Final Report
DOE/NETL Clean Coal Research Program
Carbon Storage Program
FY2013 Peer Review Meeting

Meeting Summary and Recommendations Report

Pittsburgh, Pennsylvania
October 22-26, 2012

U.S. DEPARTMENT OF ENERGY
OFFICE OF FOSSIL ENERGY
NATIONAL ENERGY TECHNOLOGY LABORATORY

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FINAL REPORT
CLEAN COAL RESEARCH PROGRAM
CARBON STORAGE PROGRAM
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MEETING SUMMARY AND RECOMMENDATIONS REPORT

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Work Done Under
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DISCLAIMER

The work performed on this task/subtask was completed under Leonardo Technologies, Inc. (LTI), Prime Contract DE-FE0004002 (Subtask 300.02.01.000) for DOE-NETL.

MEETING SUMMARY AND RECOMMENDATIONS REPORT

EXECUTIVE SUMMARY

The mission of the DOE Clean Coal Research Program (CCRP), administered by the Office of Fossil Energy's National Energy Technology Laboratory (NETL), is to ensure the availability of ultraclean, near-zero emission, abundant, and low-cost domestic energy from coal in order to fuel economic prosperity, strengthen energy security, and enhance environmental quality.[1]

The mission of the NETL-managed Carbon Storage Program is to create a public benefit by discovering and developing methods to economically and permanently store greenhouse gas (GHG) emissions from the combustion of fossil fuels. The technologies developed through the program will be used to maintain fossil fuel power plants as viable, clean sources of electric power.

The Carbon Storage Program consists of a portfolio of laboratory and field R&D projects focused on technologies that have the potential to reduce GHG emissions. In addition to these projects, DOE promotes the global implementation of carbon capture and storage (CCS) technologies through participation in initiatives such as the Carbon Sequestration Leadership Forum and the International Energy Agency's Greenhouse Gas R&D Programme. The Carbon Storage Program also collaborates globally by supporting projects that partner with international projects, including the Weyburn project in Canada, the In Salah project in Algeria, the Sleipner and Snøhvit projects in Norway, Australia's Otway project, the German CO2SINK project, and Canada's Fort Nelson and Zama Acid Gas Injection projects.

Additionally, NETL's Office of Research and Development conducts on-site research that provides the scientific basis for carbon storage options through its Geological and Environmental Systems Focus Area, which seeks to assess the resource, suitability, and permanence of potential carbon storage reservoirs; to assess the ability of unconventional reservoirs to produce gas and oil and assist in that production; and to improve environmental performance of existing power plants. NETL's Office of Program Planning and Analysis (OPPA) conducts analyses to demonstrate how R&D activities support national and international priorities related to energy supply, energy use, and environmental protection. OPPA conducts the following three types of analyses (with respect to the Carbon Storage Program): 1) Systems, which places research objectives (e.g., improvements in the cost and efficiency of CO_2 reuse technologies) in the context of their impacts on commercial power generation systems and other industrial processes; 2) Policy, which places CCS in the context of regulatory compliance and environmental policy; and 3) Benefits, which combines technology and policy options to show economic and environmental costs and benefits that a successful Carbon Storage Program will provide domestically.

Furthermore, the Carbon Storage Program collaborates with a number of states, governmental agencies, industries, national laboratories, universities, and private companies. For example, the program's Regional Carbon Sequestration Partnerships (RCSP) Initiative includes representatives from more than 400 organizations. The program has worked with agencies, such as the U.S. Environmental Protection Agency (EPA); the U.S. Department of the Interior's (DOI) Bureau of Ocean Energy Management (BOEM); DOI's Bureau of Land Management (BLM); the Interstate Oil and Gas Compact Commission (IOGCC); the Ground Water Protection Council (GWPC); and the U.S. Department of Transportation (DOT) on

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[1]. U.S. Department of Energy, Office of Fossil Energy, Office of Clean Coal, *Office of Clean Coal Strategic Plan* (Washington, D.C.: U.S. Department of Energy, September 2006), http://fossil.energy.gov/programs/powersystems/publications/OCC_Strategic_Plan_external_Sept06.pdf.

issues related to carbon dioxide (CO_2) storage and transport. DOE and EPA were the co-leads of the Interagency Task Force on CCS, which was formed in 2010.

With regard to CO_2 storage, specific Carbon Storage Program activities with these agencies include participating in EPA's CCS Working Group, participating in the preparation of several BLM reports to Congress, engaging BOEM with developing rules for offshore CO_2 injection, examining the legal and regulatory framework for CO_2 storage with the IOGCC, and examining state regulatory program data management for CO_2 storage with the GWPC. The Carbon Storage Program has also collaborated with DOT, the Federal Energy Regulatory Commission, the National Association of Regulatory Utility Commissioners, and the Surface Transportation Board to examine the regulatory framework for CO_2 pipeline siting, operation, and tariffs, and has participated in the IOGCC Pipeline Transportation Taskforce on CO_2 pipelines for carbon storage.

NETL's Carbon Storage Program is developing a technology portfolio of safe, cost-effective, commercial-scale CO_2 storage and mitigation technologies that will be available for commercial deployment. NETL's primary carbon storage R&D objective is to improve the understanding of factors affecting CO_2 storage permanence, resource, and safety in geologic formations and terrestrial ecosystems.

NETL's Carbon Storage Program received $70 million from the American Recovery and Reinvestment Act of 2009 (ARRA). These funds are being used for Geologic Sequestration Site Characterization projects ($50 million), and to provide training opportunities at universities and establish regional training centers with the goal of creating a qualified carbon storage workforce in the United States ($20 million). In 2010, an additional $50 million was provided to the 10 site characterization projects to augment the work that the projects are performing. This additional funding will allow these projects to better characterize the geology for storage opportunities for industrial sources of CO_2. The projects are now able to drill deeper wells, as well as additional wells; collect significantly more core samples; collect additional geophysical samples and data; and conduct more extensive reservoir modeling. These efforts complemented the existing goals of the program. Sixty projects were awarded with ARRA funds.

There have been significant ARRA accomplishments to date. For example, as of the end of 2011, there were 184 students and professionals trained with more than 150,000 hours of research for future work in the CCS industry.

Office of Management and Budget Requirements

In compliance with requirements from the Office of Management and Budget, DOE and NETL are fully committed to improving the quality of research projects in their programs. To aid this effort, DOE and NETL conducted a fiscal year (FY) 2013 Carbon Storage Peer Review Meeting with independent technical experts to assess ongoing research projects and, where applicable, to make recommendations for individual project improvement.

In cooperation with Leonardo Technologies, Inc., the American Society of Mechanical Engineers (ASME) convened a panel of seven leading academic and industry experts on October 22–26, 2012, to conduct a five-day Peer Review of selected Carbon Storage Program research projects supported by NETL.

Overview of Office of Fossil Energy Carbon Storage Program Research Funding

The total funding of the 16 projects reviewed, over the duration of the projects, is $50,260,867. Of this amount, $38,065,958 (76%) is funded by DOE, while the remaining $12,194,909 (24%) is funded by project partner cost sharing. The 16 projects that were the subject of this Peer Review are summarized in Table ES-1 and in Section II of this report.

TABLE ES-1 CARBON STORAGE PROJECTS REVIEWED

Reference Number	Project No.	Title	Lead Organization	Principal Investigator	Total Funding		Project Duration	
					DOE	Cost Share	From	To
1	FE0001163	In Situ MVA of CO_2 Sequestration Using Smart Field Technology	West Virginia University Research Corporation	Shahab Mohaghegh	$1,344,618	$336,508	10/01/2009	09/30/2013
2	FE0004522	Development and Test of a 1,000 Level 3C Fiber Optic Borehole Seismic Receiver Array Applied to Carbon Sequestration	Paulsson, Inc.	Björn Paulsson	$1,995,682	$2,184,927	10/01/2010	12/31/2013
3	FE0004542	Proof of Feasibility of Using Well Bore Deformation as a Diagnostic Tool to Improve CO_2 Sequestration	Clemson University	Larry Murdoch	$449,209	$112,292	10/01/2010	06/30/2014
4	FE0001922	Recovery Act: Characterization of Pilocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO_2	Terralog Technologies	Mike Bruno	$9,819,813	$2,454,953	12/08/2009	09/30/2013
5	FE0002068	Recovery Act: An Evaluation of the Carbon Sequestration Potential of the Cambro-Ordovician Strata of the Illinois and Michigan Basins	University of Illinois	Hannes Leetaru	$9,803,000	$3,002,630	12/08/2009	09/30/2013
6	FE0001159	Advanced Technologies for Monitoring CO_2 Saturation and Pore Pressure in Geologic Formations: Linking the Chemical and Physical Effects to Elastic and Transport Properties	Stanford University	Gary Mayko	$1,183,355	$315,137	10/01/2009	09/30/2013
7	FE0001580	Combining Space Geodesy, Seismology, and Geochemistry for Monitoring, Verification and Accounting of CO_2 in Sequestration Sites	University of Miami; University of South Florida	Peter Swart/ Tim Dixon	$1,768,545	$441,460	10/01/2009	12/31/2013
8	FE0004962	Inexpensive Monitoring and Uncertainty Assessment of CO_2 Plume Migration	University of Texas at Austin	Steven Bryant	$1,011,664	$253,957	10/01/2010	03/31/2014
9	DE-FE0004832	Maximization of Permanent Trapping of CO_2 and Co-Contaminants in the Highest-Porosity Formations of the Rock Springs Uplift (Southwest Wyoming): Experimentation and Multi-Scale Modeling	University of Wyoming	Mohammad Piri	$1,509,044	$1,396,085	10/01/2010	09/30/2013
10	FE0004956	Influence of Local Capillary Trapping on Containment System Effectiveness	University of Texas at Austin	Steven Bryant	$428,925	$110,172	10/01/2010	03/31/2014
11	FE0004566	Prototype and Testing a New Volumetric Curvature Tool for Modeling Reservoir Compartments and Leakage Pathways in the Arbuckle Saline Aquifer: Reducing Uncertainty in CO_2 Storage and Permanence	University of Kansas Center for Research	Jason Rush	$1,598,537	$401,460	10/01/2010	04/29/2014
12	FE0004630	Validation of Models Simulating Capillary and Dissolution Trapping During Injection and Post-Injection of CO_2 in Heterogeneous Geological Formations Using Data from Intermediate Scale Test Systems	Colorado School of Mines	Tissa Illangasekare	$525,337	$143,520	09/15/2010	12/31/2013

Reference Number	Project No.	Title	Lead Organization	Principal Investigator	Total Funding		Project Duration	
					DOE	Cost Share	From	To
13	ORD-2012.02.00 Task 5.1	Verifying Storage Performance – Natural Geochemical Signals to Monitor Leakage to Groundwater	National Energy Technology Laboratory – Office of Research and Development	Karl Schroeder	$800,239	$0	10/01/2011	09/30/2012
14	FE0004478	Advanced CO_2 Leakage Mitigation Using Engineered Biomineralization Sealing Technologies	Montana State University	Lee Spangler	$1,599,997	$400,003	10/01/2010	09/30/2013
15	FE0001040	Quantification of Wellbore Leakage Risk Using Non-Destructive Borehole Logging Techniques	Schlumberger Carbon Services	Andrew Duguid	$1,989,993	$641,805	01/01/2010	10/31/2012
16	FWP-58159 Task 2	Advanced Co-Sequestration Studies	Pacific Northwest National Laboratory	B. Peter McGrail	$2,238,000	$0	07/01/2008	09/30/2013
				TOTALS	$38,065,958	$12,194,909		

Note: Funding amounts and project durations have been obtained from project summaries submitted by the principal investigator.

CARBON STORAGE PROGRAM GOALS

The FY2013 Carbon Storage Peer Review is focused on developing technologies that can achieve 99% of CO_2 storage permanence; improve the ability to determine storage resource in geologic formations; improve efficiency of storage operations; and integrate lessons learned from the core R&D technology development efforts and field experience from the RCSPs into Best Practice Manuals for industry. The goal of DOE research in the area of geologic carbon storage is to develop technologies to safely, permanently, and cost-effectively store CO_2 in suitable geologic formations; monitor its movement and behavior; and develop tools and protocols to improve the efficiency of storage operations. Achieving this goal involves developing an improved understanding of CO_2 flow and trapping mechanisms within the geologic formations that can support the development of improved and novel technologies for site construction, reservoir engineering, and well construction. Experience gained from field tests will facilitate the development of carbon capture and storage (CCS) best practices for site development, operations, and closure to ensure that CO_2 storage is secure and does not impair the geologic integrity of underground formations. Additional information on this effort can be found in NETL's Carbon Storage Technology Program Plan.

This goal will be accomplished by reducing the cost of these technologies and conducting demonstrations based on sound science to ensure that commercial applications can reliably and safely transport, store, and monitor CO_2 injected into geologic formations.

Overview of the Peer Review Process

NETL requested that ASME assemble a Carbon Storage Peer Review Panel (hereinafter referred to as the Panel) of recognized technical experts to provide recommendations on how to improve the management, performance, and overall results of each individual research project. Each project team prepared a detailed Project Information Form containing an overview of the project's purpose, objectives, and achievements; a Statement of Project Objectives containing project objectives, a description of the scope of the project, a detailed breakdown of project tasks and subtasks to be performed, and associated deliverables and presentations; and a presentation that was given at the Peer Review Meeting. The Panel received the Project Information Forms, Statement of Project Objectives, and presentations prior to the Peer Review Meeting.

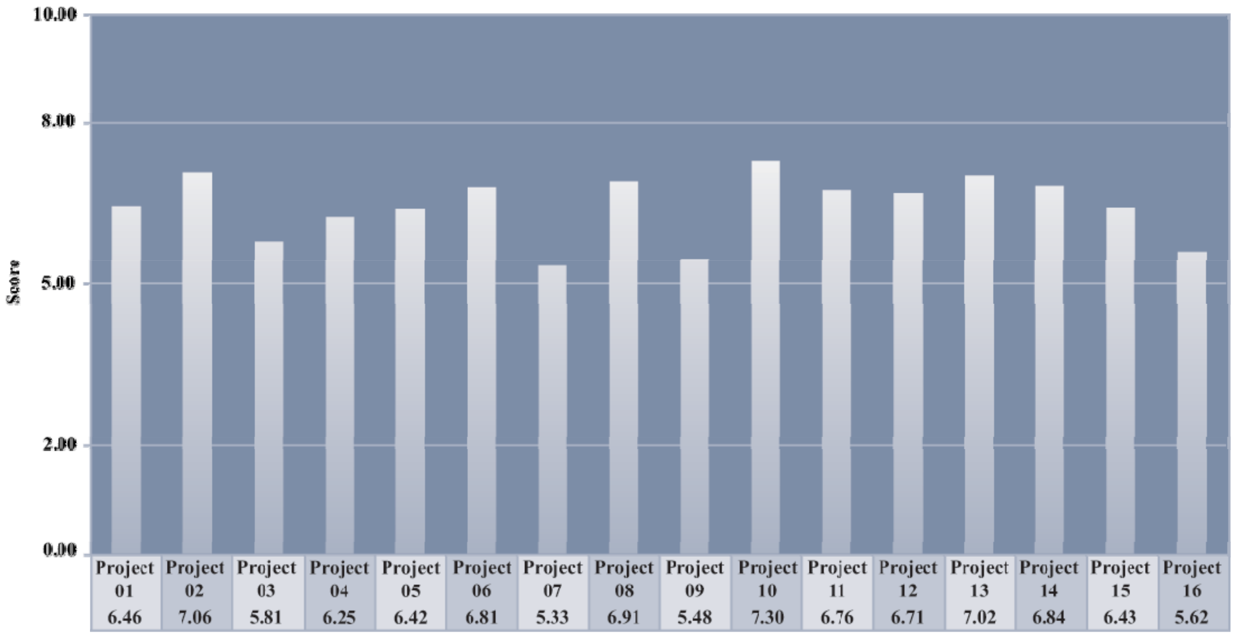
At the meeting, each research team made an uninterrupted 45-minute PowerPoint presentation that was followed by a 30-minute question-and-answer session with the Panel and a 40- to 50-minute Panel discussion and evaluation of each project. To facilitate a full and open discourse of project-related material between the project team and the Panel, all sessions were limited to the Panel, ASME project team members, and DOE-NETL personnel and contractor support staff.

After the group discussions, each panel member individually evaluated the 16 projects, providing written comments based on a predetermined set of review criteria. For each of the nine review criteria, the individual reviewer was asked to score the project as one of the following:

- Excellent (10)
- Highly Successful (8)
- Fair (5)
- Weak (2)
- Unacceptable (0)

Figure ES-2 shows the average project scores, combining the average of the nine review criteria for each of the 16 projects reviewed. As Figure ES-2 illustrates, it is relatively easy to look at the scores for an individual project and gain an impression of how well the project performed. While it is not the intent of this review to directly compare one project with another, an average score exceeding 5.0 generally indicates that a specific project was viewed as at least acceptable by the Panel. All 16 projects reviewed from the Carbon Storage Program exceeded this score.

FIGURE ES-2 AVERAGE SCORING, BY PROJECT



The "Project Average" in Table ES-3 shows the score for each criterion averaged across all 16 projects. This average intends to provide an accurate summary of the projects reviewed in the FY2013 Carbon Storage Peer Review. The series of sub-criteria used to define each criterion are provided in Appendix A of this report. The "Highest Project Rating" and "Lowest Project Rating" columns in Table ES-3 portray the highest and lowest scores received by an individual project for a given criterion. The "Project Average" is the average score for that criterion across all 16 projects. This average intends to provide an accurate summary of the projects reviewed in the FY2013 Carbon Storage Peer Review.

TABLE ES-3 AVERAGE SCORING, BY REVIEW CRITERION

Criterion	Project Average	Highest Project Rating	Lowest Project Rating
1. Scientific and Technical Merit	6.9	8.0	5.0
2. Existence of Clear, Measurable Milestones	6.6	7.9	4.2
3. Utilization of Government Resources	7.4	8.7	6.3
4. Technical Approach	6.3	8.1	4.1
5. Rate of Progress	6.1	7.5	4.6
6. Potential Technology Risks Considered	6.0	6.8	5.0
7. Performance and Economic Factors	5.6	7.0	4.1
8. Anticipated Benefits, if Successful	7.5	8.8	5.0
9. Technology Development Pathways	5.8	7.1	4.1

Note: The score for each project for a given criterion is, by definition, the average of *all reviewer ratings* for that criterion.

Criteria received average scores between 5.6 and 7.5. The highest-ranking review criterion was Anticipated Benefits, If Successful, which received a score of 7.5. Utilization of Government Resources earned a 7.4, and Scientific and Technical Merit earned a 6.9. High scores in these three criteria indicate that overall the projects reviewed during the FY2013 Carbon Storage Peer

Review Meeting are innovative, cost-effective, and scientifically sound projects aimed toward achieving both near- and long-term goals of the NETL Carbon Storage Program.

The lowest-ranking review criterion was Performance and Economic Factors (5.6 score), indicating that a few projects did not conduct sufficient cost and performance assessments, commensurate with their current Technology Readiness Level, to properly qualify the potential of the technology to achieve the goals of the NETL Carbon Storage Program. While Performance and Economic Factors had the lowest average across all projects, Technical Approach had the greatest range across projects, with project averages for that criterion ranging from 8.1 to 4.1. This large spread indicates that while some projects had feasible technical approaches, other projects reviewed did not sufficiently focus on the technical barriers the team is likely to face and pathways to overcome them in the presentation and project summary information provided to the Panel. For more on the overall evaluation process and the nine review criteria, see Section III.

Projects are categorized based on their Technology Readiness Level (TRL) at the time of the Peer Review and their anticipated TRL at the end of the project. This categorization enabled the Panel to appropriately score the review criteria within the bounds of the established scope for each project. Table ES-4 describes the various levels of technology readiness.

TABLE ES-4 DESCRIPTION OF TECHNOLOGY READINESS LEVELS (TRL)

Technology Readiness Level	Description
TRL 1 – Basic principles observed and reported	This is the lowest level of technology readiness. Scientific research begins to be translated into applied research and development (R&D). Examples include paper studies of a technology's basic properties.
TRL 2 – Technology concept and/or application formulated	Invention begins. Once basic principles are observed, practical applications can be invented. Applications are speculative, and there may be no proof or detailed analysis to support the assumptions. Examples include analytic and laboratory studies to confirm the potential practical application of basic processes and methods to geologic storage.
TRL 3 – Analytical and experimental critical function and/or characteristic proof of concept	Active R&D is initiated. This includes analytical studies and laboratory-scale studies to physically validate the analytical predictions of separate elements of the technology. Examples include components that are not yet integrated or representative. Components may be tested with simulants.
TRL 4 – Component and/or system validation in a laboratory environment	The basic technological components are integrated to establish that the pieces will work together. This is relatively "low fidelity" compared with the eventual system. Examples include integration of "ad hoc" hardware in a laboratory and testing with a range of simulants.
TRL 5 – Laboratory-scale similar-system validation in a relevant environment	Laboratory validation of system/subsystem components. Laboratory validation testing of geologic storage processes, subsystems, and/or subsystem components under conditions representative of in situ operating conditions. Subsystem and/or component configuration is similar to (or matches) the final application in almost all respects. Validation testing involves measurements under in situ operating conditions to assess performance of the process, subsystem, and/or component. Planning and design are undertaken for prototype system verification.

Technology Readiness Level	Description
TRL 6 – Engineering/pilot-scale, prototypical system demonstrated in a relevant environment	Prototype system verified. Prototype field pilot testing of geologic storage system or subsystem in relevant geologic environments. Geologic characteristics, including rock type and contained fluids, depth, pressure, and temperature, are relevant to final scale. Pilot scale involves injection of a sufficient amount of CO_2 to verify design performance of system or subsystem and components. System configured to enable pilot-scale testing, which involves measurements and operations specific to assessing performance of the system and/or subsystem and subsystem components. Performance testing relevant to the life cycle of a storage project, including site characterization, injection, and post-injection monitoring and closure.
TRL 7 – System prototype demonstrated in a plant environment	Integrated pilot system demonstrated. Geologic storage system prototype tested at pilot scale for a type of depositional environment (e.g., saline fluvial deltaic) or storage type (e.g., enhanced oil recovery [EOR] or enhanced coalbed methane [ECBM]). Pilot scale involves injection of a few hundred tonnes* to several hundred thousand tonnes. System configured to enable pilot-scale testing, which involves measurements and operations specific to assessing performance of the system, subsystem, and subsystem components. Performance testing is relevant to each stage of the full life cycle of a storage project, including site characterization, injection, and post-injection monitoring and closure. Planning and design are undertaken to test and demonstrate a full-scale system.
TRL 8* – Actual system completed and qualified through test and demonstration in a plant environment	System tested and demonstrated at final scale. This TRL represents the end of technology development for a geologic storage system for a type of depositional environment (e.g., saline fluvial deltaic) or storage type (e.g., EOR or ECBM). The complete geologic storage system is tested at final scale in a demonstration. Final scale involves injection of >1 million tonnes per year. System configured to enable final-scale testing, which involves measurements and operations specific to assessing performance of the system, subsystem, and subsystem components. Performance testing is relevant to each stage of the full life cycle of a storage project, including site characterization, injection, and post-injection monitoring and closure.
TRL 9* – Actual system operated over the full range of expected conditions	System proven and ready for final-scale geologic storage. Geologic storage system is proven through successful operations at full scale for a type of depositional environment (e.g., saline fluvial deltaic) or storage type (e.g., EOR or ECBM). Full scale involves injection of >1 million tonnes per year. System configured for final-scale deployment, including considerations of cost. Operations include full life cycle of the storage project, including site characterization, injection, and post-injection monitoring and closure.

*Not relevant to this Peer Review.

A summary of key project findings as they relate to individual projects can be found in Section IV of this report. Process considerations and recommendations for future project reviews are found in Section V.

For More Information

For more information concerning the contents of this report, contact the NETL Federal Project Manager and Peer Review Coordinator, José D. Figueroa, at (412) 386-4966 or Jose.Figueroa@netl.doe.gov.

MEETING SUMMARY AND RECOMMENDATIONS

I. INTRODUCTION

In fiscal year (FY) 2013, the American Society of Mechanical Engineers (ASME) was invited to provide an independent, unbiased, and timely peer review of selected projects within the U.S. Department of Energy (DOE) Office of Fossil Energy's Carbon Storage Program (administered by the Office of Fossil Energy's National Energy Technology Laboratory [NETL]). On October 22–26, 2012, ASME convened a panel of seven leading academic and industry experts to conduct a five-day peer review of selected research projects supported by the NETL Carbon Storage Program. This report contains a summary of the findings from that review.

Compliance with Office of Management and Budget Requirements

DOE, the Office of Fossil Energy, and NETL are fully committed to improving the quality and results of their projects. The peer review of selected projects within the Carbon Storage Program was designed to comply with requirements from the Office of Management and Budget.

ASME Center for Research and Technology Development

All requests for peer reviews are organized under ASME's Center for Research and Technology Development (CRTD). The CRTD Director of Research, Dr. Michael Tinkleman, with advice from the chair of the ASME Board on Research and Technology Development, selects an executive committee of senior ASME members that is responsible for reviewing and approving all panel members and ensuring that there are no conflicts of interest within the Panel or the review process. In consultation with NETL, ASME formulates the review meeting agenda, provides information advising the principal investigators (PIs) and their colleagues on how to prepare for the review, facilitates the review session, and prepares a summary of the results. A more extensive discussion of the ASME peer review methodology used for the Carbon Storage Peer Review Meeting is provided in Appendix A. A copy of the meeting agenda is provided in Appendix B, and profiles of the panel members are provided in Appendix C.

Overview of the Peer Review Process

ASME was selected as the independent organization to conduct a five-day peer review of 16 Carbon Storage Program projects. ASME performed this project review work as a subcontractor to prime NETL contractor Leonardo Technologies, Inc. NETL selected the 16 projects, while ASME organized an independent review panel of seven leading academic and industry experts. Prior to the meeting, project PIs submitted their PowerPoint presentations; a 12-page written summary (Project Information Form) of their project's purpose, objectives, and progress; and their Statement of Project Objectives containing project objectives, a description of the scope of the project, a detailed breakdown of projects tasks and subtasks to be performed, and associated deliverables and presentations.

This project information is given to the Panel prior to the meeting, which allows the Panel to come to the meeting fully prepared with the necessary project background information.

At the meeting, each research team made a 45-minute oral presentation, followed by a 30-minute question-and-answer (Q&A) session with the Panel and a 40- to 50-minute Panel discussion and evaluation of each project depending on the project's complexity, duration, and breadth of scope. Based on lessons learned from prior peer reviews and the special circumstances associated with Carbon Storage Program research, both the PI presentations and Q&A sessions with the Panel for the Carbon Storage Peer Review were held as closed sessions, limited to the Panel, ASME project team members, and DOE-NETL personnel and contractor support staff. The closed sessions ensured open discussions between the PIs and the Panel. Panel members were also instructed to hold the discussions that took place during the Q&A session as confidential.

Each member of the Panel individually evaluated every project and provided written comments based on a predetermined set of review criteria. This *Meeting Summary and Recommendations Report* is a publically available document prepared by ASME that provides a general overview of the Carbon Storage Peer Review and the projects reviewed therein.

Peer Review Criteria and Peer Review Criteria Forms

ASME developed a set of agreed-upon review criteria to be applied to the projects reviewed at this meeting. ASME provided the Panel and PIs with these review criteria in advance of the Peer Review Meeting, and assessment sheets with the review criteria were pre-loaded (one for each project) onto laptop computers for each panel member. During the meeting, the panel members assessed the strengths and weaknesses of each project before providing both recommendations and action items. A more detailed explanation of this process and a sample peer review criteria form are provided in Appendix D.

The following sections of this report summarize findings from the Carbon Storage Peer Review Meeting, organized as follows:

II. *Summary of Projects Reviewed in FY 2013 Carbon Storage Peer Review*:
A list of the 16 projects reviewed and the selection criteria

III. *An Overview of the Evaluation Scores for the Carbon Storage Program*:
Average scores and a summary of evaluations, including analysis and recommendations

IV. *Summary of Key Project Findings*:
An overview of key findings from project evaluations

V. *Process Considerations for Future Peer Reviews:*
Lessons learned in this review that may be applied to future reviews

II. SUMMARY OF PROJECTS REVIEWED IN FY2013 CARBON STORAGE PEER REVIEW

NETL selected key projects within the Carbon Storage Program, including projects being conducted at NETL, to be reviewed by the independent Peer Review Panel. The selected projects are listed below, along with the name of the organization leading the research. A short summary of each of the above projects is presented in Appendix E.

PROJECTS REVIEWED

01: FE0001163
In Situ MVA of CO_2 Sequestration Using Smart Field Technology
West Virginia University Research Corporation

02: FE0004522
Development and Test of a 1,000 Level 3C Fiber Optic Borehole Seismic Receiver Array Applied to Carbon Sequestration
Paulsson, Inc.

03: FE0004542
Proof of Feasibility of Using Well Bore Deformation as a Diagnostic Tool to Improve CO_2 Sequestration
Clemson University

04: FE0001922
Recovery Act: Characterization of Pliocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO_2
Terralog Technologies

05: FE0002068
Recovery Act: An Evaluation of the Carbon Sequestration Potential of the Cambro-Ordovician Strata of the Illinois and Michigan Basins
University of Illinois

06: FE0001159
Advanced Technologies for Monitoring CO_2 Saturation and Pore Pressure in Geologic Formations: Linking the Chemical and Physical Effects to Elastic and Transport Properties
Stanford University

07: FE0001580
Combining Space Geodesy, Seismology, and Geochemistry for Monitoring, Verification and Accounting of CO_2 in Sequestration Sites
University of Miami; University of South Florida

08: FE0004962
Inexpensive Monitoring and Uncertainty Assessment of Plume CO_2 Migration
University of Texas at Austin

09: DE-FE0004832
Maximization of Permanent Trapping of CO_2 and Co-Contaminants in the Highest-Porosity Formations of the Rock Springs Uplift (Southwest Wyoming): Experimentation and Multi-Scale Modeling
University of Wyoming

10: FE0004956
Influence of Local Capillary Trapping on Containment System Effectiveness
University of Texas at Austin

11: FE0004566
Prototype and Testing a New Volumetric Curvature Tool for Modeling Reservoir Compartments and Leakage Pathways in the Arbuckle Saline Aquifer: Reducing Uncertainty in CO_2 Storage and Permanence
University of Kansas Center for Research

12: FE0004630
Validation of Models Simulating Capillary and Dissolution Trapping During Injection and Post-Injection of CO_2 in Heterogeneous Geological Formations Using Data from Intermediate Scale Test Systems
Colorado School of Mines

13: ORD-2012.02.00 Task 5.1
Verifying Storage Performance – Natural Geochemical Signals to Monitor Leakage to Groundwater
National Energy Technology Laboratory – Office of Research and Development

14: FE0004478
Advanced CO_2 Leakage Mitigation Using Engineered Biomineralization Sealing Technologies
Montana State University

15: FE0001040
Quantification of Wellbore Leakage Risk Using Non-Destructive Borehole Logging Techniques
Schlumberger Carbon Services

16: FWP-58159 Task 2
Advanced Co-Sequestration Studies
Pacific Northwest National Laboratory

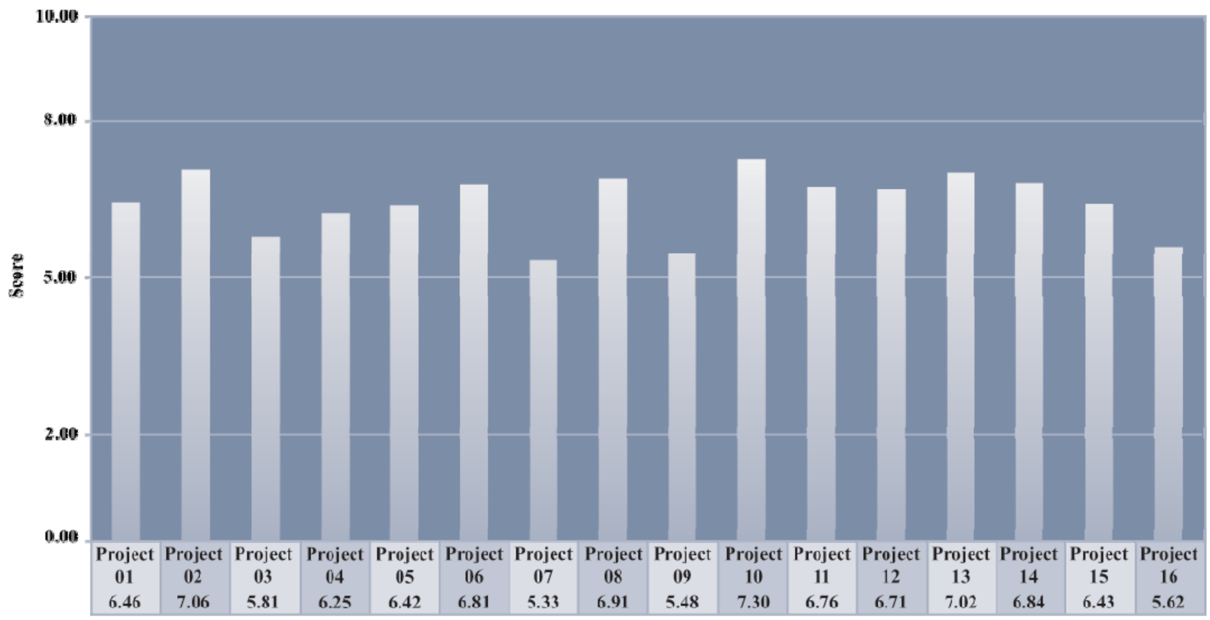
III. AN OVERVIEW OF THE EVALUATION SCORES FOR THE CARBON STORAGE PROGRAM

For each of the nine review criteria, individual reviewers were asked to score the project as one of the following:

- Excellent (10)
- Highly Successful (8)
- Fair (5)
- Weak (2)
- Unacceptable (0)

Figure 1 shows the average project scores, combining the average of the nine review criteria for each of the 16 projects reviewed. As Figure 1 illustrates, it is relatively easy to look at the scores for an individual project and gain an impression of how well the project performed. While it is not the intent of this review to directly compare one project with another, an average score exceeding 5.0 generally indicates that a specific project was viewed as at least acceptable by the Panel. All sixteen projects reviewed from the Carbon Storage Program exceeded this score.

FIGURE 1 AVERAGE SCORING, BY PROJECT



The “Project Average” in Table 1 shows the score for each criterion averaged across all 16 projects. This average intends to provide an accurate summary of the projects reviewed in the FY2013 Carbon Storage Peer Review. The “Highest Project Rating” and “Lowest Project Rating” columns portray the highest and lowest scores received by an individual project for a given criterion. The series of sub-criteria used to define each criterion are provided in Appendix A of this report.

TABLE 1 AVERAGE SCORING, BY REVIEW CRITERION

Criterion	Project Average	Highest Project Rating	Lowest Project Rating
1. Scientific and Technical Merit	6.9	8.0	5.0
2. Existence of Clear, Measurable Milestones	6.6	7.9	4.2
3. Utilization of Government Resources	7.4	8.7	6.3
4. Technical Approach	6.3	8.1	4.1
5. Rate of Progress	6.1	7.5	4.6
6. Potential Technology Risks Considered	6.0	6.8	5.0
7. Performance and Economic Factors	5.6	7.0	4.1
8. Anticipated Benefits, if Successful	7.5	8.8	5.0
9. Technology Development Pathways	5.8	7.1	4.1

Note: The score for each project for a given criterion is, by definition, the average of *all reviewer ratings* for that criterion.

These results speak to the overall opinion of the Panel on the projects they reviewed. Criteria received average scores between 5.6 and 7.5. The highest-ranking review criterion was Anticipated Benefits, If Successful, which received a score of 7.5. Utilization of Government Resources earned a 7.4, and Scientific and Technical Merit earned a 6.9. High scores in these three criteria indicate that overall the projects reviewed during the FY2013 Carbon Storage Peer Review Meeting are innovative, cost-effective, and scientifically sound projects aimed toward achieving both near- and long-term goals of the NETL Carbon Storage Program.

The lowest-ranking review criterion was Performance and Economic Factors (5.6 score), indicating that a few projects did not conduct sufficient cost and performance assessments, commensurate with their current Technology Readiness Level, to properly qualify the potential of the technology to achieve the goals of the NETL Carbon Storage Program. While Performance and Economic Factors had the lowest average across all projects, Technical Approach had the greatest range across projects, with project averages for that criterion ranging from 8.1 to 4.1. This large spread indicates that while some projects had feasible technical approaches, other projects reviewed did not sufficiently focus on the technical barriers the team is likely to face and pathways to overcome them in the presentation and project summary information provided to the Panel.

Five projects—project 03: FE0004542, Proof of Feasibility of Using Well Bore Deformation as a Diagnostic Tool to Improve CO_2 Sequestration; project 07: FE0001580, Combining Space Geodesy, Seismology, and Geochemistry for Monitoring, Verification and Accounting of CO_2 in Sequestration Sites; project 09: DE-FE0004382, Maximization of Permanent Trapping of CO_2 in the Highest-Porosity Formations of the Rock Springs Uplift; project 15: FE0001040, Quantification of Wellbore Leakage Risk Using Non-Destructive Borehole Logging Techniques; and project 16: FWP-58159 Task 2, Advanced Co-Sequestration Studies—account for all of the "Lowest Project Ratings" in the nine criteria areas.

Similarly, five projects—project 02: FE0004522, Development and Test of a 1,000 Level 3C Fiber Optic Borehole Seismic Receiver Array Applied to Carbon Sequestration; project 05: FE0002068, Recovery Act: An Evaluation of the Carbon Sequestration Potential of the Cambro-Ordovician Strata of the Illinois and Michigan Basins; project 06: FE0001159, Advanced Technologies for Monitoring CO_2 Saturation and Pore Pressure in Geologic Formations: Linking the Chemical and Physical Effects to Elastic and Transport Properties; project 10: FE0004956, Influence of Local Capillary Trapping on Containment System Effectiveness; and project 11: FE0004566, Prototype and Testing a New Volumetric Curvature Tool for Modeling Reservoir Compartments and Leakage Pathways in the Arbuckle Saline Aquifer: Reducing Uncertainty in CO_2 Storage and Performance—account for all of the “Highest Project Averages” in the nine criteria areas.

A copy of the Peer Review Criteria Form and a detailed explanation of the review process are provided in Appendix D.

IV. SUMMARY OF KEY FINDINGS

This section summarizes the overall key findings of the 16 projects evaluated at the FY2013 Carbon Storage Peer Review.

General Project Strengths

The Panel was impressed by the high quality of all of the carbon storage projects they reviewed from DOE's Carbon Storage Program. They indicated that the projects presented have ambitious goals and significant potential to advance geologic sequestration site characterization; geologic storage technologies; simulation and risk assessment; and monitoring, verification, and accounting. The Panel found that all of the projects reviewed are led by knowledgeable and dedicated principal investigators who were open to accepting constructive criticism that could help them improve upon their work. Together, the 16 projects, which are mostly being conducted at universities, represented a portfolio of fundamental science, applied laboratory experimentation and modeling, and applied field projects. Based on the progress made to date by the projects reviewed, the Panel was optimistic about the potential for important further progress toward achieving DOE's challenging goals for long-term geological storage of carbon dioxide (CO_2).

Table 1 displays the average scores across all 16 projects for each of the nine individual criteria. All of the criteria received averages ranging from 5.6 to 7.5, and all projects received scores above "fair" (5.0) performance for four of the nine criteria. As depicted in Figure 1, 12 of the 16 projects received average ratings of 6.0 or above, and three of the 16 reviewed projects received average ratings of 7.0 or above, which is exemplary.

The four criteria in which all projects earned average scores of 5.0 or higher include Scientific and Technical Merit; Utilization of Government Resources; Potential Technology Risks Considered; and Anticipated Benefits, if Successful. These high scores reflect the Panel's view that, overall, the projects were based on innovative, high-quality science; adequately assessed project risks; and leveraged government resources well. If successful, these projects could contribute significantly to achieving the long-term goals of the NETL Carbon Storage Program.

The highest-rated project was project 10, "Influence of Local Capillary Trapping on Containment System Effectiveness," conducted by the University of Texas at Austin. This project received an average rating across the nine criteria of 7.3 out of 10.0. Two other projects—project 02, "Development and Test of a 1,000 Level 3C Fiber Optic Borehole Seismic Receiver Array Applied to Carbon Sequestration" conducted by Paulsson, Inc and project 13, "Verifying Storage Performance - Natural Geochemical Signals to Monitor Leakage to Groundwater" conducted by the NETL Office of Research and Development—received average scores above 7.0. While these top three projects received exemplary scores, all 16 projects reviewed received average scores above 5.0.

General Project Weaknesses

Although the projects evaluated in the Carbon Storage Program received above average ratings in all nine criteria, three areas had average scores of 6.0 or lower: Potential Technology Risks Considered (6.0); Performance and Economic Factors (5.6); and Technology Development Pathways (5.8). The scores in these three areas indicate that the Panel found one or more project teams did not sufficiently identify and consider the economics, risks, or commercial viability of their technologies in a manner consistent with Technology Readiness Level (TRL) requirements. While Existence of Clear, Measurable Milestones received an average score of 6.6, the Panel noted that several of the projects would benefit from more measurable milestones that focus on benchmarking progress toward project deliverables instead of the execution of project tasks.

Several recurring themes arose during this Peer Review. The Panel considered it a weakness that some project teams did not adequately consider realistic field conditions representative of actual potential sites for CO_2 storage. For example, some project teams did not adequately demonstrate the real-world effects of geologic heterogeneities and flow properties (e.g., pressure and temperature gradients), which added uncertainty to model predictions of CO_2 storage permanence, migration, or leakage. Other projects did not adequately consider the potential impact of contaminants in the CO_2 stream (e.g., sulfur compounds) or subsurface species on the permanence of CO_2 storage.

Some of the projects did not conduct their work with a specific CO_2 storage site in mind, have a clear plan for upscaling experiments, or have a sufficiently defined path forward for technology development. Several modeling projects assumed injection and storage durations significantly different than the NETL baseline case of 30 years of injection followed by 100 years of monitoring. As a result, panel members pointed out that while several projects contained strong, fundamental work, the project teams did not clearly identify or articulate how their work would relate to achieving DOE goals in real-world applications and environments. In some cases, the Panel indicated that project teams lacked the necessary ties with enhanced oil recovery (EOR) and industry experts to ensure that their project was relevant to industry needs and actual field conditions for the EOR application.

Another major theme identified by the Panel was the lack of economic analyses that demonstrated the cost effectiveness of project technologies over alternatives currently available or being developed. Other recurring issues included the listing of routine activities rather than milestones with performance-based targets, the need for further refinement of project models, and the lack of comprehensive risk assessments and risk mitigation plans.

Issues for Future Consideration

While the majority of the recommendations provided by the Panel were technical in nature and specific to a particular project's technology or approach, several overarching themes did emerge. The Panel encouraged the project teams to engage outside expertise to help ensure that the project testing and modeling represents realistic field conditions and offers value to industry. The Panel indicated that it may be helpful for some project teams to add an advisory group (i.e., within NETL or consisting of members from other project teams) that they can consult, particularly for projects more focused on fundamental work.

It would also help if each project team clearly stated their design basis for the NETL Carbon Storage Program goals that they are targeting or supporting (e.g., the type of coal power plant [post-combustion, pre-combustion, and/or oxy-combustion] and whether the work is directed at CO_2 storage in deep saline aquifers, enhanced oil recovery, enhanced gas recovery, or all of these modes). All projects would benefit from a clearer definition of the portion of the 99% permanence goal that directly relates to their project work so as to avoid differing interpretations of the minimum injection period and the minimum post-injection period.

The project teams also need to account for the composition of the CO_2 stream (e.g., sulfur dioxide, hydrogen sulfide, nitrogen oxide, oxygen, and carbon monoxide) in their design basis. Because integrated gasification combined cycle (IGCC), oxy-combustion, and pulverized coal combustion plants do not produce CO_2 streams with the same contaminants, project teams should base the CO_2 stream composition on that from a pulverized coal or fluidized bed plant (as these are the most prevalent plants), and also consider the differing compositions of CO_2

streams from less prevalent IGCC and not yet commercial oxy-combustion systems. When applicable, project teams also need to consider specifications required for transporting CO_2 by pipeline for enhanced oil recovery (e.g., lower oxygen content). These recommendations would place the project teams and the Carbon Storage Program as a whole in a better position to develop technologies and techniques that create value for real-world carbon storage applications.

V. PROCESS CONSIDERATIONS FOR FUTURE PEER REVIEWS

At the end of the Carbon Storage Peer Review, the Panel and DOE-NETL managers involved offered positive feedback on the review process and constructive comments for improving future peer reviews. The following is a brief summary of ideas recommended for consideration when planning future peer review sessions.

General Process Comments

All involved agreed that the current peer review process is effective, especially the meeting organization and facilitation. Panel members found the openness of the NETL Technology Manager to be beneficial to the overall review process, and felt that the Technology Manager showed an appropriate level of restraint in providing the information needed without biasing the outcome.

The Panel noted that they were well informed about the meeting agenda, and that the SharePoint site enabled them to access the project information quickly and easily and prepare in advance for the peer review. In addition, the Panel noted that the pre-meeting organization and practices continue to enable them to fit the integral step of project information review into their busy schedules prior to the Peer Review.

Meeting Agenda

The Panel indicated that the schedule—a 45-minute presentation, 30-minute question-and-answer session, and 40- to 50-minute discussion—allowed ample time to review each project. The facilitator was able to adjust the different parts of the schedule to allow additional time where needed while still keeping each day's schedule on track. One panel member indicated that it would further help to keep the process on track if the reviewers better frame their questions, encourage the PIs to answer more directly, and indicate when their question has been answered to prevent the PI from providing extraneous information. The Panel noted that it might be helpful to have 15 minutes to write their strengths, weaknesses, recommendations, and action items immediately after each project discussion instead of the current 10 minutes.

Presentations

The Panel noted that the two-minute introduction from the Technology Manager on the focus and scope of each project was very beneficial. The Panel indicated that the guidelines and restrictions that NETL placed on the Powerpoint presentations (e.g., an introductory slide that shows each project's context within the overall Carbon Storage Program, amount of information per slide, and a limitation on the number of slides within a presentation) were helpful to the review process. It was also helpful that most of the project management items (e.g., budget/cost progress, Gantt charts, and earned value analysis) were moved to the end of the presentations for this review, as this information can be understood from the Project Information Forms. However, some of the project teams also moved slides on risk assessment to the backup slides; the Panel indicated that it is important to include these slides within the main content of the presentation.

Panel members also felt that the presenters should limit their use of acronyms because they can make the presentations more difficult to follow. When acronyms are needed, the project team should provide an acronym list that the panel members can reference to enhance their understanding of the Project Information Forms and presentations.

Evaluation Process and Criteria

Tying weaknesses to subcriteria helped the Panel to stay disciplined in the specificity of their comments and ensure that their comments were within scope. The Panel also found the requirement to identify a corresponding action item or recommendation for each weakness to be helpful. One panel member suggested that NETL should share a sample of past recommendations or action items at the start of the peer review meeting and indicate how these recommendations and action items were addressed by the project team. These examples would help the project team to provide more actionable feedback.

The Panel indicated that the classification of each project's current Technology Readiness Level (TRL) and anticipated TRL at the end of the project helped them to appropriately score the review criteria within the bounds of the established scope for each project. Several panel members indicated that some projects will have a TRL classification of "not applicable" and others will be at an early stage of development that makes it difficult to rate certain criteria (e.g., Potential Technology Risks Considered, Performance and Economic Factors, and Technology Development Pathways). While the new review criteria break down the expectations for Performance and Economic Factors and Technology Development Pathways at different TRLs, it would be helpful if the review criteria broke down the Potential Technology Risks considered criterion in this manner as well.

The Panel found their discussions about initial project ratings immediately following each project presentation, Q&A, and discussion to be constructive. This discussion forced the Panel as a whole to discuss outliers in the scoring and the reasoning for the outlier scores to gain a better understanding of each project from the diverse perspectives of individual panel members. The Panel's aim to ensure that the scores are more closely aligned---via discussion, but without forced consensus---was believed to also enable a more accurate and telling representation of the Panel's views on each project.

Review Panel

The Panel acknowledged that the diverse areas of the panel members' expertise offered other members needed insight on various topics during discussion, which allowed all reviewers to provide more accurate and comprehensive ratings and comments. The Panel and Technology Manager indicated that the addition of a geophysicist to the Panel could have expanded the range of the Panel's expertise. The reviewers enjoyed the experience and camaraderie of collaborating with their colleagues in the carbon storage field and thanked ASME and DOE for the opportunity to participate in this Peer Review. The Panel also appreciated the professionalism of all parties involved with the Peer Review and valued their fellow reviewers' ability to cooperate and remain professional despite occasional differences of opinion.

APPENDICES

APPENDIX A: ASME PEER REVIEW METHODOLOGY

The American Society of Mechanical Engineers (ASME) has been involved in conducting research since 1909, when it started work on steam boiler safety valves. Since then, the Society has expanded its research activities to a broad range of topics of interest to mechanical engineers. ASME draws on the impressive breadth and depth of technical knowledge among its members and, when necessary, experts from other disciplines for participation in ASME-related research programs. In 1985, ASME created the Center for Research and Technology Development (CRTD) to coordinate ASME's research programs.

As a result of the technical expertise of ASME's membership and its long commitment to supporting research programs, the Society has often been asked to provide independent, unbiased, and timely reviews of technical research by other organizations, including the federal government. After several years of experience in this area, the Society developed a standardized approach to reviewing research projects. This section provides a brief overview of the review procedure established for the DOE-NETL fiscal year (FY) 2013 Carbon Storage Peer Review.

ASME Knowledge and Community Sector

The Knowledge and Community Sector—one of the five sectors responsible for the activities of ASME's 127,000 members worldwide—is charged with disseminating technical information, providing forums for discussions to advance the mechanical engineering profession, and managing the Society's research activities.

Board on Research and Technology Development

ASME members with suitable industrial, academic, or governmental experience in the assessment of priorities for research and development (R&D), as well as in the identification of new or unfulfilled needs, are invited to serve on the Board on Research and Technology Development (BRTD) and to function as liaisons between BRTD and the appropriate ASME sectors, boards, and divisions. The BRTD has organized more than a dozen research committees in specific technical areas.

Center for Research and Technology Development

CRTD has undertaken the mission to plan and manage ASME's collaborative research activities effectively to meet the needs of the mechanical engineering profession, as defined by the ASME members. The CRTD is governed by the BRTD, and day-to-day operations of the CRTD are handled by the director of research and his staff. The director of research serves as staff to the Peer Review Executive Committee, handles all logistical support for the Panel, provides facilitation of the actual review meeting, and prepares all summary documentation.

Carbon Storage Peer Review Executive Committee

For each set of projects reviewed, the BRTD convenes a Peer Review Executive Committee to oversee the review process. The Executive Committee is responsible for: guaranteeing that all ASME rules and procedures are followed; reviewing and approving the qualifications of those asked to sit on the Panel; ensuring that there are no conflicts of interest in the review process; and reviewing all documentation coming out of the project review. There must be at least three members of the Peer Review Executive Committee, all of whom must have experience relevant to the program being reviewed. Members of the FY2013 Carbon Storage Peer Review Executive Committee were as follows:

- **William Worek, Michigan Technological University, Chair.** Dr. Worek is a past vice president of the ASME Energy Resources Group and former chair of the ASME Solar Energy Division. He currently serves on the ASME Mechanical Engineering Department Heads Committee, is a member of the ASME Board on Research and Technology Development and is a member-elect of the ASME Board of Governors.
- **Allen Robinson, Carnegie Mellon University.** Dr Robinson is Associate Professor of Mechanical Engineering at Carnegie Mellon University. He brings to the Executive Committee his special focus on combustion-generated air pollution, biomass conversion, and heat and mass transfer in porous media.
- **William Stenzel, Sargent & Lundy.** Mr. Stenzel is a former chair of the ASME Power Division. and past Vice Chair of the Power Division's Steam Generators Auxiliaries Technical Committee. He is currently a member of the ASME Energy Committee.

Carbon Storage Peer Review Panel

The Carbon Storage Peer Review Executive Committee accepted résumés for proposed Carbon Storage Peer Review Panel members from CRTD, from a call to ASME members with relevant experience in this area, and from the DOE-NETL program staff. From these sources, the ASME Peer Review Executive Committee selected a seven-member review panel and agreed that they had the experience necessary to review the broad range of projects under this program and did not present any conflicts of interest. Panel members and qualifications are described in Appendix C.

Meeting Preparation and Logistics

Prior to the meeting, the project team for each project being reviewed was asked to submit a 12-page Project Information Form that detailed project goals, purpose, and accomplishments to date. A standard set of specifications for preparing this document was provided by CRTD. These Project Information Forms were collected and provided to the Panel prior to the meeting.

Also in advance of the review meeting, CRTD gave the project teams a standard PowerPoint presentation template and set of instructions for the oral presentations they were to prepare for the Panel. The Panel was also given copies of each project team's PowerPoint slides.

The Project Information Forms and presentations for all projects were provided to the Panel well in advance of the meeting to help them to better prepare for their roles.

Project Presentations, Evaluations, and Discussion

At the Carbon Storage Peer Review Meeting, presenters were held to a 45-minute time limit to allow sufficient time for all presentations within the five-day meeting period. After each presentation, the project team participated in a 30-minute question-and-answer session with the Panel.

The Panel then spent 40 to 50 minutes evaluating the projects based on the presentation material. To start, each reviewer scored the project against a set of predetermined peer review criteria. Sub-criteria were provided to further define each criterion and provide clarity to the Panel. The following nine criteria were used:

1. Scientific and Technical Merit

    1.1 – Scientific feasibility of project concept
    1.2 – Degree and likelihood of achieving planned technological advancements
    1.3 – Degree of innovation evidenced

2. Existence of Clear, Measurable Milestones

    2.1 – Degree to which the number of milestones per budget period are appropriate
    2.2 – Degree to which milestones are quantitative and show progression toward project goals
    2.3 – Degree of completeness of milestones (title, completion date, success criterion)

3. Utilization of Government Resources

    3.1 – Degree of adequacy of the research team to address the project goal and objectives
    3.2 – Feasibility of rationale presented for teaming or collaborative efforts
    3.3 – Feasibility of equipment, materials, and facilities to meet the project goal and objectives

4. Technical Approach

    4.1 – Degree of adequacy of understanding of potential technical challenges and technical barriers
    4.2 – Degree of adequacy of the mitigation strategy for the identified technical challenges and barriers
    4.2 – Feasibility of technical approach to support stated project goal and objectives

5. Rate of Progress

    5.1 – Degree of adequacy of progress to date against stated project goal, objectives, milestones, and schedule
    5.2 – Likelihood of achieving continued progress against technical barriers
    5.3 – Feasibility of project goals, objectives, and expected outcomes and benefits being achieved
    5.4 – Reasonableness of the cost performance to date and plan to achieve project goals and objectives

6. Potential Technology Risks Considered

    6.1 – Degree to which potential risks to the environment or public associated with widespread technology deployment have been considered
    6.2 – Degree to which project risks are identified and effective measures to address and mitigate these risks, including potential technical uncertainties and barriers, are presented
    6.3 – Degree of recognition of scientific risks and plausibility of mitigation strategies presented

7. Performance and Economic Factors

    7.1 – Degree of adequacy of technology cost and performance assessments, given the level of technology development

7.2 – Reasonableness of cost estimates for future technology development, if warranted, given uncertainties
7.3 – Feasibility of meeting DOE program cost and performance goals

8. Anticipated Benefits if Successful
   8.1 – Reasonableness of statements regarding potential benefits of the project's research
   8.2 – Potential of technologies being developed benefitting other programs
   8.3 – Potential of technologies being developed to have a spin-off opportunity identified by the project team
   8.4 – Feasibility of the project to contribute to meeting near- and long-term program cost and performance goals

9. Technology Development Pathways
   9.1 – Feasibility of the "real world" application described
   9.2 – Adequacy of the discussed requirements (additional research, potential partners, and resources) to advance to the next level of technology development
   9.3 – Feasibility of the development pathways provided for implementing the technology being developed (if research is successful)
   9.4 – Degree to which potential barriers to commercialization have been identified and addressed

For each of these review criteria, individual panel members scored each project as one of the following:
- Excellent (10)
- Highly Successful (8)
- Fair (5)
- Weak (2)
- Unacceptable (0)

To facilitate the evaluation process, Leonardo Technologies, Inc. (LTI) provided the Panel with laptop computers that were preloaded with Peer Review Criteria Forms for each project. The Panel then discussed the project for the purpose of defining project strengths, project weaknesses, recommendations, and action items that the team must address to correct a project deficiency. After discussing and scoring the projects on these criteria, each panel member provided written comments reiterating and expanding on the discussions about each project.

APPENDIX B: MEETING AGENDA

FY13 Carbon Storage Peer Review

Pittsburgh Airport Marriott
Pittsburgh, PA
October 22-26, 2012

AGENDA

Monday, October 22, 2012 –

7:00 – 8:00 a.m.	**Registration –**
8:00 – 9:30 a.m.	**Peer Review Panel Kick Off Meeting** Open to National Energy Technology Laboratory (NETL) and American Society of Mechanical Engineers (ASME) staff only - Review of ASME Process – Michael Tinkleman, ASME - Role of Panel Chair – Ravi Prasad and James C. Sorensen, ASME - Role of NETL – José Figueroa, National Energy Technology Laboratory (NETL) - Meeting logistics/completion of forms – Justin Strock/Nicole Ryan/Dave Wildman, LTI
9:30 – 10:15 a.m.	**Overview** Open to NETL and ASME staff only - Carbon Storage Technology Manager – John Litynski, National Energy Technology Laboratory (NETL)
10:15 – 10:30 a.m.	**BREAK**
10:30 – 11:15 a.m.	***01 - Project # FE0001163*** **–** In Situ MVA of CO_2 Sequestration Using Smart Field Technology – *Shahab D. Mohaghegh*, **West Virginia University Research Corporation**
11:15 – 11:45 a.m.	Q&A
11:45 – 12:35 p.m.	Discussion
12:35 – 12:45 p.m.	Evaluation entry
12:45 – 1:45 p.m.	**Lunch (on your own)**
1:45 – 2:30 p.m.	***02 - Project # FE0004522*** **–** Development and Test of a 1,000 Level 3C Fiber Optic Borehole Seismic Receiver Array Applied to Carbon Sequestration – *Björn Paulsson*, **Paulsson, Inc.**
2:30 – 3:00 p.m.	Q&A
3:00 – 3:50 p.m.	Discussion
3:50 – 4:00 p.m.	Evaluation entry
4:00 – 4:15 p.m.	**BREAK**

Monday, October 22, 2012 –

4:15 – 5:00 p.m.	***03 - Project # FE0004542*** – Proof of Feasibility of Using Well Bore Deformation as a Diagnostic Tool to Improve CO_2 Sequestration – *Larry Murdoch*, **Clemson University**
5:00 – 5:30 p.m.	Q&A
5:30 – 6:20 p.m.	Discussion
6:20 – 6:30 p.m.	Evaluation entry

Tuesday, October 23, 2012 –

7:00 – 8:00 a.m.	**Registration** –
8:00 – 8:45 a.m.	***04 - Project # FE0001922*** – Recovery Act: Characterization of Pliocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO_2 – *Michael Bruno*, **Terralog Technologies**
8:45 – 9:15 a.m.	Q&A
9:15 – 9:55 a.m.	Discussion
9:55 – 10:05 p.m.	Evaluation entry
10:05 – 10:20 a.m.	**BREAK**
10:20 – 11:05 a.m.	***05 - Project # FE0002068*** – Recovery Act: An Evaluation of the Carbon Sequestration Potential of the Cambro-Ordovician Strata of the Illinois and Michigan Basins – *Hannes E. Leetaru*, **University of Illinois**
11:05 – 11:35 a.m.	Q&A
11:35 – 12:15 p.m.	Discussion
12:15 – 12:25 p.m.	Evaluation entry
12:25 – 1:25 p.m.	**Lunch (on your own)**
1:25 – 2:10 p.m.	***06 - Project # FE0001159*** – Advanced Technologies for Monitoring CO_2 Saturation and Pore Pressure in Geologic Formations: Linking the Chemical and Physical Effects to Elastic and Transport Properties – *Gary Mavko*, **Stanford University**
2:10 – 2:40 p.m.	Q&A
2:40 – 3:20 p.m.	Discussion
3:20 – 3:30 p.m.	Evaluation entry
3:30 – 3:45 p.m.	**BREAK**
3:45 – 4:30 p.m.	***07 - Project # FE0001580*** – Combining Space Geodesy, Seismology, and Geochemistry for Monitoring, Verification and Accounting of CO_2 in Sequestration Sites – *Timothy Hugh Dixon*, **University of Miami**
4:30 – 5:00 p.m.	Q&A
5:00 – 5:40 p.m.	Discussion
5:40 – 5:50 p.m.	Evaluation entry

Wednesday, October 24, 2012 –

7:00 – 8:00 a.m.	**Registration** –
8:00 – 8:45 a.m.	***08 - Project # FE0004962*** – Inexpensive Monitoring and Uncertainty Assessment of CO2 Plume Migration – *Steven Bryant and Sanjay Srinivasan*, **University of Texas at Austin**
8:45 – 9:15 a.m.	Q&A
9:15 – 9:55 a.m.	Discussion
9:55 – 10:05 p.m.	Evaluation entry
10:05 – 10:20 a.m.	**BREAK**
10:20 – 11:05 a.m.	***09 - Project # FE0004832*** – Maximization of Permanent Trapping of CO_2 in the Highest-Porosity Formations of the Rock Springs Uplift – *Felipe Pereira, Fred Furtado, Victor Ginting, and Marcos Alcoforado*, **University of Wyoming**
11:05 – 11:35 a.m.	Q&A
11:35 – 12:15 p.m.	Discussion
12:15 – 12:25 p.m.	Evaluation entry
12:25 – 1:25 p.m.	**Lunch (on your own)**
1:25 – 2:10 p.m.	***10 - Project # FE0004956*** – Influence of Local Capillary Trapping on Containment System Effectiveness – *Steven Bryant*, **University of Texas at Austin**
2:10 – 2:40 p.m.	Q&A
2:40 – 3:20 p.m.	Discussion
3:20 – 3:30 p.m.	Evaluation entry
3:30 – 3:45 p.m.	**BREAK**
3:45 – 4:30 p.m.	***11 - Project # FE0004566*** – Prototype and Testing a New Volumetric Curvature Tool for Modeling Reservoir Compartments and Leakage Pathways in the Arbuckle Saline Aquifer: Reducing Uncertainty in CO_2 Storage and Permanence – *Jason Rush*, **University of Kansas Center for Research**
4:30 – 5:00 p.m.	Q&A
5:00 – 5:40 p.m.	Discussion
5:40 – 5:50 p.m.	Evaluation entry

Thursday, October 25, 2012 –

7:00 – 8:00 a.m.	**Registration** –
8:00 – 8:45 a.m.	***12 - Project # FE0004630*** – Validation of Models Simulating Capillary and Dissolution Trapping During Injection and Post-Injection of CO_2 in Heterogeneous Geological Formations Using Data from Intermediate Scale Test Systems – *Tissa Illangasekare*, **Colorado School of Mines**
8:45 – 9:15 a.m.	Q&A
9:15 – 9:55 a.m.	Discussion
9:55 – 10:05 p.m.	Evaluation entry

Thursday, October 25, 2012 –

10:05 – 10:20 a.m.	**BREAK**
10:20 – 11:05 a.m.	***13 - Project # ORD-2012.02.00 Task 5.1*** – Verifying Storage Performance - Natural Geochemical Signals to Monitor Leakage to Groundwater – *Karl Schroeder*, **National Energy Technology Laboratory (NETL)**
11:05 – 11:35 a.m.	Q&A
11:35 – 12:15 p.m.	Discussion
12:15 – 12:25 p.m.	Evaluation entry
12:25 – 1:25 p.m.	**Lunch (on your own)**
1:25 – 2:10 p.m.	***14 - Project # FE0004478*** – Advanced CO_2 Leakage Mitigation Using Engineered Biomineralization Sealing Technologies – *Lee Spangler and Robin Gerlach*, **Montana State University**
2:10 – 2:40 p.m.	Q&A
2:40 – 3:20 p.m.	Discussion
3:20 – 3:30 p.m.	Evaluation entry
3:30 – 3:45 p.m.	**BREAK**
3:45 – 4:30 p.m.	***15 - Project # FE0001040*** – Quantification of Wellbore Leakage Risk Using Non-Destructive Borehole Logging Techniques – *Andrew Duguid*, **Schlumberger Carbon Services**
4:30 – 5:00 p.m.	Q&A
5:00 – 5:40 p.m.	Discussion
5:40 – 5:50 p.m.	Evaluation entry

Friday, October 26, 2012 –

7:00 – 8:00 a.m.	**Registration** –
8:00 – 8:45 a.m.	***16 - Project # FWP-58159 Task 2*** – Advanced Co-sequestration Studies – *Pete McGrail*, **Pacific Northwest National Laboratory (PNNL)**
8:45 – 9:15 a.m.	Q&A
9:15 – 9:55 a.m.	Discussion
9:55 – 10:05 a.m.	Evaluation entry
10:05 – 10:20 a.m.	**BREAK**
10:20 – 12:20 p.m.	**Meeting Wrap-up Session**

APPENDIX C: PEER REVIEW PANEL MEMBERS

After reviewing the scientific areas and issues addressed by the 16 projects to be reviewed, the Center for Research and Technology Development (CRTD) staff and the American Society of Mechanical Engineers (ASME) Peer Review Executive Committee identified the following areas of expertise as the required skill sets of the fiscal year (FY) 2013 Carbon Storage Peer Review Panel:

- Measurement, monitoring, and verification
- Modeling (performance, seismology, simulation)
- Near-surface carbon, carbon dioxide (CO_2) detectors, and tracers
- Hydrologic and groundwater impacts
- Deep reservoirs, candidate formations, and characterization
- Flow properties, fluid migration in rock, fractures, and boreholes
- Demonstration, bench testing, and field testing
- Characterization of borings, cores, sites, and boreholes
- Risk assessment and quantification
- Geologic formations and sequestration
- Geochemistry, isotopic composition, and brine
- Three-dimensional (3-D) geologic characterization, mapping, and imaging
- Economic and cost assessment
- Characterization under pressure
- Downhole instrumentation

These required reviewer skill sets were then put into a matrix format and potential panel members were evaluated on whether their expertise matched the required skills. This matrix also ensures that all the necessary skill sets are covered by the Panel. The Panel selection process also helps to guarantee that the Panel represents the distinct perspectives of both academia and industry.

Considering the areas of expertise listed above, the CRTD carefully reviewed the résumés of all those who had served on prior ASME Review Panels for DOE (acknowledging the benefit of their previous experience in this peer review process), a number of new submissions from DOE, and those resulting from a call to ASME members with relevant experience. It was determined that six individuals who had served on prior ASME Peer Review Panels were qualified to serve on the Carbon Storage Peer Review Panel, and one new member was also identified.

Appropriate résumés were then submitted to the ASME Carbon Storage Peer Review Executive Committee for review. The following seven members were selected for the FY2013 Carbon Storage Peer Review (* indicates a prior panel member):

- Ian Duncan, Ph.D., University of Texas at Austin*
- Scott Frailey, Ph.D., University of Illinois
- Neeraj Gupta, Ph.D., Battelle Memorial Institute*
- Ravi Prasad, Ph.D., Helios-NRG, LLC* – Co-Chair
- John Rupp, Indiana Geological Survey*
- James C. Sorensen, Sorensenergy, LLC* – Co-Chair
- Ed Steadman, Energy & Environmental Research Center, University of North Dakota*

Panel members reviewed presentation materials prior to the meeting and spent five days at the meeting evaluating projects and providing comments. Panelists received an honorarium for their time as well as reimbursement of travel expenses. A brief summary of their qualifications follows.

FY2013 Carbon Storage Peer Review Panel Members

Ian J. Duncan, Ph.D.

Dr. Ian Duncan is the manager of the Gulf Coast Carbon Center of the University of Texas at Austin's Bureau of Economic Geology (BEG). He is also principal investigator for multiple water resources, environmental geology, and natural resource investigations. Prior to this position, he served as the Associate Director and Research Scientist of BEG from 2004 to 2010. Prior to his work at the University of Texas at Austin, Dr. Duncan worked as Scientist Manager at the Virginia Department of Mines, Minerals, and Energy Division of Mineral Resources for 10 years. As a geology professor, he taught at Southern Methodist University and Washington University in St. Louis.

Dr. Duncan's areas of expertise include carbon management based on geologic CO_2 sequestration, development and management of large-scale pilot projects for carbon capture and long-term storage, remote sensing (geologic applications of multispectral, radar, and lidar data sets), geoinformatics, and implementation of clean technologies. Based on this expertise, Dr. Duncan has presented Congressional testimony to the House Natural Resources Committee on "CO_2 Enhanced Oil Recovery: A Key Bridge to Large Scale CO_2 Sequestration;" to the House Committee on Energy and Commerce on "Carbon Sequestration: Risks, Opportunities, and Protection of Drinking Water;" and to the House Committee on Energy and Commerce on "Carbon Sequestration Risks, Opportunities, and Learning from the CO_2-EOR Industry."

Dr. Duncan has authored 18 peer-reviewed articles and 15 other published articles. He is a member of the Structural Geology Division, Coal Division, and Hydrogeology Division of the Geological Society of America and previously served as a member of the Virginia State Agency Technical Remote Sensing Data Needs Advisory Committee through the George Mason University and Virginia Economic Development Partnership; Virginia Gap Analysis (Remote Sensing) Advisory Committee at Virginia Tech; Technical Advisory Committee of the Virginia Geographic Information Systems Network State Agency; and the Digital Geologic Mapping Committee, Data Information Exchange, and Data Capture Work Groups of the Association of American State Geologists.

Dr. Duncan received a B.A. in earth sciences from Macquarie University in Australia and a Ph.D. in geology from the University of British Columbia.

Scott M. Frailey, Ph.D.

Dr. Scott M. Frailey is a senior reservoir engineer at the Illinois State Geological Survey, where he has worked for nearly 10 years. Prior to this position, Dr. Frailey taught undergraduate and graduate courses in petroleum engineering at Texas Tech University for 11 years, primarily within the general area of reservoir engineering and formation evaluation, including courses in Core Analysis Laboratory, Reservoir Rock Properties, Petroleum Property Evaluation and Management, Well Test Analysis, Formation Evaluation, and Enhanced Oil Recovery. Dr. Frailey also worked at BP Exploration (Alaska) Inc. for three years as a reservoir engineer. In this position he was responsible for designing and analyzing pressure transient tests in Prudhoe Bay and performed compositional and black oil simulation of the Prudhoe Bay Field.

Dr. Frailey's areas of expertise include CO_2 enhanced oil recovery; carbon sequestration; well log analyses; pressure transient analyses; reservoir simulation; and pressure, volume, and temperature experiments.

Dr. Frailey holds a Ph.D., M.S., and B.S. in petroleum engineering, all from the University of Missouri-Rolla.

Neeraj Gupta, Ph.D.

Dr. Neeraj Gupta is a geologist at Battelle Memorial Institute and has been one of the leaders in Battelle's efforts to evaluate the feasibility of geologic storage of CO_2 in sedimentary formations since 1996. During this time, Dr. Gupta has played a key role in formation of several public-private joint projects on geologic sequestration. Dr. Gupta developed and led a unique $8 million field project funded by major government and energy industry organizations at American Electric Power's Mountaineer Plant. Following completion of the site characterization work, this project is now transitioning into a larger effort involving geologic storage of CO_2 captured from the plant.

Dr. Gupta also leads a complex program of geologic storage demonstrations hosted by major energy companies as part of the Midwestern Regional Carbon Sequestration Partnership (MRCSP), a $23 million multi-client program led by Battelle. His current and previous work includes field investigations; regional hydrogeology; reservoir simulations of CO_2 storage; geochemical modeling and experiments; seismic assessments; cost and regulatory aspects; and development of CO_2 capture technologies. Dr. Gupta also plays a significant technical advisory role on Battelle's FutureGen project team and has had a major role in development of the research agenda for carbon management technologies through his extensive participation in government, private, and international dialogues.

Dr. Gupta has written more than 40 reports and papers and has made invited presentations at numerous meetings, workshops, and expert panels.

Dr. Gupta earned a B.S. and M.S. in Geology from Panjab University, India; an M.S. in Geochemistry from George Washington University; and a Ph.D. in Hydrogeology from the Ohio State University.

Ravi Prasad, Ph.D., Panel Co-Chair

Ravi Prasad of Helios-NRG, LLC and formerly a corporate fellow of Praxair Inc., has 60 U.S. patents and broad industrial experience in developing and commercializing new technologies, launching technology programs ($2 million–$50 million), supporting business development, building cross-functional teams, and setting up joint development alliances. He is a founding member of an alliance involving Praxair, British Petroleum, Amoco, Phillips Petroleum, Statoil, and Sasol to develop ceramic membrane syngas technology for gas-to-liquid processes.

Dr. Prasad also established and led programs for ceramic membrane oxygen technology; co-developed proposals to secure major DOE programs in synthesis gas (syngas), worth $35 million, and in oxygen, worth $20 million; identified novel, solid-state oxygen generation technology; and conceived and implemented a coherent corporate strategy in nanotechnology. He has championed many initiatives in India, including small on-site hydrogen plants, small gasifiers, and aerospace business opportunities; and developed implementation plans resulting in a new research and development center in Shanghai.

Dr. Prasad's technical areas of expertise include membranes and separations, hydrogen and helium, industrial gas production and application, ceramic membranes and solid oxide fuel cells, new technology development, technology roadmapping, intellectual property strategy development, technology due diligence, combustion, nanotechnology, gas-to-liquids, coal-to-liquids, and silane pyrolysis reactors.

Dr. Prasad is the director and a board member of the National Hydrogen Association, a member of the steering committee for Chemical Industry V2020, and has been a recipient for Chairman's & Corp Fellows awards for technology leadership. He has authored or co-authored 30 publications, is co-author of a book on membrane gas separation, and has presented at more than 20 conferences and invited lectures.

Dr. Prasad has a B.S. in mechanical engineering from the Indian Institute of Technology in Kanpur, India, and an M.S. and Ph.D. in mechanical engineering and chemical engineering from the State University of New York, Buffalo, New York.

John A. Rupp

Mr. John Rupp is the Assistant Director for Research and section head of Subsurface Geology at Indiana University's Indiana Geological Survey. Mr. Rupp serves as the project director for Indiana on two of the U.S. Department of Energy's Regional Carbon Sequestration Partnerships: the seven-state Midwest Regional Carbon Sequestration Partnership and the three-state Midwestern Geological Sequestration Consortium.

Mr. Rupp specializes in energy issues related to petroleum, coal, and natural gas, including subsurface geology, unconventional reservoir analysis, and carbon sequestration. His current topics of research include subsurface stratigraphy, reservoir analysis, and operations development in the deep subsurface of the Illinois Basin for carbon sequestration and the evaluation of coal bed methane for gas shale enhanced production using CO_2 injection.

Mr. Rupp co-chaired the 2008 Indiana Carbon Capture and Storage Summit and has served on external review panels for research activities of the Department of Energy's National Energy Technology Laboratory and the Advanced Research Project Agency-Energy.

Mr. Rupp is a member of the American Association of Petroleum Geologists, the Indiana Academy of Science, and also serves on the Governors' Task Force on Carbon Sequestration Legislation.

Mr. Rupp earned a B.S. in geology from the University of Cincinnati and an M.S. in geology from Eastern Washington University.

James Sorensen, Panel Co-Chair

Mr. James Sorensen is a consultant with a primary focus on clean coal and supporting technologies, including integrated gasification combined cycle (IGCC), oxyfuel combustion, and coal-to-liquids. Prior to founding Sorensenergy, LLC, in 2004, he worked for Air Products & Chemicals, including as director of New Markets with responsibility for Syngas Conversion Technology Development and Government Systems; and director of Gasification and Energy Conversion. In the latter position, he had commercial responsibility for numerous studies involving air separation unit (ASU)/gas turbine integration for IGCC. Mr. Sorensen was responsible for the sale of the ASU for the Tampa Electric Polk County IGCC facility, which included the first commercial application of the Air Products cycle for nitrogen integration of the ASU with the gas turbine. He was also involved with gas turbine integration associated with Air Products's ion transport membrane oxygen program. Prior responsibilities included project management of Air Products's baseload liquid natural gas projects, commercial management of synthetic natural gas production, and general management of the membrane systems department.

Mr. Sorensen's technical interests include IGCC, oxyfuel combustion, gas-to-liquids, and air separation and hydrogen/syngas technology. His programmatic interests include Electric Power Research Institute CoalFleet, Fossil Energy Research & Development, DOE's Clean Coal Power Initiative, DOE's FutureGen program, and commercial projects. His areas of expertise include project conception and development, consortium development and management, technology and government sales and contracting, research and development program management, technology consulting and training, proposal preparation and review, commercial contract development, and intellectual property.

Mr. Sorensen was the founding chairman of the Gasification Technologies Council and the vice chairman of both the Council on Alternate Fuels and Energy Futures International. Mr. Sorensen holds eight U.S. patents, one of which involves ASU/gas turbine integration for IGCC. He has international experience with customers and partners in Algeria, Chile, China, Germany, Great Britain, Indonesia, Japan, The Netherlands, and elsewhere. He is also well published in the area of clean coal.

He received a B.S. in chemical engineering from the California Institute of Technology, an M.S. in chemical engineering from Washington State University, and an M.B.A. from the Harvard Business School.

Edward N. Steadman

Mr. Edward Steadman is a Senior Research Advisor at the University of North Dakota's Energy & Environmental Research Center. He is responsible for directing a multidisciplinary team of researchers on a carbon sequestration project that has included inventorying CO_2 sources, geologic and terrestrial sinks, and sequestration infrastructure; identifying CO_2 capture and separation technologies; investigating monitoring, verification, and accounting technologies and permitting requirements; and defining the most promising opportunities for carbon sequestration in nine states and four Canadian provinces. Some of Mr. Steadman's other responsibilities include development, marketing, management, and dissemination of commercially oriented research and development for programs focused on the environmental effects of power and natural resource production.

Mr. Steadman also currently serves as the program manager for the Plains CO_2 Reduction Partnership, one of seven regional partnerships funded by the U.S. Department of Energy's National Energy Technology Laboratory Regional Carbon Sequestration Partnership Program. The Plains CO_2 Reduction Partnership assesses the technical and economic feasibility of capturing and storing CO_2 emissions from stationary sources in the northern Great Plains and adjacent area.

Mr. Steadman's principal areas of expertise are carbon sequestration, watersheds, sustainable development, chemical transformations during coal combustion, and materials science. He has authored or coauthored numerous publications and given presentations on these topics to audiences throughout the United States and around the world.

Mr. Steadman holds a B.S. in geology from the University of Pennsylvania-Edinboro and an M.A. in geology from the University of North Dakota.

APPENDIX D: PEER REVIEW CRITERIA FORM

PEER REVIEW CRITERIA FORM

U. S. DEPARTMENT OF ENERGY
NATIONAL ENERGY TECHNOLOGY LABORATORY
FY13 CARBON STORAGE PEER REVIEW

October 22 – 26, 2012

Project Title:	
Performer:	
Presenter:	
Name of Peer Reviewer:	
Date of Review:	

The following pages contain the criteria used to evaluate each project. The criteria have been grouped into three (3) major categories: (1) **Project Overview**; (2) **Technical Discussion**; and (3) **Technology Benefits**. Additionally, each criterion is accompanied by multiple characteristics to further define the topic.

The Reviewer is expected to provide a **rating** and **substantive comments** which support that rating for each criterion. Please note that if a rating of ***"0"*** is selected, **justifying comments must be included**. To assist with determining the criterion score, descriptions of those scores are provided below.

RATING DEFINITIONS	
0	**Unacceptable** – Project fails to meet all sub-criteria objectives. Significant weaknesses/deficiencies exist that are largely insurmountable.
2	**Weak** – Project fails to meet most sub-criteria objectives. Weaknesses outweigh strengths identified.
5	**Fair** – Projects meets sub-criteria objectives. Strengths and weaknesses are in balance.
8	**Highly Successful** – Project exceeds most sub-criteria objectives. Strengths are apparent and documented.
10	**Excellent** – Project exceeds all sub-criteria objectives. Strengths are apparent and documented. No weaknesses were identified.

Page 1 of 6

Please evaluate the project against each of the nine (9) criteria listed below. For each criterion, select the appropriate rating by typing an "X" in the applicable cell. Definitions for the five ratings are provided on page 1. Reviewers need to identify the sub-criteria (i.e. 1.1, 1.2, 1.3) that are considered weak or unacceptable (see Comments section).

NOTE: If you rate any criterion as "0," a justification for this rating is required. Please include your justification in the box at the end of this table.

PROJECT OVERVIEW					
1. Scientific and Technical Merit	**0 ***	**2**	**5**	**8**	**10**
1.1 – Scientific feasibility of project concept **1.2** – Degree and likelihood of achieving planned technological advancements **1.3** – Degree of innovation evidenced					
2. Existence of Clear, Measurable Milestones	**0 ***	**2**	**5**	**8**	**10**
2.1 – Degree to which the number of milestones per budget period are appropriate **2.2** – Degree to which milestones are quantitative and show progression towards project goals **2.3** – Degree of completeness of milestones (title, completion date, success criterion)					
3. Utilization of Government Resources	**0 ***	**2**	**5**	**8**	**10**
3.1 – Degree of adequacy of the research team to address the project goal and objectives **3.2** – Feasibility of rationale presented for teaming or collaborative efforts **3.3** – Feasibility of equipment, materials, and facilities to meet the project goal and objectives					
TECHNICAL DISCUSSION					
4. Technical Approach	**0 ***	**2**	**5**	**8**	**10**
4.1 – Degree of adequacy of understanding of potential technical challenges and technical barriers **4.2** – Degree of adequacy of the mitigation strategy for the identified technical challenges and barriers **4.3** – Feasibility of technical approach to support stated project goal and objectives					
5. Rate of Progress	**0 ***	**2**	**5**	**8**	**10**
5.1 – Degree of adequacy of progress to date against stated project goal, objectives, milestones, and schedule **5.2** – Likelihood of achieving continued progress against technical barriers **5.3** – Feasibility of project goals, objectives, and expected outcomes and benefits being achieved **5.4** – Reasonableness of the cost performance to date and plan to achieve project goals and objectives					

Page 2 of 6

TECHNICAL DISCUSSION (continued)					
6. Potential Technology Risks Considered	**0 ***	**2**	**5**	**8**	**10**
6.1 – Degree to which potential risks to the environment or public associated with widespread technology deployment have been considered. **6.2** – Degree to which project risks are identified and effective measures to address and mitigate these risks, including potential technical uncertainties and barriers, are presented. **6.3** – Degree of recognition of scientific risks and plausibility of mitigation strategies presented.					
7. Performance and Economic Factors **	**0 ***	**2**	**5**	**8**	**10**
7.1 – Degree of adequacy of technology cost and performance assessments, given the level of technology development **7.2** – Reasonableness of cost estimates for future technology development, if warranted, given uncertainties **7.3** – Feasibility of meeting DOE Program cost and performance goals					
TECHNOLOGY BENEFITS					
8. Anticipated Benefits, if Successful	**0 ***	**2**	**5**	**8**	**10**
8.1 – Reasonableness of statements regarding potential benefits of the project's research **8.2** – Potential of technologies being developed benefitting other programs **8.3** – Potential of technologies being developed to have a spin-off opportunity identified by the project team **8.4** – Feasibility of the project to contribute to meeting near- and long-term program cost and performance goals					
9. Technology Development Pathways **	**0 ***	**2**	**5**	**8**	**10**
9.1 – Feasibility of the "real world" application described **9.2** – Adequacy of the discussed requirements (additional research, potential partners, and resources) to advance to the next level of technology development **9.3** – Feasibility of the development pathways provided for implementing the technology being developed (if research is successful) **9.4** – Degree to which potential barriers to commercialization have been identified and addressed					
*** Please explain why the project received a "0" for a particular criterion.**					

** Additional details to be considered for Criterion 7 (Performance and Economic Factors) and 9 (Technology Development Pathways) for specific technology readiness levels are described on pages 5 and 6.

Page 3 of 6

COMMENTS

Please provide your comments for each of the areas in the blocks below. Reviewers need to identify the sub-criteria (i.e. 1.1, 1.2, 1.3) that are considered weak or unacceptable. Please substantiate your comments (i.e., facts on why you are making the statement). General statements without explanation (e.g., great project) are not sufficient. Please avoid any use of clichés, colloquialisms or slang.

Strengths:
Weaknesses: Please identify weak/unacceptable sub-criterion and provide link from each Weakness to the corresponding Recommendation(s) and/or Action Item(s).
Recommendations: Please number.
Action Items: Please number.
General Comments:

Page 4 of 6

TECHNOLOGY READINESS LEVELS FOR ECONOMIC ANALYSIS & TECHNOLOGY DEVELOPMENT PATH

Research, Development, and Demonstration (RD&D) projects can be categorized based on the level of technology maturity. Listed below are nine (9) technology readiness levels (TRLs) of Carbon Storage RD&D projects managed by the National Energy Technology Laboratory. These TRLs provide a basis for establishing a rational and structured approach to decision-making and identifying performance criteria that must be met before proceeding to the next level.

TRL 1 - *Basic principles observed and reported.* This is the lowest level of technology readiness. Scientific research begins to be translated into applied research and development (R&D). Examples include paper studies of a technology's basic properties.

TRL 2 - *Technology concept and/or application formulated.* Invention begins. Once basic principles are observed, practical applications can be invented. Applications are speculative, and there may be no proof or detailed analysis to support the assumptions. Examples include analytic and laboratory studies to confirm the potential practical application of basic processes and methods to geologic storage.

TRL 3 - *Analytical and experimental critical function and/or characteristic proof of concept.* Active R&D is initiated. This includes analytical studies and laboratory-scale studies to physically validate the analytical predictions of separate elements of the technology. Examples include components that are not yet integrated or representative. Components may be tested with simulants.

TRL 4 - *Component and/or system validation in a laboratory environment.* The basic technological components are integrated to establish that the pieces will work together. This is relatively "low fidelity" compared with the eventual system. Examples include integration of "ad hoc" hardware in a laboratory and testing with a range of simulants.

TRL 5 - *Laboratory-scale similar-system validation in a relevant environment.* Laboratory validation of system/subsystem components. Laboratory validation testing of geologic storage processes, subsystems and/or subsystem components under conditions representative of in-situ operating conditions. Subsystem and/or component configuration is similar to (or matches) the final application in almost all respects. Validation testing involves measurements under in-situ operating conditions to assess performance of the process, subsystem and/or component. Planning and design are undertaken for prototype system verification.

TRL 6 - *Engineering/pilot-scale, prototypical system demonstrated in a relevant environment.* Prototype system verified. Prototype field pilot testing of geologic storage system or subsystem in relevant geologic environments. Geologic characteristics, including rock type and contained fluids, depth, pressure, and temperature, are relevant to final scale. Pilot scale involves injection of a sufficient amount of CO_2 to verify design performance of system or subsystem and components. System configured to enable pilot-scale testing, which involves measurements and operations specific to assessing performance of the system and/or subsystem and subsystem components. Performance testing relevant to the life cycle of a storage project, including site characterization, injection, and post-injection monitoring and closure.

TRL 7 - *System prototype demonstrated in a plant environment.* Integrated pilot system demonstrated. Geologic storage system prototype tested at pilot scale for a type of depositional environment (e.g., saline fluvial deltaic) or storage type [e.g., EOR or enhanced coalbed methane (ECBM)]. Pilot scale involves injection of a few hundred tonnes* to several hundred thousand tonnes. System configured to enable pilot-scale testing, which involves measurements and operations specific to assessing performance of the system, subsystem, and subsystem components. Performance testing is relevant to each stage of the full life cycle of a storage project, including site characterization, injection, and post-injection monitoring and closure. Planning and design are undertaken to test and demonstrate a full-scale system.

* Among key stakeholders in the carbon capture and storage communities, tonnage quantities are generally expressed as metric tons (tonnes). That protocol will be followed throughout this document. However, for other program components where its use is more customary, English "tons" are used. One tonne is equal to 1 kg or 2,205 pounds.

Page 5 of 6

TRL 8** - *Actual system completed and qualified through test and demonstration in a plant environment.* System tested and demonstrated at final scale. This TRL represents the end of technology development for a geologic storage system for a type of depositional environment (e.g., saline fluvial deltaic) or storage type (e.g., EOR or ECBM). The complete geologic storage system is tested at final scale in a demonstration. Final scale involves injection of >1 million tonnes per year. System configured to enable final-scale testing, which involves measurements and operations specific to assessing performance of the system, subsystem, and subsystem components. Performance testing is relevant to each stage of the full life cycle of a storage project, including site characterization, injection, and post-injection monitoring and closure.

TRL 9** - *Actual system operated over the full range of expected conditions.* System proven and ready for final-scale geologic storage. Geologic storage system is proven through successful operations at full scale for a type of depositional environment (e.g., saline fluvial deltaic) or storage type (e.g., EOR or ECBM). Full scale involves injection of >1 million tonnes per year. System configured for final-scale deployment, including considerations of cost. Operations include full life cycle of the storage project, including site characterization, injection, and post-injection monitoring and closure.

Table 1 describes economic analysis and technology development for technology readiness levels. These bullets are examples of the types of information that is typically determined in technology research and development projects.

Please note that the Economic Analysis and Technology Development Path are examples of the types of information that should be provided for the projects being reviewed. Projects are not expected to address all bullets for a given technology readiness level, but should address at least one of them. The Reviewer will rely on their experience and the guidance herein to assess each project.

Table 1. Economic Analysis and Technology Development

Technology Readiness Level	Economics Analysis	Technology Development Path
1-3	• Material costs available • Potential cost benefits over conventional systems identified	• Scientific feasibility proven • Application(s) considered • Potential technology developers identified
4-5	• Component or sub-system costs estimated • First-order cost-benefit analysis available • Material and energy balances calculated	• Conceptual process proposed • Potential applications well defined • Process feasibility established
6	• Conceptual process costs developed • Market analysis completed • Risk assessment completed	• Process test data available • Engineering scale-up data developed • Optimum operating conditions identified
7	• Process contingency costs identified • Full-scale process costs, including O&M calculated • Full-scale installation costs developed	• Major technology components thoroughly tested and evaluated • Technology demonstration plans firmly established • Major component optimization studies performed
8-9**	• Installation costs determined	• Business and commercialization plans developed

** Not relevant to this Peer Review.

Page 6 of 6

APPENDIX E: CARBON STORAGE PROJECT SUMMARIES

Presentation ID Number	Project Number	Title
01	FE0001163	In Situ MVA of CO_2 Sequestration Using Smart Field Technology
02	FE0004522	Development and Test of a 1,000 Level 3C Fiber Optic Borehole Seismic Receiver Array Applied to Carbon Sequestration
03	FE0004542	Proof of Feasibility of Using Well Bore Deformation as a Diagnostic Tool to Improve CO_2 Sequestration
04	FE0001922	Recovery Act: Characterization of Pliocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO_2
05	FE0002068	Recovery Act: An Evaluation of the Carbon Sequestration Potential of the Cambro-Ordovician Strata of the Illinois and Michigan Basins
06	FE0001159	Advanced Technologies for Monitoring CO_2 Saturation and Pore Pressure in Geologic Formations: Linking the Chemical and Physical Effects to Elastic and Transport Properties
07	FE0001580	Combining Space Geodesy, Seismology, and Geochemistry for Monitoring, Verification and Accounting of CO_2 in Sequestration Sites
08	FE0004962	Inexpensive Monitoring and Uncertainty Assessment of CO_2 Plume Migration
09	DE-FE0004832	Maximization of Permanent Trapping of CO_2 and Co-Contaminants in the Highest-Porosity Formations of the Rock Springs Uplift (Southwest Wyoming): Experimentation and Multi-Scale Modeling
10	FE0004956	Influence of Local Capillary Trapping on Containment System Effectiveness
11	FE0004566	Prototype and Testing a New Volumetric Curvature Tool for Modeling Reservoir Compartments and Leakage Pathways in the Arbuckle Saline Aquifer: Reducing Uncertainty in CO_2 Storage and Permanence
12	FE0004630	Validation of Models Simulating Capillary and Dissolution Trapping During Injection and Post-Injection of CO_2 in Heterogeneous Geological Formations Using Data from Intermediate Scale Test Systems
13	ORD-2012.02.00 Task 5.1	Verifying Storage Performance – Natural Geochemical Signals to Monitor Leakage to Groundwater
14	FE0004478	Advanced CO_2 Leakage Mitigation Using Engineered Biomineralization Sealing Technologies
15	FE0001040	Quantification of Wellbore Leakage Risk Using Non-Destructive Borehole Logging Techniques
16	FWP-58159 Task 2	Advanced Co-Sequestration Studies

01: FE0001163

Project Number	Project Title		
FE0001163	In Situ MVA of CO_2 Sequestration Using Smart Field Technology		
Contacts	**Name**	**Organization**	**Email**
DOE-NETL Project Mgr.	Robert Noll	NETL – Sequestration Division	Robert.Noll@netl.doe.gov
Principal Investigator	Shahab Mohaghegh	West Virginia University Research Corporation	shahab.mohaghegh@mail.wvu.edu
Partners	Consol Energy Schlumberger Advanced Resources International Battelle Memorial Institute		
Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 4	

Technical Background

The concept of "smart fields" is rapidly gaining support and popularity in the oil and gas industry. Hundreds of millions of dollars have been invested to successfully develop high-sensitivity Permanent Downhole Gauges (PDG) that are capable of operating in harsh environments for long periods of time. PDGs collect and transmit high-frequency data streams to the remote offices in real time, to be analyzed and used for reservoir management. The industry is now working on state-of-the-art software solutions that can take maximum advantage of the large amount of data that is collected, transmitted, and stored in data historians.

In this project, the West Virginia University team will develop and test a software technology based on the concept of smart fields (i.e., the analysis of high-frequency, real-time pressure data from reservoirs using pattern recognition technology) for in situ monitoring, verification, and accounting (MVA) of carbon dioxide (CO_2) storage in geologic formations. High-frequency, real-time pressure data is received from an array of PDGs that have been placed in the formation where the CO_2 is injected (gauges can be placed in the injection and in observation wells). Real-time data is collected, cleansed, summarized, and processed using smart software (e.g., an Intelligent Leak Detection System [ILDS]) in order to locate and quantify any potential CO_2 leakages from the reservoir.

This project addresses a complex deconvolution problem that cannot be solved efficiently with adequate precision using analytical and/or numerical solutions. To address the complexities associated with this problem, the Petroleum Engineering & Analytics Research Lab team at West Virginia University is using pattern recognition capabilities of state-of-the-art artificial intelligence and data mining technology.

Relationship to Program

This project will support important advances within the MVA pathway of the DOE-NETL Carbon Storage Program. This project will reduce the cost of potential CO_2 leakage by focusing the MVA team's attention on the most probable locations of the leakage. The project team also aims to advance detection technologies by incorporating pattern recognition technologies in addition to the currently used numerical and analytical approaches. As a collateral benefit, this project will advance software technologies related to smart fields in areas where software solutions currently lag behind significant advancements in hardware technologies.

Primary Project Goal

The primary goal of this project is to develop the required software technology for in situ location and quantification of CO_2 leakage in a storage project.

Objectives

This project proposes developing an in situ CO_2 MVA technology based on the concept of smart fields. This technology will identify the approximate location and the amount of the CO_2 leakage (at the reservoir level) in a timely manner so that action can be taken proactively to ensure that 99 percent of the injected CO_2 remains in the injection zone.

The uniqueness of this project stems from the fact that it attempts to identify the location and amount of the CO_2 leakage at the reservoir level, long before it reaches the surface. By providing such information to the monitoring team at the surface, ample time is provided for proactive intervention, rather than reactive responses.

Project accomplishments to date include the following:

- Completion of a geological model using information from 40 wells in the region along with core data
- Completion of a high-resolution reservoir simulation model with about 1.2 million cells
- Completion of a CO_2 leakage model
- Completion of real-time data preparation and analysis
- Hand-off of the properly processed real-time data to the leak detection model.
- Initiation and successful prototyping of the ILDS
- Successful testing of the pattern recognition technology in deconvoluting the real-time pressure signals to detect the location and quantity of the CO_2 leakage

02: FE0004522

Project Number	Project Title		
FE0004522	Development and Test of a 1,000 Level 3C Fiber Optic Borehole Seismic Receiver Array Applied to Carbon Sequestration		
Contacts	**Name**	**Organization**	**Email**
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Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 6	

Technical Background

The successful storage of carbon dioxide (CO_2) in geological media is critically dependent on a precise understanding, prior to any injection, of the complexity of the geologic formations that will serve as CO_2 repositories. A successful carbon storage program also depends on an accurate monitoring program that can enable an understanding of the dynamic processes of the CO_2 injection to assure that the CO_2 remains stored in the geologic formation and does not leak into the atmosphere.

The complex process of the storage of CO_2 will only be understood and managed in detail if robust, high-resolution reservoir imaging technology is available to assess the reservoir and monitor and evaluate the CO_2 injection processes. High-resolution imaging can only be achieved if high-quality data can be recorded and sampled properly, both spatially and temporally. Three-dimensional (3-D) vertical seismic profiling (VSP) primary-wave (P-wave) images have routinely proven to have more than twice the spatial resolution as surface seismic images in areas with good surface seismic data. In areas with poor to very poor surface seismic data, the 3-D VSP technology has still been able to record the high-quality data needed for high-resolution imaging. Converted shear wave (S-wave) data is also routinely recorded using borehole seismic acquisition. Images using converted shear waves, due to their shorter wavelengths, have an additional resolution improvement over P-wave images and are providing additional lithologic, stratigraphic, fracture, and stress information about the geologic sites surveyed. 3-D borehole seismic techniques can image much larger volumes than well logging techniques and can provide high-resolution images far away from the borehole.

Borehole seismic data is superior to surface seismic data for high-resolution imaging and monitoring for a number of reasons:

- The sensors are closer to the imaging target and clamped into a consolidated formation, which allows the recording of higher-frequency raw data.
- The sensors are away from the noisy surface environment, providing higher signal-to-noise ratio data.
- Converted shear wave data can be recorded because the sensors are avoiding the near-surface layer, which has low shear modulus and high attenuation of the shear waves.
- The downgoing P-wave and converted shear wave fields are closely sampled, allowing highly accurate P- and S-wave velocity models to be built free from the near-well

anomalies experienced by well logs and the inaccuracies inherent in the surface seismic-derived velocity models. The downgoing wave fields also allow accurate deconvolution and anisotropic parameters estimation for the 3-D processing.
- The sensors are deeper in the formation so a more sophisticated depth imaging approach is the natural and more accurate imaging technique.

Using the high-quality active and passive source P- and S-wave data that can be recorded with an ultra-long borehole seismic system equipped with sensitive geophones, the project team will be able to make quantitative 3-D maps of the reservoir architecture as well as the properties of the reservoir rocks and the rock formation forming the seal around the reservoir. By employing the highly repeatable borehole seismic method with either active or passive sources, or preferably a combination of both sources, the project team will be able to track the fluid flow and the pressure changes in the rock mass. This tracking ability is possible because P- and S-wave velocities and attention are sensitive to different properties of the reservoir and generate complementary images.

By combining a new fiber optic sensor design with novel state-of-the-art fiber optic telemetry and sensor interrogation technologies, the project team is able to deploy a large number of fiber optic geophones on one fiber while maintaining the high-resolution and high-fidelity performance attributes of the fiber optic geophones. The fiber optic geophones are immune to electric and electromagnetic interference because the system does not require any electronics at the fiber optic sensor end. This design also makes the geophones extremely robust and able to operate in extreme environments, such as in temperatures above 200°C (400°F). The drill-pipe-based deployment system is providing tubing hydraulics to power the clamping actuators. The combination of fiber optic geophones, which require no downhole electronics, and the tubing hydraulics for the clamping eliminates the need to deploy temperature-sensitive electronics in the borehole, consequently making the system extremely robust and reliable.

Relationship to Program

This project will support important advances within the geologic storage technologies and simulation and risk assessment pathway of the DOE-NETL Carbon Storage Program. The ultra-large borehole seismic fiber optic receiver array developed by Paulsson, Inc. under this program will enable effective CO_2 storage site characterization. A detailed and correct characterization of the injection site prior to the injection of CO_2 is critical to assure that the CO_2 is effectively stored. The borehole seismic array will also allow for effective monitoring of the carbon storage sites. The array will detect any leaks by mapping both the velocity changes caused by the movement of the CO_2 inside and outside the reservoir as well as the micro-seismic events caused by the pressure changes from the migration of the CO_2.

Primary Project Goal

The primary project goal is to develop an ultra-large, high-temperature- and high-pressure-capable, all-fiber-optic borehole seismic three-component (3C) clamped array with an integrated acquisition system for high-resolution carbon capture and storage site characterization and monitoring.

This system is designed to deploy up to 1,000 3C geophone levels using a novel, small-diameter drill-pipe-based deployment system, which allows the geophone array to be deployed in both deep vertical and long horizontal boreholes. This new borehole seismic technology will make high-resolution surveying and monitoring of carbon storage sites possible.

The project team will achieve the project goal by specifying and designing technology that will allow the safe deployment of 1,000 3C levels, and by building a 150-level 3C technology demonstration array and deploying the demonstration array to perform a borehole seismic survey at a carbon storage site.

Objectives

The project objectives include designing, building, and testing the next-generation borehole seismic system using a new concept for both the advanced sensor and the deployment system, and assessing the applicability of this system to carbon capture and storage in geologic formations.

To achieve the project objectives, the project team will complete a number of complex interdependent tasks to design and build the borehole system. There are three primary components of a downhole seismic system: the seismic sensor, the surface electronics and recording system, and the deployment system. To be viable, the borehole components of this system must all be able to operate at a temperature of at least 200°C (392°F) and at a pressure of 30,000 pounds-force per square inch (psi) in a corrosive CO_2 environment for long periods of time. The approach Paulsson Inc. will use for the sensor is to design a high-temperature fiber optic geophone using high-temperature polyimide-coated fibers that can operate to a temperature of 300°C (572°F). The strain of the fiber will be recorded, analyzed, and transformed into a seismic record using an interferometric technique with all electronics and instruments placed at the surface. For the deployment system, Paulsson Inc. will use a small-diameter, high-strength drill pipe with offshore drill pipe manufacturing technology as the backbone for the high-temperature deployment system, and use the hydraulic power supplied through the tubing to clamp the receiver pods to the borehole wall. Upon completion of the design and prototype testing, the project team will build a 150-level 3C array (i.e., 450 channels) demonstration system and select a field test site in collaboration with DOE for installing and testing the prototype seismic system. The sensor and deployment technology will be field tested at two stages of prototype development: a 5-level 3C array prototype system following the prototype laboratory tests and a 150-level 3C array demonstration system after the manufacturing of all the components.

The project team will analyze data collected from the seismic surveys and provide results to assess the performance of the system and applicability of the system to CO_2 storage reservoirs and operations.

03: FE0004542

Project Number	Project Title		
FE0004542	Proof of Feasibility of Using Well Bore Deformation as a Diagnostic Tool to Improve CO_2 Sequestration		
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Partners	Georgia Institute of Technology Baker Hughes		
Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 4	

Technical Background

Wellbores deform in response to changes in fluid pressure that accompany injection or pumping. In some cases, the deformation is severe and dramatic, such as when casing is collapsed or sheared, which leads to catastrophic loss of access to the well. Those cases are the end members of a spectrum that includes modest elastic deformations during any significant exchange of fluid between the wellbore and the formation. Injection elevates pressures that cause the wellbore in a permeable zone to dilate radially and lengthen, while adjacent confining units are compressed. Heterogeneities in the vicinity of the well will induce deformations that are non-radially symmetric, warping the bore into an ellipse or bending it into a sinuous or other contorted shape.

Wellbore deformation occurs in response to loadings to the casing itself, the gravel or cement, and the enveloping formation. These loads result from transient changes in fluid pressure, and their distribution is closely linked to the distribution of mechanical and fluid properties in the formation. This linkage suggests that measurements of wellbore deformation can be inverted to estimate the distribution of mechanical and fluid properties. Understanding the distribution of those properties is required to design an efficient and safe carbon dioxide (CO_2) injection well.

Another motivation is the use of wellbore deformation to monitor the CO_2 storage process itself. Injecting large volumes of fluid has the potential to create hydraulic fractures, induce faults, deform wellbore seals, break casing, and create other effects that will threaten the viability of the storage process. All of those processes will deform the well bore, so monitoring deformation could provide a warning that allows those detrimental effects to be avoided.

HYDROMECHANICAL WELL TESTS

Transient hydraulic tests, in which pressures are recorded at wells while fluid is produced or injected for a short period of time, are widely used to forecast long-term well performance in reservoirs or aquifers. Similar tests have been used to anticipate the response of wells to CO_2 injection, and hydraulic well tests will undoubtedly be a mainstay in the initial assessment of wells used for CO_2 storage.

Despite their importance, hydraulic well tests are vulnerable to problems that could cause serious errors when their results are used in simulations. For example, well tests on isolated wells are notorious for producing poor estimates of specific storage or formation compressibility. Errors in this parameter will result in either overestimating the pressure rise in the formation when the estimated compressibility is too stiff, or underestimating it when the estimated compressibility is too soft. In the first case, the capacity of the well will be underutilized and the value of the unrecognized capacity will be lost, whereas in the second case the well could create excessive injection pressures that require expensive remediation.

There is increasing awareness of the need to understand geomechanical processes during CO_2 storage, and geomechanical models will certainly be an important tool in the design process. Meaningful geomechanical simulations require characterizing the in situ poroelastic parameters of both the injection zone and confining units. Conventional well tests are not sensitive to poroelastic parameters affecting deformation, but including measurements of displacement along with pressure provides a mechanism for characterizing them in situ at scales that are relevant to the storage process.

Measuring and interpreting both pressure and deformation is referred to as a *hydromechanical well test*. The project team has developed techniques for conducting and interpreting hydromechanical well tests in shallow water wells. The field technique involves using a portable downhole tool that is anchored at multiple points along the borehole wall. Displacements are measured between the anchored points while the well is stressed by pumping or injection. The project team has developed this technology over the past eight years, and the current generation of the downhole tool, which they call *Tilt-X*, is capable of resolving displacements of approximately ±5 nanometers (nm), and tilts of ±30 nanoradians (nrad). To their knowledge, this is the only tool currently available that is capable of measuring displacement and tilt simultaneously at the same location with this resolution.

Interpretation of displacement and pressure signals is a key component of hydromechanical well tests. The project team’s approach to interpretation has been to first develop a heuristic understanding of the hydromechanical response through analytical solutions and simulations of idealized cases. This type of evaluation showed, for example, that displacements are a hysteretic function of the injection pressure, so displacements early in a test when pressure (or hydraulic head) change is increasing are always less than they are later, when pressure change is decreasing. This occurs because displacement depends on the distribution of pressure throughout the aquifer or reservoir, not just on the local pressure at the wellbore.

Analysis of data from hydromechanical tests has also shown that the response is affected by several factors, so interpretation is best done using parameter estimation schemes. The current method uses a gradient-based approach to minimize an objective function based on displacements and heads, resulting in reasonably good fits between predicted and observed data in some cases.

The project team’s recent development of a combined extensometer and tiltmeter was responding to a need to measure multiple modes of deformation in order to reduce non-uniqueness in the interpretation. For example, measuring axial displacements alone cannot distinguish between a flat-lying fracture and a dipping one. Including a tilt signal allows both the orientation and the dip of the fracture to be estimated. This strategy can be extended to evaluate other types of formation heterogeneities.

DEFORMATION MONITORING DURING INJECTION

The rate of wellbore deformation will be greatest at the beginning of injection and should decrease with time as the rate of transient pressure changes diminish, providing that the system behaves ideally. However, a variety of non-ideal behaviors will affect the rate and pattern of wellbore deformation, and the project team expects this response could be detected and used as a diagnostic tool. One such behavior is the creation of a pressurized region or a cylindrical hydraulic fracture within the annular space between the casing and the formation. The project team has created this type of annular hydraulic fracture at shallow depths, where it severely deformed polyvinyl chloride (PVC) casing by buckling it inward. The development of this type of hydraulic fracture could lead to upward migration of CO_2 and breaching of the borehole seal.

Another type of problem is the slip along faults caused by elevated fluid pressure. Fault slip is recognized as a potential problem during storage that can be difficult to predict. In many cases, fault slip is expected to be preceded by an increase in strain rate and a localization of the distribution of strain. Both of these effects are contrary to the trend of decreasing strain rates and smoothing of the strain distribution expected during ideal behavior, so they should be readily distinguished from background. As a result, the project team expects that monitoring the distribution and magnitude of wellbore strain rate could provide an important indicator of impending problems during injection.

OTHER APPROACHES FOR MEASURING WELLBORE DEFORMATION

An alternative downhole tool has been developed by a group in France in collaboration with investigators at the Lawrence Berkeley National Laboratory, who are working on a system for measuring multiple components of deformation using fiber optics. They use the acronym HPPP to refer to their device. The HPPP tool consists of a lattice of fiber optic strain gauges, which are arranged to measure normal and shear strains.

The HPPP technology appears to be synergistic to the approach the project team has developed. A lattice of optical fibers has the potential to measure more components of deformation than the team's Tilt-X system (in principle it could measure the entire strain tensor), which would help to refine the description of deformation. However, the resolution of the first-generation HPPP system is expected to be one to several orders of magnitude less than what the project team demonstrated, so it may be unable to detect displacements during tests where pressure changes are low or the formation is particularly stiff. Moreover, the HPPP technology is still under development, whereas the Tilt-X system leverages existing, high-performance technologies and has already been demonstrated in the field.

A modified approach is for the project team to adapt their existing tools for use with fiber optic sensors. An advantage of doing this is that fiber optic sensors require no electronic systems deployed downhole. This has the potential to reduce costs and improve reliability. Another advantage of using their instrument design is that it uses a reference rod that essentially amplifies the sensitivity of the measurement. The amplification scales with the ratio of the reference rod length to the strain gauge length, which is approximately 100. This improvement is likely to be significant when resolving small deformations.

An alternative strategy is to embed strain gauges into the casing itself, rather than using a separate downhole tool. Baker Hughes, the project team's industry partner, is a leader in this technology, and they have recently demonstrated this approach in the field. The technology makes use of Fiber Bragg Gratings (FBG) wrapped around the casing in a helical pattern. Commercially available FBG sensors have a resolution of 10^{-6} axial strain. Wrapping the sensors in a helix enables the resolution of both axial and shear components, although it also reduces resolution. The advantage of the instrumented casing is that it can provide multi-component deformation without the logistical difficulties of a downhole tool. The disadvantage is that it is likely to be lower resolution than the downhole tool; the helical FBG sensors are likely to resolve strain of approximately 10^{-5}, whereas the resolution of the Tilt-X device is less than 10^{-7} in axial strain and tilt.

The project team proposes to develop a technology that will complement ongoing efforts by other investigators. The theoretical analyses that they propose will benefit all of the other groups by improving understanding of the mechanisms and methods of interpreting casing deformation.

BARRIERS TO ADVANCEMENT

Hydromechanical well tests and other applications for wellbore deformation measurements appear to have significant potential applications for CO_2 storage, but the project team recognizes current shortcomings in three critical areas that prevent this approach from moving forward to the prototype field demonstration stage:

1. Wellbore deformation under conditions that could lead to failure has been investigated in detail, but the factors affecting the pattern and magnitude of elastic deformation during well tests in conditions expected for CO_2 storage have yet to be published. These simulations are required to identify the types of behavior that can be detected and the field methods required to measure them.
2. The instrumentation for hydromechanical well tests developed for applications in shallow aquifers must be evaluated and revised for applications under conditions expected for CO_2 storage.
3. Methods of inverting poroelastic analyses have been described, but only routine inverse methods have been used and more robust techniques are required that can accommodate non-uniqueness.

Relationship to Program

This project will support important advances within the geologic storage technologies and simulation and risk assessment pathway of the DOE-NETL Carbon Storage Program. Measuring and interpreting casing deformation should improve the ability to characterize flow and geomechanical properties of injection zones and confining units, and also help identify problems with wellbore integrity that could lead to leakage. This capability will address the following NETL Carbon Storage Program goals:

- Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30%.
- Develop technologies to demonstrate that 99% of injected CO_2 remains in the injection zones.

Primary Project Goal

The primary goal of this project is to evaluate the feasibility of using wellbore deformation as a diagnostic tool to improve CO_2 storage in order to assess the viability of pursuing a field demonstration.

Objectives

The project will consist of three coordinated efforts designed to identify displacements during well tests, develop methods for interpreting displacement signals, and evaluate the instrumentation that could be used to measure those displacements.

SIMULATION

Theoretical analyses will be conducted to evaluate the patterns and magnitudes of deformation that occur in different geologic formations, with different types of heterogeneity, and well completion. Modeling will be used to identify how reservoir conditions influence the pressure and displacement response and to optimize experimental conditions to maximize signal-to-noise ratios.

PARAMETER ESTIMATION

Stochastic methods will be used to assess the uncertainty and uniqueness with which model parameters can be identified for various combinations of pressure and displacement data given different signal-to-noise ratios in the measurements. Sensitivity analyses will then be used to gain insight into how this uncertainty propagates to predictions of reservoir behavior. Monte Carlo methods will allow the project team to quantify the value of the data for predicting critical events related to storage activities, such as reaching the critical stress within a reservoir to induce fault slip or activate leakage through fractures.

INSTRUMENTATION

Theoretical analyses and bench-scale tests on components will be conducted to evaluate the feasibility of adapting existing instruments used for shallow hydromechanical well tests or developing new instruments to conditions required for CO_2 storage. The evaluation will include development and testing of components for displacement and tilt sensors, anchors, registration elements, gauge rods, data acquisition and control, and other aspects. The proposal only stipulated the evaluation of components, but the project team has taken this one step further to evaluate the performance of working prototypes in the field.

04: FE0001922

<table>
<tr><th>Project Number</th><th colspan="3">Project Title</th></tr>
<tr><td>FE0001922</td><td colspan="3">Recovery Act: Characterization of Pliocene and Miocene Formations in the Wilmington Graben, Offshore Los Angeles, for Large Scale Geologic Storage of CO_2</td></tr>
<tr><th>Contacts</th><th>Name</th><th>Organization</th><th>Email</th></tr>
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<tr><td>Partners</td><td colspan="3">City of Los Angeles
California Energy Commission
California State University, Long Beach
U.S. Geological Survey</td></tr>
<tr><th colspan="4">Technology Readiness Levels (Scale 1–9)</th></tr>
<tr><td colspan="2">Current Technology Readiness Level: N/A</td><td colspan="2">End of Project Technology Readiness Level: N/A</td></tr>
</table>

Technical Background

Carbon capture and storage (CCS) technologies offer the potential to reduce carbon dioxide (CO_2) emissions without adversely affecting energy use or hindering economic growth. Deploying these technologies in commercial-scale applications requires adequate geologic formations capable of storing large volumes of CO_2, receiving injected CO_2 at efficient and economic rates, and retaining CO_2 safely over extended periods. Research efforts are currently focused on conventional and unconventional storage formations within depositional environments, which include deltaic, fluvial, alluvial, strandplain, turbidite, eolian, lacustrine, clastic shelf, carbonate shallow shelf, and reef. Research conducted by Terralog Technologies (Terralog) further advances and augments DOE's efforts to develop a national assessment of CO_2 storage resources in deep geologic formations in offshore turbidite settings.

The Terralog project focuses on the Los Angeles Basin, which presents a unique and special combination of high need and significant opportunity for large-scale geologic storage of CO_2. Due to its significant population and its historical and geologic setting as one of the most prolific oil- and gas-producing basins in the United States, the region is home to more than a dozen major power plants and oil refineries that produce more than 5 million metric tons of fossil-fuel-related CO_2 emissions each year. This project develops and assesses comprehensive data of storage formation characteristics (porosity, permeability, reservoir architecture, cap rock integrity, etc.) in a turbidite environment, which is similar to geologic settings for several major sedimentary basins in southern and central California. This project evaluates the potential to safely and permanently store more than 100 million tons of CO_2 in Pliocene and Miocene sediments within the offshore Wilmington Graben.

The City of Los Angeles and the Port of Long Beach both have efforts under way to reduce greenhouse gas emissions while still supporting the business of energy development and port commerce. These efforts include the City of Long Beach *Green Port Policy* and the City of Los Angeles *Green LA Climate Action Plan*. The City of Los Angeles, supported by Terralog, obtained a Class V well construction and injection permit (with California Environmental Quality Act approval) to drill and core new wells in the North Wilmington Graben area, as part of its ongoing *Terminal Island Renewable Energy and Carbon Sequestration Project*. Due to the fact that the property was available and the federal and local permits were already in place, drilling of the DOE #1 well was allowed to proceed immediately to characterize the Pliocene formation for CO_2 storage resources, followed by drilling into the Miocene formation. Existing power plants, refineries, and well-drilling and pipeline infrastructure throughout the harbor area provide a significant practical advantage for the eventual commercial development of large-scale CO_2 storage. Finally, several fields within the Los Angeles Basin have been successfully used for underground storage of natural gas for more than 50 years, providing a local analog and experience base for large-scale injection operations and gas storage.

Relationship to Program

This project will support important advances within the geologic sequestration site characterization pathway of the DOE-NETL Carbon Storage Program. The project team has already accomplished the following:

- Terralog has acquired 175 km of new two-dimensional (2-D) seismic lines and completed drilling of the first characterization well into the Pliocene Repetto formation.
- Rock properties have been obtained from the Pliocene Pico and Repetto formations and used to supplement existing data to develop three-dimensional (3-D) geologic structure maps.
- Both the existing and newly acquired site data have been integrated into a 3-D geologic model (Rockworks), a CO_2 migration model (TOUGH2 [Transport Of Unsaturated Groundwater and Heat]), and a geomechanical model (FLAC3D [Fast Lagrangian Analysis of Continua in Three Dimensions]). These models allow for additional quantification and analysis of storage targets and seals and have the ability to simulate long-term CO_2 injection, migration, and storage.
- A 5-year injection and 50-year CO_2 gas plume migration model for the northern and central portions of the Wilmington Graben have been completed. The CO_2 has migrated 550 m horizontally and 350 m vertically in the northern portion, and 1,100 m horizontally and 400 m vertically in the central portion of the basin. Based on the project team's simulation of various injection rates, they recommend injecting 250,000 metric tons per year of CO_2 per well to ensure that the pressure does not exceed the fracture gradient. The project team further recommends placing the well a minimum distance of 1,000 m (3,280 feet) away from any existing uncemented wells and all other injection wells to avoid extensive CO_2 plume interference.
- The top 20 industrial sources of CO_2 emissions in the Los Angeles Basin have been identified. Furthermore, sinks such as oil and gas fields, saline aquifer reservoirs, and gas storage fields, plus existing oil and gas pipelines, have been identified and digitized. An interactive map is now available online at www.socalCARB.org, where these CO_2 sources, sinks, and potential pipelines can be viewed. This data has also been submitted to the National Carbon Sequestration Database and Geographic Information System (NATCARB).
- Terralog is continuing to target the Miocene Puente formation by drilling, coring, and testing a second characterization well in the western Wilmington Graben area from an offshore platform.
- The integrated 3-D CO_2 migration and geomechanical models will be refined with lithologic properties as new well data are acquired.
- A risk analysis regarding large-scale CO_2 injection into a subaqueous saline aquifer is currently under way. The report will identify specific risks such as induced seismicity and seismic hazards, caprock integrity, lateral CO_2 migration, and existing well leakage paths.

Primary Project Goal

The overall goal of this project is to comprehensively characterize two geologic storage formations (Pliocene and Miocene formations) within the offshore Wilmington Graben and assess the CCS potential around the Los Angeles, California metro area. Preliminary CO_2 storage estimates in the Wilmington Graben exceed 100 million metric tons. Additional objectives include conducting engineering and economic analyses for CO_2 transport from significant sources in the area to the proposed storage site and a detailed risk analysis for large-scale CO_2 storage in this offshore environment.

Objectives

The project objective is to comprehensively characterize Pliocene and Miocene formations within the Wilmington Graben—located offshore of Los Angeles, a high-need area with excellent potential for large-scale CO_2 storage—through a research program that includes the following:

- Evaluation of existing and newly acquired 2-D and 3-D seismic data for the region
- Evaluation of well logs from historical exploration wells in the area, combining data from state water records (within 3 miles of the shore) and federal water records (beyond 3 miles) into a comprehensive geologic database for the area
- Drilling, coring, and testing three new stratigraphic wells within the graben and at the boundary areas (to better delineate fault boundaries)
- Development of a 3-D geologic model for the graben
- Development of a 3-D CO_2 injection flow model to simulate large-scale injection operations
- Development of geomechanical models to estimate displacements and fault activation risks
- Engineering studies of the top 20 industrial sources of CO_2 emissions in the Los Angeles Basin and feasibility and engineering design studies of existing and new pipelines that can be used to transport CO_2 from the most significant sources to the geologic storage site
- Comprehensive evaluation of storage capacity, seals, and risk assessment

05: FE0002068

Project Number	**Project Title**		
FE0002068	Recovery Act: An Evaluation of the Carbon Sequestration Potential of the Cambro-Ordovician Strata of the Illinois and Michigan Basins		
Contacts	**Name**	**Organization**	**Email**
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Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: N/A		End of Project Technology Readiness Level: N/A	

Technical Background

During the Regional Partnership's Characterization Phase, the Midwest Geological Sequestration Consortium (MGSC) and Midwest Regional Carbon Sequestration Partnership (MRCSP) found that the Mt. Simon Sandstone—a significant storage target of the Illinois Basin—is not a uniform blanket of sandstone across much of the Midwest, and that there are areas where the Mt. Simon Sandstone is too deep to be a viable target because of limited porosity and permeability. In areas where the Mt. Simon Sandstone is not a viable resource, the Cambro-Ordovician Strata, which underlies much of the Midwest of the United States, may serve as an alternate storage target. Specifically, the target reservoirs in the Cambro-Ordovician Strata above the Mt. Simon Sandstone are the porous zones within the Knox Supergroup and the St. Peter Sandstone. In addition, the Knox Supergroup and the Maquoketa (Utica) Shale are seals for the Cambro-Ordovician Strata interval and are considered secondary seals for the Mt. Simon Sandstone.

To date, only cursory studies have been conducted on the reservoir zones (sinks) of the carbonate Knox Supergroup, and no field experiments or detailed studies have been conducted on the potential seals, including the Maquoketa Shale. This project aims to evaluate the carbon storage potential of the Cambro-Ordovician Strata of the Illinois and Michigan basins. This research effort is led by the Illinois State Geological Survey in collaboration with the Indiana Geological Survey, Kentucky Geological Survey, Western Michigan University, and Schlumberger Carbon Services. The project will delineate new geologic intervals that could be used for carbon storage, possibly opening new areas for storage in southern Illinois, southern Indiana, Michigan, and western Kentucky. It will also confirm the Knox Supergroup and Maquoketa Shale as secondary seals for the Mt. Simon Sandstone. The results of this study should help reduce storage risk by documenting the uncertainties related to fracturing, injectivity, and geochemical interactions for these specific formations.

Relationship to Program

This project will support important advances within the geologic storage site characterization pathway of the DOE-NETL Carbon Storage Program. At the successful conclusion of this project, the project team expects to delineate potential new geologic intervals for carbon storage in Illinois, Indiana, Michigan, and western Kentucky, which will expand the North American carbon storage resource potential. The evaluation of the Knox and Maquoketa seals will be documented as a best practices manual (BPM) for reducing storage risk that will support the DOE program initiative to develop BPMs for site selection, characterization, site operations, and closure practices.

Primary Project Goal

The primary goal of this project is to highlight areas of high and low risk for carbon dioxide (CO_2) storage in the St. Peter Sandstone and the Knox Supergroup by evaluating the uncertainties related to fracturing, injectivity, and geochemical interactions. Study results will be documented in a BPM for reducing storage risks.

Objectives

This project is evaluating the CO_2 storage potential of the Cambro-Ordovician Strata, St. Peter Sandstone, and the Knox Supergroup in the Illinois and Michigan basins covering the states of Illinois, Indiana, Kentucky, and Michigan. There are very little reservoir and seal data for these two intervals, even though they may have the most significant CO_2 storage resource potential in areas where the Mt. Simon Sandstone is absent or too deep to be a viable target. This project will help determine if the reservoir quality of the Knox Supergroup and St. Peter Sandstone is adequate for CO_2 storage in specific areas of the basin, and if the Knox Supergroup and Maquoketa Shale have potential as confining zones (seals). This project will also help in understanding the risks of fracturing the seals or reservoirs and the interactions between injected CO_2 and the waters and mineralogy of the seals and reservoirs. The primary project objectives include the following:

- Use existing data and core samples from the Decatur Project in Illinois to develop regional maps and cross sections for upload to the National Carbon Sequestration Database and Geographic Information System (NATCARB).
- Perform a small CO_2 injection test in an existing well in Hancock County, Kentucky to evaluate the injectivity of the Knox Sandstone.
- Develop regional CO_2 storage resource estimates for the Knox Supergroup and St. Peter Sandstone for use in future versions of DOE's North American CO2 Storage Resource Atlas.
- Study seals and reservoirs for faulting and fracture risk (geomechanical studies), as well as their interactivity and reactions with CO_2 in the presence of brine (geochemical studies).
- Develop recommendations for data types needed to characterize particular reservoirs.
- Develop a BPM for reducing storage risks that includes geographic information system layers of high- and low-risk areas to upload to NATCARB.

06: FE0001159

Project Number	Project Title		
FE0001159	Advanced Technologies for Monitoring CO_2 Saturation and Pore Pressure in Geologic Formations: Linking the Chemical and Physical Effects to Elastic and Transport Properties		
Contacts	**Name**	**Organization**	**Email**
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Partners	ExxonMobil Corporate Strategic Research Ingrain, Inc.		
Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3	End of Project Technology Readiness Level: 5		

Technical Background

Despite advanced techniques for geophysical imaging of the subsurface, current methods for interpreting in situ carbon dioxide (CO_2) saturation from seismic data can be fundamentally flawed. Until now, Gassmann's equations, which relate pore fluid compressibility and the rock frame to overall rock elastic properties, have been the primary tool for interpreting saturation of CO_2 plumes from time-lapse seismic data. Gassmann's model is purely mechanical, and is best suited for conditions of single-phase fluid saturation in relatively inert systems. Yet, CO_2-rich fluid-rock systems can be chemically reactive, altering the rock frame via dissolution, precipitation, and mineral replacement. Furthermore, CO_2 systems are multiphase, with uncertain phase mixing occurring in the pore spaces. Errors from ignoring the physicochemical factors during CO_2 injection can affect not only the magnitude, but also the sign, of predicted seismic velocity changes, resulting in seriously compromised estimates of saturation and pressure of CO_2-rich fluids.

Previous research in the field of rock physics has led the project team to develop successful strategies for this project. Laboratory methods are well established for measuring ultrasonic properties of rocks under varying states of saturation and pressure. This project extends these methods in a logical but nontrivial way for monitoring—that is, repeated sampling of ultrasonic velocities during injection of brine-CO_2 mixtures at a range of pressures and for a period of several hours. Recently developed imaging methods (high-resolution computed tomography [CT] scans and scanning electron microscopy [SEM]) at the micron and nanometer scales allow samples to be studied and compared before and after exposure to the reactive fluids. Many methods exist for modeling the elastic properties of composites, including rocks. In this project, those methods are being adapted and extended to incorporate changes to rock composition and microstructure as a result of chemically induced changes.

Relationship to Program

This project will support important advances within the monitoring, verification, and accounting (MVA) pathway of the DOE-NETL Carbon Storage Program. The principal goal of the Carbon Storage Program is to gain scientific understanding of carbon storage options and provide cost-effective, environmentally sound monitoring technologies and accounting protocols. The proposed project will provide a better fundamental understanding of the seismic signatures associated to the physicochemical processes occurring upon CO_2 injection, and an essential element for remote probing and tracking of both chemical and physical processes associated with injection of reactive fluids (e.g., CO_2). The project will help DOE meet the program goals of determining formation storage capacity before injection and accounting for greater than 99% of all CO_2 injected into the storage formation.

Primary Project Goal

The primary goal of this project is to provide CO_2-optimized rock-fluid models that will aid in interpreting seismic data for estimation of underground storage capacity before CO_2 injection, and in monitoring CO_2 containment during and after injection.

Objectives

The objective of this research is to provide CO_2-optimized rock-fluid models that incorporate the seismic signatures of saturation scales and free versus dissolved gas in a CO_2-water mixing; pore pressure changes; and CO_2-induced chemical changes to the host rock. This research will involve laboratory and theoretical tasks in the field of rock physics. Measurements of the geochemical properties of the CO_2-rich fluids and their evolution during the acoustic experiments will be performed to link the chemical and the physical changes occurring in the rock samples during the injection. High-resolution SEM and micro-CT scans will image changes to the pore space associated with the injection. Samples will be selected based on mineralogy (carbonates, clean sandstones, shaley-sandstones, and calcite-cemented sandstones), microstructure, porosity, pore type, and permeability to understand the control of these factors on induced changes of seismic velocity. Ultrasonic P- and S-wave velocities will be measured over a range of confining pressures while injecting CO_2 and brine into the samples. Pore fluid pressure and temperature will also be varied and monitored together with porosity during injection. Effective medium models will be developed to help the project team understand the mechanisms and impact of observed changes and to provide the means for implementing the interpretation methodologies in the field.

07: FE0001580

Project Number	Project Title		
FE0001580	Combining Space Geodesy, Seismology, and Geochemistry for Monitoring, Verification and Accounting of CO_2 in Sequestration Sites		
Contacts	**Name**	**Organization**	**Email**
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Partners			
Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 4		End of Project Technology Readiness Level: 6	

Technical Background

Carbon capture and storage (CCS) is an important aspect of the U.S. response to the problem of anthropogenically induced global warming. However, assessing the efficiency, safety, and long-term fate of carbon dioxide (CO_2) pumped into various types of geologic reservoirs remains a challenge. The project team is taking a new systems approach that involves a highly integrated series of techniques and data types that are usually considered independently. This effort is intended to prototype a monitoring, verification, and accounting (MVA) approach that is relatively low cost, involving only surface measurements, that could enable independent academic groups to routinely perform such assessments. Specifically, the project team aims to combine the following:

- Integrated space geodesy (Global Positioning System [GPS]) and Interferometric Synthetic Aperture Radar [InSAR]) to measure surface deformation with unprecedented precision and resolution
- Finite element modeling, to relate surface deformation to volume changes at depth
- New, state-of-the-art algorithms for retrieving the ratio of P- and S-wave velocities (*Vp*, *Vs*) and attenuation from surface seismic data, to monitor fluid motions and porosity changes
- Geochemical models, to assess the fate of stored CO_2 and separate the effects of the formation of new solid reaction products (generally a desired outcome) from leakage or loss of gas or fluid from the reservoir (an undesirable outcome)
- Geochemical sampling, to investigate possible leaks

The project team summarizes the proposed approach below.

SPACE GEODESY: MEASURING SURFACE MOTION TO 1 MILLIMETER PRECISION

The project team has been involved in developing many of the key techniques that lead to mm-scale precision, and in modeling the resulting data. GPS is now capable of providing this level of precision with a time resolution of minutes. However, because this is a point measurement, there is limited spatial resolution. InSAR has equivalent precision in the displacement measurement, but lacks the same level of temporal resolution. However, it does give spatial resolution on the order of tens of meters, which is limited only by the spatial resolution of the satellite image and, therefore, much better than GPS. The project team has developed techniques to combine these two sensor types, allowing the measurement of earth surface displacement with unprecedented accuracy, spatial resolution, and temporal resolution. Changes in reservoir pressure or volume (e.g., due to the pumping of CO_2 or the loss of fluid or gas due to leakage) will cause subtle surface motions that can be monitored by this technique.

DEFORMATION MODELING

Analytical inverse models, assuming elastic rheology, are a straightforward to way to relate measured surface deformation from space geodesy to processes at depth, including the time-varying volume or pressure changes due to CO_2 injection or leakage. A reasonable assumption in such models is that rapid reductions in pressure or volume at depth are more likely due to leakage than to loss of volume to reactions that fix CO_2 in a solid state. However, the analytical models have limitations, especially in the presence of variable rheology (e.g., rigid carbonate rock units versus ductile saline formations), or for reservoir shapes that may be geometrically complex. For such situations, the project team has employed finite element models. Such models have been used successfully in volcano deformation problems, and the CO_2 storage problem is similar in some respects (in both cases, fluid injected at shallow levels causes uplift of the surface; however, in the volcano problem, the fluid source is a deep magma chamber rather than surface pumping). These models are capable of addressing both complex rheology and complex geometry, and will be employed at the selected test site. If appropriate, the project team will incorporate rheological constraints, such as Poisson's ratio, from the seismic study (below) into the finite element model. Depending on the test site details, two-dimensional (2-D) models may be adequate; if not, more computationally intensive three-dimensional (3-D) models can be employed. The essence of this aspect of the problem is to combine the deformation models with the geodetic images to observe whether changes in surface deformation patterns can be interpreted to identify leaks. In such cases, the team might expect to see subsidence in the affected region, or uplift during periods of CO_2 pumping that occurs at a lower rate than adjacent regions.

SEISMOLOGICAL BACKGROUND

Seismologically determined, Poisson's ratio is a powerful tool to complement petrological and geochemical studies of the composition of the Earth, especially for problems related to fluid flow. There is a direct relationship between Poisson's ratio ν, and *Vp/Vs*:

$$V_p / V_s = \sqrt{1 + (1 - 2\nu)^{-1}}$$

Therefore, the ratio of compressional-wave velocity to shear-wave velocity is often used to study the lithology and saturation condition of rocks. Field studies have shown that *Vp/Vs* ratios are more sensitive to changes in fluid type than *Vp* or *Vs* alone, and can be used to identify fluid type (CO_2, water, gas, or oil). In order to track the spatial and temporal variations in *Vp/Vs* ratios that may be caused by the pumping of CO_2 or loss of fluid due to leakage, the project team will focus on the following studies:

1. *Seismic Tomography*. With the development of modern computers and the availability of large amounts of seismic data, tomography has become the most commonly used method for mapping *Vp/Vs* ratios. The conventional *simul2000* and double-difference *tomoDD* tomography programs, as well as other similar approaches, have been successfully applied to the determination and interpretation of *Vp/Vs* structure in a number of studies. The recent *tomoADD* algorithm has the advantage of combining absolute times and differential times to resolve the velocity structure near the source region. In the study, the project team will apply this approach to develop high-resolution, 3-D seismic velocity models to solve for variations in *Vp*, *Vs*, and *Vp/Vs* ratios. The seismology group at the University of Miami has experience with seismic tomography at different

scales, including the shallow depths of the greater Los Angeles Basin, the crust of southern California, and the crust and upper mantle of the entire state of California.

2. *In Situ Vp/Vs Ratio*. In arrival-time tomography, *Vp/Vs* models are often affected by the different quality and quantity of P- and S-wave data. The resulting *Vp/Vs* models can display fluctuations that are unrelated to the true structure. Recently, Dr. Guoqing Lin developed and tested a high-resolution *Vp/Vs* estimation method by using differential times from waveform cross-correlation. This method offers several useful advantages. First, it provides highly precise results, as cross-correlation can measure differential times to within a few milliseconds and achieve a precision of 0.001 in an estimated *Vp/Vs* ratio, which corresponds to about 0.0004 in Poisson's ratio. This method is also simple to implement and fast to execute because it uses a robust least-squares to fit the differential times. Another advantage of this method is that it will provide the project team with a straightforward way to study spatial and temporal variations of *Vp/Vs* ratios, as it will enable them to simply select a subset of events by space and/or time. This would be difficult to achieve with other seismic techniques, such as tomography, because of the difficulties of obtaining reliable *Vp/Vs* models and the non-uniqueness of the problem. Together, high-resolution *Vp/Vs* ratios from this method and 3-D velocity structures are likely to provide significant details of fluid variation. The project team believes that the technique has the sensitivity to detect CO_2 migration and image major leaks at storage sites. A key part of the proposed research is to test and verify this hypothesis.

GEOCHEMICAL CHARACTERIZATION OF RESERVOIR ROCKS AND REACTIONS

At each site, the geochemistry/mineralogy of the reservoir rock will be determined in order to assess potential reactions between CO_2 and host rocks and fluids. Based on the availability of such data, additional geochemical/mineralogical measurements will be made as necessary. The University of Miami has all available equipment, including x-ray diffraction, inductively coupled plasma-mass spectrometry (ICP-MS), and stable isotope mass spectrometry equipment. The project team will assess the potential of such reactions using standard software, such as Geochemist Workbench.

GAS CHARACTERIZATION

The potential escape of gas during storage will be monitored using a remote CO_2 monitoring system, which will be deployed at a number of locations around the storage site. These systems will be capable of being monitored remotely and will provide a minute-by-minute record of changes in CO_2 concentration. Where appropriate, they will be colocated with the GPS and seismic equipment to share resources, such as power, communications, and security fencing. Once changes in CO_2 are identified, a more precise origin of the CO_2 can be ascertained by measuring its carbon isotopic composition. Fossil-fuel-derived CO_2 has a characteristic carbon isotopic signature (-25 to -30 per mille [‰]) relative to normal atmospheric CO_2 (-7‰ to -8‰). While there are other processes that can also produce the negative carbon isotopic signature, such as respiration of organic material, large increases in the concentration of CO_2—in association with pronounced negative carbon isotopes over prolonged periods—would confirm escape of the stored gas.

The geochemical sensors necessary to make these measurements are all based on readily available commercial technology. The field-stable isotope measurements will be determined using laser absorption spectrometry. There are two commercial systems available at the present time, each with slightly different modes of operation. Both systems are capable of stand-alone operation and continuous sampling of the isotope ratio of carbon. For budgetary purposes, the project team used the Picarro instrument. The team will determine the precise system that will be purchased after a more thorough examination of performance features. Flask samples of gases, measured on a conventional mass spectrometer, will be used to check the precision and accuracy of the field spectrometer.

During the course of the project team's investigation, they will investigate the feasibility of a coupled finite element model, linking the geodetic, seismic, and geochemical aspects in a formal way. At the present time, these are separate endeavors, linked together with an ad hoc approach.

Relationship to Program

This project will support important advances within the MVA pathway of the DOE-NETL Carbon Storage Program. The project team believes that their approach will be straightforward to implement at any future CO_2 storage site for several reasons. The team uses commercially available data and sensors, and they see no difficulty in continued use of Synthetic Aperture Radar (SAR) as a reconnaissance tool for this class of Earth observation, as there are several satellites currently in operation and more planned for launch over the next decade. In addition, the overall approach is passive. No active seismic sources or geochemical tracer injection are required; therefore, permitting should be straightforward at virtually any proposed future site. Lastly, the approach is relatively low cost, requiring only the installation of a sparse network of ground sensors. The use of reconnaissance-level satellite data as the first step in the monitoring approach simplifies the necessary wide-area inspection that is considered prudent in this class of problem (the possibility of long-distance migration of CO_2 fluids needs to be considered prior to deployment of dense ground sensor networks).

Primary Project Goal

The project team's primary goal is to integrate these reconnaissance-scale space techniques with more detailed seismic and geochemical techniques and to demonstrate them at a specific test site, which has been selected and instrumented since October 2011. Using data from this site, the project team aims to accomplish the following:

1. Assess whether the geodetic techniques are able to identify, in a reconnaissance sense, the fate of injected CO_2.
2. Provide more detailed knowledge of the fate of CO_2 gas or fluid using deformation models, advanced passive seismic imaging techniques, and geochemical models. This includes investigating the geochemical background on reaction process kinetics to allow improved interpretation of the geodetic and seismic data in terms of the fluxes and fates of CO_2. For example, if subsidence is observed, does this necessarily imply leakage, or could chemical processes be occurring that react CO_2 with ambient fluid or solid phases, producing new, lower-volume phases with consequent reductions in reservoir pressure? (Note: the project team is aware that most reaction processes are believed to be quite slow in comparison to fluid mobility and the likely time scale of possible leaks.)
3. Geochemically monitor the site to directly assess possible leakage.

Objectives

The project team aims to develop and prove an integrated, low-cost methodology for assessing the fate of CO_2 pumped into various classes of geologic reservoirs. The project team will integrate data from space geodesy, seismology, and geochemistry in a straightforward series of procedures and algorithms and assess the cost and efficacy of these procedures for long-term tracking of CO_2 and its reaction products by demonstrating their approach at an active CO_2 injection site.

08: FE0004962

Project Number	Project Title		
FE0004962	Inexpensive Monitoring and Uncertainty Assessment of CO_2 Plume Migration		
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Partners			
Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 5	

Technical Background

A key difficulty in accurately predicting the carbon dioxide (CO_2) plume migration path in the subsurface is the uncertainty in the underlying geology. To resolve that uncertainty, the observed flow response of the subsurface system can be used to optimally constrain models of the subsurface. This optimization problem is familiar, but the project team proposes a new perspective of particular relevance to CO_2 storage: rather than estimating properties of the storage formation, the project team seeks to infer the location of the plume of injected CO_2 within that formation. In particular, the project team aims to be able to identify deviations of the plume from its anticipated migration path, as these deviations can have substantial regulatory ramifications. A primary cause of such deviations is heterogeneities in the storage formation (e.g., baffles, sealing faults, and high permeability streaks), as the existence or exact locations of these heterogeneities are not known at the beginning of injection. This situation should be regarded as the default case because the cost of acquiring extensive measurements of storage formation properties is not trivial. A unique model-selection algorithm will be implemented that uses the injection data to select a subset of initial aquifer models that best adhere to observed injection characteristics. In other words, instead of seeking a single, best model, the project team seeks only a group of models, each member of which could account for the injection data. A particular benefit of this approach is that the simulation of plume displacement in this reduced subset of models yields the uncertainty in the plume location.

Numerous researchers have tried to address the issue of conditioning geologic models to dynamic flow response over the years. This problem is especially challenging due to the nonlinear relationship between the measured flow response data and the model parameters (e.g., porosity and permeability). The probability perturbation method does not suffer from multi-Gaussian restrictions that affect several other iterative methods for conditioning subsurface models to dynamic data. In this method, the problem of synthesizing a geologic model is cast in probabilistic terms as the sampling of permeability models from the conditional distribution P(A|B,C), where B is the prior geological information and available well data, C is the available dynamic data, and A is the simulated event (i.e., permeability). That conditional probability is computed using the elemental distributions P(A|B) and P(A|C) and using the permanence-of-ratio hypothesis. The probability that the permeability at a particular location in the reservoir or aquifer falls within a particular permeability category, P(A|C), is derived as a function of a dynamic parameter. This dynamic parameter is iteratively optimized until a global match to the historic data is achieved. This approach was implemented in a software Pro-HMS (Probabilistic History Matching Software) that was developed as part of an earlier DOE-funded project. The project team summarizes the drawbacks with the probability perturbation approaches to history matching as follows:

- The calibration of P(A|C) is too entwined with the process of sampling from the merged probability P(A|B,C). In other words, the calibrated P(A|B,C) is affected by the random path used to simulate P(A|B) and hence P(A|B,C). In fact, one would argue that what is calibrated at the end is not the probability P(A|C) but the probability P(model transitioning to a new state | C).
- Because P(A|C) does not result at the end, estimating the residual uncertainty after history matching requires starting the process all over again from a new realization of the permeability field.
- It is very difficult to account for uncertainty in the prior geological model within the process.

In the current project, the project team is pursuing an entirely new concept: working directly in the realization space of the random function (RF) model. The departure from existing technologies is explained most succinctly in terms of the conditional probability expression P(A|B) discussed earlier. In traditional approaches, the A in P(A|B) is interpreted at a pixel level (e.g., permeability at a location *u* in the formation), and the B refers to the available data (e.g., measurements of permeability in cores from wells). In this new approach, A will be a model realization of the RF (i.e., it will be all the pixels taken jointly). Thus, P(A|B) will be the conditional probability of a model given the measurements. This is qualitatively different from the probability that permeability at a particular location has a certain value, given the measurements. Similarly, P(A|C) is the probability of a model given the injection data C.

A crucial advantage of this concept for monitoring CO_2 plumes is that it provides a natural and convenient way to quantify uncertainty. A quantitative estimate of uncertainty is in turn valuable for monitoring and managing a storage operation. In essence, an operator or a regulator can make a more informed decision (e.g., choosing to commission a seismic survey to better resolve plume boundaries, do nothing, or deliberately change injection rates on selected wells to better illuminate a potential feature) if the estimated plume location is accompanied by a self-consistent assessment of uncertainty inherent in that estimate.

The uncertainty estimate derives from a choice of perspective: to seek a group of models consistent with injection data, rather than a single best model. The parameter estimation procedure merges the measurements at wells B (when available) and the injection data C to yield P(A|B,C), i.e., the probability of a model A given B and C. Drawing from this P(A|B,C) yields a model A that conforms to the available data to the extent dictated by the probability value P. If the distribution P(A|B,C) exhibits a peaked structure, the available data cause some models to be preferred over others. On the other hand, a uniform distribution P(A|B,C) indicates that the available data do not provide any basis for preferring one set of models over another. That is, all the models in the set are equally good (or equally bad) at accounting for the injection data. The history matching (injection data integration) approach therefore becomes an exercise in selecting the most plausible model(s) guided by the available data.

Implementing this paradigm for model selection requires the steps detailed below.

DISTANCES BETWEEN MODELS

In this new framework, the project team starts with a whole suite of plausible models for the particular subsurface system being studied. This set of prior models could be rather large and widely varying, reflecting uncertainty in depositional environments, aquifer architecture, etc. This is likely to be the situation at the outset of many geologic storage projects, and an advantage of the project team's model selection approach is that it is particularly well suited for a disparate group of initial models. This suite of prior models will be processed through a fast-transfer function model such as a streamline simulator, a particle-tracking algorithm, or any other proxy that can assess the flow connectivity of the models. A proxy is preferred over a full-physics simulation because the purpose is merely to discriminate between models in the suite, not to find a single, best model. A fast proxy is desirable because the number of prior models can be very large. Based on the response of the proxy function on the prior models, the project team can calculate a distance matrix [d_{ij}] where the distances d_{ij} are defined as the distance between the i^{th} and j^{th} prior models.

MODEL CLASSIFICATION

Application of multivariate classification techniques such as multidimensional scaling, principal component analysis (PCA), and k-mean cluster analysis on the distance matrix would yield a grouping of aquifer models in terms of similarity of the proxy function response. The project team emphasizes that this grouping procedure might result in geological models representing different environments/architecture getting grouped together. This would indicate that despite the overt differences in geology between the models, those models nevertheless exhibit similar connectivity characteristics, and those characteristics have predominant influence on the observed injection data. This feature will also be exploited below to provide a quantitative estimate of uncertainty in the plume location.

MODEL SELECTION

Based on the distances between the models that make up a group or cluster found in the preceding step, an average realization representative of the cluster can be computed by performing distance-weighted averaging of the realizations making up the cluster. Alternatively, any of the models in a cluster could be retrieved as a representative model for that cluster. Flow simulations with the full physics of the flow of CO_2 in the aquifer can be performed on the representative model for each cluster. Given the observed injection history, the mismatch between the model response and the actual observed response can be calculated. Assuming a Gaussian probability distribution for the mismatch, with the mean as observed response and the variance computed using all the model responses, the project team can calculate the probability that any model in a cluster would match the observed data. Using this likelihood function and the prior probability of the response, the posterior probability of a cluster given the observed response can be calculated using Bayes's rule. Based on these posterior probabilities, a particular model cluster can be selected.

ITERATIVE RESELECTION

After one application of the above process, a cluster of models, each of which exhibits similar dynamic characteristics to the observed response, has been found. It is quite likely that a one-time application of this process would not yield a satisfactory match to the observed injection history. Consequently, the process is repeated using the member models that make up the selected cluster. Multivariate classification (i.e., cluster analysis or PCA) is performed in order to further subdivide the members of the selected group. Repeated application of the process therefore further refines the selection of the model that is closest to the observed injection history.

Relationship to Program

This project will support important advances within the geologic storage technologies and simulation and risk assessment pathway of the DOE-NETL Carbon Storage Program. The project will increase the fundamental understanding of processes associated with CO_2 injection in geologic reservoirs by demonstrating a quantitative link between inexpensive, routinely measured injection data and large-scale features of CO_2 plume migration. Because the uncertainty of the link is also quantified, this approach can improve operational management practices at much lower cost than other monitoring technologies. For example, one significant benefit will be low-cost “early warning” of unanticipated plume movement. The warning can be used to make better informed decisions about the need for more costly but higher-resolution monitoring (e.g., commissioning a seismic survey). It thus addresses the primary objective of the DOE-NETL Carbon Storage Program: technologies to cost-effectively store and monitor CO_2 in geologic formations.

Primary Project Goal

The overall objective of this project is to develop a new computational approach for monitoring the location of CO_2 during injection. The approach being pursued has two notable advantages: it is very inexpensive and it quantifies the uncertainty in the plume location. It thus addresses a high-priority, near-term goal of the DOE-NETL Carbon Storage Program (i.e., to develop monitoring, verification, and accounting [MVA] protocols that enable 99% of stored CO_2 to be credited as net emissions reductions) and the medium-term program goal of improved algorithms for enhanced monitoring of CO_2 injected into deep formations. The project directly responds to a key research objective of Area of Interest 1, namely improved quantification of monitoring technologies at low cost.

Objectives

The objectives of the main research tasks include the following:

(i) Develop a new technique for providing a probabilistic assessment of plume migration based on the Bayesian approach for geological model selection using injection data and other information.
(ii) Develop modular software that can be readily integrated with existing flow simulators and with frameworks for MVA activities.
(iii) Demonstrate the approach on field datasets.

The model selection method being developed as part of this project mainly includes four steps: (1) assessing the connectivity/dynamic characteristics of a large prior ensemble of models, (2) model clustering using multidimensional scaling coupled with k-mean clustering, (3) model selection using the Bayes's rule in the reduced model space, and (4) model expansion using iterative resampling of the posterior models. The fourth step expresses one of the advantages of the method: it provides a built-in means of quantifying the uncertainty in predictions made with the selected models. By expanding the posterior space of models, the final ensemble of representations of geological models can be used to assess the uncertainty in predicting the future displacement of the CO_2 plume. The following sections report on the approach and the progress made to date in each of these aspects.

DETERMINE TYPE AND RANGE OF DETECTABLE HETEROGENEITIES

Prior to implementing any method for uncertainty assessment of plume location in the subsurface aquifer using injection rate data, it is necessary to systematically study the impact, if any, of geologic heterogeneities on the well injection profiles. The project team conducted this testing on a two-dimensional (2-D) synthetic aquifer model set up in the GEM (Generalized Equation-of-State Model) software by Computer Modeling Group and tuned to the physics of the CO_2–brine system. The aquifer model consists of a 100 x 100 (50 ft x 50 ft x 12.5 ft) grid with four wells injecting at similar rate schedules, to which Gaussian noise was added. The reference permeability field in the storage formation is heterogeneous, with high permeability streaks. Permeability in the reference field ranges from 1 millidarcy (mD) to 600 mD, with the high permeability streaks having a value of 10,000 mD. Four wells regularly spaced at the center of the formation inject CO_2 according to a prescribed rate schedule. The rate schedule is subject to a maximum bottom-hole injection pressure constraint of 7,500 pounds-force per square inch absolute (psia) in order to avoid fracturing the formation. The depth of the top of the aquifer is

10,000 ft, with the initial reservoir pressure calculated using the hydrostatic gradient for water (0.433 psi/ft). Very large pore volume multipliers of 30,000 have been used for the boundary blocks to simulate infinite acting boundary conditions.

In these simulations, viscous forces due to the heterogeneous permeability field significantly affect the displacement of the CO_2 plume. CO_2 flows preferentially toward the highly permeable areas, causing the unexpected deviation from the originally predicted plume**.** CO_2 injection was simulated for a period of 720 days, and injection pressure was monitored at each well every 20 days. In order to assess the effect of the high permeability streaks on the well injection pressure, the forward model was run, both including the high permeability streaks and without them. Comparison of the injection pressure computed using permeability fields with and without high permeability streaks shows that the well that is most affected is Injector-3, which has a streak passing nearby. The presence of the high permeability reduces the injection pressure significantly. On the other hand, the effect of streaks near Injectors 1, 2, and 4 is diminished because they are relatively far from the well and CO_2 has to flow through a low-permeable zone before reaching the streaks. This implies that the presence of heterogeneities close to Injector 1, 2, and 4 would be difficult using either a conventional history matching process or the model selection process.

The project team studied several other cases with reservoir models corresponding to different depositional environments and different types of heterogeneity (e.g., streaks and baffles) and concluded that, in general, the injection data carries important information about the connectivity characteristics of the reservoir, especially in the vicinity of wells.

DEVELOP FAST TRANSFER FUNCTION MODEL

Particle Tracking

The usual approach for comparing the injection behavior of all the available reservoir models to the history is to run a full-physics flow simulation on each. This is, however, computationally expensive. An alternative is to simulate a process that is a proxy for the flow physics but does not require solving detailed pressure/saturation equations. The use of a proxy is appropriate in the model selection algorithm because the project team seeks only to discriminate between groups of models. An accurate solution for any (or every) model is unnecessary.

The project team has commenced development of a particle-tracking algorithm to approximate the flow response through the reservoir models. The algorithm injects particles into an injection site (injection well grid block) in a model of the reservoir, and tracks the subsequent movement of particles through the model. The movement of a particle from any grid block to any of the adjacent grid blocks is dictated by a calculation of the transition probability from that grid block. The movement is random in that the actual transition from a grid block is based on a random sampling of the transition probability distribution for that grid block. The transition probability is dependent on the following factors:

1. Difference in particle count between the current and neighboring grid blocks—the greater the difference, the higher the probability of transition
2. Average permeability between the current grid block and the neighboring grid block
3. Number of particles in the neighboring (target) grid block, i.e., when the particle count in the target grid block is equal to the maximum, the probability of transition to that grid block is zero
4. Local pressure gradient, which could be either due to a regional gradient (e.g., due to gravity) or global or local boundary conditions that indicate the presence of an injector or a non-flowing well

Once a particle is injected, it is followed through all its subsequent transitions until it reaches a location from where it cannot move. Then, the next particle is introduced at the injection grid block and the process is repeated. Once all the models have been run, a quantity analogous to pressure is calculated from the final particle distribution in each model. The pressure analog in any cell depends on the distance of the cell from all other non-empty cells in the system and the particle count in those cells. Several walker statistics can be retained for further analysis. These could include the following: (1) average value of pressure, (2) maximum value of pressure, and (3) time at which maximum pressure is reached. Some of these statistics might exhibit a strong degree of correlation with one another. While additional physical characteristics such as capillarity and diffusion cause a gentle transition in gas saturation at the margins of the plume in the full-physics simulation, the overall spatial extent of the plume and the direction of migration are very consistent with the results of the particle-tracking simulation.

A Statistical Proxy for Connectivity

An essential aspect of the model selection algorithm is to group prior models on the basis of their connectivity. The base algorithm assesses that connectivity using a physical proxy such as particle tracking. An alternate approach would be to develop statistical tools for assessing connectivity of models. The project team introduces the notion of a connected path to describe spatial connectivity of reservoir models. Because the injected fluid flows along the permeable zone, the connected path is defined as the most permeable path between an injection point and a target point (which could be a hypothetical monitoring location located so as to delineate reservoir connectivity).

Based on the notion of the shortest connected path, a procedure for clustering models on the basis of the shape of connectivity was devised. In the first step, points of interest (e.g., well locations or points along the boundary) are determined. In the second step, the connected paths, which are the most permeable paths from the start point to the target point, are computed. In the third step, the connected paths are simplified to reduce the computational cost of measuring dissimilarity of the paths. The project team uses the Ramer-Douglas-Peucker algorithm to simplify the connected paths. In the fourth step, similarity between the connected paths is measured using the discrete Fréchet distance. The Fréchet distance is dissimilarity between two curves, and the discrete Fréchet distance is a discrete variation of the Fréchet distance. The measure of curve similarity should account for rotation, scale, and location because spatial connectivity is sensitive to them. The discrete Fréchet distance is rotation variant, scale variant, and location variant, and so it is ideal for measuring similarity of connected paths. The definition of the Fréchet distance is as follows:

$$\delta_{\mathrm{F}}(f,g) = \min \left[\max_{\mathrm{t}\in[0,1]} \left\{ \mathrm{d}\left(f\left(\alpha(\mathrm{t})\right), g\left(\beta(\mathrm{t})\right) \right) \right\} \right]$$

The main objective of the model-grouping step is to discriminate between reservoir models based on their injection characteristics in order to facilitate the process of reducing the prior set to a posterior set that reflects the injection data observed in the field. Consequently, it is necessary to implement a model classification procedure that utilizes particle-tracking results that reflect the flow connectivity of the aquifer.

As mentioned previously, these responses are highly correlated with one another, and so eigen-value decomposition of the covariance matrix is necessary. After performing PCA, the models are plotted on a space with the leading eigenvectors used as the principal axes. The models in this space form clusters that can now be analyzed using a classification tool such as cluster analysis.

Multidimensional Scaling

Multidimensional scaling is a set of data analysis methods that are usually used to explore the similarities or dissimilarities between models by visualization. In this approach, the dissimilarity distance is first defined. The distance matrix can then be built representing the dissimilarity of ensemble permeability realizations. This original distance matrix may be non-metric. In other words, when these responses are plotted on a Cartesian plot, points that are close to each other may not necessarily imply closeness of the underlying models. By applying the multidimensional scaling method, the original model responses (and associated distances) are projected to an equivalent metric space. In this transformed space, closer points mean similar response behaviors, which might imply similar geological structures and vice versa. A 2-D synthetic example is used to test the capability of the classical multidimensional scaling method. The model is discretized into 100 by 80, with all no-flow boundaries.

MODEL SELECTION

The representative model for each cluster of reservoir models has to encompass the different geological features of all the models within the cluster. The project team uses a weighted averaging process, where the weight given to a model is inversely proportional to the distance of the model from the cluster centroid. This serves to highlight the features that are common to most of the models while averaging out the features that are present only in some models but not common to the cluster. These representative models (one for each cluster) are then run through a full-flow simulator in order to compare them to the field history.

Bayesian Calculation of Posterior Probabilities

Once the representative models are run through the flow simulator, they have to be compared to the actual field history to find the cluster whose response is most similar to the field history, which will contain the models whose geology is closest to actual reservoir geology. The quantitative calculation starts with the assumption that at any given time, the mismatch of response of the different models from the history follows a Gaussian distribution, with the mean of the distribution given by the field data and the standard deviation given by the difference of the simulation response from the history. Using these values of mean and standard deviation, it is possible to calculate the probability that any model in the cluster *m* would match the observed data: $p(RF_{ref} \mid RF^m)$, where RF^m is the response calculated on the representative model. The probability of a cluster given the field history $p(RF^m \mid RF_{ref})$ can then be calculated using Bayes's rule as discussed earlier.

Once the probability of each cluster is calculated, the models in the cluster with the highest probability are identified. It is quite likely that a single application of the above described process will not yield a satisfactory match to the field history. Consequently, the process is repeated using the smaller set of models identified at the end of the previous step. The process iteratively narrows in on a smaller set of models that have responses closest to the field history. The process is terminated when the clusters become almost equiprobable or when the number of models in the cluster becomes too small, resulting in a refined cluster of models that are closest to the field history and also have consistent geological features.

APPLICATION TO A FIELD EXAMPLE

The project team uses reservoir data from the In Salah Gas Project. The reservoir model consists of three layers (8m, 4m, 8m) that have 50 x 50 (400m x 530m) blocks in each layer. The model has three phases: natural gas, water, and CO_2. The reservoir is operated with one gas producer and three CO_2 injectors. Porosity and permeability are generated with geostatistical techniques such as sequential Gaussian simulation, sequential indicator simulation, and multiple point simulation to test various geological models.

The models are assumed to have high permeability streaks**.** Porosity models are generated with sequential Gaussian simulation, and absolute permeability models are obtained conditioned to the porosity models using Gaussian cosimulation. Porosity and absolute permeability follow a normal distribution with mean 0.15 and standard deviation 0.07, a log normal distribution with mean 3 and standard deviation 1, respectively. Porosity and absolute permeability of the streaks follow a normal distribution with a mean of 0.3 and standard deviation of 0.01, a log normal distribution with a mean of 7.60 and standard deviation of 0.5, respectively.

09: DE-FE0004832

Project Number	Project Title		
DE-FE0004832	Maximization of Permanent Trapping of CO_2 and Co-Contaminants in the Highest-Porosity Formations of the Rock Springs Uplift (Southwest Wyoming): Experimentation and Multi-Scale Modeling		
Contacts	**Name**	**Organization**	**Email**
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Partners	Purdue University Southern Illinois University		
Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 5	

Technical Background

In this project, a multidisciplinary team of researchers at the University of Wyoming is combining state-of-the-art experimental studies, numerical pore- and reservoir-scale modeling, and high-performance computing to investigate various large-scale storage schemes with the goal of maximizing the permanent trapping of supercritical carbon dioxide ($scCO_2$) and mixed $scCO_2$ in the reservoir formations of Rock Springs Uplift (RSU) in southwestern Wyoming. The team is combining reservoir-conditions core-flooding experiments and physically-based core-scale pore network modeling techniques to improve the current understanding of mixed $scCO_2$ trapping mechanisms. This knowledge will inform reservoir-scale simulations that use detailed and realistic geologic models of RSU formations in order to identify schemes that maximize permanent trapping of mixed $scCO_2$ released from Wyoming coal power plants.

The research includes investigations in three fundamental areas:

(i) The experimental determination of two-phase flow; relative permeability functions; relative permeability hysteresis; and residual saturations under reservoir conditions for mixed $scCO_2$-brine systems

(ii) Improved understanding of permanent trapping mechanisms

(iii) Scientifically correct, fine-grid numerical simulations of the injection of mixed $scCO_2$ and reservoir brine into deep saline aquifers, taking into account the underlying rock heterogeneity leading to improved storage performance and storage estimates.

An existing, unique, experimental facility is used to perform core-flooding experiments. An existing University of Wyoming team multiscale parallel simulator is further developed to make accurate predictions for large-scale operations using the new National Science Foundation-funded supercomputer of the University of Wyoming National Center for Atmospheric Research partnership that is currently being installed in Wyoming. The improved high-performance simulation tool will allow for more accurate predictions of geomechanical deformation of storage formations and equilibrium calculations for mixed $scCO_2$, water, and salt. This simulator plays a crucial role in conducting uncertainty quantification using geological models within a recently developed statistical, Bayesian-type prediction framework. Testing in this project will be designed to provide criteria for optimal storage and permanent trapping.

Relationship to Program

This project will support important advances within the geologic storage technologies and simulation and risk assessment pathway of the DOE-NETL Carbon Storage Program. The research project is focused on performing reservoir conditions experiments to measure steady-state relative permeabilities, residual saturations, interfacial tensions, and contact angles. These experiments will inform models at pore, core, and reservoir scales, which can then be used to improve understanding of displacement mechanisms and design strategies that maximize capillary trapping.

Primary Project Goal

The overall goal of this project is to provide information that will assist in maximizing the permanent trapping of $scCO_2$ and co-contaminants (referred to as "mixed $scCO_2$") in the reservoir formations of the RSU.

Objectives

The specific objectives of the project include the following:

- Measure reservoir conditions drainage and imbibition relative permeabilities, irreducible brine, and residual mixed $scCO_2$ saturations and relative permeability scanning curves (hysteresis).
- Characterize wettability through measurements of contact angles and interfacial tensions under reservoir conditions.
- Develop a physically based dynamic core-scale pore network model. The model will read input contact angle and interfacial tension data also measured in this project.
- Develop new, improved high-performance modules for the University of Wyoming team simulator to provide new capabilities to the existing model in order to include hysteresis in the relative permeability functions, geomechanical deformation, and an equilibrium calculation (for mixed $scCO_2$).
- Validate the reservoir model against well-characterized, unsteady-state core-flooding experiments with mixed $scCO_2$ and brine.
- Conduct an optimization analysis of long-term permanent trapping of mixed $scCO_2$ through high-resolution numerical experiments, taking into account reservoir heterogeneity, saturation history, dissolution, capillary trapping, geomechanical deformation, well location, and injection pattern.

10: FE0004956

Project Number	Project Title		
FE0004956	Influence of Local Capillary Trapping on Containment System Effectiveness		
Contacts	**Name**	**Organization**	**Email**
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Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 4	

Technical Background

In preliminary studies that account for capillary heterogeneity in the storage formation, the amount of carbon dioxide (CO_2) that could escape from a structural trap is smaller—sometimes much smaller—than when a single capillary pressure curve is assumed. This phenomenon, referred to as “local capillary trapping,” has significant implications for estimates of permanence of storage. This project will enable a rigorous assessment of the amount of CO_2 that could escape through a compromised overlying seal. It addresses the technical need for improved understanding of CO_2 trapping mechanisms leading to improved storage permanence. The capability developed in this project will help quantify containment system effectiveness, thereby addressing a challenge in the geologic storage focus area of the DOE-NETL Carbon Storage Program.

Local capillary trapping is a consequence of three interacting phenomena: immiscible displacement of brine by CO_2, buoyancy-driven fluid phase movement, and heterogeneity of transport properties of the storage formation. Because CO_2 is the nonwetting phase, it must overcome the capillary entry pressure to enter a volume of rock. Because buoyancy forces are of similar magnitude to interfacial forces in typical formations, a region of relatively large capillary entry pressure can easily redirect a rising plume of CO_2. Because all formations are heterogeneous at multiple length scales, variation in capillary properties at small scales leads to highly ramified structures emerging as the CO_2 rises.

These structures have been shown *not* to be a consequence of the inherent instability of a buoyant displacement. The redirection of the rising CO_2 plume is analogous to the “fill and spill” process that leads to accumulations of buoyant fluid in sedimentary rocks, the only difference being the lateral extent of the accumulation. Local capillary trapping is also analogous to the well-documented pooling behavior of a dense nonaqueous phase liquid plume sinking in an aquifer, the only difference being the direction of the buoyancy force.

The novel concept in this project is local capillary trapping, which occurs during buoyancy-driven migration of CO_2 within a saline aquifer. For example, after placement of CO_2 into the lower portion of an aquifer, the rising CO_2 plume accumulates beneath regions of larger-than-average capillary entry pressure. The CO_2 also accumulates in a nonuniform manner beneath the seal that overlies the storage formation. This form of storage differs from structural trapping in that much of the accumulated saturation may not escape, even if the integrity of the overlying seal were to become compromised. It differs from residual trapping in that the accumulated saturation can be much larger than the residual saturation for the rock.

The basis of the technical approach is that a storage formation has a characteristic, spatially correlated distribution of transport properties that depends on its geologic history. The correlation yields structures within the formation that become local capillary traps for buoyant fluid. This project will develop techniques to identify and predict these structures, given a geostatistical description of the formation. The project team then uses numerical simulation to quantify the likely extent to which local traps will fill with stored CO_2. Their previous work shows that locally trapped CO_2 may not escape even if the overlying seal fails, so finally they also simulate the aftermath of a worst-case loss of containment for the storage formation. This project also develops a protocol for laboratory evaluation of this trapping concept.

Relationship to Program

This project will support important advances within the geologic storage and simulation and risk assessment pathway of the DOE-NETL Carbon Storage Program. Enabling operators to design a storage scheme with less risk of losing containment will reduce the overall cost of geologic storage. Moreover, public acceptance of large-scale storage will be strongly influenced by the perceived permanence of storage. By establishing a more rigorous foundation for an additional mode of CO_2 immobilization, this project will buttress the case that CO_2 can be stored safely. Making this case continues to be a critical sociopolitical hurdle for implementing geologic storage. Because local capillary trapping persists even if the seal above the storage formation loses integrity, this work will be particularly useful in developing realistic leakage scenarios for stakeholders and regulators.

Primary Project Goal

The overall goal of this project is to determine the extent of local capillary trapping (i.e., CO_2 immobilization beneath small-scale capillary barriers) that can be expected in typical heterogeneous storage formations.

Objectives

To accomplish the overall project goal, the project task objectives include the following:

I. Characterize the petrophysical and geologic controls upon the number and volume of potential local capillary traps.
II. Determine the degree to which potential local capillary traps are filled in anticipated storage schemes.
III. Quantify the extent of immobilization persisting after loss of integrity of the overlying seal of the storage formation.
IV. Incorporate the results into a functional form that can be readily integrated into existing reservoir simulation packages.
V. Conduct laboratory-scale experiments to validate simulations.

The work plan to achieve these objectives involves two phases. In Phase 1, the project team will systematically determine the petrophysical and geologic controls on potential trapping structures. The first step is to characterize the structure of potential local capillary traps in a storage formation, given some measures of its heterogeneity. The project team will gather correlations between key formation properties from the literature and gather a suite of geostatistical models typical of likely target formations. They will then construct a set of model storage formations to be used for subsequent investigation and identify potential local capillary traps in the models from maps of their capillary entry pressures. Using this method to identify potential traps, the project team will then study the influence of the geologic setting (e.g., dip angle, maximum height of CO_2 column) on potential trapping structures. Simultaneously with the simulation work, they will establish a protocol for conducting buoyancy-driven immiscible displacements in heterogeneous, bench-scale porous media. They will conduct experiments to validate predictions of buoyant phase accumulation beneath local capillary barriers.

In Phase 2, the project team will quantify and upscale local capillary trapping. They will conduct experiments in which the overlying seal is breached, allowing validation of predictions of buoyant phase escape from local traps. They will determine the influence of operating conditions on local trap filling, i.e., which of the potential traps identified in Phase 1 actually get filled with CO_2. The project team will first examine the limiting case of buoyancy-dominated displacement on filling, and then simulate filling when CO_2 emplacement occurs at a range of gravity numbers, corresponding to a range of injection rates. They will repeat these simulations with different amounts of CO_2 emplaced. Having established the extent of trap filling, the project team will quantify the extent of trapping persisting after the overlying seal fails and develop a coarse-scale representation of local trapping.

The technical uncertainties in this plan are twofold. First, it may prove difficult to obtain a suitable “work-alike” model that captures the fine-scale features of local capillary trapping. The fallback position in this case will be to catalog the range of trapping observed in the simulations, so that community can at least estimate the range of likely leakage amounts from a failed structural trap. Second, fine-scale simulations that include all the necessary physics (hysteretic relative permeability and capillary pressure curves that may be different in every grid element) are computationally intensive. This could limit the range of values of formation parameters explored in the sensitivity study. Thus, the project team will prioritize the set of parameters so that those anticipated to have the greatest effect will be examined first. The correlation length of the permeability field appears to be the most important parameter so far. Meanwhile, the project team has also developed an alternative “geologic method” of identifying local capillary traps, as described below.

The project team has made progress on the Phase 1 objectives and also has preliminary results for some Phase 2 objectives. One key finding so far is that computational constraints (the central processing unit [CPU] time required to carry out simulations of buoyancy-driven displacement that account for capillary heterogeneity) have proved significant. The team has consequently devoted time to developing alternative methods to assess the extent of local capillary trapping. The current algorithm works directly from the geologic model and is very effective at finding barriers. Moreover, the algorithm, which is based on the dominancy of capillary forces in the post-injection period in a CO_2 storage project, runs in seconds on models that require days for a full physics simulation. A critical entry pressure distribution is shown to be able to give acceptable estimations of a CO_2 displacement path and the resulting local capillary trapping during the post-injection period. For finding local capillary traps, the mean entry pressure predicts unrealistically large amounts of local capillary trapping. Therefore, a value smaller than the mean entry pressure is a better choice of critical entry pressure. For a suitable choice of critical entry pressure, the local traps occupied during flow simulations are almost entirely a subset of the local traps identified by the algorithm. In other words, regions the algorithm identifies as barriers also act as barriers in the simulation. However, not all the traps identified by the algorithm get filled with CO_2. Thus, the algorithm provides an upper bound on the possible extent of local capillary trapping. Therefore, the important step of selection of the critical entry pressure corresponding to a domain is a key subject of further study.

Prior to exploring the effect of heterogeneity, a series of experiments was conducted to examine the effects of grain size and fluid viscosity ratio on buoyancy-driven displacements. These baseline experiments used a homogeneous porous medium (2 ft x 2 ft x 0.04 ft) with countercurrent flow (more dense phase sinks as less dense phase rises). In addition to demonstrating the applicability of a tailored fluid/fluid pair (brine/mineral oil-decane mixture) that serves as an analog to supercritical CO_2 and brine, the experiment exhibited a form of pore-scale viscous fingering, as the CO_2 analog fluid phase rose through only a few preferential flow paths. Experiments with fluid/fluid pairs with matched viscosities and with large displacing fluid viscosity showed more compact displacement patterns characteristic of drainage and invasion percolation. These observations will be useful in interpreting the nature of buoyancy-driven displacements in the heterogeneous materials, which are the focus of this research.

The baseline experiments provided another key finding, namely that the original apparatus, which is hydrophobic, is not ideal for this study. The process of producing large quantities of hydrophobic grains (sand or glass beads) proved time-consuming and unreliable. Thus, the project team has redesigned the apparatus and the analog fluid pairs to work with hydrophilic materials. Construction and commissioning of this version of the apparatus is under way.

11: FE0004566

Project Number	**Project Title**		
FE0004566	Prototype and Testing a New Volumetric Curvature Tool for Modeling Reservoir Compartments and Leakage Pathways in the Arbuckle Saline Aquifer: Reducing Uncertainty in CO_2 Storage and Permanence		
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Partners	MV Partners LLC		
Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 4	

Technical Background

This project directly tests seismically derived volumetric curvature (VC) attributes as a tool for predicting lateral and vertical reservoir boundaries in Arbuckle paleokarst strata in Kansas. A horizontal test boring will be drilled and logged through a VC-identified paleokarst compartment within the Arbuckle saline aquifer. The Arbuckle is a promising candidate for commercial-scale, geologic carbon storage. Ongoing DOE-sponsored carbon storage projects in Kansas include regional characterization of the Arbuckle saline aquifer and a small-scale carbon dioxide (CO_2) injection pilot at Wellington Field in Sumner County, Kansas. Attributes derived from seismic VC processing routines quantify how reflectors within a seismic volume are bent or flexed in three dimensions. VC attributes have been used to infer faults, fracture swarms, fracture sets, flexures, sags, and paleokarst—all of which are present within the Arbuckle Group. However, to date, no project has directly validated what these attributes represent, whether they accurately image a feature, or whether they are acquisition or processing artifacts. A horizontal test boring was drilled through a VC-interpreted, fault-bounded paleokarst doline. Triple combo, borehole micro-imager, and full-wave sonic logging tools were tool-pushed through the ~1,800 ft test boring. Results from the formation evaluation validate the VC-based interpretation. VC can provide a cost-effective tool for addressing the following critical challenges identified in DOE Focus Area 2: (1) presence or absence of reservoir compartments at a site selected for carbon storage; (2) delineation of compartment size; (3) lateral and vertical extent of compartments; (4) CO_2 transmissibility across compartment boundaries; (5) CO_2 storage capacity of large compartments; (6) better estimation of plume containment/permanence; and (7) presence or absence of correlation between fracture/fault trends in basement and surface with those inferred from VC analysis.

Relationship to Program

This project will support important advances within the geologic storage technologies and simulation and risk assessment pathway of the DOE-NETL Carbon Storage Program. Anticipated benefits include the following:

1. A cost-effective method to identify large compartments
2. Realistic determination of tonnage of CO_2 that can be stored in a compartment
3. Realistic determination of CO_2 plume migration and permanency
4. Determination of leakage through faulted multi-storied karst deposits to identify high-risk areas for carbon storage

5. Possible use of less expensive satellite imagery and gravity/magnetic data to identify leakage pathways

Primary Project Goal

The primary goal of this project is to test the efficacy of the VC mapping tool for accurately imaging paleokarst compartments within the Arbuckle saline aquifer by means of a throughgoing horizontal test boring combined with an extensive tool-push logging program.

Objectives

Phase 1 (Year 1) project objectives are to collect geologic and engineering data, reprocess seismic data, conduct VC analysis, initiate Petrel geologic modeling, and simulate and history-match performance of existing wells to verify VC-identified compartments. Field activities include drilling, logging, and testing the horizontal lateral. Phase 2 (Year 2) objectives are to complete formation evaluation, re-interpret seismic data, optimize VC, and model seismic attributes, followed by integration of seismic, VC analysis, and well data into a comprehensive geomodel. Phase 3 (Year 3) objectives include simulation studies to model CO_2 storage and plume movement (dispersal, leakage at compartment boundary, and attenuation over time), and thereby determine the effectiveness of VC as a tool to better estimate carbon storage capacity and permanence in karst-compartmentalized saline aquifers.

GENERALIZED MILESTONES

Task-oriented milestones include the following:

1. Identify pre-spud Arbuckle paleokarst, fracture sets, and fault-bounded compartments and their vertical extent using VC attributes derived from three-dimensional (3-D) seismic data (Milestones 1.1–1.2).
2. Test initial VC-identified compartment boundaries by history-matching well performance of existing wells (Milestones 1.3).
3. Drill and log a ~1,500 ft horizontal test boring through paleokarst and fault zones interpreted from VC attributes (Milestone 1.4).
4. Run formation evaluation tools (triple combo, full-wave sonic, borehole micro-imager) to collect data on boundary architecture and petrophysics (Milestone 1.4).
5. Compare pre-spud interpretation of compartmentalization with the results from the drilling and logging program to directly confirm or refute the presence of compartment boundaries, and if present, characterize their vertical and lateral extent, and flow properties (Milestones 2.1–2.4).
6. Model and simulate carbon storage capacity and containment within and across boundaries (Milestones 3.1–3.3).

PROJECT PROGRESS TO DATE

Results from the project are valuable and unparalleled, consisting of a number of technically challenging industry firsts. This is the first pre-stack depth-migrated (PSDM) 3-D seismic volume for a Kansas reservoir and likely the first VC-processed PSDM volume worldwide. The DOE-sponsored McCord-A 20H is an industry first for an extended-reach Arbuckle/Ellenburger lateral targeting paleokarst. The extensive logging program provides a rare data set to better characterize lateral paleokarst heterogeneity.

This project is a collaboration between the Kansas Geological Survey and its industry partners MVP LLC (a partnership between Murfin Drilling Company and Vess Oil Corporation) and Noble Energy. The project study area is located in southeastern Bemis-Shutts Field (Ellis County, Kansas). Data use/confidentiality agreements for project research activities were obtained from all relevant seismic survey owners. Two seismic surveys were merged and reprocessed. This merged 3-D seismic volume covers approximately 12 square miles. About 280 hard copy wireline logs from wells in the study area were scanned and converted to LAS (Log ASCII Standard) format. Individual well production histories were acquired from the operators. Remote sensing and gravity/magnetic interpretations over the study area have been completed.

Horizons were mapped in the pre-stack time-migrated (PSTM) volume and these horizons were then used to calculate interval velocities for the PSDM seismic volume. The reprocessed PSDM seismic volume shows stratigraphic sagging within the Arbuckle and coincident thickening and upward flattening of the overlying pre-Heebner section, which is consistent with compaction-induced, growth-strata deposited above paleocaverns or paleodolines. Volumetric curvature attributes were processed for both the PSTM and PSDM seismic volumes. Twelve PSDM VC-attribute maps were generated by GeoTexture. Prior to VC-processing, the PSDM seismic volume was re-sampled using principal component analysis (PCA) at four different lateral scaling factors: (1) raw, (2) basic, (3) enhanced, and (4) robust. These four seismic volumes were then processed for volumetric curvature at three different lateral, seismic-trace resolutions: high (~50 ft), medium (~150 ft), and low (~500 ft).

The PSDM basic PCA, mid-wavelength, VC-attribute map correlated best with paleokarst features observed in the PSDM seismic volume. A drilling location was selected that had the best chance of meeting the project objectives. A fault-bounded (1,100 ft diameter), paleokarst sag (i.e., doline) was inferred from a VC anomaly and the PSDM seismic volume. The near-vertical, bounding faults appear basement-rooted and tip-out in the Chase Group. Strata overlying the Chase Group exhibit growth folds consistent with syndepositional compaction above fault tips. A horizontal borehole was planned that would cross the first bounding fault (strike: 052º) at 4,250 ft measured depth (MD), penetrate ~1,100 ft of paleokarst breccias, and exit the westernmost, near-vertical, bounding fault (strike: 000º) at 5,350 ft MD. This proposed location was approved per Decision Point 1 (Go/No-Go).

The surface location of the horizontal test boring (McCord-A 20H) is within the McCord Lease, Bemis-Shutts Field in Ellis County, Kansas (Township 11 South, Range 17, Section 26). The borehole was officially permitted for drilling by the Kansas Corporation Commission Oil & Gas Conservation Division. Because of excessive lost-in-hole costs and tool insurance for the rotary sidewall coring tool and pressure tester, the operator (MV Partners) and principal investigators decided against running these tools after conferring with DOE. A revised cost estimate for drilling and logging was prepared by MV Partners for the location. Their cost estimate was slightly less than the original budget as outlined in the award. As such, the project progressed past Decision Point 2 (Go/No-Go). The drilling rig moved in and rigged up on November 1, 2011, and the bore-hole was spud the following day. The drilling rig was on location for 24 days.

Anticipated formation tops were encountered close to the prognosis. The Arbuckle was encountered just 4 ft (true vertical depth [TVD]) below the PSDM-mapped horizon. The borehole penetrated 2,190 ft of Arbuckle with a 2,100 ft reach. The lateral borehole crossed the full extent of the fault-bounded paleokarst doline with preliminary formation evaluation results showing clearly defined intervals of paleokarst breccias, fractures, faults, and unaffected host strata consistent with the pre-spud VC interpretation. Poor borehole conditions within the Arbuckle were anticipated prior to spudding. However, there were only minor seepage losses during the drilling operation, which permitted excellent borehole conditions for log acquisition. The triple combo (gamma ray [GR]-neutron density-resistivity), full-wave sonic, and micro-imager logging tool were successfully conveyed on drill-pipe and their data quality is excellent. Log data is much better than anticipated and provides an ideal data set for detailed formation evaluation, paleokarst characterization, and compartmentalization studies.

A pre-spud, numerical simulation model was created to evaluate flux between fault/fracture blocks. The simulation model focused on the fault block including or adjacent to the planned

McCord-A 20H. The model has been validated as a predictive tool by history-matching individual well production history. The leases in the study area have been on production from 1937, but the principal validation is based on well tests and historical water cut performance over the period September 1990 through December 2011. The history match is not a unique solution. Several suitable matches were derived under different values for the uncertainty parameters. The next phase of these models will be to analyze the effect of uncertainty on the flux between fault blocks using revised geocellular models based upon results from the McCord-A 20H formation evaluation.

Structural interpretation of the McCord-A 20H image log is ongoing. Structural heterogeneities identifiable in the image log consist of fault or paleokarst breccias, clay-filled faults, solution-enlarged vugs, and faults/fractures having disparate apertures and orientations. Work on the revised fault model is ongoing. The project team is investigating whether Petrel's seismic-based automatic fault extraction can identify faults/fractures consistent with the validated VC interpretation. Different seismic pre-processing routines have been carried out ranging from variance, vertical smoothing, chaos, and ant-tracking. Such processed volumes are then used by automatic fault extraction to quickly identify potential faults. In budget period 2, the project team will: (1) acquire fluid samples from boreholes offsetting the McCord-A 20H; (2) integrate 3-D property trends derived seismic attributes; (3) finalize the facies model; (4) complete image log interpretation; and (5) conduct simulation-based sensitivity studies.

12: FE0004630

Project Number	Project Title		
FE0004630	Validation of Models Simulating Capillary and Dissolution Trapping During Injection and Post-Injection of CO_2 in Heterogeneous Geological Formations Using Data from Intermediate Scale Test Systems		
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Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 4	

Technical Background

The geological carbon storage (GCS) technology being addressed will enable the efficient injection and stable placement of supercritical carbon dioxide ($scCO_2$) in deep saline geologic formations. Both micro- and macro-scale physicochemical processes and geologic heterogeneities control trapping, mineralization, and migration of fluid phases in the water-brine saturated zones of the subsurface formation. Although the goal of a successful storage strategy is to make the trapping permanent, there is potential for the lighter-than-water supercritical liquid, or water containing dissolved CO_2, to leak to the shallower formations. The basic processes associated with CO_2 placement, migration, and leakage are complex; therefore, a fundamental and comprehensive understanding of these processes is required to estimate the capacity for CO_2 storage and understand and assess environmental and ecological risks associated with leakage. The focus of this research is on the trapping of the $scCO_2$ within heterogeneous soils due to capillary effects and dissolution.

When the non-wetting fluid ($scCO_2$) displaces the wetting fluid (saline water), the two fluids occupying the pore space form a multiphase system, where capillary effects resulting from the interfacial forces—in addition to gravitational and externally applied pressure-generated forces—contribute to flow. When the driving forces balance with the capillary forces, the non-wetting phase gets immobilized and the $scCO_2$ gets trapped. The factors that contribute to this trapping have been extensively studied in applications in petroleum engineering and in subsurface remediation fields. In reservoir engineering, the goal is to maximize the oil extraction by removing the entrapped non-wetting fluid (oil). In environmental applications, where the entrapped non-aqueous phase liquids (NAPL; e.g., solvents and petroleum products) dissolve into the flowing groundwater, effective remediation involves the maximum removal of entrapped fluids. Understanding how $scCO_2$ gets trapped in the subsurface is different from understanding petroleum and remediation applications, as effective storage involves maximizing the non-wetting fluid ($scCO_2$) entrapment. Geologic heterogeneity, which contributes to a reduction in extraction efficiencies of both hydrocarbons and entrapped contaminants, could be used in some settings to enhance the stable entrapment of $scCO_2$. Therefore, the scientific basis of the research conducted in this project is built on filling knowledge gaps related to how heterogeneity at all scales, from pore to large regional scales, affects entrapment.

Geologic heterogeneity also affects the effectiveness of dissolution trapping, which results from the entrapped CO_2 dissolving into the saline water, staying in the solution, and then diffusing into low-permeability zones. The problem of mass transfer from entrapped chemical sources in the form of NAPL has been extensively studied in the subsurface remediation field. However, there are some differences in the fundamental behavior of how dissolved CO_2 behaves compared to solvents, which will require further investigation before being incorporated into models. For example, $scCO_2$ that is lighter than water will float on the denser saline water, but dissolved CO_2 that is heavier will migrate downward. How the geologic heterogeneity affects both the dissolution and mixing needs to be better understood. Trapping at the core scale (or column scale, where the basic processes are studied and parameterized) is reasonably well understood and empirically modeled for relatively homogenous systems. However, critical knowledge gaps exist regarding how these processes manifest themselves under conditions of ubiquitous field heterogeneities. It is important to fill these gaps in order to effectively estimate or predict trapping capacities of field systems. Therefore, the project team is conducting a set of laboratory experiments in multiscale porous media test systems to further analyze CO_2 trapping mechanisms. The experimental data that is generated will be used to improve the conceptual understanding of how the natural heterogeneity of the geologic formations, manifested at all scales, affects both capillary and dissolution trapping. The improved conceptual understanding and accurate data will be used to develop and validate models that will allow for more accurate predictions of CO_2 fate and transport under various injection and post-injection scenarios, and will provide more realistic estimates of storage capacities and efficiencies under representative field conditions. The project team is not aware of any existing modeling tools that have been validated or tested for their ability to accurately capture the CO_2-brine-water flow patterns and entrapment mechanisms in porous media, specifically under heterogeneous conditions.

The uniqueness of the project derives from the research approach that is used, which combines multiscale physical modeling with numerical models. The test scales vary from small columns and two-dimensional test cells (several cm scale) to intermediate scale and large test tanks (from ~1 m up to 5 m in length). The intermediate- and large-scale tanks will be packed with well-characterized soils to quantify the parameters of various configurations of heterogeneity, to observe the dynamic processes and patterns of CO_2 trapping, and to uniquely link the observed trapped CO_2 with heterogeneity patterns. The premise used in developing the approach is that basic processes of CO_2 trapping are not easily understood and quantified through field testing, primarily because heterogeneity cannot be fully characterized in field settings of deep formations. Phenomena and processes inferred through traditional monitoring methods cannot be uniquely attributed to certain causes because of the interplay of multiple scales of heterogeneity, uncertain initial conditions, and time-dependent boundary conditions (e.g., injection rates). In contrast, the m-scale tank tests offer an opportunity to understand the effect of relatively large-scale heterogeneity on CO_2 trapping, which is more relevant to field operating conditions than cm-scale laboratory tests on rock cores. Another unique feature of the experimental approach is that the proposed experiments are conducted under ambient conditions in the laboratory, using surrogate fluids in place of $scCO_2$ and using dimensionless analysis to extrapolate the results to field conditions.

Relationship to Program

This project will support important advances within the geologic storage technologies and simulation and risk assessment pathway of the DOE-NETL Carbon Storage Program. The work that is performed in the project is covered in the Funding Opportunity Number DE-FE0000250 under "Development of Innovative and Advanced Technologies for Geologic Storage" under area of interest "Area of Interest 1– Applied Science and Engineering Studies for Proof-of-Feasibility." Projects supported by the FOA address Focus Area (2), Geologic Storage, in the Core R&D portfolio.

The findings of this project will meet the Carbon Storage Program's primary research objective to develop technologies that cost-effectively and safely store and monitor CO_2 in geologic formations and ensure storage permanence. Improved understanding of the fundamental processes that control trapping will enable the development and validation of models and field upscaling methods that will lead to cost-effective, safe geologic storage in deep saline aquifers, while storage permanence can only be assured through stable entrapment that reduces the possibility of leakage. DOE's goals are to predict geologic storage capacity to within +/-30% and permanence of geologic storage up to 99%.

Primary Project Goal

The primary project goal is to investigate how the trapping mechanisms are affected by formation heterogeneity at different scales and injection rates, with the ultimate goal of contributing toward improving numerical tools and upscaling methods to design injection strategies, estimate storage capacities and efficiency, and conduct performance assessment for stable storage. The developed numerical tools are expected to help in optimizing trapping (e.g., capillary, dissolution, and low permeability zones).

Objectives

The primary project objective is to use intermediate-scale testing in large laboratory tanks to investigate mechanisms of capillary and dissolution trapping that are affected by heterogeneity. The data generated will be used to improve conceptual understanding and develop and validate models and upscaling methods that will enable the more accurate prediction of CO_2 fate and transport in deep geologic saline formations.

In order to meet the stated objectives, the project team is performing the following tasks:

1. Generate a comprehensive data set in intermediate-scale test tanks simulating multiphase flow to investigate how effective capillary trapping at the field scale is affected by the texture transitions and variability in heterogeneous field formations.
2. Generate a comprehensive data set in intermediate-scale test tanks simulating the dissolution of partially miscible fluids to investigate how effective dissolution trapping at the field scale is affected by heterogeneity-driven preferential flow and cross-intra-layer mixing.
3. Conduct modeling efforts that include simulations of various scenarios to evaluate whether the existing modeling codes can accurately capture processes observed in the test tanks. This effort will lead to the development of upscaling methods for larger-scale applications.

Given the complexity of the problem, a comprehensive understanding of the CO_2 storage and entrapment problem is only possible through multistage analysis comprising experimental and modeling studies. The project team is investigating capillary and dissolution trapping by conducting and analyzing a series of controlled experiments. The key processes involved include viscous fingering of free-phase CO_2 along high-permeability (or high-potassium [K]) fast-flow pathways; dynamic intrusion of CO_2 from high-K zones into low-K zones by capillarity and buoyancy; diffusive transport of dissolved CO_2 into low-K zones across large interface areas; and density-driven convective mass transfer into CO_2-free regions.

The research is conducted under three tasks, including material selection and characterization; experimental study and modeling of flow and capillary trapping; and experimental study and modeling of dissolution trapping. The approach, methods, progress made, and results associated with each of these tasks are presented below.

(1) MATERIAL SELECTION AND CHARACTERIZATION

Surrogate Fluids for Trapping Experiments

The approach that is used relies on the use of fluids and soils that will be used in tanks to conduct experiments under ambient laboratory conditions. Although it is possible to create subsurface ambient temperatures in the laboratory, it is difficult to create the high pressures needed to keep the CO_2 in supercritical liquid form. Therefore, the goal of this sub-task was to select surrogate fluids that have the same scalable density, viscosity contrasts and interfacial tension, and solubility properties as a supercritical CO_2-brine-water mixture in deep formations. The selection of surrogate fluids was guided through the use of dimensionless groups such as bond number, capillary number, viscosity ratio, density ratio and Damköhler number. As the typical ranges of values of these groups for deep reservoir formation conditions are known, the findings could then be used to extrapolate the results to field systems. Soltrol 220, an insoluble NAPL, was used as the non-wetting fluid (analog of $scCO_2$) and various mass fractions of a glycerol/water mixture were used as the wetting fluid (analog of saline water). For example, with one mixture it was possible to achieve a viscosity ratio of 0.074 (field range ~0.05–0.2) and a density ratio of 0.66 (field range ~0.2–0.8).

Multiphase Flow Constitutive Models

The multiphase system parameters that are needed for modeling are the retention functions (capillary pressure vs. saturation) and relative permeability as a function of saturation. In traditional multiphase model applications (e.g., reservoir simulations), constitutive models of these parameters are determined through flow tests (e.g., pressure plate) using soil/rock cores extracted from the field. The retention functions are measured using either the fluids from the field or test fluids, and then used to generate the relative permeability functions using methods that have been reported extensively in the literature. In obtaining the constitutive models and the associated parameters, the CO_2 storage modeling problem produces two major challenges. The first is to obtain these model parameters; under ambient laboratory conditions it is not possible to use $scCO_2$ as the non-wetting fluid. Therefore, special test equipment and complex experimental methods must be used to create the pressure and temperature conditions that exist in deep formations in order to keep the CO_2 in supercritical liquid form. The second challenge is that the project team's model analysis shows that the traditional methods used to estimate the relative permeability functions are unable to predict the observed plume behavior. The goal of this sub-task was to develop scaling methods to obtain the retention functions of $scCO_2$ using surrogate fluids and to obtain the relative permeability functions independently of the retention functions. This research is currently in progress, and the project team has validated the applicability of a method, referred to as Leveret scaling, to use the ratios of the comparatively easily measurable interfacial tensions to obtain the retention functions using surrogate fluid pairs. The project team has also developed a method that uses a sensor-instrumented long column to obtain the relative permeability function independently of the retention function, which has helped to the project team obtain the relative permeability functions for both drainage and imbibition. The modeling results show that hysteresis effects that occur during drainage and imbibition have to be incorporated into the constitutive models.

Surrogate Fluids for Dissolution Experiments

The goal of this sub-task is to identify test fluids for use in the dissolution trapping experiments. A set of dissolution experiments was conducted in a small, two-dimensional (2-D) cell to test the solubility and the behavior of the resulting solutions in order to find a binary system of fluids that dissolve into each other slowly enough and create a dissolve plume that is denser than its separate components, triggering convection and enhancing the dissolution at the same time. It is widely known that density instabilities are likely to form once CO_2 dissolves into brine, leading to convective mixing and enhancing the effective dissolution process. An important issue that needs to be addressed is the related, fairly distinct time scales involved in the two-phase flow problem during injection, which takes decades, and the effective rates of large-scale dissolution of CO_2 into brine, which takes place hundreds of years after the injection has stopped. Selecting test fluids to capture these processes within laboratory time scales will be a challenge.

As the processes being investigated involve fingering, experiments were conducted in 2-D test cells. Two different fluid mixtures were tested to represent the dissolution of scCO2 in brine as well as the subsequent changes in density, as brine gradually becomes heavier as the amount of the dissolved CO_2 increases. The mixtures included the following:

- Methanol and glycerol/water mixture: Pure methanol as the non-wetting fluid, and 72% glycerol and 28% water as the wetting fluid
- Water and propylene glycol mixture: Pure water as the non-wetting fluid, and pure propylene glycol as the wetting fluid

Three test sands that are used in large tank experiments—30/40 mesh, 40/50 mesh, and 50/70 mesh (high permeability to low permeability)—were tested with the fluid combinations. The results show that it will be possible to use the methanol/glycerol mixture for the large tank dissolution experiments. The project team has also tested the hypothesis that unstable density-driven convection is not important in heterogeneous systems. The second fluid combination was able to simulate desired behavior, but the analytical methods used to determine concentrations were found to be complex, and the use of pure propylene glycol as a wetting fluid is not practical in large tanks due to cost and safety constraints.

(2) EXPERIMENTS AND MODELING OF CAPILLARY TRAPPING

The experiments under this task were designed to analyze the capillary trapping process and injection rate for different formation types and to test the applicability of the capillary entrapment models, excluding the effect of mass transfer processes. The experiments were conducted in both small and large tanks. The experimental plan relied on the project team's past experience and the extension of multiphase flow experiments (light non-aqueous phase liquids [LNAPL], dense non-aqueous phase liquids [DNAPL], and gas migration) conducted at various scales to the problem of CO_2 trapping. The project team used a fully equipped porous media test bed facility, developed at the Center for Experimental Study of Subsurface Environmental Processes at the Colorado School of Mines, to conduct the testing. The general approach for the capillary trapping experiments involved injecting the dyed surrogate non-wetting fluid into tanks packed with both homogeneous and heterogeneous configurations. The goal is to generate data sets that will allow the project team to understand how natural formation heterogeneity affects trapping efficiency and validate models and methods to upscale to field problems. Experiments were conducted in small test cell, dimensions 28 x 15 cm; intermediate scale, dimensions 92 x 60 cm; and a large tank, dimensions 4.9 x 1.2 m. After the injection, the migration of the surrogate CO_2 was tracked using time-lapse digital images and an automated x-ray attenuation system that measures the fluid saturations. Following the experiments and after the surrogate fluid was stably entrapped, samples were taken by removing frozen cores from different spatial locations in the tank. The surrogate CO_2 (Soltrol) was then chemically extracted to determine final entrapment saturations. A total of 12 experiments have been conducted in the intermediate-scale tank and three have been conducted in the large tanks.

The following three codes were used to solve the multiphase flow equations in the modeling task: a multi-phase, multi-component simulator, T2VOC, which is based on TOUGH2 (Transport Of Unsaturated Groundwater and Heat) and developed at Lawrence Berkeley National Laboratory; COMSOL, a multiphysics simulator; and a new code developed specifically for this project. The new, in-house multiphase flow solution code based on the finite volume method was developed because it is much easier to modify in a short time, compared to modifying TOUGH2/T2VOC for incorporating additional mechanisms (e.g., different constitutive relationships with hysteresis, non-equilibrium mass transfer). The new numerical code will be used to simulate the two-phase flow of the surrogate fluids in 2-D laboratory test tanks. The model has been used to evaluate trapping processes of the surrogate fluids to form a guidance for packing for the tank experiments and identify additional important mechanisms (e.g., different constitutive models with hysteresis, non-equilibrium mass transfer) that need to be incorporated into field-scale modeling tools (e.g., TOUGH2). Any critically important mechanism that the project team finds will be in turn incorporated into DOE's TOUGH2 family of codes, which will be used in field-scale applications. The project team also developed other numerical codes to analyze a degree of connectivity quantitatively for different heterogeneous systems based on an invasion percolation algorithm. This connectivity-based code allows them to classify different generalizations of a heterogeneous field and to better understand the large-scale capillary trapping due to facies changes. This code will serve as a basis approach in this project to develop upscaling approaches for the migration and trapping of injected CO_2 in large-scale geological systems.

The progress made under this task on modeling and the preliminary findings are summarized below:

- The numerical models (e.g., the project team's new code, TOUGH2) based on the classical two-phase flow theory were able to capture the main features observed during the migration of Soltrol, such as fast flow through coarse soil and coarse sand, and filling of the gravel at the right boundary.
- The traditional two-phase flow approach cannot capture the individual formation of viscous fingers observed during some of the experiments; however, the project team can predict the effective properties in the system by appropriate upscaling and development of constitutive models.
- Comparing homogeneous and heterogeneous systems during post-injection periods reveals that intermediate-scale heterogeneity (the existence of lower and higher permeability zones) enhances the capillary trapping under the laboratory test conditions.
- Based on the modeling, the project team concluded that the mass of Soltrol (surrogate $scCO_2$) retained in a control volume (e.g., a representative portion of the reservoir) as a result of capillary forces strongly depended on how the higher-permeability zones are connected in the formation.
- The presence of highly connected higher-permeability paths reduces the amount of non-wetting fluid mass retained by capillarity in the control volume during the post-injection periods.
- Selection of appropriate non-wetting phase relative permeability is critical to accurately predict dynamic changes in Soltrol distribution and post-injection capillary entrapment.
- Hysteresis effect must be included in the numerical models for accurate prediction of trapped, non-wetting phase distribution during the post-injection period.
- Recognizing the importance of hysteresis and connectivity, a new hysteretic constitutive model was developed that uses pore-size distribution and a probability distribution for connectivity among differently sized pores to compute the hysteretic capillary pressure-saturation curves. This model shows that the residual non-wetting fluid saturation during the imbibitions (post-injection period) increases with the initial non-wetting fluid saturation (at the end of injection) up to a value of the initial saturation, and then stays almost constant as the initial saturation increases further. This is a consistent result with the experimental data.

(3) EXPERIMENTS AND MODELING OF DISSOLUTION TRAPPING

The experiments and modeling performed under this task specifically focused on how the entrapped $scCO_2$ dissolves into the moving saline water, the diffusive transport of dissolved CO_2

into low-permeability zones across large interface areas in the heterogeneous formation, and density-driven convective mass transfer into CO_2-free regions. The approach used again involves the use of multiscale test systems and numerical modeling. The experiments that have been conducted to date have been in small test tanks. These experiments were used in selecting the surrogate fluids, testing a hypothesis on the effects of heterogeneity on density-driven convective mixing, and conducting initial model validation and development.

Several homogeneous small-tank dissolution experiments were performed using the second fluid mixture. Dissolution process was observed for three different sand sizes—30/40 mesh, 40/50 mesh, and 50/70 mesh—and sand packing configurations of all three experiments were the same. In these experiments, the same amount of dyed water was injected into the source zone and the dissolution of water in propylene glycol was observed. A heterogeneous media dissolution experiment was also carried out using the second fluid mixture, including an inclined interface between the two sands; the upper layer was 40/50 mesh sand and the lower layer was 50/70 mesh sand. The same amount of dyed water was injected as in the homogeneous experiments.

The project team has noted that density-driven convective mixing may not be important for some of heterogeneous media. This hypothesis was tested by calculating Rayleigh (Ra) numbers for each layer, which indicate whether mass transfer is diffusion dominated or convection dominated. The critical value for Ra number is 4π^2 (~40). Results show that Ra value calculated for coarse sand (20/30 mesh) is above the critical level (~67); however, for fine layers, Ra values are below the critical level as ~6 for 50 mesh, and ~15 for 40/50 mesh. This means that, in fine sands, the dissolution process is dominated by diffusion rather than convection. This hypothesis will be tested in a larger tank using different heterogeneous packing configurations.

A numerical model of the small-tank dissolution experiment was developed using COMSOL Multiphysics Software based on the finite element numerical solution method. The model involves mass conservation equations for the wetting and non-wetting fluids, as well as advection-diffusion-reaction equations for the dissolved components in the wetting fluid. The non-wetting fluid injected into the source zone is assumed to be immobile. Dissolution of the scCO_2 analog fluid in the brine analog was assumed to occur with a first-order mass transfer between the phases, and density changes as a result of increased dissolved components in the brine analog were taken into account.

The parameters for this demonstration were selected arbitrarily. Further modeling will be conducted using the parameters of the specific experiments and the project team's new code.

The preliminary findings of the dissolution trapping experiments and modeling are as follows:

- The project team has selected surrogate fluid pairs for the dissolution experiments through the use of small-tank experiments.
- The project team has tested the hypothesis that convective mixing due to density-driven finger flow will not be important in highly heterogeneous formations.
- The goal in testing the above hypothesis is to simplify the modeling by avoiding the complex modeling of density-driven flow that may not be of importance in heterogeneous systems at large scales.

13: ORD-2012.02.00 Task 5.1

Project Number	Project Title		
ORD-2012.02.00 Task 5.1	Verifying Storage Performance – Natural Geochemical Signals to Monitor Leakage to Groundwater		
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Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 6	

Technical Background

Detecting carbon dioxide (CO_2) migration into shallow groundwater aquifers is important both to assess storage permanence and to evaluate its impacts on water resources. This task seeks to develop methodologies for the quantitative measurement of naturally occurring geochemical tracers, which can be used to detect the leakage of CO_2 itself or the leakage of brines or other fluids displaced from the target strata. Although individual isotopic and other natural tracers can provide valuable information by themselves, it is envisioned that multiple tracers could be combined or used in combination with modeling and/or geophysical techniques to provide a more complete assessment than any one technique alone.

Unlike synthetic tracers, such as sulfur hexafluoride and perfluorinated hydrocarbons, which have no or insignificant natural sources, natural tracers are already present in the subsurface and subtle changes in their concentration, isotopic ratio, or other characteristics can indicate intrusions from other strata or sources. The approach being taken is to investigate a number of geochemical indicators that offer the possibility of providing distinct signals, rather than preselecting one or two. This approach recognizes that the probability of one tracer being applicable in all storage and usage scenarios is low. The development of multiple tracers allows for the employment of a particular subset tailored to the geochemistry at any given location.

The most direct indication of CO_2 migration is the CO_2 concentration itself. Unfortunately, the determination of CO_2 flux is difficult because of the high background CO_2 concentrations, the natural variation in the background concentration, and the inaccuracies associated with the CO_2 analysis itself. To address the last obstacle, one task is devoted to developing direct measurements of dissolved CO_2 to replace the indirect methods currently being used.

The use of stable isotope ratios to elucidate geochemical interactions is well established. Two tasks are devoted to using them as monitoring tools. The first of the two tasks uses an isotope ratio mass spectrometer to measure stable isotope ratios of carbon, sulfur, oxygen, and hydrogen, while the second employs a multi-collector inductively coupled plasma mass spectrometer (MC-ICPMS) to measure inorganic elements. Strontium (Sr) has proven to be such an excellent tracer in past work that effort was expended this year to develop a measurement protocol for rapid, reproducible, high-precision measurements of $^{87}Sr/^{86}Sr$ for use in monitoring CO_2/brine incursions.

Previous work at the Chimayo natural analog site and at the Zero Emissions Research and Technology (ZERT) test site has indicated that elevated arsenic (As) levels could be an indication that CO_2-water-rock interactions are occurring in the subsurface. At the Chimayo site, where a natural source of CO_2 carbonates the water, As levels above the maximum contaminate level were observed. At the ZERT site, As concentrations were found to increase as the duration of CO_2 injection increased. Two tasks are devoted to understanding the CO_2 interactions leading to As mobilization.

In the particular case of enhanced oil recovery (EOR), organic compounds from the reservoir can be mobilized by supercritical CO_2 ($scCO_2$) and transported out of the target zone if migration occurs. Very few quantitative assessments are available, but preliminary simulations have shown that volatile organic carbon can easily be dissolved, and thereby mobilized, in $scCO_2$ and transported into shallow aquifers. A new task begun this year is examining the ability of higher-volatility compounds to act as cosolvents to enhance the solubility of less soluble compounds. This enhanced transport might then be used as a positive indicator for $scCO_2$ migration out of an EOR zone.

Currently, analytical method development and end-member characterization studies are performed in the laboratory. Field samples of CO_2-impacted waters have been obtained from natural analogue sites were CO_2 is generated naturally, either from deep sources of CO_2 such as is seen in the Chimayo geyser, or from the reaction of acidic waters with carbonate rocks, such as is seen in acid mine drainage areas. More recently, the project team has initiated efforts to obtain water samples from prospective CO_2 EOR sites.

Relationship to Program

This project will support important advances within the MVA pathway of the DOE-NETL Carbon Storage Program. Benefits to the program include the following:

- Development of a method to detect leakage to the surface or groundwater aquifer
- Development of a method to evaluate caprock integrity

Primary Project Goal

The overall goal of this project is to address the development of a suite of indicators that, when used alone or in combination with other techniques, can indicate CO_2 losses that exceed the target of 1% over 100 years. The immediate goal is to demonstrate the use of geochemical tracers to identify CO_2 or brine intrusion into groundwater outside of the target zone.

Objectives

The detection of CO_2 migration into shallow groundwater aquifers is important to assessing storage permanence and evaluating the impact of CO_2 migration on water resources. This task seeks to develop methodologies for the quantitative measurement of naturally occurring geochemical tracers. Natural tracers can be used to detect leakage of CO_2 itself and movement of brines displaced by the influent CO_2, as well as organics, or elements leached from the strata. Changes in tracer characteristics can also aid understanding of potential impacts to shallow environments (e.g., groundwater aquifers, the vadose zone). It is envisioned that multiple tracers could be combined or used in combination with modeling and/or geophysical techniques to provide a more complete assessment than any one technique could provide alone.

The objectives of each of the sub-tasks are as follows:

- Task 5.1.1 – Inorganic Tracers: Develop methodologies using the NETL MC-ICPMS facility for quantitative measurement of trace element isotopic signatures to determine their ability to signal CO_2 intrusion.
- Task 5.1.2 – Point sources of trace contaminants: Use a suite of techniques including mass spectrometry and optical spectroscopy to characterize the distribution and speciation of trace metals in natural samples (e.g., solids and fluids from groundwater aquifers). Assess how metals will behave in the presence of a CO_2 leak by repeating analyses after exposing samples to CO_2 in the laboratory.
- Task 5.1.3 – Tracking CO_2 using stable isotope indicators: Develop methodologies to use stable isotope mass spectrometery for quantitative measurement of carbon, hydrogen, oxygen, and sulfur isotopic signatures to determine their ability to signal CO_2 intrusion.
- Task 5.1.4 – Development of field CO_2 measurement methods: Develop a field method based on the Carbo QC method (typically used in the carbonated beverage industry) to directly measure CO_2 in groundwater. Determine uncertainties and limitations of the technique by comparing results to lab standards. Investigate the potential use of microbiological indicators to monitor CO_2 and brine in geologic systems.
- Task 5.1.5 – Arsenopyrite precipitation and dissolution studies: Perform a series of packed column experiments at various pressures and temperatures that fill the data gaps related to arsenopyrite reactivity in the presence of CO_2. Present a comprehensive understanding of arsenopyrite reactivity in CO_2-rich systems of varied pressure and temperature.
- Task 5.1.6 – Use of organic compounds to track CO_2 migration from CO_2-EOR (or other storage) sites: Determine which organic compounds can migrate into shallow groundwater at a typical EOR site during CO_2 injection operations. Develop methodologies for quantitative measurement of relevant organic compounds to determine their ability to signal CO_2 intrusion into overlying formations.

14: FE0004478

Project Number	Project Title		
FE0004478	Advanced CO_2 Leakage Mitigation Using Engineered Biomineralization Sealing Technologies		
Contacts	**Name**	**Organization**	**Email**
DOE-NETL Project Mgr.	Joshua Hull	NETL – Sequestration Division	Joshua.Hull@netl.doe.gov
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Partners	Southern Company University of Alabama at Birmingham Shell International Exploration and Production		
Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 4		End of Project Technology Readiness Level: 5	

Technical Background

This project will develop a novel engineered biomineralization process into an innovative technology for leakage mitigation for application to geologic carbon dioxide (CO_2) storage systems. Geologic storage involves injection of CO_2 into underground formations including oil beds, deep un-minable coal seams, and deep saline aquifers with temperature and pressure conditions such that CO_2 will likely be in the supercritical state ($scCO_2$). The concept proposed for enhancing geologic storage is based on the use of engineered microbial biofilms, which are capable of biomineralization.

The engineered biomineralization process produces biofilm and mineral deposits that reduce the permeability of geologic media while modifying the geochemistry of brines to enhance CO_2 solubility and mineral precipitation. These processes can be targeted in the vicinity of geologic storage injection wells, as well as nearby abandoned wells, to provide long-term sealing of preferential leakage pathways. Because the fluids used to initiate biofilm formation and biomineralization are low-viscosity aqueous solutions, this technology has the potential to seal small aperture leaks or the porous rock itself, potentially providing a leakage mitigation technique that can address issues problematic for cement use.

BIOMINERALIZATION BY UREOLYSIS

Carbonate mineral formation in the subsurface can be engineered through the bacterial hydrolysis of urea, also known as ureolysis. Ureolysis can occur under dark subsurface conditions and results in the production of ammonium (NH_4^+), an increase in pH, an increase in alkalinity (Equations [Eq.] 1–5) and, ultimately, oversaturation of the aqueous phase with respect to carbonate minerals, such as calcium carbonate ($CaCO_3$; Eq. 6). Carbonate mineral formation can be engineered by controlling the concentration and activity of microorganisms, the supply of calcium ions (Ca^{2+}) and bicarbonate (HCO_3^-), growth nutrients, or urea availability. Urease, the enzyme responsible for urea hydrolysis, is common in a wide variety of microorganisms and can therefore be readily induced by adding inexpensive urea. Consequently, microbial ureolysis has been investigated for industrial utilities such as mineral plugging and immobilizing calcium and contaminants in surface and groundwater.

Eq. 1 $CO(NH_2)_2 + H_2O \rightarrow NH_2COOH + NH_3$

Eq. 2 $NH_2COOH + H_2O \rightarrow NH_3 + H_2CO_3$

Eq. 3 $H_2CO_3 \leftrightarrow HCO_3^- + H+$ (pKa2 = 6.37)

Eq. 4 $2NH_3 + 2H_2O \leftrightarrow 2NH_4+ + 2OH^-$
Eq. 5 $HCO_3- + H^+ + 2OH^- \leftrightarrow CO32^- + 2H_2O$
Eq. 6 $CO32- + Ca^{2+} \leftrightarrow CaCO_3$ (KSO [solubility product constant] = 3.8 × 10-9)

Formula key			
$CO(NH_2)_2$	urea	H^+	hydron
H_2O	water	NH_4	ammonium
NH_2COOH	carbamic acid	OH^-	hydroxide
NH_3	ammonia	$CO32^-$	carbonate
H_2CO_3	carbonic acid	Ca^{2+}	calcium ion
HCO_3^-	bicarbonate	$CaCO_3$	calcium carbonate

Prior to demonstrating this technology in the field, it is essential to first conduct this proof-of-principal testing and methodology development using a large (mesoscale), tightly controlled testing facility that can replicate actual field conditions. This indoor facility, located in the Center for Biofilm Engineering at Montana State University, is now completely operational and conducting biomineralization sealing in rock cores under temperature and pressure conditions relevant to geologic storage sites. These tests are being conducted over the three-year project duration to optimize the engineered biomineralization process and provide the basis for verification in the field. This project represents a four-way collaboration involving the Montana State University (MSU) Energy Research Institute (ERI), Shell International Exploration and Production B.V. (Shell), Southern Company (SC), and the University of Alabama at Birmingham (UAB) Department of Mechanical Engineering. MSU-ERI will lead the project and perform mesoscale biomineralization experiments, SC will provide rock samples from the field for testing, and UAB will conduct extensive core testing. Shell will bring oilfield and well expertise to help guide the research and to ensure that protocols developed for creating biomineralized barriers are consistent with oil field operations.

Relationship to Program

This project will support important advances within the geologic storage technologies and simulation and risk assessment pathway of the DOE-NETL Carbon Storage Program.

COMPARISON WITH OTHER TECHNOLOGIES

The engineered biomineralization technology offers some potential advantages over cement-related technologies currently used near wellbores. Fluids involved in biofilm formation and biomineralization are low-viscosity aqueous solutions, and therefore have the potential to seal small aperture leaks or the porous rock itself, potentially providing a leakage mitigation technique that can address issues problematic for cement use. The project team's previous research has shown that biomineralization deposits can be developed in moderate aperture channels (i.e., 1 mm wide), which suggests that this technology will also be useful for plugging fractures in the formation and in well casing cement.

ANTICIPATED BENEFITS

Successful proof-of-concept of the engineered biomineralization barrier technology will provide several benefits to CO_2 storage operations, including an alternative to cement for plugging preferential CO_2 leakage pathways in the vicinity of wellbores; a low-viscosity technology that can penetrate significant distances away from the wellbore and reach small aperture pathways and plug large fractures; and a technology that has additional benefits to geologic CO_2 storage, such as increasing solubility trapping and mineralized storage of anthropogenic CO_2.

Primary Project Goal

The overall goal of this project is to develop a biomineralization-based technology for sealing preferential flow pathways in the vicinity of wells in formations targeted for CO_2 capture and storage (CCS). This goal will be accomplished through completion of the three project objectives discussed below.

Objectives

OBJECTIVE 1. CONSTRUCT AND TEST MESOSCALE HIGH-PRESSURE ROCK TEST SYSTEMS

Design and construction of the high-pressure radial flow test and the high-pressure axial flow core testing system have been completed and experiments are under way. Discussions between MSU researchers, SC, UAB, and Shell have addressed issues concerning experimental design for both radial and axial flow, high-pressure experimental systems, and their operational protocol.

High-Pressure Radial Flow Vessel

Construction of the stainless steel, high-pressure rock core testing vessel has now been completed by Alaskan Copper Works of Seattle, Washington. The vessel was delivered to MSU in early March 2012 and has been successfully pressure tested. The initial experimental run with this vessel has also been completed, and the experiment successfully tested the project team's biomineralization protocol on a 76.2 cm (30 in) diameter rock core sample obtained from the Boyles formation in Alabama.

High-Pressure Axial Flow Core Testing System

The experimental apparatus for conducting biomineralization experiments using axial flow through 2.54 cm (1 in) rock core samples has been constructed and successfully tested.

OBJECTIVE 2. DEVELOP BIOMINERALIZATION SEAL EXPERIMENTAL PROTOCOL

The project team's experimental protocol for creating the biomineralization deposits in rock cores was initially developed from running packed column experiments in the CBE laboratories. A numerical simulation model has been developed by project collaborators, Dr. Anozie Ebigbo and Dr. Rainer Helmig, of the University of Stuttgart, Germany. This model is capable of accounting for carbonate precipitation due to ureolytic bacterial activity and the flow of two fluid phases in the subsurface. Using this model together with data from packed column experiments, the project team has developed an established protocol for conducting biomineralization experiments in packed columns. The aim of this protocol is to control biomineralization in such a way that calcium carbonate is deposited uniformly with length along the flow path. The protocol, which has been demonstrated to deposit calcium uniformly with length, is as follows:

- Rock core is inoculated with *Sporosarcina pasteurii* and growth medium for a period of 18 hours to develop a biofilm.
- Calcium-rich (1.25 molarity [M] calcium) medium (including urea) is injected to initiate biomineralization. This injection lasts for two pore volumes (PV).
- The core is then flushed for 2 PV with calcium-free media with urea prior to reinjecting 2 PV fresh calcium-rich medium.
- Periodically, the biofilm is refreshed by injecting (2 PV) fresh growth medium without calcium.

This protocol worked well for recent experiments in which the project team created biomineralization deposits in a 30 cm fracture in the large 76.2 cm (30 in) diameter sandstone core. They will continue to experiment with variations in the current protocol throughout the duration of the project, and will likewise continue to examine alternative media compositions that may be more cost effective. In summary, the project team has demonstrated that the biomineralization experimental protocol can be applied so as to control the rate and extent of calcium carbonate deposition along flow paths in porous media or in fractures. This capability is essential for proceeding toward establishing biomineralization strategies that can effectively plug preferential flow paths near CO_2 injection wells in the field.

OBJECTIVE 3. CREATION OF BIOMINERALIZATION SEAL IN DIFFERENT ROCK TYPES AND SIMULATING DIFFERENT FIELD CONDITIONS

To date, major activities related to performing biomineralization experiments using the project team's high-pressure rock testing systems have included acquiring three 76.2 cm (30 in) diameter sandstone cores from Alabama; fracturing and resealing one of the large cores; calibrating the Biomineralization Simulation Model from Stuttgart to represent the dimensions and properties of the core; successfully designing and fabricating the high-pressure stainless steel vessel to test the large cores; completing two sets of sealing experiments with the high-pressure vessel in which a 30 cm (11.81 in) fracture in the large sandstone core was resealed at 650 pounds-force per square inch (psi); and conducting two sets of biomineralization experiments to plug 2.54 cm (1 in) diameter Berea sandstone core (initial permeability 45 millidarcy [mD]) at 1,100 psi.

The biomineralized 2.54 cm diameter cores have been sent to the UAB core testing laboratory, where they will measure core porosity, permeability, and minimum capillary displacement pressure, which is the minimum capillary displacement pressure above which capillary flow of $scCO_2$ will occur through the rock, given sufficient time. These measurements will provide investigators with independent determinations of the extent to which the sealing capacity of a rock can be increased through biomineralization, and the dependence of the evolution of sealing capacity on brine composition, rock properties, reservoir conditions, and time. The resistance of the biomineralized cores to challenge by $scCO_2$ will also be determined.

15: FE0001040

Project Number	Project Title		
FE0001040	Quantification of Wellbore Leakage Risk Using Non-Destructive Borehole Logging Techniques		
Contacts	**Name**	**Organization**	**Email**
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Partners	Princeton University Los Alamos National Laboratory Rocky Mountain Oilfield Testing Center		
Technology Readiness Levels (Scale 1–9)			
Current Technology Readiness Level: 3		End of Project Technology Readiness Level: 4	

Technical Background

Abandoned wellbores may pose an important risk to the integrity of sites that have large numbers of existing wells, and that risk needs to be better understood. In most fields, existing wells and abandoned wells have not been constructed with carbon dioxide (CO_2) storage in mind; they have been designed, generally, for oil and gas production. Field and laboratory studies have shown that well cement can be affected by CO_2 at differing levels depending on conditions. However, none of this work has examined the initial conditions of the well (the conditions just prior to CO_2 exposure). Understanding the initial conditions will be important for ensuring that the risk of leakage in a field is acceptable. The collection of baseline wellbore integrity data allows for comparison during the project and may also identify any potentially problematic wells before a leak can occur. Statistical work on wellbore leakage has been conducted, but this work looked at overall well leakage and did not contain data that identifies specific leakage pathways. Field-specific data from wells must be used to begin to understand if field-wide similarities exist between wells and, if there are similarities, how they can be used to assess field-wide leakage risk. Initial results from the baseline data collection for five existing wells in the state of Wyoming are presented. The investigation used a combination of wellbore logging and sampling tools to analyze well conditions. Logging tools were selected to provide the maximum information on the materials that were used to construct wells and provide zonal isolation, and the logging suite included sonic mapping tools, ultrasonic mapping tools, dynamic testers, and sidewall coring tools.

Five wells were examined in two fields in Wyoming. All the wells in this study were constructed to be production wells. Three industry wells were located in Carbon County, Wyoming and two wells were located at the Rocky Mountain Oilfield Testing Center (RMOTC) in Natrona County, Wyoming. The Carbon County wells were completed in 2002 (Carbon County Well 1 [CC1]) and 2004 (Carbon County Well 2 [CC2] and Carbon County Well 3 [CC3]). The RMOTC wells (46-TPX-10 and 43-TPX-10) were completed in 1996 and 1985, respectively. Since production, the RMOTC wells have been used for technology testing. The Carbon County wells were constructed using 7 in J55 casing and were cemented to the surface in a single stage, using lightweight Portland cements with an 11.5 pound per gallon (lb/gal) lead and a 13 lb/gal tail. The RMOTC wells were constructed using 7 in K55 or J55 casing. They were both cemented in two stages using Class G cement or a 50/50 blend of Pozmix® and cement.

The study focused on sections of the well that had the casing cemented through shale zones, as shales play an important role in carbon capture and storage (CCS) as seals or caprocks. Although it is important to have the well cemented below the caprock to provide containment and to protect the casing from carbonated brine, it is the cement through the caprock that plays a critical role by containing the CO_2 within the storage formation.

The wells were logged with cement bond logging tools when they were constructed, which provided cement bond logs, variable-density logs and, in the case of the industry wells, also provided cement maps. The same cement bond logs were repeated when possible as part of this study, allowing a comparison to be made between the current condition of the well and the condition immediately after construction. An ultrasonic well-mapping tool, the Schlumberger Isolation Scanner cement evaluation service was used to provide maps of the condition of the casing and well cement as well as the interfaces between the casing and cement and cement and formation. Dynamics testers, specifically the Schlumberger CHDT (Cased Hole Dynamics Tester) and the Schlumberger MDT (Modular Formation Dynamics Tester), were used to collect flow-property data (permeability or mobility) in the annulus between the casing and the formation in the well over a ten-foot interval. The CHDT was used to collect point permeability/ mobility data and single-phase fluid samples from behind the casing in multiple locations while leaving the well intact. The MDT was used to collect average flow property data over vertical sections of CC1 and 46-TPX-10. Cased-hole sidewall cores were collected over the intervals that were tested using the dynamic testers. The collection of cores will allow a comparison of in situ and laboratory flow property data. Initial analysis has identified similarities between the isolation scanner and Schlumberger SCMT (Slim Cement Measurement Tool) logs between wells in the same fields. These similarities were identified by correlating peaks in the gamma-ray tracks of the logs for each well, and then identifying similarities in the other tracks between the wells. The percent of cement coverage was quantified using the solid, liquid, and gas track in the isolation scanner logs. The percent coverage was taken as the ratio of cement measurements to the total material measurements multiplied by 100. Zones in which casing collars interfered with the measurements were omitted from the calculations.

Data collection started in March 2010 with the industry wells and finished at the end of July 2010 with the RMOTC wells. The data collection for each well started with the nondestructive logging techniques. The Isolation Scanner and SCMT were run at the start of the job and provided maps used to identify testing and sampling points. The maps included internal and external casing radii and casing thickness, which were used to identify casing corrosion and cement acoustic impedance to determine the quality of the cement. Other maps showed flexural attenuation; solids, liquids, and gases behind the casing; suspected hydraulic communication; and the third interface. Following the testing, the Isolation Scanner was run again to orient the cores in the well and provide information on any changes to the well that the testing may have caused. The orientation of the cores is important because it will allow the laboratory measurements of the flow properties to be correlated to the cement maps. The CHDT was used to collect point permeability measurements and fluid samples in CC1 and CC2 and both RMOTC wells. The CHDT tests provided points for correlation of flow properties on the logs, and the fluid samples provide information on the chemical environment of the well and well cement. The Schlumberger MSCT (Mechanical Sidewall Coring Tool) was used to collect cores generally consisting of casing, cement, and formation. The MDT was used to conduct a vertical isolation test (VIT) and characterize the average well permeability in zones in CC1 and 46-TPX-10.

The results are still preliminary because the laboratory results are not complete and further analysis is needed. Wells CC1, CC2, 46-TPX-10, and 43-TPX-10 were used for sampling and testing. Results of the Isolation Scanner runs showed that it is possible to identify the core locations and the perforated intervals that were used for testing and sampling. The post-testing isolation scanner log for CC1 showed the three core points and the individual perforations in the perforated zone, at a depth near where the VIT was conducted.

Pressure tests in the cement and the formation were run at each CHDT depth. CHDT fluid samples are noted at the depth collected. The MSCT points list the materials collected in the core sample, which are included are defined in the table below.

Table 1: Testing and Sampling Points Showing the Depths and Formations Tested or Sampled

Abbreviations Used in Table 1.			
AFm	Almond formation	M	mud
ALS	Alcova Limestone	MLS	Minnehakta Limestone
C	cement	MSh	Morrison Shale
CSS	Crow Mountain Sandstone	Osh	Opeche Shale
DSS	Dakota Sandstone	RSh	Red Peak Shale
EAn	Ervay Anhydrite	S	steel casing
F	formation	SSh	Sundance Shale
FSS	Fox Hills Sandstone	WSS	Wall Creek Sandstone
LSh	Lewis Shale		

Tool	**CC1**		**CC2**		**46-TPX-10**		**43-TPX-10**	
CHDT Testing Depths	3,460.1 ft 2,517.9 ft 2,990.3 ft 2,980.5 ft	LSh LSh LSh LSh	4,850.0.1 ft 890.0 ft 2,230.0 ft (fluid sample collected)	AFm Coal FSS	3,946 ft 4,020 ft 4,010 ft 3,849 ft	MSh MSh MSh DSS	5,380 ft 4,485 ft 4,407 ft 3,849 ft 2,928 ft 3,812 ft (fluid sample collected)	MLS CSS SSh DSS WSS DSS
Perforation depth for MDT VIT	2,980-29,81 ft (6-shots) 2,990-2,991 ft (6-shots)	LSh	NA		4,009-4,010 ft (6-shots) 4,019-4,020 ft (6-shots)	MSh	NA	
MSCT Retrieved Core Depths	3,648.1 ft (S,C,F) 3,450.2 ft (S,C,F) 3,150.1 ft (S,C,M,F) 2,995.1 ft (S,C) 2,985.1 ft (S,C) 2,974.8 ft (S,C) 2,710.0 ft (S,C,M,F) 2,520.2 ft (S,C,F) 2,410.0 ft (S,C,F) 2,259.9 ft (S,C)	LSh LSh LSh LSh LSh LSh LSh LSh LSh LSh	NA		4,700 ft (C) 4,445 ft (S,C) 4,420 ft (C,F) 4,305 ft (S,C,F) 4,025 ft (C,F) 4,015 ft (S,C,F) 4,005 ft (C,F)	RSh RSh ALS SSh MSh MSh MSh	5,396 ft (S,C) 5,380 ft (S,C) 5,332 ft (C,F) 3,812 ft (C)	OSh MLS EAn DSS

In general, all three industry wells are similar, in that no major flow paths along the wells are obvious in any of the isolation scanner logs. However, there do not appear to be any similarities between the formations surrounding the wells, based on results of gamma-ray tracking that was used to identify similar formations.

The two RMOTC wells do show similarities in log properties. There are multiple places where the cement seems to be in poorer condition in the same geologic units in each well. The zone at the top of the Red Peak shale, between 4,430 ft and 4,510 ft in 46-TPX-10 and 4,330 ft and 4,410 ft in 43-TPX-10, is the largest of the zones in which the quality of the cement seems to be affected by the surrounding formation. In this zone, the log shows a reduction in solid material behind the casing that trends vertically and is filled with liquid. In the 80 ft affected in 46-TPX-10 (4,330–4,410 ft), the average cement coverage is 77.67% (standard deviation [std dev] = 15.59%). In the 80 ft zones directly above and below the affected zone, the average coverage is 96.46% (std dev 4.25%) above and 94.93% (std dev = 4.65%) below. In the affected zone in

43-TPX-10 (4,430–4,510 ft), the average cement coverage is 57.96% (std dev = 13.34%). The 80 ft zone above the affected zone has an average cement coverage of 83.13% (std dev = 12.10%) and the average cement coverage over the 80 ft below the affected zone is 79.67% (std dev = 17.85%).

The data collected and used to make the cement maps from the Isolation Scanner measurement are being used in conjunction with the point and average permeability measurements of the well. The acoustic impedance data will be statistically characterized to create distributions that describe how the data is distributed. Previous research efforts have studied links between the acoustic properties of cementicious construction materials and their flow properties. The project team is adapting relationships used for building construction materials to correlate the flow parameters of the well cement behind the casing, using the acoustic properties that can be measured through the casing. The acoustic velocities for the longitudinal and shear waves in the cement will be related to the density and elastic modulus by Equations 1 and 2, below, where *E* is Young's modulus, ν is Poisson's ratio, and ρ is density.

$$V_L = \sqrt{\frac{E}{\rho}\frac{1-\nu}{(1+\nu)(1-2\nu)}}$$ Equation 1

$$V_T = \sqrt{\frac{E}{\rho}\frac{1}{2(1+\nu)}}$$ Equation 2

The relationship between Young's modulus and porosity (*p*) is given by Equation 3, where E_0 is the Young's modulus of the cement at zero porosity and *c* is an experimental fitting parameter.

$$E = E_0(1-p)^c$$ Equation 3

The relationship between density and porosity is given by Equation 4, where ρ_0 is the zero porosity density.

$$\rho = \rho_0(1-p)$$ Equation 4

Ignoring the influence of porosity V_L and V_T can be approximated by the following:

$$V_L = V_{L0}(1-p)^a$$ Equation 5

$$V_T = V_{T0}(1-p)^a$$ Equation 6

Where VL_0 and VT_0 are the zero porosity velocities and the following equations apply:

$$V_{L0}\sqrt{\frac{E_0}{\rho_0}\frac{1-\nu_0}{(1+\nu_0)(1-2\nu_0)}}$$ Equation 7

$$V_{T0}\sqrt{\frac{E_0}{\rho_0}\frac{1}{2(1+\nu_0)}}$$ Equation 8

$$a = \frac{c-1}{2}$$ Equation 9

For low porosity (porosity available for flow, in the case of cement), Equations 5 and 6 can be approximated by the following:

$$V_L = V_{L0}(1 - bp)$$ Equation 10

$$V_T = V_{T0}(1 - bp)$$ Equation 11

Where:

$$b = 15\frac{1-\nu_0}{7-5\nu_0}$$ Equation 12

Using a bundle of tubes model the permeability, *k*, is derived to be the following:

$$k = \frac{pd^2}{32}$$ Equation 13

Where d is the diameter of the capillary "tube," solving equations 10 and 11 for *p* and then plugging into equation 13:

$$k = \frac{d^2}{32b}\frac{\Delta V_L}{V_{L0}}$$ Equation 14

$$k = \frac{d^2}{32b}\frac{\Delta V_T}{V_{T0}}$$ Equation 15

Using the derived equations or similar equations, the project team will transform the measured acoustic properties data to permeability data and create permeability maps of the cement in the wells.

Relationship to Program

This project will support important advances within the MVA area of the DOE-NETL Carbon Storage Program.

Benefits of the project include the following:

- Increased ability to evaluate wellbore leakage potential
- Increased understanding of well-isolation capacity
- Understanding of the pre-CO_2-injection condition of existing wells
- Decreased cost of wellbore leakage evaluation
- Method for estimation of in situ well-flow properties

Primary Project Goal

The primary goal of the project is to develop a non-destructive method to measure well flow properties.

Objectives

This project has the following objectives:

- Objective 1: Develop methods to establish the average flow parameters (porosity and permeability or mobility) from individual measurements of the material properties and defects in a well.
- Objective 2: Develop a correlation between field flow-property data and cement logs that can be used to establish the flow properties of well materials and well features using cement mapping tools.
- Objective 3: Establish a method that uses the flow-property model developed in Objective 2 to analyze the statistical uncertainties associated with individual well leakage that can provide basis for uncertainty in risk calculations.

16: FWP-58159 Task 2

<table>
<tr><th>Project Number</th><th colspan="3">Project Title</th></tr>
<tr><td>FWP-58159 Task 2</td><td colspan="3">Advanced Co-Sequestration Studies</td></tr>
<tr><th>Contacts</th><th>Name</th><th>Organization</th><th>Email</th></tr>
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<tr><td>Partners</td><td colspan="3">North Dakota State University</td></tr>
<tr><th colspan="4">Technology Readiness Levels (Scale 1–9)</th></tr>
<tr><td colspan="2">Current Technology Readiness Level: 3</td><td colspan="2">End of Project Technology Readiness Level: 5</td></tr>
</table>

Technical Background

Combustion of coal generates flue gas streams containing carbon dioxide (CO_2), carbon monoxide (CO), oxygen (O_2), sulfur oxides (SO_x), nitrogen oxides (NO_x), and various mercury (Hg)- and arsenic (As)-containing compounds. The fate of these contaminants is of considerable environmental importance, independent of CO_2 emissions. Co-sequestration—the capture and geologic storage of CO_2 combined with some or all of these other contaminants in the gas stream—eliminates the need for one or more individual pollutant capture systems (e.g., sulfur dioxide [SO_2] scrubbers). This can increase the potential for more economically acceptable carbon management through significant savings in plant and retrofit capital costs, reduced operating costs, and decreased energy use. Eliminating the SO_2 scrubbers alone during a carbon capture, use, and storage (CCUS) retrofit would result in a 13% reduction in capital costs and an 8% reduction in annual operating expenses based on an amine capture system. The potential savings as a percentage of total costs become even more significant if the capital and operating costs for NO_x or Hg control can also be eliminated. Co-sequestration may be particularly beneficial when applied to older, existing coal plants not currently equipped with SO_2 scrubbers, NO_x, and Hg control, but which would be considered worthy of a CCUS retrofit. If carbon capture and storage (CCS) or CCUS could also perform the function of these costly emissions control systems, it would simplify the overall retrofit process; possibly reduce land, area, and water requirements; achieve significant cost savings; and thereby facilitate CCS deployment on such plants.

Although the cost savings potential of avoided capture systems under co-sequestration is relatively straightforward to estimate, the viability of subsurface storage of mixed-gas streams is considerably less certain. The fate and transport of mixed-gas streams in the subsurface are much less understood than the fate and transport of pure CO_2. Recently issued Environmental Protection Agency Class VI regulations for CO_2 storage projects do not resolve whether supercritical CO_2 ($scCO_2$) mixed with trace gases would constitute a hazardous waste regulated under different underground injection control protocols. Hence, there is a critical need to better understand the fundamental behavior of mixed-gas supercritical fluids in the subsurface to help craft sensible regulations regarding the injection of mixed gases for utilization and storage. Moreover, there is virtually no industrial experience with compression and transport of CO_2-SO_2-O_2 gas mixtures on which to base appropriate specifications for pipelines and injection well construction materials.

When this project was initiated in late fiscal year (FY) 2008, Pacific Northwest National Laboratory (PNNL) was directed to coordinate the preparation of an R&D Roadmap that would form the basis for conducting follow-on work to close identified technical gaps associated with co-sequestration. That roadmap was issued in 2009 and covered R&D needs associated with capture, transport, and geologic storage of mixed-gas streams. Task activities associated with all three R&D areas were initiated and have been conducted under this project, but only activities associated with transport and geologic storage will be addressed in this project summary.

Impurities in CO_2 from coal combustion can impact a wide range of storage system components, including the following:

- Thermodynamic, physical, and chemical properties, as well as corresponding equations of state for multicomponent gas mixtures
- Corrosion of metals used in pipeline and wellbore construction
- Reactivity with reservoir fluids and rocks and subsequent feedback on porosity and permeability
- Caprock stability and permanence of CO_2 storage
- Regulatory and permitting uncertainty

In this project, the PNNL team has addressed these issues through targeted studies on: (1) the corrosion behavior of mild steels in $scCO_2$ water (H_2O)-R systems, where R is a contaminant gas such as hydrogen sulfide (H_2S), SO_x, NO_x, nitrogen (N_2), O_2, and carbonyl sulfide (COS); (2) the fundamental properties of CO_2 that contains a variety of important contaminant gases, including H_2O, and the molecular-scale interactions of those components with various minerals and steels; and (3) in situ stripping processes occurring with carbonate rocks. As will be discussed in the next sections, the discovery and recognition of the significance of wet $scCO_2$ reactions that occurred under this project has had broad national and international impacts across a suite of application areas.

Relationship to Program

This project will support the following important advances within the geologic storage technologies and simulation and risk assessment pathway of the DOE-NETL Carbon Storage Program:

- Evaluating and demonstrating the compatibility of non-industry standard mixed-gas streams with pipeline and well construction materials
- Establishing water content specification requirements for CO_2-SO_2-O_2 mixtures
- Demonstrating a new in situ scrubbing technique for integrated management (surface and subsurface) of emissions captured from post-combustion and oxy-fired coal plants
- Providing fundamental experimental data and theoretical underpinnings for modeling chemical reactivity in wet $scCO_2$ and mixed gases of importance for all CCUS projects
- Providing fundamental data on mixed-gas storage and permanent storage of contaminants necessary to inform the regulatory process for CCUS projects considering mixed-gas injections
- Extending concepts developed under this project into enhanced gas recovery for depleted shale gas formations

Primary Project Goal

The primary goal of this project is to develop geologic storage technologies with a near-zero cost penalty—a grand challenge with major economic benefits for emissions capture, use, and storage. This project employs an integrated systems approach to pursue major research needs in the following principal areas:

- Establishing technical baselines for transport and injection of CO_2 mixed with gases—effects examined include metals corrosion/erosion (including pipeline and well

construction materials), impact on phase behavior in the subsurface and permanence of CO_2 storage, and regulatory and permitting impacts
- Identifying constraints and potential economic opportunities for use of CO_2 mixed with one or more contaminants

Objectives

STEEL CORROSION STUDIES

Within this task, the project team is conducting studies of the corrosion behavior of steels used for pipeline and wellbore construction when they are exposed to mixed gases containing small amounts of water. The project team examined interactions between steel surfaces and contaminant gases both experimentally and theoretically, and designed and conducted pressurized experiments to assess the rates of corrosion and corrosion product formation. Molecular dynamics (MD) simulations were used to model the adsorption of water on the metal surfaces, hydroxylation of the surface, and subsequent reactions with CO_2 to form corrosion product phases such as siderite ($FeCO_3$). The work in this task focused on a number of topics of general importance, including H_2O/CO_2 complexation at the iron (Fe)-gas interface using simulation methods such as classical and ab initio MD, which allow investigation of the structure and reactivity of metal oxide surfaces as well as the distribution of solutes near the charged surfaces. The important reactions and species involved in the corrosion process were obtained from the quantum mechanical calculations and subsequently used as initial starting points for density functional theory (DFT) modeling to investigate the dynamic nature of the reactions observed in high-pressure experiments.

To address questions that were raised during the initial FutureGen site selection process regarding pipeline specifications for CO_2, the project team initiated laboratory testing under this task that explored the reactivity of trace amounts of water in various liquid and $scCO_2$ mixtures. McGrail et al. (2009) showed that the most important chemical reactivity and impacts on steel components occurred in the liquid CO_2 phase instead of water, where most attention has been focused. This led the project team to ask the question “Has half the story been neglected?” MD simulations show that traces of water assist in the process by hydroxylating the Fe(100) surface sites, thus lowering the energy barrier to CO_2 addition, enabling the formation of carbon trioxide (CO_3), while water is regenerated after the $FeCO_3$ formation. Furthermore, MD simulations that examined fundamental interactions of CO_2 and H_2O on the Fe(100) surface indicated that corrosion and CO_3 formation proceeds through the spontaneous activation and decomposition of CO_2 on the surface, rather than through formation of carbonic acid. These studies led to the first recognition of the broader implications of chemical reactivity in wet $scCO_2$ with reservoir rocks, caprocks, and well construction materials. All reservoir simulators, even now, still treat wet $scCO_2$ as an inert phase, despite the overwhelming evidence now showing the contrary. Nevertheless, this recognition has had sweeping impacts, including a $15 million investment in new high-pressure instrumentation at PNNL to study wet $scCO_2$ reactivity, a DOE Basic Energy Sciences effort to advance the fundamental science of wet $scCO_2$ interactions with silicates, a DOE Office of Energy Efficiency and Renewable Energy focus area on $scCO_2$ reactivity in geothermal systems, and most recently studies on brine solute partitioning into the $scCO_2$ phase. A new geochemical paradigm is in the process of being formulated around these ideas.

Another area of focus under Task 3 was an investigation into fundamental interactions of $scCO_2$ in the presence of co-existing compounds (e.g., H_2O, SO_2) and at the interface of these condensed media with metal surfaces. Laboratory testing that exposed a standard CO_2 grade-steel (X65) pipeline to mixed-gas streams (liquid CO_2 containing ~13,000 parts per million by weight [ppmw] SO_2 and 760 ppmw H_2O) indicated a strong tendency of SO_2 to bind directly to manganese (Mn). After nine days of testing, the metal surface was coated in hydrated Mn- and Fe-rich sulfite and sulfate compounds. Molecular simulations showed that the water on the metal surface remained in molecular form, and DFT calculations confirmed that SO_2 preferred Mn binding sites. The coupling of experimental results with molecular modeling conducted in these scoping studies indicates that commonly accepted materials for CO_2 transportation may be unsuitable for mixed-gas systems.

GEOLOGIC CO-SEQUESTRATION

This task brings together experimental studies of in situ reactions occurring between reservoir formations and mixed-gas systems with molecular dynamics modeling to help interpret those experiments and develop rate laws for wet $scCO_2$ reactions that can be incorporated into reservoir simulators.

In Situ Stripping Reactions

The concept of utilizing in situ reactions to remove contaminants from flue gas is analogous to implementing a modified wet limestone scrubbing process in the subsurface. In the wet limestone process, a limestone slurry in water is contacted with flue gas to drive the reaction:

$$SO_2 + CaCO_3 \text{ (calcium carbonate)} + H_2O \rightarrow CaSO_3 \text{ (calcium sulfite)} + H_2O + CO_2$$

Typically, the $CaSO_3$ is then oxidized to form calcium sulfate or gypsum. However, laboratory experiments conducted under this task demonstrated that similar reactions could be induced in situ at supercritical conditions with several different types of reservoir rocks. Hence, the $scCO_2$ phase could be stripped of its SO_2 content—and likely other key contaminants such as Hg—via natural thermodynamic driving forces with no additional energy input required. Through a coupled experimental and theoretical approach, the project team tested the reactivity between select and morphologically important surfaces of carbonate minerals with $scCO_2$ and co-existing H_2O and SO_2. Small amounts of SO_2 in CO_2 caused the formation of $CaSO_3$ in the form of hannebachite on dolomite samples, with the SO_2 content in the CO_2 being reduced below instrument detection levels within hours. Atomistic simulations based on density functional theory of these initial steps indicate accumulation of water over the magnesium (Mg) sites, and suggest depletion of Mg over the calcium (Ca) from the mineral surface. The sulfur-containing species bind preferentially on surface calcium atoms, creating the first nucleation sites. Formation of bisulfites (surface-hydrated sulfur dioxide [SO_2OH]) occurs with a low barrier of ca 0.5 eV, estimated by the climbing image-nudged elastic band method. Collectively, the experimental results and ab initio molecular dynamics simulations suggest the potential of carbonate reservoirs for in situ chemical scrubbing of CO_2 captured from fossil fuel sources, which could be stored permanently for storage purposes or extracted and utilized for enhanced oil recovery.

Tracking Reactivity in $scCO_2$ with 18O Isotopes

Water clearly plays a critical role in the chemical reactivity of $scCO_2$ and $scCO_2$-containing mixed gases, but the reaction paths and mechanisms are still virtually unknown, thus preventing construction and parameterization of appropriate chemical rate equations for simulators. Tracking carbonate reactions in the $scCO_2$ phases using Raman spectroscopy coupled with ^{18}O-labeling of H_2O and CO_2 has proven beneficial in discerning the role of water in the reaction process. Under this subtask, the project team conducted fundamental studies examining the kinetics of $^{18}O/^{16}O$ isotopic exchange in $scCO_2$ containing liquid water through the use of a specially designed Raman spectroscopy high-pressure optical cell. The team reported the first Raman spectra of fully ^{18}O-labeled $scCO_2$ and various isotopic mixtures. The experimental results, coupled with ab initio MD calculations, demonstrate that the frequencies assigned to the Fermi dyad of the CO_2 molecule transpose upon isotopic labeling of both oxygen atoms. This is the first confirmation of the effect in the Raman spectrum of the supercritical fluid and provides necessary groundwork for future Raman spectroscopy studies of reactions in $scCO_2$ fluids. More importantly, the work yields a quantitative assessment of the mixing of states upon labeling that provides the needed clarification concerning the pedigree of the assignments for the dyad of CO_2 under supercritical conditions. This manuscript was selected as a cover article and a graphic highlighting the key results appeared on the February 28, 2012 issue of *Physical Chemistry Chemical Physics*.

Additional experimental results measuring the uptake of ^{18}O by $scC^{16}O_2$ mixtures containing liquid H_2O were summarized and published in *Spectrochimica Acta Part A*. Characteristic bands from the $C^{16}O^{18}O$ and $C^{18}O_2$ molecules were identified in the supercritical phase and measured in the spectra as a function of time after introducing liquid $H_2{}^{18}O$ into $scC^{16}O_2$. Temporal dependence indicated the isotopic exchange was diffusion-limited in the project team's cell for both molecules, and that the chemical reactions within the liquid phase were comparatively rapid. However, the ratio of concentrations of the ^{18}O-labeled CO_2 molecules, $C^{18}O_2/C^{16}O^{18}O$, was much higher than expected in the supercritical phase, suggesting the role of an intermediate step, possibly desorption, in moderating the concentrations of these species in the liquid water phase. The combination of these two studies has laid the groundwork to conduct labeled water experiments in new systems, particularly shale gas experiments planned for FY13 that will examine the role of CO_2, SO_2, and H_2O in intercalation and the expansion of key layered clay minerals in shales.

APPENDIX F: LIST OF ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Definition
‰	per mille
°C	degrees Celsius
°F	degrees Fahrenheit
2-D	two-dimensional
3C	three-component
3-D	three-dimensional
AFm	Almond formation
ALS	Alcova Limestone
ARRA	American Recovery and Reinvestment Act of 2009
As	arsenic
ASME	American Society of Mechanical Engineers
ASU	air separation unit
BLM	U.S. DOI Bureau of Land Management
BEG	Bureau of Economic Geology (at the University of Texas at Austin)
BOEM	U.S. DOI Bureau of Ocean Energy Management
BPM	best practices manual
BRTD	ASME Board on Research and Technology Development
C	cement
Ca	calcium
Ca^{2+}	calcium ion
$CaCO_3$	calcium carbonate
$CaSO_3$	calcium sulfite
CC1	Carbon County Well 1
CC2	Carbon County Well 2
CC3	Carbon County Well 3
CCC	Copyright Clearance Center
CCRP	Clean Coal Research Program
CCS	carbon capture and storage
CCUS	carbon capture, use, and storage
CHDT	Cased Hole Dynamics Tester
cm	centimeter
CO	carbon monoxide
CO_2	carbon dioxide
CO_3	carbon trioxide
$CO32^-$	carbonate
$CO(NH_2)_2$	urea
COS	carbonyl sulfide
CPU	central processing unit
CRTD	ASME Center for Research and Technology Development
CSS	Crow Mountain Sandstone

Acronym or Abbreviation	Definition
CT	computed tomography
DFT	density functional theory
DNAPL	dense non-aqueous phase liquids
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
DSS	Dakota Sandstone
EAn	Ervay Anhydrite
ECBM	enhanced coalbed methane
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
Eq.	equation
ERI	Energy Research Institute
F	formation
FBG	Fiber Bragg Gratings
Fe	iron
$FeCO_3$	siderite
FLAC3D	Fast Lagrangian Analysis of Continua in Three Dimensions
FSS	Fox Hills Sandstone
ft	feet
FY	fiscal year
GEM	Generalized Equation-of-State Model
GHG	greenhouse gas
GIS	geographic information system
GCS	geological carbon storage
GPS	Global Positioning System
GR	gamma ray
GWPC	Ground Water Protection Council
H^+	hydron
H_2CO_3	carbonic acid
H_2O	water
H_2S	hydrogen sulfide
HCO_3^-	bicarbonate
Hg	mercury
ICP-MS	inductively coupled plasma-mass spectrometry
IGCC	integrated gasification combined cycle
ILDS	Intelligent Leak Detection System
in	inch
InSar	Interferometric Synthetic Aperture Radar
IOGCC	Interstate Oil and Gas Compact Commission
IRMS	isotope ratio mass spectrometer
K	potassium
KSO	solubility product constant

Acronym or Abbreviation	Definition
LAS	Log ASCII Standard
lb/gal	pound per gallon
LNAPL	light non-aqueous phase liquids
LTI	Leonardo Technologies, Inc.
LSh	Lewis Shale
m	meter
mm	millimeter
M	molarity
MC-ICPMS	multi-collector inductively coupled plasma mass spectrometer
mD	millidarcy
MD	measured depth
MDT	Modular Formation Dynamics Tester
Mg	magnesium
MGSC	Midwest Geological Sequestration Consortium
MLS	Minnehakta Limestone
Mn	manganese
MRCSP	Midwest Regional Carbon Sequestration Partnership
MSCT	Mechanical Sidewall Coring Tool
MSh	Morrison Shale
MSU	Montana State University
MVA	monitoring, verification, and accounting
N_2	nitrogen
NAPL	non-aqueous phase liquids
NATCARB	National Carbon Sequestration Database and Geographic Information System
NETL	National Energy Technology Laboratory
NH_2COOH	carbamic acid
NH_3	ammonia
NH_4^+	ammonium
nm	nanometer
NO_x	nitrogen oxides
nrad	nanoradians
OH^-	hydroxide
OPPA	NETL Office of Program Planning and Analysis
O_2	oxygen
Osh	Opeche Shale
P-wave	primary or pressure wave
Pc-S	capillary pressure-saturation
PCA	principal component analysis
PDG	Permanent Downhole Gauges
PI	principal investigator
PNNL	Pacific Northwest National Laboratory
ppmw	parts per million by weight

Acronym or Abbreviation	Definition
Pro-HMS	Probabilistic History Matching Software
PSDM	pre-stack depth-migrated
psi	pounds-force per square inch
psia	pounds-force per square inch absolute
PSTM	pre-stack time-migrated
PV	pore volumes
PVC	polyvinyl chloride
R&D	research and development
Ra	Rayleigh number
RCSP	Regional Carbon Sequestration Partnerships
RF	random function
RMOTC	Rocky Mountain Oilfield Testing Center
RSh	Red Peak Shale
RSU	Rock Springs Uplift
SAR	Synthetic Aperture Radar
SC	Southern Company
$scCO_2$	supercritical carbon dioxide
SCMT	Slim Cement Measurement Tool
SEM	scanning electron microscope/microscopy
SF_6	sulfur hexaflouride
Shell	Shell International Exploration and Production B.V.
SO_2	sulfur dioxide
SO_2OH	hydrated sulfur dioxide
SO_x	sulfur oxides
Sr	strontium
SSh	Sundance Shale
std dev	standard deviation
TOUGH2	Transport Of Unsaturated Groundwater and Heat
TRL	technology readiness level
TVD	true vertical depth
UAB	University of Alabama at Birmingham
VC	volumetric curvature
VIT	vertical isolation test
Vp	P-wave velocity
Vs	S-wave velocity
VSP	vertical seismic profile
WSS	Wall Creek Sandstone
ZERT	Zero Emissions Research and Technology