successfully developed for and applied to the oil and gas industry, especially for wellbore applications (e.g. Bradford et al., 2000).

Building a 3D Static Mechanical Earth Model

In a second step towards a full Mechanical Earth Model, the mechanical properties associated to deformation and strength are used to populate a 3D grid. The methods are similar to those used for the upscaling of reservoir properties when building a reservoir model, with the exception of also taking care of the overburden. Pore pressure is added from wellbore data. A numerical reservoir simulator is then run to equilibrate the pore pressure.

As for in-situ stresses, the critical tool is a coupled reservoir/geomechanics simulator, where the reservoir and the overburden are considered as poro-elasto-plastic materials, thus effectively coupling pore pressure with rock deformation and rock stresses (e.g. Han, 2005). Boundary conditions of the model are adjusted to match log-derived stress data and wellbore observations. Automatic inversion methods are currently being studied to simplify this step.

Note that once the static 3D-MEM is finished, a 1D-MEM can be extracted along any wellbore trajectory for fast computation purposes. The workflow leading to the complete static 3D-MEM is presented in Figure 1.

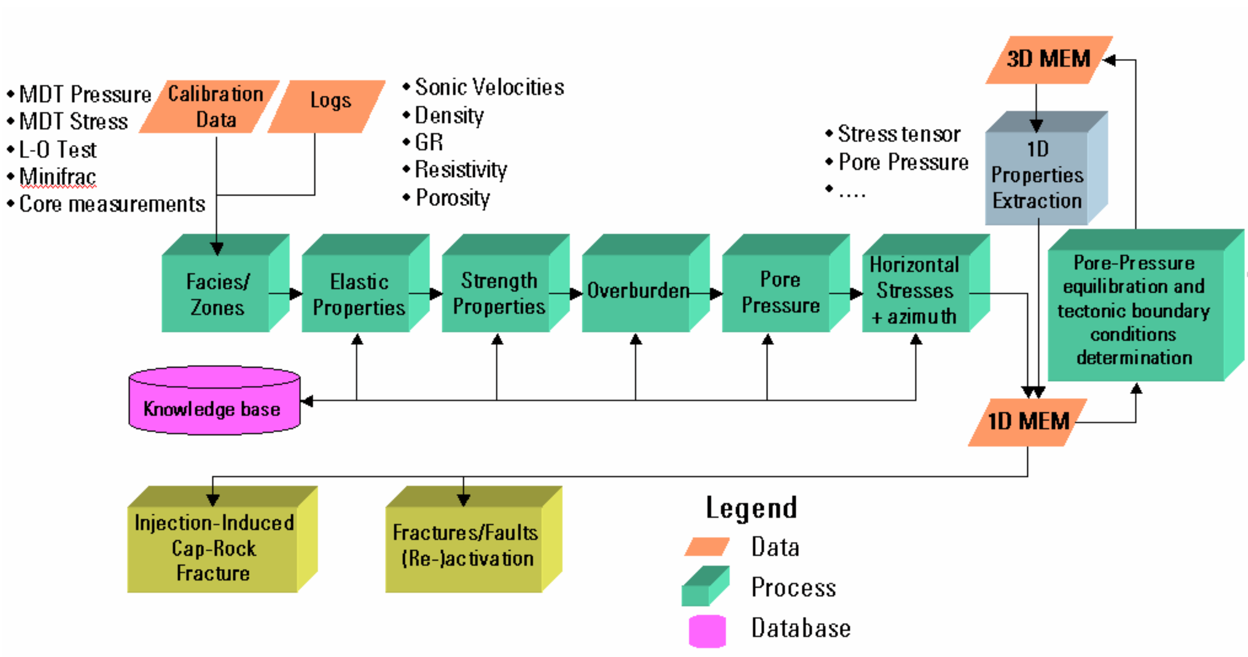


Figure 1. Mechanical Earth Model Modeling

BUILDING A 3D DYNAMIC MECHANICAL EARTH MODEL

From the static 3D-MEM, a 3D dynamic Mechanical Earth Model can be built by using the coupled reservoir/geomechanics simulator previously mentioned. Any CO2 injection schedule can be used as an input, and pore pressure, stresses and rock mechanical properties variations can be predicted as a function of time. The results can then be exploited for two specific applications, cap rock integrity and fault stability.

INJECTION-INDUCED FRACTURE INITIATION

Stress changes both in the injection zone and the cap rock can lead to the creation of hydraulic fractures linked to injecting wells or to that of fractures in the cap rock itself.

Data can be extracted along the trajectory of injection wells to first check whether a hydraulic fracture will be created and then to verify if it will be contained by the cap rock. Semi-analytical solutions based on fracture mechanics can be used for that purpose (see for example Simonson, 1978, Fung, 1987).

Several methods can be used to obtain estimates of the state of stress in the cap rock. Either it can be obtained directly if the Mechanical Earth Model extends sufficiently into the cap rock, which is the preferred option. If that is not the case, analytical and semi-analytical methods can be used to estimate the transfer of stresses between the storage and the cap rock. Fracture initiation and containment can then be studied.

Such analyses can be repeated for various injection scenarii, in order to establish operational limits for the injection program that will not compromise the cap rock integrity. Note that such an analysis could prove crucial if, during the life of the storage, it is deemed necessary to fracture the formation around the injection wells to maintain the injectivity without having to drill new injection wells.

FAULT STABILITY ANALYSIS

The dynamic 3D-MEM can also be used to study whether faults can be reactivated or not during the injection process. The analysis of fault stability will indicate whether fault seal can be breached or not while disposing the CO2. As a first step, one determines whether there are any faults of any orientation that would slip due to the changes in stresses (see Figure 2).

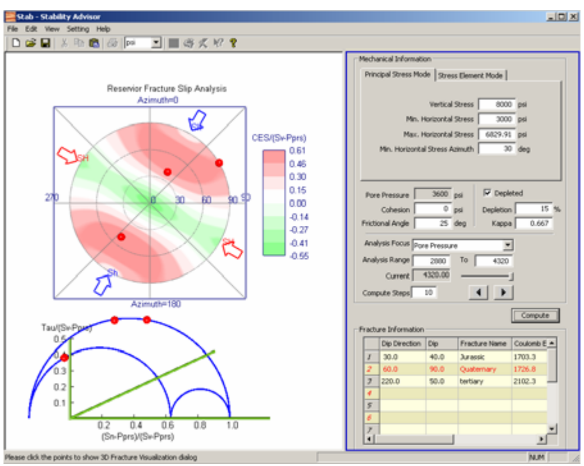


Figure 2. The orientation of faults that can slip, weighted by stress imbalance (here in red) can be easily visualized and compared with the orientation of existing faults.

If the answer is positive, more elaborate tools taking fully into account the presence of the fault can be used to evaluate the possible displacement of the fault (Chanpura, 2001, see also Figure 3).

WELLBORE INTEGRITY APPLICATIONS

The same methodology can be applied to look at the effect of changing the state of stress around existing wells on the integrity of the completion, and particularly that of the cement sheath. The 3D-MEM provides boundary conditions for semi-analytical models (see e.g. Boukhelifa et al., 2004), that predict the risk of micro-annulus or the risk of fracturing the cement sheath, both leading to potential loss of zonal isolation.

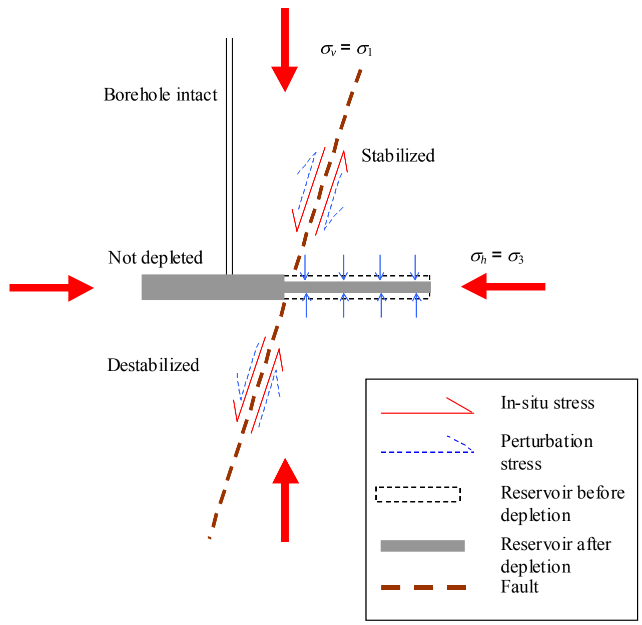


Figure 3. Effect of pore pressure variations on a fault crossing a reservoir. In this case, the lower part of the fault is destabilized, whereas the upper part of the fault, that crossing the cap rock, is stabilized by pore pressure changes (Chanpura, 2001).

Finally, one should not forget more classical applications during the construction of new wells (e.g. new injectors) such that the cap rock is not damaged in the vicinity of the well during drilling of completion of the well to preserve the integrity of the cap rock.

CONCLUSIONS

In this paper, we presented a methodology to build a calibrated 3D Mechanical Earth Model. The coupling between geomechanics and reservoir simulation opens applications that are critical for the integrity of a CO_2 storage, at the scale of the wellbore, the near-wellbore or that of the storage itself. The characterization of mechanical effects that could lead to leaks is of paramount importance for the analysis of storage performance and the evaluation of associated risks.

REFERENCES

Boukhelifa L., Moroni N., James S. G., Le Roy-Delage S., Thiercelin M. J., Lemaire G., *Evaluation of Cement Systems for Oil and Gas Well Zonal Isolation in a Full-Scale Annular Geometry*, SPE Paper 87195, Proc. of the 2004 Drilling Conference, Dallas, Texas, U.S.A., 2-4 March 2004.

Bradford, I.D.R., W.A. Aldred, J.M. Cook, E.F.M. Elewaut, J.A. Fuller, T.G. Kristiansen and T.R. Walsgrove, *When rock mechanics met drilling: effective implementation of real-time wellbore stability control*, SPE Paper 59121, Proc. of the 2000 IADC/SPE Drilling Conference, New Orleans, Louisiana, 23-25 February 2000.

Chanpura, R.A., *Fault reactivation as a result of reservoir depletion*, Ph.D. Thesis, Georgia Institute of Technology, Atlanta, GA, USA, 2001.

Fung, R.L., S. Vilajakumar and D.E. Cormack, *Calculation of Vertical Fracture Containment in Layered Formations*, SPE Paper 14707, SPE Formation Evaluation , 2, No. 4, 518-523, December 1987.

Han, G., T. Stone, Q. Liu, J. Cook and P. Papanastasiou, *3-D elastoplastic FEM modelling in a reservoir simulator*, SPE paper 91181, Proc. of the 2005 SPE Reservoir Simulation Symposium, Houston, Texas, 31 January – 2 February 2005.

Simonson, E.R., A.S. Abou-Sayed and R.J. Clifton, *Containment of Massive Hydraulic Fractures*, SPE Journal, pp. 27-32, February 1978.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

A FINANCIAL DECISION TOOL FOR CO_2 STORAGE

N. Müller, Y. B. Altundas, T. S. Ramakrishnan

Schlumberger Doll Research
36 Old Quarry Road
Ridgefield, CT, 06877, USA
e-mail: nmuller@ridgefield.oilfield.slb.com

INTRODUCTION

Questions with regard to assessment of a storage site and how much and how best to sequester CO_2 will likely be dictated by economics. Since the potential damage caused by the emitted CO_2 is difficult to estimate and will be inconclusive because of the large uncertainties associated with the inputs to the models, a first-principled based cost minimization will be elusive. This paper presents a simple but novel approach to overcome these limitations by constructing a cost function based on lumped factors that are well specified.

The financial tool takes into account the capital and running costs of a sequestration project due to the consideration of separation, transportation, and storage. All of the environmental and societal costs are assumed to be reflected by a penalty for emitting CO_2, either as a tax or through a trading system.

PROCESSES

In most industrial scenarios for CO_2 sequestration, be it a fossil fuel fired power plant or a CO_2 producing natural gas well, the carbon emission needs to be captured and separated before storage.

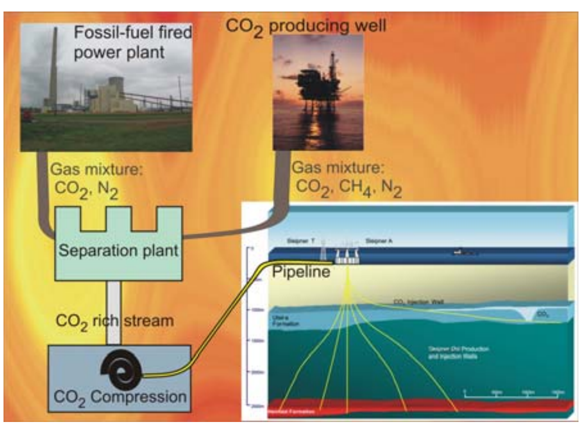


Figure 1. Schematic diagram of the carbon capture and storage (CCS) system.

The CO_2 rich stream is compressed to a dense phase, often a more cost effective choice. The primary cost components for carbon capture and storage (CCS) are shown in Figure 1 and consist of piping the gases to a separation unit, the capital and running cost of separation, the compression of CO_2, piping to the well-site, capital cost associated with the well-construction, including reservoir characterization and completion, the running costs associated with well maintenance and the running and capital cost for monitoring the storage site. We add to this any cost associated with the CO_2 that is vented, be it a carbon tax or a trade.

We regard our financial tool as a decision-enabling tool, primarily because we anticipate that the algorithm will aid in providing a quantitative determination for drilling decisions. In other words, optimal points for drilling new well(s) are automatically computed. In financial decision making in oil and gas production, we are expected to provide a detailed reservoir description: porosity and permeability maps, reservoir boundaries, faults, relative permeabilites and capillary pressures, and fluids' properties. Invariably the decision to drill *when* and *where* is an extremely cumbersome process and is often linked to a reservoir simulator. The calculations of those are time consuming.

In our approach, the novel step is that we circumvent an *integrated* reservoir simulation step. Once the reservoir characterization is carried out, we presume sites for injection well may be chosen. In the first level algorithm, the wells are assumed to be sufficiently well separated that they are non-interfering. Then an *injection decline curve* (IDC) may be obtained for each of the chosen sites. This may be done via any of the available reservoir compositional simulators that include CO_2. Given such decline curves, then what we propose that a cost function is readily constructed so that minimizing this cost function readily provides the drilling sequence, and the associated time when the wells are best drilled. In our formulation the cost function is based on net present value (NPV). The description of how cost from each process is taken into account in NPV formulae is given below. The advantage of this procedure is that the details of the simulation are relegated to an independent step, and the tedious calculations are to be done once. If more than one reservoir is available and the best among these need to be picked, we recommend an optimal calculation for each, and then the minimum amongst the optimal choices be picked.

1. Separation

For the present, the assessment tool considers only the separation CO_2, CH_4, N_2. CH_4 has intrinsic value. Any venting of CH_4 may be associated with significantly larger penalty than venting CO_2, in addition to loss of methane value. Thus, optimization will automatically drive the choice towards a process parameters or the process itself towards more efficient capture and piping of CH_4. After the separation of gases, venting of CO_2 will suffer a penalty in proportion to the amount vented and the venting penalty. N_2 emission is not accounted for, although vent sizing and overall plant cost will be slightly affected. Obviously, both running costs and capital costs (plant size) will be included. The next component involves transport of the separated CO_2.

2. Transport

Only pipeline transport is considered. The CO_2 rich stream needs to be cooled and compressed to form the liquid CO2 phase. Liquid or supercritical conditions are favorable for the pipeline transmission due to the reduced compressibility. The liquid CO_2 at the source is pumped through the pipeline to the sink.
The pipeline construction and the compression units determine the capital cost whereas the running cost is given by operational costs of piping and maintenance. Clearly, proximity of source and storage drives transportation costs down, possibly compromising on reservoir quality.

3. Storage

a. Sink selection

To pick an optimal site among the storage sites, the algorithm follows a pre-screener. The pre-screener is used to narrow the choices to a few, so that flow simulations are restricted to a few.
To build a reservoir simulation model for the injection decline curve, the algorithm requires some input on rock and fluid properties and the initial reservoir conditions. Note that the exercise of populating the reservoir model in itself points to additional necessary measurements both in terms of cores and logs. The central point about an injection decline curve is that given the maximum pressure for safe injection, a flow rate curve may be computed. The rate is a maximum at $t = 0$, followed by an asymptotic decay to zero flow as t goes to infinity. As stated before, each well is associated with a decline curve suitably parameterized.

b. Injection

During the injection phase the cost of sequestration is offset by any gain from reduced or no emission (see Figure 2). The goal then is to maximize the NPV. In our work, the drilling time for each well is an optimizable parameter. Once the well is drilled, each of the wells has its own capital cost, and running cost as well as its own decline curve. A revenue or cost function taking these into account is easily formulated.
The following relationship needs to be maintained at any time t:

$$P(t) = \sum_m S_m(t;\tau_m) + E(t)$$

where $P(t)$ is to total CO_2 mass produced by sources tied to sinks (m = 1,…,M), $S_m(t, \tau_\mu)$ is the sequestered amount, and $E(t)$ is the vented amount of CO_2 at time t, where $t = 0$, defines the onset of the project. τ_m is the onset time of injection for well m.

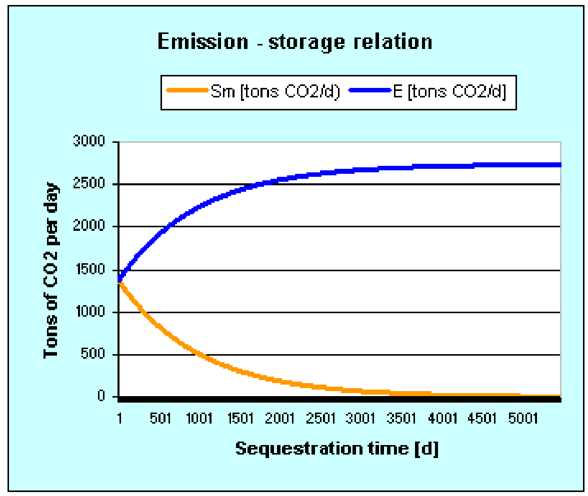


Figure 2. Emission-storage relation. The less CO_2 can be injected, the more CO_2 has to be emitted.

For simplicity each well may be thought of as one with an exponentially declining injection curve. In a simple version of the algorithm, one may rank the wells as per the injection potential or proximity, and force an ordering of τ. A more complete scheme may be written to force the ranking of the wells.

Net present value or NPV calculation

The discounted cash flow method is used to derive NPV. A discount rate, inflation, depreciation and a tax rate need to be specified. We also specify a salvage value for the equipment deployed.
The terms that are part of the NPV are:

1. n number of years the sequestration project runs
2. Initial investment
3. Revenue, which is derived from the amount of CO_2, emitted each year and the cost per ton of CO_2
4. Salvage value of the plant, pipeline and the wells after n years
5. Depreciation rate

6. Tax rate
7. Inflation rate
8. Annual investment as capital cost
9. Annual investment as running cost
10. Discount rate

In the first pass approach we propose with an a priori ordering of wells, the goal of the optimization process is to maximize NPV by finding the optimum times to drill the *M* wells.

DISCUSSION AND CONCLUSION

The NPV is the final output of the tool and shall provide the user with the fundamental information, if the sequestration project is profitable.

This generation of financial decision tool tackles the essential parts of the processes involved and uses the appropriate financial approach, the NPV, to evaluate the CO_2 sequestration project.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

QUICK-LOOK ASSESSMENTS TO IDENTIFY OPTIMAL CO_2 EOR STORAGE SITES

Vanessa Núñez Lopez, Mark H. Holtz, Derek J. Wood, and Susan D. Hovorka

Gulf Coast Carbon Center
Bureau of Economic Geology
The University of Texas at Austin
University Station, Box X
Austin, Texas, 78713-8924, USA
e-mail: vanessa.nunez@beg.utexas.edu

INTRODUCTION

Sequestration of CO_2 in oil fields, especially as they near the end of primary and secondary production, is an attractive alternative to help reduce the content of greenhouse gases in the atmosphere, not only because of the economic offset through enhanced oil recovery (EOR), but also because oil fields are known to have trapped hydrocarbons for geological time periods and may therefore have the easiest public acceptance and regulatory environments of available storage options. Oil fields also have the advantage of having been broadly studied so that large volumes of data are available from publications, the industry, and state agencies. The data availability allowed us to create an extensive database, including all major oil reservoirs in the Gulf Coast, as a starting point for a multistage quick-look approach to identifying optimal CO_2 EOR storage sites.

We have developed a multistage approach to identifying optimal CO_2 EOR storage sites. This approach was developed in our study area, the onshore US Gulf Coast, because the number of reservoirs is unmanageably large, and tested in several other regions. In the first stage oil reservoirs are first screened in terms of technical and practical feasibility for miscible CO_2 EOR. The second stage uses a dimensionless group model that estimates the oil recovery and CO_2 storage potential using appropriate inputs for the rock and fluid properties but which does not consider reservoir architecture and sweep design. The third stage validates and refines the potential recovery and storage estimations by simulating flow in a model that describes the internal architecture and the distribution of fluids in the reservoir.

STAGE 1: SCREENING OF CANDIDATE RESERVOIRS

In stage one there are two steps in screening reservoirs as candidates for CO_2 miscible EOR and subsequent sequestration. The first step is to determine if an oil reservoir would make a good miscible CO_2 EOR flood. The second step is to analyze the location of the oil reservoir relative to CO_2 sources and compare its characteristics with those of other nearby candidates. This stage uses readily available reservoir and fluid properties, and production history of the fields.

In the first step of our quick-look screening of candidate reservoirs we estimate the minimum miscibility pressure (MMP), pressure at which the CO_2 starts to become miscible with the oil and, thus, the most critical constraint for the applicability of miscible CO_2 EOR. Under miscible conditions, optimal oil recovery could be achieved.

A relationship published by Holm and Josendahl (1974) and extended by Mungan (1981), which estimates MMP from molecular weight of the C_5+ components of reservoir oil and reservoir temperature is applied. The new miscibility information is added to our database at the reservoir level, and only reservoirs that are estimated to be miscible move on to the next step.

Additional screening is performed during the second step in order to integrate the engineering analysis into the geologic setting. Issues of permanence and economics are also considered in an integrated way. Deeper reservoirs will most likely offer more effective storage and sequestration of CO_2 from the atmosphere and will probably reduce the risks of leakage to underground sources of drinking water. A set of assets and liabilities (Table 1) is assigned to remaining candidate reservoirs.

Table 1. Set of Assets and Liabilities

Candidate Assets	Candidate Liabilities
Field unitized	Questionable seals
Cumulative oil production greater than 1 MMSTB	Extreme reservoir heterogeneity
Short distance to CO_2 source	Reservoir in urban area

Applying our screening methodology results in a map of oil field candidates. An example from the Galveston area is shown in Fig. 1. The map shows the distribution of the 35 candidate reservoirs in which miscible EOR is feasible, and the top 11 candidate reservoirs, with their field outlines, that best accommodate our candidate assets and liabilities table.

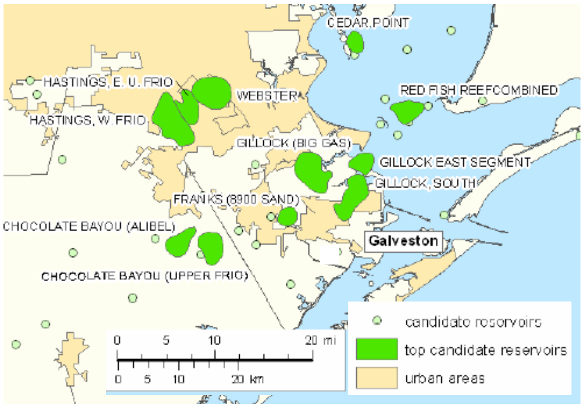


Figure 1. Galveston area map with candidate reservoirs for CO_2 EOR Storage

STAGE 2: QUICK-LOOK MODEL TO ESTIMATE RECOVERY AND STORAGE POTENTIALS

Reservoir-specific parameters from the individual prospects generated in the previous stage are introduced in a newly developed model that improves estimates of oil recovery and CO_2 storage potential without the need for comprehensive simulations. In this stage we do not consider reservoir geometry but more rigorously consider the fluid and rock properties (this model is an approximation assuming homogeneous, Cartesian rock volume with realistic properties). The model uses dimensionless groups, necessary to describe CO_2 flooding for a typical line-drive pattern, in a Box-Behnken experimental design, which is most applicable to Gulf Coast reservoirs. Past screening models from the literature, Rivas et al. (1992) and Diaz et al. (1996), focused only on oil recovery and simply assigned qualitative rankings to reservoirs, whereas this model focuses on both oil recovery and CO_2 storage potential and produces quantitative results for each.

Results show that CO_2 flooding can be fully described using 10 dimensionless groups:

$$R_L = \frac{L}{H}\sqrt{\frac{k_z}{k_x}}$$ Effective Aspect Ratio

$$N_\alpha = \frac{L}{H}\tan\alpha$$ Dip Angle

$$M_w^o = \frac{k_{rw}^o * \mu_o}{k_{ro}^o * \mu_w}$$ Mobility Ratio (water)

$$M_g^o = \frac{k_{rw}^o * \mu_o}{k_{ro}^o * \mu_w}$$ Mobility Ratio (CO_2)

$$N_g^o = \frac{H \Delta\rho g \cos\alpha}{\Delta P}$$ Buoyancy Number

$$P_{injD} = P_{inj} / MMP$$ Injection Pressure

$$P_{pD} = P_p / MMP$$ Producing Pressure

S_{oi} Initial Oil Saturation

S_{orw} Residual Oil Saturation to Water

S_{org} Residual Oil Saturation to Gas

The effects of capillary forces and dispersion are shown to be negligible in this approach and thus not included in the scaling. Reservoir heterogeneity is neglected in the second stage because of the difficulty inherent in properly scaling it and the relative paucity of heterogeneity data available for most reservoirs. Dimensionless oil recovery is effectively modeled with the dimensionless oil breakthrough time and the dimensionless recovery at three different dimensionless times, whereas CO_2 storage potential is calculated only at the final dimensionless time.

The model uses response surface fits to estimate five parameters, four for oil recovery and one for CO_2 storage. Each fit contains only six or seven terms, making the model simple to implement. This simplicity is intended to make a tool useful for smaller reservoir operators and improve the estimates in our large database.

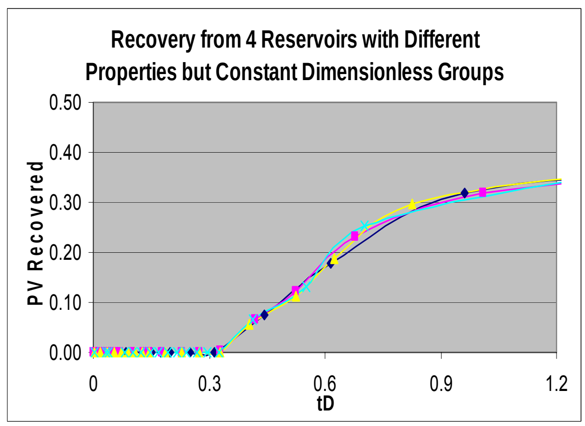


Figure 2. Recovery curves from four different reservoirs with constant dimensionless group values

Effectiveness of the model is demonstrated by consistent output from different reservoirs when applying the same dimensionless constants (Fig. 2). Each simulation is run until 1.2 pore volumes of CO_2 are injected (t_D = 1.2). The oil recovery is modeled with four data points. The first point is the dimensionless oil breakthrough time (t_D^O), at which significant amounts of oil are recovered. Recovery at all points before this time is assumed to be zero. The final three points are the dimensionless oil recovery at t_D=0.8 (R_1), t_D=1.0 (R_2), and t_D=1.2 (R_3). Dimensionless recovery is the fraction of the total pore volume recovered, and not the typical measure of the percentage of the original oil in place (%OOIP) recovered.

STAGE 3: RESERVOIR CHARACTERIZATION

Reservoir characterization is the process of building of a geologic and engineering model that describes the reservoir's internal architecture and the distribution of fluids in porous media which provides needed input into a full reservoir simulation. The model should consider all important geologic scales of heterogeneity, from gigascopic basin-scale characteristics to microscopic pore-level characteristics. The internal architecture delineated is based on the integration of geologic character with measured engineering parameters. A reservoir model can integrate, for example, wireline logs, seismic surveys, basic or advanced core analysis, thin section analysis, production and pressure history, laboratory miscibility determination, and fluid geochemistry. This integration results in a model that describes fluid-flow paths and barriers. Identifying the location within the reservoir of both the initial and remaining hydrocarbon resource allows the model to be applied as a tool for assessing CO_2 EOR potential and storage capacity.

The purpose of reservoir characterization is to develop a tool that honors factors such as reservoir geometry, heterogeneity, past development, or anisotropy that can be applied in determining and optimizing hydrocarbon recovery for reserve growth and the calculation of sequestration volume.

SUMMARY

The completion of the three stages described in this paper outlines the Quick-Look methodology that we are developing to identify optimal CO_2 EOR/storage sites. The staged approach quickly reduces the number of possible sequestration sites, thus saving time and allowing more resources to be applied to best the candidates. The process sequentially considers (1) the feasibility for miscible CO_2 displacement, (2) the location of the miscible candidate reservoirs with respect to CO_2 anthropogenic sources, (3) reserve growth and storage capacities, and (4) the reservoir character and heterogeneities at all geologic scales.

REFERENCES

Diaz, D., Bassiouni, Z., Kimbrell, W., and Wolcott, J., *Screening Criteria for Application of Carbon Dioxide Miscible Displacement in Waterflooded Reservoirs Containing Light Oil,* paper SPE 35431 presented at the 1996 SPE Improved Oil Recovery Symposium, Tulsa, April 21-24.

Holm, L.W., and Josendal, V.A., *Mechanisms of Oil Displacement by Carbon Dioxide*, JPT, Dec. 1974 1427-36, Trans., AIME, Vol. 257.

Mungan, N., *Carbon Dioxide Flooding Fundamentals*, JCPT, 1981, 87.

Rivas, O., Embid S., and Bolivar F., *Ranking Reservoirs for CO2 Flooding Processes*, paper SPE 23641 presented at the 1992 SPE Latin American Petroleum Engineering Conference, Caracas, March 8-11.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

HEALTH, SAFETY, AND ENVIRONMENTAL SCREENING AND RANKING FRAMEWORK FOR GEOLOGIC CO_2 STORAGE SITE SELECTION

Curtis M. Oldenburg

Earth Sciences Division, Lawrence Berkeley National Laboratory
1 Cyclotron Road
Berkeley, CA 94720
e-mail: cmoldenburg@lbl.gov

INTRODUCTION

In order to minimize the possibility that carbon dioxide (CO_2) storage projects will result in health, safety, and environmental (HSE) impacts due to CO_2 leakage and seepage, it is essential that sites be chosen to minimize HSE risk. Apart from site-specific operational choices once a given CO_2 pilot injection project is underway, the best way to avoid unintended leakage and seepage is to choose a good site at the outset.

A spreadsheet-based Screening and Ranking Framework (SRF) for evaluating multiple sites on the basis of their potential for HSE risk due to CO_2 leakage and seepage is described here. The results of comparisons can be used to help select the best CO_2 injection sites from a number of candidate sites through screening and ranking. This document, an extended abstract of Oldenburg (2005), briefly describes the philosophy behind the approach, and presents a single example application to demonstrate the use and applicability of the framework.

Before describing the framework, it is useful to clarify terminology. The term *leakage* refers to migration of CO_2 away from the intended target formation. *Seepage* is slow or diffuse CO_2 migration across an interface in the near-surface environment such as the ground surface or the bottom of water body such as a lake. The *near-surface environment* is defined loosely as +/- 10 m from the ground surface. The word *impact* refers to consequences or effects of a given high CO_2 concentration on people and biota for a given time. *Risk* is often defined as the product of probability of occurrence and consequence in order to reflect both the elements of likelihood and impact, and this same definition is used here. However, rather than treating likelihood in any kind of formal probabilistic sense, the SRF is qualitative with respect to risk and uses subsurface properties as general proxies for processes and features as described in the next section.

PHILOSOPHY BEHIND THE APPROACH

Although there is a wide variety of potential pathways for leakage and seepage of CO_2 to the near-surface environment, leakage pathways generally involve the potential for secondary entrapment at higher levels in the system. Furthermore, there is potential for attenuation or dispersion along the leakage pathway. The HSE effects of CO_2 that are of concern are caused by high concentrations of CO_2 in the near-surface environment where humans, plants, and other living things reside. To minimize HSE effects, it is necessary either to (1) prevent CO_2 leakage, (2) prevent CO_2 leakage from reaching the near-surface environment, or (3) attenuate the leakage flux or disperse the CO_2 if it should reach the near-surface environment so that CO_2 never builds up to persistent high concentrations at which it is an HSE risk.

The approach assumes that potential HSE impact is related to three fundamental characteristics of a geologic CO_2 storage site:

(1) Potential of the target formation for long-term containment of CO_2;
(2) Potential for secondary containment should the primary target site leak; and
(3) Potential of the site to attenuate and/or disperse leaking CO_2 should the primary formation leak and secondary containment fail.

The SRF spreadsheet was designed to provide a qualitative and independent assessment of each of these three characteristics through an evaluation of the properties of various attributes of these characteristics.

SCREENING AND RANKING FRAMEWORK

Although developed based on past experience with CO_2 storage rather than with the formality of decision analysis, the approach falls loosely under the category of multi-attribute utility theory (e.g., Keeney, 1980; Keeney and Raiffa, 1976). The three scores that are evaluated for each site are proxies for combinations of impact and likelihood (i.e., risk) of leakage, secondary entrapment, and attenuation. The input required by the SRF is quite general and may rely primarily on expert opinion depending on the degree of characterization and/or published information available for the sites. The SRF is implemented in an Excel© spreadsheet.

The assessment made in the framework is based on four classes of information: (1) site characteristics which are defined by (2) attributes, which are defined by (3) properties which are defined by (4) values. For example, the first *characteristic* (potential of the site for primary containment of CO2) has three *attributes* as follows: (1) the nature of the primary caprock seal; (2) the depth of the reservoir; and (3) the properties of the reservoir. The *properties* of the primary caprock seal attribute are thickness, lithology, demonstrated sealing capacity, and lateral continuity. These four properties are proxies for (1) likely effectiveness of the seal, (2) permeability and porosity of the seal, (3) the probability of leakage through the seal, and (4) the integrity of the seal against CO_2 spreading that could exceed the spillpoint. Similar attributes, properties, and values are defined for the characteristics of potential for secondary containment, and potential for attenuation.

USING THE SRF SPREADSHEET

The main thing the user of the SRF spreadsheet does is assign a numerical value to the properties. The numerical values are chosen as integers ranging from –2 (poor) to +2 (excellent) with 0 considered neutral (neither good nor bad). Broad ranges of values are offered for various conditions in the pop-up comments to guide the user in selecting an integer between –2 and +2. The next thing the user does is assign weighting factors for each of the properties of each attribute. The weighting option allows the user great latitude in applying his/her judgment to the evaluation. The third thing the user does is enter a value for the certainty with which each property is known (2 is very certain, 0.1 is highly uncertain). This confidence information will be carried along and plotted with attribute assessments for each of the three characteristics.

The fundamental calculation the spreadsheet does is add up the weighted property assessments and average them across the attributes to arrive at a score for each of the three fundamental characteristics. The spreadsheet also produces a graphical summary page for each site as described below.

EXAMPLE APPLICATION

Rio Vista Gas Field

The Rio Vista Gas Field is located in the delta region of the Sacramento-San Joaquin Rivers in the Sacramento Basin of California, approximately 75 km northeast of San Francisco. The Rio Vista Gas Field is the largest on-shore gas field in California, and has been producing gas since 1936 from reservoirs in an elongated dome-shaped structure extending over a 12 km by 15 km area. The largest production has been from the Domengine sands in fault traps at a depth of approximately 4500 ft (1400 m) with sealing by the Nortonville shale. Details of the field can be found in Burroughs (1967) and Johnson (1990).

To summarize this SRF application, we present in Figure 1 the Summary worksheet for the Rio Vista gas field site. Some general aspects of the summary worksheet are worth noting before discussing the specifics for Rio Vista. Note in Figure 1 to the right of the plot is shown a table (Chart Details) with numerical values of the averages of the three characteristics and uncertainties as shown by the large circle symbol in the plot. The third number in the table to the right of the plot is the distance from the lower-left-hand corner of the plot (lowest assessment, least certainty) to the average point. This distance is a measure of the overall quality of a site taking into account both the average scores and average uncertainty.

Additional scores of the three characteristics are displayed along the bottom of the plot and defined in comments. These scores are automatically colored based on the scores (red implies poor, green implies good). The overall score ranges from –4 to +4 and is a product of the assessments and uncertainties. The low end –4 would be a site that the user is very certain is very poor, while a +4 would be a site that the user is very certain is very good. Because the overall score collapses expected behavior and certainty together into one number, it is not emphasized nor plotted but rather included simply as additional information. The summary worksheet graphic displays tentative screening curves delineating Good, Fair, and Poor regions on the summary graphic.

As for Rio Vista, we have used published materials and our knowledge of the geology to fill in values in the SRF spreadsheet and arrive at overall attribute assessments and certainties for the Rio Vista Gas Field under the assumption that it would be used as a geologic CO_2 storage site. As shown in the Summary worksheet of Figure 1, the high attribute score displayed by the SRF spreadsheet reflects the very effective primary containment expected at Rio Vista. Secondary containment is not expected as sealing formations above the Nortonville shale are largely absent. However, the attenuation potential is excellent at Rio Vista due largely to steady winds and flat topography. As shown in Figure 1, confidence in the attribute assessments is quite high for subsurface and surface characteristics at Rio Vista due to the long history of gas production at the site. The high score and certainty at this site suggest that Rio Vista Gas Field is a good candidate for geologic CO_2 storage.

CONCLUSIONS

A framework for screening and ranking candidate sites for geologic CO_2 storage on the basis of HSE risk has been developed based on three fundamental characteristics of a CO_2 sequestration site. The framework allows users to arbitrarily weight and assign uncertainty to the properties of the attributes of the fundamental characteristics to evaluate and rank two or more sites. We emphasize that this is a screening and ranking risk assessment tool intended to guide the selection of the most promising sites for which more detailed risk assessment would be carried out. Further details can be found in Oldenburg (2005).

ACKNOWLEDGMENT

I thank Tom McKone, Christine Doughty, Larry Myer, and Sally Benson (LBNL) for reviews, support, and encouragement. This work was supported in part by WESTCARB through the Assistant Secretary for Fossil Energy, Office of Coal and Power Systems, through the National Energy Technologies Laboratory (NETL), and by Lawrence Berkeley National Laboratory under Department of Energy Contract No. DE-AC03-76SF00098.

REFERENCES

Burroughs, E., *Rio Vista Gas Field. Summary of California oil fields*, *53*, *No. 2-Part 2*, State of California, Dept. of Conservation, Division of Oil and Gas, 25-33, 1976.

Johnson, D.S., Rio Vista Gas Field-USA Sacramento Basin, California, in N.H. Foster and E.A. Beaumont, eds., *Atlas of oil and gas fields, Structural Traps III, AAPG Treatise of Petroleum Geology, Atlas of Oil and Gas Fields*, Tulsa OK, 243-263, 1990.

Keeney, R.L., *Siting Energy Facilities*, Academic Press, New York, 413 pp., 1980.

Keeney, R.L., and H. Raiffa, *Decisions with Multiple Objectives: Preferences and Value Tradeoffs*, John Wiley and Sons, New York, 569 pp., 1976.

Oldenburg, C.M., Health, Safety, and Environmental Screening and Ranking Framework for Geologic CO_2 Storage Site Selection, Lawrence Berkeley National Laboratory Report *LBNL-58873*, September 2005.

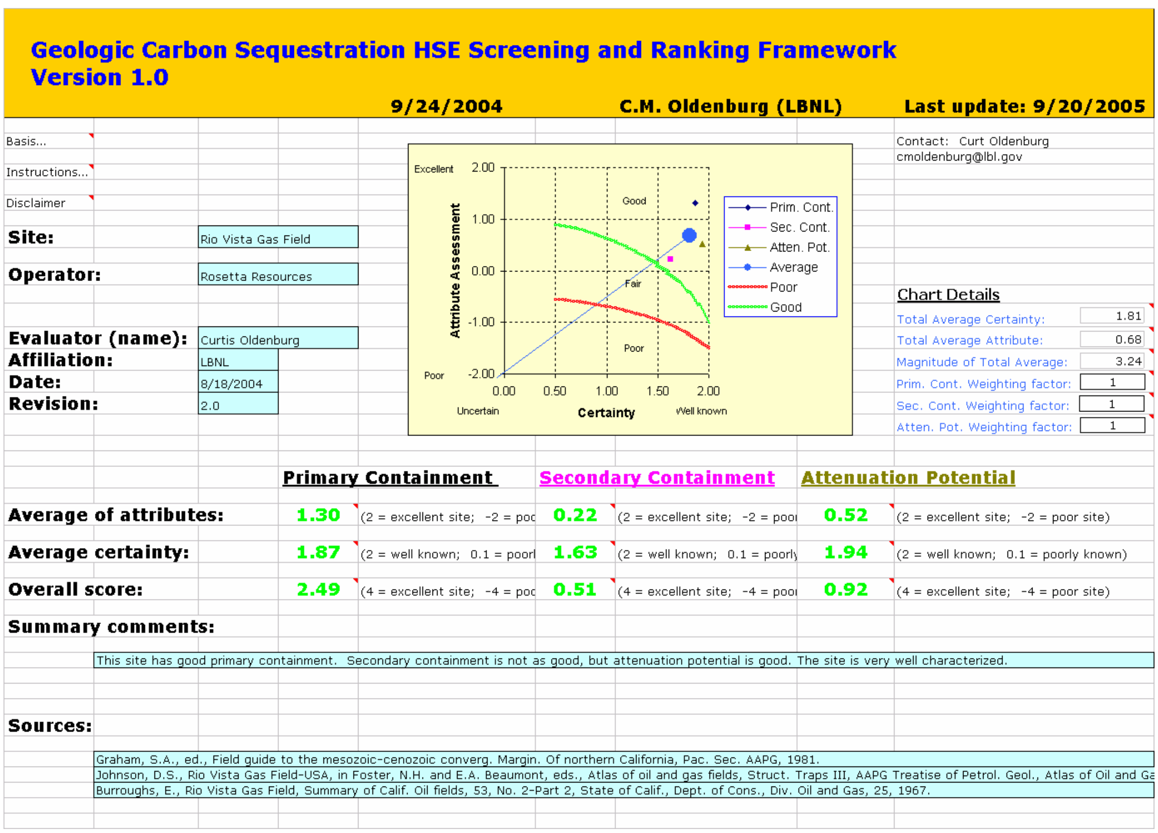


Figure 1. Screenshot from the SRF spreadsheet showing the summary page for the Rio Vista application.

PROCEEDINGS, CO2SC Symposium 2006
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

A COUPLED GIS AND 3D GEOLOGIC MODELING SYSTEM FOR SITE CHARACTERIZATION

J.L. Wagoner[1], D. John[1], L. Neher[1], S. Pack[2], and L. Wilder[1]

[1]LLNL
P. O. Box 808
Livermore, CA 94551
e-mail: wagoner1@llnl.gov

[2]Dynamic Graphics, Inc.
2603 Augusta Dr. Suite 1080
Houston, TX 77057-5639
e-mail: skip@dgi.com

ABSTRACT

Geologic sequestration of carbon dioxide (CO_2) is one of several options for carbon management. Potential sequestration sites include deep saline aquifers, depleted oil and gas reservoirs, and coal beds; evaluating the geologic and hydrologic characteristics of these sites involves collection, synthesis, and analysis of both 2d and 3d information. Geographic information systems (GIS) do a good job organizing and analyzing 2d spatial data. Geologic modeling codes do a good job organizing and analyzing 3d spatial data, as well as generating 3d geologic models. We investigate methods of linking these capabilities into a stand-alone system that can be used to evaluate and characterize a site for potential sequestration of CO_2.

We have integrated ArcGIS (ESRI) and Earthvision (Dynamic Graphics, Inc.) into a self-contained system that can be used to evaluate and analyze not only the surface features of a site, but also the subsurface. We use ArcGIS as the graphical interface (GUI) , which serves as a front-end for the system (Figure 1). The GIS is linked to Earthvision (Dynamic Graphics, Inc.), a 3d geologic modeling code that will run processes in the background. We also use a tool called ModelBuilder to process and diagram tools and these are represented in Figure 1. The flow diagrams created with ModelBuilder are a convenient way to construct, modify, document, and present these processes.

Analytical capability is the power of a GIS. This process involves converting, combining, and analyzing raw data to produce useful information. Spatial analysis can reveal patterns and anomalies that would not always be apparent and then graphically communicate the information. The GIS can be a predictive modeling tool for optimization and hypothesis testing. We created a GIS that contains numerous cultural data layers, such as roads, demographics, schools, land use, power plants, etc. Additional data are available for the Navajo Nation, such as topography, geology, stratigraphic contacts, oil and gas and water wells, reservoir data, and sample location data.

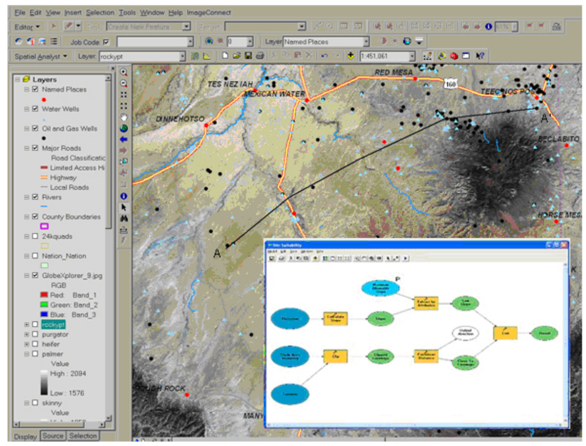


Figure 1. Illustration of graphic user interface using ArcMap. The line of section for the cross section is shown (A-A').

For demonstration purposes, we are using a recently-collected dataset from the Navajo Nation of north-eastern Arizona. These data include structural tops for ~30 stratigraphic units, well data, physical property data, and sample data. We constructed a 3d geologic framework model of an area that is 67 km x 67 km. We modeled ~10 of the available stratigraphic units; the topographic surface is a 10m digital elevation model (DEM). Two faults (not real) were added, mainly to show the functionality of the Earthvision software.

The underlying 3d geologic model (Figure 2) can be accessed from the GUI at the ArcGIS level. For example, to generate a 2d geologic cross section through an area of interest, the operator creates a traverse line by simply clicking on 2 or more points in ArcGIS. The line of section can be at any angle within the range of the 3d geologic framework model. This invokes a script that will generate a 2d geologic cross section (Figure 3) through the un-

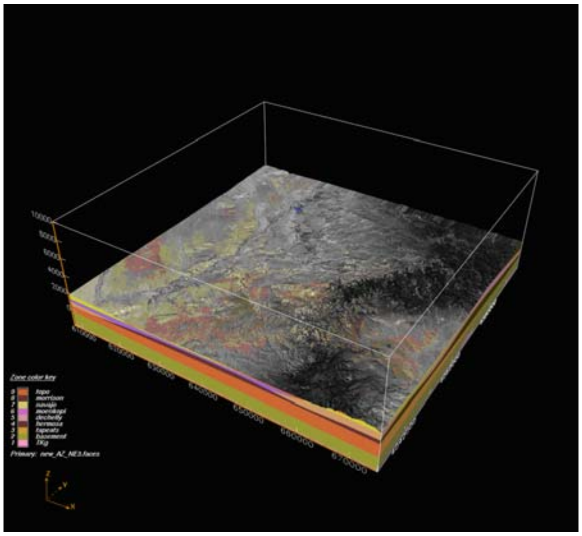


Figure 2. This is a 3D geologic framework model of a portion of the Navajo nation

derlying 3d geologic model along the prescribed traverse line. The cross section can be delivered to the desktop as a raster image, vector graphics, or ascii data.

Properties can also be modeled within the 3d structural framework model. Any physical property or geophysical parameter can be modeled in 3d within the structural and stratigraphic framework, and these data can also be accessed as discussed in the previous paragraph.

All models can be faulted and there is no limit on the number of faults per model. Faults are modeled as 2d grids that cut through and offset the stratigraphic layers. This is an important capability, since faults are a concern in site characterization for geologic CO2 sequestration.

There are numerous queries that can be made of the underlying geologic and property models, through the ArcGIS interface. The results can be retrieved not only as raster images, but also as ascii data. Retrieving the results as data allows the operator to use the GIS for further analysis of the data from the 3d model.

This work was performed under the auspices of the U.S. Department of Energy by University of California, Lawrence Livermore National Laboratory under Contract W-7405-Eng-48.

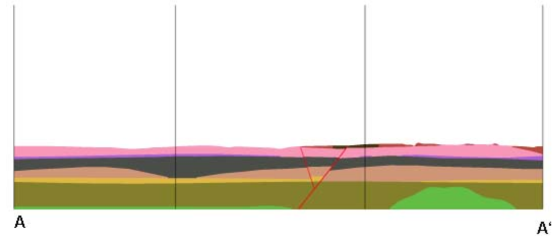


Figure 3. This is a cross section along the line of section A-A'.

REFERENCES

Dynamic Graphics, Inc., *Earthvision*, 2006. http://www.dgi.com/earthvision/productinfo.shtml.

ESRI-Environmental Systems Research Institute, *ARCGIS,* 2006. http://www.esri.com/software/arcgis/about/desktop.html

REGULATORY AND SOCIAL ISSUES

USEPA RECENT PROGRESS IN DEVELOPING A WELL PERMITTING FRAMEWORK FOR THE UNDERGROUND INJECTION OF CO2

B.J. Kobelski, R.E. Smith, and A.L. Whitehurst

USEPA, Office of Ground Water and Drinking Water
Washington, DC 20460

Since the late 1990s, the United States Environmental Protection Agency (USEPA) has been gathering information necessary to establish a cogent framework to regulate long-term storage of carbon dioxide in deep saline aquifers. Initially, when the first discussions were held advocating geologic sequestration of CO2, the USEPA participated in the GEOSEQ partnership providing expertise on injection wells and explaining the regulatory scope of the Underground Injection Control (UIC) program under the Safe Drinking Water Act (SDWA).

As geologic sequestration came to the forefront in the scientific community as an effective means of capturing and storing CO2 to potentially mitigate long term climate effects, EPA began to increase its participation in related Carbon Capture and Storage (CCS) conferences. In 2004, the Agency's Office of Air and Radiation and the Office of Water convened a Geologic Sequestration Workgroup in order to identify and help respond to technical issues on geologic sequestration, and to coordinate EPA's participation on the growing number of CCS activities.

In order to better inform the workgroup on CCS technology issues, EPA initiated several internal meetings between key involved parties including federal agencies, academia, climate scientists, petroleum industry experts, and environmental organizations. In 2005, EPA began sponsoring several conferences to bring various groups together to discuss these technical issues, and to establish a presence regarding an opinion on potential risks to human health and the environment from the application of CCS technology on a national scale. The conferences included a workshop on computer modeling of CO2 injection, and a broader risk assessment workshop.

EPA has concluded that any underground well injection of CO2 for the purposes of storage, disposal, or enhanced hydrocarbon recovery is clearly covered under the SDWA, and the Agency is proceeding to first develop an appropriate course of action to take for reviewing DOE's initial CCS pilot projects. Then, EPA will likely undertake addressing future potential large-scale commercial projects involving CCS. A symposium conducted to address site characterization and selection is, therefore, essential in considering and ensuring that any site for long-term CO2 storage will be effective and pose no extraordinary risks to the public. Applicable findings from the conference may be used by EPA's GS Workgroup as they proceed to develop options to address the permitting of CO2 injection wells.

ALTERNATIVE PATHWAYS, POTENTIAL OBSTACLES, AND PRACTICAL SOLUTIONS TO REGULATING CO_2 GEOLOGICAL STORAGE

Michel J. Paque [1], Robert F. Van Voorhees[2], Barton D. Day[2], Brandon W. Neuschafer[2]

[1]Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142 USA
405-516-4972405-516-4973 FAX
Email: mike@gwpc.org

[2]Environmental Practice Group
Bryan Cave LLP
700 13th Street, N.W., Suite 700
Washington, DC 20005-3960
(202) 508-6014//(202) 220-7314 FAX
e-mail: rfvanvoorhees@bryancave.com

ABSTRACT

Future use of fossil fuels, including coal in particular, as clean, zero-emission fuels for power generation will undoubtedly require reliance on carbon capture and storage technologies, including geological storage. Industry and regulators have extensive experience with CO_2 injection for enhanced oil recovery. Indeed, most near-term CO_2 injection is likely to be for enhanced hydrocarbon recovery. Some CO_2 storage is a consequence but not the principal purpose of enhanced recovery, and some enhanced recovery projects are likely to make the transition to geological storage. Substantial reductions in CO_2 emissions, however, will require a more diversified approach. Extensive scientific and technical studies and demonstration projects are establishing a solid foundation for much broader application of CO_2 injection for geological storage. With the broader application of the technology and the more diversified application scenarios will come challenges for the regulatory agencies at the state and federal levels that potentially will be charged with responsibility for authorizing and monitoring these projects.

Although existing regulatory programs for using CO_2 injection in enhanced recovery operations are fairly well established, the expanded use of CO_2 injection for long-term geological storage in the absence of enhanced recovery will raise a number of questions regarding how such injection operations should be addressed under existing regulatory programs. One key question will be determining when an enhanced recovery operation ceases to be enhanced recovery and becomes an operation for CO_2 storage and whether such a change should trigger the application of a different regulatory regime notwithstanding that CO_2 will still be the fluid injected. Such changes should occur only if truly warranted by the scientific and technical demands for monitoring, maintenance, and verification of the projects.

From a scientific and technical standpoint, natural gas injection operations may appear to provide an analogue for CO_2 storage, but it is not clear whether existing regulatory programs for "natural gas" storage could simply be applied to CO_2 storage absent significant modification to account for economic, legal and policy differences. CO_2 has been defined as a "natural gas" in some contexts but not previously under the Safe Drinking Water Act (SDWA) underground injection control (UIC) program. The Environmental Protection Agency (EPA) will probably make that call and has previously declined to define CO_2 as a natural gas for UIC program purposes. If the value of CO_2 emission credits provided comparable economic incentives for containment, then the natural gas storage model would have more obvious comparability.

Application of the natural gas storage model for geological storage would suggest the need to acquire property rights from both surface and mineral estate owners whereas the UIC model could be viewed as questioning the need for such acquisitions absent direct interference with other reasonable and foreseeable uses of the subsurface geological formations used for such storage.

Other legal issues concern how existing regulatory pathways would address such issues as the movement of injected CO_2 in deep geological formations, the rights of landowners and mineral rights owners with respect to ownership of the pore space in receiving formations and ownership of the CO_2 gas injected for long-term storage, and potential liability for operational failures and long-term releases. Such issues need to be resolved in a way that will facilitate the

broader application of this proven environmental management technology without stifling its potential use by imposing burdensome but unnecessary regulatory requirements.

This presentation highlights and discusses key legal issues that will need to be resolved and discusses them in the context of alternative regulatory pathways. Practical solutions can be found inherent in the flexibility allowed within specific regulatory regimes. It is most important for regulatory agencies at both the state and federal levels to fully explore the flexibilities and to apply those to the permitting and authorization processes in a way that allows the technology to develop without being cabined by preconceived notions that served as the bases for requirements developed for injection wells and operations serving totally different purposes and injecting different fluids. Current UIC program requirements are designed to authorize imposition of siting, construction, operating, and monitoring requirements deemed necessary to meet the essential performance requirement of the program to prevent endangerment of underground sources of drinking water (USDWs). To the extent that regulation of CO_2 storage must go beyond this mandate to fulfill the needs of the program, additional authority may need to be sought.

PROCEEDINGS, CO2SC Symposium
Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006

SITING GEOLOGICAL SEQUESTRATION PROJECTS: PUBLIC PERCEPTION, REGULATORY STRUCTURES AND LEGAL CONSIDERATIONS

Elizabeth Wilson and Carissa Schively

Humphrey Institute of Public Affairs
University of Minnesota
Minneapolis, MN, 55455, USA
e-mail: ewilson@umn.edu

INTRODUCTION

When geologic sequestration (GS) projects are sited, the technical project details will be judged by the surrounding community, state regulators and local property owners. The public perception of the technology, project compliance with the extant regulatory system and insurances that injection of millions of tons CO_2 into the subsurface will not harm private property rights will influence site approval and eventual project deployment.

This article seeks to redress the imbalance between the depth of technical research on GS and the paucity of information on the surrounding public policy context within which the technology would be deployed. It is this relationship between the technical elements of GS projects and the social and legal systems needed for eventual deployment that must be fully understood if GS is to play a significant role in reducing anthropogenic CO_2 emissions. These elements are central components of site selection and for eventual project deployment.

GS projects are likely to be large. Calculations by Tsang *et al.* demonstrate that some geologic sequestration (GS) projects will underlie areas on the order of a hundred square kilometers, with pressure effects felt over thousands of square kilometers. (2002). Given this scale, it is possible that GS projects could underlie many different environments. Depending on where the injection project was located, the project could be on public or private land, close to aquifers supplying public drinking water, or under population centers.

Additionally, it seems likely that siting considerations and potential difficulties will change over time. If 'first generation' GS projects are associated with enhanced oil recovery operations, the siting considerations will be quite different than 'second generation' projects injecting into saline aquifers. Some siting differences of these projects could be influenced by familiarity of community members with injection technology, regulatory frameworks managing non-hydrocarbon producing formations, lack of mechanism to create a large and legal sequestration sites. Also, the activities might be perceived differently in terms of benefit and risk that injection offers.

This paper outlines some of these concerns and provides an overview of a few potential public perception, regulatory, and legal considerations that could influence the siting process.

PUBLIC PERCEPTION CONSIDERATIONS

Several studies have been completed on how the public views CCS technologies (Palmgren *et al.,* 2004; Curry *et al.*, 2004). In these initial studies, the public has not been found to be very knowledgeable about the technology, and some initial concerns were expressed (Palmgren, 2004). Palmgren *et al.* also found that participants ranked CCS below nuclear energy when evaluating future energy technology options.

Given the lack of public opinion on CCS technologies, coupled with the large subsurface scale of the projects, siting activities could potentially be subject to 'Not in my backyard' or NIMBY sentiments. The rich-body of experience on NIMBY and risk and impact communication in other areas can be particularly informative for GS. The siting of the first few projects is particularly important, as any mishap could serve to color public opinion and media attention on the technology, making future project siting potentially more difficult.

The location of the GS project may influence both the public involvement and the potential opposition, (e.g. population centers vs. remote locations). Opposition could be both local and from elsewhere, as national or international groups concerned with broader environmental or social justice issues seek to use the siting process as an opportunity to interject their particular interest into the policy process.

The perceived fairness of the project siting is also considered important from a NIMBY perspective. Environmental justice concerns could play a role if projects were located in predominately minority or poor areas.

LEGAL CONSIDERATIONS

In addition to public perception issues, some legal considerations are particularly relevant for siting GS projects. Establishing large and legal sequestration reservoirs is a key consideration, especially for second generation projects. In most countries, ownership of subsurface pore space is retained by the Crown or central government.

In the U.S. the situation is slightly different. While pore space ownership under public lands is indeed controlled by the state, the situation under private lands is more complicated. In the U.S., surface owners have largely been found to also own the subsurface pore space. Methods to contract for the use of this pore space to store natural gas (backed up by state and federal powers of eminent domain if the surface property owner will not comply) have been developed and are a useful analog, to a point.

For the 'first generation' GS projects, which are likely to be linked to an enhanced recovery operation, it is almost certain, that due to liability considerations, injection will only happen in an already unitized field. Unitization is a mechanism whereby individual field liability and management considerations are pooled into a larger structure able to more efficiently extract the hydrocarbon resource. States have well developed procedures and rules for field unitization.

How large and legal reservoirs for sequestration will be established in 'second generation' projects, injecting into saline aquifers is less certain. Given the current political climate and increased emphasis on property rights, it remains to be determined if the political will to grant powers to create large and legal subsurface reservoirs exists. If legal rights of eminent domain are only granted by certain jurisdictions this could influence siting of GS projects. Until this problem is solved, siting projects on public lands will be, from a legal perspective, much simpler.

Another important consideration is long-term liability. Understanding who will be responsible if something goes wrong is a key legal consideration that feeds directly into public perception and is controlled partially by the regulation.

REGULATORY CONSIDERATIONS

Some significant regulatory considerations also exist when considering where to site projects. While injection wells are regulated under 40 CFR 144-146 and managed under the U.S. Environmental Protection Agency's Underground Injection Control Program, in states with primacy (34 states), actual permits will be granted by a state office.

For first generation projects, the permit granting institution will probably be associated with oil and gas production. For the second generation projects, where no hydrocarbon resources are involved, it could be the state department of the environment or natural resources. The level of familiarity with deep injection permitting varies significantly between departments and between states.

Also, many states have designated sole source aquifers that are crucial for public water supply. No underground injection can exist where these aquifers have been designated. Another important consideration is that some states have forbidden deep well injection altogether. Clearly, siting a GS project in one of these locations would face significant difficulties.

RECOMMENDATIONS

In addition to the technical data that is being assembled to aid siting, additional policy relevant data should be included as well. In addition to the GIS data assembled on rock permeability, abandoned wells, and sedimentary formations, overlays of the following "public policy" data should be included:

- Population demographics,
- Native American Lands,
- National Parks,
- Endangered Species Habitats,
- Sole source aquifers,
- Aquifers for public drinking water,
- Jurisdictions that don't allow deep injection wells

The addition of these data layers will allow for a more nuanced appreciation of both potential sites as well as highlight potential opposition to planned GS projects.

CONCLUSIONS

As sites for GS projects are selected, the legal, regulatory and public perception considerations will play a key role in actual project deployment. Identifying and understanding where the technology rubs up against the current system now should allow for both better project planning and sufficient time to resolve and manage any difficulties.

REFERENCES

Curry, Tom E., David Reiner; S. Ansolabehere, and Howard Herzog. *How Aware is the Public of Carbon Capture and Storage?* Paper presented at Seventh International Conference on Greehnouse Gas Technologies, Vancouver, Canada. 2004.

Palmgren, Claire R.; Granger M. Morgan; Wandi Bruine de Bruin,: and David W. Keith. 2004. Initial Public Perceptions of Deep Geological and Oceanic Disposal of Carbon Dioxide. *Environmental Science and Technology 38*, 6443-6450, 2004.

Tsang, Chin Fu; Sally M. Benson, Bruce Kobelski, and Robert E. Smith, Scientific Considerations Related to Regulation Development for CO2 Sequestration in Brine Formations. *Environmental Geology 42*, 275-281, 2002.

Wilson, Elizabeth J., and Mark de Figueiredo. Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law. *Environmental Law Reporter 36*:10114-10124, 2006.